Refinery GHG emissions from dirty crude

Preliminary estimate based on oil input quality, process intensity and energy intensity of U.S. oil refineries, 2003-2007.

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The mission of **Communities for a Better Environment** (CBE) is to achieve environmental health and justice by building grassroots power in and with communities of color and working class communities. Founded in 1978, CBE combines in-house scientific, legal and organizing expertise to leverage plant-specific pollution prevention and regional policy progress that could not be achieved using science, organizing or legal advocacy alone. Thousands of CBE members and supporters live in the greater Los Angeles and San Francisco Bay Areas.

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Summary

Fuel combustion for process energy causes greenhouse gas emissions from oil refineries, and lower-quality oil requires more intensive processing and more energy. This analysis compares process intensity and energy with oil input quality across U.S. refining districts during 2003-2007. Refining heavier and higher-sulfur oil can explain 93% of the differences in processing intensity and 91% of the differences in energy consumed between districts and years. Other oil quality factors might explain some of the remaining differences in energy consumed. Product slates do not explain the observed impacts of oil quality on energy consumed. As oil input quality worsened across districts, energy consumed increased by 47% (from 522,000-770,000 Btu/b v. 138-143 kg/b gravity+sulfur). This rate of increase suggests that a switch to heavy oil or tar sands could double or triple greenhouse gas emissions from U.S. oil refineries. Limiting the worsening quality of refinery oil inputs is critical to our environmental health.

Purpose and scope

Petroleum energy is the largest GHG polluter in the U.S., accounting for roughly 40% of total emissions. *(1)* However, some crude oils are fundamentally different from others, and making them into gasoline and other transport fuels entails substantially different energy and environmental costs. *(2)* California officials identify this potential for increased energy costs and resulting increased emissions from using lower quality oil but have not yet estimated those refinery emissions. *(3)* U.S. EPA has not estimated those emissions. U.C. Berkeley researchers estimated that a switch to heavy and natural bitumen ("tar sands") oils might double GHG emissions from oil production *and* refining for gasoline. *(4)* CBE showed that refining higher-sulfur crude has increased GHG emissions from steam reforming to feed hydroprocessing by California refiners, and worsening crude input quality could double or triple emissions from this one refinery process by 2020. *(5)* Here we make a preliminary estimate for all refining processes. This analysis uses reported differences between U.S. refining districts in processing, fuel consumed, and oil input quality to estimate current and potential GHG emissions from fuel combustion energy for refining lower-quality oil.

Data, limitations and methods

Table 1 shows refinery crude input capacities in the five U.S. Petroleum Administration Defense districts (PADDs, or districts). Comparable data on the gravity and sulfur content of crude oil inputs, process capacities, fuels consumed in refineries and product yields are reported for each district on an annual basis by the U.S. EIA and Oil & Gas Journal. *(6, 7)* These data, and fuel energy units conversions, are shown in the Appendix. Crude input quality varies between districts. *(8)* We compare these data for 2003 through 2007 to assess the increase in fuel con-

Table 1. Refinery capacity by PADD & state

Million barrels/day

1 Delaware	0.190	3 Alabama	0.140
1 New Jersey	0.554	3 Arkansas	0.077
1 Pennsylvania	0.767	3 Louisiana	2.912
1 Virginia	0.059	3 Mississippi	0.353
1 West Virginia	0.019	3 New Mexico	0.130
PADD 1 total	*1.589*	3 Texas	4.829
2 Illinois	0.897	*PADD 3 total*	*8.440*
2 Indiana	0.428	4 Colorado	0.122
2 Kansas	0.293	4 Montana	0.187
2 Kentucky	0.227	4 Utah	0.174
2 Michigan	0.100	4 Wyoming	0.147
2 Minnesota	0.393	*PADD 4 total*	*0.630*
2 North Dakota	0.058	5 Alaska	0.382
2 Ohio	0.535	5 California	1.983
2 Oklahoma	0.486	5 Hawaii	0.148
2 Tennessee	0.190	5 Washington	0.635
2 Wisconsin	0.33	*PADD 5 total*	*3.148*
PADD 2 total	*3.640*	**U.S. total**	**17.447**

Data from crude charge capacities in b/calendar day reported as of 1/1/08 by Oil & Gas Journal (Ref. 7).

sumed for processing lower-quality oil. Fuel combustion for process energy causes the vast majority of refinery GHG emissions *(9)*, so energy use is a measure of these emissions.

Oil quality Gravity (mass/barrel) indicates the abundance of denser, higher boiling-point, larger hydrocarbons in a crude oil. Heavier oils have more of these denser compounds, which require distillation in a vacuum, and cracking to break them into smaller motor fuel-size compounds. Severe cracking such as coking is needed to make the heavier streams from vacuum distillation into high-value fuels such as gasoline. This requires more energy.

Sulfur is the major refinery process poison in crude oil by mass. In addition to producing corrosive acids in processing and causing flaring and other toxic refinery and tailpipe emissions, sulfur deactivates catalysts used in certain refining processes. Higher-sulfur oil requires more intensive hydroprocessing to remove the additional sulfur from the oil fed to those processes. This requires more energy.

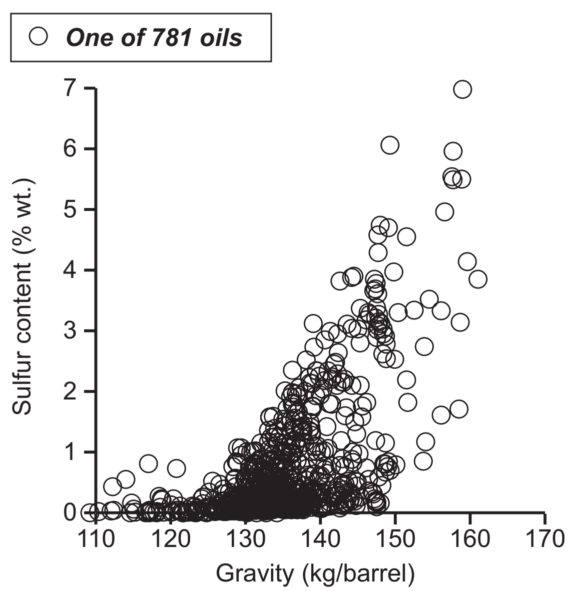
Sulfur concentrates in the larger hydrocarbons that are abundant in heavier crude oils. *(2)* This means that sulfur tends to be both higher and more variable in heavier oils. See Figure 1.

Crude gravity and sulfur content also interact to cause a greater-than-additive impact on processing intensity. Both hydrogen and cracking are required to break open the larger hydrocarbons and remove the sulfur trapped in them from the oil. This hydrocracking requires higher pressure, and several times more hydrogen/barrel than does sulfur removal from lighter oils. *(11)* The amount of this more intensive hydroprocessing that is required increases as refiners process heavier and/or higher-sulfur crude oils. For example, California refineries used nearly three times as much hydrogen to process heavier gas oil and residua streams as they used to process lighter distillates, naphtha and gasoline in 2007. *(5)* In these comparisons with processing intensity and energy, gravity-sulfur interactions are addressed by adding the mass of sulfur in the crude to its gravity. This gravity-plus-sulfur value weights changes in sulfur content twice as heavily as changes in whole crude gravity (because sulfur is already included in crude gravity measurements). That weighting may be conservative based on data from California. *(5)* However, process intensities and oil input qualities in other refining districts differ from those in California, and regression analysis suggests that this gravity-plus-sulfur weighting best fits the distribution of nationwide refinery data during 2003-2007.

