Energy Intensity and Greenhouse Gas Emissions from Crude Oil Production in the Eagle Ford Region: Input Data and Analysis Methods

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TABLE OF CONTENTS

TABLE OF CONTENTS (Cont.)

LIST OF TABLES

LIST OF TABLES (Cont.)

LIST OF TABLES (Cont.)

LIST OF FIGURES

LIST OF FIGURES (Cont.)

ENERGY INTENSITY AND GREENHOUSE GAS EMISSIONS FROM CRUDE OIL PRODUCTION IN THE EAGLE FORD REGION: INPUT DATA AND ANALYSIS METHODS

by

Abbas Ghandi, Sonia Yeh, Adam R. Brandt, Kourosh Vafi, Hao Cai, Michael Q. Wang, Bridget R. Scanlon, and Robert C. Reedy

ABSTRACT

An exponential increase in horizontal drilling and hydraulic fracturing in shale and “tight” formations in the U.S. since 2007–2008 has resulted in record increases in oil and natural gas (NG) production from seven of the most significant tight oil and shale formations, including the Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, Permian, and Utica plays. Crude oil and gas production in Eagle Ford has steadily increased since 2010. By the summer of 2015, oil and gas production reached 1.59 million barrels (bbl) per day and 7.14 billion cubic feet, respectively. This study summarizes liquids and gas production in the Eagle Ford Shale in South Texas from 2010 through 2013 and calculates energy consumption and greenhouse gas (GHG) emissions associated with the crude oil and NG extraction using the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model. OPGEE is an engineering-based life cycle assessment tool for estimating GHG emissions from the production, processing, and transport of crude petroleum. The system boundary of OPGEE extends from initial exploration to the refinery entrance gate. The operational energy consumption and flaring/fugitive emission intensities that are modeled by OPGEE provide the key inputs for the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model developed at Argonne National Laboratory for modeling the life-cycle GHG emissions of crude oil and NG production in the Eagle Ford shale.

The Eagle Ford can be characterized by four distinct production zones—the black oil (BO), volatile oil (VO), condensate (C), and gas (Gas) zones—with average monthly gas-to-liquid ratios (million cubic feet /bbl/month/well) that vary from 0.91 in the BO zone to 13.9 in the Gas zone. We found that the recovery energy efficiency, process fuel consumption, flaring and fugitive intensities, and water use showed little variation over time between 2010 and 2013. Wide variations in energy use and production among the thousands of wells were observed. In the BO zone, on an energy basis, about 20% of the NG produced is either flared (12%), emitted (1.5%), or used for self-consumption (5.7%), and 81% is sent to the market as pipeline NG and natural gas liquids (NGL). In comparison, only about 2% of the NG produced in the Gas zone is either flared (0.1%), emitted (0.01%), or used for self-consumption (2.4%), and 98% is sent to

the market as pipeline NG and NGL. The proportion of NG sent to the market is about 45–49% as NG and 51–55% as NGL (on an energy basis). Process fuel consumption rate, flaring and fugitive intensities, and water use rate are in general higher in the Gas and C zones than in the BO and VO zones. The total MMBtu of energy (including diesel, NG, and electricity) used for production, extraction, and surface processing per MMBtu energy produced (including liquids, net NG sale, and net NGL sale) ranges from 0.012 MMBtu/MMBtu in the BO zone to 0.024 MMBtu/MMBtu in the Gas zone, with an average of 0.015 MMBtu/MMBtu across all wells. The well-to-wheels GHG emissions of gasoline, diesel and jet fuel derived from crude oil produced in the BO and VO zones in the Eagle Ford play are 89.2, 87.8, and 82.5 gCO_2e/MJ, respectively.

1 INTRODUCTION

An exponential increase in horizontal drilling and hydraulic fracturing (HF) in shale and "tight" formations in the U.S. since 2007–2008 has resulted in record increases in oil and natural gas (NG) production from seven of the most significant tight oil and shale formations, including the Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara, Permian, and Utica plays (EIA 2014a).

Oil and gas production in Eagle Ford has steadily increased since 2010. By the summer of 2015, oil and gas production reached 1.59 million barrels/day (bbl/d) and 7.14 billion cubic feet per day (Bcf/d), respectively (FIGURE 1, left). At the same time, new-well production[1] has steadily gone up for oil production since 2007 and almost doubled for gas production between 2012 and 2015 (FIGURE 1, right). Appendix A shows the geographic location of the Eagle Ford formation.

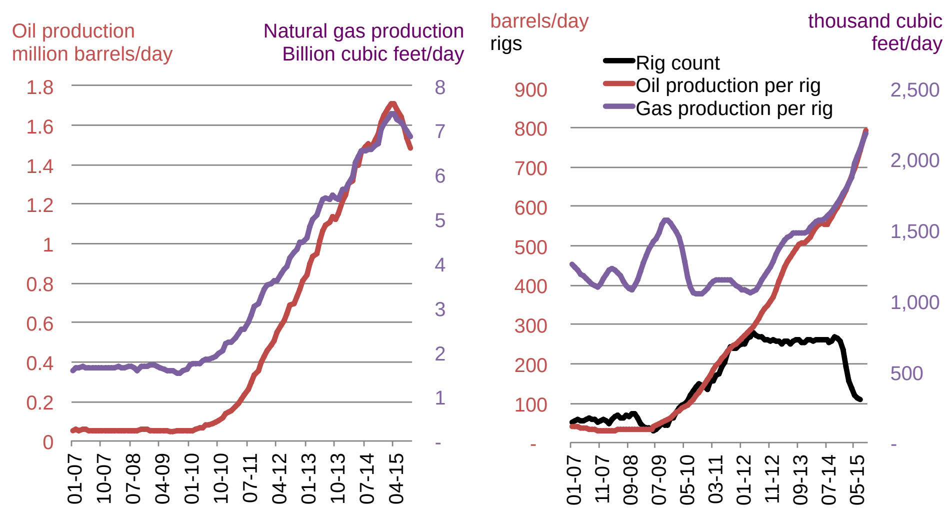


FIGURE 1 Left: Oil and gas production in the Eagle Ford play, 2007–2015. Right: New-well oil and gas production and annual rig counts. Data source: EIA (2015)

Compared with other shale formations, the Bakken, Eagle Ford and Permian regions are the three largest oil-producing regions in the U.S. (FIGURE 2). Eagle Ford and Bakken have been the second and third largest shale oil producing region in the U.S., respectively, since 2012. Compared to Bakken, the Eagle Ford is gas-rich, producing almost 5 times more gas in 2014 than Bakken (FIGURE 2).

1 According to EIA, "A new well is defined as one that began producing for the first time in the previous month. Each well belongs to the new-well category for only one month."

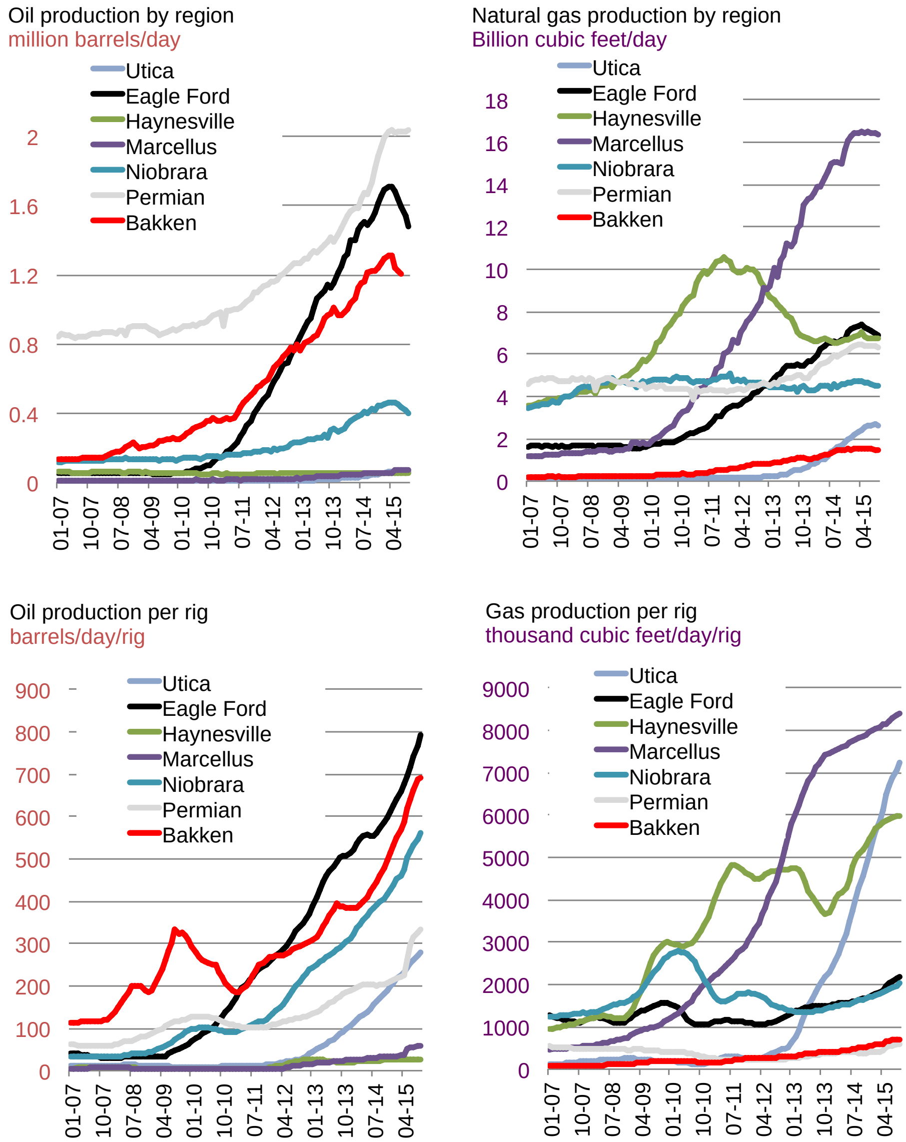


FIGURE 2 Oil and gas production by region (top row) and oil/gas production per rig (bottom row) for seven of the most significant U.S. shale and tight oil and shale gas plays. Data source: EIA (2015)

The average well productivity was 435 and 536 bbl/d/rig for Bakken and Eagle Ford, respectively, for oil production in 2014; and 438 and 1,603 thousand cubic feet (Mcf)/d/rig for Bakken and Eagle Ford, respectively, for gas production in 2014. Together, Bakken and Eagle Ford accounted for 54% of oil production and 19% of gas production within these seven production regions in 2014.

Note that "oil" production defined by the U.S. Energy Information Administration (EIA) in fact represents both crude and condensate production, and NG production estimated by the EIA comprises the volumes at the well before any flaring, refining, or gas processing; i.e., all hydrocarbon production in the liquid state at the wellhead is treated as oil, and all unprocessed gas production (known as gross production) is treated as NG.

The goal of the present study is to summarize liquids and gas production in Eagle Ford Shale in South Texas from the period of 2010 through 2013 and calculate energy consumption and greenhouse gas (GHG) emissions associated with the oil and gas extraction using the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model. OPGEE is an engineering-based life cycle assessment (LCA) tool for estimating GHG emissions from the production, processing, and transport of crude petroleum. The system boundary of OPGEE extends from initial exploration to the refinery entrance gate. More detailed documentation of the OPGEE model is given by El-Houjeiri et al. (2014). The operational energy consumption and flaring/fugitive emission intensities that are modeled by OPGEE provide the key inputs for the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model developed at Argonne National Laboratory for modeling the life-cycle GHG emissions of shale oil and shale gas production in the Eagle Ford.

2 METHODS

In this section, we document data sources and summary statistics that will be the inputs for characterizing operational energy consumption and flaring/fugitive emissions in the Eagle Ford play by means of the OPGEE model that we will discuss in greater detail in Section 3. First, we outline the data sources and cleaning, processing and development of the original data to its final format for the OPGEE model. We provide analyses such as monthly gas-to-liquid ratio (GLR), productivity, and water-to-liquid ratio in relation to well or zone categories in the Eagle Ford. Finally, we discuss Eagle Ford-specific estimates for other OPGEE input parameters based on our developed data and reviews of the literature and commercial sources.

2.1 DATA SUMMARY

The database that we developed for the OPGEE Eagle Ford model was based on IHS well-based monthly data. In their original formats, these databases consisted of three Excel files with several worksheets. A complete list of the parameters in the three original databases is included in the following appendices:

Appendix B: IHS-Bureau of Economic Geology (BEG) Database Summary;
Appendix C: IHS Initial Well Test Database;
Appendix D: IHS Follow-up Well Test Database.

The first file[2] has well-based monthly liquids,[3] NG, and water production data in addition to HF and some well characteristics data in four worksheets. The second file contains IHS-based Initial Test data on a variety of parameters, including the initial flow of oil, condensate, gas and water in addition to oil and condensate gravity. The third file contains Follow-up Test variables.

We developed, cleaned and processed the IHS-BEG Excel-based worksheets and files into one master database consisting of 144,924 observations representing 11,314 wells in the Eagle Ford, including 2009 through 2013 data on production (8,218 wells) and HF water and proppant use (8,301 wells), and 2009 to 2014 data on Initial Tests (11,298 wells) and Follow-Up Tests (3,430 wells). The data development and processing included several stages of cross checking, cleaning and analyzing, as we discuss in this section.

2.2 MONTHLY PRODUCTION AND COMPLETION

IHS-BEG production data include monthly per-well production data on liquids (bbl/month/well), gas (Mcf/month/well), and water (gal/month/well) as the three main production variables for 2009–2013. As stated in the previous section and in Table B3 of

[2] This IHS-BEG database was processed on Nov 2, 2014, by the BEG at the University of Texas at Austin. We call our final developed database UCDavis-EagleFordGHGProject.

[3] The dataset does not differentiate between oil and condensate production; both are called liquids.

Appendix B, all hydrocarbon production in the liquid state at the wellhead is reported as liquids (which includes crude and condensate), and all unprocessed gas production (known as gross production) is reported as NG (which contains dry gas and field condensate that is separated in the subsequent processes).

TABLE 1 IHS-BEG monthly production data summary statistics

Variable	Obs	Mean	Std. Dev.	Min	Max
Liquids (bbl/month/well)	136,040	4,639	5,373	0	89,561
Gas (Mcf/month/well)	138,160	21,109	29,518	0	397,671
Water (gal/month/well)	128,776	4,434	97,363	0	2.19e+07

As shown in Figure 3 and Figure 4, monthly liquids production per well has increased over time, remaining roughly at the same level since 2011 or slightly decreasing in 2013, whereas monthly per-well gas production has decreased since 2010. This confirms the suggestion that shale gas production in the region has shifted from gas-rich areas to oil-rich areas during this period, and also that the overall well productivity has increased (FIGURE 1 and EIA (2014b)). The median monthly gas-to-liquids production ratio (standard cubic feet (scf)/bbl) per well decreased by more than 4 times, from 11,700 scf/bbl per well in the first quarter of 2010 to around 2,400 scf/bbl per well in 2013 (Figure 4).

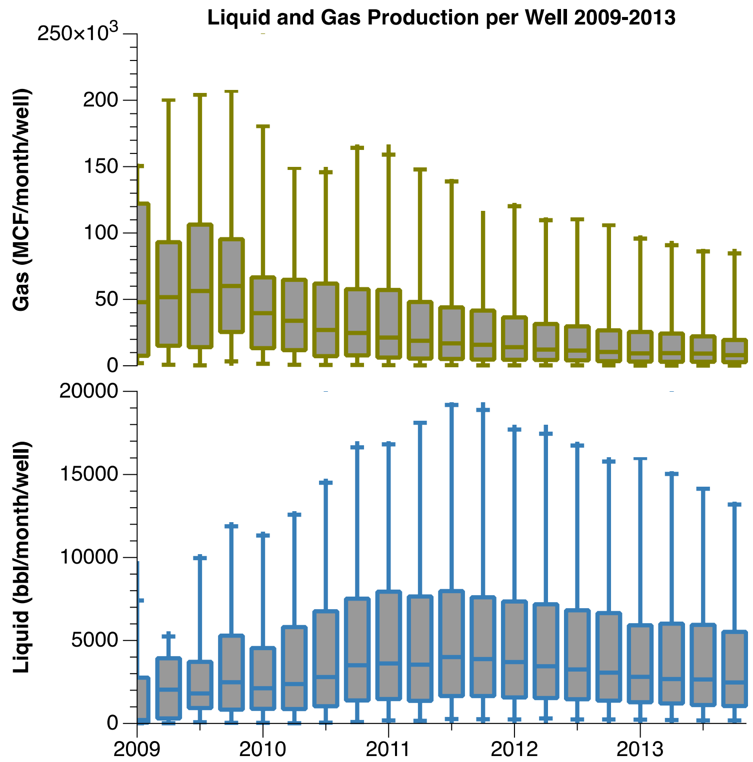


FIGURE 3 Box plots of monthly gas (top) and liquids (bottom) production at Eagle Ford, TX, 2009–2013. The box plots show median, the 1st and the 3rd quartile (boxes), and 5th and 95th percentile (whiskers) values.

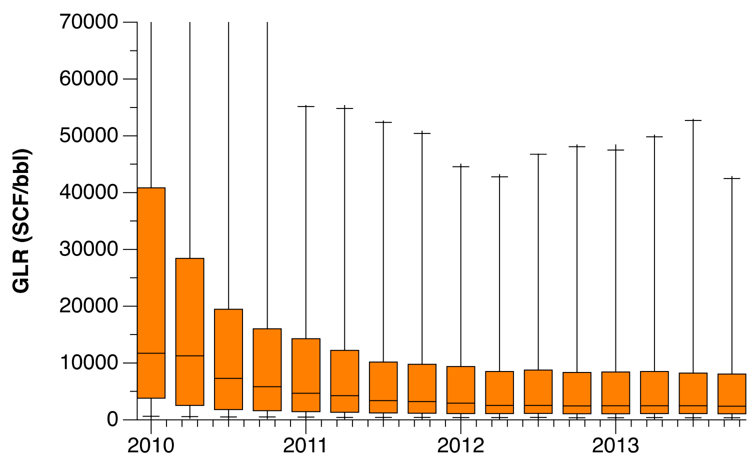


FIGURE 4 Box plots of monthly gas-to-liquid production ratio (scf/bbl) in Eagle Ford, TX, 2010–2013. The box plots show the median, the 1st and the 3rd quartile (boxes), and 5th and 95th percentile (whiskers) values, except for the values in 2010, where the 95th percentile values are off-scale.

The annual liquids and gas production volumes are reported in Table 2. In 2013, liquids production reached 0.93 million bbl/d and gas production reached 3.86 Bcf/d.

TABLE 2 IHS-BEG annual liquids and gas production, 2009–2013

	Liquid		Gas	
Year	million bbl	million bbl per day	billion cubic feet	billion cubic feet per day
2009	0.64	0.00	16.5	0.05
2010	11.1	0.03	111	0.30
2011	75.1	0.21	444	1.22
2012	204	0.56	938	2.57
2013	340	0.93	1,408	3.86

After a well was completed, Initial Tests were conducted to measure the initial flow rate of oil (bbl/d, or BPD, per well), condensate (BPD/well)[4] and gas (1000 ft^3/d, MCFD, per well), the properties of the fuels (e.g., oil API gravity), etc. A detailed list of parameters is provided in Appendix C, and the initial flow rates of oil, condensate and gas are summarized in Figure 4 and Table 3, Table 4, and Table 5. More discussion about oil vs. condensate in the Initial Test data is provided in Section 2.1.2.

4 IHS defines condensate as "liquid hydrocarbons that are separated from gas during production." (Source: https://penerdeq.ihsenergy.com/dynamic.splashscreen/documents/USDC.pdf) Note that the EIA defines lease condensate as "light liquid hydrocarbons recovered from lease separators or field facilities at associated and non-associated natural gas wells. They are mostly pentanes and heavier hydrocarbons and normally enter the crude oil stream after production." (Source: http://www.eia.gov/tools/glossary/index.cfm?id=Lease)

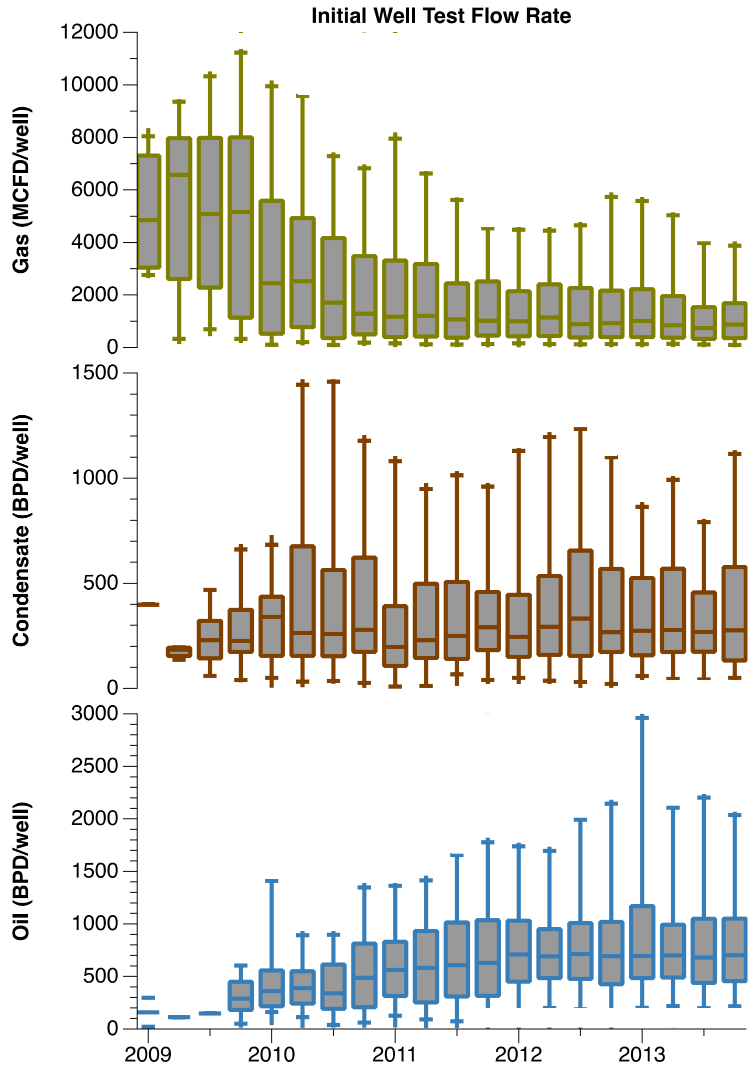


FIGURE 5 Box plots of initial gas (top), condensate (middle) and oil (bottom) flow rates in the Initial Test data. The box plots show the median, the 1st and the 3rd quartile (boxes), and 5th and 95th percentile (whiskers) values.

