Updates to Petroleum Refining and Upstream Emissions

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I. Updated Estimation of Energy Efficiencies of U.S. Petroleum Refineries

Background

Evaluation of life-cycle (or well-to-wheels, WTW) energy and emission impacts of vehicle/fuel systems requires energy use (or energy efficiencies) of energy processing or conversion activities. In most such studies, petroleum fuels are included. Thus, determining the energy efficiencies of petroleum refineries becomes a necessary step for life-cycle analyses (LCAs) of vehicle/fuel systems. Energy efficiencies of petroleum refineries can then be used to determine the total amount of process energy used for refinery operation. Furthermore, because refineries produce multiple products, the allocation of energy use and the emissions associated with petroleum refineries to various petroleum products is needed to perform WTW analysis of individual fuels, such as gasoline and diesel.

In particular, GREET, the life-cycle model developed at Argonne National Laboratory (Argonne) with sponsorship from the U.S. Department of Energy, compares energy use and emissions of various transportation fuels, including gasoline and diesel. Energy use in petroleum refineries is a key component of well-to-pump (WTP) energy use and in the emissions of gasoline and diesel. In GREET, the overall energy efficiencies of petroleum refineries are used to determine energy efficiencies specific to petroleum products.

Argonne has developed petroleum refining efficiencies from LP simulations of petroleum refineries and Energy Information Administration (EIA) survey data of petroleum refineries up to 2006 (see Wang 2008). This memo documents Argonne's most recent update of petroleum refining efficiencies.

Update of Petroleum Refinery Energy Efficiencies with EIA Survey Data

Argonne has used new data from the 2011 EIA annual *Refinery Capacity Report* (EIA 2011a) and the 2010 EIA *Petroleum Supply Annual* report (EIA 2011b) to update the process fuel use in U.S. refineries (Table 1) and the U.S. petroleum refinery input and output tables (Table 2).

Table 1. Process Fuel Use in U.S. Refineries in 2010 (in 1,000 barrels/year, excepted as noted) (Source: EIA, 2011a)

	PADDs[a]					U.S.
	I	**II**	**III**	**IV**	**V**	**Total**
Liquefied Petroleum Gas	43	1,040	345	93	883	2,404
Distillate Fuel Oil	33	21	132	1	253	440
Residual Fuel Oil	74	101	43	9	753	980
Still Gas	12,631	47,621	107,427	8,474	43,737	219,890
Marketable Petroleum Coke	0	0	0	752	145	897
Catalyst Petroleum Coke	9,316	16,480	43,341	2,590	10,347	82,074
Natural Gas (million cubic feet)	25,074	138,233	415,660	25,287	151,808	756,062
Coal (thousand short tons)	29	0	0	0	0	29
Purchased Electricity (million kWh)	3,598	10,910	24,798	1,957	4,964	46,227
Purchased Steam (million lbs.)	5,305	14,484	93,948	1,214	14,030	128,981
Other Products	27	65	1,009	3	1,254	2,358

[a] PADD = Petroleum Administration for Defense Districts.

Argonne also obtained updated hydrogen use data from the *Chemical Economics Handbook* (CEH). It reports that in 2006, U.S. refineries used 1,470.4 billion standard cubic feet (SCF) of captive hydrogen and 497 billion SCF of merchant hydrogen. CEH classifies captive hydrogen as the hydrogen produced by refineries for use in the same refinery and excludes hydrogen generated as a by-product of other refinery operations (e.g., catalytic reforming or FCC). Although excluding the hydrogen generated as a by-product of other refinery operations does not affect the refinery efficiency (the producing fuels are accounted for already), it does artificially lower the calculated CO_2 emissions. Merchant hydrogen is defined as that supplied by industrial gas companies for “small-volume intermittent uses, requirements in excess of captive production or large quantities on a short-term basis when the usual supply source is down” (CEH 2007). Argonne decided to add hydrogen as a separate refinery process fuel instead of converting it to the equivalent natural gas (NG) necessary for its production.

Since 2009, the annual EIA *Refinery Capacity Report* has added a new entry for “natural gas used as feedstock for hydrogen production.” The amount reported in 2011, 155 billion SCF of NG, is much lower than the numbers cited in the CEH (815 billion SCF of NG) (EIA 2011a). Argonne decided not to use the EIA-reported number as we understand that the new entry in the EIA annual survey (Form EIA-820) must include only a subset of refinery-produced hydrogen.