Other crude oil properties are not reported for oil inputs to U.S. refining districts. Since gravity predicts abundance of denser hydrocarbons in the oils, the most important refinery energy question posed by this limitation in the data involves levels of other powerful catalyst poisons—nitrogen, vanadium and nickel—in the crude inputs to these refining districts.

Nitrogen, vanadium and nickel are at much lower levels than sulfur in crude *(10)*, but they

Figure 1. Sulfur v. gravity in crude oils



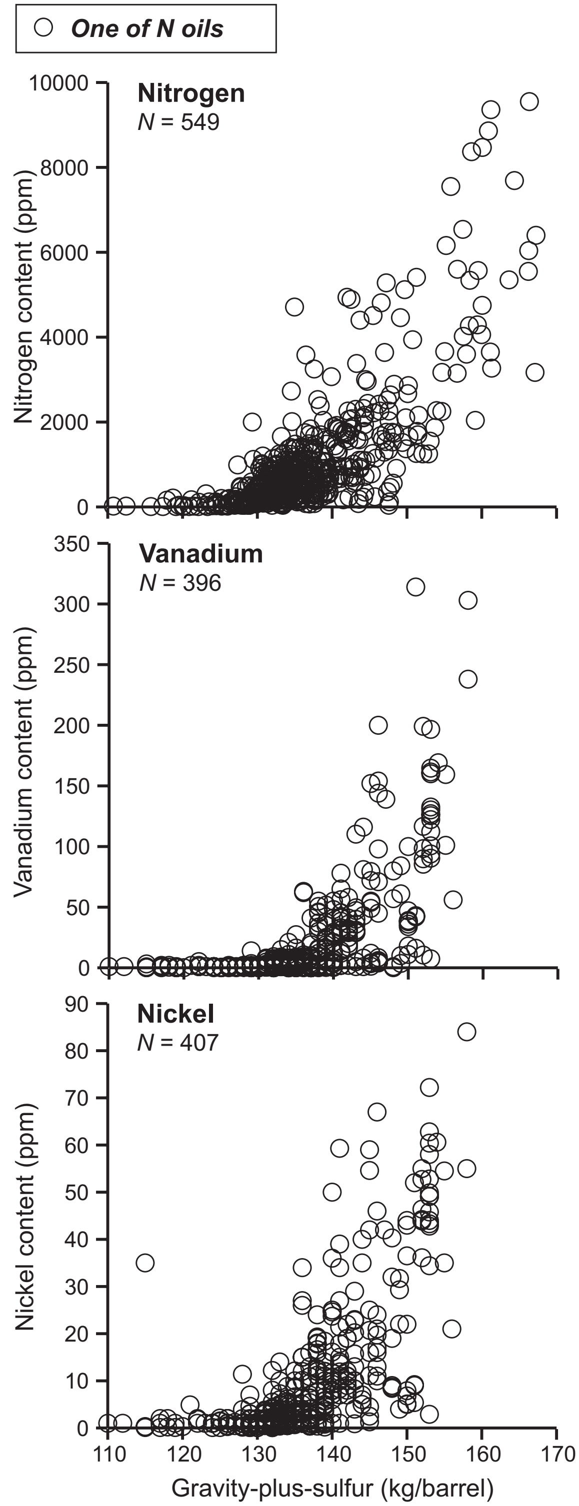
From publicly reported petroleum quality data compiled by CBE (Ref. 10). All oils in the compilation with gravity and sulfur data are shown.

are similarly concentrated in heavier oils *(2)*, and the levels of these contaminants tend to be higher and more variable as gravity-plus-sulfur increases in crude oils. See Figure 2. These observations suggest that gravity+sulfur is a predictor of energy-consuming process poisons in mixtures of many crude oils. A mix of oils from at least 20 countries was processed during 2003-2007 in each district but one. *(6)* The exception is Rocky Mountain District 4, where roughly half of the crude processed was from Canada. *(6)* Canadian oils have high vanadium and nickel relative to their gravity and sulfur. *(10)* Gravity and sulfur may not account for the full impact of unreported oil quality factors on process energy in District 4.

Energy intensity This analysis measures energy intensity as total refinery energy consumption per barrel of crude input. EIA reports fuels consumed in refineries except for those used to make hydrogen for hydroprocessing. *(6, 12)* Hydrogen production data based on 90% utilization of capacity from Oil & Gas Journal *(7)*, and hydrogen steam methane reforming data for 100% natural gas fuel from DOE *(13)* are used to estimate energy use for hydrogen. Ninety percent utilization is a standard default assumption. *(7)* The natural gas fuel assumption is conservative. The data, and factors used to convert fuel energy into common units, are shown in the Appendix.

Process intensity Oil quality impacts on processing can be identified to check that observed differences in energy consumption are from refining lower quality oil. This analysis uses process capacities in barrels/calendar day from Oil & Gas Journal *(7)* because EIA does not report actual or estimated (b/cd) usage rates for every process. *(6)* Review of these data reveals a greater range of capacities for processes needed to run lower quality oil. On a per barrel of crude capacity basis, coking capacity ranges nearly threefold, and hydro-

Figure 2. Nitrogen, nickel and vanadium v. gravity and sulfur in crude oils



Each chart uses the same gravity-plus-sulfur scale. From publicly reported petroleum quality data compiled by CBE (Ref. 10). All oils in the compilation with gravity, sulfur, and either N, Ni or V data, are shown.