The Initial Test oil flow rate (BPD/well) has increased over the years (Figure 5, Table 3 and Table 4), whereas the initial gas flow rate has decreased (Figure 5, Table 5) and the initial condensate flow rate (BPD/well) has remained relatively flat (Figure 5, Table 4). Between 2009 and 2014, the Initial Test data indicated that liquids production contained 27–62% condensate.

TABLE 3 Initial Test oil flow rate (bbl/d/well, BPD/well) summary statistics by year

Year	Obs	Mean	Std. Dev.	Min	Max
2009	13	235	197.7	5	611
2010	206	496	393.0	10	2,208
2011	974	689	509.5	2	3,658
2012	1,691	811	581.7	1	5,379
2013	2,189	883	710.2	11	7,513
2014	1,964	954	727.2	5	5,414

TABLE 4 Initial Test condensate flow rate (bbl/d/well, BPD/well) by year

Year	Obs	Mean	Std. Dev.	Min	Max
2009	30	274	193.8	28	979
2010	166	454	478.1	2	3,420
2011	525	352	301.8	1	1,710
2012	960	403	351.5	1	2,468
2013	1,299	378	338.7	2	6,522
2014	983	437	344.2	1	2,045

TABLE 5 Initial Test gas flow rate (1000 ft^3/d/well, MCFD/well) by year

Year	Obs	Mean	Std. Dev.	Min	Max
2009	60	5,183	3,750.6	1	17,255
2010	423	2,759	3,095.6	5	24,869
2011	1,518	1,811	1,898.2	5	13,551
2012	2,701	1,571	1,600.3	1	16,662
2013	3,514	1,414	1,582.2	3	23,095
2014	2,958	1,345	1,823.1	1	23,319

For a subset of wells, data on Follow-up Test results were also provided. A detailed list of parameters documented in the Follow-up Tests appears in Appendix D. The Follow-up Test data were collected after well completions that ranged from 1 to 1719 days (approximately 4.7 yr). Table 6 and Table 7 include the summary statistics from the Follow-up Test data on the liquids flow rates and cumulative gas produced, by the year the Follow-up Tests were conducted.

TABLE 6 Follow-up Test hydrocarbon liquids flow rate (BPD/well) by year

Year	Obs	Mean	Std. Dev.	Min	Max
2009	34	264	204	12	979
2010	266	299	346	1	2,525
2011	939	255	407	1	7,978
2012	1,775	199	208	1	2,095
2013	3,234	147	196	1	5,388
2014	3,002	116	169	1	3,191

TABLE 7 Cumulative produced gas at time of Follow-up Test (1000 ft^3/d/well, MCFD/well) by year

Year	Obs	Mean	Std. Dev.	Min	Max
2009	50	148	182	13	1,104
2010	333	597	920	2	4,988
2011	1,075	934	1,236	1	7,151
2012	2,021	1,415	1,718	0	10,582
2013	3,625	1,898	1,969	1	12,417
2014	3,388	2,295	1,955	0	13,198

Figure 6 plots the ratio of follow-up oil/gas flow rate to initial oil/gas flow rate as a function of days after well completion. The liquids flow rate shows a rapid decline immediately after well completion and eventually drops to below 10% of the initial flow rate in less than three years after well completion. The gas flow rate, however, has not markedly decreased, but remains roughly the same as or higher than the initial flow rate (Figure 6). This finding is consistent with the observations that, for each well, oil production tends to steadily decrease during production, and the GLR increases over the production lifetime (Gong et al. 2013).

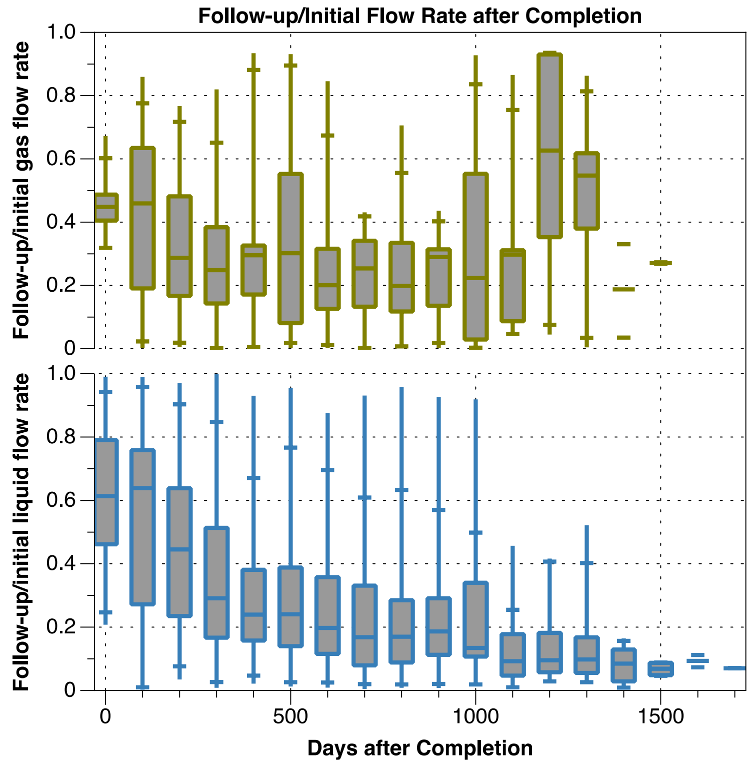


FIGURE 6 Box plots of Follow-up Test to Initial Test flow rate ratio as a function of days after completion. The box plots show the median, the 1st and the 3rd quartile (boxes), 5th and 95th percentile (whiskers), and the min and max values (lines).

2.3 API GRAVITY

As part of developing the data from its original format for OPGEE, we needed to assign oil API gravity to each of the 11,314 wells in the database.[5] In this section, we discuss our methodology for assigning oil API gravity to all wells in the database. We also report condensate and gas gravity for all the wells with available data from the IHS-BEG original Initial and Follow-up Test data. The only modification we enforce on the condensate and gas gravity data is to make sure that we correct for any data out of reasonable range as reported in the literature for condensate and gas gravity, respectively.

As summarized in Table 8, the 11,314 total wells fall into several categories with regard to reported oil API gravity. Table 8 also summarizes our methodology in assigning oil API gravity for wells without such reported values or for wells with both initial and follow-up oil gravity reported. We also report condensate and gas gravity for any wells with such reported

[5] In the IHS-BEG original data, API gravity for oil (OilGravity) and condensate (CondGravity) have been reported separately for 10901 and 2754 wells out of the total 11314 wells of the database. The 2754 wells with reported condensate gravity also have reported oil gravity. In the database and on the basis of the IHS-BEG Follow-up Test data, we also have oil and gas gravities for 3087 and 3420 wells, respectively.

values. In all, 96% of the wells (3056 + 7845 wells) reported initial oil API gravity. An additional 31 wells reported follow-up oil API gravity, which is treated as initial oil API gravity. 33% of wells (3420 + 287 wells) reported API gas gravity, and 24% of wells (2754 wells) reported condensate gravity.

TABLE 8 Categorization of Eagle Ford wells with respect to the reported oil gravity

Well Description	Number of Wells	Methodology Description	Additional Explanation
Wells with initial oil gravity and follow-up oil gravity	3056	The initial oil gravity is reported as the oil gravity.	
Wells with only initial oil gravity	7845	The initial oil gravity is reported as the oil gravity.	
Wells with only follow-up oil gravity	31	The follow-up oil gravity is reported as the oil gravity.	
Wells with only initial condensate gravity	2754	The condensate gravity is reported.	These wells also report the initial oil gravity.
Wells with follow-up gas gravity	3420	The follow-up gas gravity is reported.	3133 of these wells also report the initial oil gravity. In addition, among the 2754 wells with reported initial condensate gravity, 2744 wells also report follow-up gas gravity.
Wells with only follow-up gas gravity	287	The median oil gravity is assigned.	
Wells with no reported gravity	126	The median oil gravity is assigned.	
The bolded wells all together account for all wells in the database.	11314		

On the basis of the analysis provided above, we generated a new variable, "OilAPIGravity." We populated this new variable for each group of wells using the methodology described in Table 8. In doing so, we also replaced all OilAPIGravity values below 27 with 46.2, the median of the sample of wells with non-missing values, as it is not reasonable to have oil API gravity below 27. In addition, we replaced all missing values of OilAPIGravity with the median value of 46.2. Table 9 gives summary statistics for the final calculated OilAPIGravity, accounting for all wells in the database. Table 9 also includes summary statistics for condensate gravity and gas gravity, for wells with such data reported. For wells with gas gravity below 0.55, we replaced that value with the median value, 0.73. This is because 0.55 represents the molecular weight of CH_4 divided by the molecular weight of air (16/29), and gas gravity below 0.55 is unrealistic.

TABLE 9 Summary statistics for the final calculated OilAPIGravity, accounting for all wells in the database

Variable	Obs	Median	Mean	Std. Dev.	Min	Max
OilAPIGravity	11314	46.2	48.0	8.59	27	94
Condensate Gravity	2754	58	57.7	5.46	34.8	79.4
Gas Gravity	3420	0.73	0.73	0.07	0.56	1.44

We also show the frequency of the developed oil API gravity in Figure 7. For plotting the OilAPIGravity, we only used the original data, without considering wells with reported OilAPIGravity below 27 (127 wells out of 10901 wells with non-missing reported initial oil API gravity), since we replaced those with the median value in the dataset.

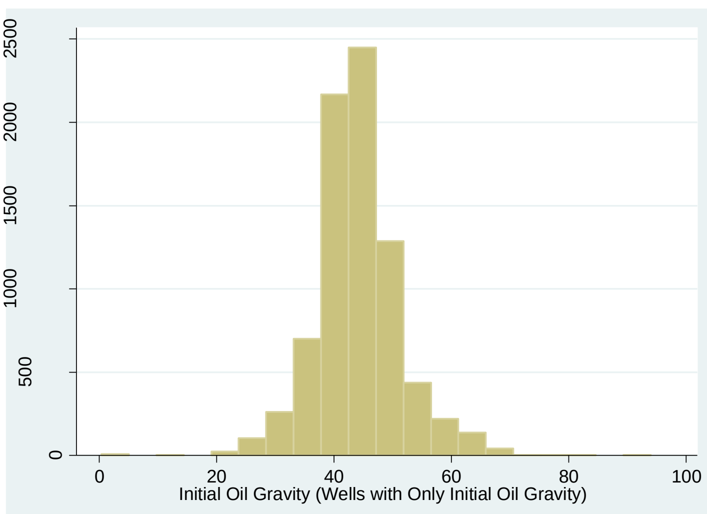


FIGURE 7 Histogram of initial oil API gravity of Eagle Ford wells with only initial oil API gravity available (N=7845 wells).

Figure 7 and Figure 8 suggest that oil API gravities of the wells with both Initial and Follow-up oil gravity (Figure 8) are much higher than those of the wells with only Initial oil gravity (Figure 7). Among the 3056 wells with both Initial and Follow-up oil API gravity reported, as shown in Figure 8, only 265 wells report an initial flow of oil. In addition, among the 7000 wells with a reported initial flow of oil, only 202 wells also report initial condensate gravity.[6] In the OPGEE model, “liquid” production is fed into the model such that each well has a corresponding oil API gravity value that we describe here.

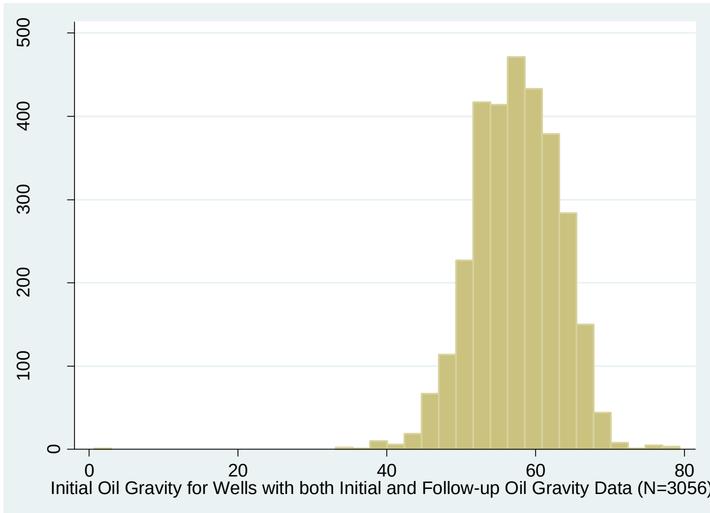


FIGURE 8 Histogram of oil gravity for wells with both Initial and Follow-up oil API gravity data (N=3056 wells).

2.4 WELL ZONE CATEGORIZATION

The gas-to-oil ratio (GOR) is typically described as the ratio of total gas (10^3 ft^3 or Mcf) to total oil (bbl) produced during months 2 through 4 for each well (Gong, et al. 2013; EIA 2014a; Scanlon et al. 2014). We adopt the zone categorization scheme of Scanlon et al. (2014), with GOR as the ratio of total produced gas (scf) to total produced liquids (bbl) for months 2, 3, and 4 combined. The numbers of wells in each of the four production zones are summarized in Table 10. TABLE 10 shows that between 2009 and 2014, the majority of wells (76%) were located in oil and volatile oil zones where GOR was < 10,000.

[6] Please see Appendix E for complete analysis and detailed descriptions of identifying condensate wells.

TABLE 10 Well categories with number of wells in each category, based on the IHS-BEG original well categorization

Well Category	GOR Range	Number of Wells in the Category	%
Black Oil Zone	Below 1500	3695	45%
Volatile Oil Zone	Between 1500 and 10,000	2855	34%
Condensate Zone	Between 10,000 and 100,000	1237	15%
Gas Zone	Above 100,000	514	6%
Total		7513	

2.5 GAS-TO-LIQUID RATIO (GLR) BY ZONE TYPE

Because IHS-BEG Production datasets report "liquids," which is a mixture of oil and condensates, we use the term GLR instead of GOR to refer to gas-to-liquid ratio. We calculate "Producing GLR Ratio" as the monthly produced gas (scf/well/month) to monthly produced liquids (bbl/well/month) for each well. The Monthly GLRs based on monthly production data for each well by zone are shown in FIGURE 9. The slopes of the linear regressions representing the average monthly GLR (Mcf/bbl) by zone are also reported in FIGURE 9.

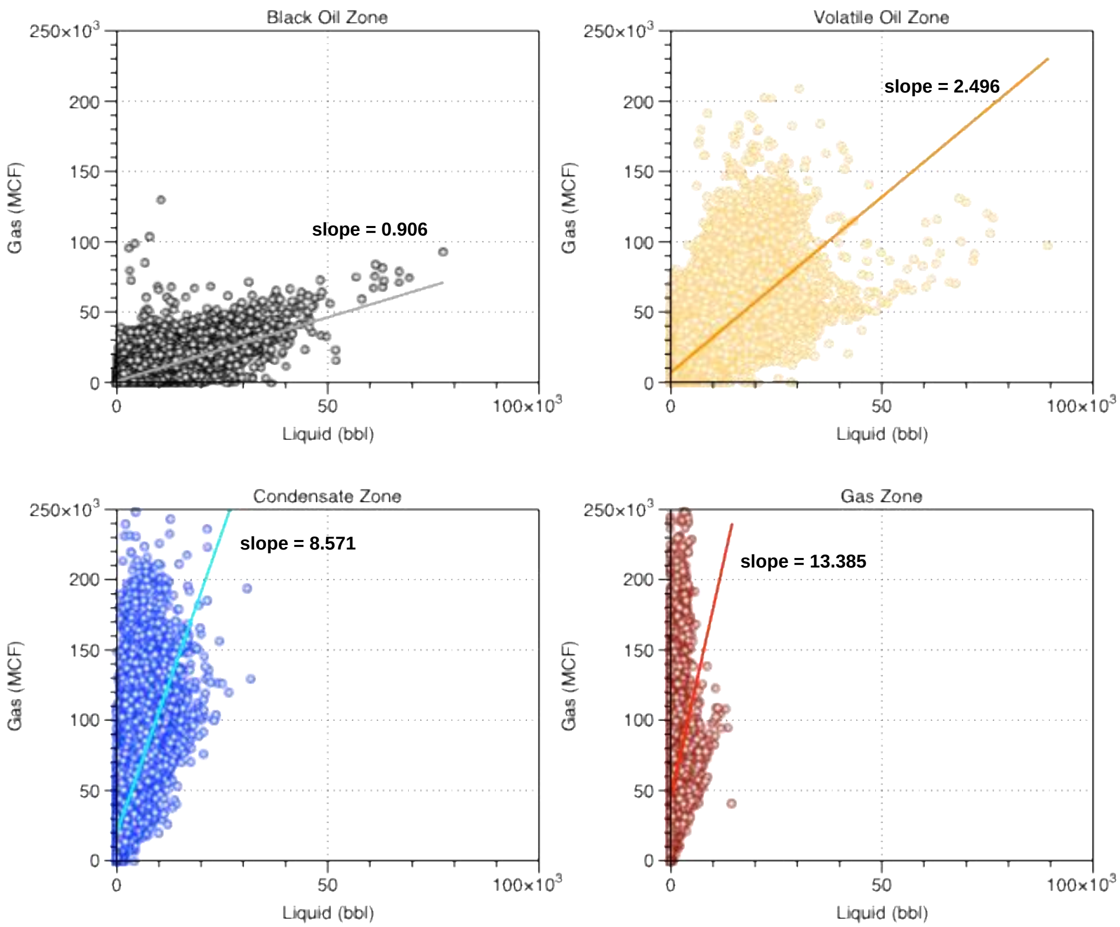


FIGURE 9 Monthly Gas-to-Liquid (GLR) ratio based on monthly production data for each well by zone, 2009–2013.

The annual liquids and gas productions by zone are reported in Table 11.

TABLE 11 IHS-BEG monthly liquids and gas production by year and by zone type

	Liquids (billion bbl)					Liquids (million bbl per day)				
Production Zone	BO	VO	C	Gas	Total	BO	VO	C	Gas	Total
2009	0.12	0.22	0.21	0.09	0.64	0.33	0.59	0.58	0.25	1.74
2010	3.6	4.8	2.4	0.23	11.1	9.94	13.26	6.51	0.63	30.3
2011	29.7	34.5	10.5	0.36	75.1	81.5	94.5	28.8	0.98	206
2012	93.6	87.9	21.4	0.99	204	256	241	58.5	2.72	558
2013	169	139	30	2.47	340	462	382	82.0	6.75	933
	Gas (million cubic feet)					Gas (million cubic feet per day)				
Production Zone	BO	VO	C	Gas	Total	BO	VO	C	Gas	Total
2009	0.12	1.15	3.92	11.3	16.5	0.00	0.00	0.01	0.03	0.05
2010	3.5	21.3	38.1	47.9	111	0.01	0.06	0.10	0.13	0.30
2011	27.6	129	173	113	444	0.08	0.35	0.47	0.31	1.22
2012	95.8	321	333	187	938	0.26	0.88	0.91	0.51	2.57
2013	181	520	469	238	1,408	0.49	1.42	1.29	0.65	3.86

2.6 WELL COMPLETION

As shown in Table 12, the number of completed wells increased continuously from 2009 to 2013. In addition, the average length of wells increased slightly from 3570 ft/well in 2009 to 5,310 ft/well in 2013, while the average depth decreased slightly.

TABLE 12 Eagle Ford well completion summary, based on the HIS-BEG Data (2009-2013)

		Length (ft/well)				Depth (ft/well)			
	Well Completions	Mean	Med.	5th	95th	Mean	Med.	5th	95th
All Years	8,301	5,094	4,971	3,417	7,150	9,957	10,021	6,730	13,215
2009	61	3,572	3,627	1,635	5,019	10,111	10,887	5,936	13,052
2010	426	4,292	4,345	2,263	5,768	9,775	9,775	5,741	13,385
2011	1,554	4,826	4,792	3,285	6,571	10,074	10,447	6,585	13,400
2012	2,747	5,131	4,996	3,544	7,207	10,065	10,163	6,797	13,279
2013	3,513	5,307	5,151	3,662	7,417	9,839	9,813	6,798	13,008

2.7 WELL DEPTH

Data on the Depth Total Driller (DTD, total well depth based on driller report, i.e., total length drilled) and Depth True Vertical (DTV, true vertical depth at total depth drilled) variables exist for 8301 and 8259 wells, respectively. There are also 3013 wells with missing DTD values and 3055 wells with missing DTV values. For the wells with missing values, we replace the missing values with calculated median values, as summarized in Table 13:

TABLE 13 Depth Total Driller (DTD) and Depth True Vertical (DTV) summary statistics

Variable	Obs	Mean	Median	Std. Dev.	Min	Max	Missing Values
Depth Total Driller, DTD (ft)	8301	15584	15564	1749.20	5329	21912	3013
Depth True Vertical, DTV (ft)	8259	9978	10049	1762.57	2760	15549	3055

FIGURE 11 and FIGURE 12 show the distribution of DTD and DTV values, respectively, with respect to well counts.

