ARB response to request pursuant to the California Public Records Act

Attachment to 24 October Comment to LCFS Program Advisory Panel

Air Resources Board

Mary D. Nichols, Chairman
1001 I Street • P.O. Box 2815
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Linda S. Adams
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June 23, 2011

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EMAIL to *gkatcbe@gmail.com*

Dear Mr. Karras:

This letter responds to your request dated May 19, 2011 to the California Air Resources Board (ARB) regarding average density and total sulfur content of crude oil inputs to petroleum refining in California and documents that include the type and amount of each fuel consumed by petroleum refining in California. Unfortunately, staff was unable to find any responsive documents to your request.

ARB is closing your request as completed. If you have any questions, please contact me at 916-322-0362.

Sincerely,

Alexa Barron
Public Records Coordinator
Office of Legal Affairs

Karras, 2010. *Env. Sci. Technol.* 44(24): 9584–9589

Attachment to 24 October Comment to LCFS Program Advisory Panel

Combustion Emissions from Refining Lower Quality Oil: What Is the Global Warming Potential?

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The greenhouse gas emission intensity of refining lower quality petroleum was estimated from fuel combustion for energy used by operating plants to process crude oils of varying quality. Refinery crude feed, processing, yield, and fuel data from four regions accounting for 97% of U.S. refining capacity from 1999 to 2008 were compared among regions and years for effects on processing and energy consumption predicted by the processing characteristics of heavier, higher sulfur oils. Crude feed density and sulfur content could predict 94% of processing intensity, 90% of energy intensity, and 85% of carbon dioxide emission intensity differences among regions and years and drove a 39% increase in emissions across regions and years. Fuel combustion energy for processing increased by approximately 61 MJ/m^3 crude feed for each 1 kg/m^3 sulfur and 44 MJ/m^3 for each 1 kg/m^3 density of crude refined. Differences in products, capacity utilized, and fuels burned were not confounding factors. Fuel combustion increments observed predict that a switch to heavy oil and tar sands could double or triple refinery emissions and add 1.6–3.7 gigatons of carbon dioxide to the atmosphere annually from fuel combustion to process the oil.

Introduction

Replacing limited conventional crude oil (*1*) with heavy oil and natural bitumen (tar sands) resources could have substantial energy and environmental costs (*2*). Physical and chemical properties of the lower quality, heavier, more contaminated oils predict the combustion of more fuel for the energy necessary to convert them into product slates dominated by light hydrocarbon liquids (*3*−*8*). Preliminary estimates from fuel cycle analyses suggest that a switch to heavy oil and tar sands could increase the greenhouse gas emission intensity of petroleum energy by as much as 17−40%, with oil extraction and processing rather than tailpipe emissions accounting for the increment (*3, 4*). This raises the possibility that a switch to these oils might impede or foreclose the total reduction in emissions from all sources that is needed to avoid severe climate disruption. Accurate prediction of emissions from substitutes for conventional petroleum is therefore critical for climate protection. However, estimates of the emissions from processing lower quality oils have not been verified by observations from operating refineries.

Crude oils are extremely complex, widely ranging mixtures of hydrocarbons and organic compounds of heteroatoms and metals (*2, 7*). Refiners use many distinct yet interconnected processes to separate crude into multiple streams, convert the heavier streams into lighter products, remove contaminants, improve product quality, and make multiple different products in varying amounts from crude of varying quality (*5*−*11*). Factors that affect emissions from refinery process energy consumption include crude feed quality, product slates, process capacity utilization, fuels burned for process energy, and, in some cases, preprocessing of refinery feeds near oil extraction sites. Estimates that construct process-by-process allocations of emissions among these factors have not been verified by observations from operating refineries in part because publicly reported data are limited for refinery-specific crude feeds and unavailable for process-level material and energy inputs and outputs (*4*−*6*). Research reported here distinguishes effects of crude feed quality on processing from those of the other factors using refinery-level data from multiple operating plants to estimate and predict the process energy consumption and resultant fuel combustion emissions from refining lower quality oil.

Experimental Section

Refinery crude feed volume, density, and sulfur content, process capacity, capacity utilization, yield, and fuels were reported annually for each U.S. Petroleum Administration Defense District from 1999 to 2008 (*9, 10*). See the Supporting Information for this data (Table S1, Supporting Information). Districts 1 (East Coast-Appalachia), 2 (Midwest), 3 (Gulf Coast and vicinity), and 5 (West Coast, AK, and HI) each refined diverse crude feeds (19−41 source countries) at multiple facilities. Smaller, landlocked District 4 (Rocky Mountain states) refined nondiverse crude feeds (2−3 source countries).

At concentrations 4−8 times those of nitrogen and 160−500 times those of nickel and vanadium, sulfur is the major process catalyst poison in crude by mass (*2, 11*). In addition, for diverse blends of whole crude oils from many locations and geologic formations, distillation yield, and asphaltic, nitrogen, nickel, and vanadium content are roughly correlated with density and sulfur (*2, 7*). Variability in the effects of unreported crude feed characteristics on processing is thus constrained by the density and sulfur content of well-mixed crude feeds. Mixing analysis suggested that density and sulfur are reasonably reliable predictors of natural variability in unreported characteristics for annual crude feeds processed in Districts 1, 2, 3 and 5 but could not exclude the potential for unpredicted effects in processing the poorly mixed District 4 feed (Table S2, Supporting Information). The District 4 feed also was proportionately higher in synthetic crude oil (SCO) than those of other districts (Table S3, Supporting Information), and variant hydrogen production that was not predicted by crude feed density was found in District 4 (Table S4, Supporting Information). SCO may increase refinery hydroprocessing requirements (*12, 13*). High hydrogen capacity coincided with SCO refining in Districts 2 and 4 during 1999−2008, but the effect on refinery energy was minimal in District 2, while it was significant and more variable in District 4; other anomalies in the District 4 feed might cause this effect (Tables S2 and S4, Supporting Information). For these reasons, District 4 data were excluded from analysis of refinery observations and used only in estimates including upgrading for SCO. Districts 1, 2, 3, and 5 accounted collectively for 97% of U.S. refining capacity, 1999−2008. Analysis compared the reported data among these districts and years for interactions of the variables defined below.

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Oil quality *(OQ)* was defined as the density (*d*) and sulfur content (*S*) of crude feeds in mass per cubic meter (1 m^3, 6.29 barrels oil; 264 gallons). The density of crude oils is proportional to the fraction of higher molecular weight, higher boiling point, larger hydrocarbon compounds in the oils that are distilled in a vacuum, then cleaved (cracked) into fuel-size compounds to make light hydrocarbon fuels. The larger hydrocarbons have lower hydrogen/carbon ratios that require hydrogen addition to improve product quality and higher concentrations of sulfur and other catalyst poisons that are freed by cracking and bonded with hydrogen to remove them from the oil and protect process catalysts (*2, 11*). This hydrocracking and hydrotreating of gas oil and residua uses several times more hydrogen than does hydrotreating of lighter streams such as naphtha (*11*). These processing characteristics require increased capacity for vacuum distillation, cracking, and hydroprocessing of gas oil and residua in refineries designed to make light liquid products from heavier, higher sulfur crude oils (*4, 8, 14*).

Crude processing intensity (*PI*) was thus defined as the ratio by volume of vacuum distillation capacity, conversion capacity (catalytic, thermal, and hydrocracking), and crude stream (gas oil and residua) hydrotreating capacity to atmospheric crude distillation capacity. These processes account for the primary processing acting on the crude and "reduced crude" that *Speight* distinguishes from secondary processes acting on product streams such as gasoline, naphtha, and distillate oils (*7*). PI measures the increasing portion of the crude input fed to these processes that is predicted by worsening *OQ* (increasing *d, S*, or both) and indicates the additional energy needed for heat, pressure, and reactants such as hydrogen to process those increasing feed volumes. It also defines an operational distinction between "crude stream" processing that acts on crude, gas oils, and residua and the subsequent "product stream" processing that acts on the unfinished products from crude stream processing. This distinction was useful in the absence of reported data for more detailed process-level analyses of material and energy flows. *PI* was analyzed with refinery-level crude feed, fuel, capacity utilization, and product yield data to verify the refinery process energy predicted by *OQ*.

Energy intensity (*EI*) was defined as total refinery process energy consumed per volume crude feed, based on reported fuels consumed (Table S1, Supporting Information). Purchased fuels consumed by refiners, such as electric power from the transmission grid, were included in *EI*. Energy used by hydrogen production plants was estimated based on 90% of production capacity and data for new natural gas-fed steam methane reforming facilities (*10, 15*, Table S1, Supporting Information). *EI* integrates all factors in refineries that consume fuel energy, allowing analysis of *EI* with *OQ* and processing to account for refinery capacity utilized and yield.

Effects of variable product slates on refinery energy consumption were distinguished from those of *OQ* in five ways. First, product slate effects on the relationships observed among crude feed quality, crude stream processing, and energy were estimated directly. This was done by including the products ratio, defined as the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products, as an explanatory variable in comparisons of *OQ, PI*, and *EI*. Second, the products ratio, combined yield of gasoline and distillate, and combined yield of petroleum coke and fuel gas were analyzed with *EI* and *OQ*. This quantified changes in refinery energy with yield and changes in yield with crude feed quality for key conversion products and byproducts. Third, energy use was analyzed with product stream process capacities to estimate changes in *EI* that could be explained by changes in product processing rates. Fourth, effects of product stream processing on energy for hydrogen were compared with those of crude stream processing by analyzing hydrogen production capacity with product hydrotreating capacity, hydrocracking capacity, and *OQ*. Finally, estimated total energy for processing product slates (Eproducts) was analyzed with *OQ*. Eproducts was estimated based on product-specific factors developed by Wang et al. (*6*) and yield data (Tables S1 and S5, Supporting Information). Refinery capacity utilization was included as an explanatory variable in all comparisons.

Analysis was by partial least squares regression (PLS, XLSTAT 2009). PLS was used based on the expectation that explanatory (*x*) variables may be correlated, the primary interest in prediction of *y* (e.g., *EI*) and a secondary interest in the weights of *x* variables (e.g., *S* and *d*) in predicting *y*. Distributions of PLS residuals appeared normal (Shapiro-Wilk; Anderson-Darling; Lilliefors; Jarque-Bera tests, α 0.05).

Synthetic Crude Oil (SCO). Coking- and hydrocracking-based upgrading of bitumen in Western Canada uses energy to yield SCO that has poor gas oil and distillate qualities but lower density and sulfur than the bitumen (*12, 13*). Refinery crude feeds and energy consumption do not reflect the original bitumen quality for this SCO or the energy used in its upgrading. SCO comprised appreciable fractions of annual crude feeds in Districts 2 (2−8%) and 4 (2−12%), based on limited estimates that may exclude SCO in some blended oil streams (Table S3, Supporting Information). Process modeling data for energy consumed and density and sulfur lost in coking- and hydrocracking-based upgrading (*16*) were applied to the estimated SCO volume in refinery feeds (Table S3, Supporting Information). Districts and years were compared for total processing (upgrading and refining) energy estimated and that predicted by including estimated original oil quality (*d, S*) in the prediction mode of the PLS model based on refinery observations (Table S6, Supporting Information).

Emissions. Emissions were assessed for carbon dioxide (CO_2), the predominant greenhouse gas emitted by refineries (Table S7, Supporting Information). Direct measurements for all emission vents were not reported. Observed fuel consumption and fuel-specific emission factors developed by the U.S. Energy Information Administration (*17, 18*) were used to estimate "observed" emissions, and estimation details were documented (Table S1, Supporting Information). Fuel energy consumed ranged more widely among districts and years than the emission intensity of the fuel mix. Emissions predicted by *OQ* were based on *EI* predicted by *OQ* results from PLS and the emission intensity of the fuel mix. Observed and predicted emissions were compared among districts and years by PLS. Emissions estimates by government agencies (*5, 19−21*) that could be matched to data for *OQ* were superimposed on this comparison by including their *OQ* and predicted *EI* values in the prediction mode of the PLS models for the districts data (Tables S8 and S9, Supporting Information).

For heavy oil and natural bitumen, *OQ* data reported by the U.S. Geological Survey (*2*) and the average (1999−2008) U.S. refinery capacity utilization and products ratio were used in the prediction mode of the PLS model for observed *EI* versus *OQ* to predict *EI* (Table S8, Supporting Information). Predicted emissions from heavy oil and natural bitumen were derived from the products of these *EI* predictions (95% confidence for observations) and the emission intensity of the average (1999−2008) U.S. refinery fuel mix.

Results

Figure 1 shows results from comparisons of *OQ, PI*, and *EI* among districts and years from 1999 to 2008. Observed *OQ* ranges by 7.85 kg/m^3 crude feed (kg/m^3) for *S* and 37.6 kg/m^3 for *d*. Observed *PI* ranges by 0.42, or 42% of atmospheric crude distillation capacity. Observed *EI* ranges by 1.89 GJ/m^3 crude feed. *PI* is strongly and positively associated with

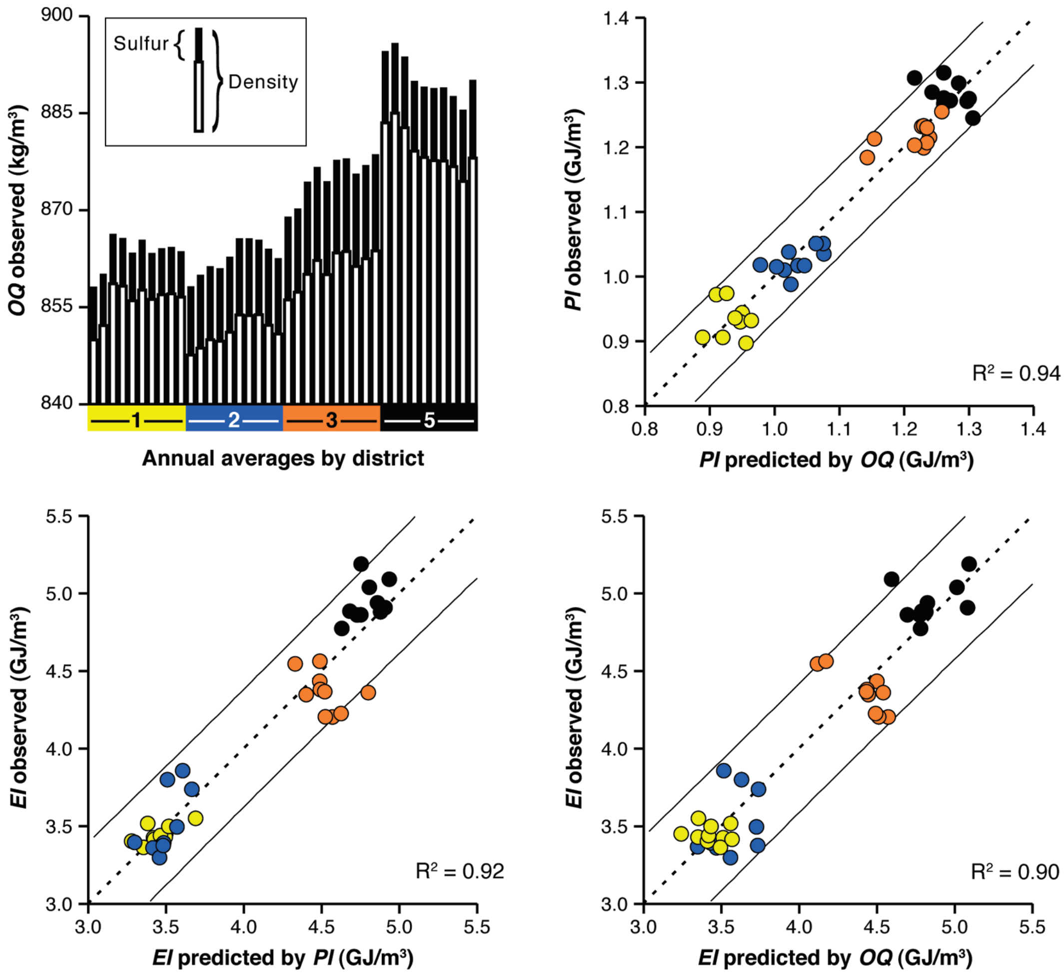

FIGURE 1. Increasing crude processing intensity and energy intensity with worsening oil quality. *OQ:* Crude feed oil quality. *PI:* Crude processing intensity. *EI:* Refinery energy intensity. Observations are annual weighted averages for districts 1 (yellow), 2 (blue), 3 (orange), and 5 (black) in 1999–2008. Diagonal lines bound the 95% confidence of prediction for observations.

worsening *OQ* (increasing *d*, *S*, or both). *EI* is strongly and positively associated with worsening *OQ* and increasing *PI*. *EI* increases by approximately 44 MJ/m³ for each 1 kg/m³ *d* and 61 MJ/m³ for each 1 kg/m³ *S* based on the PLS regression analysis for *EI* versus *OQ*. The equation of the model (*EI* vs *OQ*) can be expressed as

$$EI = 0.044d + 0.061S + 0.010(\text{Capacity utilized}) - 0.159(\text{Products ratio}) - 35.092 \quad (1)$$

where *EI* is the central prediction in GJ/m³, *d* is in kg/m³, *S* is in kg/m³, capacity utilized is in percent, products ratio is expressed as a quotient, and the last term is the coefficient for the intercept.

Table 1 shows additional results from analysis of refinery observations. *PI* increases strongly with *d* and *S* (95% confidence for observations). *EI* increases strongly with *d* and *S* and with vacuum distillation, conversion, and crude stream hydrotreating capacities. Hydrogen production capacity increases strongly with *d* and hydrocracking capacity. Sulfur recovery capacity increases strongly with *S*. These observations describe increasing portions of crude feeds processed by crude stream capacity and resultant effects on total refinery energy consumption as crude density and sulfur content increase.

In contrast to crude stream processing, except for cracking byproducts and two processes that treat them, product slate indicators are not significant or decrease with increasing *OQ* and *EI*. The products ratio is not significant in the strong relationships among *EI*, *PI*, and *OQ*, perhaps in part because light liquids yield is less variable than *S* or *EI* among these districts and years. However, the ratio of light liquids to other products decreases with increasing *d* (products ratio vs *OQ*) and *EI* (*EI* vs products processing), and yield shifts, from gasoline and distillate to coke and fuel gas, as *OQ* worsens and *EI* increases.

Products processing reflects this shift from light liquids to cracking byproducts. Product stream hydrotreating, reforming, asphalt, aromatics, and polymerization/dimerization capacities decrease as *EI* increases. Those five processes account for 83–90% of total product stream processing capacity among districts (Table S1, Supporting Information). Among products processes, only alkylation and isomerization (7–13% of products capacity), which receive light streams from conversion processes, are positively associated with *EI*. Product hydrotreating cannot explain the observed increase in hydrogen production with increasing *d*. Estimated refinery energy use for products processing (Eproducts) decreases with increasing *d*. These results appear to measure the decreasing fraction of crude inputs converted to light liquid product streams and increasing creation of cracking byproducts such as coke and fuel gas that result from incomplete conversion as crude feed density and sulfur increase.

A weak inverse association of hydrogen production with product hydrotreating capacity (Table 1) results from a strong increase in H_2 capacity with *d* and hydrocracking, a steady decrease in the hydrotreating/hydrocracking ratio with increasing H_2 capacity, and lower hydrotreating at high

TABLE 1. Results from Refinery Crude Feed Quality, Processing, Energy, Yield, and Emission Comparisons[a]

effects of crude feed oil quality (*OQ*)

y vs *x*	R^2	standardized coefficients of *x* variables (coeff) density	sulfur	cap. utilized	products ratio
process intensity *(PI)* vs *OQ*	0.94	**0.73**	**0.42**	**0.09**	−0.02
energy intensity *(EI)* vs *OQ*	0.90	**0.80**	**0.23**	0.05	−0.10
hydrogen production vs *OQ*	0.91	**1.09**	−0.01	0.05	**0.35**
sulfur recovery vs *OQ*	0.94	−0.01	**0.95**	−0.06	**−0.15**
pet. coke + fuel gas vs *OQ*	0.95	**0.80**	**0.34**	−0.04	
gasoline + distillate vs *OQ*	0.75	**−0.85**	−0.07	−0.04	
products ratio vs *OQ*	0.26	**−0.40**	−0.12	0.17	
Eproducts vs *OQ*	0.74	**−0.61**	0.13	**0.49**	

effects of oil quality (*OQ*) and fuels on CO_2 emissions

y vs *x*	R^2	standardized coefficients of *x* variables (coeff) *EI* predicted by *OQ*	fuel mix emission intensity
observed vs predicted CO_2	0.85	**0.88**	−0.04

effects of processing and products yield

y vs *x*	R^2	coeff.	*y* vs *x*	R^2	coeff.
EI vs *PI*	0.92		*EI* vs yield	0.93	
vacuum distillation		**0.35**	pet. coke + fuel gas		**0.59**
conversion capacity		**0.35**	gasoline + distillate		**−0.42**
csHydrotreating		**0.22**	capacity utilized		−0.01
capacity utilized		**−0.16**	products ratio		−0.02
products ratio		−0.14			
			EI vs psProcessing	0.91	
H_2 production vs hydrocracking	0.97		psHydrotreating		**−0.17**
hydrocracking		**1.02**	reforming		**−0.19**
capacity utilized		−0.06	asphalt		**−0.30**
products ratio		**0.14**	aromatics		**−0.33**
			polym./dimerization		**−0.25**
H_2 production vs product-stream hydrotreating			lubricants		0.04
	0.18		alkylation		**0.30**
psHydrotreating		**−0.33**	isomerization		**0.24**
capacity utilized		−0.09	capacity utilized		−0.06
products ratio		**−0.17**	products ratio		**−0.33**

[a] *R*-squared values and standardized coefficients from PLS regressions on annual data from refining districts 1, 2, 3 and 5, 1999−2008. **Boldface**: significant at 95% confidence. Eproducts: estimated energy use to process a given product slate. Prefix cs (ps): crude stream (product stream) processing.

H_2 capacity among these districts and years (Figure S1, Supporting Information). Refinery capacity utilization was not significant in the effects of *OQ* on *EI* and affected the relationships between *PI* and *OQ* and between *PI* and *EI* only marginally, possibly because capacity utilization varied little among districts and years (Table S1, Supporting Information). Significant capacity utilization results are consistent with marginally increased energy consumption and decreased flexibility to process lower quality crude when refineries run closer to full capacity.

Rough estimates including the energy, *d*, and *S* lost in bitumen upgrading for SCO refined reveal greater effects of total processing for crude feeds refined in Districts 2 and 4 and follow the relationships observed in refining (Figure 2). Estimated total processing energy falls within the prediction based on *OQ* from refinery observations in 43 of 50 cases and exceeds the 95% confidence of prediction by more than 2% only in two cases explained by District 4 hydrogen anomalies discussed above. Oil quality−energy relationships observed in refining can predict those for total processing because upgrading and refining use similar carbon rejection, hydrogen addition, and utility technology.

Emissions calculated from observed fuels consumed are strongly and positively associated with *EI* predicted by *OQ* (Table 1) and range by 39%, from 257 to 358 kg/m^3 crude feed (Figure 3). Observed emissions fall within the 95% confidence of prediction based on *OQ* in 36 of 40 cases and are within 3% of the confidence of prediction in all cases. Despite emission differences among fuels, the fuel mix is not significant in this prediction. The emission intensity of the fuel mix varies much less than *EI* and decreases slightly with decreasing petroleum coke contributions and a shift in cracking processes as *EI*, *d*, and *S* increase (Table S1 and Figure S1, Supporting Information). Refinery emission estimates by government agencies that could be matched to *OQ* differ from each other by as much as 12−30% but fall within 2% of the central prediction based on *OQ* or within 4% of its confidence interval (*5, 19*−*21*, Table S8, Supporting Information). The 2008 San Francisco Bay Area estimate in Figure 3 (360 kg/m^3) is close to estimated 2008 California refinery emissions (354 kg/m^3) (*21*), for which matching *OQ* data were not available. California gasoline and diesel production may account for 56% (197.2 kg) and 22% (78.7 kg) of this 354 kg/m^3, respectively, based on fuel-specific estimates for the average California crude feed (*21*−*23*, Table S8, Supporting Information).