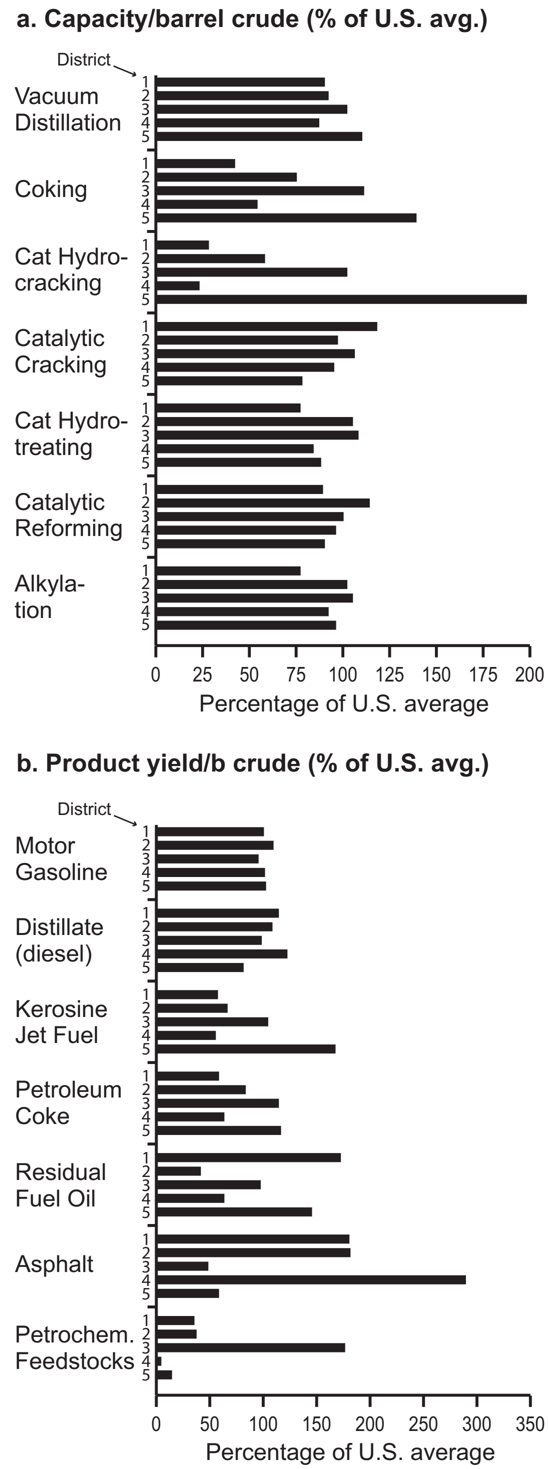
cracking capacity ranges sixfold, between districts. See Figure 3. Districts 3 and 5 have the most vacuum distillation, coking and hydrocracking capacity. Consistent with this result, districts 3 and 5 have the lowest-quality crude inputs among the U.S. refining districts. *(6)*

High catalytic cracking capacity in East Coast District 1 is offset by low coking and hydrocracking capacities in that district. This illustrates a need to consider the total capacity for lower-quality oil. Here, process intensity is measured as total vacuum+cracking capacity per barrel of atmospheric crude distillation capacity, in barrels per calendar day.

<u>Product slates</u> Gasoline and distillate fuels are more than two-thirds of total products in each district *(6)*, but the amounts of refiners' ancillary products and byproducts vary widely. Chart b in Figure 3 illustrates this variability in jet fuel, coke, residual fuel oil, asphalt and petrochemical feedstock yields between refining districts. Changes in the quality of feedstock, the amounts of products made from it, and the energy needed to make the products are intertwined. For example, districts 3 and 5, which run lower quality oil, have more coking and make more petroleum coke, while the other districts produce more asphalt. See Figure 3.

Making these different products consumes different amounts of energy. Product efficiency factors *(12, 14)* and product yields *(6)* can be used to predict differences in energy consumption from the different product slates of the refining districts. Since the product efficiency factors are calculated for the average U.S. refinery and crude quality *(12, 14, 15)*, this exercise can serve as a check on how differences in product slates might affect refinery energy *independently* from oil quality. Yields used for this calculation are shown in the Appendix, and the product efficiency factors used are shown in Table 2. Results show that different product slates explain less than 15% of the dif-

Figure 3. Process configuration and products differences between refining districts



Capacities/barrel atmospheric crude distillation and yields/b crude input to atm. distillation, as a percentage of the U.S. average from 2003-2007. Charge capacities in b/cd from Ref. 7. Yields from Ref. 6.

ferences in energy use observed from refinery fuels consumed. Further, energy use predicted based on product slates *decreases* as observed energy use, process intensity and oil input gravity+sulfur increase. At least in this data set, different product slates cannot explain increasing energy use for lower-quality oil.

Energy v. process intensity In refining districts 1, 2, 3 and 5, gravity+sulfur is expected to predict vacuum distillation and cracking process energy for the diverse mix of oils refined based on the oil quality data assessment above. Refinery energy intensity increases with increasing process intensity across these districts. See Figure 4. Across districts 1, 2, 3 and 5, energy intensity is positively associated with process intensity, this association is statistically significant ($p < 0.001$), and process intensity can explain 93% of the variability in energy intensity between districts and years (R-squared = 0.93).

In contrast, oil quality data suggest impacts from unreported oil quality factors in the uniquely non-diverse District 4 oil input, and District 4 appears unique in Figure 4. Its energy intensity is high relative to that of some other districts with similar or greater vacuum distillation and cracking capacities/b crude. This suggests other oil quality factors, perhaps metals that increase hydrogen demand *(20)* and thus energy requirements to make that hydrogen in the case of District 4, might explain some of the variability in energy intensity observed during 2003-2007. These observations confirm the limitation in District 4 data suggested by the oil quality data assessment.

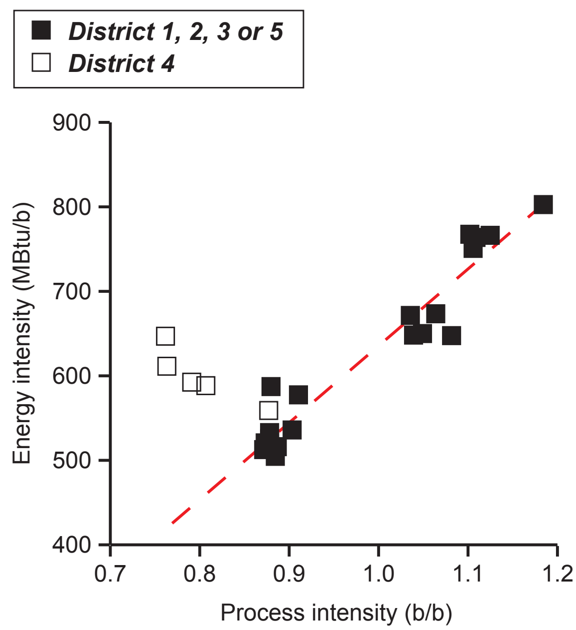
Overall, available data for refining districts 1, 2, 3 and 5 support analysis relating oil input quality (gravity+sulfur) to process intensity (vacuum+cracking) and observed energy intensity based on fuels consumed, to estimate GHG combustion emissions. These four districts account for 96% of U.S. refining capacity.

Table 2. Product efficiency factors based on the average U.S. refinery and crude

Efficiency (%)			
Residual oil[a]	94.3	LPG[a]	94.3
Fuel (still) gas[b]	89.2	Gas oil[b]	89.0
Naphtha[a]	94.3	Heavy fuel oil[b]	93.5
Diesel[a,c]	90.3	Lube stocks[b,c]	85.4
Kerosine[b]	93.6	Asphalt[b]	88.2
Gasoline[a]	87.7	Waxes[b]	85.3
Coke[b]	89.3		

[a] Product energy efficiency from Wang, 2008 (Ref. 12).
[b] Energy content-based product efficiency for a current typical U.S. refinery from Wang et al., 2004 (Ref. 14) adjusted for current average overall refinery efficiency (90.1%, from Ref. 12) using Equation 3 in Ref. 14. Typically used for fuel cycle analysis models (such as GREET), these factors are based on on a single hypothetical refinery configuration and average U.S. crude input quality (Refs. 12, 14,1 5), and estimate energy for product slates independently from oil input quality.
[c] Refinery yields reported by EIA (Ref. 6) categorize or label some products differently from Refs. 12 and 14. The diesel, and lube, factors are applied to EIA (Ref. 6) yield data for distillate, and petrochemical feedstock oils, respectively, to ensure that differences between refining districts are not underestimated.