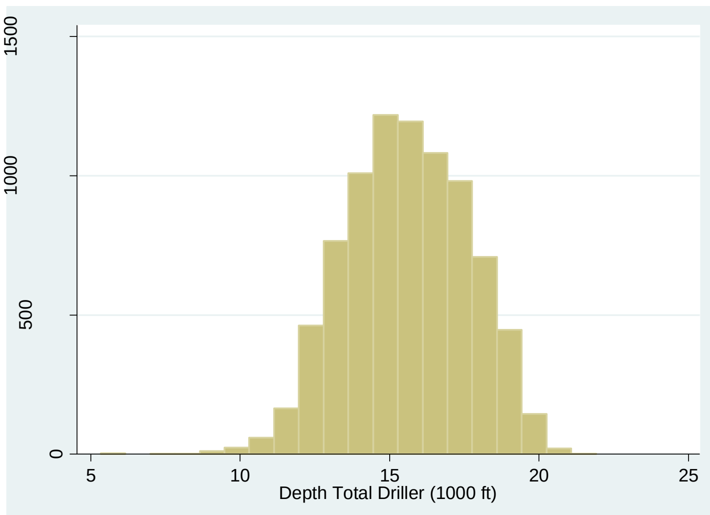


FIGURE 10 Depth Total Driller (1000 ft) for each well in Eagle Ford (8301 wells).

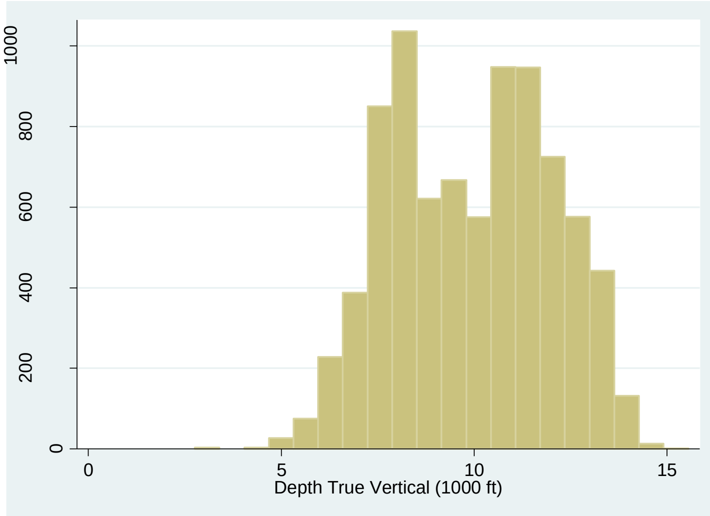


FIGURE 11 Depth True Vertical (1000 ft) for each well in Eagle Ford (8259 wells).

Figure 12 shows the Depth Total Driller trend as determined by the date of the completion of each well.

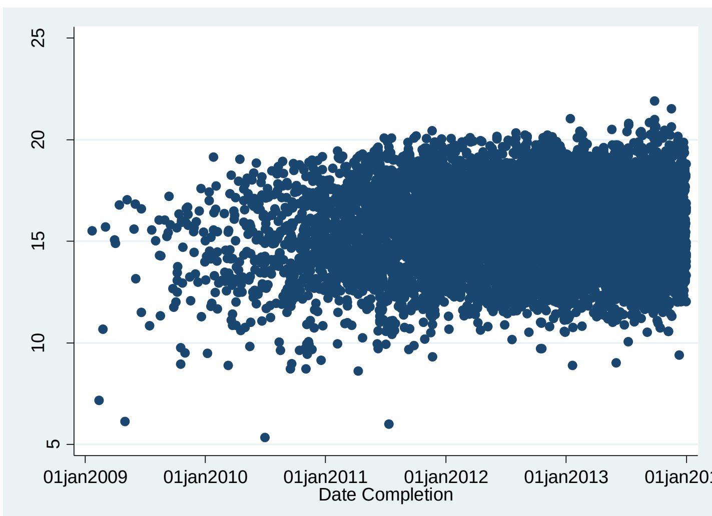


FIGURE 12 Depth Total Driller (1000 ft) as a function of date of well completion.

A scatter plot of DTD vs DTV shows a linear relation between the two depth variables, as shown in FIGURE 13, suggesting DTD is equal to DTV plus 5000 ft.

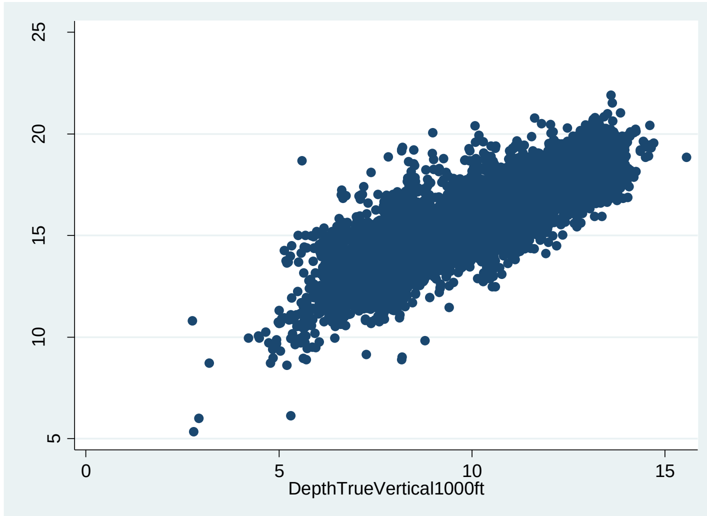


FIGURE 13 Scatter plot of Depth Total Driller and Depth True Vertical.

2.8 FRACTURING WATER AND PROPPANT USE

The water and proppant use variables for HF have been developed by the BEG from IHS and FracFocus water data after going through a rigorous data cleaning and verification process. Wells with missing data were represented by values based on the quarterly average water and proppant use data from the wells with available data. In Table 14, we report the annual total water use and proppant use from the IHS-BEG dataset. Both annual total water use and proppant use have sharply increased from 2009 to 2013.

TABLE 14 Total HF water and proppant use in Eagle Ford (2009–2013) based on IHS-BEG Dataset

Year	HF Water Used (10^9 gal)	HF Proppant Used (10^9 lb)
2009	0.4	0.1
2010	2.4	1.5
2011	7.0	6.4
2012	12.5	12.2
2013	17.8	17.6
Total	40.1	37.8

The data for water and proppant use as listed in TABLE 14 only include 8301 wells. Water and proppant use refer to the amount of water and proppant used for HF and before the start of production. In other words, the reported volumes of water and proppant use represent total amounts used up to the completion of the wells in Eagle Ford for the 8301 wells with available data. The water and proppant use data are missing for 3013 wells. We replaced the missing values with their respective medians, i.e., 4.3 million gal water per well (Figure 14) and 4.3 million lb proppant per well (Figure 15). We also calculated the average ratio of proppant to water at 1.06 lb proppant/gallon of water. The value was calculated by averaging the ratios for each well.

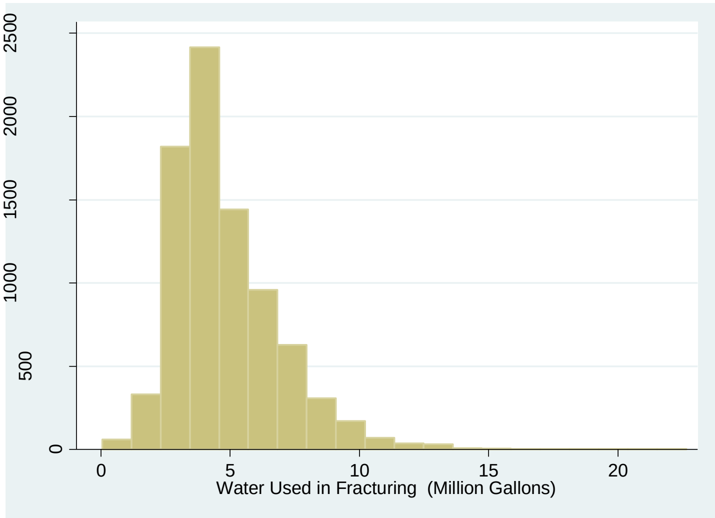


FIGURE 14 Water used for fracturing in Eagle Ford (N=8301 wells).

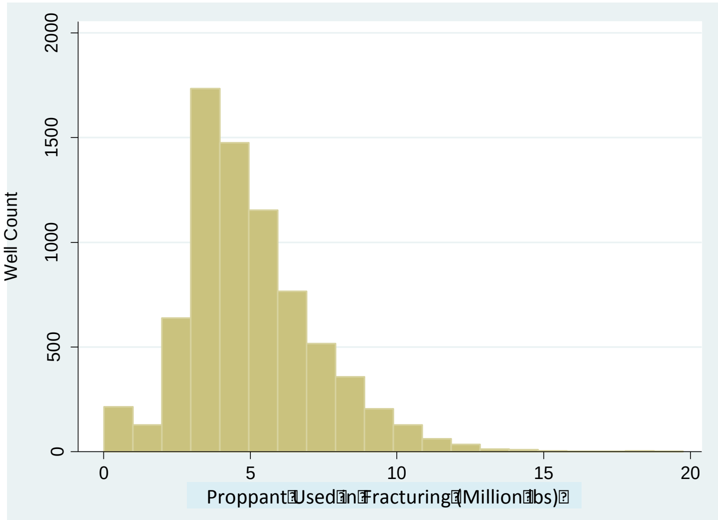


FIGURE 15 Proppant used for hydraulic fracturing in Eagle Ford (7460 wells: 8301 wells with reported proppant used, minus 14 wells with >20 million lb proppant used and 827 wells with zero proppant used).

With regard to outliers or misreported data for proppant use, we implemented two changes in the data. First, for wells with reported proppant use higher than 20 million lb, we replaced those values with the median value. This affected only 14 wells in the database. This cutoff point is the same as the suggested range for Bakken by Brandt et al. (2015). In addition, for 827 wells, we replaced the reported zero proppant use with the median. These wells are indeed fracturing wells because they have reported non-zero water use. FIGURE 15 is the histogram of the developed data on proppant use for wells in Eagle Ford.

TABLE 15 includes the distributions of water use per horizontal lateral length (gal/ft) and proppant use per horizontal lateral length (lb/ft) by year. As shown in

TABLE 15 and
FIGURE 16, water use and proppant use per horizontal lateral length have remained stable in the last several years.

TABLE 15 Distribution of water use (gal/ft) and proppant use (lb/ft)

	Water Use (gal/ft)				Proppant Use (lb/ft)			
	Mean	Med.	5th per-centile	95th per-centile	Mean	Med.	5th per-centile	95th per-centile
All Years	946	845	459	1,728	896	841	0	1,794
2009	1,709	1,776	419	3,443	616	667	0	1,444
2010	1,313	1,220	493	2,517	829	844	0	1,513
2011	931	857	493	1,640	858	830	0	1,616
2012	883	793	446	1,619	864	841	0	1,704
2013	953	866	451	1,701	944	911	0	1,883

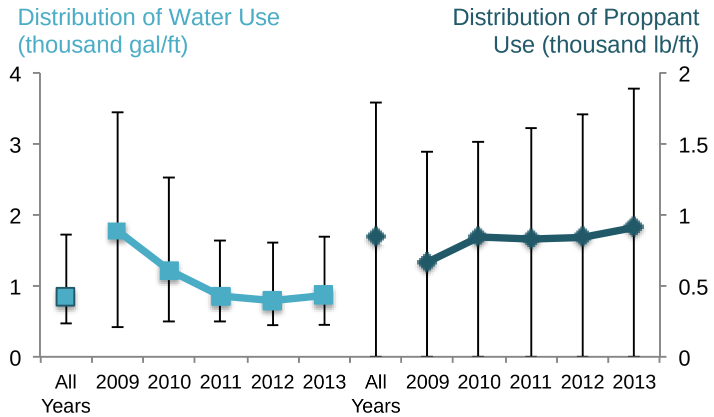


FIGURE 16 Median water use per horizontal lateral length (gal/ft, square dots) and proppant use

(lb/ft, diamond dots) for Eagle Ford shale oil/gas production. Also shown are the 5th and 95th percentile values.

2.9 GAS COMPOSITION

The IHS-BEG original databases do not include gas composition. Table 16 and Table 17 show typical characteristics, compositions, and initial production of five shale plays in the U.S., including Eagle Ford, as suggested in the literature.

TABLE 16 Typical characteristics of five U.S. unconventional plays (Conder and Lawlor 2014)

	Characteristics	Bakken	Eagle Ford	Utica	Marcellus	Niobrara
Reservoir Characteristics	Estimated basin area, sq. mi.	200,000	N/A	170,000	95,000	8,000
	Depth, ft.	8,500-10,500	4,000-14,000	2,000-2,000	4,000-8,500	4,000-8,000
	Net thickness, ft.	140	100-500	100-1,000	50-200	270-375
	Total organic carbon	6-20	3-7	1.25 – 3.0	3-12	4.0-4.5
	Total porosity, %	5	6-11	3-12	7-12	4-14
	Permeability	<.01 mD	<.01 mD	<.01 mD	<.01 mD	<.01 mD
	Well spacing, acres	40-160	20-160	60-160	40-160	40-320
	Original gas in place, Tcf/MMbbl	7,400 MMbbl	8.4 Tcf/1,250 MMbbl	60 Tcf/1,140 MMbbl	1,500 MMbbl	20-30 MMbbl
	Technically recoverable resources, Tcf/MMbbl	40,000 MMbbl	10 Tcf/2.0 MMbbl	38.2 Tcf/940 MMbbl	410 Tcf	OOIP 40 MMboe
Well Details	Typical initial decline rate	45%	40%	N/A	70%	45%
	Well spacing, acres	20-320	20-160	20-160	40-320	160-640
	Gross EUR (Bcfe)	5.1	1.5	1.2	3.6	1.1
	Net EUR (Mboe)	697	575	455	570-950	400
	Gross well cost ($MM)	6.5	5.5 to 9.5	6.0	4.5	5.0
Composition	Gas Btu/cf	1,200-1,600	900-1,600	1,000-1,400	900-1,550	1,200-1,600
	Oil, °API gravity	38-45	32-47	35-42	48-60	35-40
	CO_2 content	Moderate	Variable	Low	Low	Low
	H_2S content	Moderate	Variable	Low	Low	Low
	Chloride content	Low	Variable	Low	Moderate	Low

TABLE 17 Typical compositions (mol %) and initial production rates for five U.S. shale plays (Conder and Lawlor 2014)

	Bakken	Marcellus	Utica	Niobrara	Eagle Ford
Nitrogen	1.62	0.2	0.533	1.77	0.297
Carbon dioxide	0.37	2.42	0.086	1.39	1.99
Hydrogen sulfide, ppmv	10-400	N/A	0.000	N/A	0.0
Methane	52.67	76.75	81.212	68.49	66.62
Ethane	24.6	12.58	12.835	11.21	16.30
Propane	12.86	5.06	3.716	10.41	8.52
Isobutane	1.34	1.08	0.467	1.03	1.14
Butane	3.78	1	0.719	3.68	2.71
Isopentane	0.71	0.35	0.156	0.72	0.66
Pentane	1.05	0.32	0.123	0.84	0.75
Hexanes Pus	1	1.62	0.153	0.46	0.99
GPM	12.78	5.78	4.99	8.082	8.8
Btu/cf (dry, gross)	1,576	1,234	1,197	1,402	1,409
Flow rate, Mcf/d	500	2,500	2,000	250	500
Temperature, °F	130	100	75	130	100
Pressure, psig	30	150	1,200	30	150

Compared with the data we previously reported, the depth in Table 16 (4000–14000 ft) is in the same range. Table 16 suggests that the gas heat content is in the range of 900–1600 Btu/cf for Eagle Ford and 1200–1600 Btu/cf for Bakken. Brandt et al. (2015) reported 1500 Btu LHV/scf, based on a fraction of wells reporting gas composition (< 10% of wells in the dataset), which is close to the 1576 Btu/scf reported for Bakken in Table 17. Table 17 indicates that the gas composition (mol%) for Eagle Ford is 66.2% methane, 16.3% ethane, 8.52% propane, and 2.71% butane, and the heating value is 1409 Btu/scf.

2.10 FRACTURING GRADIENT AND FRACTURING PRESSURE

Table 18 summarizes the range of reported values for the fracturing gradient for Eagle Ford. To calculate the fracturing pressure, we assumed 0.9 psi/ft for the fracturing gradient.

TABLE 18 Fracturing gradient summary for Eagle Ford

Value (psi/ft)	Source	Notes
>0.9	Basu et al. (2012)	
1.05	McNealy (2013)	
0.85	Breitling (2012)	>1 as fracturing progresses to the heel
>0.9	Bazan et al. (2011)	Fracture gradients greater than 1 psi/ft are a result of shale storage and well-bore effects, and not a physical characteristic of the fracture extension pressure.

We calculated the fracturing pressure by multiplying the fracturing gradient by true vertical depth for each well (8259 wells), as shown in Table 19 for FracturePressure. For the remaining wells with missing fracture pressure, we replaced the missing value for each well with the median of the fracturing pressure for all wells, as summarized in Table 19 as “FracturePressureUpdated.”

TABLE 19 Fracture pressure summary for Eagle Ford, based on 0.9 psi/ft fracture gradient

Variable	Obs	Mean	Std. Dev.	Min	Max
FracturePressure	8259	8957	1856	2484	13994
FracturePressureUpdated	11314	8980	1586	2484	13994

2.11 SUMMARY OF EAGLE FORD MAIN WELL CHARACTERISTICS

Table 20 includes a summary of Eagle Ford's main well characteristics from the UCDavis-EagleFord database.

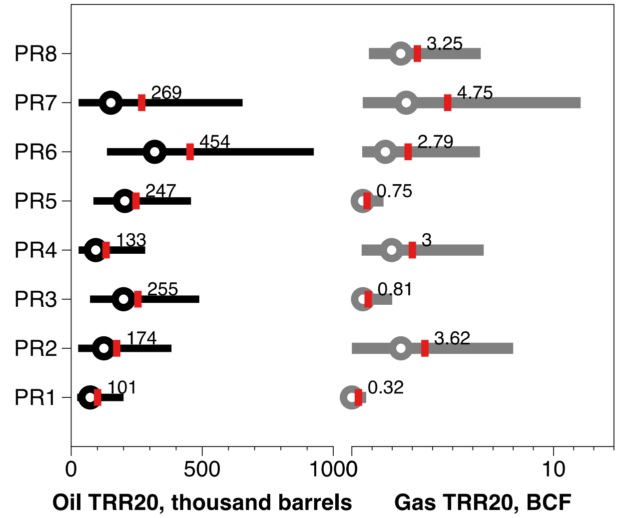
TABLE 20 Well property summary (averages across all zones and all years)

Property	Obs	Median	Mean	Std. Dev.	Min	Max	Units
Oil API Gravity	11314	46.2	48.03	8.59	27	94	[deg. API]
Condensate Gravity	2754	58	57.72	5.46	34.8	79.4	Condensate Gravity
Gas Gravity	3420	0.73	0.73	0.07	0.56	1.44	Gas Gravity
Depth Total Driller	11314	15564	15584	1749	5329	21912	[ft]
Proppant Used	11314	4285680	4772159	1898980	3415	1.98E+07	[lb]
Depth True Vertical	11314	10049	9978	1763	2760	15549	[ft]
Water Used	11314	4303740	4679970	1820315	52868	2.26E+07	[gallon]
FracturePressureUpdated	11314	9044	8980	1586	2484	13994	[psi]

2.12 ESTIMATED ULTIMATE RECOVERY (EUR)

Gong (2013) used the Markov Chain Monte Carlo method to develop probabilistic decline curves to forecast reserves and resources in Eagle Ford. Individual well reserves and resources were estimated and then aggregated probabilistically within each production zone[7] and arithmetically between production zones. The results are shown in Figure 17.

[7] Gong (2013) categorizes production region on the basis of geology, production indicators and fluid types.



Production Region	Fluid Type	Initial oil rate	Formation	True Vertical Depth, ft	Area, Acres
PR1	Black Oil	Low	Upper and Lower	4,056	799,836
PR2	Condensate/Volatile Oil	Medium-Low	Upper and Lower	6,505	942,734
PR3	Black Oil	Medium	Upper and Lower	7,719	1,617,410
PR4	Condensate	Medium-Low	Upper and Lower	10,874	584,070
PR5	Black Oil	Medium-High	Lower	9,450	977,484
PR6	Volatile Oil	High	Lower	12,286	338,000
PR7	Condensate	Medium	Lower	13,470	468,888
PR8	Dry Gas	None	Upper and Lower	10,532	1,201,185

FIGURE 17 Estimated oil and gas technical recoverable resources for 20 years (TRR20) by production region as estimated by Gong (2013). The range shows the 10th and 90th percentiles as well as the median (circles) and mean (red lines) values. The numbers shown are the mean values. Also included are the definitions of production zones used by Gong (2013).

The EIA fits monthly production to a decline curve: A hyperbolic curve is used to characterize initial production, and the curve shifts to exponential when the annual decline rate reaches 10%. As defined by the EIA (2014b), the estimated ultimate recovery (EUR) is "the sum of actual past production from the well, as reported in the data, and an estimate of future production based on the fitted production decline curve over a 30-year well lifetime." Significant variability exists for production decline curves and the associated EURs for individual wells within single plays, and even within discrete sections (i.e., counties, the level of aggregation used by EIA as a basis for projections of overall production totals both for oil and for NG) of a single play (EIA, 2014c, pp. IF-11). According to EIA's analysis, for many wells in tight formations, nearly 50% of the EUR has been produced within three years. Thus EUR estimates tend to stabilize after three years of production even though all EURs are fitted to four years of production in EIA's analysis. Table 21 shows EIA's estimated EURs for both oil and gas by county. Compared with EIA's values, the values estimated by Gong (2013) are at least two times higher for oil EURs and several times higher for gas EURs in gas-producing zones.