Table 2. 2010 U.S. Petroleum Refinery Inputs and Outputs (in 1,000 barrels/year)
(Source: EIA, 2011b)

	PADDs					U.S.
	I	II	III	IV	V	Total
Refinery and Blender Net Inputs						
Crude	**408,118**	**1,197,677**	**2,713,054**	**197,172**	**858,073**	**5,374,094**
Natural Gas Liquids	**5,600**	**39,223**	**90,975**	**5,093**	**20,588**	**161,479**
Pentanes Plus	8	14,581	34,174	1,032	6,891	56,686
Liquefied Petroleum Gases	5,592	24,642	56,801	4,061	13,697	104,793
Ethane/Ethylene	0	0	0	0	0	0
Propane/Propylene	0	0	0	0	0	0
Normal Butane/Butylene	1,737	9,637	22,653	1,676	8,099	43,802
Isobutane/Isobutylene	3,855	15,005	34,148	2,385	5,598	60,991
Other Liquids	**818,841**	**154,103**	**−350,219**	**6,362**	**121,217**	**750,304**
Other Hydrocarbons/Oxygenates	110,419	80,838	40,436	5,953	51,768	289,414
Oxygenate (excl. Fuel Ethanol)	0	0	901	0	0	901
Renewable Fuels (incl. Fuel Ethanol)	110,419	80,250	39,535	5,953	51,768	287,925
Fuel Ethanol	110,066	78,951	39,528	5,935	51,403	258,883
Renewable Fuels exc. Fuel Ethanol	353	1,299	7	18	365	2,042
Other Hydrocarbons	0	588	0	0	0	588
Unfinished Oils	39,022	13,060	150,181	−1,135	14,580	215,708
Motor Gasoline Blend. Comp.	669,400	60,205	−540,891	1,544	54,869	245,127
Reformulated	182,993	17,684	−137,399	10	17,918	81,206
Conventional	486,407	42,521	−403,492	1,534	36,951	163,921
Aviation Gasoline Blending Component	0	0	55	0	0	55
Refinery and Blender Net Production						
Natural Gas Liquids	**14,586**	**41,547**	**156,304**	**3,894**	**24,123**	**240,454**
Pentanes Plus	0	0	0	0	0	
Liquefied Petroleum Gases	14,586	41,547	156,304	3,894	24,123	240,454
Ethane/Ethylene	91	0	7,133	4	0	7,228
Propane/Propylene	13,999	38,073	131,462	3,526	17,163	204,223
Normal Butane/Butylene	960	3,281	18,989	568	6,483	30,281
Isobutane/Isobutylene	-464	193	-1,280	-204	477	-1,278
Finished Motor Gasoline	**993,681**	**797,994**	**843,854**	**109,263**	**561,608**	**3,306,400**
Reformulated	448,755	133,670	144,425	0	387,888	1,114,738
Conventional	544,926	664,324	699,429	109,263	173,720	2,191,662
Finished Aviation Gasoline	**0**	**961**	**3,721**	**132**	**540**	**5,354**
Kerosene-Type Jet Fuel	**23,755**	**79,441**	**261,049**	**10,163**	**143,067**	**517,475**
Kerosene	**2,527**	**242**	**2,825**	**589**	**697**	**6,880**
Distillate Fuel Oil	**134,679**	**351,513**	**810,321**	**62,451**	**182,539**	**1,541,503**
15 ppm Sulfur and Under	80,890	331,378	623,998	57,971	160,845	1,255,082
15 to 500 ppm Sulfur	1,779	12,854	92,290	4,319	8,349	119,591
Greater than 500 ppm Sulfur	52,010	7,281	94,033	161	13,345	166,830
Residual Fuel Oil	**25,379**	**16,167**	**124,510**	**3,012**	**44,425**	**213,493**
0.31 percent Sulfur and Under	7,528	9	8,014	1,134	677	17,362
0.31 to 1.00 Percent Sulfur	7,352	2,144	9,853	500	11,341	31,190
Greater than 1.00 Percent Sulfur	10,499	14,014	106,643	1,378	32,407	164,941
Petrochemical Feedstocks	**3,719**	**13,601**	**101,920**	**47**	**57**	**119,344**
Naphtha for Petrochemical Use	3,719	10,085	62,484	0	79	76,367