Figure 4. Energy v. process intensities for U.S. refining districts, annual weighted averages, 2003-2007



Energy intensity observed from total fuel consumed/barrel of crude to atm. distillation. Process intensity is the sum of vacuum distillation, thermal cracking, cat-cracking and hydrocracking (vacuum+cracking) capacities/b atm. distillation capacity, in barrels/calendar day. Data from Refs. 6, 7.

Energy and oil input quality 2003-2007

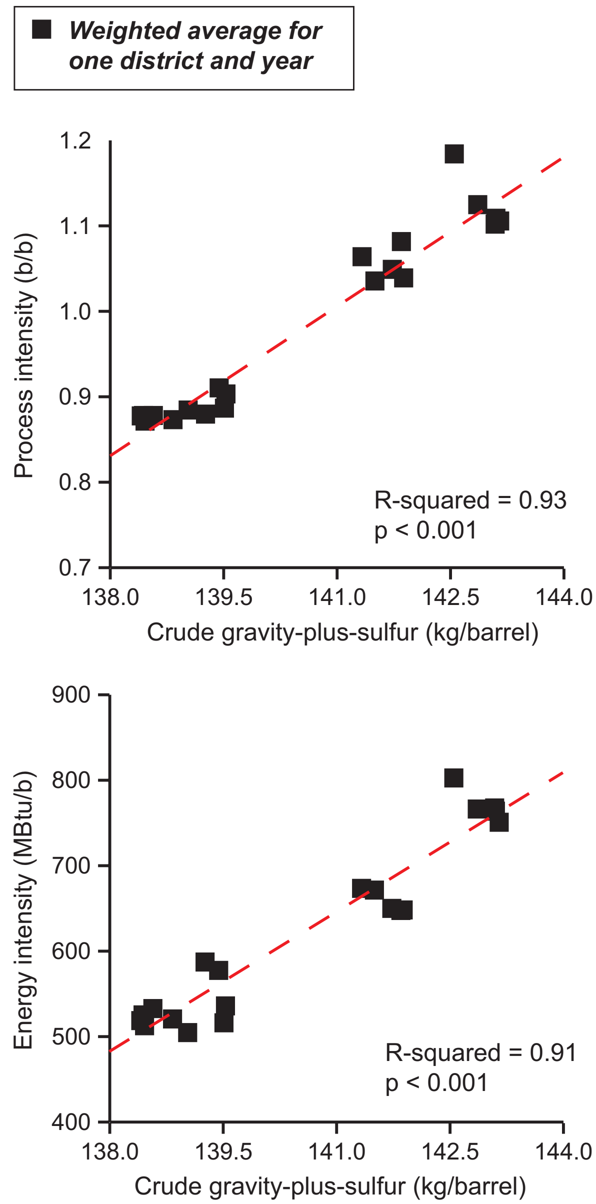
Figure 5 illustrates results of this analysis. The top chart shows the weighted average processing intensity and crude input quality for all refineries in each of four U.S. refining districts for each year from 2003 through 2007. Districts 1, and 2 refined relatively higher-quality oil, had lower process intensities, and cluster in the lower left of this chart. District 5 refined lower-quality oil, had a higher processing intensity and clusters at the upper right of the chart. District 3 is in between these extremes in its oil input quality, its processing intensity and its position on the chart.

Process intensity increases strongly as the quality of oil refined worsens. Process intensity is positively associated with refinery crude input gravity-plus-sulfur, this association is statistically significant ($p < 0.001$), and oil input quality can explain 93% of the variability in process intensity between refining districts and years (R-squared = 0.93).

The bottom chart in Figure 4 shows the weighted average energy consumed per barrel of crude refined and crude input quality for all refineries in each of the four districts for each year from 2003-2007. This chart reveals the same pattern for energy consumption that is observed among the districts for process intensity. Districts 1 and 2 are clustered at the lower left, District 5 is at the upper right, and District 3 is in between these extremes, on both charts in Figure 4.

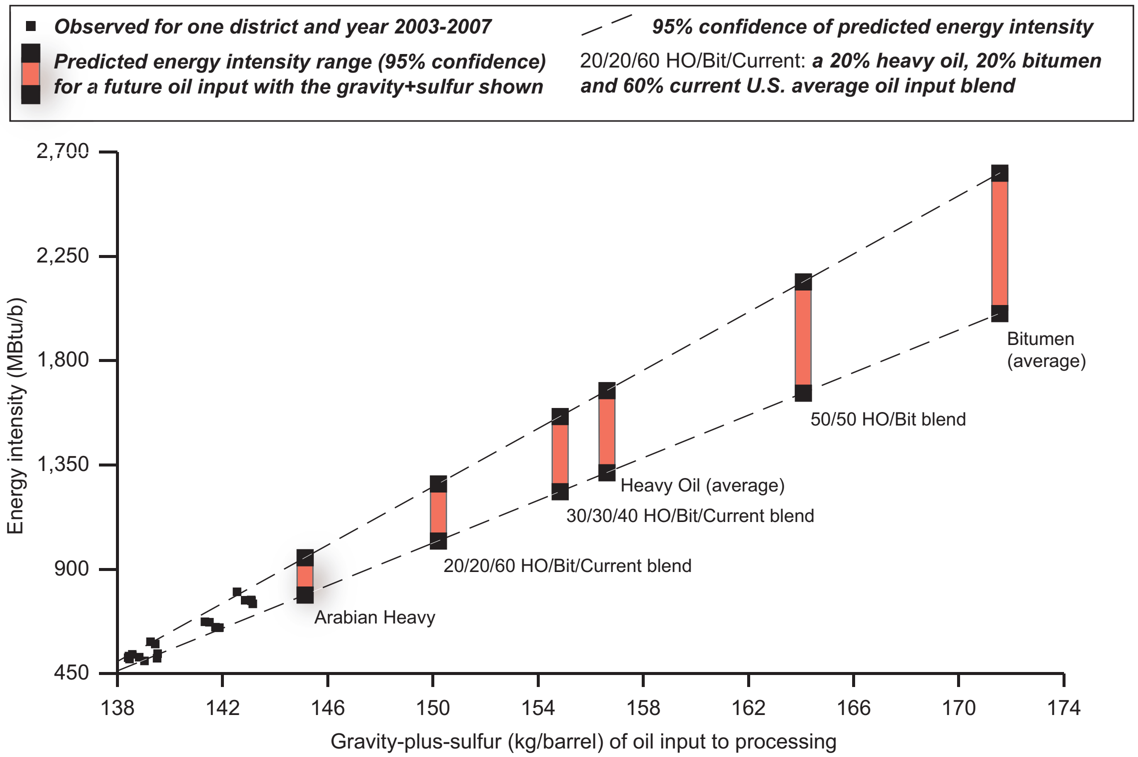
Refinery energy intensity increases strongly as the quality of oil refined worsens. Energy consumed per barrel of crude refined is positively associated with refinery crude input gravity-plus-sulfur, this association is statistically significant ($p < 0.001$), and oil input quality can explain 91% of the variability in energy consumed/barrel between refining districts and years (R-squared = 0.91). Average refinery energy consumed increases by 47%, from