TABLE 21 EIA's EUR estimates based on 2008–2013 oil and gas production in Eagle Ford

Zone	County	EUR (Mbbl/well)	Zone	County	EUR (Mbbl/well)
Eagle Ford-Oil	Atascosa, TX	133	Eagle Ford-Dry Gas	Bee, TX	1,032
Eagle Ford-Oil	Brazos, TX	83	Eagle Ford-Dry Gas	Dewitt, TX	1,321
Eagle Ford-Oil	Burleson, TX	23	Eagle Ford-Dry Gas	Karnes, TX	1,468
Eagle Ford-Oil	Dewitt, TX	365	Eagle Ford-Dry Gas	Live Oak, TX	1,717
Eagle Ford-Oil	Dimmit, TX	124	Eagle Ford-Dry Gas	Webb, TX	2,169
Eagle Ford-Oil	Frio, TX	87	Eagle Ford-Wet Gas	Dewitt, TX	1,653
Eagle Ford-Oil	Gonzales, TX	193	Eagle Ford-Wet Gas	Dimmit, TX	872
Eagle Ford-Oil	Karnes, TX	218	Eagle Ford-Wet Gas	Karnes, TX	1,066
Eagle Ford-Oil	Lavaca, TX	118	Eagle Ford-Wet Gas	Live Oak, TX	1,159
Eagle Ford-Oil	Lee, TX	38	Eagle Ford-Wet Gas	Webb, TX	1,839
Eagle Ford-Oil	Maverick, TX	24	Eagle Ford-Dry Gas	Bee, TX	1,032
Eagle Ford-Oil	Webb, TX	76	Eagle Ford-Dry Gas	Dewitt, TX	1,321
Eagle Ford-Oil	Wilson, TX	98	Eagle Ford-Dry Gas	Karnes, TX	1,468

Source: EIA 2014c. Eagle Ford-Oil, Dry Gas and Wet Gas are defined in Figure A.3. in the Appendix A.
Mbbl = thousand barrels

2.13 OTHER OPGEE PARAMETERS

In this section, we discuss our methodology for calculating other Eagle Ford-specific OPGEE input parameters on the basis of our developed data and literature reviews. These parameters include production methods, type of drilling equipment, typical rates of penetration, typical rates of torque applied, and typical rates of pressure drop through the downhole mud motor.

2.13.1 Production Methods

An artificial lift is used to lower the bottom hole pressure of a reservoir in order to increase the production rate (PetroWiki 2014). A reservoir contains enough natural lift "if reservoir pressure is higher than the pressure exerted by a full column of a single-phase well bore fluid, and the fluid flows to the surface if the flow path is unobstructed." The rise of gas bubbles is another type of lift, which does not require the enforcement of an artificial lift. For the reservoir with rising gas bubbles, "the gas passing through the water will prevent it from settling quickly, and if the gas flow is high enough—above the critical gas flow velocity—it will force the water up the hole and out to the separators at some rate less than the gas velocity" (King 2012).

Error! Reference source not found. summarizes the most common conventional artificial lift systems and the horizontal profiles for which each system works best.

TABLE 22 Artificial lift options (Presley 2012)

Lift Mechanism	Deviation Applicability	Lift Efficiency in Horizontal	Volume Lifted per Day	Solids Tolerance	Gas Tolerance
Sucker Rod Pump (Beam Pump)	Vertical section	Not usually deviated	1,000 bbl/d	Poor	Requires separation
Gas Lift	Any position	Poor	Varies with gas used	Excellent	Excellent
Electric Submersible Pump (ESP)	Full horizontal	Excellent	>20,000 bbl/d	Poor	Requires separation
Jet pump	Full horizontal	Moderate	Tubular & depth limited	Moderate	Limited
Plunger	To 20 degrees	Not used	10–50 bbl/d	Poor	Good
Progressing Cavity Pump	Full horizontal	Good	Varies, usually low	Excellent	Moderate
Chamber Lift	Vertical	Unknown	Low	Good	Good

A well's profile is a determining factor in choosing a suitable artificial lift system. **Error! Reference source not found.** summarizes our recommended parameters for artificial lift for Eagle Ford production. More descriptions of these technologies can be found in Appendix F.

TABLE 23 Eagle Ford production methods input for OPGEE

Data input	OPGEE Default	Bakken Value*	Eagle Ford Value	Source	Notes
Downhole Pump	1	1	0–1	(Alvarez et al. 2014, PetroWiki 2014)	Third stage of production
Water Reinjection	1	0	0		
Gas Reinjection	1	0	0		
Water Flooding	0	0	0[8]		Some tests have been performed and seemed to prove the method to be effective and profitable.
Gas Flooding	0	0			
Gas Lifting	0	0	1–0	(Presley 2012, Baker Hughes 2014)	Potentially used in stage 2 production. Inefficient and expensive for liquids-rich areas.
Steam Flooding	0	0	0		
Eagle Ford Electric Submersible Pump (ESP)	NA	NA	1–0	(Ferguson and Narvaez 2013, Baker Hughes 2014)	1 for high GOR areas—used in transitional stage.

* See Brandt et al. (2015).

8 Several water flooding techniques have been tested. Water flooding has the potential to be adopted as a secondary technique to increase production and profitability.

2.13.2 Field properties

The new OPGEE model will treat each well as a field. In addition, for each month, there is a worksheet, which contains all wells with production data in that month. In this section, we discuss well-relevant properties for the OPGEE model instead of field properties.

Field Name: Well API number in Eagle Ford OPGEE.

Well Age: Months of production or number of months from completion.

Well Depth: In the IHS Eagle Ford data, we have the variable "ave depth," which represents "Average depth (ft) of lateral section." However, we consider true vertical depth for each well as the well depth, following Brandt et al. (2015).

Oil Production Volume: Liquids production volume.

Number of Producing Wells: This number is 1 for Eagle Ford because in each run we treat each well as a field.

Number of Water Injecting Wells: This is zero in Eagle Ford, owing to the concept of horizontal drilling and HF.

Well Diameter: The IHS data do not include this value for each well. However, as summarized below, for Eagle Ford the well diameter range could be from 2.5 to 5.5 in.:

- The range is 2.5 to 4 in.[9]

- Observations on drilling shale wells in the U.S. shale plays, including Eagle Ford:
  - "Completion part of hole typically drilled out of 7 in. casing set either before or after the curve." (Kennedy et al. 2012)
  - "Cased hole wells typically use either a 4.5 in. or 5.5 in. completion string." (Kennedy et al. 2012)

Reservoir Pressure: Tables 24 and 25 provide summary statistics of the pressure variables in the IHS-BEG Initial Test and Follow-up Test datasheets.

[9] Personal communication with Adam Brandt, Stanford University, February 2015.

TABLE 24 Pressure variables from the IHS-BEG Initial Test data

Variable	# Wells	Mean	Std. Dev.	Min	Max
PressureFlowingTubingPSI	7528	2484	1878	2	13333
PressureFlowingCasingPSI	4819	2706	2202	1	9014
PressureShutinTubingPSI	2197	4735	2351	265	14333
PressureShutinCasingPSI	1692	4622	2384	15	10500
PressureBottomHolePSI	97	4587	2037	200	9457

TABLE 25 Pressure variables from the IHS-BEG Follow-up Test data

Variable	# Wells	Mean	Std. Dev.	Min	Max
PressFlowingTubePSI	3248	2082	2029	1	8732
PressFinalShutInPSI	3422	3409	2231	15	13161
PressCasingPSI	0				
PressBHStaticPSI	491	5628	3544	498	15369

Field properties are summarized in Table 26.

TABLE 26 Eagle Ford fields (wells) parameters for OPGEE

Data Input	Unit	Default	Eagle Ford	Data Source
Field Location (Country)	NA	Generic	NA	
Field Name	NA	Generic	Well API number	IHS
Field Age	yr.	35	Months	IHS
Field Depth	ft	7240	Average depth (ft) of lateral section	IHS
Oil Production Volume	bbl/d	1500	Oil, Gas Production (Mcf)	IHS
Number of Producing Wells	[-]	8	1	
Number Of Water-injecting Wells	[-]	5	0	
Well Diameter	in.	2.775	See discussion	
Productivity Index	bbl/psi-d	3	See discussion	
Reservoir Pressure	psi	1557	See discussion	

2.13.3 Processing practices

Heater/Treater:

For Eagle Ford, we set heater/treater to 1 because operators need to break up oil/gas/water emulsion in the oil wells and to remove contaminants from NG before sending the gas to the pipeline, as summarized below:

"Heater treaters are used at upstream oil wells to break up oil/gas/water emulsions and to separate the crude oil from water and other foreign materials. At gas wells, a heater treater may be used to remove contaminants (liquid hydrocarbons and water) from the natural gas at or near the well head before the gas is sent down the production line to the gas plant. The heater treater is a combination of a heater, free water knockout, and oil/condensate and gas separator. It prevents the formation of ice and natural gas hydrates that may form under the high pressures associated with the gas well production process. These solids can plug the wellhead. Since chokes in the wellhead restrict the flow of the oil and gas from the well, temperatures may drop due to the pressure changes of the choke. This may cause the water or hydrates to freeze and plug the well, thereby slowing or stopping the condensate and gas production." (Lang et al. 2013)

Table 27 includes recommendations for calculating heater emissions in Eagle Ford, as prepared by the Eastern Research Group for the Texas Commission on Environmental Quality, Air Quality Division, in 2013.

TABLE 27 Recommendations for calculating heater emissions in Eagle Ford (Lang et al. 2013)

Average Number of Heaters Per Well	Average Heater Size (MMBtu/hr)	Average Hours of Operation (hr/yr)	Average Fuel Heat Content (Btu/scf)
0.54	0.906	7574	1289

Stabilizer Column:

"Flowing from the gathering pods, condensate liquids are captured in large separators. Condensates may contain a relatively high percentage of light and intermediate components, which can be separated easily from entrained water because of the lower viscosity and greater density difference with water. Therefore, some sort of condensate stabilization should be installed for each gas well production facility, whether centralized or for each well pad. The term "condensate stabilization" refers to the process of increasing the amount of intermediates such as propane (C3) and pentanes plus (C5+), and heavy components such as hexane plus (C6+), in the condensate. This process is performed primarily to reduce the vapor pressure of the condensate liquids so that a vapor phase is not produced on flashing the liquids to atmospheric storage tanks." (Conway and Perkins 2011)

Application of AGR (Acid Gas Removal) Unit:

Amine acid gas removal is performed as part of gas processing to remove H_2S from produced gas. Owing to the presence of H_2S in Eagle Ford production, treatment of the produced gas is necessary. However, the very low H_2S-to-CO_2 ratio and the obligation to meet pipeline specification on CO_2 content make the treatment of the gas challenging. In particular, the use of

N-methyldiethanolamine (MEA) as the solvent for H_2S removal and CO_2 slip might be economical and effective. In addition, the effectiveness of modified methods such as using multi-pass trays, as argued by Weiland and Hatcher (2012), suggests that it is necessary to consider application of AGR units in Eagle Ford.

Application of Gas Dehydration Unit:

As heard by the Railroad Commission of Texas in connection with the application of Forest Oil Corporation to continue flaring gas at three completed wells in 2014, owing to the strict pipeline limitations on H_2S, CO_2 and N_2, operators must first flow compressed gas through an amine unit for H_2S and CO_2 removal and through a glycol dehydration unit for moisture removal. Operators must also apply a Joules-Thompson unit to remove heavy components or natural gas liquids (NGL). In addition, a nitrogen scavenging unit is used for nitrogen removal (Railroad Commission of Texas 2015).

Application of Demethanizer Unit:

"To assist in the fractionation, a large demethanizer column performs the duty of assisting the separation of the methane gas from the condensed ethane plus liquids. This column has varying points of entry of reflux streams and inlets that allows the column to function in an efficient manner." (Conway and Perkins 2011)

2.13.4 Flaring and venting

Flaring/Venting-to-Oil Ratio:

We report the 2013 monthly averages of flared/vented gas from gas wells and casinghead[10] gas for Districts 1, 2 and 4, which represent the three main Eagle Ford districts as reported by the Texas Railroad Commission. We divide flared/vented average monthly volume (Table 28) by the liquids production for oil and gas wells separately. We find a flaring/venting-to-liquid ratio of 123.48 scf/bbl for oil wells and 90.24 scf/bbl for gas wells, as summarized in Table 28. In 2013, 81% of flared/vented gas came from casinghead gas. The variations in the flaring/venting-to-liquid ratio are smaller between gas wells and casinghead gas.

TABLE 28 Monthly average flared/vented gas (Mcf) and flaring/venting-to-liquid ratio (scf//bbl) in Eagle Ford Districts (2013)

District	1	2	4	Total Eagle Ford	Flaring/Venting-to-Liquid Ratio (scf/bbl)
Gas Wells (Mcf)	509,489	53,357	51,701	614,546	90.24
Casinghead Gas (Mcf)	2,395,660	253,114	11,120	2,659,894	123.48

[10] Casinghead (oil well) gas is "natural gas produced along with crude oil from oil wells. It contains either dissolved or associated gas or both." Source: http://www.eia.gov/dnav/ng/tbldefs/ng_prod_sum_tbldef2.asp.

While we don't have separate vented/flared data, it might be reasonable to consider vented gas as part of the reported flared gas in Eagle Ford: "Once drilling and other well construction activities are finished, a well must be completed in order to begin producing. The completion process requires venting of the well for a sustained period of time to remove mud and other solid debris in the well, to remove any inert gas used to stimulate the well (such as CO_2 and/or N_2) and to bring the gas composition to pipeline grade." In Eagle Ford, gas vented during the completion process is usually flared (Alamo Area Council of Governments 2014, p. 22).

To get a more precise estimate, we extracted data from EPA GHG Reporting Program Data Sets (http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html) for 2013 on well completions flaring CO_2 and methane emissions for oil wells and gas wells. The results are shown in Table 29; we found that in oil wells, 87.3% of flared/vented methane was flared, whereas in gas wells 99.6% of flared/vented methane was flared. The total flaring and venting CO_2 and methane emission rates per completion are shown in the far-right column in Table 29.

TABLE 29 Annual average flared and vented gas per completion (million metric ton (MT) CO_2e/completion) in Eagle Ford

	Emissions (MT CO_2e)	Flared or Vented CH_4 (MT CH_4)	Flare Combustion Efficiency	% Flared	Emissions (MT CO_2e/ Completion)
TX-Oil					
Well Completions Flaring CO_2 Emissions (MT CO_2)	22,258	8,094	99.3%	87.3%	61.49
Well Completions Flaring Methane Emissions CO_2 Equivalent (MT CO_2e)	1,405	56			3.88
Well Completions Venting CO_2 Emissions (MT CO_2)	646				1.79
Well Completions Venting Methane Emissions CO_2 Equivalent (MT CO_2e)	29,522	1,181			81.55
# Completions	362				
TX-Shale Gas					
Well Completions Flaring CO_2 Emissions (MT CO_2)	109,031	39,648	98.9%	99.6%	128.27
Well Completions Flaring Methane Emissions CO_2 Equivalent (MT CO_2e)	10,981	439			12.92
Well Completions Venting CO_2 Emissions (MT CO_2)	7				0.01
Well Completions Venting Methane Emissions CO_2 Equivalent (MT CO_2e)	4,322	173			5.08
# Completions	850				

2.13.5 Extraction loss

Extraction Loss-to-Liquid Ratio:

The average extraction loss-to-liquid ratio across the districts is 1127 scf/bbl (Table 30), using the data from the Railroad Commission of Texas (2015). According to the EIA, "extraction loss" is simply shrinkage due to removal of natural plant liquid (NGL), which is not lost but removed and sent to market. The reduction in volume of NG is due to the removal of NGL constituents such as ethane, propane, and butane at NG processing plants. Because OPGEE already calculates this loss separately using its methodology, these values are ignored.

TABLE 30 Monthly average extraction loss for gas wells (Mcf) and extraction-to-liquid ratio (scf/bbl) in Eagle Ford districts (2013)

	District 1	District 2	District 4	Total Eagle Ford	Extraction Loss-to-Liquid Ratio (scf/bbl)
Gas Wells (Mcf)	3,150,575	3,736,918	814,875	7,702,368	1127.33

Summary of Processing Practices Assumptions for OPGEE

TABLE 31 summarizes Eagle Ford production processing practices.

TABLE 31 Eagle Ford processing practices for OPGEE

Data Input	Unit	Default	Eagle Ford	Source/Note
Heater/Treater	NA	0	1	
Stabilizer Column	NA	1	1	(Conway and Perkins 2011)
Application of AGR Unit	NA	1	1	(Weiland and Hatcher 2012)
Application of Gas Dehydration Unit	NA	1	1	(Railroad Commission of Texas 2015)
Application of Demethanizer Unit	NA	1	1	(Conway and Perkins 2011)
Flaring Rate	scf/bbl oil		123.5	Apportioned per barrel of EUR
Flowback Flaring Volume	scf/bbl oil		10.7 (median) 16.6 (mean)	
Fugitive Emissions	scf/bbl oil		36.5	1.3% of the median GLR of >2500 scf/bbl
Venting Rate	scf/bbl oil		1 (median)	13% of the flowback gas volume, apportioned per barrel of EUR (median value ~1 scf/bbl)
Volume Fraction of Diluent	[-]	0.000	NA	

2.13.6 Land use impacts

Parameters that determine the GHG emissions from land use change include ecosystem carbon richness and relative disturbance intensity. Ecosystem carbon richness determines the amount of carbon emissions per unit of disturbed land. We selected "moderate" to represent the carbon richness of the disturbed land, as the land is somewhere between arid or semi-arid grasslands and forested land. For relative disturbance intensity, we selected "low-intensity development," as the land use intensity closely resembles that of conventional NG development or directional drilling from centralized drill pads, where the land disturbed per well is small (FIGURE 18). TABLE 32 shows the default OPGEE inputs for land use impacts as well as the assumed OPGEE inputs for the Eagle Ford case.

FIGURE 18 Example of land disturbance prior to (left, October 2008) and after (right, December 2013) oil drilling in the Eagle Ford play, Dewitt County. Source: Google Earth. Eye Alt 42122 ft.

TABLE 32 Eagle Ford land use impacts for OPGEE inputs

	Default	Eagle Ford
Crude Ecosystem Carbon Richness		
Low carbon richness (semi-arid grasslands)	0	0
Moderate carbon richness (mixed)	1	1
High carbon richness (forested)	0	0
Field Development Intensity		
Low-intensity development and low oxidation	0	0
Moderate-intensity development and moderate oxidation	1	1
High-intensity development and high oxidation	0	0

2.13.7 Crude oil transport

In this section, we first discuss Eagle Ford liquids transport by truck, rail, pipeline, barge and tankers. We also discuss our methodology in estimating the share of each mode of transport used for Eagle Ford liquids transport, in addition to the distance over which each mode is used. The share and distance of each mode are used as input parameters in OPGEE.

2.13.7.1 Eagle Ford liquids production transport by pipeline

FIGURE 19 depicts Eagle Ford transport via crude and condensate pipelines. As shown in FIGURE 19, Gardendale is the convergence point of the Eagle Ford gathering systems in the West. Gardendale, with its several storage facilities and a truck unloading facility, is in fact the main starting hub of pipelines at the west side of the Eagle Ford. The rail terminal in Gardendale that connects to the Class 1 Union Pacific railroad also connects the hub to Houston and beyond to the East via rail. From Gardendale, five pipelines, with a capacity of 830 thousand barrels per day (kb/d) bring Eagle Ford crude and condensate to Three Rivers. The Valero Three Rivers, with a capacity of 90 kb/d, could process part of the volume from Gardendale. The rest is transported to Corpus Christi in the East via six pipelines with 970 kb/d capacity. The additional capacity from Three Rivers to Corpus Christi is due to additional truck unloading facilities in Three Rivers. From the Koch gathering system in the northeast of Three Rivers, two separate pipelines carry crude and condensate with 280 kb/d capacity. In total, pipelines ending in Corpus Christi have 1.25 million bbl/d (MMbbl/d) crude and condensate capacity.

Three main refineries in Corpus Christi—Flint Hills Resources, Valero, and Citgo—have 790 kb/d combined capacity, and they process around 172 kb/d Eagle Ford crude and condensate. The remainder is transported on barges via marine routes to destinations in the Gulf of Mexico and on tankers or seagoing barges to the U.S. Northeast (the Phillips 66 refinery in New Jersey) and Canada. Operators use barges to transport crude to U.S. East Coast destinations in addition to moving condensate to Houston and other refineries along the Gulf Coast to St. James, LA.

Figure 19 also shows two other pipelines connecting Eagle Ford to Houston. The first is the 350-kb/d Enterprise Product Partners crude pipeline and the other is the 300-kb/d Kinder Morgan crude and condensate pipeline.

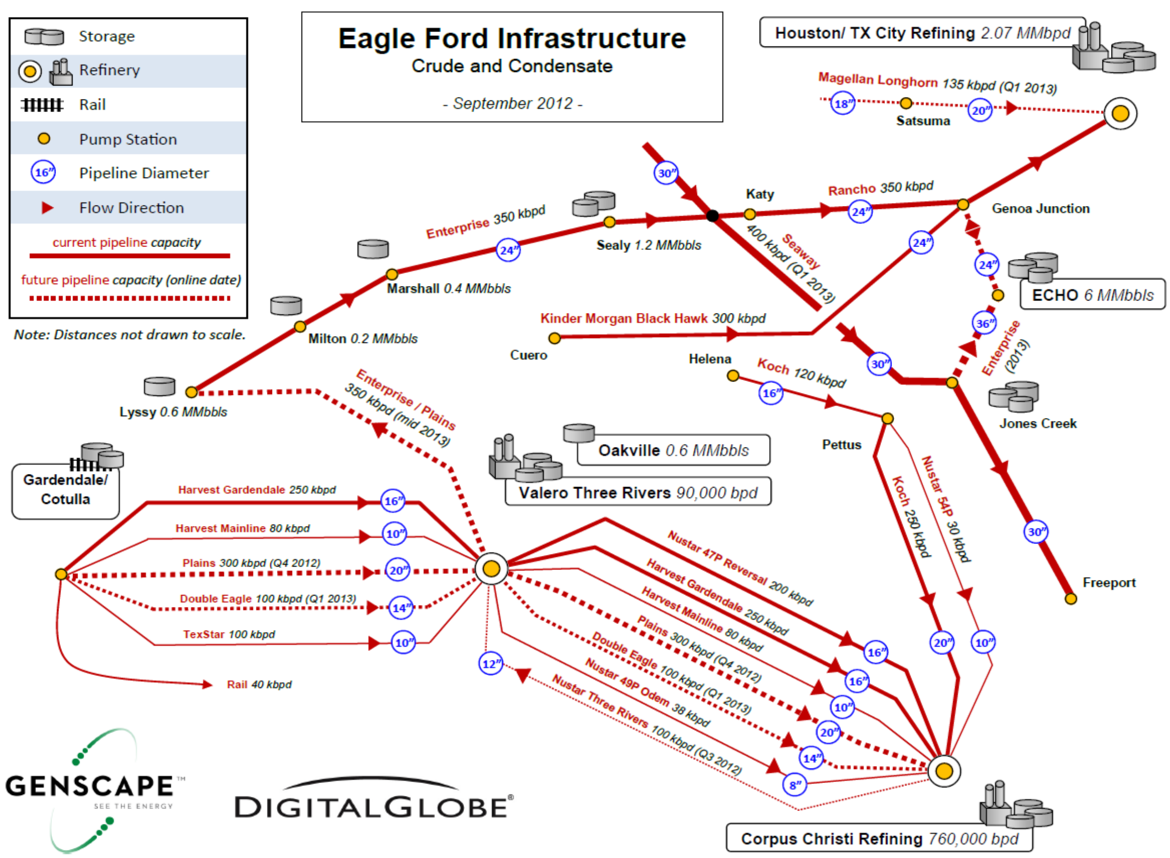


FIGURE 19 Eagle Ford pipeline infrastructure (Sternberg and Kovacs 2012)

Table 33 lists major pipelines for Eagle Ford crude and condensate.

