Ethane-Based Enhanced Oil Recovery: An Innovative and Profitable Enhanced-Oil-Recovery Opportunity for a Low-Price Environment

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Summary

This paper summarizes the current state of the ethane industry in the United States (US) and explores the opportunity for using ethane for enhanced oil recovery (EOR). We show both simulation data and field examples to demonstrate that ethane is an excellent EOR injectant.

After decades of research and field application, the use of carbon dioxide (CO_2) as an EOR injectant has proved to be very successful. However, there are limited supplies of low-cost CO_2 available, and there are also significant drawbacks, especially corrosion, involving its use. The rich gases and volatile oils developed by horizontal drilling and fracturing in the shale reservoirs have brought about an enormous increase in ethane production. Ethane prices have dropped substantially. In the US, ethane is no longer priced as a petrochemical feedstock, but is priced as a fuel. Also, substantial quantities of ethane are currently being flared.

Ethane-based EOR can supplement the very successful CO_2-based EOR industry in the US. There simply is not enough low-cost CO_2 available to undertake all the potential gas EOR projects in the US. The current abundance of low-cost ethane presents a significant opportunity to add new gas EOR projects. The ethane-based EOR opportunity can be summarized as follows:

- CO_2-based EOR works well, and is well-understood.
- Ethane has more solubility in oil, lower minimum miscibility pressures (MMPs), and better solvent efficiency than CO_2.
- Ethane is operationally simpler than CO_2 for EOR.
- Ethane is now inexpensive, and will likely stay inexpensive.
- Ethane-based EOR has become a viable option in the Lower 48 (lower 48 states in US). Large volumes of low-cost ethane are available. Recent additions to the growing ethane infrastructure now deliver ethane to locations where ethane-based EOR targets are plentiful.

Introduction

EOR has been very successfully used in the US for decades. US EOR production has been sustained at roughly 700,000 MBOPD. The most important technology before the 1990s was thermal EOR, mostly cyclic steam and steamdrive in California. Beginning in the 1980s, thermal EOR was supplemented with CO_2 EOR in the Permian Basin and hydrocarbon water-alternating-gas (WAG) in Alaska. As shown in **Fig. 1,** thermal EOR is a mature technology with slowly declining production rates. During the same time span, gas EOR has continued to increase in both absolute rates (left figure) and in the fraction of EOR in the US (right figure), and in 2014 accounted for more than 60% of the US EOR production.

Although oil-rate forecasting is by no means exact, the EOR production from US CO_2 projects is forecast to increase substantially **(Fig. 2).** The absolute numbers in the forecast may not be correct, but the trend of increasing CO_2 EOR production is clear. New CO_2 EOR projects are under way in Wyoming, Kansas, Oklahoma, Texas, and Louisiana. CO_2 EOR onshore is a very successful, very mature technology, and the risks are low.

The magnitude of the CO_2 EOR potential in the US is tens of billions of additional barrels of recovery. Most of this potential is in old onshore fields in the Lower 48, where costs are relatively low and the geology is well-understood. The US Department of Energy (DOE) report on "Next Generation" CO_2 EOR (shown in **Table 1**) estimated that the economic-recovery potential of CO_2 EOR in the Lower 48 onshore is 60 billion bbl [2012 Advanced Resources International (ARI 2012) update of DOE/NETL-2011/1504].

CO_2 Supply

Extensive experience in designing and evaluating EOR projects around the world has made one thing extremely clear: Successful EOR projects are always based on the economical availability of the appropriate EOR injectants. Good EOR targets exist almost everywhere, but the limiting factor is the availability of an appropriate EOR injectant at an acceptable cost. The biggest obstacle for the huge CO_2 EOR reserves in Table 1 was cited as the need for an additional 25 billion t (475 Tcf) of relatively low-cost CO_2. Currently, available CO_2 supplies were estimated at 2.3 billion t (44 Tcf). This represents a tenfold increase in the need for low-cost CO_2 supplies.

Fig. 3 shows the existing CO_2 EOR infrastructure in the US. With one exception, the major natural sources of CO_2 have all been developed. The St. Johns CO_2 field on the Arizona/New Mexico border was expected to provide 1.3 Tcf of CO_2 at a total project cost of USD 982 million (Brock 2014). In January 2015, the project was deferred, and the right-of-way application was withdrawn (Arenivas 2015). The remaining undeveloped natural CO_2 sources all appear to be much smaller than St. Johns. In addition, the "easy" industrial sources have almost all been developed. These "easy" sources, those that emit concentrated CO_2, include methane reformers, ethanol plants, and ammonia/fertilizer plants that are near good CO_2 EOR targets.

CO_2 EOR injection rates are currently approximately 3.2 Bscf/D (60 million t/a), with increasing volumes from the Gulf Coast and Wyoming. This will be nowhere near enough to supply the CO_2 demand laid out in Table 1. **Fig. 4** shows a schematic of the existing supply and remaining demand for low-cost CO_2 (Hill 2013). The dashed line is the CO_2 required to implement the CO_2 projects on which the EOR reserves of Table 1 are based. The brown and green regions give the CO_2 rates from currently available sources.

If natural CO_2 sources and "easy" industrial sources will be insufficient, where will the CO_2 come from to satisfy the remaining CO_2 demand? One possibility is carbon capture from coal-fired power plants. The DOE Carbon Capture, Utilization, and Storage (CCUS) Demonstration Projects have received billions of dollars of subsidies to commercialize the capture of CO_2 from coal-fired power plants. **Fig. 5** from the DOE (Middleton 2014) shows the demonstration projects. The figure includes the

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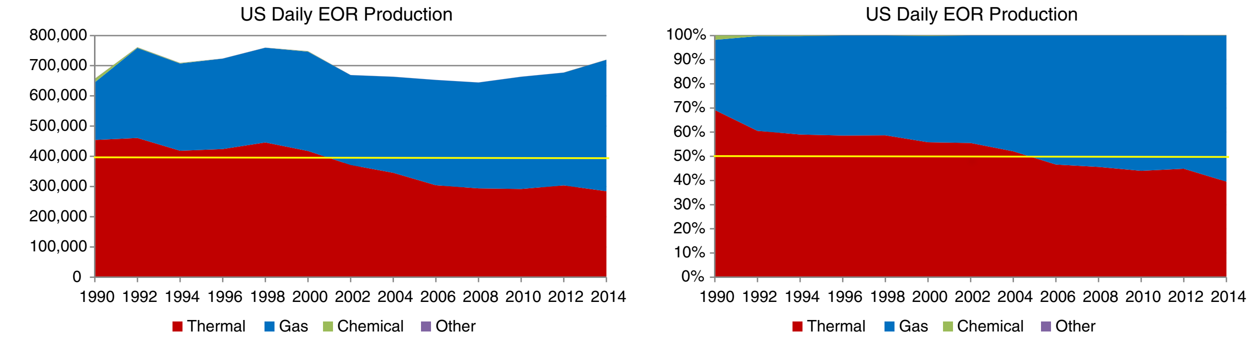

Fig. 1—United States EOR production (*The Oil and Gas Journal* 2014 EOR survey).

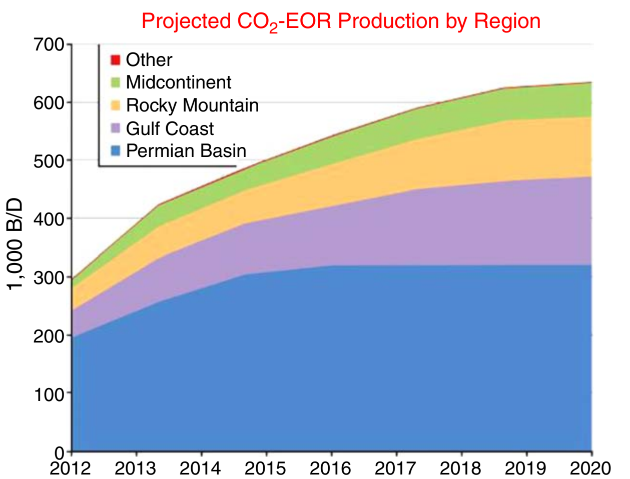

Fig. 2—CO_2 EOR forecast (ARI adjustment to *The Oil and Gas Journal* 2014 EOR survey).

approved estimated-construction cost. The status of these CCUS projects and the currently estimated costs for those projects now under construction have been added in red. The actual costs are proving to be, on average, more than twice as high as initially estimated. Barring any change of technology, CO_2 capture from coal plants will not be able to supply much of the remaining low-cost CO_2 demand shown in Fig. 4.

Ethane as a Supplement to CO_2

Decades of research and dozens of field applications have proved that CO_2 EOR works very well. However, most economic sources of CO_2 are already on line, and developing substantial volumes of additional CO_2 supply will be difficult. The US could really use ≈300 Tcf of "something that works" to recover some of the potential CO_2 EOR reserves. What else is there besides CO_2 that would work? One answer to this question can be found in **Fig. 6** (Verma 2015), which shows the US EOR production by recovery mechanism. The blue wedge is EOR from both miscible and immiscible hydrocarbon-gas injection, virtually all which is on the North Slope of Alaska. Similar to CO_2 EOR, the engineering and economic issues and opportunities of hydrocarbon-gas EOR are well-understood and have been proved by decades of research and field experience. The Alaskan EOR experience is different from the Lower 48 because there has been no market for North Slope gas, and the operators could take advantage of enriched-gas injection. The conventional wisdom has been that hydrocarbon-gas EOR is too expensive in the Lower 48 because natural-gas prices are too high.

The North Slope projects have injected methane that has been enriched with ethane, propane, and butane. Some of the projects also use CO_2 (the Prudhoe Bay Field and east), whereas some do not (the Kuparuk River Field and west). The Prudhoe Bay Miscible Gas Project (PBMGP) makes an interesting case study. It is the world's largest enriched gas flood, with an ultimate EOR expected to range between 400 and 500 million STB (Cockin 1993).

A typical Prudhoe Bay miscible-injectant (MI) composition contains roughly 20 mol% CO_2 and 20 mol% ethane, as shown in **Fig. 7** (McGuire et al. 2005). Slimtube simulations [using 100 cells in a finite-difference model with the Peng-Robinson (1978) equation of state (EOS) (Zick 2016)] show that the MI is miscible at the average reservoir pressure of 3,600 psi, whereas the CO_2 is clearly immiscible. In this system, the CO_2 is a carrier gas, and the miscibility is provided by the ethane and propane.