Predictions for heavy oil (957.4 kg/m^3 *d;* 27.8 kg/m^3 *S*) and natural bitumen (1 033.6 kg/m^3 *d;* 45.5 kg/m^3 *S*) (USGS average) (*2*) reflect their low quality compared with crude feeds observed (Figure 1). On the basis of the PLS model for

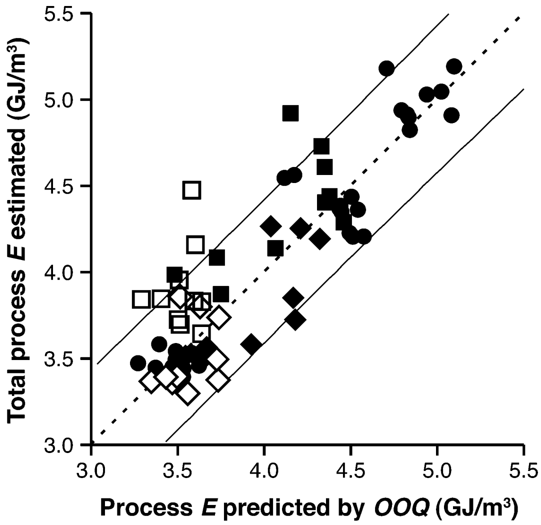

FIGURE 2. Estimated process energy for bitumen upgrading and refining versus that predicted by oil quality (GJ/m^3 crude), 1999–2008. *OOQ:* original oil quality including bitumen quality for synthetic oil inputs. Black diamonds: District 2. Black squares: District 4. Black circles: Districts 1, 3, and 5. White diamonds (squares): District 2 (District 4) refinery energy and oil quality only. Diagonal lines bound the 95% confidence of prediction for refinery observations.

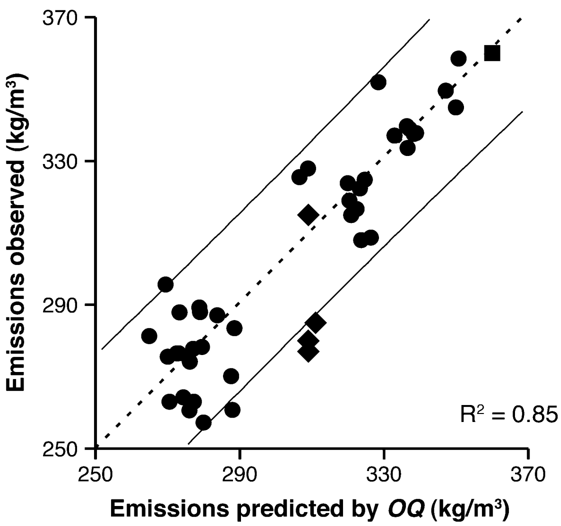

FIGURE 3. Refinery CO_2 emission intensity observed versus predicted by oil quality. *OQ:* Oil quality. Black circles: District 1, 2, 3, or 5 annually, 1999–2008. Black diamonds: United States in 2002, 2005, 2006, 2007. Black square: San Francisco Bay Area in 2008. Diagonal lines bound the 95% confidence of prediction for observations. R^2 value shown is for the comparison among districts and years.

observations from Districts 1, 2, 3, and 5 (*EI* vs *OQ*) and the emission intensity of the U.S. refinery fuel mix (73.8 kg/GJ), processing the range of heavy oil/bitumen blends could use 8.23–14.13 GJ/m^3 fuel (Table S8, Supporting Information) and emit 0.61–1.04 t/m^3 CO_2.

Discussion

Strongly coupled increases in energy and crude stream processing intensities with worsening oil quality (Figure 1) describe energy for carbon rejection, aggressive hydrogen addition, and supporting processes acting on larger portions of heavier, higher sulfur crude feeds to yield light liquid product streams. The creation of cracking reaction byproducts that limits conversion of heavier oils to light liquid product streams is observed in the shift from gasoline and distillate to coke and fuel gas yield as *OQ* worsens and *EI* increases. Observed decreases in light liquids yield and most major product stream processes as *EI* increases are consistent with this rising reliance on incomplete conversion. Differences in product slates cannot explain increasing *EI* as *OQ* worsens because capacities of processes comprising 83–90% of product stream processing capacity decrease as *EI* increases, and estimated energy use for products processing decreases as *OQ* worsens. Hydrogen production increases with crude density and hydrocracking. *EI* drives emissions variability. *OQ* predicts 94% of *PI*, *PI* predicts 92% of *EI*, and *OQ* predicts 90% of *EI* and 85% of emissions variability. These observations from operating plants across the four largest U.S. refining districts over 10 years provide evidence that crude feed density and sulfur content predict processing, energy, and CO_2 emission intensities for large groups of refineries with diverse feeds.

Slight, unexpected decreases in product hydrotreating at high hydrogen production and in fuel mix emission intensity with increasing *d* and *S* can be explained by a coincident shift from hydrotreating and catalytic cracking to hydrocracking with worsening *OQ*. Refiners can substitute hydrocracking for hydrotreating and catalytic cracking to some extent. *OQ*, along with other factors beyond this study scope, may influence those business decisions.

Energy increments predicted by density (44 MJ/kg) and sulfur (61 MJ/kg) in crude feeds (eq 1) compare to energy inputs of 40–70 MJ/kg density (including sulfur) lost from bitumen upgrading for SCO, based on process modeling of coking- and hydrocracking-based upgraders ((*16*), Table S6, Supporting Information). At an energy cost of 16.4 MJ/m^3 (Table S1, Supporting Information), hydrogen for density reduction by hydrocracking could account for 44 MJ/kg, based on the H_2/oil feed ratio of 308 m^3/m^3 Robinson and Dolbear report for 22°API feed and 44°API yield (*11*).

Results help to explain differences among government estimates of refinery emissions (Figure 3) and support the high case fuel cycle emission increments from a switch to heavy and tar sands oils reported for gasoline by Brandt and Farrel (+40%) (*3*) and for diesel by Gerdes and Skone (+17%) (*4*). Predicted emissions from processing heavy oil/natural bitumen blends (0.61–1.04 t/m^3) are 2–3 times the average of observed and estimated emissions in Figure 3 (0.30 t/m^3). Assuming this 0.30 t/m^3 refining average and 2007 world petroleum emissions (11.27 Gt) (*24*) as a baseline, processing heavy oil/bitumen blends at 2009 world refining capacity (5.06×10^9 m^3) (*10*) could increase annual CO_2 emissions by 1.6–3.7 gigatons and total petroleum fuel cycle emissions by 14–33%. Extraction emissions would add to these percentages.

This prediction applies to average CO_2 emissions from large, multiplant refinery groups with diverse, well-mixed crude feeds and appears robust for that application. However, the method used here should be validated for other applications. If it is applied to different circumstances, the potential for significantly different product slates, poorly mixed crude feeds, synthetic crude oil impacts on refining, and effects on fuel mix emission intensity and hydrotreating resulting from choices among carbon rejection and hydrogen addition technologies should be examined.

Several issues suggest future work. Other properties of crude feeds and incremental efficiencies from modernization of equipment and catalyst systems might explain up to 10% of the variability in *EI* observed among U.S. refining districts and years and could be more important for single plants and nondiverse crude feeds. Burning more fuel to refine lower quality oil emits toxic and ozone–precursor combustion products along with CO_2. Pastor et al. estimate that refinery emissions of such "co-pollutants" dominate health risk in nearby communities associated with particulate matter emitted by the largest industrial sources of greenhouse gases in California and identify racial disparities in this risk as important in emission assessment (*25*). Better facility-level *OQ* data could improve local-scale pollutant assessment. Better crude quality predictions could improve energy, and climate protection, forecasts. Assessments of the need, scope, and timing for transition to sustainable energy should account for emissions from lower quality oil.

Acknowledgments

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Supporting Information Available

Data and details of methods, analyses, and results. This material is available free of charge via the Internet at http://pubs.acs.org.

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Attachment to 24 October Comment to LCFS Program Advisory Panel

Oil Refinery CO_2 Performance Measurement

Prepared for the

Union of Concerned Scientists

Technical analysis prepared by
Communities for a Better Environment (CBE)

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Contents

Executive Summary

Statewide, oil refineries in California emit 19–33% more greenhouse gases (GHG) per barrel crude refined than those in any other major U.S. refining region.

For this report we gathered nationwide refinery data and new California-specific data to analyze refinery emission intensity in California. The goal of the analysis is to compare and evaluate the factors driving the relatively high emission intensity of California refineries.

Petroleum process engineering knowledge was applied to identify factors that affect refinery emission intensity. Data on these causal factors from observations of real-world refinery operating conditions across the four largest U.S. refining regions and California was gathered for multiple years. Those data were analyzed for the ability of the factors and combinations of factors to explain and predict observed refinery emission intensities.

This report summarizes our findings.

Crude feed quality drives refinery energy and emission intensities.

Making gasoline, diesel and jet fuel from denser, higher sulfur crude requires putting more of the crude barrel through aggressive carbon rejection and hydrogen addition processing. That takes more energy. Burning more fuel for this energy increases refinery emissions.

Differences in refinery crude feed density and sulfur content explain 90–96% of differences in emissions across U.S. and California refineries and predict average California refinery emissions within 1%, in analyses that account for differences in refinery product slates.

Analysis of other factors confirms that crude quality drives refinery emissions.

Total fuel energy burned to refine each barrel—energy intensity—correlates with crude quality and emissions, confirming that the extra energy to process lower quality crude boosts refinery emissions. Dirtier-burning fuels cannot explain observed differences in refinery emissions; the same refining by-products dominate fuels burned by refineries across regions.

Increasing capacity to process denser and dirtier oils enables the refining of lower quality crude and correlates with refinery energy and emission intensities when all data are compared, confirming the link between crude quality and energy intensity. But some of this "crude stream" processing capacity can be used to improve the efficiency of other refinery processes, which causes processes to emit at different rates, and process capacity does not predict refinery emissions reliably.

As refinery crude feed quality and emissions increase, gasoline, distillate and jet fuel production rates change little, and in some cases gasoline and distillate yield declines slightly. Product slates do not explain or predict refinery emissions when crude quality is not considered.

An ongoing crude supply switch could increase or decrease California refinery emissions depending on what we do now.

Ongoing rapid declines of California refineries' current crude supplies present the opportunity to reduce their emissions by about 20% via switching to better quality crude—and the threat that refining even denser, dirtier crude could increase their emissions by another 40% or more.

Purpose, scope, and approach

We set out to identify the main factors driving the high carbon intensity of California's refining sector. This project evaluates factors that drive refinery emissions, so that one can identify opportunities for preventing, controlling, and reducing those emissions.

Analysis focuses on carbon dioxide (CO_2) emissions from fuels refineries in California. This reflects known differences between fuels refining and asphalt blowing, and the recognition that CO_2 dominates the total global warming potential of GHG (CO_2e) emitted by oil refining *(1–3)*. CO_2 emissions from fuels refining account for 98–99% of 100-year horizon CO_2e mass emitted by oil refining in California *(2, 3)*.

The scope includes emissions at refineries and from purchased fuels consumed by refineries. (Many refiners rely on hydrogen or steam from nearby third-party plants and electricity from the public grid; ignoring that purchased refinery energy would result in errors.) This focus excludes emissions from the production and transport of the crude oil refined and from the transport and use of refinery products. That allows us to isolate, investigate, and measure refinery performance.

At the same time, oil refining is a key link in a bigger fuel cycle. Petroleum is the largest GHG emitter among primary energy sources in the U.S., the largest oil refining country, and in California, the refining center of the U.S. West *(3–5)*. So the "boundary conditions" used here, while appropriate for the scope of this report, are too narrow to fully address the role of oil refining in climate change.

Analysis of key factors driving emissions is based on data from observations of refineries in actual operation. This approach differs from those that use process design parameters to generate data inputs, which are then analyzed in computer models constructed to represent refinery operations. This "data-oriented" approach avoids making assumptions about processing parameters that vary in real-world refinery operation. It also more transparently separates expected causal relationships from observations.

However, this approach is limited to available publicly reported data. We use a ten-year data set encompassing 97% of the U.S. refining industry that was gathered and validated for recently published work *(2)* as our comparison data. We had to gather and validate the California refinery data ourselves *(4, 6–30)*. The comprehensive six-year statewide data for California refining and facility-level 2008–2009 data we analyze are presented in one place for the first time here *(31)*.

A recently published study used national data to develop a refinery emission intensity model based on crude feed density, crude feed sulfur content, the ratio of light liquids to other refinery products, and refinery capacity utilization *(2)*. This report builds on that published analysis using California data.

For a more formal presentation of the analysis, the raw data, and data documentation and verification details, please see the technical appendix to this report.

Emissions intensity—higher in California

California refineries emit more CO_2 per barrel oil refined than refineries in any other major U.S. refining region.

Figure 1 compares California with other major U.S. refining regions based on emissions intensity—mass emitted per volume crude oil refined. Crude input volume is the most common basis for comparing refineries of different sizes generally *(4),* and it is a good way to compare CO_2 emissions performance among refineries as well *(2).*

Consider the *emissions* part of emissions-per-barrel for a moment. This measurement is fundamental to refinery emissions performance evaluation. We need to know where it comes from and if we can trust it.

The bad news: many refinery emission points are not measured. Instead, measurements of some sources are applied to other similar sources burning known amounts of the same fuels to estimate their emissions. This "emission factor" approach makes many assumptions and has been shown to be inaccurate and unreliable for pollutants that comprise small and highly variable portions of industrial exhaust flows. The best practice would directly measure emissions, and apply emissions factors only until direct measurements are done.

The good news, for our purpose here, is that the emissions factor approach is prone to much smaller errors when applied to major combustion products that vary less with typical changes in combustion conditions, like CO_2. This means that in addition to being the best information we have now, the emission factor-based "measurements" we use here for CO_2 *(2, 8, 30, 31)* are relatively accurate as compared with some other refinery emissions "measurements" you might see reported.

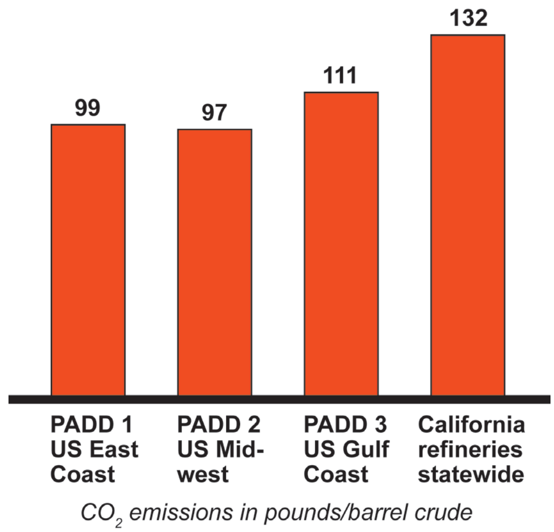

Figure 1. Average refinery emissions intensity 2004–2008, California vs other major U.S. refining regions. Emissions from fuels consumed in refineries including third-party hydrogen production. PADD: Petroleum Administration Defense District.

Data from Tech. App. Table 2-1 *(31).*

Thus, the substantial differences in refinery emissions intensity shown in Figure 1 indicate real differences in refinery performance. They demonstrate extreme-high average emissions intensity in California. They suggest that other refineries are doing something California refineries could do to reduce emissions. The big question is what *causes* such big differences in refinery emissions.

Energy intensity—the proximate cause of high emissions intensity

California refineries are not burning a dirtier mix of fuels than refineries in other U.S. regions on average. Their high emissions intensity comes from burning more fuel to process each barrel of crude. During 2004–2008 refineries in California consumed 790–890 megajoule of fuel per barrel crude refined, as compared with 540–690 MJ/b in other major U.S. refining regions (PADDs 1–3) *(31)*.

This is consistent with recent work showing that increasing energy intensity that causes refineries to consume more fuel, and not dirtier fuels, increases emissions intensity across U.S. refining regions *(2)*. Increasing fuel energy use per barrel crude refined—increasing energy intensity—is the proximate cause of increasing average refinery emissions intensity.

Looking at where refineries get the fuels they burn for energy helps to explain why energy intensity, and not dirtier fuel, drives the differences in refinery emissions intensity we observe.

The fuel mix shown for California refineries in Figure 2 is dominated by refinery fuel gas, natural gas, and petroleum coke just like in other U.S. refining regions. Coke and fuel gas burn dirtier than natural gas but are self-produced, unavoidable by-products of crude oil conversion processing that are disposed or exported *(32)* to be burned elsewhere if refineries don't burn them. Natural gas is brought in when refinery energy demand increases faster than coke and fuel gas by-production. The net effect is that emission per MJ fuel consumed does not change much as refinery energy intensity increases and demands more fuel per barrel processed.

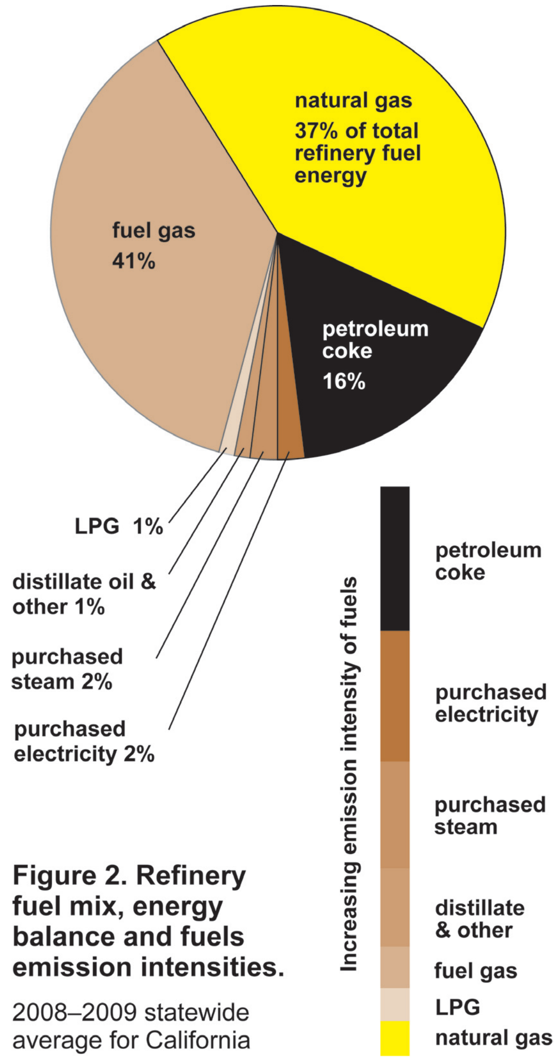

Figure 2. Refinery fuel mix, energy balance and fuels emission intensities.

2008–2009 statewide average for California

Data from Tech. App. *(31)*.

The root cause—making motor fuels from low quality crude

Making motor fuels from denser, more contaminated crude oil increases refinery energy intensity.

A hundred years ago the typical U.S. refinery simply boiled crude oil to separate out its naturally occurring gasoline (or kerosene) and discarded the leftovers. Not any more. Now after this "distillation" at atmospheric pressure, refineries use many other processes to further separate crude into component streams, convert the denser streams into light liquid fuels, remove contaminants, and make many different products and by-products from crude of varying quality *(1, 2)* But even complex refineries still make crude into motor fuels by the same steps: separation; conversion; contaminant removal, product finishing and blending.

The middle steps—conversion, and removal of contaminants that poison process catalysts—are the key to the puzzle.

Making light, hydrogen-rich motor fuels from the carbon-dense, hydrogen-poor components of crude requires rejecting carbon and adding hydrogen *(1, 2, 16, 25)*. This requires aggressive processing that uses lots of energy. Refiners don't have to make gasoline, diesel and jet fuel from low quality crude, but when they decide to do so, they have to put a larger share of the denser, dirtier crude barrel through energy-intensive carbon rejection, hydrogen addition, and supporting processes. That aggressive processing expands to handle a larger share of the barrel even when the rest of the refinery does not.

Figure 3 illustrates this concept: Refineries A and B make fuels from the same amounts of crude but Refinery B runs low quality crude. Their atmospheric distillation capacities are the same, but more of the low quality crude goes through expanded carbon rejection and aggressive hydrogen addition processing at Refinery B. The extra energy for that additional processing makes Refinery B consume more energy per barrel refined.

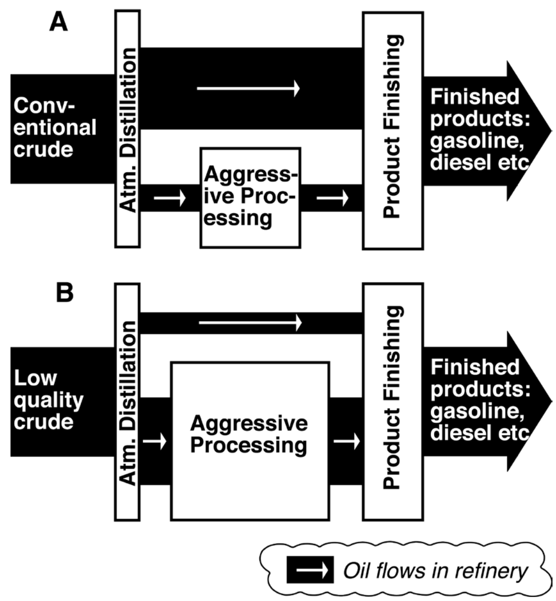

Figure 3. Simple refinery block diagram. Aggressive processing (vacuum distillation, cracking, and aggressive hydroprocessing) acts on a larger portion of the total crude refined to make fuels from low quality crude. Figure reprinted with permission from Communities for a Better Environment.

In fact, as crude feed quality worsens across U.S. refining regions, the average portion of crude feeds that can be handled by refiners' vacuum distillation, conversion and aggressive hydrogen addition processes combined increases by more than 70%, from 93–167% of refiners' atmospheric crude distillation capacity *(31)*.

California refineries have more of this aggressive processing capacity on average than refineries in any other U.S. region. Of the five major "crude stream" processes that act on the denser, more contaminated streams from atmospheric distillation (vacuum distillation, coking, catalytic cracking, hydrocracking, and hydrotreating of gas oil and residua), California refineries stand out for four. *(Figure 4.)* Meanwhile, consistent with the example described above, average California product hydrotreating and reforming capacities are similar to those of other U.S. refining regions.

Vacuum distillation boils the denser components of crude in a vacuum to feed more gas oil into carbon rejection and hydrogen addition processing. Conversion capacity (thermal, catalytic and hydrocracking capacity) breaks denser gas oil down to lighter motor fuel-type oils. Hydrocracking and hydrotreating of gas oil and residua are aggressive hydrogen addition processes. They add hydrogen to make fuels and remove sulfur and other refinery process catalyst poisons.

This aggressive hydroprocessing uses much more hydrogen per barrel oil processed than product hydrotreating *(25)*, especially in California refineries *(Fig. 5)*. That is important because refiners get the extra hydrogen from steam reforming of natural gas and other fossil fuels at temperatures reaching 1500 ºF, making hydrogen plants major energy consumers and CO_2 emitters *(2, 26, 28, 29, 33, 37)*.

Hydrogen production increases with crude feed density and hydrocracking rather than product hydrotreating across U.S. refineries *(2)*, and is higher on average in California than in other U.S. regions *(31)*.