TABLE 33 Eagle Ford pipeline infrastructure, summarized from Sternberg and Kovacs (2012)

Name	Origin-Destination	Length (mi)	Capacity (kb/d)
Harvest Gardendale	Gardendale-Three Rivers	73	250
Harvest Mainline	Gardendale-Three Rivers	73	80
Plains	Gardendale-Three Rivers	73	300
Double Eagle	Gardendale-Three Rivers	73	100
TexStar*	Gardendale-Three Rivers	73	100
Nustar	Three Rivers-Corpus Christi	73	200
Harvest Gardendale	Three Rivers-Corpus Christi	73	250
Harvest Mainline*	Three Rivers-Corpus Christi	73	80
Plains	Three Rivers-Corpus Christi	73	300
Double Eagle	Three Rivers-Corpus Christi	73	100
Nustar 49P Odem	Three Rivers-Corpus Christi	73	38
Koch*	Helena-Pettus	30	120
Nustar 54p*	Pettus-Corpus Christi	70	30
Koch*	Pettus-Corpus Christi	70	250
Enterprise	Lyssy-Sealy	147	350
Rancho	Sealy-Houston	50	350
Kinder Morgan*	Cuero-Houston	146	300

* Pipelines that are already built, as identified by Sternberg and Kovacs (2012). The total length of these pipelines is 406 mi.

2.13.7.2 Eagle Ford liquids transport by barge and tankers

FIGURE 20 shows the three main modes of transporting crude on the water in the U.S. The two main modes that also apply to Eagle Ford liquids production are Gulf Coast to U.S. Northeast (tanker or seagoing barge) and Gulf Coast to Canada (tanker). While there is no separation of conventional and unconventional crude in this figure, we could consider the 2013 ramp-up of crude-on-water vessel transport volume as the result of the unconventional production increase, and mostly Eagle Ford liquids production, in the Gulf Coast region. In 2013, while 7.5 MMbbl were transported by tankers and seagoing barges to the U.S. northeast, 12 MMbbl were sent to Canada via tankers or seagoing barges. On the basis of data from the first quarter of 2014, we could assume annual transport of 12 MMbbl to the U.S. Northeast and 44 million barrels to Canada, all via tankers or seagoing barges. Owing to the Jones Act and limited available U.S.-flag tankers (Frittelli et al. 2014), we consider all crude transport to the U.S. Northeast to be via seagoing barges. We also consider crude transport to Canada to be via tankers. The second marine route brings crude to Canada's Valero refinery in Quebec via tankers (2250 miles onshore).[11]

[11] As of January 2013, no such shipment had been reported (Fielden 2013b).

These annual seagoing barge and tanker transport volumes to the U.S. Northeast and Canada are equivalent to 33,000 bbl/d (barge) and 120,000 bbl/d (tanker). Therefore, for OPGEE, we add 33,000 bbl/d to the crude transport by barge to Houston refineries, as discussed below and not shown in Figure 20.

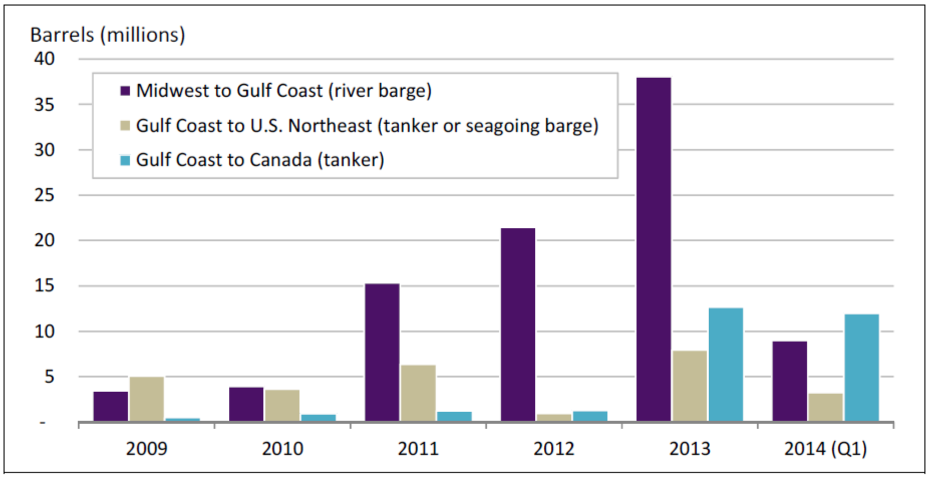


FIGURE 20 Waterborne crude oil movements between selected regions (Frittelli et al. 2014).

The total quantity of crude oil shipped from the Port of Corpus Christi in 2012 was 36 MMbbl or 98,000 barrels/d. Considering the 172,000 bbl/d refinery capacity for Eagle Ford liquids in local refineries in Corpus Christi, we estimate that an average of 270,000 bbl/d were shipped to Corpus Christi in 2012. From Corpus Christi, most of the 98,000 bbl/d have been shipped to Houston refineries using barges (Fielden 2013b). Another origin for the Eagle Ford liquids production on barges is the Port of Victoria on the barge canal. From the Port of Victoria, 1.6 million bbl per month or 53,000 bbl/d have been shipped to Houston refineries (Gold 2013). Therefore, we consider 151,000 bbl/d as the volume of Eagle Ford liquids transported by barge to the Gulf Coast. Adding this to the crude transport by barge to the U.S. Northeast, we estimate 184,000 bbl/d of crude transported by barge.

For Eagle Ford crude transported by barge, the marine distance around Florida to the refinery in Linden, NJ, is 2,200 miles (Gold 2013).[12] The distance between Corpus Christi and Canada's Valero refinery in Quebec, which is the tanker route, is 2250 miles onshore. In addition, the shortest length is between Corpus Christi and Houston (211 miles onshore). Therefore, we consider 184,000 bbl/d to be transported via barge, with an average trip length of

[12] "Phillips 66 has chartered two Jones Act tankers to move crude oil from Eagle Ford, TX, to a refinery in Linden, NJ (in proximity to New York Harbor). Phillips 66 has stated that if more Jones Act-eligible tankers were available, it would like to receive 100,000 bbl/d of Eagle Ford oil at this refinery (it would need several tankers to accomplish this, the exact number depending on the size of the tankers). EIA data (which specify oil movement only between regions, not to individual refineries) indicate that roughly five times more Texas crude oil is being shipped in foreign-flag tankers to refineries in eastern Canada than is being shipped in Jones Act-qualified tankers to U.S. Northeast refineries (Frittelli, et al. 2014).

568 miles. And 120,000 bbl/d are transported to Canada via tankers with a trip length of 2250 miles.

2.13.7.3 Eagle Ford liquids transport by rail

Table 34 lists six main rail loading terminals in the Eagle Ford shale play.

TABLE 34 Eagle Ford main rail loading terminals (Fielden 2013a)

Railroad	Location	Facility Type	Operator	Shipper/Capacity
Union Pacific	Gardendale	Transload, Unit Trains	Plains, USDC	40 Mbbl/day
Union Pacific	La Feria	Transload	Atlas Oil Co	
Texas, Gonzales & Northern Railway Co. – Union Pacific	Harwood	Transload, Unit Trains	EOG	70-Car Unit Trains, 45 Mbbl/d/Train
Union Pacific	Live Oak	Transload Truck to Unit Trains	Howard Energy	
Union Pacific	Elmendorf	Transload,	Frontier Logistics	
BNSF – Hondo Railway LLC	San Antonio	Transload, Unit Trains	Hondo Rail Co.	

As shown in Table 34, Union Pacific is the number one railroad operator in the Eagle Ford shale play. In fact, “Union Pacific, which operates 6,319 miles of track in Texas and an overwhelming majority of the rail lines servicing the Eagle Ford play, has experienced a strong increase in the movement of products related to development of shale fields.” (Institute of Economic Development (2012), p. 45)

As shown in Figure 21, the direction of the liquids movements by rail in Eagle Ford is from west to east. Therefore, we consider each of the five rail loading terminals shown in Figure 22 as the starting point for crude transport by rail in Eagle Ford. Four of these locations—Hondo Railway LLC, Gardendale Railroad Inc., Live Oak Railroad, and Texas, Gonzales & Northern Railway Co.—are among the six main rail loading terminals listed in Table 34. The Union Pacific La Feria terminal, however, is located on the Gulf Coast south of Corpus Christi. Therefore, we do not consider La Feria as one of the Eagle Ford crude-by-rail transport destinations. We also consider the Elmendorf location near San Antonio as one of the origins of Eagle Ford crude-by-rail transport. In fact, as outlined by the Union Pacific and shown in Figure 23, it is reasonable to consider Houston as the final destination of all Eagle Ford crude-by-rail transport.

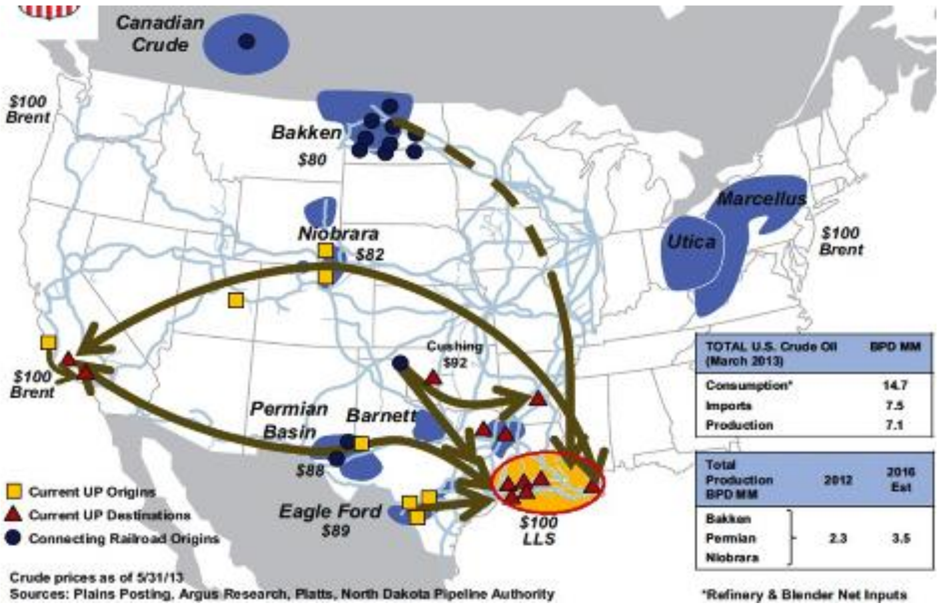


FIGURE 21 Union Pacific: crude-by-rail routes (Casey 2013)

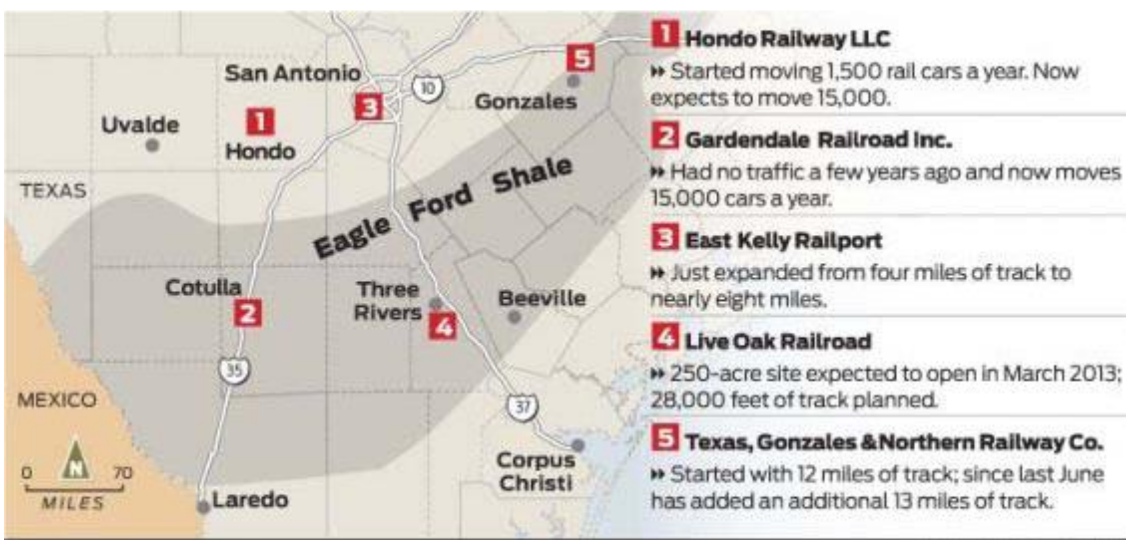


FIGURE 22 Expansion of rail loading terminals in Eagle Ford (Hiller 2012)

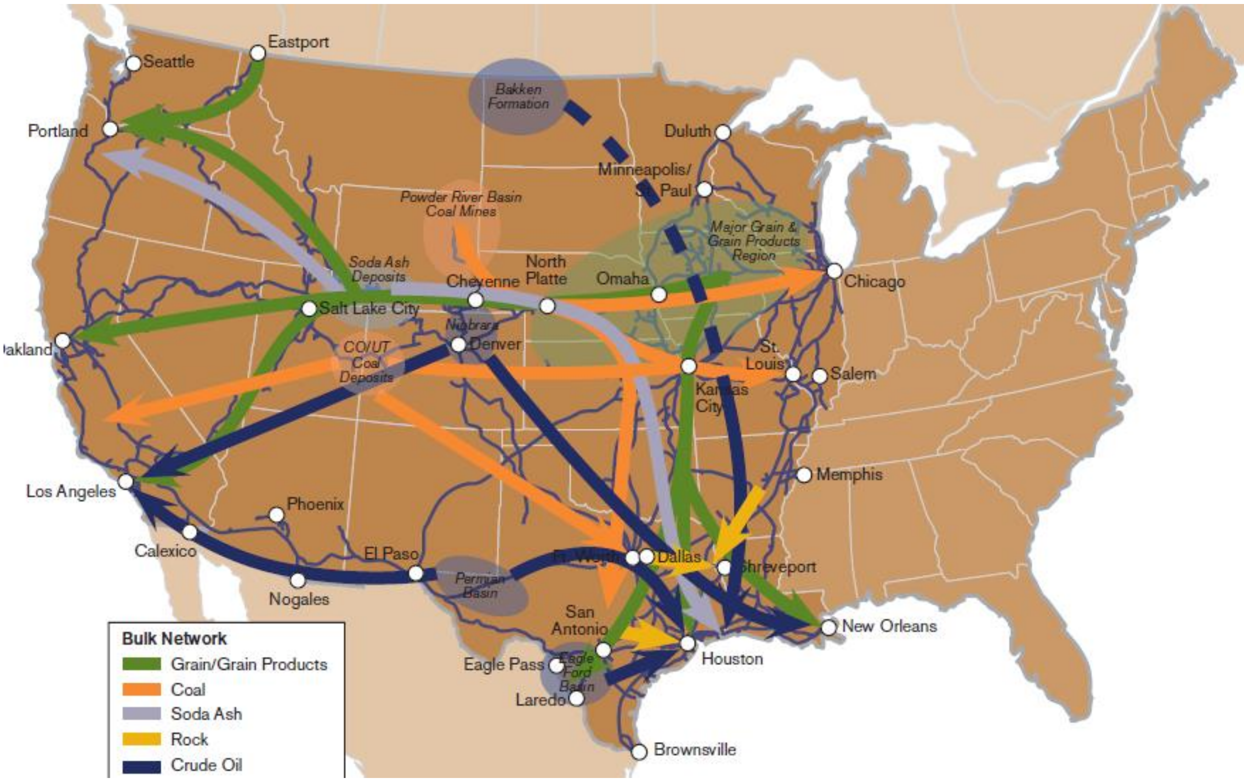


FIGURE 23 Union Pacific bulk network (Union Pacific 2012)

In summary, there are five main rail loading terminals servicing Eagle Ford crude. In Table 35, we have listed these five terminals and their distances from Houston.[13] We assume that the average distance by rail is 200 mi.

TABLE 35 Five main rail loading terminals servicing Eagle Ford crude and their distances from Houston

Railroad	Basin	Location	Distance to Houston (mi)
Union Pacific	Eagle Ford	Gardendale	277
TX, Gonzales & Northern Railway Co. – Union Pacific	Eagle Ford	Harwood	140
Union Pacific	Eagle Ford	Live Oak (Three Rivers)	220
Union Pacific	Eagle Ford	Elmendorf	200
BNSF – Hondo Railway LLC	Eagle Ford	San Antonio	200

[13] "For railroads, the much more lucrative aspect is the constant flow of inbound materials—such as frac sand, minerals, pipe, fracking fluids, cement and construction aggregate—used to support drilling operations in the regions." (Stagl 2014)

2.13.7.4 Eagle Ford liquids transport by truck

Trucks are used primarily to transport liquids to the starting point of the pipelines and rail loading stations. The pipelines in Eagle Ford take delivery from hundreds of trucks on a daily basis bringing liquids from the well heads in the play (Gold 2013). Owing to the continuous movement of heavy trucks loaded with liquids, the Texas Department of Transportation has begun to convert 83 miles of paved road in six6 oil-boom counties to gravel in order to reduce the cost of repair. Trucks also transport part of the produced liquids for 100 miles to the barge canal to be transported via barge to Houston refineries. Therefore, for OPGEE, it is reasonable to consider trucks as the main mode of local transport of Eagle Ford liquids, for an average of 90 miles.

2.13.7.5 Eagle Ford liquids transport by mode as OPGEE inputs

Pipelines are also used extensively to transport Eagle Ford liquids to Corpus Christi and to Houston. Railroads, mostly Union Pacific, are used to transport liquids to Houston. Railroads, in particular Union Pacific, transported 326,000 bbl/d of Eagle Ford liquids for 850 miles in 2012. On the basis of the data that we developed from the original IHS-BEG datasets, in 2012, total annual liquids production was 2.038×10^8 bbl, equivalent to 560,000 bbl/d. The 326,000 bbl/d transported by rail leaves 234,000 bbl/d for pipelines. As a result, for OPGEE, we assume 58% of the total liquids are transported by rail and 42% by pipeline, for 850 and 3200 miles, respectively. However, in 2013, on the basis of our calculation, average daily liquids production has been much higher, at 933,000 bbl/day. With consideration of a fixed volume capacity for rail transport in 2012 and 2013 at 326,000 bbl/d, 607,000 bbl/d have been transported by pipeline. Therefore, in 2013, the mode share stands at 35% versus 65% for rail versus pipeline. Going into the future, as more pipelines become available, it is reasonable to consider a mode share between rail and pipeline based on the 2013 liquids production data, as summarized in Table 36.

As we discussed above for offshore transport, we consider 120,000 bbl/d as the volume of Eagle Ford crude transported by tanker. In addition, we estimate that 184,000 bbl/d of Eagle Ford crude have been transported via barge. Therefore, for OPGEE, we assign a mode share of 61% for barges (1000 miles) and 39% for tankers (2250 miles). In TABLE 36, we summarize the share of each mode and the average distance of transport for the Eagle Ford liquids production. These assumptions are briefly summarized below:

Barge: Barges are used to transport crude or refined products on the following routes: Corpus Christi–Houston, Victoria–Houston, and Corpus Christi–U.S. Northeast. The weight average distance is 568 miles. About 20% of the Eagle Ford crude oil is transported via barge.

Pipeline: The total distance covered by the currently existing pipeline from Eagle Ford, on the basis of a combination of data from EIA Energy Mapping System and Sternberg and Kovacs (2012), is 462 miles, and pipeline transport accounts for about 65% of local Eagle Ford production. We are uncertain about the average pipeline transport distance; therefore, 462 miles is used as a conservative estimate.

Rail: The average distance that Eagle Ford crude is transported by rail is assumed to be 200 miles; rail accounts for about 35% of local production.

Truck: The average distance that Eagle Ford crude is transported by truck is 90 miles; 100% of local production is transported via truck to nearby refineries, or to pipelines or other transportation sites.

TABLE 36 Eagle Ford transport parameters for OPGEE

	Unit	Default	Eagle Ford
Fraction of oil transported by each mode			
Ocean Tanker	[-]	1	0*
Barge	[-]	0	0.20
Pipeline	[-]	1	0.65
Rail	[-]	0	0.35
Truck	[-]	NA	1.0
Transport distance (one way)			
Ocean Tanker	Mile	5082	0*
Barge	Mile	500	568
Pipeline	Mile	750	462
Rail	Mile	800	200
Truck			90

* This study focuses on domestic oil products; therefore, transport to Canada is ignored.

3 OPGEE MODEL SIMULATIONS

This section describes the processes of preparing data, making input assumptions, and exporting data from the OPGEE model.