Other Oils for Petrochemical Use	0	3,516	39,436	47	-22	42,977
Special Naphthas	**313**	**−503**	**13,450**	**0**	**364**	**13,624**
Lubricants	**5,075**	**2,871**	**45,221**	**−2**	**6,988**	**60,153**
Waxes	**123**	**568**	**2,337**	**0**	**-**	**3,028**
Petroleum Coke	**12,286**	**52,325**	**171,115**	**7,855**	**52,802**	**296,383**
Marketable	2,974	35,845	127,774	5,265	42,455	214,313
Catalyst	9,312	16,480	43,341	2,590	10,347	82,070
Asphalt and Road Oil	**22,873**	**61,034**	**31,915**	**11,815**	**10,365**	**138,002**
Still Gas	**14,281**	**46,240**	**128,679**	**8,467**	**47,635**	**245,302**
Miscellaneous Products	**552**	**4,511**	**16,496**	**1,361**	**4,752**	**27,672**

The majority of “Other Hydrocarbons/Oxygenates” is fuel ethanol that is used for blending. However, GREET does not include blending of ethanol and gasoline in the refining stage, but rather has a separate step for blending after refining. Therefore, we assume that all “Other Hydrocarbons/Oxygenates” is fuel ethanol, and the amount is taken out from both the inputs and the outputs. Using this assumption and the new 2010 data, Argonne has updated the overall petroleum refining efficiency to 91.4% vs. 90.8% using the 2008 data.

Update of Shares of Process Fuels

The materials consumed in the refining process can be categorized into three groups: consumed process inputs, converted process inputs, and consumed intermediates. Consumed inputs are the material inputs coming from outside of the refineries that are combusted or used in the refining process (e.g., NG, coal, and electricity in Table 1). Converted inputs are the material inputs coming from outside of the refineries that are converted into outputs (e.g., unfinished oil in Table 2). Some materials can be both consumed and converted inputs. For example, the liquefied petroleum gases (LPG) input in Table 2 is 105 million barrels/year, whereas the LPG consumption in Table 1 is only 2 million barrels/year. Consumed intermediates are the intermediate products that are combusted or used in the refining process (e.g., still gas and petroleum coke in Table 1). The upstream of material inputs (but not intermediates) are included in the LCA calculation. Also, the combustion emissions of combusted inputs and intermediates (not converted inputs) are included in the LCA calculation.

Argonne created Table 3 with data from Tables 1 and 2 for use in GREET modeling. The “Other Products” from Table 1 and “Pentanes Plus” from Table 2 are included as LPG in Table 3. “Distillate Fuel Oil” and “Residual Fuel Oil” from Table 1 and “Unfinished Oils” from Table 2 are included in “Residual oil + Unfinished oils” in Table 3, using the same upstream assumptions as those that apply for residual oil.

Table 3. Process Fuels and Intermediates in U.S. Petroleum Refineries (billion Btu/year, based on 2010 refinery data)

	PADDs					U.S. Total	Shares
	I	II	III	IV	V		
Crude	0	0	0	0	0	0	0.0%
LPG	193	67,741	163,732	4,785	39,105	275,556	9.1%
Combusted	312	4,142	7,097	354	10,465	22,369	8.1%
Converted	-119	63,599	156,635	4,431	28,640	253,187	91.9%
Natural gas	35,788	169,508	604,570	28,306	182,622	1,020,793	33.8%
Hydrogen	25,109	118,928	424,170	19,859	128,129	716,195	23.7%
Coal	643	0	0	0	0	643	0.0%
Purchased electricity	12,276	37,225	84,611	6,677	16,937	157,727	5.2%
Residual oil + Unfinished oils	62,925	253,283	351,180	64,225	121,505	853,117	28.2%
Combusted	657	757	1,039	62	6,208	8,724	1.0%
Converted	62,267	252,525	350,141	64,163	115,297	844,393	99.0%
Total Process Fuel Inputs	136,934	646,684	1,628,263	123,853	488,297	3,024,031	
Still Gas, Intermediates Combustion	75,786	285,726	644,562	50,844	262,422	1,319,340	
Pet Coke, Intermediates Combustion	56,120	99,276	261,086	20,132	63,204	499,817	
Total Energy Outputs	2,574,805	6,896,512	16,547,464	1,094,305	5,031,375	32,143,856	
Efficiencies	95.0%	91.4%	91.0%	89.8%	91.2%	91.4%	

[a] Petroleum coke here includes both marketable and catalyst petroleum coke. Between the two, catalyst petroleum coke accounts for the majority of the petroleum coke share.