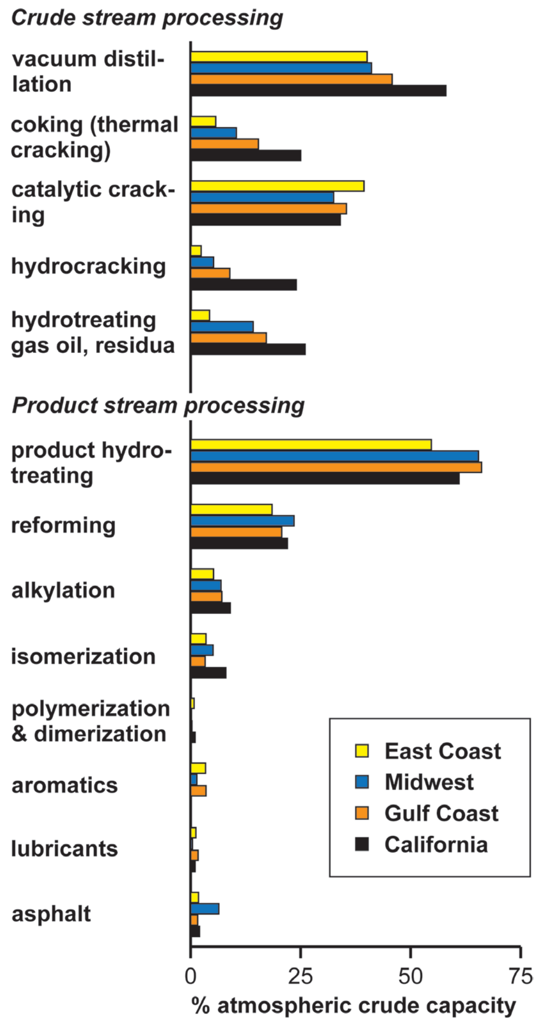

Figure 4. Refinery process capacities at equivalent atmospheric crude capacity, PADDs 1–3 and California (5-yr. avg.) *(31).*

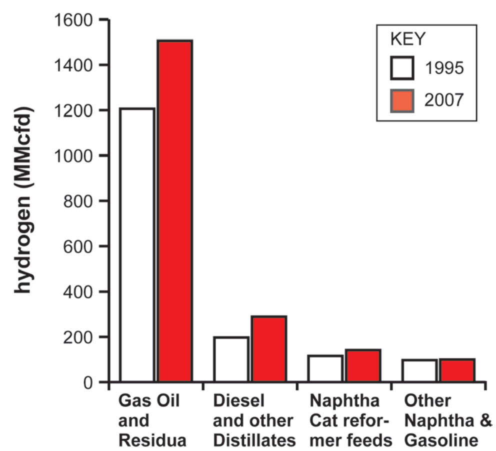

Figure 5. Hydrogen use for hydroprocessing various feeds, California refineries, 1995 and 2007. Figure from CBE *(33)*.

Observations of operating refineries across the U.S. and California reveal the impact of crude quality on refinery energy and emission intensities. Crude feed density increases from Midwest Petroleum Administration Defense District (PADD) 2 on the left of Figure 6 to California on the right. Refinery energy intensity increases steadily with crude feed density. Crude stream processing capacity also increases with crude density, reflecting the mechanism by which refineries burn more fuel for process energy to maintain gasoline, diesel and jet fuel yield from lower quality oil. As a result, refinery output of these light liquid products stays relatively flat as crude density increases.

Figure 7 shows comparisons of the same nationwide data using nonparametric analysis to account for potential nonlinear relationships among causal factors. Crude feed density (shown) and sulfur content (not shown) can explain 92% of observed differences in refinery emissions (Chart A). Together with the light liquids/other products ratio, crude feed density and sulfur content can explain 96% of observed differences in emissions (Chart B). Increasing crude stream processing capacity (Chart C) confirms the mechanism for burning more fuel energy to process denser, higher sulfur crude.

The ratio of light liquids to other products does not explain refinery emission intensity (Chart D). This is consistent with recently published work showing that the products ratio was not significant in the strong relationships among refinery energy intensity, processing intensity, and crude quality *(2)*. Differences in refinery products alone cannot provide an alternative explanation for the large differences in refinery emissions that are observed.

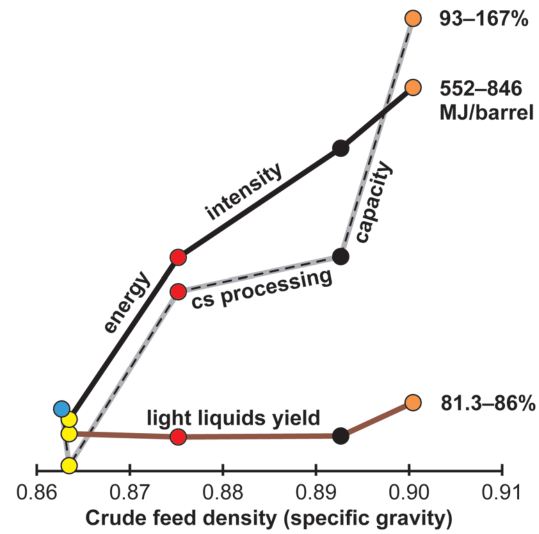

Figure 6. Average energy intensity (MJ/b), crude stream processing capacity (% atm. distillation capacity), and light liquids yield (% crude) by refining region. East Coast PADD 1, 1999–2008 (yellow). Midwest PADD 2, 1999–2008 (blue). Gulf Coast PADD 3, 1999–08 (red). West Coast PADD 5, 1999-2003 (black). California, 2004–2009 (orange). Data from Tech. App. Table 2-1.

But the same differences in product slates that affect emissions only marginally (compare charts A and B) may be more strongly related to processing capacity. PADDs 1 and 5 produce less light liquids than other regions that refine similar or denser crude (compare charts B and D), which should require marginally less crude stream processing capacity in PADDs 1 and 5. Consistent with this expectation, PADD 1 and PADD 5 data are shifted to the left in Chart C relative to their positions in Chart A. Conversely, California maintains light liquids production despite refining denser crude than that refined elsewhere, and the California data are shifted to the right in Chart C. These shifts are independent from any similarly large difference in observed emissions—the data shift horizontally while emission intensity changes verti-

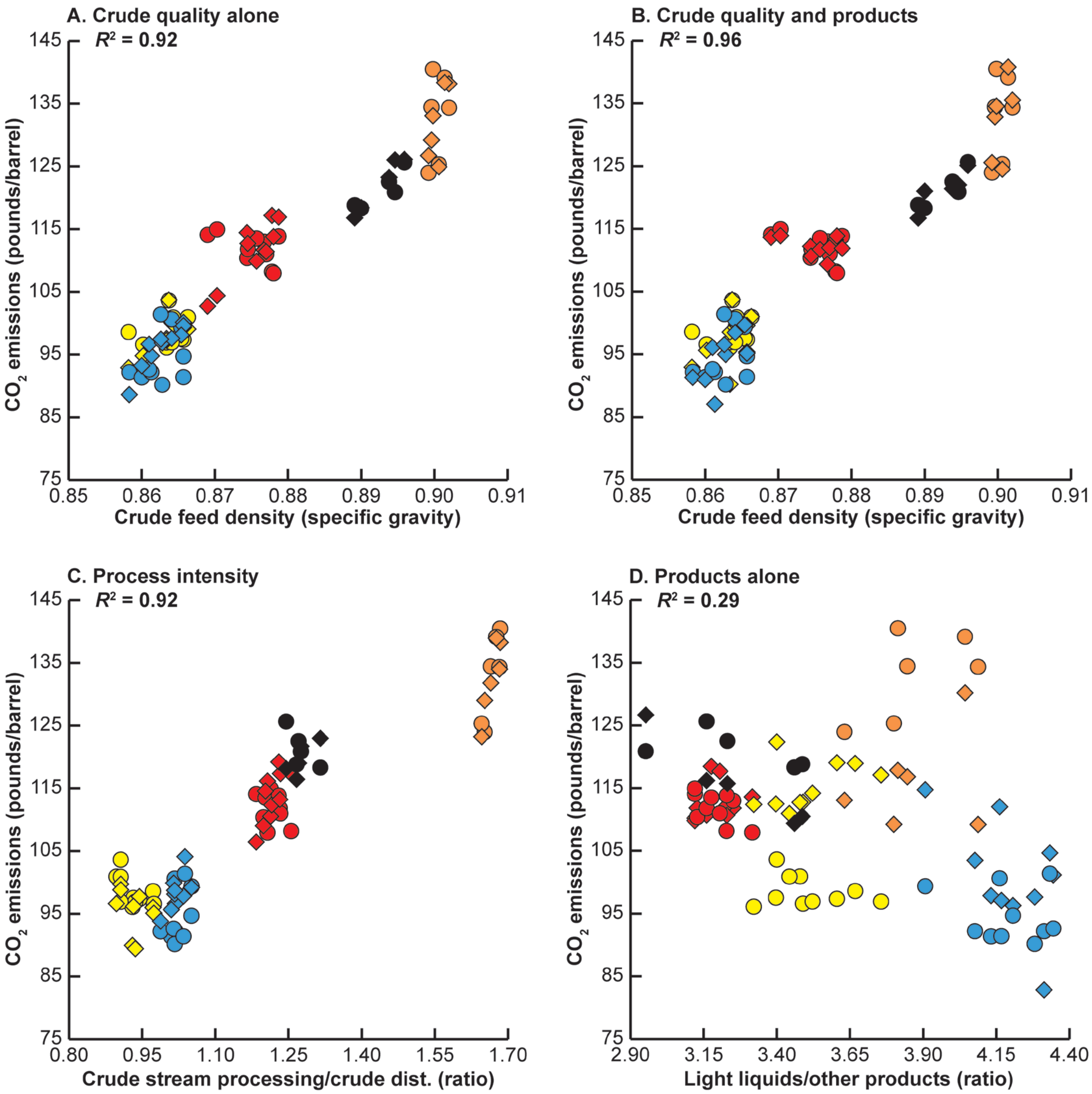

Figure 7. Comparison of refinery emission intensity drivers. Results from nonparametric regression analyses comparing emission intensity with crude feed quality (density, shown; and sulfur, not shown; see Chart A); crude quality and light liquids/other products ratio (B); crude stream processing capacity (C); and products ratio (D). All comparisons account for refinery capacity utilization. Circle [diamond]: annual average observation [prediction] for PADD 1 1999-2008 (yellow), PADD 2 1999–2008 (blue), PADD 3 1999–2008 (red), PADD 5 1999–2003 (black), and California 2004–2009 (orange). Data from Technical Appendix tables 2-1, 2-10.

cally in Chart C—so that at least some of the differences in process capacity do not reflect real differences in emissions.

Thus, observations of operating refineries across U.S. regions and California demonstrate the impact of crude quality on refinery CO_2 emission intensity. However, while it can enable the refining of lower quality crude, processing capacity does not equate to emissions intensity, because it can be used in different ways to target different product slates, which could require different process energy inputs, and thus emit at different rates.

Drivers of refinery CO_2 intensity: assessing correlations

The petroleum process engineering logic and comparisons of refineries in real-world operation documented above suggest the following model for interactions of the major factors affecting refinery CO_2 emission intensity:

- Making lower quality crude into light liquid fuels consumes more energy and this increases refinery emissions.
- Differences in fuels product slates alone cannot explain differences in emissions when crude quality is not considered. However, light liquids yield that is high or low relative to crude feed quality may reflect differences in crude stream processing capacity and its relationship to energy and emission intensities.
- Crude stream processing capacity can be used to refine lower quality crude, make more light liquid fuels from crude of a given quality, and/or treat other process feeds. Different uses of this processing capacity may consume energy and emit CO_2 at different rates.

If this model is correct, crude quality and fuels products should be able to predict refinery emission intensity. Further, crude quality and products should predict emission intensity better than either refinery products or processing capacity alone. The following analyses test this hypothesis by predicting California refinery emissions based on U.S. refinery data.

Unlike the comparison analyses shown in Figure 7, these predictive analyses use all of the U.S. data and only some of the California data: the California refinery energy and emission intensity observations are withheld. Because the resultant analyses do not "know" the California emissions that are actually observed, their results represent true predictions of California refinery emissions. Those predictions can then be compared with the emissions actually observed to test the ability of products output, process capacity, and crude quality along with products, to predict California refinery emissions.

This model is taken from previously published work that showed crude quality and fuels produced resulted in reasonably accurate predictions *(2)*. However, the new California data analyzed for the first time here reveal new extremes of high crude feed density, crude stream processing capacity, and refinery energy and emission intensities *(31)*. At the same time, while light liquids yields and crude stream processing capacities are slightly lower relative to crude feed density among some of the previously analyzed U.S. data, those yields and capacities are slightly higher in California. *(Discussion of Fig. 7 above.)* For all of these reasons its ability to predict California refinery emissions based on the nationwide data represents a good test of this model.

Refinery products alone

Total light liquids yield varies little *(Figure 6)* and the light liquids/other products ratio cannot explain differences in refinery emissions *(Figure 7)*. However, gasoline, distillate diesel, and kerosene jet fuel are made in different ways that may consume energy and emit at different rates *(16, 28, 33–38)*. Analyzing differences in the relative amounts of individual fuels produced instead of only their lump-sum could provide more information about the relationship of refinery products and emissions. Therefore we test whether the mix of gasoline, distillate, and kerosene jet fuel produced—the "fuels products mix"—can predict refinery emissions.

U.S. refinery emissions line up with the mix of fuels produced but *decrease* as the portion of refinery emissions caused by differences in fuels produced *increases* (compare charts A and B in Figure 8). This counter intuitive result is caused by decreasing gasoline and distillate yields as crude feed density increases *(2)* that are reflected in lower light liquid yields as emissions increase among U.S. PADDs *(Figure 7)*. In addition, consistent with the small differences in yields shown in Figure 6, the range of emissions from differences fuels products yields (~10 lb/b) is small compared with that of observed refinery emissions (~50 lb/b; Chart 8-B).

Observed California refinery emissions exceed those predicted based on the fuels products mix by 15–31% annually and by a six-year average of 22%. This prediction error results from equating California to other regions that have a similar mix of fuels yields but lower refinery emissions. These results show that fuels product slates cannot explain or predict refinery emissions when crude quality is not considered, further supporting effects of crude quality on refinery emissions.

Processing capacity alone

This analysis tests the ability of crude stream processing capacity—equivalent capacities for vacuum distillation, conversion (thermal, catalytic and hydrocracking), and gas oil/residua hydrotreating relative to atmospheric crude distillation capacity—to predict refinery emissions. Although products processing or refinery wide processing equivalent capacities provide alternative measurements of refinery "complexity" *(Figure 4),* crude

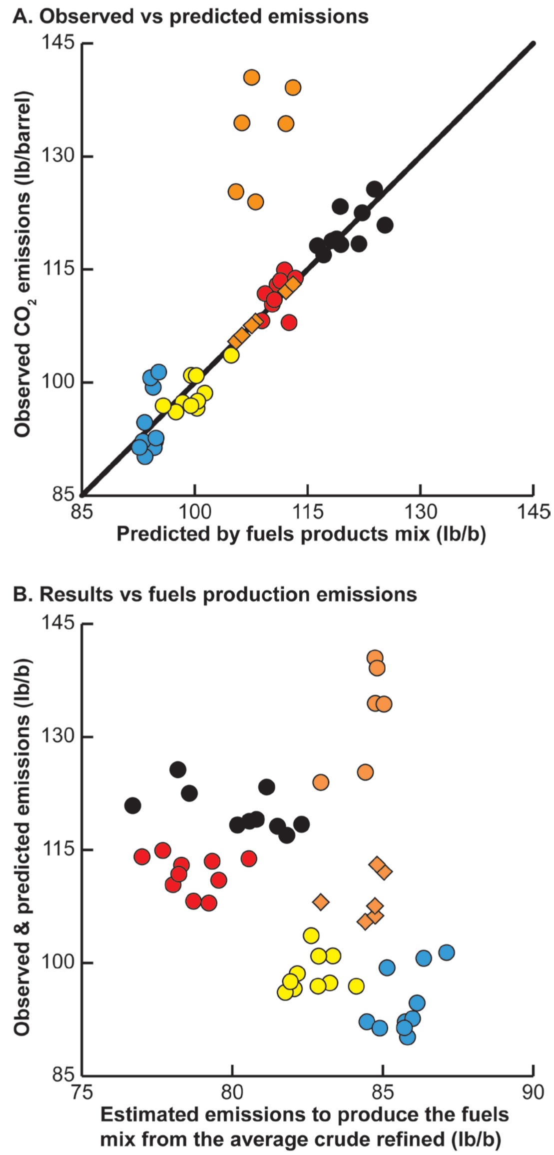

Figure 8. Refinery emission intensity vs gasoline, distillate, and kerosene jet fuel yields. Prediction for California (2004–2009) by partial least squares regression on U.S. data (1999–2008; R^2 0.94). Circle [diamond]: annual average observation [prediction] for PADD 1 (yellow), 2 (blue), 3 (red), 5 (black), or California (orange). Differences in the mix of these products among U.S. PADDs correlate with refinery emissions (Chart A) that cannot be explained by emissions from producing the products alone (Chart B) and do not predict California refinery emissions. Gasoline, distillate, and kerosene production CO_2 estimates (46.0, 50.8, 30.5 kg/b respectively) from NETL *(28).* All other data from Technical Appendix tables 1-5, 2-1.

stream processing capacity enables refining of lower quality crude and explains refinery energy and emission intensities when all data are compared while products processing and refinery wide capacities do not *(2, Figure 7, Tech. Appendix)*.

Chart A in Figure 9 shows results for the prediction of California refinery emission intensity based on crude stream processing capacity. Although it can explain differences in emissions *(observed PADDs emissions included in analysis)*, the prediction based on crude stream processing alone *(observed California emissions excluded from analysis)* exceeds observed emissions by 13–22% and by a six-year average of 17%.

This prediction error can be explained by refiners using processing capacity in different ways. In California, equivalent capacities for coking, hydrocracking and gas oil/residua hydrotreating exceed those of other U.S. regions *(Figure 4)*, and total crude stream processing capacity exceeds atmospheric distillation capacity by an average of 67% *(Figure 6)*, indicating uniquely greater capacity for serial processing of the same oil in multiple crude stream processes. That serial processing can alter the composition of feeds to various processing units, which can alter process reaction conditions, firing rates, and resultant fuel consumption and emission rates.

For example, gas oil hydrotreating capacity adds hydrogen to the H_2-deficient gas oil from vacuum distillation and removes contaminants from the oil that otherwise interfere with processing by poisoning catalytic cracking and reforming catalysts, thereby also removing those contaminants from unfinished products *(2, 16, 25)*. In these ways, inserting more gas oil hydro-

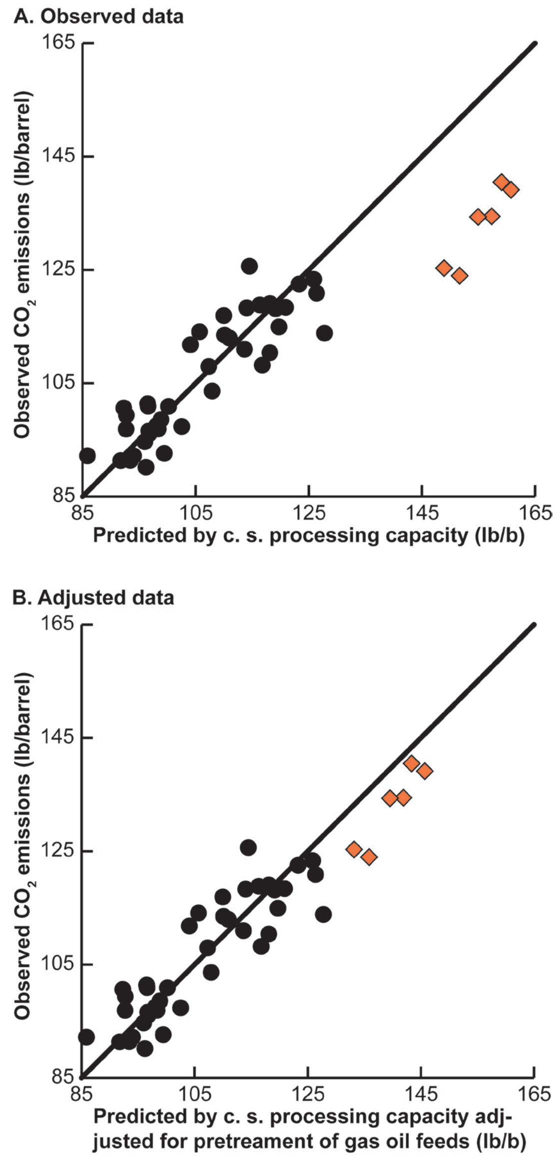

Figure 9. Emission intensity vs vacuum distillation, conversion, and gas oil/residua hydrotreating equivalent capacities. Prediction for California (2004–2009) by partial least squares regression on U.S. data (1999–2008; R^2 0.92). Black circle [orange diamond]: annual avg. for PADD 1, 2, 3 or 5 [California]. Chart A: Prediction based on observed data. Chart B: Identical to Chart A analysis except that California gas oil hydrotreating data are replaced by the lowest equivalent capacity observed among all these regions and years. Hydrotreating gas oil can improve other process efficiencies, so Chart B shows a plausible hypothetical example of why process capacity does not predict California emissions. Data from Tech. App. tables 1-3, 2-1.

treating in the middle of their crude stream processing trains helps refiners make more fuels product from denser and dirtier crude while improving downstream processing efficiency and reducing the need to treat product streams in order to meet "clean fuels" standards.

Thus, California refiners' very high gas oil hydrotreating capacity *(Figure 4)* is consistent with their abilities to maintain fuels yield despite denser crude and meet California fuel standards despite product hydrotreating and reforming capacities similar to those elsewhere *(figures 4, 7)*.

And because improved efficiencies from better cracking and reforming feed pretreatment may offset emissions from this additional gas oil hydrotreating, that may help explain why, relative to other refining regions, average refinery emission intensity does not increase as much as crude stream processing capacity in California.

Chart 9-B explores this plausible explanation. It shows results from the same analysis as Chart 9-A except that observed California gas oil hydrotreating capacity is replaced by the lowest U.S. crude stream hydrotreating capacity observed. Those adjusted California data thereby predict California emissions for the assumed scenario described above, where California gas oil hydrotreating capacity would not increase refinery emissions because its emissions are offset by efficiency improvements in downstream cracking and reforming processes.

In this hypothetical scenario, the prediction based on "adjusted" crude stream process capacity exceeds observed California refinery emissions by a six-year average of 5%, as compared with the 17% average error shown in Chart 9-A.

This hydrotreating example cannot exclude other differences in crude stream processing configuration or usage as causes of the prediction error shown in Chart 9-A. Indeed, the lack of publicly reported data for specific process units that makes it difficult or impossible to verify exactly how much each specific difference in processing changes emissions *(12, 28, 34)* is another reason why processing capacity alone is not a reliable predictor of refinery emission intensity.

These results support our hypothesis by showing that the ability to use crude stream processing in different ways, which can consume energy and emit at different rates, can explain the poor prediction of California emissions based on observed processing capacity alone.

Crude quality and fuels produced

Recently published work found that crude feed density, crude feed sulfur content, the ratio of light liquids to other products, and refinery capacity utilization[1] explain observed differences in energy and emissions intensities among U.S. refining regions and predict most of the differences among various government estimates of refinery emissions *(2)*. To test our hypothesis, we predict California refinery emissions based on this crude quality and products model *(2)* using all the U.S. data but only the California crude quality, products, and capacity utilization data.

In addition to the statewide data included in all our analyses, available data allow analysis of individual San Francisco Bay Area refineries. Reported crude feed data are too limited for such facility-level analysis of other California refineries.

[1] Capacity utilization is included as an explanatory factor in all the predictive analyses (figures 8–10).

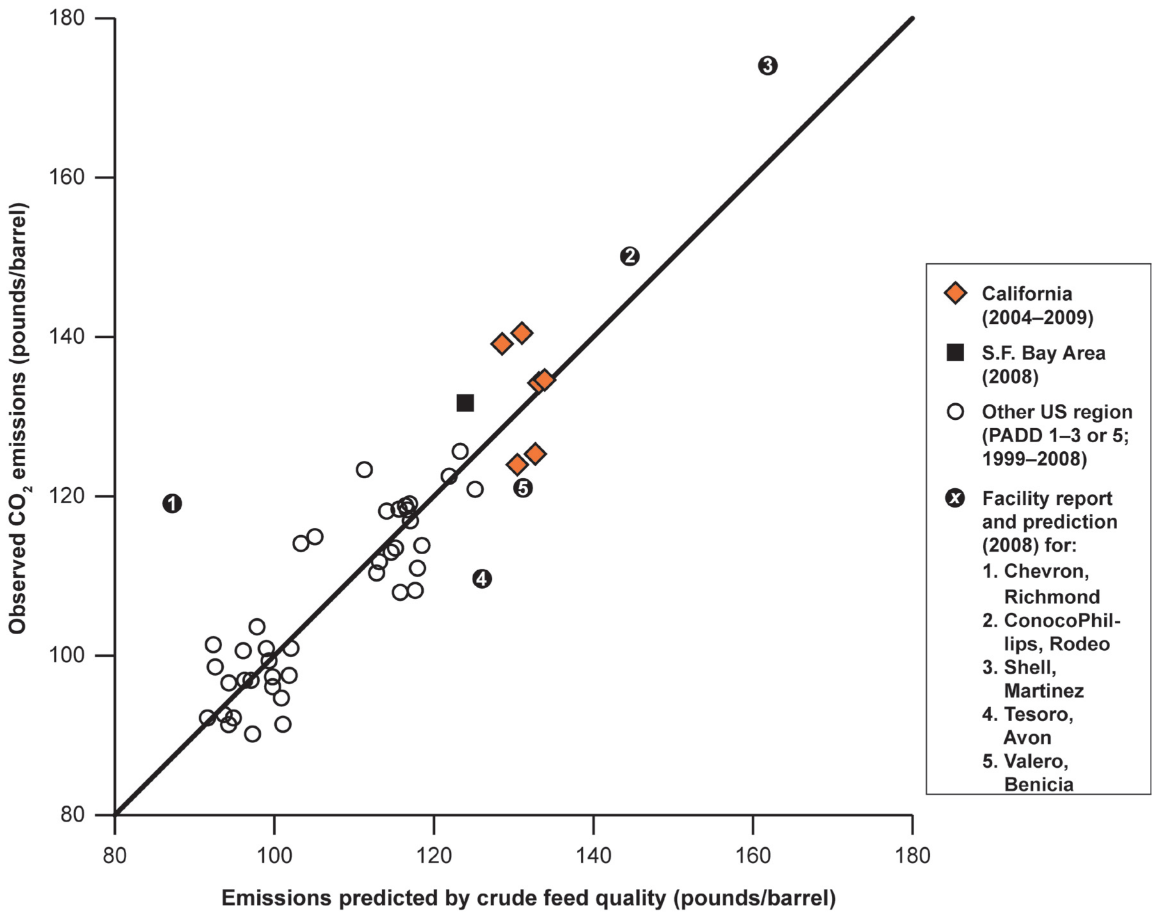

Figure 10. Refinery emission intensity vs crude feed density, sulfur content and light liquids/other products ratio. Predictions for California by partial least squares regression on U.S. data (R^2 0.90). Chart legend identifies annual average data. Data from Tech. App. tables 1-1, 2-1.