Experimental work was carried out in the 1990s to investigate ethane and CO_2 as EOR injectants for the viscous oil in the West

	Oil Recovery*** (Billion Barrels)		CO_2 Demand/Storage*** (Billion Metric Tons)	
Reservoir Setting	Technical	Economic**	Technical	Economic**
L-48 Onshore	104	60	32	17
L-48 Offshore/Alaska	15	7	6	3
Near-Miscible CO_2-EOR	1	*	1	*
ROZ (below fields)****	16	13	7	5
Subtotal	136	80	46	25
Additional From ROZ "Fairways"	40	20	16	8

*The values for economically recoverable oil and economic CO_2 demand (storage) represent an update to the numbers in the NETL/ARI report "Improving Domestic Energy Security and Lowering CO_2 Emissions with 'Next Generation' CO_2-Enhanced Oil Recovery (CO_2-EOR)" (June 1, 2011).
**At USD 85 /bbl oil price and USD 40 t CO_2 market price with ROR of 20% (before tax).
***Includes 2.6 billion bbl already being produced or being developed with miscible CO_2-EOR and 2300 million t of CO_2 use from natural sources and gas.

Table 1—Potential of "Next generation" CO_2 EOR.

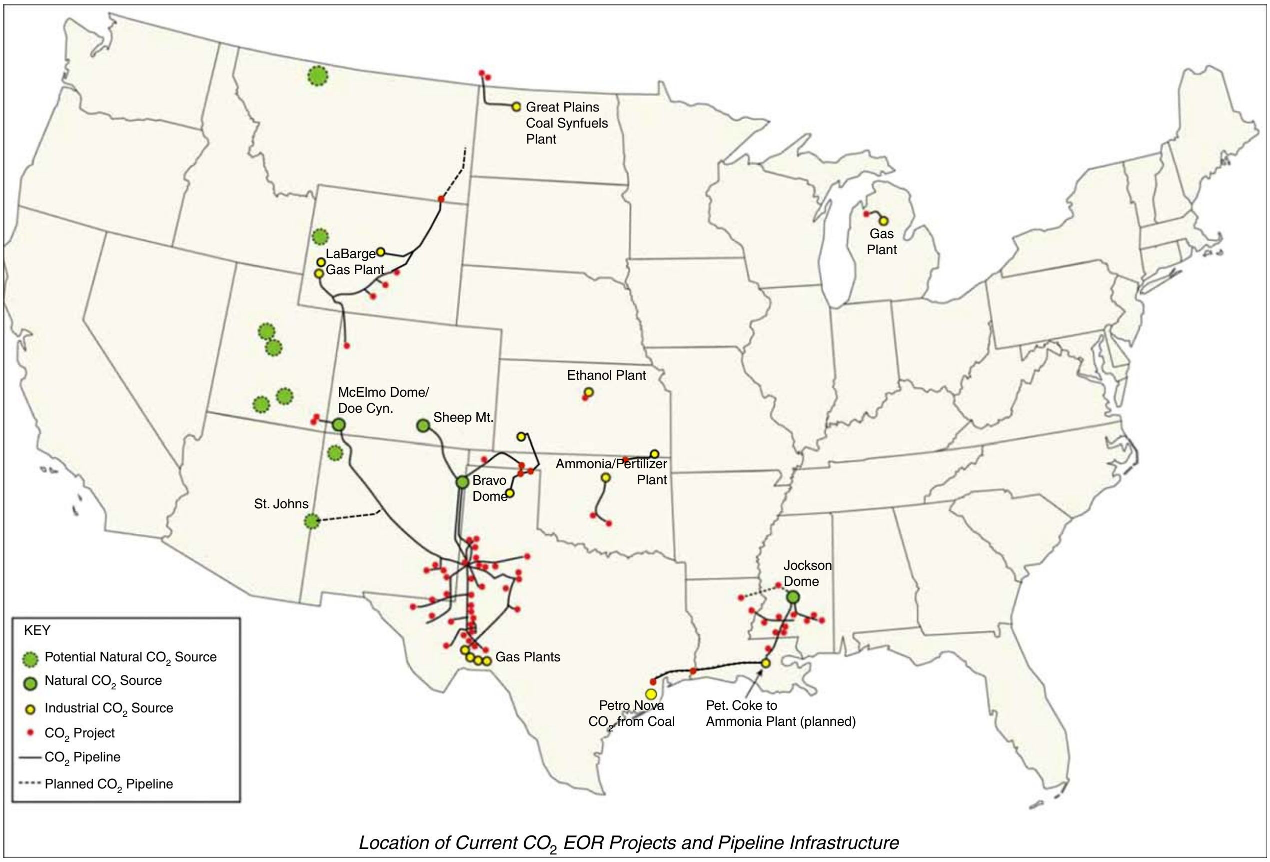

Fig. 3—CO_2 EOR infrastructure in the US (updated from DOE).

Sak Field. Both pressure/volume/temperature (PVT) cell studies and slimtube floods were conducted with an 18.5°API West Sak crude oil at 65°F (DeRuiter et al. 1994). The difference in behavior between ethane and CO_2 with this oil (shown in **Fig. 8**) was striking. The gas solubility and viscosity reduction of ethane were much greater than those of CO_2. As stated by Sharma (1990), "STD [slimtube displacement] results and EOS predictions indicate that CO_2 was unable to develop dynamic miscibility with West Sak crude at reservoir pressure and temperature conditions." Ethane was miscible with the West Sak oil at 600 psi (DeRuiter et al. 1994), whereas CO_2 failed to achieve miscibility even at pressures as high as 6,600 psi (Sharma et al. 1989). In this viscous-oil system, liquid ethane is far more effective as an EOR injectant than liquid CO_2.

The superiority of ethane as an EOR injectant, either in terms of solubility, swelling, and viscosity reduction or in terms of developing multiple-contact miscibility, is illustrated in **Fig. 9.** Ethane and CO_2 have almost identical critical temperatures (≈90°F), whereas the critical pressure of CO_2 is roughly 50% higher than that of ethane. To achieve a similar liquid-like state in the reservoir, CO_2 will require a substantially higher reservoir pressure. This has major implications for shallow, low-pressure reservoirs, and for deep, hot reservoirs such as those at Prudhoe Bay. Ethane may have a lower density than CO_2 in the reservoir (see Fig. 9), which could affect gravity override and impact vertical-sweep efficiency.

Additional comparisons between ethane and CO_2 injectant were made with 11 oils that had a Peng-Robinson EOS that had been calibrated with CO_2 experimental data (Peng and Robinson 1976; Kumar and Okuno 2016). PennPVT (Ahmadi and Johns 2011) was used in these miscibility calculations. It proved to be very difficult to use analytical methods to determine the MMP of pure CO_2 or pure ethane for these comparisons. Most of the oils were from low-temperature reservoirs in the Permian Basin, and tended to form a solvent-rich upper liquid phase with high concentrations of CO_2 or ethane. Diluting the CO_2 or ethane with

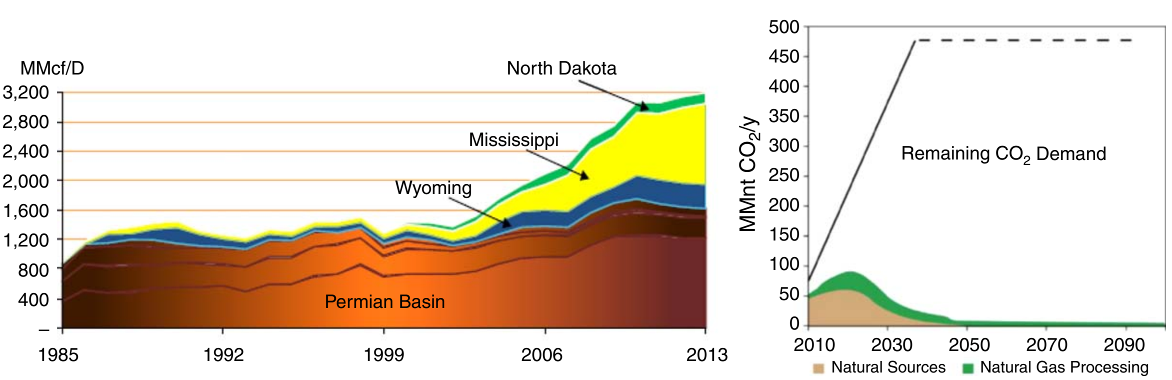

Fig. 4—CO_2 production (Brock 2014) and demand (ARI, CCUS, EPRI Cost Workshop, April 25–26, 2012).

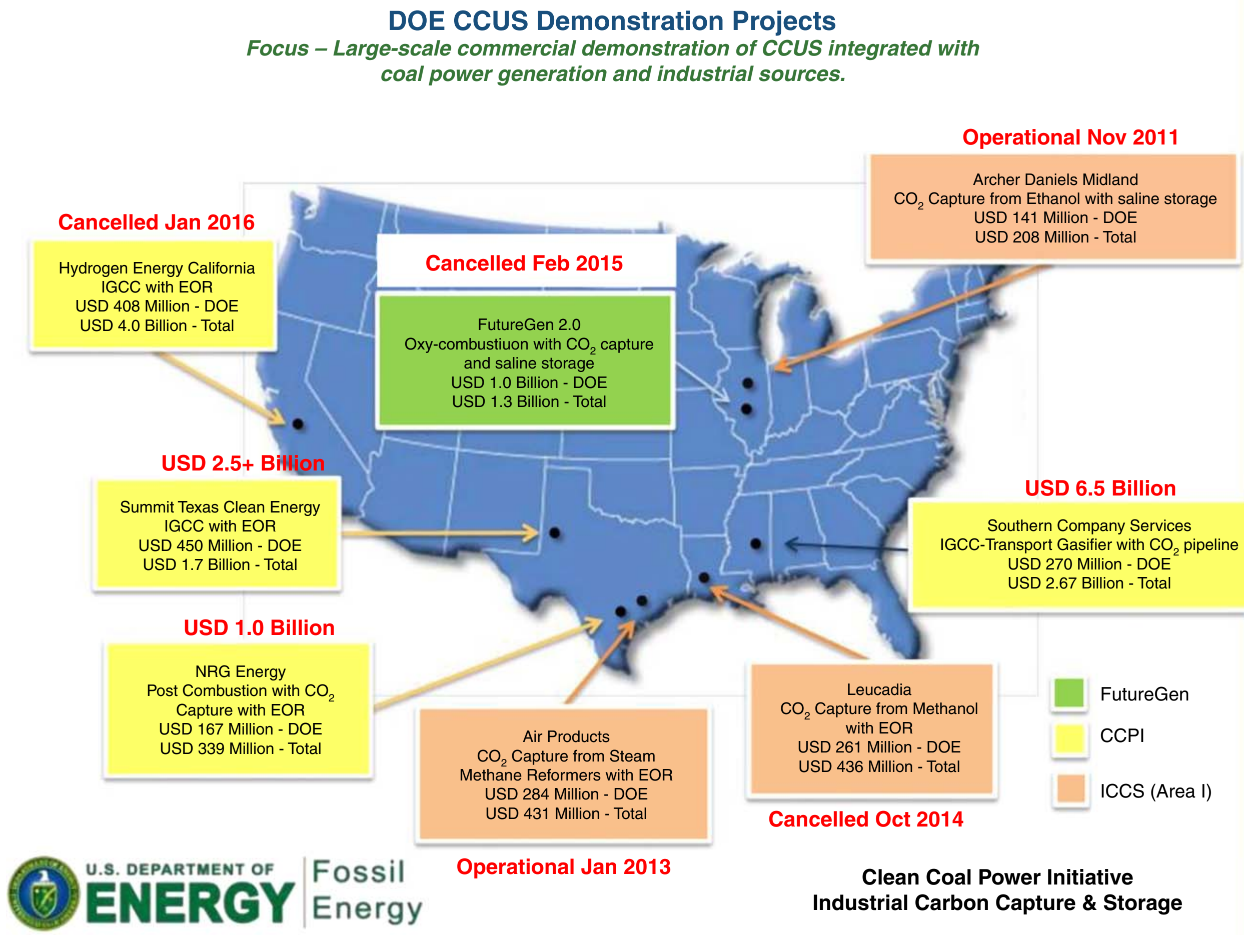

Fig. 5—Current status of DOE Carbon Capture, Utilization, and Storage demonstration Projects.

sufficient methane avoided the three-phase region and made the solutions stable. Stable solutions with some of the oils were found with 50, 75, and 90% enriching component, with the remainder being methane. On average, the 75% ethane MMP was approximately 27% of the 100% methane MMP. The CO_2 MMP at the same dilution was approximately 38% of the 100% methane MMP. The 75% ethane MMP was approximately 60% of the CO_2 MMP at the same dilution. The MMP data for the 11 oils are shown in **Table 2.** It should be noted that there is significant uncertainty in EOS-calculated MMPs, and consistent sets of ethane and CO_2 swell experiments and slimtube experiments should be run to design actual gas EOR projects.