Figure 5. Refinery process intensity and energy consumption v. crude oil input quality, annual data for 4 U.S. refining districts from 2003-2007



Processing intensity shown is the sum of vacuum distillation, coking, thermal cracking, cat-cracking and hydrocracking (vacuum+cracking) capacities per barrel of atmospheric crude distillation capacity, in barrels/calendar day. Energy consumed is total fuel energy consumed by refineries per barrel of crude input to atm. distillation. Gravity-plus-sulfur is the total mass of the crude plus the mass of the sulfur present in the crude oil input to refineries. Data from refs. 6, 7 for PADDs 1, 2, 3 & 5. See Appendix for data and fuel energy conversion factors.

Figure 6. Processing energy intensity predicted from a switch to lower quality oil



Based on 95% confidence from regression analysis of U.S. refining districts 1, 2, 3 and 5 data for 2003-2007 (45,959 to 62,792 Btu/b increase for each 1 kg increase in gravity+sulfur; R-squared = 0.91 and p < 0.001; data shown in the Appendix) and oil quality data for potential future oil inputs to processing from Refs. 2 and 10. Heavy oil, as defined by USGS, has an average gravity of 152.2 kg/b and averages 2.9% sulfur, and natural bitumen has an average gravity of 164.3 kg/b and averages 4.4% sulfur (Ref. 2). Arabian Heavy has an average gravity of 141.0 kg/b and 2.9% sulfur (Ref. 10). Potential oil inputs and blends shown are examples for reference; many different blends are possible.

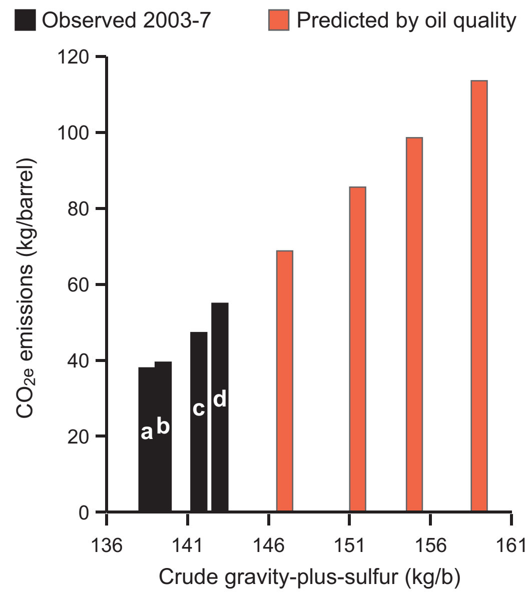
approximately 522,000 to 770,000 British thermal units/barrel crude refined, as oil input gravity-plus-sulfur rises from 138 to 143 kg/b.

Prediction for lower-quality oil

Figure 6 shows a prediction of the increase in energy required for refining lower-quality oil based on the increase in energy intensity with sulfur+gravity in four U.S. refining districts during 2003-2007. These 2003-7 data appear in the lower left of this chart. The much higher average gravity and sulfur of heavy oil (10-20º API, as defined by USGS) and especially bitumen (e.g., tar sands; < 10º API; see Ref. 2) is reflected in their positions far to the right of the 2003-7 refinery oil inputs on this chart. Oils and blends listed on the chart are examples of potential low-quality inputs. Dashed lines show the 95% confidence limits of the prediction based on analysis of district 1, 2, 3 and 5 data for 2003-7 (45,959-62,792 Btu/b increase for each 1 kg/b increase in gravity+sulfur; R-squared = 0.91, p < 0.001).

This predicts a range of increasing energy intensity that *could* occur *if* (and when) increasingly lower-quality oil is processed. As compared with the 2003-7 U.S. average of 639 MBtu/b, the energy intensity of oil processing could increase by 23-49% if Arabian Heavy is refined. It could increase by 60-98% if a 20% heavy oil, 20% bitumen, 60% current average U.S. oil input is refined. It could increase by 93-140% if a 30/30/40 HO/Bit/Current oil blend is refined. If refiners switch to a 50/50 heavy oil/bitumen blend, process energy intensity could increase by 160-230%. Oil blends in this spectrum could increase energy intensity by amounts within this total range. GHG (CO_2e) emissions could increase proportionately as more of the same fuels are burned to supply this energy. A dirtier fuel mix may result from combustion of the additional gases, coke and residual oil byproducts of lower-quality oil processing as refinery fuel. For purposes of this preliminary prediction, however, a constant fuel mix is assumed. Emission locations could include current and new refineries, and initial refining near bitumen extraction sites. Figure 7 shows this prediction for average emissions from refineries.

Figure 7. GHG emissions increase from refining lower-quality crude oil



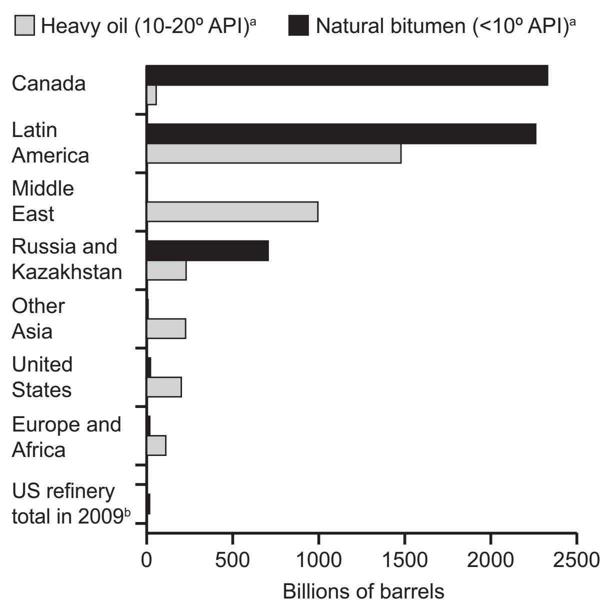
[a] U.S. East Coast Refining District-1; [b] Midwest District-2; [c] Gulf Coast District-3; [d] West Coast District-5. Emissions based on average oil quality-related energy intensities observed or predicted (see Fig. 6), the average U.S. refinery fuel mix, and fuel emission factors from Ref. 18. See Appendix for data.

Discussion

These findings appear consistent with previous work that predicted GHG emissions from extraction *and* refining of extra-heavy and tar sands oils could increase by 66-182% *(4)*, and emissions from steam reforming to feed refining of higher-sulfur crude could double or triple. *(5)* Here, observations across the U.S. refining industry link oil quality-driven energy to its processing mechanism quantitatively, allowing a more precise prediction of GHG emissions from refining lower-quality oils. To our knowledge this is the first report of that quantitative link across U.S. refining districts.