The diagonal line in Figure 10 shows the prediction defined by applying this model to the nationwide refinery data. Consistent with our hypothesis, the model tells us to expect increasing emissions intensity as crude feed density, sulfur content, or both increase. Observed emissions fall on or near the line in almost every case. California statewide refinery emissions range from 6% below to 8% above those predicted and are within 1% of predictions as a six-year average. San Francisco Bay Area refinery emissions exceed the prediction by 6%. Emissions reported by four of the five individual Bay Area refineries fall within the confidence of prediction when uncertainties caused by lack of facility products reporting are considered, and range from 13% below to 8% above the central predictions for these facilities.

The only data point that is clearly different from the emissions predicted by this model is for the Chevron Richmond refinery, and that result was anticipated as Chevron has reported inefficiency at this refinery. A 2005 Air Quality Management District permit filing by the company *(39)* cited relatively antiquated and inefficient boilers, reformers, and hydrogen production facilities at Richmond.

These results show that the crude quality and products model is relatively accurate and reliable for California refineries.

Crude supply is changing now

California refineries can and do import crude from all over the world *(24),* but their historically stable crude supply sources in California and Alaska are in terminal decline *(40–42).* This is driving a refinery crude switch: foreign crude imports were only 6% of the total California refinery crude feed in 1990; in 2009 they were 45% of total California crude feed *(21).* By 2020 roughly three-quarters of the crude oil refined in California will *not* be from currently existing sources of production in California or Alaska *(41, 42).*

An urgent question is whether, by 2020, California will switch to alternative transportation energy, or switch to the better quality crude now refined elsewhere, or allow its refiners to retool for a new generation of lower quality crude.

The model developed from analysis of nationwide refinery data that is validated for California refineries in this report predicts that a switch to heavy oil/natural bitumen blends could double or triple U.S. refinery emissions *(2).* Based on this prediction, replacing 70% of current statewide refinery crude input with the average heavy oil *(19)* could boost average California refinery emissions to about 200 pounds/barrel crude refined.[2] This would represent an increase above observed 2009 statewide refinery emissions of approximately 44% or 17 million tonnes/year.

Based on the same prediction model *(2),* and the average California refinery yield, fuels, and capacity utilization observed 2004–2009 *(2, 31),* replacing 70% of current statewide refinery crude input with crude of the same quality as that refined in East Coast PADD 1 (2005–2008) could cut statewide refinery emissions to about 112 pounds/barrel—a reduction of about 20%, or ~8 million tonnes/year below observed 2009 emissions.

Comparison with the 10% cut in refinery emissions envisioned by 2020 via product fuels switching under California's Low Carbon Fuel Standard suggests that this possible range of emissions changes (+44% or –20%) could overwhelm other emissions control efforts.

In light of the findings reported here, the California refinery crude supply switch that is happening now presents a crucial challenge—and opportunity—for climate protection and environmental health.

[2] This prediction for heavy oil as defined by USGS does not represent worst-case refinery emissions; it is near the low end of the heavy oil/natural bitumen range predicted *(ref. 2; SI; Table S8; central prediction for heavy oil).* Nor does it include emissions from crude production: work by others *(12, 16, 38)* has estimated an *additional* emission increment from extraction of heavy and tar sands oils versus conventional crude that is roughly as great as this emissions increase from refining.

Recommendations

To ensure environmental health and climate stability it will be necessary to develop and enforce policies that prevent or limit emissions from refining lower quality grades of crude oil.

Existing state and federal policies have not identified crude quality-driven increases in refinery emissions. As a result they have not limited or otherwise prevented very large increases in the emission intensity of refining that exceed the emission targets of these current policies. Continuation of these policies without change will likely fail to achieve environmental health and climate goals.

Expand refinery crude feed quality reporting to include crude oil from U.S. sources.

Currently, every refinery in the U.S. reports the volume, density, and sulfur content of every crude oil shipment it processes, and that is public—but only for foreign crude. (www.eia.gov/oil_gas/petroleum/data_publications/company_level_imports/cli.html) The quality of crude refined from wells on U.S. soil is exempted. Since California's major fuels refineries use U.S. crude too, this hides facility crude quality from the public and from publicly verifiable environmental science. That limits this report's analysis of individual refineries, but very high crude quality-driven emissions found at two of the five facilities analyzed suggest that GHG copollutants disparately impact communities near refineries processing dirtier oil. The public has a right to know about how U.S. oil creates pollution of our communities and threatens our climate. State and federal officials should ensure that the U.S. crude refined is reported just like the foreign crude refined.

Compare refinery carbon emission performance against national or world-wide refinery performance.

The extreme-high average CO_2 emission intensity of California refineries revealed in this report was discovered only by comparing them with refineries in other parts of the U.S. This alone makes the case for rejecting the alternative of comparing refinery performance only within California. Doing that would compare "the worst with the worst," and thus risk erroneously establishing a statewide refinery emissions rate that is 33% dirtier than the average emissions rate achieved across a whole U.S. refining region as environmentally "acceptable" performance.

Moreover, this report demonstrates that comparing refinery performance across U.S. regions allows one to verify and know which causal factors do and do not drive changes in refinery emissions. That knowledge enables actions to prevent and reduce emissions. This is the *reason* one tracks emission performance.

The crude feed quality and products model evaluated here measures and predicts emissions per barrel crude refined based on the density and sulfur content of crude feeds, refinery capacity utilization, and the ratio of light liquids (gasoline, distillate, kerosene and naphtha) to other refinery products. It is based on data for U.S. Petroleum Administration Defense districts 1, 2, 3 and 5 over ten recent years. Energy intensity predicted by these parameters is compared with fuels data using CO_2 emission factors developed for international reporting of greenhouse gas emissions in the U.S. Data and methods are freely available at http://pubs.acs.org/doi/abs/10.1021/es1019965.

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Attachment to 24 October Comment to LCFS Program Advisory Panel

Technical Appendix,

Oil Refinery CO_2 Performance Measurement

Revision 1, September 2011

Prepared for the

Union of Concerned Scientists

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Technical Appendix, Oil Refinery CO_2 Performance Measurement

Part 1. Narrative

List of figures

List of tables

Part 2. Data tables.

Purpose and scope

The purpose of this project is to develop and recommend a metric that can be used to measure petroleum refinery greenhouse gas (GHG) emissions intensity accurately and identify potential changes in emissions for controlling them reliably (a "benchmark"). Closely tied to this purpose, the project seeks to document the ability of alternative benchmark options to measure factors that drive refinery emissions, and thus be used to help identify opportunities for preventing, controlling, and reducing those emissions.

Four assumptions that were introduced at project conception served to focus, limit, and define its scope. First, the project was limited to technical assessment. Second, at least three types of refinery emission performance metrics would be assessed:

- A metric that would attempt to benchmark refinery emissions against refinery complexity—a term that refers to measurements based on the types and capacities of processes used by a refinery following initial atmospheric crude distillation.
- A metric that would attempt to benchmark refinery emissions against refinery products output, meaning the production or yield of some or all refined products.
- A metric that would benchmark refinery emissions against crude feed quality; specifically, the density and sulfur content of crude oil feedstock processed by refineries. These metrics are described in detail below.

The third initial assumption was that the applicability of the benchmark to refineries in California and other regions would be assessed. Fourth, available California-specific refinery data would be assessed.

Analysis focused on carbon dioxide (CO_2) emissions from fuels refineries. This reflected known differences between fuels refining and asphalt blowing, and the recognition that CO_2 predominates the total global warming potential of greenhouse gases emitted by oil refining. Taken together these two limitations in project focus exclude only 1–2% of 100-year horizon CO_2e mass emitted by oil refining in California *(1, 2).*

Boundary conditions were set to include emissions at refineries and from purchased fuels consumed by refineries. The alternative of excluding purchased fuels consumed by refineries was rejected because ignoring relationships of refinery processing and feeds to those energy and emissions commitments—especially with respect to captive and third party hydrogen plants often co-located with refineries—would introduce potentially large and unnecessary errors. This boundary excludes emissions from the production and transport of refinery feedstock and from the transport and use of refinery products.

Approach

Assessment was based on data from observations of refineries in actual operation. This approach differs from those which use process design parameters to generate data inputs that are then analyzed in linear programming (LP) or analogous models constructed to represent refinery operations. See, for example Keesom et al. *(3);* Brederson et al. *(4).* Strengths of the "data-oriented" approach used here include avoidance of error associated with the need to make assumptions about processing parameters that vary within and sometimes beyond design parameters in actual refinery operation, and transparent separation of observations from expected causal relationships. Observed data and expected causal relationships may be intertwined by the assumptions embedded in inputs generated from process design data and embedded in algorithms of LP models. A weakness is its limitation to observed and recorded data, which limits its use in cases of not-yet-built breakthrough technology that do not apply here, and limited its use, for this project, to analysis of available publicly reported data.

A ten-year data set encompassing 97% of the U.S. refining industry that was gathered and validated for recently published work *(1)* was selected as the comparison data for this assessment (the "U.S. data"). Data from California refineries were gathered and assessed for their quality. The data were assessed based on petroleum refinery engineering and physical chemistry knowledge to identify causal bases for interactions of variables to be analyzed, and were compared with the U.S. data to check for consistency of response strength among variables, before quantitative analysis.

Quantitative analysis was designed first to assess the power of a metric option to predict refinery emissions intensity, based on independently observed emissions, and second; its reliability of prediction related to factors explaining emissions intensity based on comparison observations. These criteria flowed from the measurement accuracy, and identification of potential emission intensity change, purposes described above.

Partial least squares regression (PLS, XLSTAT 2009) was used where supported by available data. This analysis model was described previously *(1).* PLS allowed for the intended focus on the primary interest in prediction of y (e.g., emission intensity) and secondary interest in weights of x variables (e.g., factors driving emissions) while addressing the expectation that these factors may be correlated. Analysis by PLS also afforded comparability with recently published analysis of the U.S. data *(1).* Support for PLS by available data was defined for each analysis run as results suggesting that PLS residuals were distributed normally for each of four descriptive tests (Shapiro-Wilk; Anderson-Darling; Lilliefors; Jarque-Bera tests, α 0.05). If this requirement was not met for PLS, analysis was by nonparametric regression (LOWESS, XLSTAT 2009) with the same criterion for acceptable distribution of residual error by all of those four tests.

California refinery data were analyzed in the prediction mode of the PLS or LOWESS models on the U.S. data. Data inputs were reported with results for each analysis.

Narrative description of the data

Annual average data for refinery groups. Weighted annual average refinery crude feed volume, density and sulfur content, process capacity, fuels, yield, capacity utilization, energy, and emissions data for California (2004–2009) and U.S. Petroleum Administration districts (PADDs) 1, 2, 3 and 5 are shown in Table 2-1. PADD 4 data were excluded based on observed anomalies that could not be resolved due in part to incomplete crude feed data reporting. These U.S. data were taken from recently published work that describes the U.S. data and PADD 4 anomaly in detail *(1)*.

The California Energy Commission (CEC) *(5)* reported annual average California crude feed volume data. California refinery crude feed quality data are discussed below. Refinery process capacities shown were volumes that could be processed during 24 hours after making allowances for types and grades of inputs and products, environmental constraints and scheduled downtime, from *Oil & Gas Journal (6)*.

Fuels consumed by California refineries shown in Table 2-1 for 2006–2009 were provided by the CEC *(7)*, and those shown for 2004–2005 were provided by Air Resources Board (ARB) staff *(8)*. Errors in the 2006–2007 fuels data were discovered, investigated, and corrected by CEC staff during the data gathering effort for this project *(7)*. Table 2-1 includes the fuels data corrected and revised by CEC staff with one exception: For the "other products" fuel category, which accounts generally for only ~1% of refinery energy and emissions, CEC staff suspected an as-yet unresolved error in the 2006–2009 data reported *(7)*. Those suspect data were replaced for these years (2006–2009) in Table 2-1 with the 1999–2005 average of "other" fuels reported for California.

Although impacts of all U.S. refinery hydrogen demand required estimation *(1)*, for California refineries the CEC data included energy consumed by refinery-owned hydrogen production *(7)*. The method used for U.S. refinery hydrogen was applied only to California refinery hydrogen purchased from third-party plants, and broken out as hydrogen purchased by California refineries ("H_2 purch.") or "third-party H_2 prod." in Table 2-1. This application of 90% capacity utilization, energy and emission factors for modern-design natural gas fed steam reforming *(1)* was conservative for California refineries given the evidence that they are generally hydrogen-limited *(9)* and the known use of naphtha steam reforming by some of them *(6)*. Independent emissions reports by third-party plants *(2)* supplying hydrogen to California refineries showed good agreement within 2–3%. Calculations for this third-party refinery hydrogen supply data check are shown in Table 2-2. Note that although these emissions are clearly related to steam reforming's great hydrocarbon fuel and feedstock consumption and high operating temperatures (~1500 ºF) *(9)*, most of the CO_2 emitted by this process forms in its shift reaction rather than as a direct product of combustion.

Products yield was calculated as defined by the U.S. Energy Information Administration (EIA) from California refinery input and output data reported by the CEC *(10, 11)*. Reporting inconsistencies for kerosene subcategories in 2009 that were identified during project data gathering were confirmed and corrected by CEC staff *(11)*. The kerosene and kerosene jet fuel yields for 2009 in Table 2-1 reflect those corrections. Utilization of operable refinery capacity for California was calculated as defined by EIA from the feed volume *(5)* and atmospheric distillation capacity *(6)* data in Table 2-1. Annual average refinery capacity utilization 2004–2009 ranged 83–95%. Process-level capacity utilization was not otherwise reported, indicating a processing data limitation.

California refinery energy consumption and CO_2 emissions were calculated from fuels consumed and the same fuel-specific energy and emission factors used for the U.S. *(1)* except for the emission factor for electricity purchased from the grid. The U.S grid factor (187.78 kg/GJ) was replaced by the California factor (97.22 kg/GJ) to reflect the greater share of hydropower in the California grid purchases by these refiners. Emission factors applied to combustion of fuels, including both of these grid factors, were developed, documented and used by EIA for international reporting of U.S. emissions *(1, 12, 13).*

Table 2-1 shows emissions by fuel energy (kg/GJ) and crude volume processed (kg/m^3). These emissions for California refineries (354–401 kg/m^3, 2004–2009), span previously reported S.F. Bay Area emissions (360 kg/m^3, 2008), which exceed reported average U.S. refinery emissions (277–315 kg/m^3, various years) for reasons that could be explained primarily by differences in crude feed quality *(1).* These fuels-based emissions, however, may also exceed the average from California refineries' total from Mandatory GHG Reporting Rule (MRR) reports (351–354 kg/m^3 with purchased H_2, 2008–2009) *(2).* It was not possible to account for that apparent discrepancy because data and calculation details for the MRR-reported emissions are kept secret from the public by ARB policy. The more transparently supported fuels consumption-based emissions estimates were used in quantitative analysis of average California refinery emissions for these reasons.

Average California refinery crude feed density and sulfur content was not previously reported *(1).* EIA reported these data for U.S. PADDs and some other states but not for California *(14).* California Petroleum Industry Information Act forms M13, M18 and A04 do not require these data to be reported. The ARB responded to a formal request by confirming that its staff could find no records related to these data *(15).* These data were reported for the foreign crude streams processed at each facility monthly *(14).* They were also reported for the Trans-Alaska pipeline stream from the Alaskan North Slope *(16),* but not for the average California-produced crude stream refined.

Because California-produced crude was not refined in appreciable amounts outside California *(17–20),* the quality of the California-produced stream refined statewide could be estimated based on that of total California production. The density and sulfur content of California crude feeds shown in Table 2-1 was calculated from these annual estimates for California-produced crude and the other crude streams refined in California by the standard weighted averaging method that is summarized in Table 2-3.

Public databases reported density and sulfur content data for most of the oil streams produced in California *(16, 21–24).* Annual production volumes *(25)* were matched to the average of these reported density and sulfur data by field, and where data were reported, by area, formation, pool or zone. The matched data are shown in Table 2-4. Some 480–550 areas, pools, formations or zones produced crude among California oil fields annually 2004–2009; more than 99% of that total volume was matched to density measurements and 94–96% was matched to sulfur, 2004–2009. In light of the knowledge that the specific geologic conditions containing an oil deposit constrain its quality, this measured coverage and large number of component streams (Table 2-4) provide support for the California-produced crude quality estimates shown in Table 2-3. However, the quality of crude produced from the same formation, zone and even well can vary to some extent over time, and individual refineries run crude of non-average quality. Reporting domestic refinery inputs in the way foreign inputs are reported would provide substantially better quality data for future analysis, especially facility-level analysis.

California facility-level data. Process capacities were reported in barrels per calendar day for each major fuels refinery and some of the smaller plants targeting other products in California, by *Oil & Gas Journal (6).* These data are presented in Table 2-5. Capacity data were found to be aggregated among facilities in three cases. Two of these paired facilities were located near each other in Wilmington and Carson. In those cases the aggregated data are reported in Table 2-5.

In the third case, facilities reporting aggregated capacities were too distant (~250 miles) for integration of process energy flows, such as shared hydrogen and steam. In addition, these facilities had reported capacities separately to EIA *(14)* and had reported emissions separately to ARB *(2).* Capacities of these two facilities, the ConocoPhillips Rodeo and Santa Maria refineries, were disaggregated by process-level comparisons between the *Oil & Gas Journal (6)* and EIA-reported data *(14)* to obtain capacities for each refinery in barrels/calendar day. The EIA data were not substituted directly because EIA reported capacities for most processes in barrels per stream day, which in general would provide less accurate indications of actual operation. Historic effluent discharge permits files for the Rodeo refinery provided a check on, and compared to, the disaggregated results.

Facilities were ranked by crude capacity (atmospheric crude distillation capacity) in Table 2-5 to facilitate visual inspection of the data. The larger facilities from the top through most of the vertical span of the table are California's fuel refiners: smaller facilities at the bottom of the table largely target different products or intermediates. Hydrotreating of gas oil, residua and oils to be fed into catalytic cracking units is tabulated separately from product hydrotreating to reflect a distinction among refinery processes perhaps first articulated by *Speight (29).* The first six processes shown in the table[1] are the primary processes acting on crude and its denser gas oil and residual oil components; product hydrotreating and the following half-dozen processes act on the unfinished products from those primary or "crude stream" processes *(29, 1).* Primary processing capacity was concentrated among the large fuels refineries in California.

Emission intensities of individual California fuels refineries were estimated by adding excluded emissions associated with hydrogen to refinery emissions reported under California's Mandatory GHG Emissions Reporting Rule (MRR), and comparing mass emitted against the facility's atmospheric distillation capacity (Table 2-5). This was necessary because facility-level fuel consumption, crude feed volume, and products yield data were not reported, and MRR reporting excluded much of the emissions from making hydrogen used by refineries from refinery emission reports.

[1] Atmospheric distillation, vacuum distillation, coking and thermal cracking, catalytic cracking, hydrocracking, and hydrotreating of gas oil, residua and catalytic cracking unit feeds.

Refiners did not report emissions from hydrogen production they relied upon through purchase agreements with nearby third-party producers under MRR; those emissions were reported separately by the third-party hydrogen plants *(2)*. Refiners did, however, report the third party hydrogen capacity asset they had secured to *Oil & Gas Journal (6)*. Those reported capacities compare reasonably well to emissions from the third-party plants reported in 2008 and 2009 under the MRR (Table 2-2). During this period the facilities reporting third-party hydrogen supply and their third-party suppliers were co-located: in the northeastern S.F. Bay Area; and in a stretch of the Los Angeles Area from El Segundo to Wilmington in *(2, 6)*. Third-party hydrogen emissions were assigned to refiners in proportion to their reported reliance on that hydrogen in each region. The calculation is shown with estimated facility emission intensity results in Table 2-6.

Average California refinery capacity utilization rates and MRR-reported emissions approaching but less than 100% of reported capacity and fuels emissions implied both the potential for underestimation of facility-level emissions intensities for some refineries, and constraints on the magnitude of that error for the facility data set as a whole. Table 2-6 results were accepted, conditioned on this uncertainty, to account for facility-level variability that could otherwise be obscured by focus on statewide averages alone, and because better facility estimates were unavailable due to limitations in reported data.

Crude feed quality data reported at the facility level were sparse at best. Although EIA reported the density and sulfur content of all foreign-sourced crude refined by each facility *(14),* these data were not reported for domestically produced crude inputs to facilities. Foreign crude volumes refined *(14)* remained significantly smaller than atmospheric distillation capacities (Table 2-5) for the major California fuels refineries 2004–2009, indicating that these facilities processed Californian and/or Alaskan crude as a significant or substantial portion of their feeds. Nonreporting of crude feed quality was thus a major limitation in the data. This lack of domestic crude feed quality reporting at refineries contrasted with the public reporting of density and sulfur measurements for nearly all of the crude streams refined in California (tables 2-3, 2-4) *before* the oil passed through the refinery gate.

Site-specific supply logistics allowed crude streams of known quality to be traced to S.F. Bay Area refineries by volume. Bay Area refineries received crude from well reported foreign sources *(14),* adequately documented Alaska North Slope (ANS) crude blends *(16)* delivered by ship from the TAPs pipeline terminus, and via a pipeline carrying a blend of the crude oils produced in California's San Joaquin Valley *(1, 5, 19, 20, 26)*. Recently published work apportioned those crude supply streams among facilities to derive crude feed density and sulfur estimates that supported an emission prediction which compared well to that independently reported for 2008 by Bay Area refineries *(1)*. This project built on that previous work.

San Joaquin Valley (SJV) crude supply data gathered for 2008 (Table 2-4) matched density and sulfur content measurements to 99.9% and 98.8%, respectively, of the total crude volume produced by 489 production streams in the SJV. These data were used to update the weighted average density and sulfur content of the SJV pipeline stream. The same ANS data used for the California average, which was from in the TAPs pipeline terminus at Valdez *(16),* was applied to the Bay Area ANS stream as well. Weighted averages of the SJV, ANS and foreign streams were taken to estimate Bay Area refineries' crude feed quality. The calculations are shown in Table 2-7.

A crude feed mixing analysis was performed by the same method used to assess the adequacy of crude feed quality data in recently published work *(1)*. Gravity (density) and sulfur content are among the most widely used indicators for crude value, and are used to price crudes, largely because they are general predictors for other characteristics of oil that affect its processing for fuels production. Density and sulfur correlate roughly with distillation yield and with asphaltic, nitrogen, nickel and vanadium among well-mixed blends of crude oils from various locations and geologies *(1, 28, 29)*. California crude feeds 2004–2009 were found to be roughly as well mixed as those shown to be adequately mixed to support predictions of processing, energy, and emission effects among U.S. PADDs 1, 2, 3 and 5 *(1)* (Table 2-8). This supported the adequacy of the California crude feed density and sulfur data for purposes of the analysis targeted here.