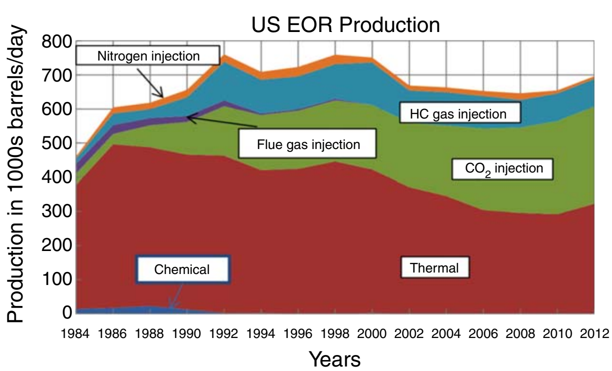

Fig. 6—US EOR oil production with various EOR methods.

Ethane WAG vs. CO_2 WAG Operational Issues

There are numerous challenges in the widespread implementation of CO_2 flooding. The most significant issue has been that of corrosion. This has been a problem in surface facilities, pipelines, injection wells, and production wells. Examples of this corrosion are shown in **Fig. 10.** The problems are well-understood, and successful mitigation strategies have been developed [American Petroleum Institute (API) recommendations for CO_2-injection wells (Meyer 2007) are shown in **Table 3**].

The following description by Meyer of the experience at the SACROC CO_2 flood is an excellent summary of the problems encountered and how they have been overcome. *Meter runs, initially constructed of plastic-coated carbon-steel piping and valves with plastic-coated carbon-steel bodies with 316 SS trim, were subject to severe corrosion at any point of coating damage, particularly at flange faces. Where 316 SS was used, no corrosion was observed. Meter runs are now constructed entirely of 316 SS pipe and valving. Initially, injection wellheads were equipped with 410 SS wellheads and 410 SS valves. They were subject to severe pitting-type corrosion that occurred primarily under deposits from settled suspended matter contained in the injection water. Plastic coating the 410 SS wellheads and valve bodies and changing the gates and seats to 316 SS prolonged the life of many of the wellheads. A replacement program using all 316 SS wellheads was eventually undertaken. Injection wells were initially equipped using primarily 2-7/8 in. and 2-3/8 in. J-55 plastic-coated tubing set on plastic-coated double-set packers. The plastic coating used was a thin-film epoxy modified phenolic type. Up to 25% of the injection wells had tubing pulled and inspected each year due to tubing leaks or for workover purposes. The*

COMP.	Mol. Wt	SPE 93914 MI	Pure CO_2	Pure ethane
N_2	28.01	0.13%	0.00%	0.00%
CO_2	44.01	19.84%	100.00%	0.00%
C_1	16.04	33.70%	0.00%	0.00%
C_2	30.07	19.46%	0.00%	100.00%
C_3	44.10	23.53%	0.00%	0.00%
IC_4	58.12	1.68%	0.00%	0.00%
NC_4	58.12	1.65%	0.00%	0.00%
IC_5	72.15	0.00%	0.00%	0.00%
NC_5	72.15	0.00%	0.00%	0.00%
C_6	86.18	0.01%	0.00%	0.00%
Total Models		100.00%	100.00%	100.00%
	MPP	~3500	~5000	~2500

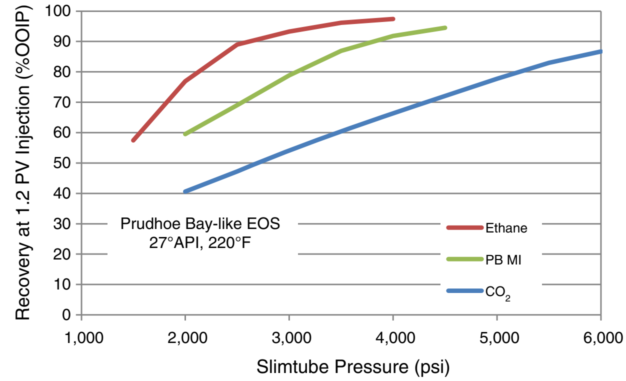

Fig. 7—Slimtube simulations of ethane and CO_2 at Prudhoe Bay conditions.

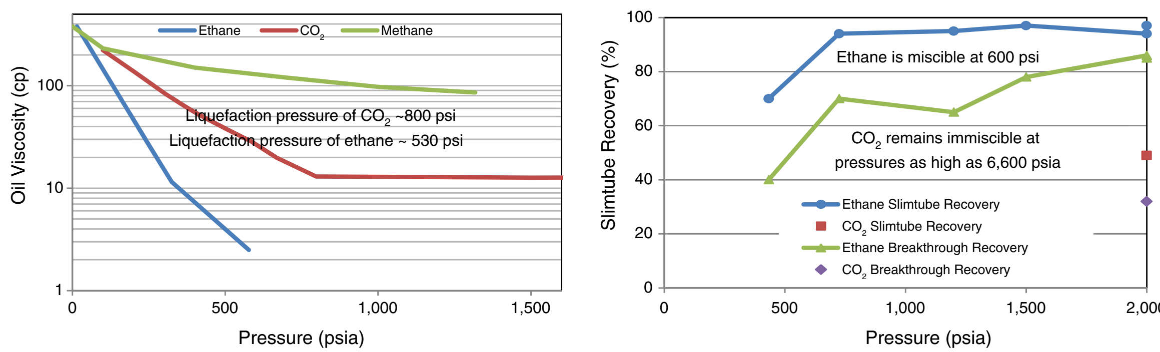

Fig. 8—Viscosity reduction and slimtube recovery with 18.5°API West Sak oil at 65°F.

primary cause of failure was identified as mechanical damage occurring during hauling, running, and pulling of the tubing. Handling and installation procedures were modified to circumvent these problems. Powder applied epoxy-phenolics, 8–16 mil in thickness, exhibited improved resistance to mechanical damage and was not subject to blistering. Tubing with this coating is now in use.

Ethane is noncorrosive, and, by dilution, should act to reduce the partial pressure and corrosivity of any acid-gas components that may be present in the waterflood-produced fluids. There are no foreseen additional metallurgical requirements to implement ethane WAG injection. However, ethane, an excellent solvent, will affect lube oils, greases, thread sealants, and O-ring and valve-packing elastomers in a manner similar to CO_2. As with any gas-injection project, tubing-collar leaks could be a problem with ethane injection. New or reconditioned tubing with premium threads and an ethane-resistant thread compound may be warranted. The advantages of ethane WAG over CO_2 WAG will be particularly important in areas with limited-corrosion problems where the produced oil is sweet.

An additional advantage of ethane over CO_2 is the dramatically smaller solubility in water. CO_2 is approximately 20 times as soluble in water as is ethane (shown in **Fig. 11**). In addition to increased corrosivity, the "parasitic losses" of CO_2 to the large volumes of water contacted in a mature waterflood will significantly increase the volume of CO_2 required for a WAG flood. A

	C_2H_6	CO_2	
Molecular Weight	30.07	44.01	lb/lb-mole
Critical temperature	89.9	87.8	°F
Critical pressure	707	1071	psia
Critical density	12.9	29.1	lb/ft³

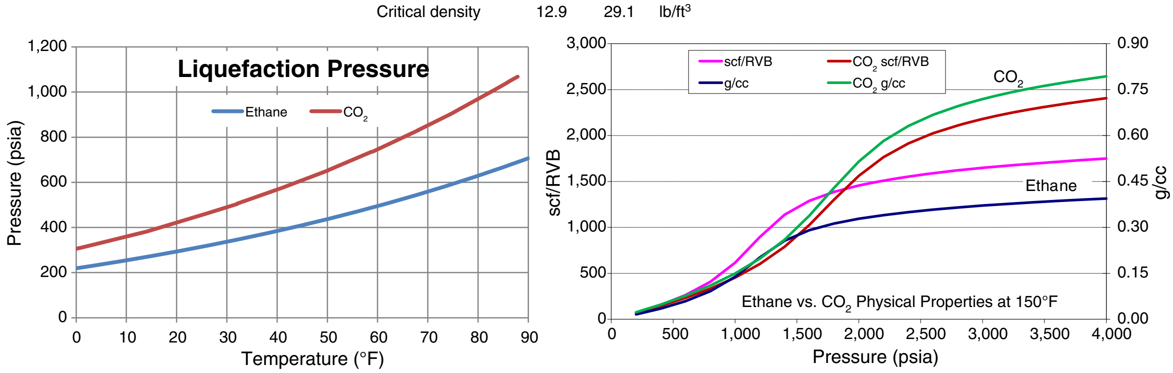

Fig. 9—Ethane and CO_2 critical properties, liquefaction pressure, and physical properties at 150°F.