Climate implications From the well to the refinery, gas station and internal combustion engine, to the pavement using more than 40,000 square miles of U.S. land *(19)*, oil is more deeply entrenched than the other major GHG emitters. *(17)* Lower-quality oil might supply 100% of current U.S. refining capacity for hundreds of years. See Figure 8. A cumulative impact stems from this vast untapped potential and the huge investment in different extraction and refining equipment to tap this fundamentally different oil. *(2, 8, 11, 16, 20)*

Figure 8. Estimated heavy oil and natural bitumen resources of the world



[a] Total original oil in place including discovered oil (87%) and prospective additional oil (13%). Less than 2% of this heavy oil and bitumen has been consumed to date. Data from Ref. 2.
[b] Total US refinery capacity in 2009 from Ref. 7.

Refinery GHG emissions from dirty crude

Exploiting the next generation of lower-quality oil means increased extraction and refining emissions *and* retrenchment of oil infrastructure, which allows blending other liquids into the gasoline burned but stunts growth of non-combustion alternatives.† Table 3 illustrates some consequences of this cumulative impact.

Lower-quality oil emissions are represented by the +25% and +100% increase scenarios for oil-based fuel production in Table 3. These are within the range of emissions predicted above. Impacts from entrenched reliance on a "new" oil resource and its associated liquid-fuel transportation infrastructure are represented by a slower shift from oil-based fuels that are replaced by combustion of other liquid fuels. The 10% slower pace than IPCC goals is consistent with current policy proposed in California. *(3)* Emissions from oil-fuels replaced are based on blending of ethanol into the gasoline stream and conservative impact assumptions.

Heroic emissions reduction efforts by other sources might compensate for increased GHG emissions from lower-quality oil through 2020, but even if 70% of all oil used in 2020 is replaced by 2050, further emission reductions from these other sources cannot compensate for using dirtier oil and burning liquid replacement fuels in 2050. See Table 3. This is consistent with previous warnings that low-quality oil could thwart climate protection. *(4,5,8)*

A switch to lower-quality oil could result in the failure to achieve total emission reductions believed necessary to prevent severe climate disruption. Meanwhile, toxic emissions from refining that oil could increase in even greater proportions than GHG emissions *(8)*, worsening already serious environmental health risks in the disproptionately exposed communities near oil refineries.

† Plug-in hybrid and electric vehicles using solar or wind energy, pedestrian communities and free access to public transit compete with oil's dominant liquid fuel combustion infrastructure for money and use of land.

Table 3. Potential impact of low-quality oil infrastructure and emissions on IPCC climate change goals

(100 = 100% of current total GHG emissions)

Year	2009[a]	2020	2050
IPCC Goal[b]	—	-20%	-80%*
Scenario 1 (+25%/barrel)[c]			
Total emissions / goal	100.0	80.0	16.0
Oil-energy systems	40.0	38.8	14.9
Fuel production	9.9	11.1	3.3
Product fuels use	30.1	27.1	8.1
Oil-fuels replaced	—	0.5	3.4
All other sources	60.0	41.2	1.1
Non-oil % reductions	—	*-31%*	*-97%**
Scenario 2 (+100%/barrel)[c]			
Total emissions / goal	100.0	80.0	16.0
Oil-energy systems	40.0	45.4	16.9
Fuel production	9.9	17.8	5.3
Product fuels use	30.1	27.1	8.1
Oil-fuels replaced	—	0.5	3.4
All other sources	60.0	34.6	-0.9
Non-oil % reductions	—	*-42%*	*-102%**

**** Percent reduction in 2020 emissions to meet 2050 goal.***

[a] 2009 source apportionment from Refs. 1 and 3.
[b] International Panel on Climate Change-2 emission reduction goals; -20% from current by 2020 and -80% from 2020 emission levels by 2050. (16% of 2009 emissions by 2050.)
[c] Scenario 1: +25% emissions/barrel oil for fuel production, phaseout of oil-based transport fuels is slowed (10/70% replaced in 2020/2050), and liquid fuel replacements are favored by retrenched oil-based fuel infrastructure. Scenario 2 is the same except +100% emissions/b. Fuel production emissions from ranges in Figs. 6, 7 (see also Ref. 4). Oil-fuels replaced assumptions are overly conservative: 25% of new fuels emit at the rate for ethanol v. gasoline combustion only, using emission factors from Ref. 18 (6.1 v. 8.55 kg/gallon).

<u>*Oil input quality caps*</u> Limiting the worsening quality of refinery oil inputs is critical to our environmental health. The analysis above indicates that limiting the gravity and sulfur content of refinery oil inputs could prevent 91% of the increased GHG emissions from refining lower-quality oil—on average.

But real-world changes in refinery feedstock involve oil sourcing and retooling actions at individual plants. Crude gravity and sulfur predict refinery energy intensity less reliably in the smallest U.S. refining district with the least diverse oil input: individual plants may process still less diverse blends of oils. Comparisons with nitrogen, vanadium and nickel show that despite their predictive power for energy impacts from mixtures of many oils, gravity and sulfur are less reliable predictors of other energy-consuming contaminants in single oils. See Figure 2. Similarly, the fractions of crude that distill at higher temperatures and require vacuum distillation, cracking and more energy—the gas oil distilled in a vacuum at the atmospheric equivalent of ~650-1,050º F and the residua left over from that distillation—are less reliably predicted by the gravity of a single oil than by the average gravity of many oils.

Thus, for climate protection, each refinery should be prohibited from refining oil with higher gravity, sulfur, nitrogen, vanadium, nickel, vacuum gas oil yield or residua yield than the oil it refines now. To protect nearby communities and workers from pollution incidents and pass-through of toxic chemicals from dirtier oils into the environment, mercury, selenium and corrosive acids content of the oil blends refined should be capped as well. *(8)*

Such an oil input quality cap would not require any change by the refinery. It allows any equal or better quality oil or blend. It reliably stops only those that are inherently more polluting.

Available technology requirements This work demonstrates that process configurations can be assessed to identify equipment changes that are required for and enable the refining of lower-quality, inherently more polluting oils. Therefore, environmental reviews of proposals to build or retool refineries can identify such "dirty oil" infrastructure plans and require available least-polluting technology, including equipment for same-quality oil refining. These reviews can require extensive public time and resources, however, and refiners often claim many relevant data are trade secrets *(14, 15)*, so these reviews should be considered as a complement and not an alternative to refinery oil input quality caps.

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Appendix *(Tables 4-9)*

Table 4. Gross input to atmospheric crude oil distillation units
Data from U.S. Energy Information Administration (EIA), 2009.

Data in thousands of barrels per day

Year	U.S.	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
2003	15,508	1,584	3,224	7,297	531	2,872
2004	15,783	1,570	3,301	7,494	557	2,861
2005	15,578	1,599	3,314	7,204	562	2,899
2006	15,602	1,486	3,309	7,375	557	2,874
2007	15,450	1,473	3,238	7,402	546	2,791

Table 5. API gravity, weighted average refinery crude input qualities
Data from U.S. Energy Information Administration (EIA), 2009.