3.1 RUNNING OPGEE

OPGEE version 1.1, Draft D, was used as the basis for the Eagle Ford analysis. The OPGEE "Bulk Assessment" feature was used with all attendant algorithmic data handling procedures (see El-Houjeiri et al. (2013) and El-Houjeiri et al. (2014)). A total of 144,924 runs in OPGEE were performed, with one model run performed for each well-month combination in the dataset. A total of 11,314 unique well identifiers were included in the dataset. A number of OPGEE inputs were set equal to Eagle Ford default settings for all wells, including gas composition, ecosystem disturbance, transport distance, processing configuration, lifting technology, well-bore diameter, and "small sources" emissions term.

The following well-specific data are taken from the above datasets for each well-month combination:

- Completion date and production month
- True vertical depth of well
- Liquids production (crude + lease condensate, per month)
- Gas production (as producing GLR)
- Water production (as percent water)
- Crude API gravity.

Drilling energy requirements were computed using the GHGfrack model (Vafi and Brandt 2015) for a typical Eagle Ford casing plan and the given well geometry in the above datasets. GHGfrack reports results as energy use (diesel fuel) for top-drive torque, mud pump work, and fracturing water pumps. Energy use for transport of fracturing materials is not reported in GHGfrack.

Fracturing flowback gas volumes are either flared or vented in the Eagle Ford, and these can form a possible emissions source. Flowback volumes are computed using a modified version of the method of O'Sullivan and Paltsev (2012). Initial production test results from the above datasets report initial gas production rate. This initial gas production rate (per day) is multiplied by an effective flowback period of 3 days. Flowback volumes increase as the well bore clears, and O'Sullivan and Paltsev (2012) assume 4.5 days of effective flowback (9 days of flowback, linearly increasing from 0 to initial production rate). Later analysis by the Environmental

Defense Fund (EDF) suggests that 3 days of effective flowback may be more appropriate (EDF 2014). We chose a 3-day flowback period to be conservative.

The flaring rate is taken from an aggregate of reported per-bbl flaring rate, which is determined each month, along with 87% of the flowback gas, apportioned per barrel of EUR. A single per-bbl flaring intensity of 123.5 scf/bbl was generated using the above-reported regional data for the Eagle Ford region, because well-specific or monthly flaring figures were not available (see Section 2.13.4). The flowback flaring volumes are, in comparison, small over the life of the well, with a median rate of 10.7 scf/bbl and a mean rate of 16.6 scf/bbl. For both flowback and per-bbl flaring, a default flaring methane destruction efficiency of 99% was used in all cases.

Fugitive emissions were calculated a single time for a typical Eagle Ford well, and all wells have fugitive emissions set equal to this value for all operating months. A lack of well-specific data on parameters relevant to fugitive emissions suggests that using well-specific fugitive calculations is not justified. The fugitive emissions rate used across all wells was 36.5 scf/bbl, or 1.3% of the median GLR of >2500 scf/bbl. The venting rate due to flowback emissions (which is computed in addition to the well-default fugitive emissions rate above) was 13% of the flowback gas volume, apportioned per barrel of EUR (median value ~1 scf/bbl).

The assumptions about the heat content of natural gas in OPGEE are shown in Table 37.

TABLE 37 Heat content (LHV) of natural gas at different production and processing stages. (El-Houjeiri et al. 2014)

Total Production	BTU/scf	1274
Fugitives	BTU/scf	497
Flaring	BTU/scf	1274
Pipeline Natural Gas (NG)	BTU/scf	926
Natural Gas Liquids (NGL)[14]	BTU/scf	2168

3.2 EXPORTING RESULTS FROM OPGEE

Net NG exports were collected from the OPGEE "Energy Consumption" sheet. This quantity represents net export of NG after on-site use and use in processing facilities are subtracted. Because OPGEE system boundaries include gas processing, this quantity represents net gas exports after gas processing occurs, meeting pipeline export gas heating value and acid gas specifications. Net NGL exports from the "Energy Consumption" sheet represent exports of

[14] The NGL production calculated from OPGEE is consistent with EIA's definition, "natural gas liquids removed from natural gas in lease separators, field facilities, gas processing plants, or cycling plants" (http://www.eia.gov/tools/glossary/index.cfm?id=N).

NGLs from processing facilities. Oil production results were gathered from the "User Inputs and Results" sheet. They represent net exports of crude oil plus lease condensate.

Drilling and development diesel energy use is diesel fuel use in drilling and fracturing, divided by EUR for the well. Production and extraction energy use represents a sum of all on-site energy use for lifting of fluids from the formation. Surface processing energy use as NG from the "Energy Consumption" sheet represents thermal energy used for crude separation (heater/treater) and stabilization, amine reboiler, glycol reboiler, and demethanizer. Surface processing energy use as electricity from the "Energy Consumption" sheet (cells H40, H41, H45, and H50–H53) represents electrical energy used for amine treater pumps and air coolers, glycol pumps, and water treatment.

4 RESULTS

This section is broken into three subsections. Section 4.1 describes additional summary results of some input parameters. Section 4.2 summarizes the results of OPGEE calculations in terms of fuel use, flaring and fugitive emission factors for shale oil and gas production by zone type. In Section 4.3, we present the same OPGEE results based on GREET's allocation method.

4.1 ADDITIONAL SUMMARIES OF INPUT VARIABLES

4.1.1 API gravity and heating values of liquids

As shown in FIGURE 7 and FIGURE 8 and discussed in Section 2.2, liquids produced in Eagle Ford contain oil and condensate. The average API gravity of Eagle Ford liquids is higher than that of typical crudes in the U.S., whose values are typically below 45. FIGURE 24 shows the range of API gravity values of Eagle Ford liquids produced by zone type and the corresponding heating values. Liquids produced from the oil zone have the higher heating values, whereas liquids produced from the condensate zone have the lowest heating values, though the variation is quite small, less than 3%.

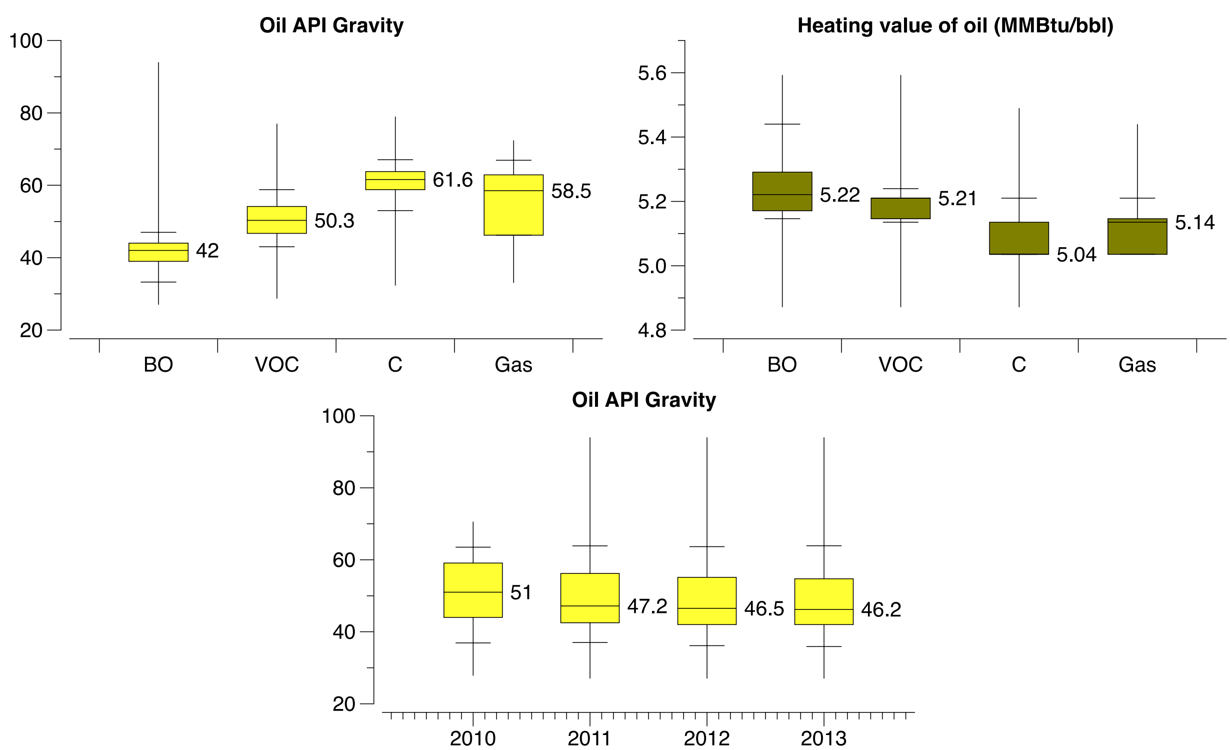


FIGURE 24 Oil API gravity values by Eagle Ford zone type (top left) and the corresponding heating values of liquids (top right). Also show is the oil API gravity value by year (bottom). The box plots show the median, the 1st and 3rd quartile (boxes), the 5th and 95th percentile (whiskers), and min and max values (lines).

TABLE 38 shows the breakdown of oil, condensate and gas on an energy basis from the Initial Test data, where tests were conducted for oil and condensate separately; and the breakdown of liquids (where oil and condensate were reported together as liquids) vs. gas on a total monthly production basis across all years. In the BO zone, almost all of the liquids produced are oil (99%), whereas the majority of the liquids produced in the C and Gas zones are condensate (98% and 91%, respectively). In the VO zone, the oil/condensate split is about 60/40. Since liquids production declined faster than gas production (as shown in FIGURE 6), the overall breakdown over the entire production period between 2009 and 2013 is about 80% liquids in the BO zone, vs. 8.5% liquids in the Gas zone.

TABLE 38 Relative contributions of oil, condensate, and gas to energy content in Initial Test sampling, and relative contributions of liquids and gas to total production

	Energy (Initial Test Data)			Total Production	
Zone Type	Oil	Condensate	Gas	Liquids	Gas
Black Oil (BO)	84%	1%	15%	79%	21%
Volatile Oil (VO)	37%	26%	37%	52%	48%
Condensate (C)	0.5%	21%	79%	21%	79%
Gas (G)	0.4%	4.6%	95%	8.5%	92%

4.1.2 Shale oil and gas cumulative production and EUR

FIGURE 25 shows the cumulative shale oil and gas production to date compared with the estimated EUR, based on the data of Gong (2013). On average, per-well cumulative production to date is about 30% of the estimated oil EUR and 14% of the estimated gas EUR.

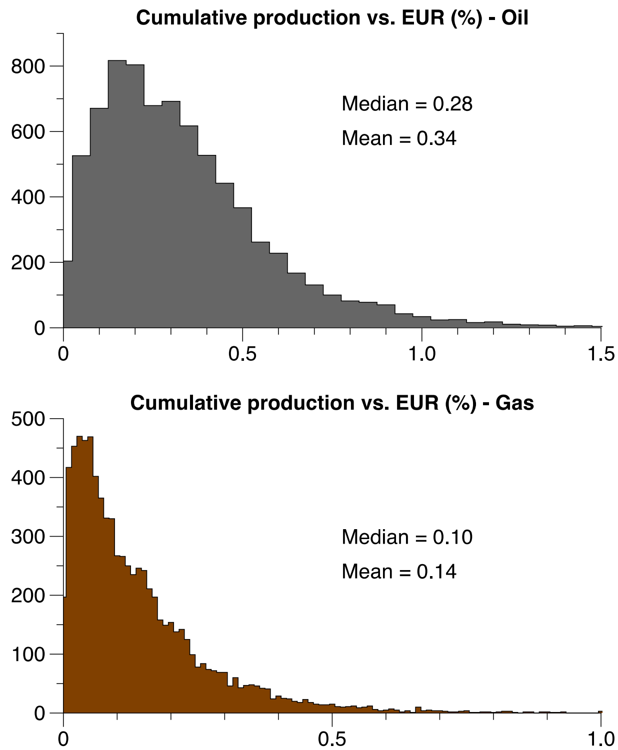


FIGURE 25 Cumulative production to date vs. estimated EUR for shale oil and shale gas production in Eagle Ford, based on the data of Gong (2013)

As shown earlier in FIGURE 6, as production increases, oil production rate declines more rapidly compared with gas production rate. A comparison of cumulative oil and gas production to date vs. estimated EUR by well zone shows that if production continues, more gas is expected to be produced than oil in each well in the Eagle Ford region (FIGURE 26). Note that the EUR estimates are based on the geology and the technical assessment of the field properties and technology. The actual extraction decision, however, is based on a combination of the above-mentioned factors plus the economic considerations. If operators decide to stop producing as soon as oil production declines below a certain level in each well, then these wells will never reach their full gas EUR potentials.

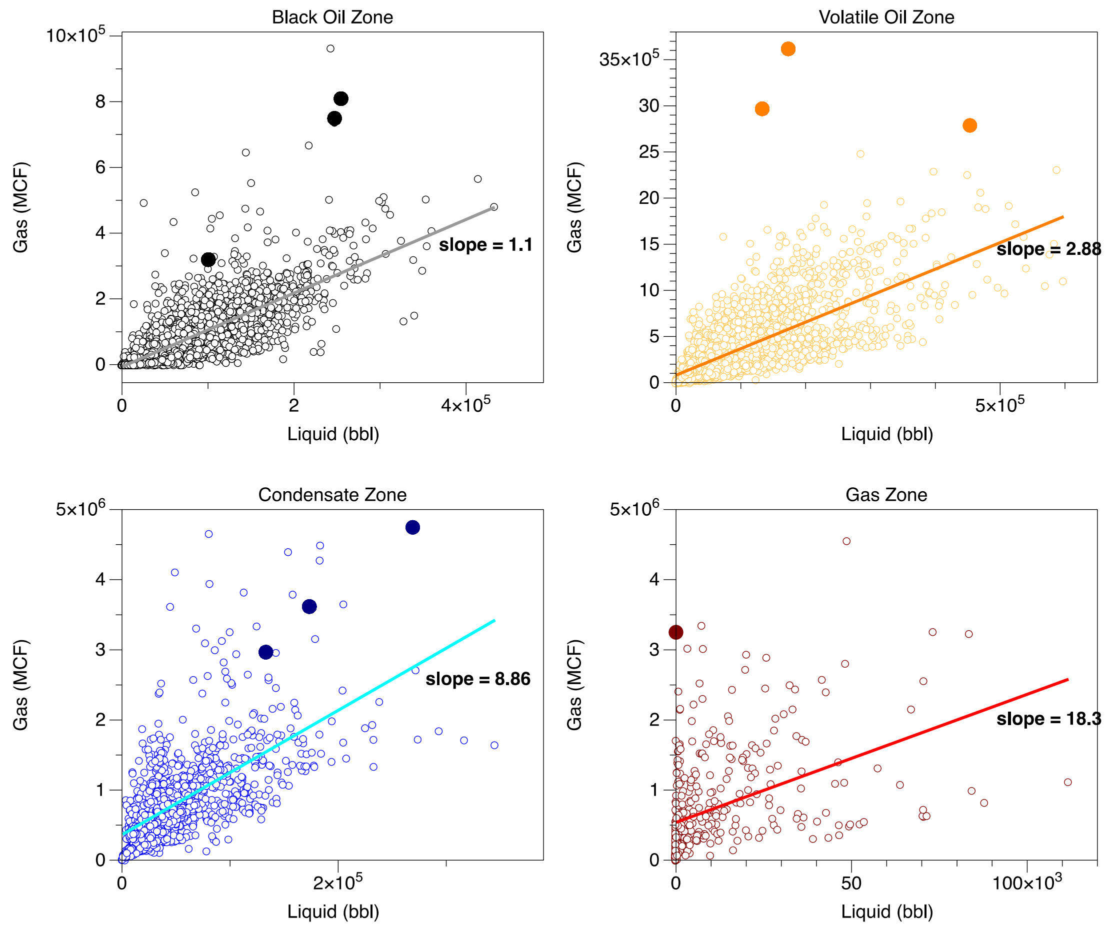


FIGURE 26 Well-based cumulative shale oil and gas production to date (open circles) between 2009 and 2013, and the regression lines. Also shown are the estimated oil and gas EUR based on the data of Gong (2013). Notice the different scales in all panels.

4.2 SUMMARY OF OPGEE RESULTS: WELL-BASED ANALYSIS BY ZONE TYPE

This section summarizes the well-based energy balances calculated by OPGEE on the basis of the input assumptions described in Sections 2 and 3. OPGEE generates the following output variables:

- NG net sale (MMBtu/d)
- NGL net sale (MMBtu/d)
- Drilling & development (diesel, MMBtu/d)
- Production & extraction (NG, MMBtu/d)

- Surface processing (NG, MMBtu/d)
- Surface processing (electricity, KWh/d)
- Flaring rate (MMcf/d)
- Flaring efficiency (%)
- Fugitives rate (constant for all wells, scf/bbl)

FIGURE 27 presents the well-based energy balance of Eagle Ford wells by zone, showing the mean and median values. Natural gas balance shows the breakdown of NG fugitive emissions, flaring, self-consumption, and NG and NGL net sales calculated by OPGEE. The values for self-consumption, fugitive emissions and flaring are too small to notice in the figure. These numbers are listed in Table 39.

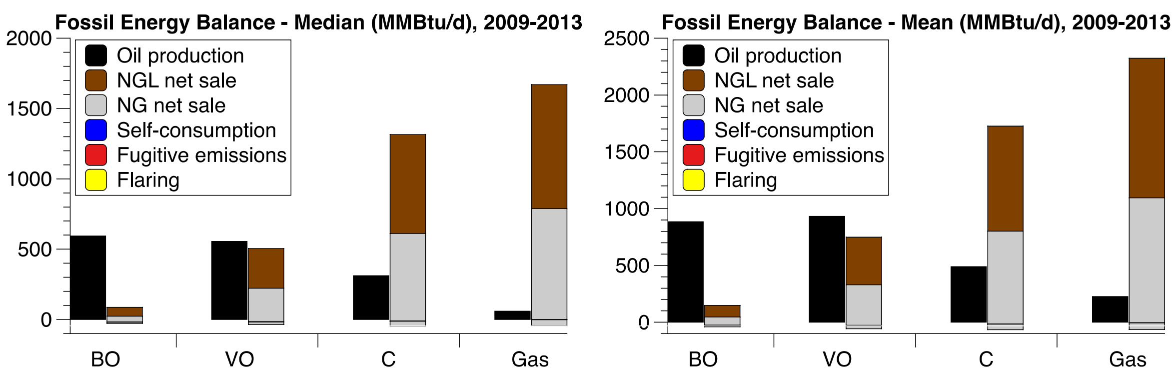


FIGURE 27 Well-based energy balance of Eagle Ford wells by well zone (2009–2013). The values for self-consumption, fugitive emissions, and flaring are too small to notice.

TABLE 39 shows the mean and median well-based NG production and NG balance (including flaring, fugitive emissions, self-consumption for production & extraction and surface processing, NG net sale and NGL sale) calculated by OPGEE. In the BO zone, about 20% of the NG produced is either flared, emitted, or used for self-consumption, and only about 80% is sent to the market; whereas over 94–98% of the NG produced in the VO, C, and Gas zones are sent to the market as pipeline NG and NGL.

TABLE 39 Mean and median well-based oil and natural gas production (MMBtu/d/well) and natural gas balance calculated by OPGEE. Also shown (in parentheses) are the shares of NG balances in percentages.

			OPGEE Calculation				
	Monthly Oil Production	Monthly Gas Production	Flaring	Fugitive emissions	Self-consumption	NG net sale	NGL sale
Median							
BO	594	148	17 (12%)	2.1 (1.5%)	8.1 (5.7%)	51 (36%)	63 (44%)
VO	556	586	15 (2.7%)	2.0 (0.3%)	18 (3.2%)	258 (45%)	282 (49%)
C	312	1,414	10 (0.7%)	1.1 (0.1%)	35 (2.5%)	659 (47%)	703 (50%)
Gas	59	1,755	1.5 (0.1%)	0.1 (0.0%)	42 (2.4%)	831 (47%)	882 (50%)
Mean							
BO	884	233	26 (11%)	3.1 (1.3%)	12 (5.2%)	87 (38%)	102 (44%)
VO	932	868	26 (3.1%)	3.3 (0.4%)	27 (3.1%)	386 (45%)	420 (49%)
C	489	1,862	16 (0.8%)	1.7 (0.1%)	48 (2.6%)	866 (47%)	925 (50%)
Gas	226	2,449	4.5 (0.2%)	0.5 (0.0%)	58 (2.4%)	1,157 (47%)	1,229 (50%)

Total energy use is defined as MMBtu of energy (including diesel, NG, and electricity) used for production, extraction, and surface processing per MMBtu of energy produced (including liquids, net NG sale, and net NGL sale). Energy use tends to increase with higher gas production (FIGURE 28), as gas production requires more energy use for lifting and processing.

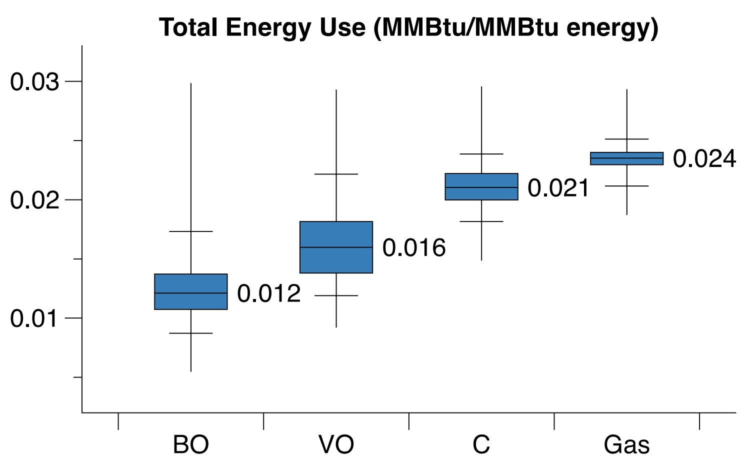


FIGURE 28 Well-based total energy use for shale oil and gas production by zone type. Whiskers show the 5th and 95th percentile values.