	Rangely	Oil G-CS	Oil B-S & Y	Oil JEMA	Oil NWE	Oil BSB	Oil D	Oil C_2	Oil B_2	Oil B_1	West Sak	
°F	160	94	94	110	83	105	105	105	106	106	80	
C_5 + MWT	208	191	213	218	206	207	234	212	215	208	368	
°API (by correlation)	32.1	35.3	31.2	30.4	32.3	32.2	28.0	31.3	30.8	32.0	16.6	
	MMP, psia	MMP, psia	MMP, psia	MMP, psia	MMP, psia	MMP, psia	MMP, psia	MMP, psia	MMP, psia	MMP, psia	MMP, psia	Average
C_1	11,518	3,389	7,869	4,081	5,236	4,059	6,975	4,700	5,268	4,786	15,808	6,699
C_1+CO_2(50:50)	5,608	2,063	3,022	2,446	2,340	2,407	3,228	2,546	2,691	2,529	7,457	3,303
C_1+CO_2(25:75)	4,099	1,675	1,929	1,846	1,588	1,710	2,057	1,747	1,792	1,822	7,612	2,534
C_1+CO_2(10:90)	3,369	1,255	1,534	1,352	1,284	1,362	1,640	1,340	1,433	1,349	8,000	2,174
100% CO_2	2,024	-	-	-	-	-	1,370	-	-	1,515	8,248	
C_1+C_2(50:50)	4,318	1,672	2,682	2,068	1,928	2,197	3,046	2,193	2,187	2,281	3,851	2,584
C_1+C_2(25:75)	2,748	974	1,423	1,486	1,265	1,652	1,618	1,405	1,275	1,660	1,995	1,591
C_1+C_2(10:90)	2,021	806	975	1,120	804	842	-	-	912	1,157	1,156	1,088
100% C_2	1,112	-	-	-	-	-	-	-	-	-	-	
C_1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
C_1+CO_2(50:50)	49%	61%	38%	60%	45%	59%	46%	54%	51%	53%	47%	51%
C_1+CO_2(25:75)	36%	49%	25%	45%	30%	42%	29%	37%	34%	38%	48%	38%
C_1+CO_2(10:90)	29%	37%	19%	33%	25%	34%	24%	29%	27%	28%	51%	30%
100% CO_2	18%						20%			32%	52%	
C_1+C_2(50:50)	37%	49%	34%	51%	37%	54%	44%	47%	42%	48%	24%	42%
C_1+C_2(25:75)	24%	29%	18%	36%	24%	41%	23%	30%	24%	35%	13%	27%
C_1+C_2(10:90)	18%	24%	12%	27%	15%	21%			17%	24%	7%	18%
100% C_2	10%											

Table 2—MMP of C_2 and CO_2 mixtures with C_1 using 11 different CO_2-calibrated EOSs.

CO_2 trapping study (Kuuskraa 2004) of a representative reservoir (1,900 psi, 102°F, 10% porosity, 90 Ft net pay, 30,000 ppm brine) showed that more than 2 Bscf of CO_2 per square mile was trapped by being dissolved in the reservoir brine at a solubility of 140 scf CO_2 per bbl. Ethane will not see the solution trapping associated with CO_2, and as a result, there is a large economic benefit for comparable ethane EOR projects.

A final advantage of ethane over CO_2 is that the produced gas from an ethane WAG flood will have intrinsic value as sales gas or fuel, and no acid-gas removal plant would be required, either for gas sales or for gas reinjection. High-GOR fields before significant ethane breakthrough could produce lean gas that is too diluted with methane to make recycle desirable. The gas could continue to be sold or burned for fuel until the gas C_{2+} mole fraction becomes high enough to be a good injectant. Eventually, returned ethane will overwhelm the solution gas production.

Ethane Cost and Availability

The conventional wisdom has been that hydrocarbon WAG works well in Alaska but not in the Lower 48. In general, methane is ineffective as a WAG injectant, whereas ethane and propane are too expensive to inject. Indeed, this perception has been true for decades. However, this perception is no longer true. The "shale revolution" in the US has created a major EOR opportunity for using low-cost ethane in both miscible and immiscible WAG projects. Ethane prices have dropped substantially because of this increased production **(Fig. 12).** In the US, ethane is no longer

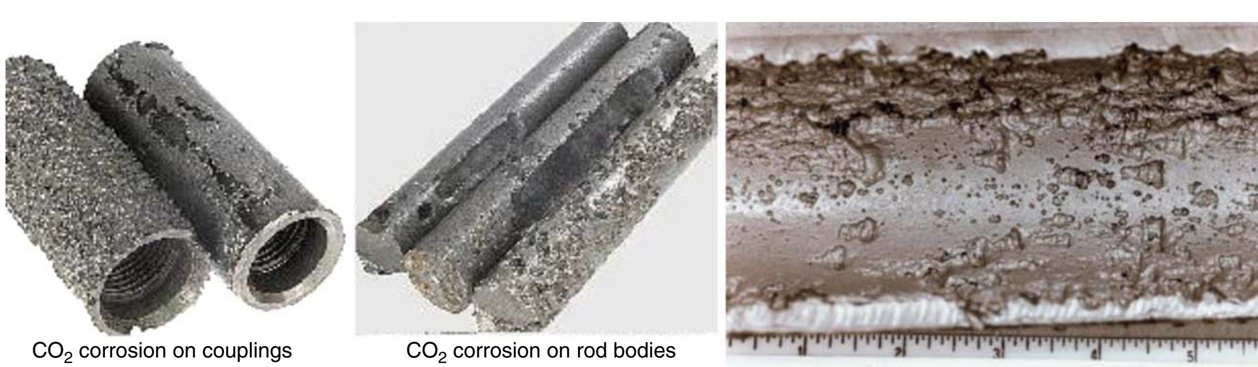

Fig. 10—Examples of CO_2-induced corrosion (Norris 2016; Himipex Oil Company 2016).

Materials of Construction (MOC) for CO_2 Injection Wells

Component	MOC
Upstream Metering and Piping Runs	316 SS, Fiberglass
Tree (Trim)	316 SS, Nickel, Monel
Valve Packing and Seals	Teflon, Nylon
Wellhead (Trim)	316 SS, Nickel, Monel
Tubing Hanger	316 SS, Incoloy,
Tubing	GRE-lined carbon steel, IPC carbon steel, CRA
Tubing-Joint Seals	Seal ring (GRE), coated threads and collars (IPC)
ON/OFF Tool, Profile Nipple	Nickel-plated wetted parts, 316 SS
Packers	Internally coated hardened rubber of 80–90 durometer strength (Buna-N), nickel-plated wetted parts
Cements and Cement Additives	API cements and/or acid-resistant specialty cements and additives

Table 3—API recommended materials for CO_2 injectors.

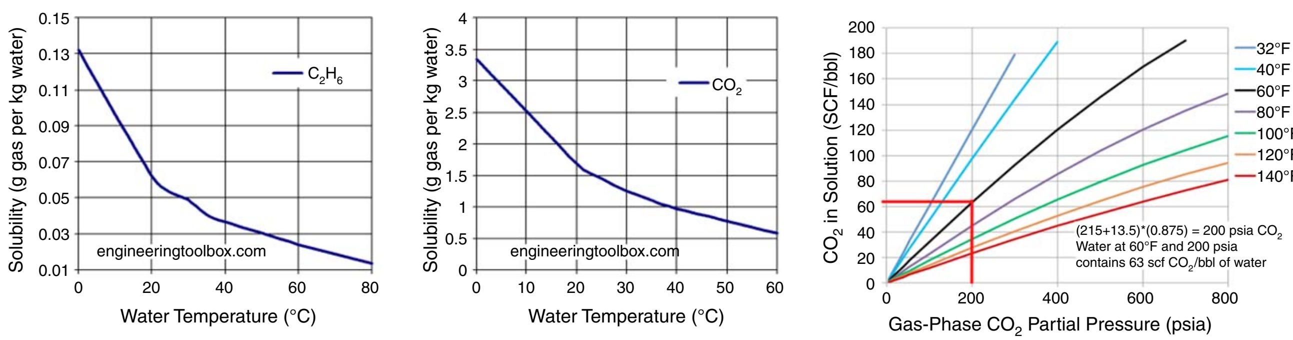

Fig. 11—Solubility of ethane and CO_2 in water (Engineering Toolbox 2016; PetroSkills 2016).

priced as a petrochemical feedstock, but is priced as fuel. Burning ethane as fuel is not optimal from an environmental viewpoint. The carbon/hydrogen ratio of ethane is higher than that of methane, and ethane releases approximately 13% more CO_2 per Btu of fuel energy (Kolodziej 2013). Because of higher flame temperatures, NO*x* emissions are also higher for fuels containing ethane (Goldmeer et al. 2015).

The price of ethane for the week ending 1 January 2016, was USD 0.153 per gallon, which is USD 2.33 per million Btu, or USD 4.15 per Mscf. Wellhead prices for ethane in many areas are far lower than the spot prices listed previously. Propane remains far more expensive than ethane on a Btu basis, as shown in **Fig. 13.** The enriching agent of choice at this time is clearly ethane.

Although forecasting the ethane price is risky, it appears likely that the prices will remain low for a long time. The ethane supply is being driven by light oil and rich gas production from the shale reservoirs, and this light-oil production, with its associated ethane, is forecast to increase substantially [see Bakken gas-production forecast in **Fig. 14** (Zhang 2015) and typical Bakken gas composition (Wocken et al. 2013) in **Table 4**]. Additional planned

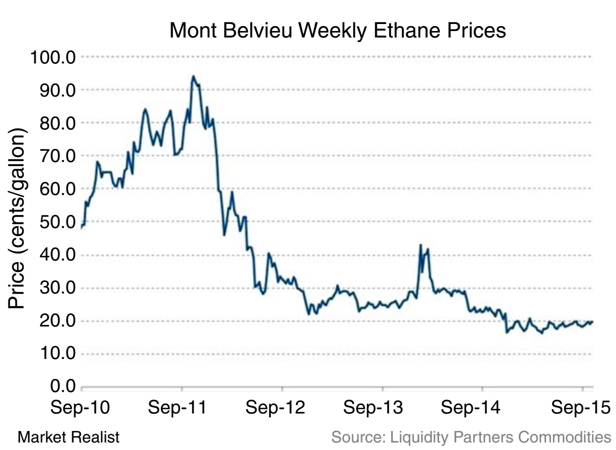

Fig. 12—Ethane-price history in the US.

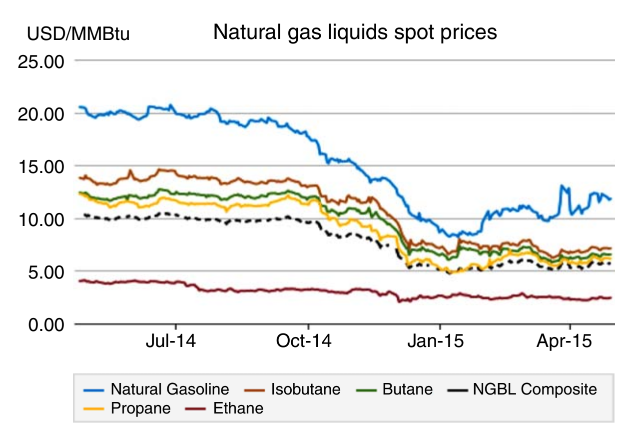

Fig. 13—Recent liquefied-petroleum-gas component prices (Energy Information Agency 2015).