Refinery capacity utilization, light liquids/other products ratios and fuel mix emission intensities were not available at the regional and facility levels because crude volume processed, products yield, and fuels consumption by refineries were not reported at the regional and facility levels, for California refineries. Previous work addressed this data limitation, as it applies to predictions based on available data, by assigning the most representative available average reported among U.S. PADDs, as in the Bay Area emissions prediction referenced above *(1)*. The California average data gathered by the project allowed this proxy to be refined to some extent by applying the 2008 California average data to the S.F. Bay Area region. Facility-level analysis for Bay Area refineries conservatively assumed the full variability observed among all regions and years.

<u>Data adequacy overview</u>. For California refineries as a group, the quality of data that could be found from verifiable public reports was adequate but poorly accessible. The errors found and addressed as disclosed above were judged to reflect the intensity of data validation effort rather than a departure from the typical—and perhaps inevitable—error rate for data sets of this kind. At the facility level, however, data quality was poor: Feed volume, fuels usage, products yield and emissions verification data as well as crude feed density and sulfur content for most refineries were not reported. The need for attention to refinery crude feed quality reporting and documentation beyond this project, perhaps obvious from the foregoing, appears urgent. This assessment applies to publicly reported data for the parameters identified above: confidential, proprietary, or otherwise secret data are not publicly verifiable and were not used.

Validation that the data adequately describe refinery emissions performance across regions accounted for the limited quantity of California data that could be gathered and the potential for nonlinear relationships among causal drivers of emissions. PADD 5 data were excluded for years when California data were included in the comparison mode of regression analyses because California is part of PADD 5. An attempt to balance observation counts among regions by subsampling the data led to a relatively small analysis sample (N = 24). Results from that too-small sample, reported for transparency only (Table 2-9), were discarded and were not used in the analysis. Instead, California (2004–2009) and PADD 5 (1999–2003) data were resampled to balance data counts among regions without excluding any PADDs 1–3 data (1999–2008) from the sample analyzed (N = 52). Analysis was by nonparametric regression to account for nonlinear relationships among causal factors. Refinery emission intensity, energy intensity, crude feed density and sulfur, fuel mix emission intensity, light liquids/other products ratio, primary processing capacity, and capacity utilization were analyzed in the comparison mode of the model. Residuals from these analyses appeared normal (Shapiro-Wilk; Anderson-Darling; Lilliefors; Jarque-Bera tests, α 0.05). Results supported consistent relationships among causal factors across regions. Crude quality and products could explain 97% of variability in energy intensity and 96% of variability in emissions, and observed and predicted values differed by ≤ 4% for California refineries and ≤ 9% for all refining regions in all cases. Crude quality alone could explain 92% of variability in emissions, and observed and predicted values differed by ≤ 6% for California and ≤ 11% for all regions in all cases. Data inputs and results are shown in Table 2-10.

Emission measurement is central to every emissions performance benchmark assessed herein and therefore warrants explicit attention. Briefly: Applying emission factors developed from measurements taken elsewhere to a new, unmeasured source requires many assumptions. Direct sampling and analysis of samples taken at the points of emission—in cases where it was done well—has demonstrated that errors related to those assumptions render the "emission factor" approach inaccurate or unreliable for pollutants that vary dramatically with combustion conditions. Best practices for assessing such emissions apply emission factors to known activity rates, such as the types and amounts of fuels burned, only where direct sampling measurements are not available or suspect. Direct measurement of emissions is the best practice and should be required and reported.

The assumption of constant combustion conditions is prone to relatively smaller errors, however, when applied to combustion products that dominate the emission stream and vary proportionately little with typical combustion variability, such as CO_2. Importantly, CO_2 predominates among greenhouse gases in refinery emissions, accounting for more than 98% of emitted CO_2e in 100-year horizon assessments *(1, 2)*. Thus, the application of appropriate emission factors to accurate fuels data is relatively, and perhaps uniquely, accurate and reliable for the pollutant of main interest in the present analysis. This is fortunate, since comprehensive direct measurements of refinery emissions have not yet been required or reported.

Documentation of analysis methods

<u>Support for causal relationships of variables analyzed</u>. The physical chemistry of petroleum fuels refining presents an inescapable equation: Making light, hydrogen-rich fuels from crude that is more carbon-dense and hydrogen-poor requires more energy *(3, 4, 9, 28, 30–35)*. Carbon must be rejected, hydrogen must be added, or both, and burning fuel for that energy emits more CO_2 and other combustion products. Carbon rejection and aggressive hydrogen addition—thermal cracking, coking, catalytic cracking, hydrocracking, and hydrotreating of gas oil and residua—are the core of oil refining in the U.S. and California (tables 2-1, 2-5). As these processes, the vacuum distillation capacity that helps to feed gas oil to them, and the fossil energy-fed production of

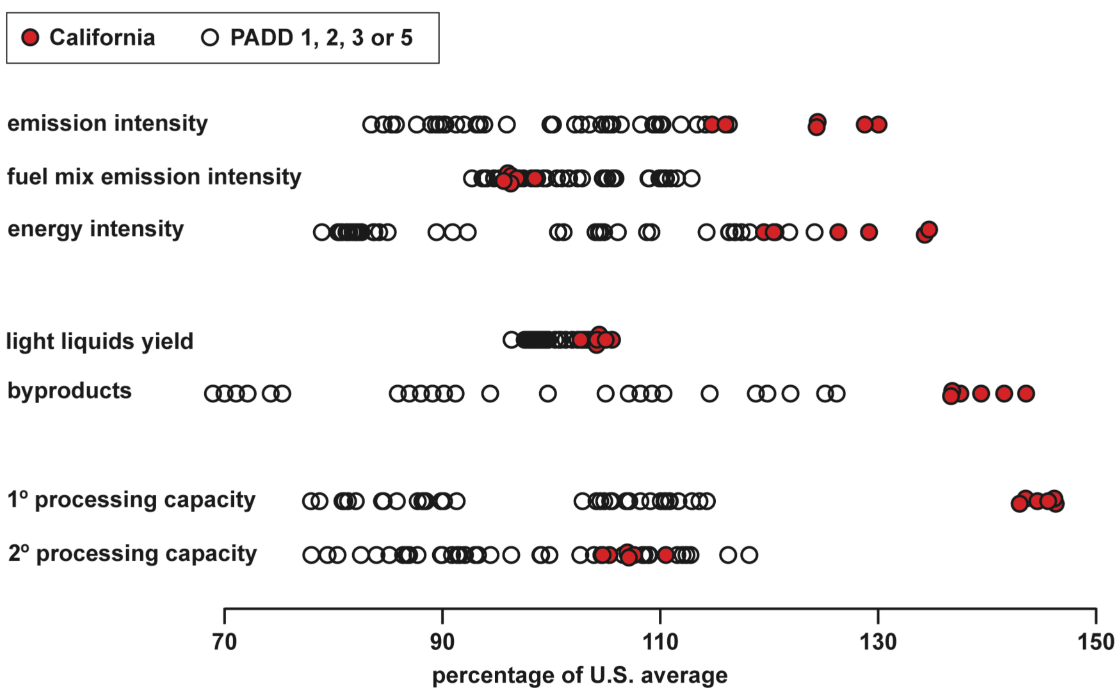
hydrogen feeding them, expand to a larger share of the lower-quality crude barrel, energy and emission intensities grow. Effects of these causal relationships have been observed and measured across the U.S. refining industry *(1)*.

Annual average statewide California refinery performance followed and extended the continuum of U.S. regional performance and showed consistent responses with the U.S. data for causally related factors, but represented the extreme of high emission intensity (Figure 1-1). California emissions and energy intensities were high while fuel mix emissions intensity was not, indicating that burning more fuel, rather than burning dirtier fuel, caused the high California emissions.

California refineries' capacity for "primary" processing acting on the crude stream and its denser components *(29),* and their by-production of coke and fuel gas created by that processing, were also high, while their light liquids (gasoline, distillate and jet fuel) yield and "secondary" products finishing capacity were within or near the national range.

These relationships among performance factors are consistent with those observed among U.S. refining regions, where lower quality crude feeds boosted emissions by increasing refinery energy intensity *(1)*.

Figure 1-1. Refinery performance data for California 2004–2009, and other U.S. regions 1999–2008

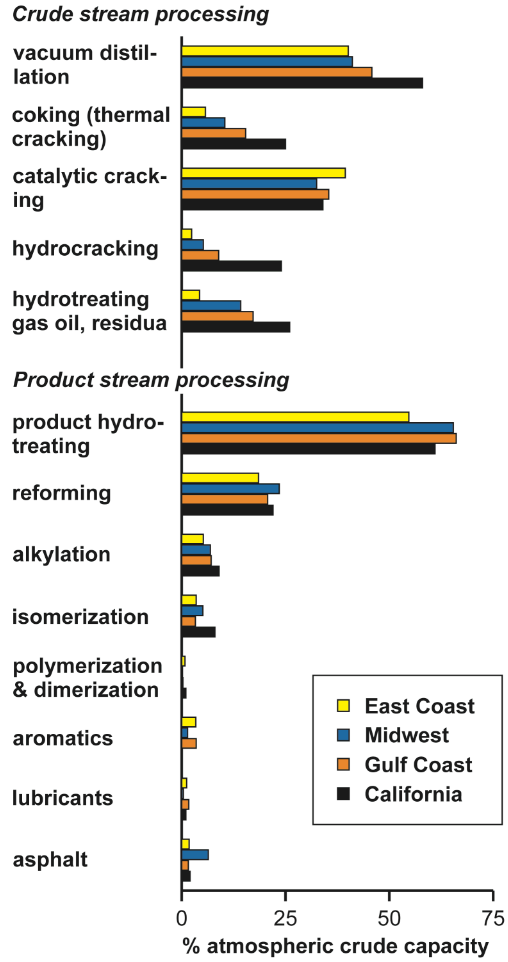


Annual observations. Data from Table 2-1.
Emission intensity: CO_2 emitted/barrel crude refined. **Fuel mix emission intensity:** CO_2 emitted/Btu fuel energy burned. **Energy intensity:** fuel energy burned /barrel crude refined. **Light liquids:** gasoline, distillate and jet kerosene fuel. **Byproducts:** petroleum coke and fuel gas.
Primary processing: processes acting on crude, gas oil and residua ("crude stream" processing).
Secondary processing: processes acting on product streams produced from crude by primary processing.

The extreme-high average refinery emissions intensity cannot be explained by treating product streams harder to make California-compliant gasoline and distillate diesel alone. California product hydrotreating and reforming capacities are similar to those elsewhere (Figure 1-2). Instead, greater crude stream processing capacity—driven by greater vacuum distillation, thermal coking hydrocracking, and hydrotreating of gas oil—distinguishes California from other U.S. refining regions, in terms process capacity.

Hydrocracking and hydrotreating of gas oil and residua uses much more H_2 per barrel processed than does product hydrotreating *(38)*. Combined capacity for hydrocracking and hydrotreating gas oil that is almost as large as product hydrotreating capacity (Figure 1-2) would thus use much more hydrogen than product hydrotreating in California (Fig. 1-3). Across U.S. PADDs refiners' hydrogen use increases with crude density *(1, 3),* and with hydrocracking rather than product hydrotreating *(1).* This is important because hydrogen is among the major sources of CO_2 emissions from oil refining *(36, 37, 4).*

Figure 1-2. Refinery process capacities at equivalent atmospheric crude distillation capacity, averages for U.S. PADDs 1–3 (2003–2008) and California (2004–2009)



Data from Table 2-1.

Figure 1-3. Hydrogen use for hydroprocessing various feeds, California refineries, 1995 and 2007

MMscf/day
Based on 100% capacity

Figure adapted from CBE (2008) analysis citing references 6 and 38 herein.

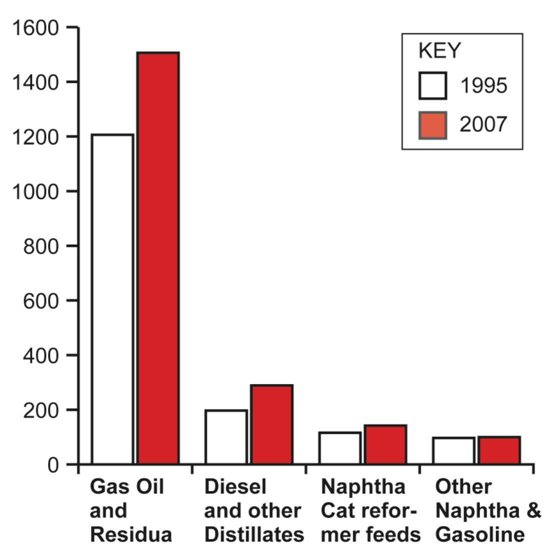
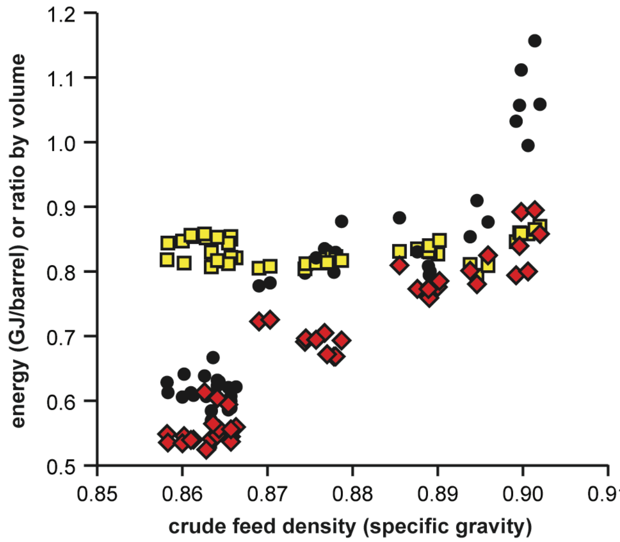


Figure 1-4. Refinery fuels production, conversion capacity and energy intensity with increasing crude density: annual observations from U.S. PADDs 1, 2, 3 and 5 (1999–2008) and California (2004–2009)

- ◻ refinery light liquids yield on crude, ratio by volume
- ● conversion capacity/light liquids produced, ratio by volume
- ◆ refinery energy consumed/vol. crude refined, GJ/barrel

Light liquids: gasoline, distillate, kerosene jet fuel and naphtha.

Data from Table 2-1



Total liquids production stays relatively flat across U.S. regions and California while refinery energy intensity rises steadily with crude feed density, and conversion capacity (thermal, catalytic and hydrocracking)—rising more steeply—becomes decoupled from energy intensity in California. (Figure 1-4). California conversion capacity exceeds California's total light liquid fuels production, implying more intensive serial processing or reprocessing of feeds in California conversion units. The pattern suggests California refineries may be squeezing out more gasoline, distillate, and jet fuel from lower quality crude in ways that may alter firing rates and emissions per unit processing capacity.

Poor refinery emissions performance on average in California 2004–2009, and the additional observation that this extreme-high refinery emissions intensity apparently went unnoticed until performance was compared with other U.S. regions, support benchmarking against national refinery performance.

Primary processing capacity and conversion capacity, which are types of refinery "complexity" metrics, are related to refinery crude feed variability, and expanded conversion capacity is probably helping to maintain California fuels yield despite declining crude feed quality. However, the decoupling of conversion capacity from energy intensity observed in California 2004–2008 indicates that refinery complexity did not measure emissions performance or that another factor confounded its measurement.

The types and amounts of products manufactured can be expected to affect emissions, but the variability observed among products was divergent: light liquids yield appeared to be maintained while byproducts yield increased with declining crude feed quality. This indicates that a products metric excluding some products could be unreliable, and further suggests the need to address crude quality as part of this metric.

Supporting discussion of causal relationships of crude quality is continued directly below.

<u>Crude feed quality metric</u>. Physical chemistry, petroleum engineering, and observational evidence consistently supports an energy intensity-crude feed quality causal pathway for observed differences in refinery emission intensity. This evidence supports the need for the emissions benchmark to address feedstock quality.

Recently published work *(1)* shows that crude feed density and sulfur predict energy and CO_2 emission intensities for U.S. and Bay Area refinery groups with diverse feeds, and provides a specific measurement and prediction model and robust data set spanning 97% of the U.S. refining industry and ten years. Assessment of the crude feed quality metric for California refineries adopted that metric and data set whole and without change and used them together with the newly-gathered California refinery data detailed and presented in this report.

U.S. data from PADDs 1, 2, 3 and 5, 1999–2008 *(1)* were used as the basis for prediction. California statewide average and Bay Area refineries data were analyzed in the prediction mode of PLS on the U.S. data. In the prediction mode of the model, emission intensity is predicted in two steps. First, refinery energy intensity (GJ/m^3 crude) is predicted by four explanatory variables:

- The density *(d)* of the crude feed in mass/volume crude;
- The sulfur content *(S)* of the crude feed in mass/volume crude;
- The refinery capacity utilization rate, as defined by U.S. EIA, in percent; and
- The light liquids/other products ratio, which is defined as the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products.

This gives the predicted refinery energy intensity in GJ/m^3. Second the prediction is multiplied with the measured fuel mix emission intensity (see Table 2-1 and/or reference 1 for fuel measurement detail), as CO_2 mass emitted/fuel energy (kg/GJ). Thus;

$$GJ/m^3 \bullet kg/GJ = kg/m^3$$

predicts refinery CO_2 emissions intensity in kg/m^3 crude refined. Refinery CO_2 emissions are essentially the same as refinery CO_2e emissions *(1, 2)* as discussed in the data section.

In practical terms, the energy and emissions intensity results make this an emissions performance *and* energy efficiency metric. That is important given that energy intensity is the dominant proximate cause of refinery emission intensity differences among U.S. *(1)* and California refineries on average. Finally, product slate effects on the relationships among crude feed quality and energy intensity are estimated directly through the inclusion of the products ratio as an explanatory variable. Thus, the metric also addresses products "output" yield.

Method development and validation is detailed in the original work *(1)*. All data used in this analysis of the metric are given in Table 2-1. Analysis input data are tabulated with the presentation of results below as well.

Equipment complexity metric. This option would attempt to use the size and variety of refinery process equipment capacities as a measurement or predictor for refinery emissions intensity. The concept for complexity most widely used by refiners is *equivalent capacity* (EQC): the ratio by volume of other process capacities to the capacity for atmospheric crude distillation. EQC is applied in different ways for different purposes. It is applied to the primary processing of crude, gas oil and residua as a way to measure a refinery's capacity for lower quality crude feeds *(1)*. In contrast, the Solomon indices are intended to be used, at least in part, for evaluating potential projects for their effects on margins and competitive position, according to Solomon Associates *(42)*.

Similarly, the Nelson Complexity Index applies weighting factors to the EQC of each process in a refinery as a way to calculate the value of a refinery or refinery capacity addition *(43)*. The Nelson Index predates the Solomon indices and remains in use as an industry standard for refinery complexity benchmarking by *Oil & Gas Journal (43)*.

An oil industry lobby group proposed a benchmark that would use an adjusted version of the Solomon Energy Intensity Index (EII) *(39)*. Air Resources Board (ARB) staff proposed that some type complexity metric should be considered, and stated that this metric might be based on the Solomon EII, although ARB acknowledged that Solomon EII data and methods are claimed proprietary and kept secret *(40, 41)*.

Because its data and methods are secret, the Solomon EII could not be assessed quantitatively. However, significant refinery capacity data are available for publicly verifiable analysis now (tables 2-1, 2-5). Initial assessment of these data, for example, identified the decoupling of conversion capacity from energy intensity observed in California (Figure 1-4), and raised questions about whether refinery complexity can measure emissions performance reliably. A range of publicly available complexity metrics was analyzed for this assessment.

Complexity was calculated for California and U.S. refineries as equivalent capacity applied to all refinery processing (refinery EQC), EQC applied to primary processing (primary processing EQC), and Nelson Complexity Index EQC (Nelson Index), using the California refinery capacity data in tables 2-1 and 2-5.

California refinery data were analyzed in the prediction mode of PLS or nonparametric models on U.S. data. Analysis was by nonparametric regression (LOWESS) for the Nelson Index and by PLS for the refinery EQC and primary processing EQC complexity metrics. Annual average California refinery data were analyzed for all three metrics. In addition, major refineries in the Los Angeles and Bay Area regions that collectively represent California fuels refining capacity were analyzed in the prediction mode of PLS on the U.S. data for the primary processing EQC. Finally, as an example of the potential for using process capacity in different ways to result in different capacity/energy intensity relationships, "adjusted" primary processing equivalent capacity, calculated by replacing observed gas oil/residua hydrotreating data for California with the lowest value observed (PADD 1, 2006–2008), was analyzed.

Product yield output metric: This option measures emissions against products yield (refinery products output). Air Resources Board (ARB) staff proposed emission-per-volume products as a benchmark option for consideration. This proposal would measure refinery emissions against the sum of "primary products" produced by California refineries: aviation gasoline, motor gasoline, distillate, kerosene jet fuel, renewable liquid fuels, and asphalt *(40, 41)*. Note that although this proposal includes "renewable liquid fuels," refineries report no production these fuels at this time (Table 2-1). ARB's proposal measures the sum of these products against emissions directly, without necessarily targeting energy efficiency, as is attempted by at least some of the concepts for complexity metrics.

The foregoing analysis (see discussion of figures 1-1, 1-4; crude feed quality metric) suggest that a products-based metric may be sensitive to the choice of which products to include or exclude, and that products and crude feed quality can be integrated into the refinery performance metric. Additionally, this metric may differ from the others assessed here and may warrant additional assessment discussed below.

Observed emissions were analyzed with the ARB primary products sum by nonparametric regression (LOWESS) and with the primary products "mix" by PLS. The "mix" analysis entered data for each fuel as PLS inputs instead of summing them to one input, which may provide additional information—and it excluded asphalt based on its difference from the light liquid fuels. Average California refinery data were analyzed in the prediction mode of the models run on the U.S. data. Facility-level analysis of this metric was not possible because facility-level yield data were not reported publicly. Estimated CO_2 emissions to produce gasoline, diesel, and kerosene (46.0, 50.8, and 30.5 kg/b respectively) from NETL *(32)* were applied to observed gasoline, distillate, and kerosene yields *(Table 2-1)* to derive "fuels emit" estimates for comparison with results.

Major plant capacity addition and thus refinery complexity is largely constrained by capital and permit requirements; and crude feed quality is constrained within fairly narrow limits by refinery configuration; the constraints supported focus on confirmed pathways of causality to support the variables analyzed. Relatively less "hard" evidence for causality was found for the variability, or stability, of product slates. This suggests products may change. That implies the need to assess the stability of this metric as a measurement that can be predicted by or related to other factors.

In part because of this consideration, and also because products were already integrated with crude quality as an explanatory *(x)* variable in the crude feed quality metric, this products metric was analyzed with crude quality as the dependent *(y)* variable in two forms. Emissions/volume total products, and emissions/volume light liquids (aviation gasoline, motor gasoline, jet kerosene, distillate, naphtha) were calculated for the California and PADDs averages each year. Each emission/volume product measurement was analyzed against the crude feed metric explanatory variables and California *x* data were analyzed in the prediction mode of the model on the U.S. data. Nonparametric regression was used for the emission/total products analysis; PLS was used for the emission/light liquids analysis.

Results

<u>Crude feed quality metric results</u>. Figure 1-5 shows results for energy intensity predicted by oil quality from this analysis. The *R*-squared value (0.90) and diagonal lines bounding the 95% confidence of prediction for observations indicate the power of prediction by this metric. Those results are derived from the U.S. refinery data, and were reported previously *(1)*.

Orange diamonds showing observations and predictions for California refineries annually 2004–2009 provide new information about the reliability of prediction by this metric. The energy intensity *(EI)* of California refineries falls within the prediction based on oil quality in 4 of 6 cases and falls within 2% of the confidence of prediction in all cases.

Table 1-1 shows data inputs, calculations, and results for CO_2 emissions as well as *EI* predicted by this metric. Predicted emissions are the product of *EI* predicted by crude feed quality in GJ/m^3 crude refined, and the emission intensity of the refinery fuel mix in kilograms CO_2 emitted per Gigajoule fuel energy (GJ/m^3 • kg/GJ = kg/m^3 crude refined). Results for emissions are similar to those for *EI* because the fuel mix did not change much in these years. Predictions for multi-plant emissions include the six statewide observations from 2004–2009 and S.F. Bay Area refinery emissions in 2008. The statewide/regional emissions fall within the confidence of prediction in 5 of 7 cases and fall within 2% of its confidence interval in all cases.