Data in degrees API

Year	U.S.	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
2003	30.61	32.38	32.50	30.31	32.80	27.65
2004	30.18	32.00	31.96	29.70	32.54	27.69
2005	30.20	32.39	31.96	29.66	32.48	27.67
2006	30.44	32.25	32.00	30.09	32.94	27.91
2007	30.42	32.21	32.26	29.85	32.58	28.29

Table 6. Sulfur content, weighted average refinery crude oil input qualities
Data from U.S. Energy Information Administration (EIA), 2009.

Data in percent weight

Year	U.S.	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
2003	1.43	0.86	1.35	1.65	1.45	1.23
2004	1.43	0.90	1.37	1.64	1.35	1.26
2005	1.42	0.83	1.38	1.64	1.30	1.28
2006	1.41	0.83	1.34	1.64	1.32	1.23
2007	1.43	0.84	1.37	1.65	1.36	1.25

Appendix *continued*

Table 7. Fuel consumed at refineries

PADD	Year	Hydrogen (MMcf)	Crude oil (Mbbls)	LPG (Mbbls)	Distillate (Mbbls)	Residual fuel oil (Mbbls)	Still gas (Mbbls)	Petroleum Coke (Mbbls)	Other products (Mbbls)	Natural gas (MMcf)	Coal (M sht tons)	Purchased electricity (MM kWh)	Purchased steam (MM lbs)
1	2003	53,363	0	494	624	1,762	22,221	12,359	444	28,366	32	3,415	3,691
1	2004	53,363	0	495	466	1,133	22,278	12,817	141	32,410	29	3,410	5,186
1	2005	54,057	0	722	366	1,146	22,317	12,812	141	35,603	33	3,520	4,912
1	2006	61,357	0	329	23	920	21,232	11,033	54	36,225	31	3,576	5,716
1	2007	47,122	0	185	22	826	22,890	11,973	21	28,709	32	3,984	5,784
2	2003	143,591	0	1,623	37	590	45,897	17,207	1,031	94,385	9	8,885	5,682
2	2004	144,759	0	1,079	37	195	49,846	15,938	1,752	103,310	8	9,486	6,311
2	2005	175,237	0	779	50	163	50,213	17,342	1,686	106,480	8	9,875	5,033
2	2006	272,071	0	567	45	206	49,585	16,502	1,961	114,721	3	10,488	7,298
2	2007	275,356	0	842	47	189	49,429	15,701	395	120,047	7	10,555	10,738
3	2003	566,663	0	1,100	44	0	122,633	42,753	1,879	429,800	0	15,682	31,869
3	2004	615,573	0	371	82	0	120,050	43,774	1,418	395,157	0	17,044	32,687
3	2005	608,784	0	359	86	4	111,798	41,299	1,300	395,980	0	16,620	34,738
3	2006	572,941	0	277	111	1	125,046	45,589	1,971	395,627	0	18,612	38,999
3	2007	568,050	0	208	115	3	120,930	42,748	1,510	363,004	0	20,433	63,471
4	2003	32,631	0	49	0	168	8,697	2,541	865	18,783	0	1,515	887
4	2004	33,398	0	67	1	147	8,517	2,750	544	19,324	0	1,583	1,112
4	2005	49,385	0	24	0	167	8,208	2,828	502	21,585	0	1,601	952
4	2006	49,385	0	15	0	121	8,496	2,818	142	24,830	0	1,704	757
4	2007	64,204	0	13	0	83	8,304	3,072	62	22,513	0	1,744	1,191
5	2003	524,651	0	2,169	246	727	46,767	14,984	1,619	132,350	0	4,520	18,949
5	2004	522,206	0	1,549	230	723	46,522	15,373	1,969	124,784	0	4,871	19,251
5	2005	528,228	0	2,291	253	727	45,700	15,371	1,700	123,271	0	4,978	17,956
5	2006	562,027	0	1,468	255	770	44,999	14,550	2,199	126,190	0	4,973	17,999
5	2007	574,948	0	1,415	236	743	45,553	14,521	1,716	133,713	0	5,113	17,838

Data from US EIA, 2009. Fuel Consumed at Refineries; except fuel for hydrogen. Hydrogen data shown are from Oil & Gas Journal, Worldwide Refining Survey, US Refineries-State Capacities and are for hydrogen production based on 90% of available captive and third-party capacity. These data were converted to fuel energy assuming hydrogen steam reforming data for 100% natural gas fuel based on DOE data in Ref. 13. Steam energy is based on latent heat of evaporation at 20.3 psig/259 ºF. All other factors for converting fuel energies into common units are from Cal. Air Resources Board (Ref. 18). These factors are:
Coal (22.18 MMBtu/short ton); crude (5.8 MMBtu/barrel); distillate (5.825 MMBtu/b); electricity (3,412 Btu/kWhr);
hydrogen (459 Btu/scf); LPG (3.861 MMBtu/b); natural gas (1,027 Btu/scf); other products (5.825 MMBtu/b);
petroleum coke (6.024 MMBtu/b); residual fuel oil (6.287 MMBtu/b); still gas (refinery fuel gas, 6.0 MMBtu/b); and steam (939 Btu/lb).

Appendix *continued*

Table 8. Refinery Capacity Data

Data in barrels per calendar day

		Charge capacity								*Production capacity*
PADD	Year	Crude	Vacuum Distillation	Coking	Thermal Operations	Catalytic Cracking	Catalytic Reforming	Catalytic Hydrocracking	Catalytic Hydrotreating	Alkylation
1	2003	1,577,170	627,380	91,100	0	618,120	286,080	37,890	959,330	81,130
1	2004	1,574,000	627,350	91,100	0	618,100	292,400	37,900	942,850	81,140
1	2005	1,589,000	638,400	91,100	0	627,100	294,400	37,900	924,850	84,000
1	2006	1,589,000	638,350	91,100	0	627,100	294,400	38,700	924,450	83,950
1	2007	1,589,000	638,350	91,100	0	627,100	294,400	38,700	928,450	83,950
2	2003	3,496,305	1,425,853	352,999	0	1,162,062	839,005	151,600	2,654,227	241,194
2	2004	3,492,613	1,444,175	365,930	0	1,149,010	833,220	137,800	2,727,960	239,432
2	2005	3,551,527	1,489,975	375,020	0	1,167,048	840,800	176,000	2,919,706	250,612
2	2006	3,554,150	1,502,975	374,120	0	1,165,976	839,529	192,800	2,953,070	251,012
2	2007	3,640,100	1,457,275	379,370	0	1,132,776	846,629	232,800	2,922,080	246,012
3	2003	7,980,291	3,674,321	1,209,590	10,000	2,882,032	1,703,757	714,450	6,147,745	564,936
3	2004	8,052,965	3,801,658	1,250,900	10,000	2,901,209	1,730,797	746,500	6,581,535	661,288
3	2005	8,322,867	3,753,888	1,251,500	0	2,923,189	1,689,399	719,500	6,898,491	575,139
3	2006	8,389,562	3,764,456	1,269,900	0	2,933,038	1,689,249	720,000	7,101,448	581,968
3	2007	8,440,262	3,840,206	1,304,420	12,520	2,939,088	1,727,074	758,480	7,278,784	560,237
4	2003	567,255	226,175	43,205	0	182,785	119,545	5,500	369,410	39,125
4	2004	584,700	267,600	43,700	0	185,530	111,450	16,000	346,500	35,600
4	2005	574,200	220,300	44,700	0	183,680	120,600	5,500	375,800	36,700
4	2006	630,100	223,900	44,700	0	196,280	122,050	16,000	411,100	37,500
4	2007	630,000	218,400	45,700	0	198,200	122,850	17,600	421,400	38,000
5	2003	3,077,205	1,484,183	586,802	21,500	792,750	556,481	505,903	2,013,329	195,850
5	2004	3,064,600	1,476,750	588,300	21,500	799,850	559,500	511,850	2,070,378	196,150
5	2005	3,088,575	1,480,475	590,800	21,500	802,700	562,700	519,450	2,062,900	198,300
5	2006	3,109,775	1,505,175	592,300	21,500	819,300	591,250	559,550	2,118,000	211,300
5	2007	3,147,875	1,679,955	607,700	21,500	838,570	605,950	580,000	2,157,250	211,450