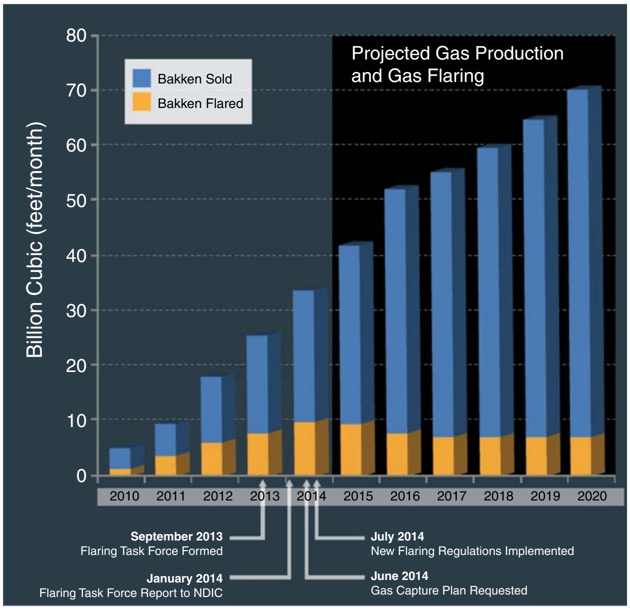

Fig. 14—Bakken gas-supply forecast.

Component	mol%
H_2O (water)	0.02
N_2 (nitrogen)	5.21
CO_2 (carbon dioxide)	0.57
H_2S (hydrogen sulfide)	0.01
C1 (methane)	57.67
C2 (ethane)	19.94
C3 (propane)	11.33
I-C4 (isobutane)	0.97
N-C4 (*n*-butane)	2.83
I-C5 (isopentane)	0.38
N-C5 (*n*-pentane)	0.55
C6 (hexane)	0.22
C7	0.09
C8	0.04
C9	0.01
C10-C11	0.00
C12-C15	0.00

Table 4—Typical Bakken gas composition.

ethylene plants and ethane exports do not appear to be enough to end the ethane surplus from this increasing ethane supply.

Ethane EOR Opportunities

In recent years, an extensive ethane infrastructure has been built in the US. This includes ethane pipelines and natural-gas-liquids (NGL) pipelines from ethane-rich shale plays such as the Bakken, the Eagle Ford, and the Marcellus/Utica (see **Fig. 15**). This has opened up ethane EOR opportunities either in areas that do not have sufficient CO_2 available to address the huge EOR targets in Table 1 or in fields that are not appropriate for CO_2 WAG. We will conclude with three examples of different types of ethane EOR targets: one field in Illinois, one field in Oklahoma, and one field in Texas. These evaluations will focus on WAG-

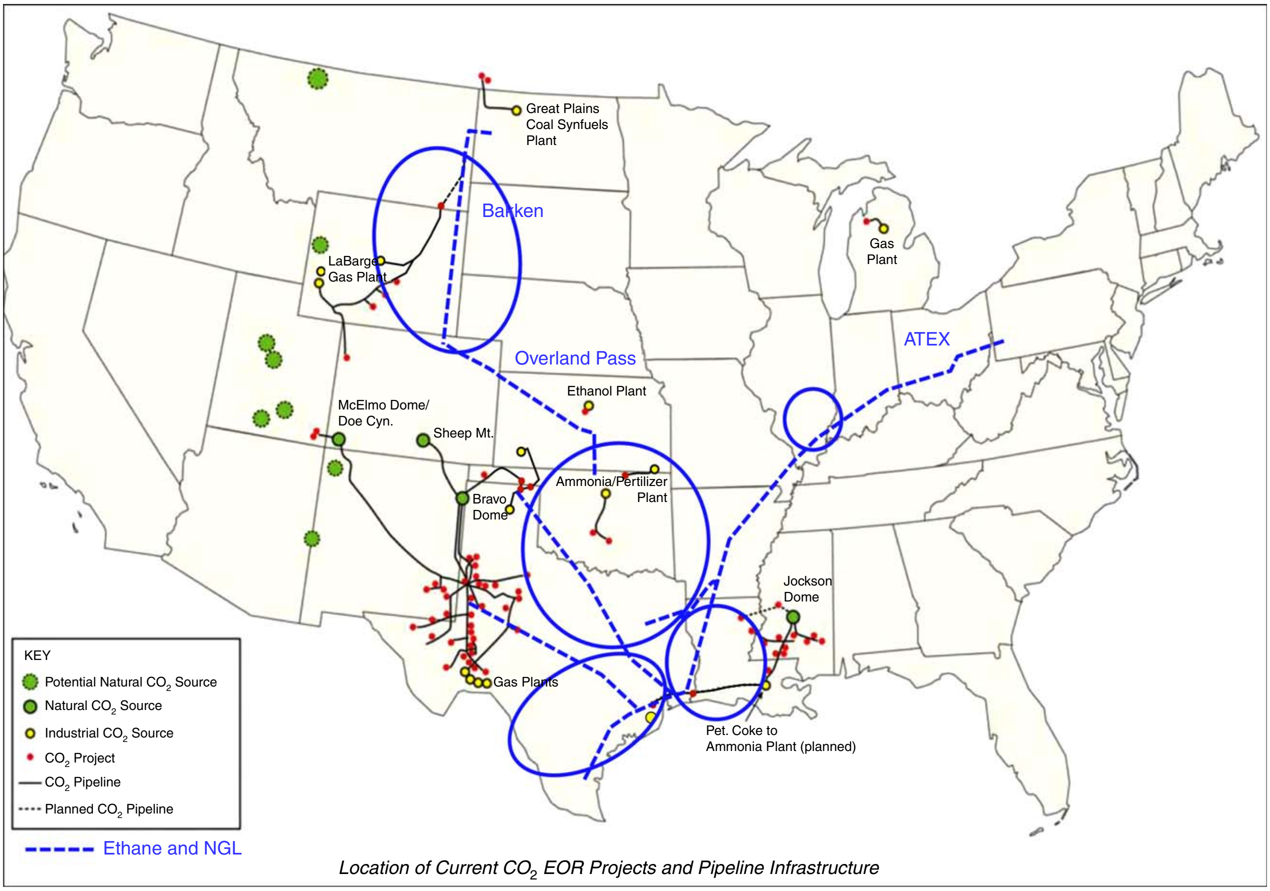

Fig. 15—Ethane pipelines or key NGL pipelines, and areas of high-ethane EOR potential.

Lawrence Field		Bridgeport	Cypress
Depth	ft	950	1,600
Oil Gravity	°API	34	34
Pressure	psia	Pi≈400	Pi≈650
Temperature	°F	71	80
Permeability	md	20–1000+	76
Net Pay	ft	71	54
Residual Oil Saturation	%	30	30
Oil Viscosity	cp	11	8
Water Cut	%	98+	98+

Table 5—Lawrence Field properties.

displacement efficiency and miscibility in the reservoir, with a commercial simulator, and are not intended to accurately represent the reservoir geology or sweep efficiency.

Lawrence Field. A very promising target for ethane EOR is the Illinois Basin. In 2005, the DOE identified a target of 370 million STB EOR from the largest fields in the Illinois Basin under their "Moderate Oil Price/High CO_2 Cost Scenario" (ARI 2005). No viable source of CO_2 currently exists to develop these reserves. The largest field in the basin is the Lawrence Field [1.05 billion STB original oil in place (OOIP)], which was discovered in 1906. Cumulative oil recovery is just under 40% OOIP. The Lawrence Field has two active alkaline–surfactant–polymer (ASP) pilots under way—one in the shallower Bridgeport interval and one in the deeper Cypress interval. The properties of the Lawrence Field at the ASP pilot locations are shown in **Table 5** (Rex Energy 2008; Dean 2011). The Lawrence Field is approximately 20 miles north of the Princeton, Indiana, terminal of the ATEX ethane pipeline (see Fig. 15).

One obvious issue for a WAG project in the Bridgeport interval is the shallow depth of the reservoir. At a depth of 950 ft, a safe injection pressure will be perhaps no more than 700 psi. Slimtube simulations (with 100 cells in a finite-difference model) were run to determine the MMP of both ethane and CO_2 in the Lawrence Field (see **Fig. 16**). An EOS model for the Lawrence Field was not available, so the CO_2-calibrated 32°API NWE oil with a temperature of 83°F was used as a proxy. The oil composition was adjusted to 34°API, and the Bridgeport and Cypress reservoir temperatures of 71 and 80°F, respectively, were used. The MMP for ethane in the Bridgeport was just under 600 psi, whereas the MMP for CO_2 was approximately 950 psi.

A quarter-five-spot model of the Bridgeport was built with the SPE3 Comparative Solution Project Problem, which was a $9 \times 9 \times 4$-layer gas cycling and blowdown problem. Reasonable estimates of the depth, initial pressure, reservoir thickness, well spacing, fluid composition, average porosity, and average permeability from the Lawrence Bridgeport were used in the model. The 10-acre spacing base model was waterflooded for 20 years (7,305 days). For the ethane evaluation, the model was placed on waterflood for 4,000 days, and then 12 WAG cycles of ethane and water were injected at 700 psi. A similar procedure was followed to inject 12 WAG cycles of CO_2, and to inject 12 cycles of methane. In these models, CO_2 and ethane had the same relative permeability (gas-like).

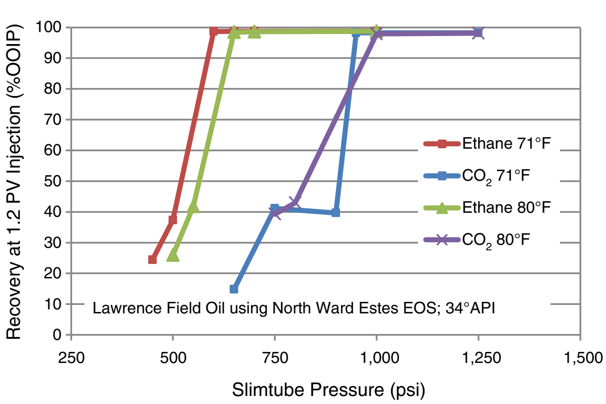

Fig. 16—Slimtube simulations of Lawrence Field.

The cumulative recoveries in %OOIP from the waterflood (WF), the ethane WAG, the CO_2 WAG, and the methane WAG are shown in **Table 6.** The ethane WAG recovered an additional 11.8% OOIP at a gross efficiency of 1.8 Mscf of ethane per STB EOR. The net efficiency (including gas recycle) was a very attractive 0.9 Mscf ethane per STB EOR. The results of the pattern model waterflood and ethane WAG simulations are shown in **Fig. 17.** The CO_2 WAG recovered an additional 3.2% OOIP at a gross efficiency of 7.3 Mscf of CO_2 per STB EOR. Net efficiency was 3.7 Mscf of CO_2 per STB EOR As expected, the methane WAG recovered no additional oil.

A comparison between the ethane WAG and the CO_2 WAG is shown in **Fig. 18.** Oil-saturation maps and oil-viscosity maps from the ethane and CO_2 WAG runs are shown in **Fig. 19.** The ethane WAG was miscible and reduced the oil viscosity by a factor of ten. The CO_2 WAG was not miscible, and reduced the oil viscosity by approximately half.