Update of Energy Efficiencies for Producing Individual Petroleum Products

Argonne has decided to modify the methodology used for the allocation of energy efficiencies between individual refinery products. A new paper by Bredeson et al. (2010) presents a modified allocation method that utilizes a hydrogen-energy equivalency to better allocate emissions consistently with refinery behavior. The simple energy allocation method fails to account properly for emissions associated with hydrogen production. Hydrogen is generated in a refinery's catalytic reformer in order to boost gasoline's octane rating. This same hydrogen is used in the refinery to hydro-process distillate material into commercial diesel and jet fuel. From this perspective, catalytic reforming transfers energy from gasoline to distillate products. The paper's conclusions show that the energy efficiencies of LPG, gasoline, and distillate (diesel and jet) products should be considered equal. Furthermore, the energy efficiency of the heavier cuts (vacuum residue) will depend on the refinery's configuration (residue upgrading capacity) and type of crude being processed (heavy or light).

Argonne conducted an analysis of available residue upgrading units in U.S. refineries using the 2009 EIA annual *Refinery Capacity Report* (EIA 2009). Roughly 67% of crude is processed by refineries that include residue upgrading units (mostly delayed coker units, but also a few vis-breakers and others). Residue upgrading units are large energy consumers and produce hydrogen-deficient intermediate products that need further upgrading before becoming commercial products, thus using more hydrogen.

Argonne decided to classify refinery products in two categories in order to calculate their energy efficiencies, with LPG/gasoline/distillate as one group, and the remaining products (residual oil and naphtha, mostly) as another group. As of June of 2011, the first group accounted for 85.2% of the energy content of all petroleum products from U.S. refineries, while the other group carried the remaining 14.8%. Using Figures 2 and 3 from Bredeson et al. (2010), Argonne estimated an energy intensity ratio of 2.6 between the LPG/gasoline/distillate and residuals, using a weighted average between coker and residual oil #6 cases with the 67%/33% split above.

Assigning an energy efficiency of 90.6% to the LPG/gasoline/distillate group (0.8% lower than the 91.4% level of overall refining) equates to a relative energy intensity of 1.10 and an energy allocation of 93.9% for this group. This result corresponds to a 6.1% energy allocation for the residual group, and thus a relative energy intensity of 0.41 and an energy efficiency of 96.3%. The calculated ratio between the two groups' energy intensities is 2.7, the same value as was calculated from the Bredeson paper. Table 4 presents these final product-specific energy efficiencies.

Table 4. Refining Energy Efficiencies for Individual Petroleum Products

	Allocated % of Total Refining Fuel Use	% of Total Refinery Products Energy Content	Relative Energy Intensity	Overall Petroleum Refinery Efficiency	
				91.4% (with all products included)	**88.3%** (with less desirable products excluded)
LPG Gasoline Distillate	93.9%	85.2%	1.10	**90.6%**	**87.3%**
Other (residue, naphtha)	6.1%	14.8%	0.41	**96.3%**	**94.9%**

The refining efficiency of conventional jet fuelis set to be 0.5% higher than that of the LPG/gasoline/distillate group (91.1%) because of its larger share of straight-run jet fuel. The refining efficiency of ultra low sulfur jet fuel is set to be 1.5% lower than that of conventional jet fuel (89.6%) due to its lower sulfur content.

Outstanding Issues

Energy Efficiencies of Refinery By-Products (LPG, residual oil)

Allocating energy efficiencies to refinery products is a difficult task. Refineries operate to produce transportation fuels (gasoline, jet fuel, diesel, etc.) as best suited to current economic conditions, but they also produce other, less commercially important by-products, such as LPG and residual oil. The energy efficiency of residual oil (and of other heavier products) can be calculated from data from refineries without residue upgrading capacity, as explained in Bredeson et al. (2010). The case of LPG (a lighter product) is a bit different, as its production in refineries stays fairly constant, only depending on the type of crude being processed and the refinery configuration. Depending on those two factors, the actual LPG energy efficiency can be calculated from somewhat higher to somewhat lower from the gasoline/distillate group. Argonne has decided to fix the LPG energy efficiency to that of the gasoline/diesel group of products.