Capacity expressed in barrels per calendar day (b/cd) is the maximum number of barrels of input that can be processed during a 24-hour period, after making allowances for the following: Types and grades of inputs to be processed; types and grades of products to be manufactured; environmental constraints associated with refinery operations; scheduled downtime such as mechanical problems, repairs, and slowdown.

All data from Oil & Gas Journal, Worldwide Refining Survey (annual; Ref. 7), except Sinclair Oil, Sinclair, WY (PADD 4) catalytic cracking and hydrocracking (2004, 2006, 2007) and crude (2004) data from EIA Downstream Charge Capacity Data (in b/cd) because Ref. 7 crude (2004), catalytic cracking and hydrocracking (2004, 2006, 2007) data are suspect.

Appendix *continued*

Table 9. Refinery Yield
Data from U.S. Energy Information Administration (EIA), 2009.

Data in percent

	LPG	Motor gasoline	Aviation gasoline	Kerosine jet fuel	Kerosine	Distillate	Residual fuel oil	Petrochem. feedstock naphtha	Petrochem. feedstock other oils	Special naphtha	Lubricants	Waxes	Petroleum coke	Asphalt	Still gas	Miscel-laneous	Proces-sing gain
PADD 1 Refinery Yield																	
2003	3.00	46.40	0.20	5.20	0.80	27.20	7.80	0.80		0.10	1.00	0.00	2.90	5.70	3.80	0.10	-5.00
2004	2.60	46.50	0.40	6.10	0.70	26.60	6.90	0.80		0.10	1.10	0.00	3.10	6.20	3.90	0.10	-5.30
2005	2.40	46.60	0.30	5.70	0.70	28.80	6.20	0.80		0.10	1.00	0.00	2.90	5.70	3.80	0.10	-5.10
2006	2.60	45.80		5.10	0.40	29.20	7.10	1.10		0.10	1.10	0.00	3.00	5.60	3.60	0.20	-4.90
2007	3.20	45.50	0.10	5.00	0.50	29.40	7.20	1.10		0.00	1.00	0.00	3.20	5.00	3.90	0.20	-5.10
PADD 2 Refinery Yield																	
2003	3.30	51.50	0.10	6.20	0.30	26.00	1.70	0.50	0.00	0.60	0.50	0.10	4.20	5.60	4.10	0.40	-5.10
2004	3.30	51.60	0.10	6.40	0.30	25.70	1.80	0.80	0.30	0.10	0.40	0.10	4.30	5.70	4.10	0.40	-5.40
2005	3.10	50.40	0.10	6.50	0.30	27.10	1.60	0.80	0.30	0.20	0.40	0.10	4.50	5.70	4.10	0.50	-5.80
2006	4.00	49.40	0.10	6.20	0.30	27.30	1.70	0.90	0.20	0.20	0.50	0.10	4.40	6.10	4.10	0.50	-5.90
2007	3.90	49.80	0.10	6.10	0.10	28.20	1.70	0.90	0.20	0.10	0.40	0.10	4.30	5.30	4.20	0.40	-5.80
PADD 3 Refinery Yield																	
2003	5.50	44.80	0.10	9.90	0.40	23.00	4.10	2.60	2.30	0.40	1.50	0.10	5.70	1.60	4.40	0.50	-6.90
2004	5.30	44.60	0.10	10.00	0.50	23.50	3.90	2.80	2.40	0.50	1.60	0.10	5.90	1.50	4.30	0.40	-7.60
2005	4.70	43.80	0.10	10.20	0.60	24.50	3.90	2.30	2.10	0.40	1.60	0.10	6.00	1.60	4.30	0.40	-6.80
2006	4.80	43.50	0.20	9.70	0.40	25.20	3.80	1.90	2.40	0.40	1.70	0.10	6.20	1.50	4.60	0.50	-6.80
2007	5.00	43.20	0.10	9.40	0.30	26.00	4.10	1.90	2.40	0.50	1.70	0.10	6.00	1.30	4.30	0.50	-6.90
PADD 4 Refinery Yield																	
2003	0.80	47.90	0.10	4.90	0.40	29.50	2.40		0.10			0.40	3.20	9.10	4.50	0.40	-3.70
2004	0.80	47.50	0.10	4.90	0.30	30.40	2.50		0.10			0.40	3.20	9.30	4.20	0.40	-4.20
2005	0.70	46.00	0.10	5.40	0.30	30.60	2.70		0.10	0.00		0.40	3.30	9.50	4.10	0.40	-3.70
2006	1.30	46.40	0.10	5.30	0.40	30.60	2.80		0.10	0.00		0.30	3.30	8.50	4.20	0.40	-3.60
2007	1.50	46.30	0.10	5.40	0.30	29.80	2.60		0.10	0.00		0.00	3.40	8.90	4.20	0.30	-3.00
PADD 5 Refinery Yield																	
2003	2.90	47.20	0.10	16.00	0.00	19.50	5.80	0.10	0.30	0.10	0.80		6.20	1.90	5.60	0.30	-6.80
2004	2.60	47.30	0.10	16.20	0.00	19.50	6.10	0.00	0.30	0.00	0.70		6.10	1.90	5.40	0.30	-6.40
2005	2.50	47.30	0.10	16.20	0.00	20.40	5.80	0.00	0.40	0.00	0.70		6.20	1.70	5.10	0.30	-6.70
2006	2.80	47.70	0.10	15.30	0.00	20.30	5.80	0.00	0.40	0.10	0.70		6.00	1.80	5.20	0.40	-6.60
2007	2.80	46.60	0.10	15.60	0.00	20.80	6.30	0.00	0.30	0.00	0.60		5.80	1.80	5.40	0.40	-6.40

Note: blank entries are blank in EIA's reported data