Figure 1-5 Refinery energy intensity *(EI)* predicted by crude feed density and sulfur

Prediction for California refineries on 1999–2008 data from U.S. refineries

R^2 0.90

Diagonal lines bound the 95% confidence of prediction for observations

Figure adapted from Figure 1 in *Env. Sci. Technol.* 44(24) 9584–9589; DOI 10.1021/es1019965; American Chemical Society

Data from Table 1-1

◆ **California annual average 2004–2009**

● **PADD 1, 2, 3 or 5 1999–2008**

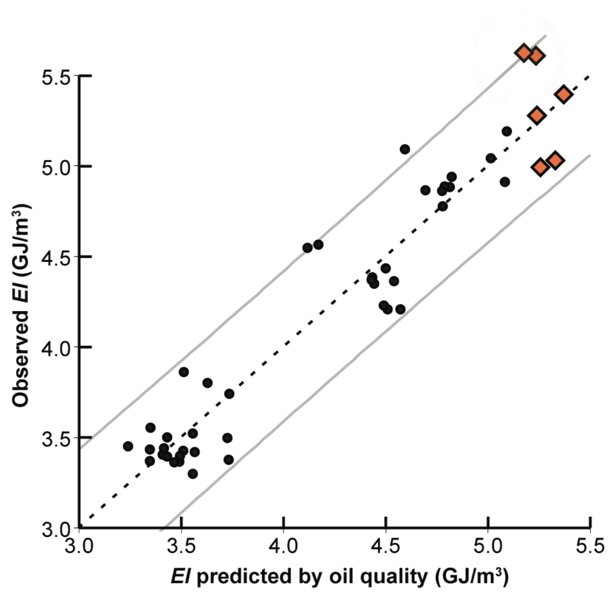


Table 1-1. Emissions predicted by crude feed quality

PADD	Year	*EI* (GJ/m^3)	density (kg/m^3)	sulfur (kg/m^3)	Cap. ut. (%)	Prod. ratio	*EI* pred. 95% confidence Lower	Central	Upper	Fuel mix (kg/GJ)	Emit pred. 95% confidence Lower	Central	Upper	Obs. CO_2 (kg/m^3)
1	1999	3.451	858.20	8.24	90.9	3.668	2.877	3.241	3.604	81.53	235	264	294	281
1	2000	3.430	860.18	8.00	91.7	3.489	2.987	3.349	3.711	80.34	240	269	298	276
1	2001	3.518	866.34	7.71	87.2	3.479	3.198	3.559	3.919	81.85	262	291	321	288
1	2002	3.426	865.71	7.45	88.9	3.605	3.152	3.511	3.870	81.08	256	285	314	278
1	2003	3.364	863.44	7.43	92.7	3.321	3.133	3.493	3.853	81.51	255	285	314	274
1	2004	3.416	865.44	7.79	90.4	3.397	3.209	3.568	3.927	81.46	261	291	320	278
1	2005	3.404	863.38	7.17	93.1	3.756	3.048	3.410	3.772	81.23	248	277	306	277
1	2006	3.440	864.12	7.17	86.7	3.522	3.054	3.417	3.780	80.40	246	275	304	277
1	2007	3.499	864.33	7.26	85.6	3.443	3.067	3.433	3.800	82.28	252	282	313	288
1	2008	3.551	863.65	7.08	80.8	3.400	2.972	3.352	3.733	83.26	247	279	311	296
2	1999	3.368	858.25	10.64	93.3	4.077	2.984	3.347	3.711	78.11	233	261	290	263
2	2000	3.361	860.03	11.35	94.2	4.132	3.104	3.468	3.832	77.56	241	269	297	261
2	2001	3.396	861.33	11.37	93.9	4.313	3.126	3.495	3.863	77.46	242	271	299	263
2	2002	3.393	861.02	11.28	90.0	4.345	3.068	3.432	3.796	77.90	239	267	296	264
2	2003	3.298	862.80	11.65	91.6	4.281	3.195	3.558	3.922	78.00	249	278	306	257
2	2004	3.376	865.65	11.86	93.6	4.167	3.369	3.733	4.098	77.25	260	288	317	261
2	2005	3.496	865.65	11.95	92.9	4.207	3.362	3.725	4.089	77.27	260	288	316	270
2	2006	3.738	865.44	11.60	92.4	3.907	3.380	3.738	4.095	75.84	256	283	311	284
2	2007	3.800	864.07	11.84	90.1	4.161	3.270	3.629	3.989	75.55	247	274	301	287
2	2008	3.858	862.59	11.73	88.4	4.333	3.154	3.515	3.875	74.97	236	263	291	289
3	1999	4.546	869.00	12.86	94.7	3.120	3.759	4.117	4.476	71.61	269	295	321	326
3	2000	4.563	870.29	12.97	93.9	3.120	3.813	4.172	4.531	71.87	274	300	326	328
3	2001	4.348	874.43	14.34	94.8	3.128	4.086	4.444	4.803	72.43	296	322	348	315
3	2002	4.434	876.70	14.47	91.5	3.251	4.140	4.499	4.859	72.71	301	327	353	322
3	2003	4.381	874.48	14.43	93.6	3.160	4.076	4.435	4.794	72.81	297	323	349	319
3	2004	4.204	877.79	14.40	94.1	3.228	4.213	4.572	4.930	73.43	309	336	362	309
3	2005	4.205	878.01	14.40	88.3	3.316	4.149	4.511	4.873	73.24	304	330	357	308
3	2006	4.367	875.67	14.36	88.7	3.176	4.067	4.433	4.798	74.15	302	329	356	324
3	2007	4.226	876.98	14.47	88.7	3.205	4.127	4.491	4.856	74.93	309	337	364	317
3	2008	4.361	878.66	14.94	83.6	3.229	4.165	4.540	4.915	74.48	310	338	366	325
5	1999	4.908	894.61	11.09	87.1	2.952	4.713	5.082	5.451	70.27	331	357	383	345
5	2000	5.189	895.85	10.84	87.5	3.160	4.725	5.092	5.460	69.09	326	352	377	358
5	2001	5.039	893.76	10.99	89.1	3.231	4.648	5.014	5.380	69.38	322	348	373	350
5	2002	4.881	889.99	10.86	90.0	3.460	4.450	4.814	5.178	69.15	308	333	358	338
5	2003	4.885	889.10	10.94	91.3	3.487	4.422	4.788	5.153	69.40	307	332	358	339
5	2004	4.861	888.87	11.20	90.4	3.551	4.410	4.775	5.140	69.89	308	334	359	340
5	2005	4.774	888.99	11.38	91.7	3.700	4.409	4.780	5.151	69.88	308	334	360	334
5	2006	4.862	887.65	10.92	90.5	3.615	4.331	4.695	5.060	69.32	300	325	351	337
5	2007	5.091	885.54	11.07	87.6	3.551	4.235	4.594	4.953	69.12	293	318	342	352
5	2008	4.939	890.16	12.11	88.1	3.803	4.456	4.824	5.191	68.39	305	330	355	338
Predictions for California refineries														
California average, 2004			899.23	11.46	93.0	3.633	4.881	5.256	5.632	70.82	346	372	399	354
California average, 2005			900.56	11.82	95.0	3.801	4.937	5.329	5.721	71.06	351	379	407	358
California average, 2006			899.56	11.73	91.5	3.845	4.861	5.239	5.616	72.65	353	381	408	384
California average, 2007			899.84	11.89	88.3	3.814	4.866	5.234	5.603	71.43	348	374	400	401
California average, 2008			902.00	12.85	91.0	4.087	4.980	5.370	5.759	71.02	354	381	409	383
California average, 2009			901.38	11.70	82.9	4.045	4.837	5.200	5.564	70.54	341	367	392	397
Bay Area '08 avg. assm.			895.72	10.95	91.0	4.087	4.602	4.980	5.357	71.02	327	354	380	376
Martinez '08 avg. assm.			932.08	9.86	91.0	4.087	6.076	6.504	6.931	71.02	432	462	492	497
Martinez '08 high case			932.08	9.86	95.0	3.160	6.276	6.690	7.105	83.26	523	557	592	497
Martinez '08 low case			932.08	9.86	80.8	4.333	5.974	6.365	6.756	68.39	409	435	462	497
Rodeo '08 avg. assm.			918.45	8.22	91.0	4.087	5.410	5.808	6.207	71.02	384	412	441	428
Rodeo '08 high case			918.45	8.22	95.0	3.160	5.609	5.995	6.381	83.26	467	499	531	428
Rodeo '08 low case			918.45	8.22	80.8	4.333	5.300	5.670	6.039	68.39	362	388	413	428
Benicia '08 avg. assm.			903.15	10.39	91.0	4.087	4.886	5.271	5.655	71.02	347	374	402	345
Benicia '08 high case			903.15	10.39	95.0	3.160	5.084	5.457	5.831	83.26	423	454	486	345
Benicia '08 low case			903.15	10.39	80.8	4.333	4.771	5.132	5.493	68.39	326	351	376	345
Richmond '08 avg. assm.			858.28	13.61	91.0	4.087	3.143	3.504	3.866	71.02	223	249	275	340
Richmond '08 high case			858.28	13.61	95.0	3.160	3.335	3.691	4.046	83.26	278	307	337	340
Richmond '08 low case			858.28	13.61	80.8	4.333	3.004	3.365	3.727	68.39	205	230	255	340
Avon '08 avg. assm.			899.24	9.80	91.0	4.087	4.685	5.064	5.443	71.02	333	360	387	313
Avon '08 high case			899.24	9.80	95.0	3.160	4.883	5.251	5.619	83.26	407	437	468	313
Avon '08 low case			899.24	9.80	80.8	4.333	4.567	4.925	5.284	68.39	312	337	361	313

Key to S.F. Bay Area prediction cases. Case inputs:
Average conditions assumption: avg 2008 California Cap. utiliztion, products ratio and fuel mix
Low case assumptions: D-1 2008 Cap Ut; D-2 2008 Pratio; D-5 2008 fuels mix
High case assumptions: CA-2005 Cap Ut; D-3 2003 Pratio; D-1 2008 fuels mix

Data from Table 2-1.

Individual refinery predictions in Table 1-1 compare to emissions reported for 2008 under California's Mandatory Greenhouse Gases Reporting Rule (see Table 2-6). Refinery-level capacity utilization, products ratio, and fuel mix data were not reported. Average 2008 California values as well as the lowest and highest values observed for California or any PADD were used for these inputs to create low, average, and high predictions. The low–high range of these predictions shown in Table 1-1 thus represents uncertainty in prediction caused solely by the unreported data. Accounting for that uncertainty, emissions reported by individual Bay Area refiners fall within the prediction in 4 of 5 cases. Emissions reported by the Chevron Richmond refinery in 2008 exceeded the upper bound of the high prediction by about 1% and exceeded the average prediction by 24%. This was expected, because inefficiency was reported by this refinery.[2]

Together with the results from previous analysis of the U.S. refinery data *(1),* and the causal relationships analysis above, these results provide evidence that crude quality is a relatively accurate and reliable predictor of California refinery emissions.

For the statewide refinery comparisons over the six annual observations, the central prediction for average California refinery emissions by this crude quality metric is within 1% of observed emissions.

[2] Its hydrogen plant, reformers and steam boilers were reported to be outdated and inefficient. *Chevron Renewal Project Application;* ChevronTexaco 17 June 2005 submission to Air Quality Mgmt. District.

Figure 1-6. Emission intensity predicted by Nelson Complexity

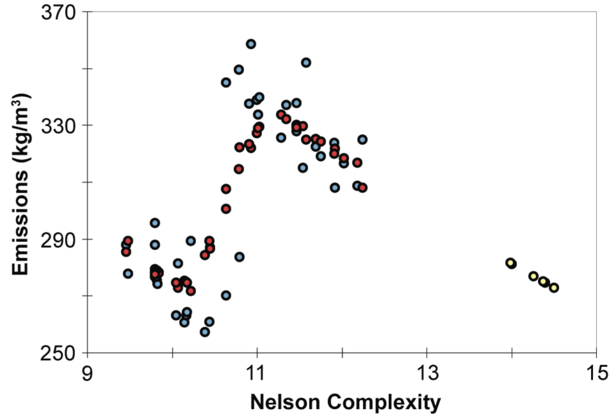
Prediction for California refineries on 1999–2008 data from U.S. refineries by nonparametric regression

R^2 0.66

For California refineries, observed emissions exceed emissions predicted by complexity in this analysis by 26–46%

Data from Table 2-1
Nelson's complexity factors (1998)

- Observations for PADD 1, 2, 3 or 5
- Predictions for PADD 1, 2, 3 or 5
- Predictions for California 2004–2009



Equipment complexity metric results. Figure 1-6 shows results for refinery emissions predicted by Nelson Complexity. The relatively low *R*-squared value (0.66) indicates relatively poor power of prediction for emissions. The undulating prediction curve (red and yellow circles in the chart), which trends downward at high complexity and predicts average emissions lower than those from most other refineries in California, indicates prediction error. Observed average California refinery emissions exceed those predicted by Nelson complexity substantially in all years (2004–2009), exceeding the complexity predictions by 26–46%.

In this analysis (Figure 1-6), complexity includes secondary processing that acts on product streams along with primary processing that acts on crude, gas oil and residua, because the Nelson Index values both classes of processing. However, the increasing energy intensity that drives refinery emissions is not significantly related to increasing capacity for major products processes and has mixed relationships to other products processes *(1),* and the conversion capacity excess observed (Figure 1-4) did not reflect observed California energy intensity. The poor power and reliability of Nelson Complexity for predicting emissions shown in Figure 1-6 is thus consistent with the decoupling of conversion capacity and energy intensity observed in the California data. However, it may also reflect a bias due to the *Nelson's* weighting factors being developed to measure the value of process capacity instead of measuring refinery emissions.

Energy intensities predicted by refinery equivalent capacity, and by primary processing equivalent capacity, are shown in figures 1-7 and 1-8, respectively. For complexity as refinery EQC, the very low *R*-squared value (0.35) and very wide confidence interval indicates very poor power of prediction. Observed average California refinery *EI* is consistently lower than predicted by refinery EQC. These emissions fall within the wide confidence of prediction by refinery EQC, but that only reflects its poor power. Average California refinery emissions intensity could increase by 21–30% and still be within the confidence of prediction by this metric (see Table 1-2).

For complexity as primary processing EQC, the relatively good power of *EI* prediction (*R*-squared 0.92; Figure 1-8) was expected, because increasing primary processing is strongly associated with worsening crude feed quality—the major driver of *EI*.

Figure 1-7. Energy intensity *(EI)* predicted by refinery equivalent capacity (EQC)

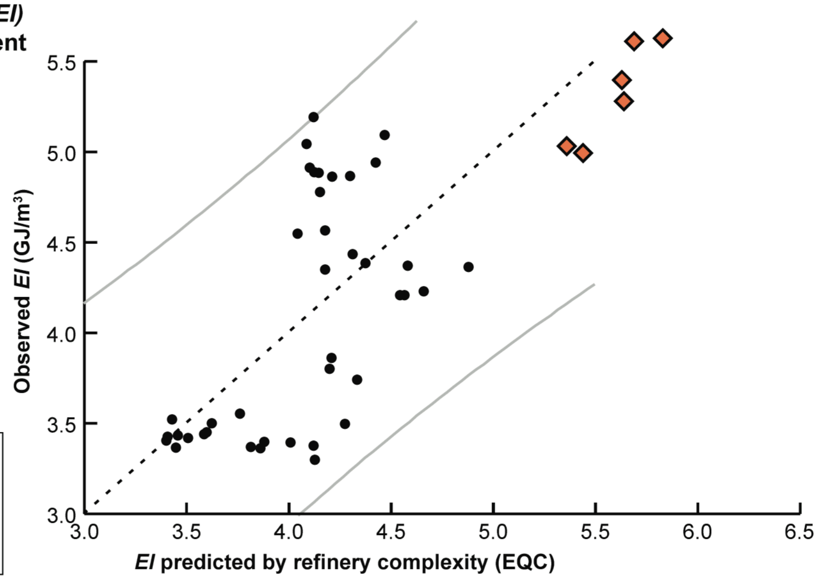
Prediction for Calif. on 1999–2008 data from U.S.

R^2 0.35

Diagonal lines bound 95% confidence of prediction for observations

Data from tables 1-2 and 2-1

- ◆ **California annual average 2004–2009**
- ● **PADD 1, 2, 3 or 5 1999–2008**



However, Figure 1-8 reveals a large shift to the right in the *EI* predicted for California observations. Average observed California emissions are exceeded by the lower bound of prediction by 9–15% in 6 of 6 years, and are 14% below the central prediction as a six-year average (Table 1-3). This demonstrates the reliability problem with complexity metrics that was suggested by the decoupling of conversion capacity from energy intensity observed in California. Complexity is not measuring energy intensity or emissions. It is erroneously equating capacity to energy intensity. In California, where conversion, hydrocracking, and gas oil hydrotreating capacities are high, predictions of energy and emission intensities based on complexity are biased high.

Figure 1-8. Energy intensity *(EI)* predicted by primary processing equivalent capacity

Prediction for Calif. on 1999–2008 data from U.S.

R^2 0.92

Diagonal lines bound 95% confidence of prediction for observations

Data from tables 1-3 & 2-1

- ◆ **California annual average 2004–2009**
- ● **PADD 1, 2, 3 or 5 1999–2008**

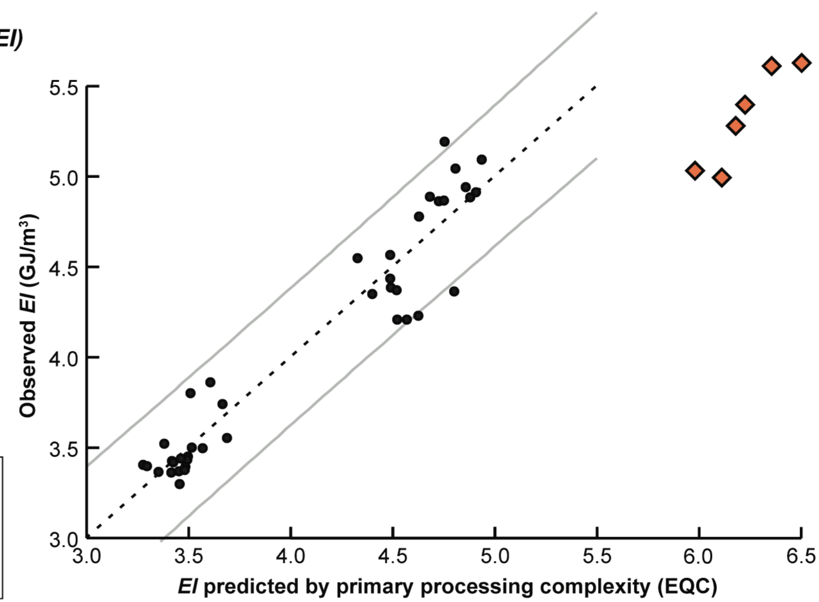


Table 1-2. Emissions predicted by refinery equivalent capacity (EQC)

PADD	Year	*EI* (GJ/m^3)	Refinery EQC	Cap. ut. (%)	*EI* pred. 95% confidence Lower	Central	Upper	Fuel mix (kg/GJ)	Emit pred. 95% confidence Lower	Central	Upper	Obs. CO_2 (kg/m^3)
1	1999	3.451	1.861	90.9	2.69	3.60	4.51	81.53	219	294	368	281
1	2000	3.430	1.811	91.7	2.54	3.46	4.38	80.34	204	278	352	276
1	2001	3.518	1.744	87.2	2.51	3.43	4.36	81.85	205	281	357	288
1	2002	3.426	1.755	88.9	2.48	3.41	4.34	81.08	201	276	352	278
1	2003	3.364	1.819	92.7	2.53	3.45	4.38	81.51	206	281	357	274
1	2004	3.416	1.817	90.4	2.59	3.51	4.43	81.46	211	286	361	278
1	2005	3.404	1.804	93.1	2.47	3.40	4.33	81.23	201	276	352	277
1	2006	3.440	1.804	86.7	2.68	3.59	4.50	80.40	215	289	362	277
1	2007	3.499	1.807	85.6	2.72	3.63	4.54	82.28	223	298	373	288
1	2008	3.551	1.807	80.8	2.86	3.77	4.67	83.26	238	313	389	296
2	1999	3.368	1.983	93.3	2.92	3.82	4.72	78.11	228	298	369	263
2	2000	3.361	2.014	94.2	2.97	3.87	4.76	77.56	230	300	370	261
2	2001	3.396	2.017	93.9	2.98	3.88	4.78	77.46	231	301	370	263
2	2002	3.393	2.025	90.0	3.12	4.01	4.91	77.90	243	313	382	264
2	2003	3.298	2.095	91.6	3.23	4.13	5.03	78.00	252	322	392	257
2	2004	3.376	2.117	93.6	3.23	4.13	5.02	77.25	249	319	388	261
2	2005	3.496	2.174	92.9	3.38	4.28	5.18	77.27	261	331	400	270
2	2006	3.738	2.192	92.4	3.44	4.34	5.24	75.84	261	329	397	284
2	2007	3.800	2.106	90.1	3.30	4.20	5.10	75.55	250	317	385	287
2	2008	3.858	2.090	88.4	3.32	4.21	5.11	74.97	249	316	383	289
3	1999	4.546	2.096	94.7	3.15	4.04	4.94	71.61	225	290	354	326
3	2000	4.563	2.144	93.9	3.28	4.18	5.08	71.87	236	300	365	328
3	2001	4.348	2.156	94.8	3.29	4.18	5.08	72.43	238	303	368	315
3	2002	4.434	2.172	91.5	3.41	4.32	5.22	72.71	248	314	379	322
3	2003	4.381	2.224	93.6	3.47	4.38	5.28	72.81	253	319	385	319
3	2004	4.204	2.302	94.1	3.63	4.55	5.46	73.43	267	334	401	309
3	2005	4.205	2.241	88.3	3.66	4.57	5.49	73.24	268	335	402	308
3	2006	4.367	2.251	88.7	3.67	4.58	5.50	74.15	272	340	408	324
3	2007	4.226	2.285	88.7	3.74	4.66	5.59	74.93	280	349	419	317
3	2008	4.361	2.316	83.6	3.94	4.88	5.83	74.48	293	364	434	325
5	1999	4.908	2.029	87.1	3.21	4.11	5.00	70.27	226	289	351	345
5	2000	5.189	2.042	87.5	3.23	4.13	5.02	69.09	223	285	347	358
5	2001	5.039	2.047	89.1	3.19	4.09	4.99	69.38	222	284	346	350
5	2002	4.881	2.083	90.0	3.25	4.15	5.05	69.15	225	287	349	338
5	2003	4.885	2.089	91.3	3.23	4.13	5.02	69.40	224	286	349	339
5	2004	4.861	2.116	90.4	3.32	4.22	5.11	69.89	232	295	357	340
5	2005	4.774	2.106	91.7	3.26	4.16	5.05	69.88	228	290	353	334
5	2006	4.862	2.154	90.5	3.40	4.30	5.20	69.32	236	298	361	337
5	2007	5.091	2.190	87.6	3.56	4.47	5.38	69.12	246	309	372	352
5	2008	4.939	2.177	88.1	3.52	4.43	5.33	68.39	241	303	365	338
Predictions for California refineries												
California average, 2004			2.670	93.0	4.40	5.44	6.49	70.82	312	386	460	354
California average, 2005			2.657	95.0	4.32	5.36	6.40	71.06	307	381	454	358
California average, 2006			2.732	91.5	4.56	5.64	6.71	72.65	331	409	488	384
California average, 2007			2.717	88.3	4.62	5.69	6.77	71.43	330	407	483	401
California average, 2008			2.722	91.0	4.55	5.63	6.70	71.02	323	400	476	383
California average, 2009			2.711	82.9	4.76	5.83	6.91	70.54	336	412	487	397
BP Carson 2008			2.547	91.0	4.22	5.21	6.21	71.02	300	370	441	308
BP Carson 2009			2.544	82.9	4.44	5.44	6.44	70.54	313	384	454	302
Chevron El Segundo 2008			2.336	91.0	3.79	4.72	5.65	71.02	269	335	401	307
Chevron El Segundo 2009			2.333	82.9	4.01	4.94	5.88	70.54	283	349	415	273
Chevron Richmond 2008			2.843	91.0	4.78	5.91	7.05	71.02	339	420	500	340
Chevron Richmond 2009			2.830	82.9	4.98	6.11	7.25	70.54	351	431	512	321
CP Carson & Wilm. 2008			2.888	91.0	4.86	6.02	7.17	71.02	345	427	510	363
CP Carson & Wilm. 2009			2.888	82.9	5.08	6.25	7.42	70.54	358	441	523	320
ConocoPhillips Rodeo 2008			3.096	91.0	5.23	6.51	7.79	71.02	371	462	553	428
ConocoPhillips Rodeo 2009			3.346	82.9	5.87	7.33	8.79	70.54	414	517	620	425
ExxonMobil Torrance 2008			3.033	91.0	5.12	6.36	7.60	71.02	363	452	540	329
ExxonMobil Torrance 2009			2.943	82.9	5.18	6.38	7.58	70.54	365	450	535	311
Shell Martinez 2008			2.744	91.0	4.60	5.68	6.76	71.02	326	403	480	497
Shell Martinez 2009			3.001	82.9	5.28	6.52	7.76	70.54	373	460	547	514
Tesoro Avon 2008			3.186	91.0	5.38	6.72	8.06	71.02	382	477	572	313
Tesoro Avon 2009			3.186	82.9	5.60	6.95	8.31	70.54	395	491	586	276
Tesoro Wilmi./Carson 2008			3.238	91.0	5.47	6.84	8.21	71.02	388	486	583	376
Tesoro Wilmi./Carson 2008			3.238	82.9	5.69	7.07	8.46	70.54	401	499	597	341
Ultramar-Valero Wilm. 2008			3.871	91.0	6.50	8.33	10.17	71.02	462	592	722	287
Ultramar-Valero Wilm. 2008			3.871	82.9	6.72	8.57	10.42	70.54	474	604	735	293
Valero Benicia 2008			3.000	91.0	5.06	6.28	7.50	71.02	359	446	533	345
Valero Benicia 2009			3.000	82.9	5.28	6.52	7.75	70.54	372	460	547	357

Data from Table 2-1.