4.3 ASSUMPTIONS OF SHALE OIL AND SHALE GAS PRODUCTION FOR INCORPORATION INTO GREET

To model GHG emissions associated with shale oil and gas production in Eagle Ford with the GREET model, process fuel consumption by fuel type, flaring intensity of produced gas, flaring efficiency, fugitive produced gas emissions, and chemical composition of produced gas were calculated from the OPGEE model and used as input values in the GREET model.

We applied the energy-based allocation method to allocate the process fuel consumption, flaring and fugitive emissions by assuming that the utility of the energy embedded in oil, NG, and NGL is the same for their respective end users, as shown in Equation 1. There is no universally mandated allocation method. Other allocation methods, such as market value-based allocation, could be used to allocate energy use, GHG emissions, and water use to the energy products on the basis of their market values.

$$F_{i,j,x} = F_{i,j} \times \left(\frac{E_{j,x}}{E_{j,oil}+E_{j,NG}+E_{j,NGL}}\right)/E_{j,x} \qquad \text{(Equation 1)}$$

Where

i = process fuel consumed (Btu or MMBtu);

j = well identification;

x = energy product as oil, NG, or NGL;

$F_{i,j,x}$ = fuel i consumption rate (Btu or MMBtu/MMBtu of product x) for well j and energy product x;

$F_{i,j}$ = monthly fuel i energy consumed (Btu or MMBtu /month) for well j; and

$E_{j,x}$ = monthly energy production of x (MMBtu of product x /month) for well j where x is either oil, net NG sale, or net NGL sale calculated from OPGEE.

Note that $F_{i,j,x}$ is the same regardless of the energy product (oil, net NG sale or net NGL sale) produced, and $F_{i,j}$ is simply the sum of fuel i consumption rate multiplied by the energy produced, i.e., $F_{i,j} = \sum_x (F_{i,j,x} \times E_{j,x})$ or $F_{i,j} = F_{i,j,x} \times \sum_x E_{j,x}$.

The equation is identical for the calculation of flaring and fugitive emission rates (in scf/MMBtu of product x).

The equation for water consumption is slightly different as, unlike fuel use, flaring and fugitive emissions, the HF water use has not been normalized to total lifetime production. Thus, the water consumption rate is shown in Equation 2:

$$W_{j,x} = W_j \times \left(\frac{EUR_{j,x}}{EUR_{j,oil} + EUR_{j,NG}}\right) / EUR_{j,x} \qquad \text{(Equation 2)}$$

Where

$W_{j,x}$ = water consumption rate (gal/MMBtu of product *x*) for well *j* and energy product *x*;

W_j = HF water use (gal) for well *j*; and

$EUR_{j,x}$ = EUR of energy product *x* (MMBtu of product *x*) for well *j* where *x* is either oil or NG.

Note that the NG in EUR_{NG} in Equation 2 is the raw unprocessed NG that is technically recoverable from each well, whereas the net NG sale and net NGL sale in Equation 1 are energy products calculated from OPGEE on the basis of the reported monthly production of raw NG.

A two-sample Kolmogorov–Smirnov test was conducted with the statistical package Stata to determine if there is any difference in the distributions of the oil-to-gas output (O/G) ratios by energy content for all wells from 2010 to 2013. The test showed that the distributions of the O/G ratios for 104,345 observations of well-month production in the BO and VO zones and 27,889 observations of well-month production in the G and C zones are statistically significantly (p-value=0) different from each other (FIGURE 29). We therefore report the fuel consumption rate, flaring and fugitive emission rate, and water consumption rate for oil production zones (BO and VO zones) and gas production zones (C and Gas zones) separately.

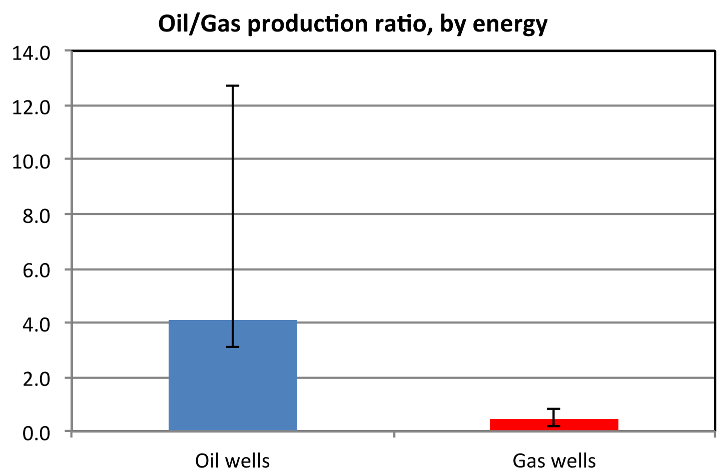


FIGURE 29 Comparison of the oil-to-gas production ratio by energy between wells located in BO and VO zones (oil wells) and wells in G and C zones (gas wells) in Eagle Ford, 2010–2013. Error bars represent the P10 and P90 values.

As shown in FIGURE 30, the recovery energy efficiency[15], process fuel consumption, flaring and fugitive intensities, and water use in the oil zone showed little variation over time between 2010 and 2013. The same holds for the production in the gas zone.

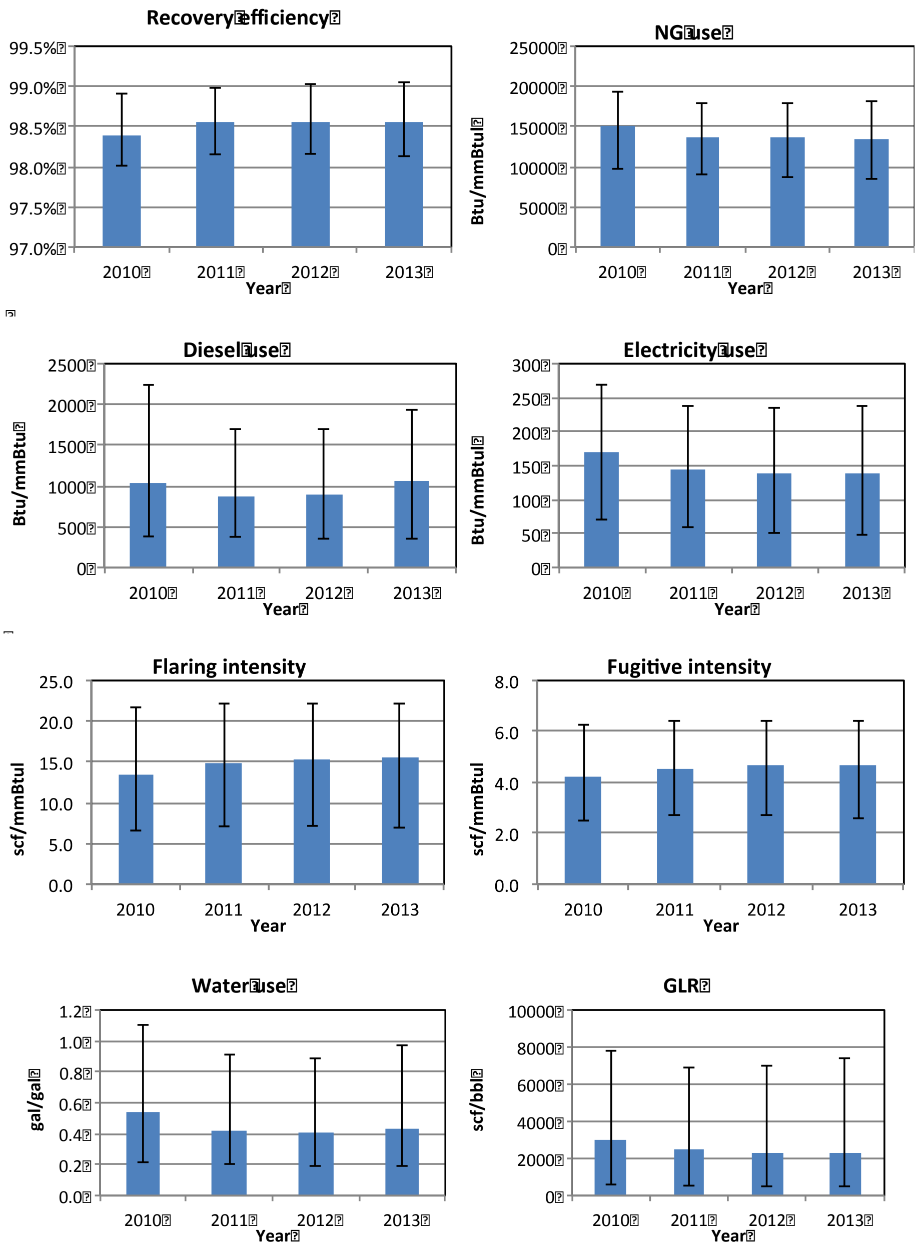


FIGURE 30 Operational performances of shale oil production in Eagle Ford from wells located in black oil and volatile oil zones from 2010 to 2013. Error bars represent the P10 and P90 values.

[15] Recovery energy efficiency is the total products (by energy content) divided by the total inputs (by energy content) for each well. The total products include oil, net NG sale and net NGL sale. The total inputs are the total products plus the total consumption of process energy including NG, diesel, and electricity.

TABLE 40 and

TABLE 41 summarize the recovery energy efficiency, process energy use by fuel type, flaring intensity, fugitive intensity, water use, oil API gravity, GLR, and ratios of oil, NG, and NGL to the total output for shale production in the oil production zone and gas production zone, respectively, in Eagle Ford from 2010 to 2013.

TABLE 40 Summary of energy and water use indicators associated with production (Btu, scf or gal per MMBtu of oil, NG or NGL produced) from wells located in the black oil and volatile oil zones in Eagle Ford, 2010–2013, using energy allocation method except as noted

	Recovery energy efficiency	NG use	Diesel use	Electricity use	Flaring intensity	Fugitive intensity	Water use	Oil API Gravity	GLR[b]	O/T ratio[c]	NG/T ratio[d]	NGL/T ratio[e]
Unit		Btu/mmBtu	Btu/mmBtu	Btu/mmBtu	SCF/mmBtu	SCF/mmBtu	gal/mmBtu		SCF/bbl			
Weighted average[a]	**98.56%**	**13629**	**976**	**140**	**15.4**	**4.6**	**2.2**	**47.7**	**2338**	**0.66**	**0.16**	**0.18**
Arithmetic average	98.60%	13141	1024	137	16.1	4.8	1.7	45.5	6030	0.69	0.15	0.16
P1	97.48%	6259	167	14	2.8	1.1	0.9	30.0	108	0.16	0.00	0.00
P10	98.14%	8518	346	50	7.0	2.6	1.4	38.0	488	0.37	0.03	0.04
P25	98.39%	10172	516	75	11.4	3.8	1.8	41.0	906	0.53	0.07	0.08
P50	98.67%	12305	811	117	17.9	5.2	2.5	45.0	1679	0.74	0.12	0.14
P75	98.87%	15368	1194	180	20.6	6.0	2.9	49.9	3825	0.85	0.22	0.24
P90	99.03%	18028	1854	237	22.2	6.4	2.8	54.8	7183	0.93	0.30	0.33
P99	99.25%	24403	4463	363	24.1	7.0	2.1	60.3	22769	1.00	0.41	0.44

a: Weighted by total output of energy products, i.e., oil, natural gas, and natural gas liquids;

b: Without energy-based allocation applied;

c: Output ratio of oil to total products (i.e. oil, NG and NGL) by energy content;

d: Output ratio of NG to total products by energy content;

e: Output ratio of NGL to total products by energy content.

TABLE 41 Summary of energy and water use indicators associated with production (Btu, scf or gal per MMBtu of oil, NG or NGL produced) from wells located in the gas and condensate zones in Eagle Ford, 2010–2013, using energy allocation method except as noted

	Recovery energy efficiency	NG use	Diesel use	Electricity use	Flaring intensity	Fugitive intensity	Water use	Oil API Gravity	GLR[b]	O/T ratio[c]	NG/T ratio[d]	NGL/T ratio[e]
Unit		Btu/mmBtu	Btu/mmBtu	Btu/mmBtu	SCF/mmBtu	SCF/mmBtu	gal/mmBtu		SCF/bbl			
Weighted average[a]	**97.9%**	**21528**	**380**	**297**	**3.4**	**1.3**	**1.5**	**60.8**	**19061**	**0.18**	**0.40**	**0.42**
Arithmetic average	97.8%	22293	387	314	3.4	1.3	1.6	60.2	698786	0.18	0.40	0.42
P1	97.1%	15606	0	187	0.0	0.0	0.2	46.2	4589	0.00	0.24	0.27
P10	97.7%	18063	41	235	0.5	0.2	0.6	53.1	8571	0.03	0.32	0.35
P25	97.8%	19373	152	262	1.6	0.6	0.9	58.0	12678	0.09	0.36	0.39
P50	97.9%	20799	291	289	3.2	1.2	1.3	61.3	19820	0.17	0.40	0.43
P75	98.0%	22421	455	319	4.7	1.8	2.1	63.6	41866	0.25	0.44	0.47
P90	98.1%	23439	728	339	6.4	2.3	3.2	65.9	156685	0.33	0.47	0.50
P99	98.4%	28404	1993	414	11.6	3.4	5.1	69.5	20666769	0.48	0.49	0.51

a: Weighted by total output of energy products, i.e., oil, natural gas, and natural gas liquids;

b: Without energy-based allocation applied;

c: Output ratio of oil to total products (i.e. oil, NG and NGL) by energy content;

d: Output ratio of NG to total products by energy content;

e: Output ratio of NGL to total products by energy content.

It is evident from Tables 40 and 41 and the findings in Section 4.2 that process fuel consumption rate, flaring and fugitive intensities, and water use rate are in general higher in the gas zone than in the oil zone. Wide variations in energy use and production among the thousands of wells are observed. To account for the effect of this variability on the estimation of GHG emissions with GREET, we developed probability distribution functions (PDFs) for the major parameters, using 104,345 well-month observations for wells located in the BO and VO zones and 27,889 well-month observations for wells located in the Gas and C zones.

We employed Easyfit^{TM}, a curve-fitting toolbox, to find the probability distribution type from a pool of 55 distributions, e.g., normal distributions, Weibull distributions, and uniform distributions, that best fit the observations for each parameter. With the energy-based allocation method, we applied the total energy output of the main product and coproducts as the weighting factor to fit the distribution. The higher the value of the weighting factor corresponding to a sample value of the parameter, the higher the possibility that the parameter has the sample value in the PDF to be fitted for the parameter. The toolbox uses one of the four well-known methods to estimate distribution parameters on the basis of available sample data: maximum likelihood estimates, least squares estimates, method of moments, and method of L-moments. The toolbox calculates the goodness-of-fit statistics, including the Kolmogorov Smirnov statistic, the Anderson Darling Statistic, and the chi-squared statistic, for each of the fitted distributions. Then the toolbox ranks the distributions on the basis of the goodness-of-fit statistics. We then selected the distribution with the highest rank, primarily based on the Kolmogorov Smirnov statistic.

TABLE 42 summarizes the PDFs of process fuel consumption intensities, recovery energy efficiencies, flaring intensities, fugitive intensities, and water use for shale oil and shale gas production for 2010-2013.

TABLE 42 Probability distribution functions of key parameters for production in oil (top) and gas (bottom) production zones in Eagle Ford, 2010–2013

Production in BO and VO Zones				
Parameter	PDF type	PDF parameter		
NG Use, MMBtu/MMBtu	Lognormal	Mu -4.3468	Sigma 0.27789	
Diesel Use, MMBtu/MMBtu	Lognormal	Mu -7.1976	Sigma 0.70936	
Electricity Use, MMBtu/MMBtu	Gamma	Alpha 3.3389	Beta 4.2544E-05	Gamma -2.351E-06
Recovery Energy Efficiency	Weibull	Alpha 333.41	Beta 0.98723	Gamma 0
Flaring Intensity, scf/MMBtu	Uniform	min 5.3755	max 25.368	
Fugitive Intensity, scf/MMBtu	Uniform	min 2.2134	max 7.0483	

Water Use, gal/MMBtu	Gamma	Alpha 2.2737	Beta 1.015	Gamma -0.0042

TABLE 42 (Cont).

Production in C and Gas Zones				
Parameter	PDF type	PDF parameter		
NG Use, MMBtu/MMBtu	Gamma	Alpha 0.98398	Beta 0.0003863	Gamma 2.807E-08
Diesel Use, MMBtu/MMBtu	Gamma	Alpha 25.906	Beta 0.0004827	Gamma 0.00839
Electricity Use, MMBtu/MMBtu	Weibull	Alpha 5.6818	Beta 0.00024	Gamma 6.261E-05
Recovery Energy Efficiency	Weibull	Alpha 478.16	Beta 0.97992	Gamma 0
Flaring Intensity, scf/MMBtu	Weibull	Alpha 1.4485	Beta 3.9308	Gamma -0.14767
Fugitive Intensity, scf/MMBtu	Weibull	Alpha 1.8043	Beta 1.6069	Gamma -0.15545
Water Use, gal/MMBtu	Lognormal	Mu -0.22829	Sigma 0.58344	

4.4 WELL-TO-WHEELS GHG EMISSIONS OF PETROLEUM FUELS FROM EAGLE FORD PLAY

We use assumptions summarized in TABLE 40 to calculate the well-to-wheels (WTW) GHG emissions of petroleum fuels derived from crude oil produced from wells located in the BO and VO zones in the Eagle Ford play. CO_2 and CH_4 emissions from gas flaring and fugitives, as shown in TABLE 43, are based on the chemical compositions of the gases, as shown in TABLE 17. It is noted that we constrained the upper limit for the API gravity in the regression formula to 39, which was the highest API observation that we sampled for developing the regression formula (Elgowainy et al. 2014), owing to lack of information on the effect of higher API gravity than 39 on the refinery energy efficiencies.

TABLE 43 CO_2 and CH_4 emissions from gas flaring and fugitive emissions

	CO_2, g/mmBtu	CH_4, g/mmBtu
Flaring	1,303	2
Fugitive	136	62

Total	1,439	64

We apply the regression formula developed for estimating the overall refinery energy efficiency and the relative refinery energy requirements for specific petroleum products by Elgowainy et al. (2014) to calculate the GHG emissions associated with refining of crude oil from the Eagle Ford, assuming an API gravity of 48 and a sulfur content of 0.2% (PR Newswire 2015). TABLE 44 summarizes the WTW GHG emissions of gasoline, diesel, and jet fuels; TABLE 45 summarizes the WTW water consumption. The results show that the WTW GHG emissions of gasoline, diesel and jet fuel derived from crude oil produced in the BO and VO zones in the Eagle Ford play are 89.2, 87.8 and 82.5 gCO_2e/MJ, respectively.

TABLE 44 WTW GHG emissions, in g CO_2e/MJ, of gasoline, diesel, and jet fuels derived from crude oil produced in the BO and VO zones in the Eagle Ford play

	WTR[a]	WTP[b]	PTW[c]	WTW
Gasoline Blendstock	4.3	16.0	73.2	89.2
Diesel	5.0	12.2	75.6	87.8
Jet	5.1	9.6	72.9	82.5

[a] Well-to-refinery gate
[b] Well-to-pump
[c] Pump-to-wheels

TABLE 45 WTW water consumption, in gal/MMBtu, of gasoline, diesel, and jet fuels derived from crude oil produced in the BO and VO zones in the Eagle Ford play

	WTR[a]	WTP[b]	PTW[c]	WTW
Gasoline Blendstock	2.5	18.7	0	18.7
Diesel	3.0	16.3	0	16.3
Jet	3.0	16.0	0	19.0

[a] Well-to-refinery gate
[b] Well-to-pump
[c] Pump-to-wheels

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APPENDIX A:

GEOGRAPHIC LOCATION OF EAGLE FORD IN PETROLEUM ADMINISTRATION FOR DEFENSE DISTRICT 3 INLAND (REFINERY REGION 5)

Figure A1 shows the seven major shale plays in the U.S., including Eagle Ford in Texas.

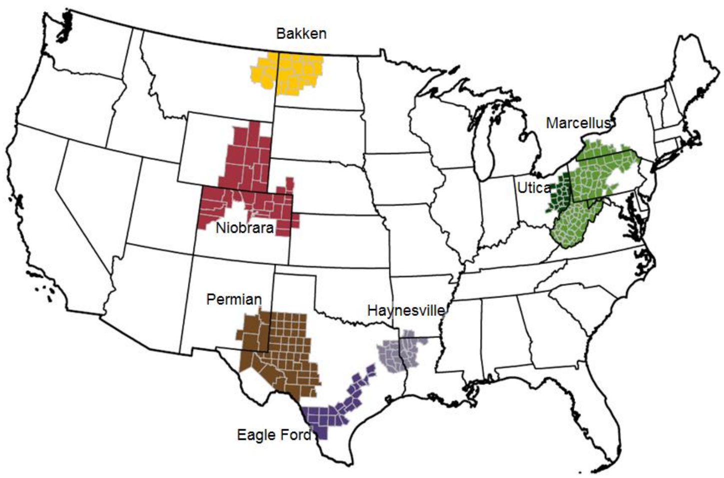

FIGURE A1 Major U.S. shale plays. Source: http://www.eia.gov/petroleum/drilling/images/dpmapv4l-wtitle.png

As shown in Figure A2, Eagle Ford is part of the Petroleum Administration for Defense District 3 (Gulf Coast District) defined by the EIA.