Cushing Field. A second very promising target for ethane EOR is the midcontinent area. In 2005, the US DOE identified a target of 2,890 million STB EOR from the largest fields in Oklahoma under their "Moderate Oil Price/High CO_2 Cost" Scenario (ARI 2005a, b). Most of the available CO_2 in Oklahoma from industrial sources has already been developed, and several CO_2 floods are already operating. **Table 7** lists Oklahoma fields with more than one-billion barrels of remaining OIP, whereas **Fig. 20** shows the location of these large fields (ARI 2005a, b). No viable source of CO_2 currently exists to develop the potential CO_2 EOR reserves from these fields, although there is a small CO_2 flood under way in Sho-Vel-Tum. The Glenn Pool Field, like the Lawrence Field, is too shallow for CO_2 flooding. The other fields have excellent reservoir properties for CO_2 WAG.

Process	Recovery
WF	36.4
C_2 WAG	48.2
CO_2 WAG	39.4
C_1 WAG	36.2

Table 6—Bridgeport EOR.

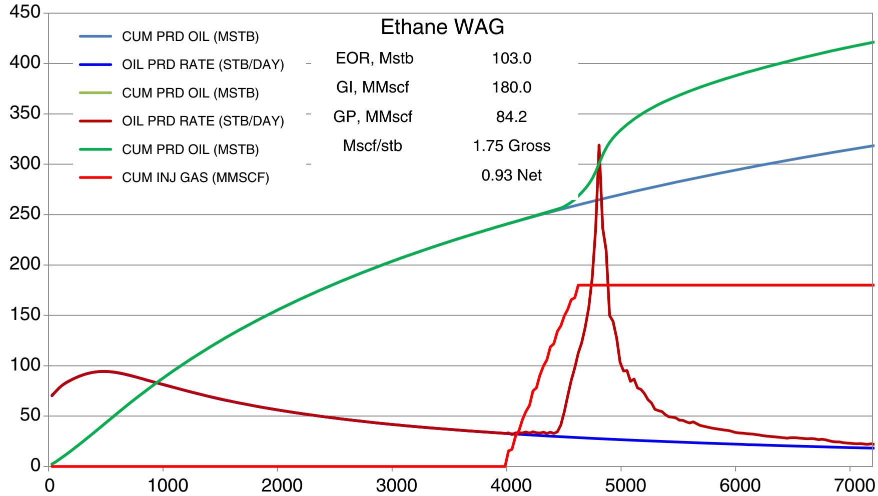

Fig. 17—Bridgeport waterflood and ethane WAG.

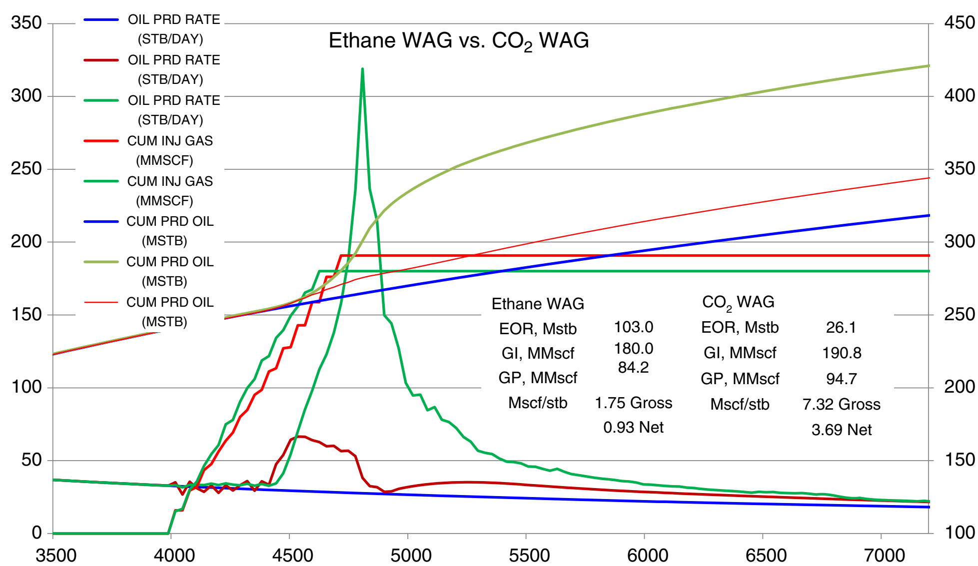

Fig. 18—Bridgeport CO_2 and ethane WAG.

Cushing Field was chosen for evaluation of ethane EOR because it is centrally located in the so-called "pipeline capital of the world." Very-large volumes of ethane are flowing into and out of this region, as shown in **Fig. 21** (Gillaspie 2015). The properties of the Cushing Field are shown in **Table 8** (Llave 1996).

Slimtube simulations (with 100 cells in a finite-difference model) were run to determine the MMP of both ethane and CO_2 in the Cushing Field (see **Fig. 22**). An EOS model for Cushing was not available, so the CO_2-calibrated 32°API Oil-B1 oil with a temperature of 83°F was used as a proxy. The oil composition was adjusted to 38°API, and the Cushing reservoir temperature of 108°F was used. The MMP for ethane in the Cushing Field was approximately 875 psi, whereas the MMP for CO_2 was approximately 1,250 psi.

A quarter-five-spot model of Cushing was built with the SPE3 Comparative Solution Project Problem. Reasonable estimates of

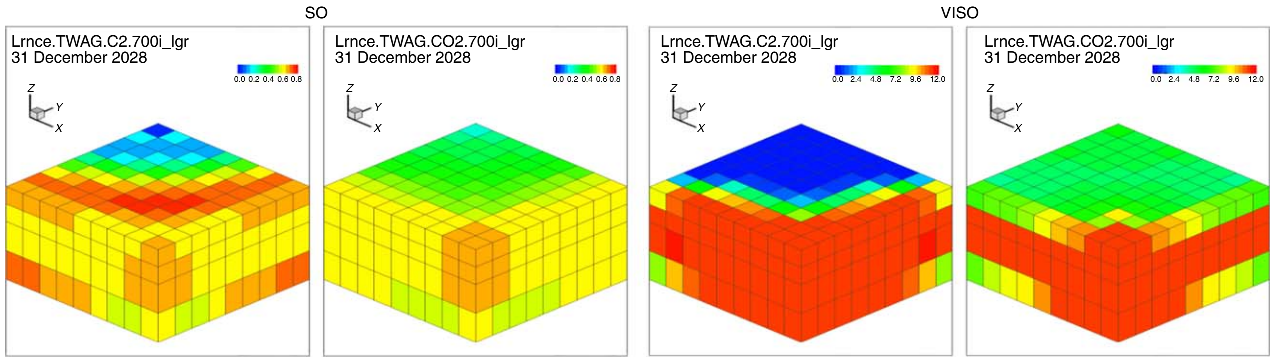

Fig. 19—Lawrence Bridgeport ethane and CO_2 WAG simulation oil saturation and oil viscosity.

Field	Cumulative Production (million bbl)	Estimated Reserves (million bbl)	Remaining Oil in-Place (million bbl)	Depth (ft)	Oil Gravity (°API)
Sho-Vel-Tum	1,417	63	2,749	3,050	29
Sooner Trend	317	12	1,687	6,000	39
Glennpool	388	4	1,570	1,500	38
Oklahoma City	754	4	1,843	6,000	39
Earlsboro	208	1	1,185	3,500	39
Cushing	458	7	1,110	2,600	38

Table 7—Large Oklahoma ethane EOR candidate fields.

the depth, initial pressure, reservoir thickness, well spacing, fluid composition, average porosity, and average permeability from Cushing were used in the model. The 20-acre spacing base model was waterflooded for 20 years (7,305 days). For the ethane evaluation, the model was placed on waterflood for 4,000 days, and then 16 WAG cycles of ethane and water were injected at 1,600 psi. A similar procedure was followed to inject 16 WAG cycles of CO_2, and to inject 10 cycles of methane. The cumulative recoveries in %OOIP from the waterflood, the ethane WAG, the CO_2 WAG, and the methane WAG are shown in **Table 9.** The ethane WAG recovered an additional 9.1% OOIP at a gross efficiency of 3.8 Mscf per STB EOR. The net efficiency was a very attractive 1.6 Mscf ethane per STB EOR. The results of the pattern-model waterflood and ethane WAG simulations are shown in **Fig. 23.** The CO_2 WAG recovered an additional 6.5% OOIP at a gross efficiency of 4.3 Mscf of CO_2 per STB EOR. Net efficiency was 2.8 Mscf of CO_2 per STB EOR. As expected, the methane WAG did not recover any additional oil.

A comparison between the ethane WAG and the CO_2 WAG for Cushing is shown in **Fig. 24.** Oil-saturation maps and oil-viscosity maps from the ethane and CO_2 WAG runs are shown in **Fig. 25.** The ethane WAG was miscible and reduced the oil viscosity by almost an order of magnitude. The CO_2 WAG was not miscible away from the injection well, but significantly swelled the oil and reduced the oil viscosity by a factor of four. Both ethane and CO_2 had good gross and net gas efficiencies.

East Texas Field. Another very promising target for ethane EOR is Texas. In 2011, the DOE identified a "Next Generation CO_2" potential recovery of 13.5 billion STB from East and Central Texas (ARI 2011). Recovering this oil would require roughly 2.8 billion t (55 Tcf) of CO_2 from sources that have not been identified. The biggest field in this region is the supergiant East Texas Field (ETOF), with an OOIP of roughly 7.0 billion STB. The ETOF was chosen for evaluation of ethane EOR because it is a very large target and it is connected with the ATEX ethane pipeline system. Very-large volumes of ethane are flowing into and out of this region, as shown in Figs. 15 and 21. The properties of the East Texas Field are shown in **Table 10** (Wang 2014).

One major issue facing the ETOF is the large number of very old wells in the field. A 1972 study showed that one-quarter of the wells in the ETOF had casing leaks (East Texas Engineering Association 1972). The 2014 Research Partnership to Secure Energy for America/DOE report on the ETOF (Wang 2014) concluded that "with most wells over 80 years old, leaking of CO_2 will be an environmental and economic issue that is difficult to overcome." Increasing the average reservoir pressure in an ETOF WAG project much above the current 1,100 psi will likely result in gas-containment issues.