Table 1-3. Emissions predicted by primary processing EQC

		EI	Equivalent process capacities			Cap.	Prod.	EI_{pred} 95% confidence			Fuel mix	$Emit_{pred}$ 95% confidence			Obs. CO_2
PADD	Year	(GJ/m³)	Vac. Dist.	Conv.	1°Hydrtg	ut. (%)	ratio	Lower	Central	Upper	(kg/GJ)	Lower	Central	Upper	(kg/m³)
1	1999	3.451	0.402	0.516	0.054	90.9	3.668	3.171	3.498	3.826	81.53	259	285	312	281
1	2000	3.430	0.395	0.525	0.054	91.7	3.489	3.168	3.495	3.823	80.34	254	281	307	276
1	2001	3.518	0.387	0.481	0.029	87.2	3.479	3.049	3.382	3.716	81.85	250	277	304	288
1	2002	3.426	0.386	0.474	0.084	88.9	3.605	3.090	3.419	3.747	81.08	251	277	304	278
1	2003	3.364	0.398	0.474	0.059	92.7	3.321	3.022	3.355	3.688	81.51	246	274	301	274
1	2004	3.416	0.399	0.475	0.059	90.4	3.397	3.097	3.425	3.754	81.46	252	279	306	278
1	2005	3.404	0.402	0.476	0.058	93.1	3.756	2.947	3.279	3.611	81.23	239	266	293	277
1	2006	3.440	0.402	0.476	0.028	86.7	3.522	3.130	3.464	3.799	80.40	252	279	305	277
1	2007	3.499	0.402	0.476	0.028	85.6	3.443	3.181	3.518	3.856	82.28	262	289	317	288
1	2008	3.551	0.402	0.476	0.028	80.8	3.400	3.329	3.690	4.051	83.26	277	307	337	296
2	1999	3.368	0.408	0.486	0.125	93.3	4.077	3.124	3.454	3.784	78.11	244	270	296	263
2	2000	3.361	0.415	0.488	0.107	94.2	4.132	3.085	3.416	3.747	77.56	239	265	291	261
2	2001	3.396	0.407	0.485	0.096	93.9	4.313	2.967	3.298	3.629	77.46	230	255	281	263
2	2002	3.393	0.405	0.481	0.129	90.0	4.345	3.156	3.485	3.814	77.90	246	271	297	264
2	2003	3.298	0.408	0.477	0.132	91.6	4.281	3.130	3.458	3.786	78.00	244	270	295	257
2	2004	3.376	0.413	0.473	0.148	93.6	4.167	3.152	3.482	3.813	77.25	243	269	295	261
2	2005	3.496	0.420	0.484	0.148	92.9	4.207	3.242	3.570	3.898	77.27	251	276	301	270
2	2006	3.738	0.423	0.488	0.140	92.4	3.907	3.339	3.666	3.994	75.84	253	278	303	284
2	2007	3.800	0.400	0.479	0.137	90.1	4.161	3.182	3.509	3.837	75.55	240	265	290	287
2	2008	3.858	0.405	0.487	0.146	88.4	4.333	3.277	3.607	3.937	74.97	246	270	295	289
3	1999	4.546	0.466	0.566	0.151	94.7	3.120	3.992	4.330	4.667	71.61	286	310	334	326
3	2000	4.563	0.479	0.579	0.155	93.9	3.120	4.155	4.489	4.824	71.87	299	323	347	328
3	2001	4.348	0.470	0.600	0.129	94.8	3.128	4.066	4.401	4.736	72.43	294	319	343	315
3	2002	4.434	0.457	0.611	0.148	91.5	3.251	4.161	4.488	4.815	72.71	303	326	350	322
3	2003	4.381	0.460	0.604	0.168	93.6	3.160	4.158	4.492	4.826	72.81	303	327	351	319
3	2004	4.204	0.472	0.610	0.174	94.1	3.228	4.234	4.570	4.905	73.43	311	336	360	309
3	2005	4.205	0.451	0.588	0.168	88.3	3.316	4.197	4.524	4.850	73.24	307	331	355	308
3	2006	4.367	0.449	0.587	0.167	88.7	3.176	4.194	4.520	4.847	74.15	311	335	359	324
3	2007	4.226	0.455	0.594	0.184	88.7	3.205	4.298	4.625	4.952	74.93	322	347	371	317
3	2008	4.361	0.459	0.600	0.171	83.6	3.229	4.459	4.800	5.141	74.48	332	358	383	325
5	1999	4.908	0.468	0.613	0.195	87.1	2.952	4.576	4.908	5.240	70.27	322	345	368	345
5	2000	5.189	0.465	0.613	0.167	87.5	3.160	4.424	4.754	5.084	69.09	306	328	351	358
5	2001	5.039	0.478	0.619	0.174	89.1	3.231	4.477	4.807	5.137	69.38	311	333	356	350
5	2002	4.881	0.484	0.636	0.196	90.0	3.460	4.548	4.879	5.210	69.15	315	337	360	338
5	2003	4.885	0.482	0.620	0.165	91.3	3.487	4.354	4.682	5.010	69.40	302	325	348	339
5	2004	4.861	0.482	0.627	0.167	90.4	3.551	4.399	4.728	5.056	69.89	307	330	353	340
5	2005	4.774	0.479	0.626	0.166	91.7	3.700	4.303	4.630	4.957	69.88	301	324	346	334
5	2006	4.862	0.484	0.641	0.160	90.5	3.615	4.423	4.752	5.081	69.32	307	329	352	337
5	2007	5.091	0.484	0.656	0.167	87.6	3.551	4.599	4.935	5.272	69.12	318	341	364	352
5	2008	4.939	0.491	0.645	0.163	88.1	3.803	4.522	4.859	5.195	68.39	309	332	355	338
Predictions for California refineries															
California average, 2004			0.577	0.813	0.262	93.0	3.633	5.738	6.110	6.482	70.82	406	433	459	354
California average, 2005			0.575	0.811	0.260	95.0	3.801	5.603	5.979	6.355	71.06	398	425	452	358
California average, 2006			0.582	0.832	0.251	91.5	3.845	5.811	6.178	6.545	72.65	422	449	476	384
California average, 2007			0.582	0.843	0.259	88.3	3.814	5.985	6.354	6.722	71.43	428	454	480	401
California average, 2008			0.590	0.838	0.255	91.0	4.087	5.857	6.224	6.590	71.02	416	442	468	383
California average, 2009			0.595	0.830	0.252	82.9	4.045	6.122	6.501	6.880	70.54	432	459	485	397
BP Carson 2008			0.527	0.527	0.527	91.0	4.087	5.159	5.522	5.885	71.02	366	392	418	308
BP Carson 2009			0.527	0.527	0.527	82.9	4.045	5.450	5.804	6.158	70.54	384	409	434	302
Chevron El Segundo 2008			0.555	0.555	0.555	91.0	4.087	5.487	5.863	6.238	71.02	390	416	443	307
Chevron El Segundo 2009			0.547	0.547	0.547	82.9	4.045	5.681	6.043	6.404	70.54	401	426	452	273
Chevron Richmond 2008			0.453	0.453	0.453	91.0	4.087	4.257	4.595	4.934	71.02	302	326	350	340
Chevron Richmond 2009			0.453	0.453	0.453	82.9	4.045	4.543	4.878	5.212	70.54	320	344	368	321
CP Carson & Wilm. 2008			0.577	0.577	0.577	91.0	4.087	5.750	6.137	6.524	71.02	408	436	463	363
CP Carson & Wilm. 2009			0.577	0.577	0.577	82.9	4.045	6.044	6.419	6.794	70.54	426	453	479	320
ConocoPhillips Rodeo 2008			0.784	0.784	0.784	91.0	4.087	8.183	8.714	9.244	71.02	581	619	657	428
ConocoPhillips Rodeo 2009			0.784	0.784	0.784	82.9	4.045	8.484	8.996	9.508	70.54	598	635	671	425
ExxonMobil Torrance 2008			0.659	0.659	0.659	91.0	4.087	6.720	7.157	7.594	71.02	477	508	539	329
ExxonMobil Torrance 2009			0.656	0.656	0.656	82.9	4.045	6.977	7.397	7.816	70.54	492	522	551	311
Shell Martinez 2008			0.574	0.574	0.574	91.0	4.087	5.722	6.107	6.493	71.02	406	434	461	497
Shell Martinez 2009			0.628	0.628	0.628	82.9	4.045	6.656	7.059	7.462	70.54	470	498	526	514
Tesoro Avon 2008			0.894	0.894	0.894	91.0	4.087	9.459	10.08	10.71	71.02	672	716	760	313
Tesoro Avon 2009			0.894	0.894	0.894	82.9	4.045	9.762	10.36	10.97	70.54	689	731	774	276
Tesoro Wilmi./Carson 2008			0.620	0.620	0.620	91.0	4.087	6.262	6.674	7.086	71.02	445	474	503	376
Tesoro Wilmi./Carson 2009			0.620	0.620	0.620	82.9	4.045	6.558	6.956	7.354	70.54	463	491	519	341
Ultramar-Valero Wilm. 2008			0.575	0.575	0.575	91.0	4.087	5.729	6.115	6.501	71.02	407	434	462	287
Ultramar-Valero Wilm. 2009			0.575	0.575	0.575	82.9	4.045	6.023	6.397	6.771	70.54	425	451	478	293
Valero Benicia 2008			0.563	0.563	0.563	91.0	4.087	5.583	5.962	6.341	71.02	396	423	450	345
Valero Benicia 2009			0.563	0.563	0.563	82.9	4.045	5.876	6.244	6.613	70.54	414	440	466	357
California adjusted, 2004*			0.577	0.813	0.028	93.0	3.633	5.131	5.473	5.814	70.82	363	388	412	354
California adjusted, 2005*			0.575	0.811	0.028	95.0	3.801	5.004	5.348	5.691	71.06	356	380	404	358
California adjusted, 2006*			0.582	0.832	0.028	91.5	3.845	5.232	5.573	5.914	72.65	380	405	430	384
California adjusted, 2007*			0.582	0.843	0.028	88.3	3.814	5.379	5.726	6.072	71.43	384	409	434	401
California adjusted, 2008*			0.590	0.838	0.028	91.0	4.087	5.265	5.606	5.947	71.02	374	398	422	383
California adjusted, 2009*			0.595	0.830	0.028	82.9	4.045	5.523	5.893	6.262	70.54	390	416	442	397

Data from Table 2-1. * Adjusted by replacing observed gas oil/residua hydrotreating data with lowest value (PADD 1, 2006–2008).

In the context of emissions oversight and control, a metric that is biased-high can be considered a special case. It could cause serious problems if it is used as a benchmark to define "acceptable" emissions performance. Such a benchmark could erroneously define emissions that are greater than actual current emissions as acceptable, resulting in the allowance of excessive and potentially increasing emissions. If excess pollution caused by this "baseline inflation" problem were to occur, it would likely manifest as emissions oversight and control failure at the facility level.

Major refineries in the Los Angeles and Bay Area regions that collectively represent California fuels refining capacity were analyzed to assess the potential breadth and magnitude of this problem. Analysis was based on each facility's reported emissions and primary processing EQC based on reported process capacities for 2008 and 2009 (tables 2-5, 2-6). Reported emissions were compared with the 95% confidence of prediction lower bound for observations to assess the frequency of emissions baseline inflation that could remain undetected by the primary processing complexity metric. This lower bound of prediction exceeded reported annual refinery emissions in 18 of 22 cases, indicating the potential for widespread failure of emissions oversight and control.

To assess the magnitude of potential emissions that could be undetected by this complexity metric, reported emissions were compared with the its 95% confidence of prediction upper bound for observations. Individual facility annual emissions could increase above emissions reported for a refinery and year by more than 10% in 19 of 22 cases, and by more than 50% in ten of these cases, without exceeding the 95% confidence of prediction by this complexity metric.

Finally, the "adjusted" primary processing equivalent capacity prediction in Table 1-3 shows an example of how the decoupling of capacity from *EI* and emissions observed could explain this prediction error. This adjustment replaces observed California gas oil hydrotreating data with lowest value observed (PADD 1, 2006–2008). California's high gas oil hydrotreating capacity is consistent with maintaining light liquids yield from denser crude while meeting California's "clean fuels" standards. It also is likely to improve efficiencies of downstream processes via better pretreatment of their feeds: Gas oil hydrotreating removes sulfur and metals that poison catalysts in catalytic cracking and reforming processes *(1, 29, 38),* and is used for such pretreatment in California *(6).* Downstream process efficiency improvements may thereby offset emissions from California's extra gas oil hydrotreating. This adjustment thus represents a plausible, yet hypothetical,[3] scenario. Observed statewide emissions are exceeded by the lower bound of prediction in this hypothetical scenario by 3% in 1 of 6 years, and emissions are 5% below the central prediction as a six-year average (as compared with the 9–15% in 6 of 6 years and 14% six-year average without this adjustment; Table 1-3).

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[3] Exact capacity/energy relationships cannot be verified because process-level material and energy inputs/outputs are not reported: therefore, this example may be one of multiple possible examples.

Product yield output metric results.
Figure 1-9 shows results for emissions intensity predicted by the primary products sum. The results show poor power of prediction (R^2 0.40) and poor reliability as well. Average observed California emissions exceed emissions predicted by this metric in 6 of 6 years and by 26–48% (Table 1–4).

Figure 1-9. Emission intensity predicted by the sum of ARB-proposed primary products

Prediction for California refineries on 1999–2008 data from U.S. refineries by nonparametric regression

R^2 0.40

Actual California refinery emissions in this period ranged from 354–401 kg/m³

Data from Table 1-4

- Observations for PADD 1, 2, 3 or 5
- Predictions for PADD 1, 2, 3 or 5
- Predictions for California 2004–2009

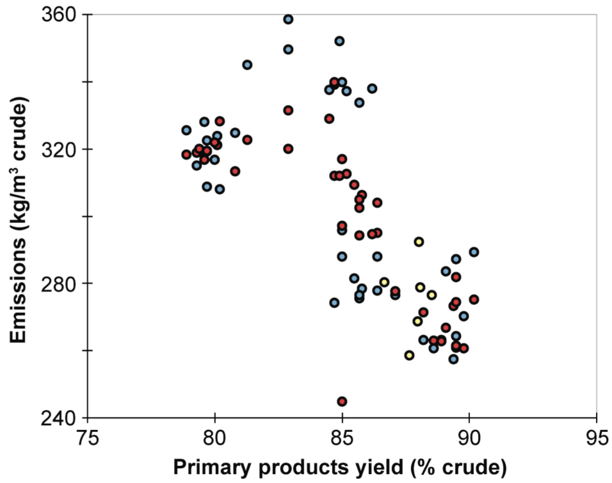

Figure 1-10 shows emissions intensity predicted by the primary liquids mix. Including fuel-specific yield instead of a lump sum, and excluding asphalt, improved the power of prediction substantially over the summing method (R^2 0.94), but California emissions exceeded the upper bound of prediction by 9–25% each year (Table 1-5).

Figure 1-10. Emisssions predicted by gasoline, distillate and jet fuel yield

Prediction for California refineries on 1999–2008 data from U.S. refineries

R^2 0.94

Diagonal lines bound the 95% confidence of prediction for observations

Data from Table 1-5

- California annual average 2004–2009
- PADD 1, 2, 3 or 5 1999–2008

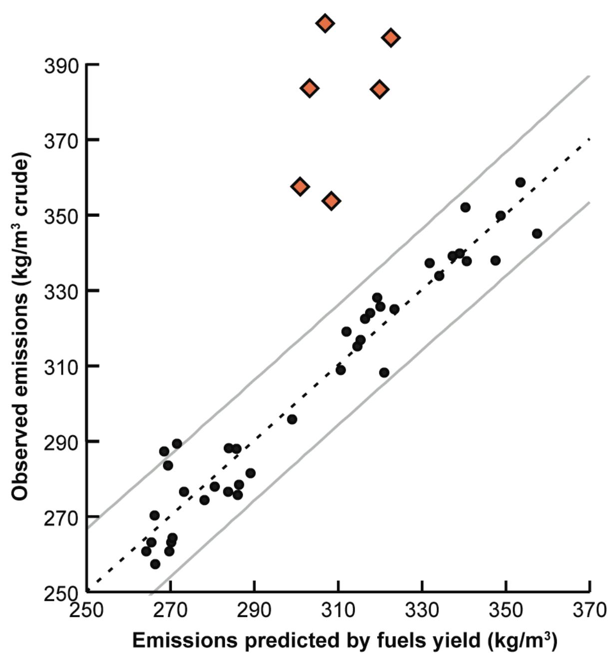

Table 1-4. Emissions predicted by primary products yield.[a]

		Inputs			*Results*		
		Observed CO_2	Primary products	Capacity utilization	Prediction	Observation	Obs–Pred.
PADD	Year	(kg/m^3)	(% crude)	(%)	(kg/m^3)	(kg/m^3)	%Δ
1	1999	281	85.50	90.9	309	281	-9
1	2000	276	85.70	91.7	302	276	-9
1	2001	288	86.40	87.2	295	288	-2
1	2002	278	86.40	88.9	304	278	-9
1	2003	274	84.70	92.7	340	274	-19
1	2004	278	85.80	90.4	306	278	-9
1	2005	277	87.10	93.1	278	277	0
1	2006	277	85.70	86.7	305	277	-9
1	2007	288	85.00	85.6	297	288	-3
1	2008	296	85.00	80.8	245	296	21
2	1999	263	88.20	93.3	271	263	-3
2	2000	261	88.60	94.2	263	261	-1
2	2001	263	88.90	93.9	263	263	0
2	2002	264	89.50	90.0	282	264	-6
2	2003	257	89.40	91.6	273	257	-6
2	2004	261	89.50	93.6	261	261	0
2	2005	270	89.80	92.9	261	270	4
2	2006	284	89.10	92.4	267	284	6
2	2007	287	89.50	90.1	274	287	5
2	2008	289	90.20	88.4	275	289	5
3	1999	326	78.90	94.7	318	326	2
3	2000	328	79.60	93.9	317	328	4
3	2001	315	79.30	94.8	319	315	-1
3	2002	322	79.70	91.5	319	322	1
3	2003	319	79.40	93.6	320	319	0
3	2004	309	79.70	94.1	319	309	-3
3	2005	308	80.20	88.3	328	308	-6
3	2006	324	80.10	88.7	321	324	1
3	2007	317	80.00	88.7	322	317	-2
3	2008	325	80.80	83.6	313	325	4
5	1999	345	81.30	87.1	323	345	7
5	2000	358	82.90	87.5	320	358	12
5	2001	350	82.90	89.1	331	350	5
5	2002	338	84.50	90.0	329	338	3
5	2003	339	84.70	91.3	312	339	9
5	2004	340	85.00	90.4	317	340	7
5	2005	334	85.70	91.7	294	334	13
5	2006	337	85.20	90.5	313	337	8
5	2007	352	84.90	87.6	312	352	13
5	2008	338	86.20	88.1	294	338	15
Calif. avg.	2004	354	86.68	93.0	280	354	26
Calif. avg.	2005	358	87.66	95.0	259	358	38
Calif. avg.	2006	384	88.07	91.5	279	384	38
Calif. avg.	2007	401	88.04	88.3	292	401	37
Calif. avg.	2008	383	88.53	91.0	276	383	39
Calif. avg.	2009	397	87.98	82.9	269	397	48

[a] Observed emissions analyzed against the sum of yield for aviation gasoline, motor gasoline, distillate fuel oil, kerosene jet fuel, and asphalt by nonparametric regression (LOWESS). Data from Table 2-1.

Table 1-5. Emissions predicted by primary liquid products; PLS regression[a]

		Inputs					*Results*					
		Obs. CO_2	Gasol-	Jet kero-	Distill-	Capac.	Emit pred. 95% confidence			Obs.	Δ	Fuels emit
PADD	Year	(kg/m^3)	ine (%)	sene (%)	ate (%)	ut. (%)	Lower	Central	Upper	(kg/m^3)	(%)	(kg/m^3)[b]
1	1999	281	46.6	7.0	26.3	90.9	275	289	303	281	0	234
1	2000	276	45.2	6.3	27.9	91.7	272	286	300	276	0	234
1	2001	288	45.8	5.3	29.1	87.2	270	284	298	288	0	238
1	2002	278	46.7	5.3	28.1	88.9	267	281	295	278	0	237
1	2003	274	46.4	5.2	27.2	92.7	264	278	292	274	0	233
1	2004	278	46.5	6.1	26.6	90.4	273	286	300	278	0	234
1	2005	277	46.6	5.7	28.8	93.1	260	273	287	277	0	240
1	2006	277	45.8	5.1	29.2	86.7	270	284	298	277	0	236
1	2007	288	45.5	5.0	29.4	85.6	272	286	300	288	0	236
1	2008	296	44.6	5.7	29.6	80.8	284	299	314	296	0	236
2	1999	263	51.1	6.6	24.8	93.3	256	270	284	263	0	241
2	2000	261	50.4	6.9	25.7	94.2	256	270	284	261	0	242
2	2001	263	51.1	6.6	26.0	93.9	251	266	280	263	0	245
2	2002	264	52.0	6.7	25.4	90.0	257	271	285	264	0	245
2	2003	257	51.5	6.2	26.0	91.6	252	266	280	257	0	245
2	2004	261	51.6	6.4	25.7	93.6	250	264	279	261	0	245
2	2005	270	50.4	6.5	27.1	92.9	252	266	280	270	0	246
2	2006	284	49.4	6.2	27.3	92.4	256	270	283	284	0	243
2	2007	287	49.8	6.1	28.2	90.1	255	269	282	287	2	246
2	2008	289	48.5	6.3	30.0	88.4	258	272	286	289	1	249
3	1999	326	44.8	11.1	21.1	94.7	306	320	334	326	0	220
3	2000	328	44.7	11.1	21.9	93.9	306	319	333	328	0	222
3	2001	315	44.3	10.5	22.8	94.8	301	315	328	315	0	223
3	2002	322	45.4	10.3	22.3	91.5	303	317	330	322	0	223
3	2003	319	44.8	9.9	23.0	93.6	298	312	326	319	0	223
3	2004	309	44.6	10.0	23.5	94.1	297	311	324	309	0	225
3	2005	308	43.8	10.2	24.5	88.3	307	321	335	308	0	226
3	2006	324	43.5	9.7	25.2	88.7	304	318	332	324	0	226
3	2007	317	43.2	9.4	26.0	88.7	302	315	329	317	0	227
3	2008	325	41.6	9.6	28.4	83.6	309	323	338	325	0	230
5	1999	345	44.7	15.8	18.3	87.1	343	357	372	345	0	219
5	2000	358	45.7	16.2	18.5	87.5	339	353	368	358	0	223
5	2001	350	45.5	16.0	19.2	89.1	335	349	363	350	0	224
5	2002	338	47.3	16.0	19.0	90.0	327	341	355	338	0	229
5	2003	339	47.2	16.0	19.5	91.3	323	337	351	339	0	230
5	2004	340	47.3	16.2	19.5	90.4	325	339	353	340	0	231
5	2005	334	47.3	16.2	20.4	91.7	320	334	348	334	0	233
5	2006	337	47.7	15.3	20.3	90.5	318	332	346	337	0	233
5	2007	352	46.6	15.6	20.8	87.6	327	340	354	352	0	232
5	2008	338	45.6	17.5	21.6	88.1	334	348	362	338	0	235
Calif. avg.	2004		53.4	13.7	17.3	93.0	294	308	323	354	9	237
Calif. avg.	2005		53.3	13.6	18.8	95.0	286	301	316	358	13	241
Calif. avg.	2006		53.9	13.3	18.7	91.5	289	303	318	384	21	242
Calif. avg.	2007		53.7	12.9	19.2	88.3	293	307	321	401	25	242
Calif. avg.	2008		50.6	15.7	20.6	91.0	306	320	334	383	15	243
Calif. avg.	2009		53.5	14.3	18.7	82.9	309	323	336	397	18	242

[a] Observed emissions vs motor gasoline, distillate, and jet kerosene yield with refinery capacity utilization analyzed by partial least squares (PLS) regression. Data from Table 2-1.