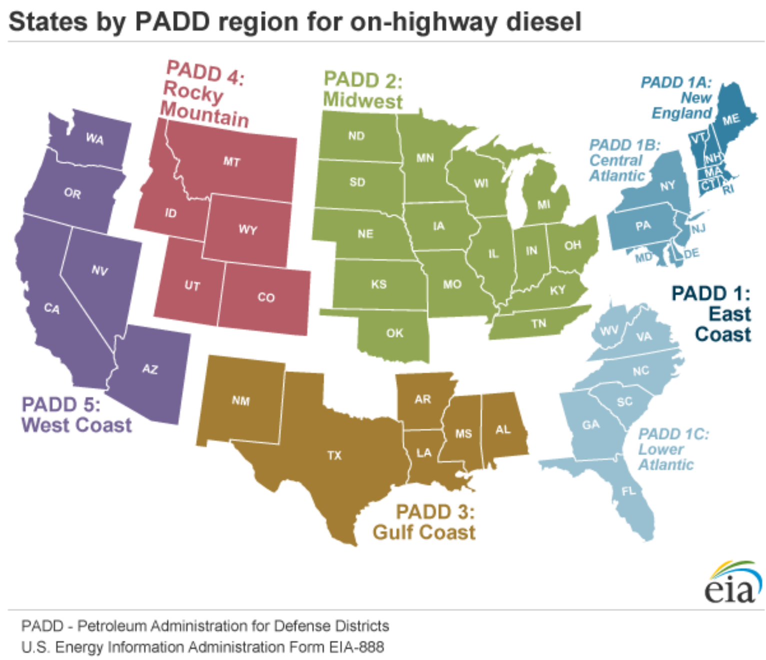

FIGURE A2 Petroleum Administration for Defense Districts. Source: http://www.eia.gov/petroleum/gasdiesel/diesel_map.cfm

Table A1 lists Texas counties identified as part of the Eagle Ford region by the EIA.

TABLE A1 List of Eagle Ford counties in Texas

ATASCOSA	FRIO	MADISON
BASTROP	GONZALES	MAVERICK
BEE	KARNES	MCMULLEN
BRAZOS	LA SALLE	MILAM
BURLESON	LAVACA	WEBB
DEWITT	LEE	WILSON
DIMMIT	LEON	ZAVALA
FAYETTE	LIVE OAK	MADISON

Source: EIA Drilling Productivity Report, http://www.eia.gov/petroleum/drilling/#tabs-summary-1

Figure A3 shows the locations and gas-to-oil ratios of producing wells in Eagle Ford from 2006 to 2010.

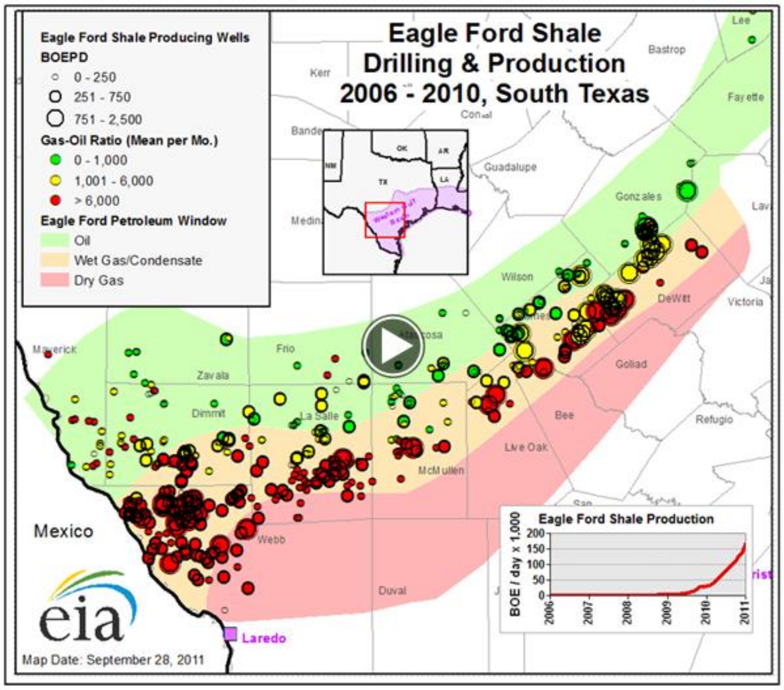

FIGURE A.3: Producing wells in Eagle Ford shale.
Source: http://www.eia.gov/todayinenergy/detail.cfm?id=3770

APPENDIX B:

IHS-BEG DATABASE SUMMARY

The IHS-BEG database is an Excel-based spreadsheet with four worksheets, as shown in Tables B1 to B4.

TABLE B1 IHS-BEG Database, Header

Variable	Description
API	Unique Well Identifier, same as UWI number
Source	
APINumber	Unique Well Identifier, same as UWI number
ICNumber	
Operator Name	Original well operator
Current Operator Name	Current well operator
Lease Name	Lease name
Well Num	Well number on lease
Field Name	Local field name
State Name	State name
County Name	County name
Hole Direction	Horizontal, Vertical, Pinnate, Directional
Well Status	Oil or Gas
Current Status	(A)ctive
Geologic Province Name	
Play Name	Play name
Play Type	
Permit Number	Well permit number
Permit Date	Date permit issued
Depth Total Driller	Total well depth based on driller report (total length drilled)
Depth Total Logger	Total well depth based on survey
Depth True Vertical	True vertical depth at total depth drilled
Depth Whipstock	
Class Initial Name	Initial well classification name
Class Initial Code	Initial well classification code
Class Final Name	Final well classification name
Class Final Code	Final well classification code
Status Final Code	
Formation Projected Name	Mostly Eagle Ford
Depth Total Projected	
Formation at TD Name	Expected target formation prior to completion
Formation Producing Name	Expected depth prior to completion
Elevation Reference Value	Elevation of reference point
Elevation Reference Datum	Name of reference point
Ground Elevation	Elevation of ground surface
Date Spud	Date of initial drilling
Date Completion	Date of final well completion

TABLE B1 (Cont.)

Variable	Description
Date Rig Release	Date rig left site
Date Abandonment	Date well abandoned
Date First Report	Date of first well activity
Date Last Activity	Date of latest reported well activity
Depth Water Value	
Depth Water Datum	
Surface Latitude	Latitude coordinate of top of hole
Surface Longitude	Longitude coordinate of top of hole
Surface LL Source	Source of coordinates
Proposed BH Latitude	Expected target bottom hole latitude coordinate prior to completion
Proposed BH Longitude	Expected target bottom hole longitude coordinate prior to completion
Proposed BH LL Source	Source of coordinates
BH Latitude	Actual bottom hole latitude coordinate
BH Longitude	Actual bottom hole longitude coordinate
BH LL Source	Source of coordinates
Activity Code	
Permit Filer Long	
Permit Phone	

TABLE B2 IHS-BEG Database, HF Analysis Worksheet

Variable	Description
UWI	Unique Well Identifier
Status	Oil or Gas
Completed	Date of final well completion
Year	Year of final well completion
Quarter	Quarter of final well completion
YearQuarter	
Avg Depth	Average depth (ft) of lateral section
Water Use Value Used	HF water use value (gal) used in BEG analysis
HF Source	Source of HF water use value
Proppant (lb)	Proppant use (lb)
Prop Source	Source of proppant data
Lateral Length	Length (ft) of horizontal lateral section
Use HF	Flag to use (1) or not use (0) HF water from FracFocus or IHS
Use lbs	Flag to use (1) or not use (0) proppant from FracFocus or IHS
Use Len	Flag to use (1) or not use (0) lateral length from IHS
County	County name
Region	East or West
Zone	Production zone
Zone Type	Production zone
CountyZone	

TABLE B3 IHS-BEG Database, Production Data Worksheet

Variable	Description
Entity	Taxable legal entity
Source	
Entity Type	
Primary Product	Primary well product "O"il or "G"as
Lease Name	Legal name of the lease
Well Number	Lease well number
API	American Petroleum Institute well ID (same as UWI)
Regulatory API	
Year	Production calendar year
Month	Production calendar month
Liquid	Monthly total hydrocarbon liquids produced in barrels (42 gal/bbl). Note: this represents oil for oil wells and gas condensate for gas wells.*
Gas	Monthly total hydrocarbon gases produced in thousand cubic ft (Mcf)
Water	Monthly total liquid water produced in barrels (42 gal/bbl)
GOR	Gas to Oil ratio calculated by HIS
Percent Water	Amount of produced water as a percentage of total liquids produced

* This statement is from the description in the original IHS-BEG data. Our approach in this study is slightly different. We consider liquids production as oil if the well Initial Test suggests the initial flow is oil and consider the liquids production as condensate if the well Initial Test suggests the initial flow is condensate. This is explained in greater detail in Section 2

TABLE B4 IHS-BEG Database, Disposal Data

Variable	Description
Entity	Taxable legal entity
County	County name
Entity Type	
Primary	Primary well use code - presence of "l" indicates injection
Lease Name	Legal name of the lease
Well Number	
API	American Petroleum Institute well ID (same as UWI)
Hole_Direction	Well direction "Vertical" or "Horizontal"
Unit_Well	
Depth_Total_ft	Well depth in feet
Perforate_top	Top depth of well perforations in feet
Perforate_bottom	Bottom depth of well perforations in feet
Status	Current (2013) status "Active," "Inactive"
Latitude	Surface latitude coordinate NAD83
Longitude	Surface longitude coordinate NAD83
Type_Name	
Date_Compl	

APPENDIX C:

IHS INITIAL WELL TEST DATABASE

The IHS initial production test dataset has three worksheets, as summarized in Tables C1 to C3.

TABLE C1 IHS Initial Production Test, Header Worksheet

Header	Header Information from IHS Database
API Number	Well API number
Operator Name	Initial operator name
Current Operator Name	
Lease Name	
Well Num	
State Name	
County Name	
Hole Direction	All "Horizontal"
Well Status	Oil, Gas, Abandoned Oil, Abandoned Gas
Permit Number	
Permit Date	
Depth Total Driller	Total borehole length according to driller
Depth Total Logger	Total borehole length according to logger survey
Depth True Vertical	True depth at total borehole length
Class Final Name	
Ground Elevation	(ft)
Date Spud	Date drilling started
Date Completion	Date well completed
Date Rig Release	Date rig left site
Date Abandonment	Date well abandoned
Date First Report	Date of first reported site activity
Date Last Activity	Date of last reported site activity
Surface Latitude	Surface latitude coordinate of borehole
Surface Longitude	Surface longitude coordinate of borehole
BH Latitude	Bottom hole latitude coordinate of borehole
BH Longitude	Bottom hole longitude coordinate of borehole

TABLE C2 IHS Initial Production Test, Test Worksheet

Test	Initial Production Test Results from IHS Database
API Number	Well API number
Depth Top	Depth of top perforation
Depth Base	Depth of bottom perforation
Flow Oil	Oil flow rate value (bbl/day, BPD)
Flow Condensate	Condensate flow rate value (bbl/day, BPD)
Flow Gas Value	Gas flow rate value (1000 ft^3/day, MCFD)
Flow Water Value	Water produced during test (bbl, BBL)
Test Date	Date test started
Pressure Flowing Tubing	Tubing pressure under flow conditions (PSI)
Pressure Flowing Casing	Casing pressure under flow conditions (PSI)
Pressure Shutin Tubing	Tubing pressure under shut-in conditions (PSI)
Pressure Shutin Casing	Casing pressure under shut-in conditions (PSI)
Pressure Bottom Hole	Bottom hole static pressure (PSI)
Choke Size	Size of choke (fractional in.)
Oil Gravity	Produced oil API gravity value
GOR	Gas-to-Oil ratio for the test
Cond Gravity	Produced condensate API gravity value
Cond Ratio	? Not populated (should be dropped from the final data)
Method Name	
Gross Interval Note	
Shutoff Type	

TABLEC3 IHS Initial Production Test, Summary Worksheet (Prepared by BEG)

Summary	Summary of Test Results - Prepared by BEG
API Number	Well API number
Lat	Surface latitude coordinate of borehole
Long	Surface longitude coordinate of borehole
Zone	Production zone (Black Oil, Volatile Oil, Condensate, Dry Gas)
Year	Year of test
Oil_BPD	Initial well oil flow rate (bbl/day, BPD)
Cond_BPD	Initial condensate oil flow rate (bbl/day, BPD)
Gas_MCFD	Initial well gas flow rate (1000 ft^3/day, MCFD)
Water_BPD	Initial well water flow rate (bbl/day, BPD)
Oil_API	API gravity of produced liquids
GOR	Initial well gas-to-oil ratio

APPENDIX D:

IHS FOLLOW-UP WELL TEST DATABASE

The IHS follow-up test dataset has three worksheets, as summarized in Tables D1 to D3.

TABLE D1 IHS Follow-up Test Data, Notes Worksheet

Production Well	Header Information from IHS Database for Producing Wells in This Data Set
Entity	Legal entity ID number
Primary Product	"G"as or "O"il
Lease Name	Name of lease
Well Number	Well number on lease
API	Well API number
Hole Direction	All "Horizontal"
Unit Well Number	Unit Well Number
Depth Total Maximum	Well total pipe length
Perforation Upper	Depth (pipe length) of upper perforation
Perforation Lower	Depth (pipe length) of lower perforation
Status Prod Current Name	Current status
Surface Latitude	Borehole surface latitude
Surface Longitude	Borehole surface longitude
Type Name	Reason for current status
Date Completion	Date well completed
Date Abandonment	Date well abandoned
Play Name	Play Name
Play Type	Play Type

TABLE D2 IHS Follow-up Test Data, Production Test Worksheet

Production Test	Production Test Results from IHS Database
Entity	Legal entity ID number
Entity Type	Entity Type Well or Lease
Primary Product	"G"as or "O"il
Lease Name	Name of lease
Well Number	Well number on lease
API	Well API number
Unit Well Number	Unit Well Number
Number	Test number
Date	Test date
Choke Size	Choke size (in.)
Cum At Test Gas	Cumulative produced gas at time of test (1000 ft^3, Mcf)
Flow Liquid	Test hydrocarbon liquids flow rate (bbl/day, BPD)
Flow Gas	Test gas flow rate (1000 f^3/day, MCFD)
Flow Water	Test water flow rate (bbl/day, BPD)
Press Flowing Tube	Tubing pressure under flow conditions (PSI)
Press Final Shut In	Tubing pressure under shut-in conditions (PSI)
Press Casing	Casing pressure (PSI)
Press BH Static	Bottom hole static pressure (PSI)
Gravity Oil	API gravity of produced hydrocarbon liquids
Gravity Gas	API gravity of produced gas

TABLE D3 IHS Follow-up Test Data, Summary Worksheet

Summary	Summary of Test Results - Prepared by BEG
API	Well API number
Lat	Borehole surface latitude
Long	Borehole surface longitude
Zone	Production zone (Black Oil, Volatile Oil, Condensate, Dry Gas)
Tests	Number of tests
From	Year of first test
To	Year of last test
OilAPI	Average API gravity of produced hydrocarbon liquids

APPENDIX E:

IDENTIFYING WELLS THAT PRODUCE CONDENSATE-TYPE LIQUIDS

In the IHS-BEG original production database, wells have been identified as either oil (O) or gas (G) wells. In our final developed database after merging IHS-BEG different datasets, we also have 1028 wells without any notes on the well type. However, as shown in FIGURE 8, there are 3056 wells that have the potential to be considered as wells with condensate-type liquids production. To identify these wells among O, G, and unmarked wells in the IHS-BEG database, we implemented the following methodology:

The most likely candidates for condensate-type liquids producing wells are the 3962 wells that report an initial flow of condensate. As discussed above, among the wells that report an initial flow of condensate, only 3 wells also report an initial flow of oil. Among these wells, as discussed below, we confirmed condensate-type liquids producing wells as the wells that report both initial and follow-up oil gravity, as shown in FIGURE 8. The 3962 wells with initial flow of condensate were divided into three groups: those marked O (536 wells), marked G (2398 wells), or given no mark (1028 wells). Among the 536 wells marked O, only 15 wells reported both initial and follow-up oil gravity. Therefore, among the 536 wells marked O, we confirmed 521 wells as oil-producing and 15 wells as condensate-type liquids producing wells.

For the second group of wells, marked G (2398 wells), we could confirm 2331 wells as condensate-type liquids producing wells after enforcing the condition of having non-missing reported initial and follow-up oil API gravity. We considered as gas wells the 67 wells that reported only initial oil API gravity and not follow-up oil API gravity, following their IHS-BEG original identification as gas wells.

Among the 1028 wells in the third group with reported initial flow of condensate, we could confirm 415 wells as condensate-type liquids producing wells after enforcing the condition of having non-missing reported initial and follow-up oil API gravity.*

Therefore, among 3962 wells that reported an initial flow of condensate, we confirmed 2761 wells (15 O wells, 2331 G wells, and 415 unmarked wells) as condensate-type liquids producing wells. Now, by comparing these 2761 wells with the 3056 wells that reported both initial and follow-up oil gravity, we ended up with 295 wells having no report of condensate flow rate. Among these 295, 265 wells reported initial oil flow and 30 wells did not report initial oil flow. Among the 265 wells with reported initial oil flow, 36 wells were marked O, 189 wells were marked G, and 40 wells were unmarked. In the database, therefore, we left the 36 O and 189 G wells as they were and we marked 29 wells out of the 40 unmarked wells as condensate-type liquids producing wells, since they did report initial condensate gravity. For the remaining 30 wells, 29 wells were marked G and only one well had no marking.

*Using this approach, we still have 613 unmarked wells that report only initial oil API gravity and not follow-up oil API gravity.

This approach accounts for all 3056 wells with both initial and follow-up oil gravity reported. In short, we confirmed 2790 wells (29+2716) as condensate-type liquids producing wells, most of which were among the wells shown in FIGURE 8. This exercise of identifying condensate-type liquids producing wells in the database does not affect our developed database for the OPGEE input parameters. However, it helps explain higher oil API gravity for the 3056 wells that reported both initial and follow-up oil gravity as shown in FIGURE 8 compared with FIGURE 7. Through the above-described approach, we confirm that 2790 of those 3056 wells are condensate-type liquids producing wells.

APPENDIX F:

DETAILED DESCRIPTIONS OF PRODUCTION TECHNOLOGIES

Artificial lift techniques are used in liquids-rich shale plays such as Eagle Ford to increase the liquids flow rates (Dunham 2012). In Eagle Ford in particular, wells with liquids production experience three stages of production. In the first stage, which could last a few months, liquids production rate is high and there is no need for artificial lift. In the second stage and after the first few months, wells require artificial lift systems. The two most common ones are gas lift and electric submersible pump (ESP) lift systems. In the third stage, owing to a drop in liquids production below 350 bbl/d, ESP and gas lift systems become inefficient. For this stage, operators tend to use beam pumping (Alvarez et al. 2014).

Applying artificial lift systems in horizontal wells (reservoirs) is complicated because of tight well-bore turns. long laterals, and multiphase flow regimes (King 2012). Other reasons include reservoirs' steep decline rates and lateral profiles (Dunham 2012).

Below we have summarized artificial lift systems and their potentials for Eagle Ford. These systems include **gas lifting** (Stage 2 production), **electric submersible pumping** (Stage 2 production), **beam pumping** (Stage 3 production), and **water flooding** (some testing has been performed and seems to show this method to be effective and profitable). Testing of steam flooding systems is under way, and that method is not discussed further here.

Eagle Ford Gas Lifting

Gas lifting is an artificial lift technique used for reservoirs without a sufficient degree of natural lift. The main purpose of using a gas lift is to lower the density of the fluid in the tubing (PetroWiki 2014).

A gas lift system could be applied to any deviation. In addition, such a system tolerates solids and gas flow very well. These three characteristics make the gas lift system a viable candidate for horizontal wells and in particular for wells with high gas-to-oil ratios (GORs). However, positioning the gas lift system in the horizontal section is challenging (Dunham 2012).

Gas lift systems are inherently inefficient. In addition, and as is the case for Eagle Ford, operating a gas lift system is expensive for the operators in the oil-rich window. That is, in part, because operators have to sell their produced gas and then buy back additional gas, including the produced gas amount, for reinjection (Baker Hughes 2014).

Eagle Ford Electric Submersible Pumping

Baker Hughes Artificial Lift Systems has introduced an ESP system[16] as a solution to the problem of operating an artificial lift system in a low-GOR reservoir in a more economical way.

[16] Known as ProductionWave solution with FLEXPump technology (Baker Hughes, 2014).

Baker Hughes has applied this technique on 1400 wells (reservoirs) for unconventional applications, including Eagle Ford. ESP systems could perform well in horizontal wells except for their intolerance for large solids and gas volumes. In fact, high liquids volume is an essential requirement for an ESP system (King 2012). To deal with these problems, Baker Hughes provides a comprehensive ESP package that includes a pump, a gas separator, and a monitoring system (Baker Hughes 2014). The gas separator is required to separate the intake gas (King 2012) by venting the free gas (Baker Hughes 2014). The monitoring system is also an essential component, since such ESP systems require constant monitoring of the flow of liquids (King 2012) and other important parameters.

Ferguson and Narvaez (2013) discuss the implementation and expanded roll-out of the Schlumberger-modified ESP system on Magnum Hunter Resources Corp. assets in the Eagle Ford shale play. The Schlumberger-modified ESP implementation was developed as a result of the failure of a traditional ESP in Eagle Ford. They also argue that "ESP systems are used in the transitional artificial lift phase to provide an integrated program that maximizes production over the complete life of the well." In other words, they assert the necessity of using artificial lift systems for shale plays and in particular in the transitional phase. Their description of the transitional phase is based on their categorization of the production phase as consisting of "initial production or natural flow, transitional artificial lift, and traditional beam pump or gas lift for the remainder of the well life."

Alvarez et al. (2014) have also emphasized the three stages of production in the shale plays and the use of ESP in the second stage (first year) and beam pumping in the third stage as "the most flexible form of artificial lift available."

Eagle Ford Beam Pumping

The sucker-rod lift method, also known as beam pumping, is the oldest artificial lift technique. In a beam pumping system, "linked rods attached to an underground pump are connected to the surface unit. The linked rods are normally called sucker rods and are usually long steel rods. The steel sucker rods typically fit inside the tubing and are stroked up and down by the surface-pumping unit. This activates the downhole, positive-displacement pump at the bottom of the well. Each time the rods and pumps are stroked, a volume of produced fluid is lifted through the sucker-rod tubing annulus and discharged at the surface." (PetroWiki 2015) As mentioned above, operators in Eagle Ford tend to use beam pumping during the third stage of production, when liquids production drops below 350 bbl/day.

Eagle Ford Water Flooding

Some operators have started testing the possibility of water flooding in Eagle Ford, in view of some strong evidence about the effectiveness of the technique and its potential as a secondary technique to enhance the operator's profit. There are also a few peer-reviewed studies looking at the water flooding potentials in Eagle Ford, including those of Morsy et al. (2013) and Morsy and Sheng (2014).

References for Appendix F

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