Slimtube simulations (with 100 cells in a finite-difference model) were run to determine the MMP of both ethane and CO_2 in the ETOF (see **Fig. 26**). An EOS model of the ETOF was not available, so the CO_2-calibrated 32°API Rangely oil with a

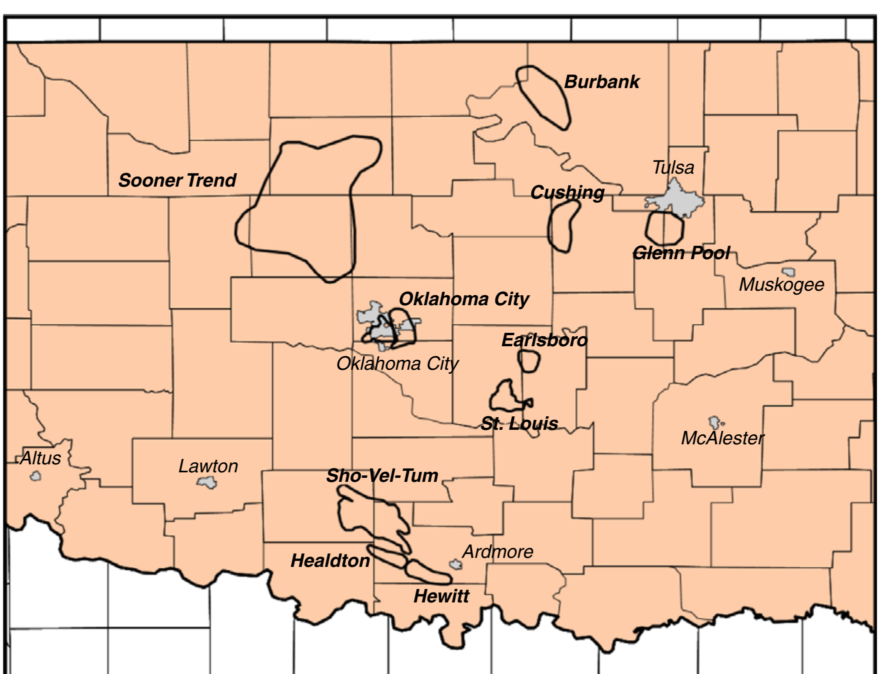

Fig. 20—Location of largest Oklahoma fields.

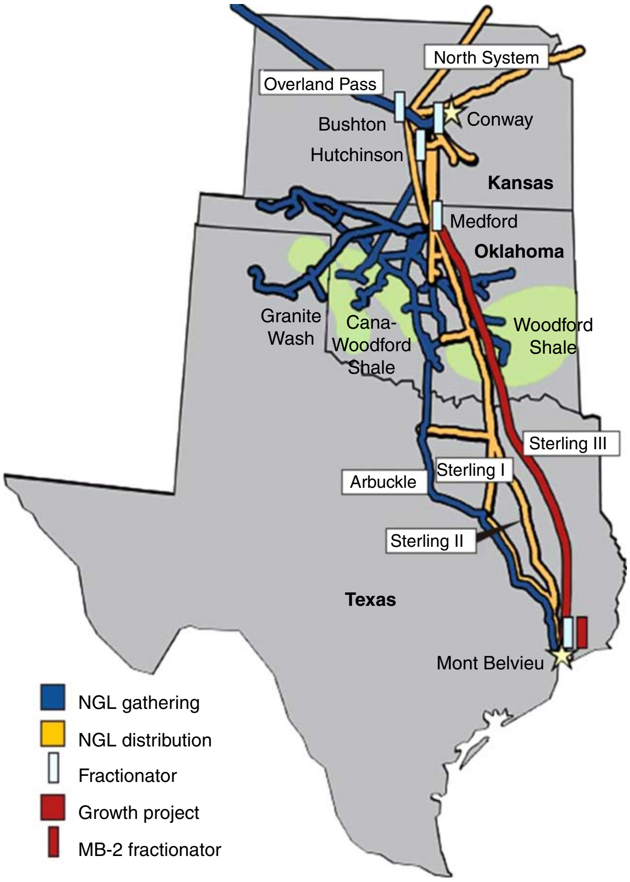

Fig. 21—Oklahoma NGL infrastructure.

temperature of 160°F was used as a proxy. The oil composition was adjusted to 39°API, and the ETOF reservoir temperature of 146°F was applied. The MMP for ethane in the ETOF was approximately 1,150 psi, whereas the MMP for CO_2 was approximately 1,900 psi. The slimtube simulation comparison with the ETOF CO_2 Berea Sand coreflood and slimtube experimental data (Wang 2014) was quite good.

A quarter-five-spot model of the ETOF was built with the SPE3 Comparative Solution Project Problem. Reasonable estimates of the depth, initial pressure, reservoir thickness, well spacing, fluid composition, average porosity, and average permeability from the ETOF were used in the model. Injection pressure was limited to 1,600 psi to reduce gas-containment issues. The 10-acre spacing base model was waterflooded for 20 years (7,305 days). For the ethane evaluation, the model was placed on waterflood for 4,000 days, and then 12 WAG cycles of ethane and water were injected at 1,600 psi. A similar procedure was followed to inject both 12 WAG cycles of CO_2 and 12 cycles of methane.

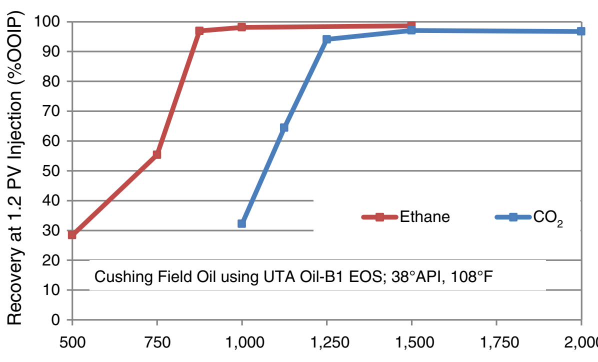

Fig. 22—Slimtube simulations of Cushing Field.

Cushing Field		Bartlesville Sand
Depth	ft	2,700
Oil Gravity	°API	38
Pressure	psia	1,200
Temperature	°F	108
Permeability	md	250
Net Pay	ft	100
Residual Oil Saturation	%	30
Oil Viscosity	cp	2–3
Water Cut	%	99+

Table 8—Cushing Field properties.

The cumulative recoveries in %OOIP from the waterflood, the ethane WAG, the CO_2 WAG, and the methane WAG are shown in **Table 11.** The ethane WAG recovered an additional 10.9% OOIP at a gross efficiency of 7.1 Mscf per STB EOR. The net efficiency was a very attractive 1.5 Mscf ethane per STB EOR. The results of the pattern-model waterflood and ethane WAG simulations are shown in **Fig. 27.** The CO_2 WAG recovered an additional 3.0% OOIP at a gross efficiency of 18.4 Mscf of CO_2 per STB EOR. Net efficiency was 3.3 Mscf of CO_2 per STB EOR As expected, the methane WAG did not recover significant additional oil. A comparison between the ethane WAG and the CO_2 WAG for the ETOF is shown in **Fig. 28.** Oil-saturation maps and oil-viscosity maps from the ethane and CO_2 WAG runs are shown in **Fig. 29.** The ethane WAG was miscible and reduced the oil viscosity significantly. The CO_2 was near-miscible at the injection well, but did not effectively reduce the residual oil saturations at the average pattern pressure of 1100 psi.

A summary of the EOR performance and the gross and net solvent efficiencies for the three example fields is shown in **Table 12.** The costs were assumed to be USD 4.15 per Mscf for ethane and USD 2.00 per Mscf for CO_2. These prices are illustrative only; actual component pricing and availability will vary with both location and time.

Conclusions

The "shale revolution" in the US has brought about an enormous increase in ethane production, and ethane prices have dropped steeply. Ethane-based EOR can supplement the very successful CO_2-based EOR industry in the US. The current abundance of low-cost ethane presents a significant opportunity to add new gas EOR projects. The ethane-based EOR opportunity can be summarized as follows:

- CO_2-based EOR works well, and is well-understood. The CO_2 EOR potential in the Lower 48 is roughly 60 billion bbl of incremental oil. There is not, and very likely will not be, enough low-cost CO_2 available to undertake most of these potential gas EOR projects.
- Ethane has more solubility in oil and lower MMPs than CO_2. In shallow fields, such as the Lawrence Field, or in low-pressure fields, such as the East Texas Field, ethane EOR will recover more oil than CO_2 EOR. In higher-

Process	Recovery
WF	63.8
C_2 WAG	72.9
CO_2 WAG	70.3
C_1 WAG	63.6

Table 9—Cushing Field EOR.

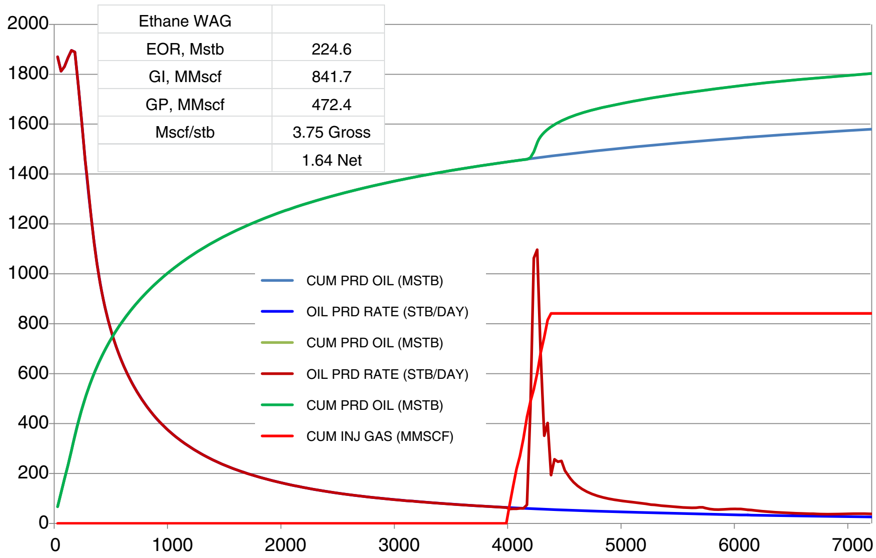

Fig. 23—Cushing waterflood and ethane WAG.

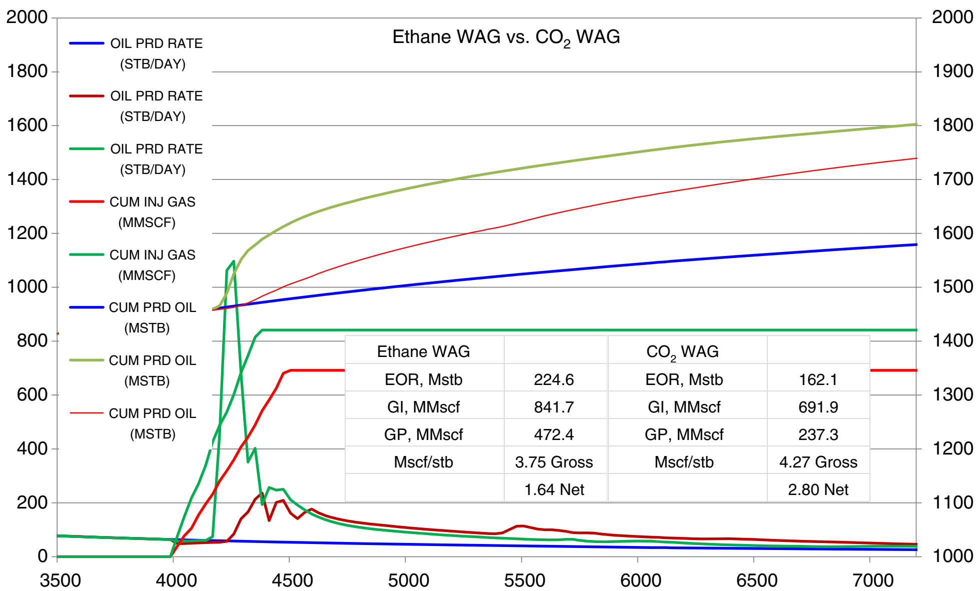

Fig. 24—Cushing CO_2 and ethane WAG.

pressure fields, such as the Cushing Field, both gases work well. Which gas works better in the higher-pressure cases will likely depend on gravity override and the reservoir description.