Energy Efficiencies of Refineries Processing Heavy Crudes

Refineries consume more energy when processing heavier crudes. Heavier crudes have a larger vacuum residue fraction that needs to be upgraded in order to maintain a commercially viable product slate. Residue upgrading consumes large amounts of energy (i.e., delayed coker units with high CO_2 emissions) and hydrogen. Residue upgrading units produce hydrogen-deficient intermediate products that need to be further hydro-processed into commercial refinery products (gasoline/jet fuel/diesel). Argonne may eventually consider introducing a dependency on the crude heaviness (API gravity and/or distillation curve points) for future calculations of refinery energy efficiencies.

Oil Sands

Currently, Argonne's methodology pushes all the burden of oil sands processing to the upstream recovery steps. In the currently used methodology, processing oil sands–derived crudes (syn-crudes) does not impact the energy efficiencies of refineries. Argonne will evaluate the existing arguments for separating the extra energy burdens of processing syn-crudes between the oil sands recovery steps and the refinery processing.

Hydrogen

Argonne will work to reconcile the hydrogen consumption numbers coming from the EIA and those from the Chemical Economics Handbook. One possible explanation is that the EIA number only includes hydrogen generation from steam methane reforming (SMR), whereas the CEH captive production figure would include both the hydrogen amounts from SMR of natural gas but also from other fuels, such as naphtha.

References

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II. Associated Gas Flaring and Venting for Crude Oil Production

Associated gas is a by-product of conventional crude oil production. Associated gas contains large amounts of methane, so its disposal has important greenhouse gas (GHG) consequences. A significant portion of the produced associated gas is wasted, usually for commercial or structural reasons. A majority of this wasted gas is flared to the atmosphere, while the rest is vented.

The GHG emissions that are attributable to associated gas flaring and venting need to be assigned to the crude oil production in which they originate. Crude oil production is an international endeavor, and therefore these emissions need to be considered on an international scale. The GHG emissions produced in their countries of origin should be charged to an average U.S. market barrel of crude with the appropriate weights.

Associated Gas Flaring

Since 2002, the World Bank has sponsored the *Global Gas Flaring Reduction Partnership* (GGFR) with the explicit mission of reducing gas flaring and venting in oil-producing countries. One of its most valuable outcomes is the compiling of gas flaring data. Flaring data was collected through surveys until 2005 and from satellite data afterwards. The collection and analysis of satellite data for the estimation of gas flaring volumes is conducted by the Earth Observation Group at the National Oceanic and Atmospheric Administration's National Geophysical Data Center (Elvidge 2007). The published data contains the estimated volumes of gas flared (in billions of cubic meters, *bcm*) by specific country (in the *Global Gas Flaring Estimates* [NOAA NGDC undated]). Using 2009 as our reference year, we combine this flaring data with oil production data for the same countries obtained from the EIA (available at http://www.eia.gov) (EIA undated) to calculate a ratio of gas flared to crude oil produced (by cubic meter of associated gas flared per barrel of oil produced, m^3/bbl) for all significant countries. We can then compile a list of U.S. oil imports from the EIA and, after adding the U.S. crude oil production, calculate the proportional contribution of each country to the average barrel of crude oil used in U.S. refineries. The weighted average comes out to $3.37\ m^3/bbl$, spanning from a maximum of $48.81\ m^3/bbl$ for crude oil imported from Congo (Kinshasa), to a minimum of $0.36\ m^3/bbl$ for Azerbaijani crude, and with $0.62\ m^3/bbl$ for domestic U.S. crude oil. These results are presented by oil-producing regions in Table 5.

Determination of flare efficiencies is critical for estimating the GHG effects of associated gas flaring. Flare efficiency is defined as the ratio of the "mass rate of carbon in the form of CO_2 produced by the flame" to the "mass rate of carbon in the form of hydrocarbon fuel exiting the flare" (Kostiuk et al. 2004). The flare efficiency value typically used in the literature (Buzcu-Guven et al. 2010; Kostiuk et al. 2004; EPA 2009) is 98%, although on rare occasions, efficiencies can drop to as low as 70%.