- Ethane is simpler than CO_2 for EOR. The ethane does not cause additional corrosion, and no special materials are required for injection wells, production wells, pipelines, or surface facilities. "Parasitic losses" from gas solubility in

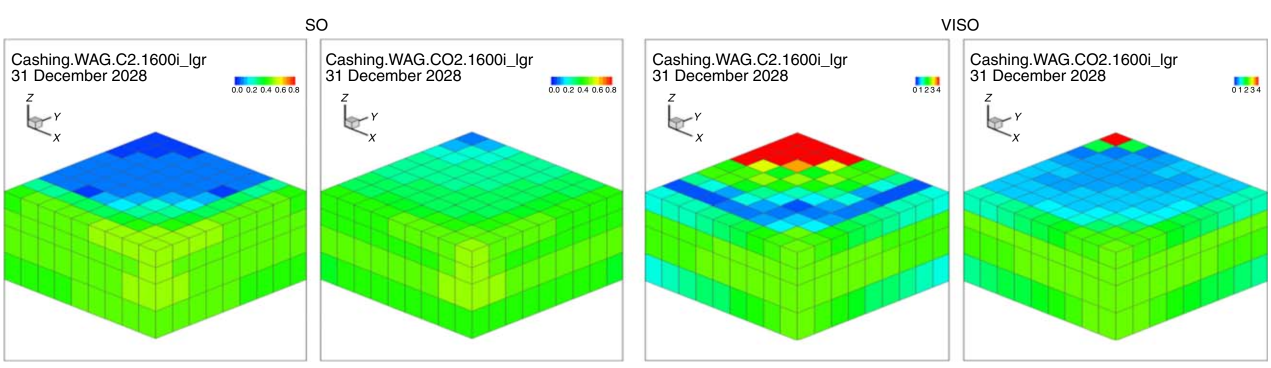

Fig. 25—Cushing CO_2 and ethane WAG simulation oil saturation and oil viscosity.

East Texas Field		Woodbine Sand
Depth	ft	3,500
Oil Gravity	°API	39
Pressure	psia	1,100
Temperature	°F	146
Permeability	md	2,100
Net Pay	ft	39
Residual Oil Saturation	%	20
Oil Viscosity	cp	1.0
Water Cut	%	99+

Table 10—East Texas Field properties.

Process	Recovery
WF	71.9
C2 WAG	82.8
CO2 WAG	74.9
C1 WAG	72.0

Table 11—East Texas Field EOR.

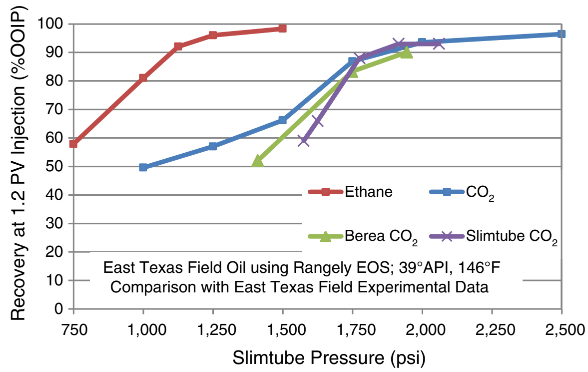

Fig. 26—Slimtube simulations of the East Texas Field.

water are dramatically smaller with ethane than with CO_2. The produced gas from an ethane WAG flood will have intrinsic value as sales gas or fuel, and no acid-gas-removal plant is required.

- Ethane is now inexpensive in the US, and it will very likely stay inexpensive for a long time. Supplies of ethane from shale plays such as the Bakken, the Marcellus/Utica, and the Eagle Ford are forecast to increase for years to come.

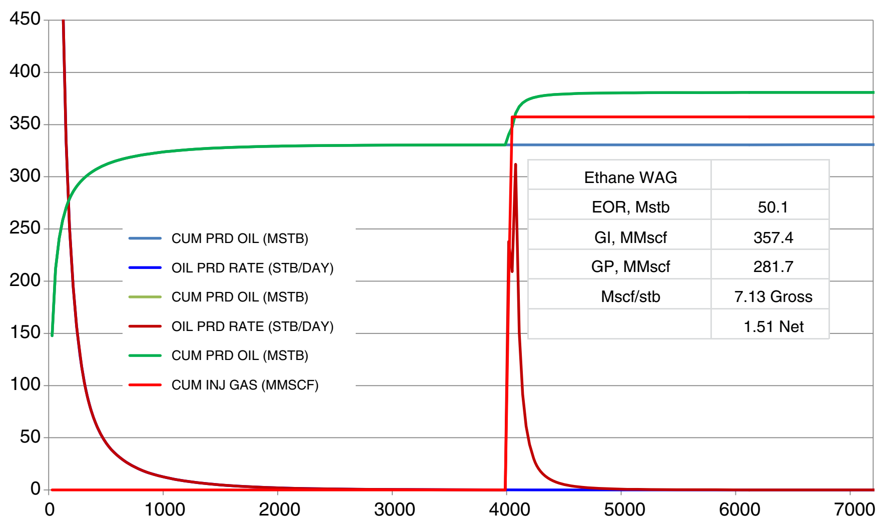

Fig. 27—East Texas Field waterflood and ethane WAG.

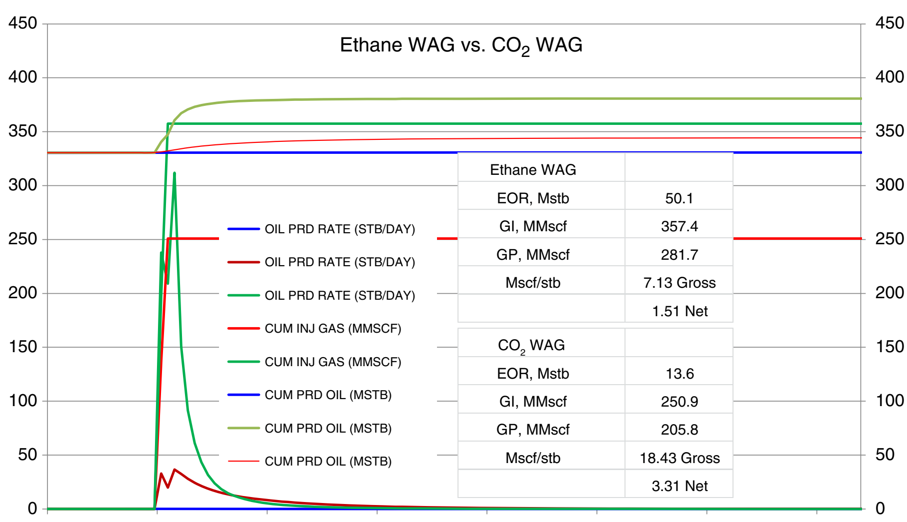

Fig. 28—East Texas Field CO_2 and ethane WAG.

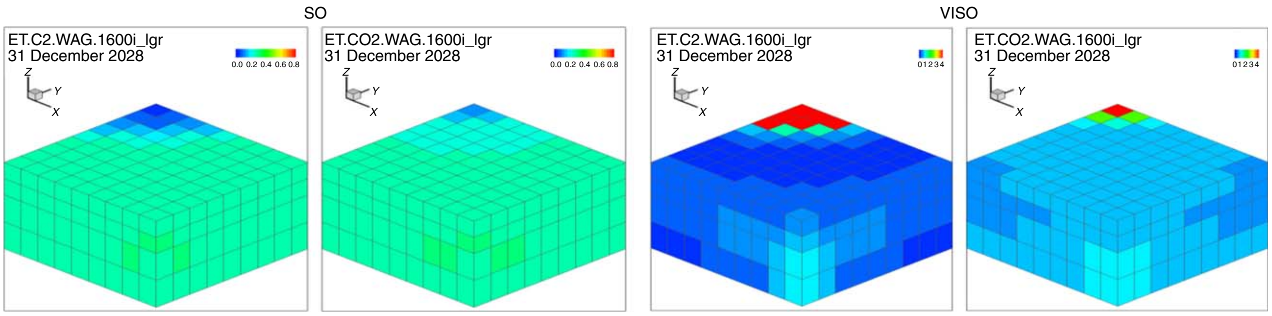

Fig. 29—East Texas Field CO_2 and ethane WAG simulation oil saturation and oil viscosity.

	Lawrence		Cushing		East Texas	
	Ethane	CO_2	Ethane	CO_2	Ethane	CO_2
EOR (1,000STB)	103.0	26.1	224.6	162.1	50.1	13.6
Gas Inj. (MMscf)	180.0	190.8	841.7	691.9	357.4	250.9
Gas Prod. (MMscf)	84.2	94.7	472.4	237.3	281.7	205.8
Mscf/STB Gross	1.75	7.32	3.75	4.27	7.13	18.43
Mscf/STB Net	0.93	3.69	1.64	2.80	1.51	3.31
Cost per Mscf	USD 4.15	USD 2.00	USD 4.15	USD 2.00	USD 4.15	USD 2.00
Cost per bbl EOR	USD 3.86	USD 7.37	USD 6.82	USD 5.61	USD 6.27	USD 6.63

Table 12—EOR performance and the gross and net solvent efficiencies for the three example fields.

However, there will not be enough ethane available to implement EOR in all the potential target fields.

- Ethane-based EOR has become a viable option in the Lower 48. Large volumes of low-cost ethane are available. Recent additions to the growing ethane infrastructure, such as the ATEX and Bakken pipelines, now deliver ethane to locations where ethane-based EOR targets are plentiful.
- Some of the ethane is currently being flared, and much of it is being used as fuel. Ethane has higher CO_2 emissions per unit of energy than methane. Using ethane for higher-value applications, such as petrochemicals or EOR, will reduce CO_2 emissions if methane is burned for fuel instead of ethane.

Nomenclature

API = American Petroleum Institute
DOE = United States Department of Energy
EIA = Energy Information Agency
EOS = equation of state
ETEA = East Texas Engineering Association
GI = gas injection
GP = gas production
MMP = minimum miscibility pressure
NETL = National Energy Technology Laboratory
Pi = initial reservoir pressure
PR EOS = Peng-Robinson equation of state (1976, 1978) EOS
RPSEA = Research Partnership to Secure Energy for America
STD = slimtube displacement
T_C = critical temperature
T_P = critical pressure
WAG = water alternating gas

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