Table 5. 2009 Gas Flaring Data by Oil-Producing Regions

	Estimated Gas Flared	**Crude Oil Production**	**Gas Flared per Oil Produced**	**U.S. Crude Oil Origin**		**Flared Gas Contribution**	
	(bcm)	**(kbpd)**	**(m3/bbl)**	**(kbpd)**	**(%)**	**(m3/bbl)**	**(%)**
Africa	**36.19**	**10,056**	**9.86**	**1,910**	**13.37**	**1.72**	**50.94**
Nigeria	15.18	2,211	18.80	776	5.43	1.02	30.28
Congo (Kinshasa)	*0.39*	*22*	***48.81***	*9*	*0.06*	*0.00*	*0.00*
Rest of Africa	20.62	7,823	7.22	1,125	7.87	0.70	20.66
Asia	**6.92**	**6,984**	**2.72**	**88**	**0.62**	**0.02**	**0.64**
Vietnam	0.52	346	4.13	27	0.19	0.01	0.23
Rest of Asia	6.40	6,638	2.64	61	0.43	0.01	0.40
Europe	**1.31**	**3,852**	**0.93**	**161**	**1.13**	**0.01**	**0.43**
Former Soviet Union (FSU)	**39.17**	**12,486**	**8.59**	**322**	**2.25**	**0.17**	**4.93**
Russia	35.24	9,934	9.72	230	1.61	0.16	4.64
Azerbaijan	*0.13*	*1,012*	***0.36***	*75*	*0.52*	*0.00*	*0.00*
Rest of FSU	3.80	1,540	6.75	17	0.12	0.01	0.29
Middle East	**19.53**	**19,880**	**2.69**	**1,687**	**11.81**	**0.43**	**12.79**
Iraq	9.13	2,400	10.42	449	3.14	0.33	9.71
Rest of Middle East	10.40	17,480	1.63	1,238	8.67	0.10	3.08
North America	**6.71**	**15,586**	**1.18**	**8,348**	**58.43**	**0.64**	**18.90**
United States	*2.06*	*9,141*	*0.62*	*5,317*	*37.22*	*0.23*	*6.82*
Canada	2.07	3,294	1.72	1,899	13.29	0.23	6.78
Rest of North America	2.58	3,151	2.24	1,132	7.92	0.18	5.29
South America	**6.39**	**7,208**	**2.43**	**1,755**	**12.28**	**0.38**	**11.37**
Venezuela	2.83	2,471	3.14	951	6.66	0.21	6.20
Rest of South America	3.56	4,736	18.12	804	5.63	0.17	5.17
TOTAL	**116.22**	**76,053**	**22.29**	**14,271**	**100.00**	**3.37**	**100.00**

Associated Gas Venting

Associated gas venting data from crude oil production is not widely available. It cannot be estimated from satellite images as vented gas is not visible. Therefore, we need to rely on surveyed data to estimate vented volumes. We decided to model gas venting volumes by using the ratio of vented to flared gas, drawing on data from several references. These references present gas flaring and venting quantities for a collection of representative countries (NETL 2008), for the Canadian case (CAPP 2002), and for a subset of self-reported companies worldwide (OGP 2010). For U.S.-bound crude, we estimate an average venting-to-flaring ratio of 0.2, with a distribution very much centered between 0.1 and 0.3.

For U.S.-originated crude, the U.S. Environmental Protection Agency GHG inventory (EPA 2011) shows venting of *719 Gg* of CH_4 at the wellhead, or equivalently *0.91 bcm*. The estimated gas flared volume for the United States is *2.06 bcm*, giving a ratio of vented-to-flared gas of 0.44. This ratio compares well with the values for all U.S.-bound crude (0.1 to 0.3), as U.S.-originated crude should have lower associated flared gas volumes as it is being produced in a tightly regulated environment.

Associated Gas Composition

Another important data point for calculating the GHG effects of gas venting and flaring is the composition of the considered associated gas. Some references point out the similarities between associated gas and natural gas (Buzcu-Guven et al. 2010). We have used full composition data from a Word Bank–sponsored study (The World Bank/GGFR 2006). The study presents a range of representative gas compositions, classified according to the percentage of C_3 and C_4 hydrocarbon gases present. Our typical gas composition contains 5% C_3+C_4, while we consider a distribution between 0% and 15%. In order to model the gas composition, we use carbon content (weight % carbon, to estimate CO_2 emissions after flaring), methane content (very important for vented gas and non-burned flared portions), CO_2 content (also mostly for vented and non-burned flared portions), and the lower heating value (LHV) of the three representative gas compositions (Table 6).

Table 6. Representative Gas Compositions by Percentages of C_3 and C_4 Hydrocarbons Present

Associated Gas Data		**0% C_3+C_4**	**5% C_3+C_4**	**15% C_3+C_4**
C content	**wt%**	69.40	71.08	73.71
CH_4	**mol%**	87.00	82.26	73.95
CO_2	**mol%**	2.80	2.65	2.38
LHV	**BTU/cuft**	941	1,026	1,209

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