[b] NETL estimated average refinery emissions of 46.0, 50.8, and 30.5 kg/barrel conventional gasoline, diesel, and kerosene produced, respectively *(32)*. These estimates are applied to total yields of gasoline, distillate and kerosene *(Table 2-1)* to estimate emissions that can be explained by production of these fuels in each region and year ("fuels" emit").

The prior analyses tested the metric's ability to predict energy or emissions intensities as an explanatory or *x* variable. The next two analyses test the products-based metric's stability as a measurement that is predictable in relation to other factors (as a *y* variable).

Figure 1-11 presents results for the case where the products metric includes all products and is predicted by crude feed quality. Results suggest good power of prediction (R^2 0.90), and much less error of California predictions than observed in the product metrics that exclude crude feed quality, but observed California emissions still exceed the prediction in all cases by 6–17%.

Figure 1-11. Emission intensity predicted by total products yield and oil quality, nonparametric regression

Prediction for California refineries on 1999–2008 data from U.S. refineries

R^2 0.90

Predictions and observations for all parameters plotted against density

Data from Table 1-6

- Observation for PADD 1, 2, 3 or 5
- Prediction for PADD 1, 2, 3 or 5
- Observation for Calif. 2004–2009

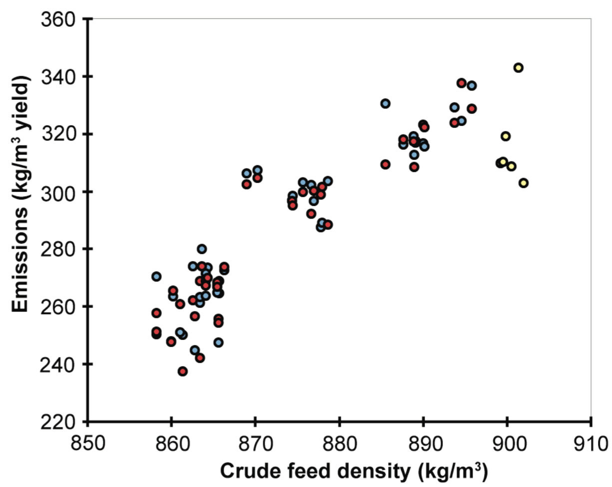

Figure 1-12 presents results where the products metric includes light liquids (aviation and motor gasoline, jet kerosene, distillate and naphtha) and is predicted by crude feed quality. Power of prediction is good (R^2 0.91), and California observations fall within the prediction in 2 years but exceed the prediction by 4–7% during four years.

Figure 1-12. Emissions/product output predicted by crude feed quality

Prediction for California refineries on 1999–2008 data from U.S. refineries

R^2 0.91

Diagonal lines bound the 95% confidence of prediction for observations

aviation gasoline, motor gasoline, jet fuel, distillate and naphtha

Data from tables 1-7 and 2-1

- California annual average 2004–2009
- PADD 1, 2, 3 or 5 1999–2008

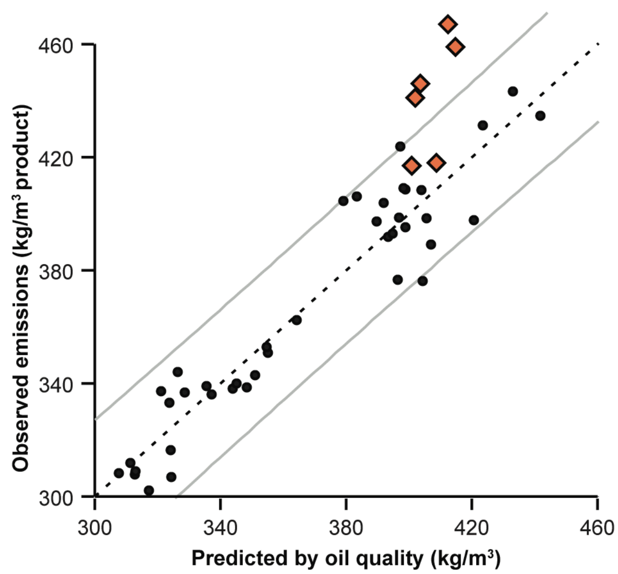

Table 1-6. Emissions/total products predicted by crude feed quality

Emit/prod: products include all products

PADD	Year	Emit/TotProd (kg/m³)	density (kg/m³)	sulfur (kg/m³)	Cap. ut. (%)	Prod. ratio	Prediction (kg/m³)	Observed (kg/m³)	Obs-Pred %Δ
1	1999	270.2	858.20	8.24	90.9	3.668	258	270	5
1	2000	263.5	860.18	8.00	91.7	3.489	265	263	-1
1	2001	272.4	866.34	7.71	87.2	3.479	274	272	0
1	2002	264.5	865.71	7.45	88.9	3.605	269	265	-2
1	2003	261.1	863.44	7.43	92.7	3.321	269	261	-3
1	2004	264.8	865.44	7.79	90.4	3.397	268	265	-1
1	2005	263.1	863.38	7.17	93.1	3.756	242	263	9
1	2006	263.6	864.12	7.17	86.7	3.522	269	264	-2
1	2007	273.4	864.33	7.26	85.6	3.443	270	273	1
1	2008	280.0	863.65	7.08	80.8	3.400	274	280	2
2	1999	250.3	858.25	10.64	93.3	4.077	251	250	0
2	2000	247.8	860.03	11.35	94.2	4.132	248	248	0
2	2001	250.1	861.33	11.37	93.9	4.313	237	250	5
2	2002	251.0	861.02	11.28	90.0	4.345	261	251	-4
2	2003	244.8	862.80	11.65	91.6	4.281	256	245	-5
2	2004	247.4	865.65	11.86	93.6	4.167	256	247	-3
2	2005	255.6	865.65	11.95	92.9	4.207	254	256	1
2	2006	267.5	865.44	11.60	92.4	3.907	267	267	0
2	2007	271.4	864.07	11.84	90.1	4.161	267	271	2
2	2008	273.9	862.59	11.73	88.4	4.333	262	274	5
3	1999	306.2	869.00	12.86	94.7	3.120	302	306	1
3	2000	307.3	870.29	12.97	93.9	3.120	305	307	1
3	2001	296.8	874.43	14.34	94.8	3.128	297	297	0
3	2002	302.1	876.70	14.47	91.5	3.251	292	302	3
3	2003	298.4	874.48	14.43	93.6	3.160	295	298	1
3	2004	287.4	877.79	14.40	94.1	3.228	299	287	-4
3	2005	288.9	878.01	14.40	88.3	3.316	301	289	-4
3	2006	302.9	875.67	14.36	88.7	3.176	300	303	1
3	2007	296.5	876.98	14.47	88.7	3.205	300	296	-1
3	2008	303.6	878.66	14.94	83.6	3.229	288	304	5
5	1999	324.5	894.61	11.09	87.1	2.952	337	324	-4
5	2000	336.6	895.85	10.84	87.5	3.160	329	337	2
5	2001	329.2	893.76	10.99	89.1	3.231	324	329	2
5	2002	316.6	889.99	10.86	90.0	3.460	323	317	-2
5	2003	317.4	889.10	10.94	91.3	3.487	317	317	0
5	2004	319.0	888.87	11.20	90.4	3.551	317	319	1
5	2005	312.7	888.99	11.38	91.7	3.700	308	313	1
5	2006	316.2	887.65	10.92	90.5	3.615	318	316	-1
5	2007	330.4	885.54	11.07	87.6	3.551	309	330	7
5	2008	315.4	890.16	12.11	88.1	3.803	322	315	-2
Predictions for California refineries									
California average, 2004			899.23	11.46	93.0	3.633	310	328	6
California average, 2005			900.56	11.82	95.0	3.801	309	330	7
California average, 2006			899.56	11.73	91.5	3.845	310	354	14
California average, 2007			899.84	11.89	88.3	3.814	319	370	16
California average, 2008			902.00	12.85	91.0	4.087	303	354	17
California average, 2009			901.38	11.70	82.9	4.045	343	368	7

Data from Table 2-1.

Table 1-7. Emissions/product output predicted by crude feed quality

Emit/prod: products include aviation and motor gasoline, jet fuel, distillate, and naphtha

PADD	Year	Emit/prod. (kg/m^3)	density (kg/m^3)	sulfur (kg/m^3)	Cap. ut. (%)	Prod. ratio	Emit pred. 95% confidence Lower	Central	Upper	Observed (kg/m^3)
1	1999	344	858.20	8.24	90.9	3.668	304	326	348	344
1	2000	339	860.18	8.00	91.7	3.489	313	335	357	339
1	2001	351	866.34	7.71	87.2	3.479	333	355	377	351
1	2002	338	865.71	7.45	88.9	3.605	322	344	366	338
1	2003	340	863.44	7.43	92.7	3.321	323	345	367	340
1	2004	343	865.44	7.79	90.4	3.397	329	351	373	343
1	2005	333	863.38	7.17	93.1	3.756	301	324	346	333
1	2006	338	864.12	7.17	86.7	3.522	326	348	370	338
1	2007	353	864.33	7.26	85.6	3.443	333	354	376	353
1	2008	362	863.65	7.08	80.8	3.400	342	364	386	362
2	1999	312	858.25	10.64	93.3	4.077	289	311	334	312
2	2000	308	860.03	11.35	94.2	4.132	290	313	335	308
2	2001	308	861.33	11.37	93.9	4.313	285	307	330	308
2	2002	309	861.02	11.28	90.0	4.345	290	313	335	309
2	2003	302	862.80	11.65	91.6	4.281	295	317	339	302
2	2004	307	865.65	11.86	93.6	4.167	302	324	346	307
2	2005	316	865.65	11.95	92.9	4.207	302	324	346	316
2	2006	336	865.44	11.60	92.4	3.907	315	337	359	336
2	2007	337	864.07	11.84	90.1	4.161	306	328	351	337
2	2008	337	862.59	11.73	88.4	4.333	299	321	343	337
3	1999	404	869.00	12.86	94.7	3.120	357	379	401	404
3	2000	406	870.29	12.97	93.9	3.120	361	383	405	406
3	2001	392	874.43	14.34	94.8	3.128	371	393	415	392
3	2002	395	876.70	14.47	91.5	3.251	377	399	421	395
3	2003	393	874.48	14.43	93.6	3.160	372	394	416	393
3	2004	376	877.79	14.40	94.1	3.228	374	396	418	376
3	2005	376	878.01	14.40	88.3	3.316	382	404	426	376
3	2006	398	875.67	14.36	88.7	3.176	383	405	427	398
3	2007	389	876.98	14.47	88.7	3.205	385	407	429	389
3	2008	398	878.66	14.94	83.6	3.229	398	420	443	398
5	1999	434	894.61	11.09	87.1	2.952	419	442	464	434
5	2000	443	895.85	10.84	87.5	3.160	410	433	455	443
5	2001	431	893.76	10.99	89.1	3.231	401	423	446	431
5	2002	408	889.99	10.86	90.0	3.460	382	404	426	408
5	2003	408	889.10	10.94	91.3	3.487	377	399	421	408
5	2004	409	888.87	11.20	90.4	3.551	376	398	420	409
5	2005	397	888.99	11.38	91.7	3.700	368	390	411	397
5	2006	404	887.65	10.92	90.5	3.615	370	392	414	404
5	2007	423	885.54	11.07	87.6	3.551	375	397	419	423
5	2008	398	890.16	12.11	88.1	3.803	375	397	419	398
Predictions for California refineries										
California average, 2004			899.23	11.46	93.0	3.633	387	409	431	418
California average, 2005			900.56	11.82	95.0	3.801	379	401	423	417
California average, 2006			899.56	11.73	91.5	3.845	382	404	426	446
California average, 2007			899.84	11.89	88.3	3.814	390	412	435	467
California average, 2008			902.00	12.85	91.0	4.087	380	402	424	441
California average, 2009			901.38	11.70	82.9	4.045	393	415	437	459

Data from Table 2-1.

Estimates of emissions explained directly by fuels production ("fuels emit" in Table 1-5) are smaller (219–249 vs 257–401 kg/m^3) and range much less (30 vs 144 kg/m^3) than observed emissions. Further, among PADDs, emissions explained by fuels production trend downward as those predicted based on product fuels output, and those observed, trend upward (Table 1-5). Thus, the relative amounts of motor fuel products outputs cannot explain observed emissions, trends in observed emissions, or trends in the predictions based on the mix of primary liquid fuels. Therefore, the prediction error shown in Figure 1-10 must be explained by this prediction (erroneously) equating California refineries to those in other regions that have a similar mix of fuel product yields but very different (in this case lower) refinery emission intensities.

Accounting for crude feed quality in the emissions/volume products metric clearly reduces the errors of its predictions for California observations by substantial amounts (compare figures 1-11, 1-12 with 1-9, 1-10). This was already known from the crude feed quality metric results, because that metric includes products data alongside density, sulfur, and capacity utilization. What is new is that the results for the two methods including fuels product output and crude feed quality are not the same.

Comparison of the results in tables 1-6 and 1-7 with those for the crude feed quality metric results (Table 1-1) provides information about the emissions/volume products metric because it is the only variable that differs from the crude feed quality metric. It replaces emission/volume crude as the *y* variable. Different product slates can be made from the same crude feed. Also, depending upon the crude feed, product, and processing intensity, volume expansion of products over crude (yield "gain" on crude) can result in some variance in products volumes as compared with crude feeds. Thus, the emission/vol. products value can change with changes in fuel products volume that may not change the emission/vol. crude value as much or may not be associated with a change in crude feed volume. Evidence for this is observed in the data set analyzed here.

Low products ratio values for PADD 3 in 2008 and PADD 5 1999–2001 (Table 1-7) drove emissions/vol. product assigned to those regions and years higher than California values. This changed the distribution of observed emission values, which affected the prediction, and pushed the California predictions in Figure 1-12 to the left (compare with Figure 1-5). Had that not happened, the predictions for California refineries shown in Figure 1-12 might appear very good instead of fairly poor.

These results suggest instability of the emissions/vol. product metric as an emission performance benchmark: it reports emission intensity values that may be overly sensitive to changes in product volume. Facility-level variability is significantly greater than variability between refining regions in general, suggesting that errors for individual facilities are likely to be larger than those found here from statewide and U.S. regional averages. These considerations further highlight the need to resolve unanswered questions about facility-level reporting of products data.

Discussion

Data gathered from California refineries, though limited by poor facility-level reporting and poor accessibility that limited the California data gathered to six years, add information to the nationwide refining performance picture. Comparison with the U.S. data (Table 2-1) shows that average California refinery CO_2 emission intensity is at the high extreme among regions, exceeding that of PADD 3 by 20% and that of PADD 2 by 38%, based on the six most recent years for each region. The decoupling of conversion capacity from energy intensity is also more extreme in California, where product fuels yield stays relatively flat as crude feed density and energy intensity increments remain coupled (Figure 1-4), adding regional detail to the relationship of feedstock and products with refinery fuel combustion rates. The California data, presented in one place for the first time, can support additional analysis beyond the scope of the present assessment. Here the California data together with the U.S. data support observations for analysis of emissions performance metrics.

This assessment treats each refinery emissions performance metric option as an hypothesis—refinery emission intensity can be measured and predicted accurately and reliably by this metric—and tests the hypothesis against real world observations from refineries in actual operation. Table 1-8 summarizes the results from analysis of alternative metric options for their ability to measure and predict refinery CO_2 emissions intensity accurately and reliably.

The very poor R-squared value for refinery equivalent capacity (0.35) indicates that this complexity metric is not related to observed emission intensity. Among the remaining metrics, large differences between observed California emissions and those predicted by the metric on average over the six years of record (six-yr %Δ) show that metrics which exclude crude feed quality do not measure and predict California refinery emissions accurately or reliably.

Primary processing capacity is consistently (100% outlier rate) and substantially (six-yr %Δ –14%) biased high. This reflects the more extreme decoupling of conversion capacity from energy intensity in California, and is exacerbated by the correlation of this complexity metric with emissions (R^2 0.92). That correlation is expected because primary processing capacity enables lower quality crude feeds, but capacity can be used in different ways with different energy and emission effects, as shown by the California observations (Figure 1-4). As an emissions benchmark, this complexity metric assumes process capacity equates to emissions when it does not. Benchmarking emissions by this metric could artificially assign "good" performance to California refineries that, in the real world, are at the high extreme of emissions intensity.

Excluding crude feed quality from the products-based approach, the CO_2/vol. product fuels metric has the highest prediction error among these metrics (six-yr %Δ +22%) and a 100% outlier rate. Production of the fuels targeted by this metric is causally linked to refinery energy and emission commitments *(3, 4, 31–35).* However, crude quality effects on processing vary more than those of products *(1),* and the association of hydrogen

Table 1-8. Summary of benchmark option performance on U.S. refinery data (1999–2008) and comparison to California annual average observations (2004–2009).

%Δ: difference of observation from prediction, in percent

			comparison with 95% confidence of prediction		
		prediction	outlier	magnitude of prediction error	
benchmark option	R^2	six-yr %Δ	rate (%)	minimum %Δ	maximum %Δ
crude quality & product ratio	0.90	< 1	33	0	1
refinery equivalent capacity	0.35	–5	0	0	0
primary processing eq. cap.	0.92	–14	100	–9	–15
CO_2/vol. product fuels	0.94	22	100	9	25
CO_2/vol. fuels & crude qual.	0.91	8	66	0	7

Fuels are gasolines, distillate, jet kerosene and naphtha. Product ratio is the ratio by volume of these fuels to other refinery products. Equivalent capacity is the capacity of specified processes relative to that of atmospheric crude distillation and is the most widely used basis for refinery complexity metrics. Predictions and California observations for emissions summarized from tables 1-1, 1-2, 1-3, 1-5 and 1-7. Prediction six-yr %Δ is the difference of observation from the central prediction averaged across the six years of data. Minimum and maximum %Δ are the min. and max. excess of observation from the confidence of prediction.

production emissions with crude feed quality and hydrocracking rather than product hydrotreating found nationally *(1)* is observed in California as well (figures 1-2, 1-3). Much better results for the remaining metrics, which include crude feed quality and products, confirm that excluding crude feed quality causes most of the problem with the products-only metric.

The CO_2/vol. fuels & crude quality metric (outlier rate 66%; six-yr %Δ 8%) is less reliable than the crude quality & product ratio metric (outlier rate 33%; six-yr %Δ < 1%) because it includes products volume in its emissions term. This makes the stability of its emission performance value vulnerable to product slate variability that is unrelated to actual emissions. Unfortunately, that problem will likely be worse at the facility level than it appears in the multi-facility averages shown in Table 1-8, and will likely be exacerbated by unresolved questions of transparency and reporting of products data.

Including crude feed quality with light liquid fuels product output, and assigning neither causal component to the emissions intensity term—as is done in the crude quality & products ratio metric—is the more accurate and reliable approach among the metrics assessed. This feedstock-and-products approach also has the strongest causal support.

Making light liquid fuels from the denser, more contaminated components of crude requires aggressive processing to reject carbon and inject hydrogen, and supporting processes that also consume energy. More of the lower quality crude barrel is comprised of these denser, more contaminated components; putting more of the barrel through carbon rejection and aggressive hydrogen addition processing requires more energy to refine each barrel. This extra energy requires burning more fuel. That emits more combustion products at refineries. Thus, observed relationships among crude feed quality, the ratio of light liquids to other refinery products, and refinery capacity utilization can measure and predict impacts of those causal factors on emissions.

Crude feed quality explains 90% of energy intensity and 85% of CO_2 emission intensity differences observed among the four largest U.S. refining regions over ten years. Emissions predicted by crude density, crude sulfur content, products ratio, and capacity utilization explain most of the regional differences among government estimates of refinery emissions. CO_2 emissions can be measured and predicted for groups of refineries with diverse feeds by these four parameters *(1)*.

A larger, and crucial, reason for benchmarking refinery emissions performance against crude feed quality along with fuels product output is that California refineries are switching crude supplies. Government projections *(18),* industry projections *(19),* and the long, continuing decline in California crude production observed since the mid-1980s *(5, 44)* all indicate that 70–76% of the California refinery crude feed will *not* be from current in-state sources by 2020. Declining production from Alaska's currently-tapped fields *(18, 19)* and the ease of switching among foreign supplies mean that, in practical terms, up to three-quarters of the 2020 crude feed will be "new." Therefore, despite the large planning and capital equipment costs typically incurred to re-tune refineries for crude feed of different quality, an acceleration of the currently observed refinery retooling trend is foreseeable in California because of the *need* to switch crude supplies. The choice among supplies that could plausibly range from current PADD 1 crude feed quality (863.9 kg/m^3 density, 7.17 kg/m^3 sulfur, 2005–2008 data from Table 2-1) to that of the average heavy oil (957.4 kg/m^3 density, 27.8 kg/m^3 sulfur) *(28)* is being made now.

Whether business or policy choices lead California refineries to compete on the global crude market for lower or higher quality crude for this new supply could affect emissions dramatically. Recently published work predicts that a switch from conventional crude to heavy oil/natural bitumen blends could double or triple U.S. refinery emissions *(1)*. Replacing 70% of current (2009) statewide refinery crude input with heavy oil (central prediction, Table S8 in ref. 1) could boost average California refinery emissions to about 573 kg/m^3, an increase of approximately 44% or 17 million tonnes/year. Based on the same prediction model *(1)* and the average California refinery products, capacity usage and fuels data from Table 2-1, replacing that 70% with current PADD 1 average crude could cut average California refinery emissions to about 318 kg/m^3, a reduction of 20% or ~8 million tonnes/year (2005–2008 data, Table 2-1). Intermediate scenarios are certainly possible, but it should be noted that these examples exclude the worst-case emissions increase that might occur if the industry switches to tar sands bitumen.

Comparison of these potential emissions changes to the 10% cut in refinery emissions envisioned by 2020 via product fuels switching under California's Low Carbon Fuel Standard shows that the crude switch happening now could overwhelm other emissions control efforts for much better, or much worse. Further, the new crude slate will likely be locked in over the next, decades-long, refinery capital equipment cycle by the sunk costs in equipment retooled for the feed quality chosen. Again, this choice is being made now. California's refinery emissions performance benchmark could succeed if it addresses crude quality effects on emissions and will likely fail if it does not.

Recommendations

1. Expand refinery crude feed quality reporting to include crude oil from U.S. sources.

   Currently, every refinery in the U.S. reports the volume, density, and sulfur content of every crude oil shipment it processes, and that is public—but only for foreign crude. (www.eia.gov/oil_gas/petroleum/data_publications/company_level_imports/cli.html) The quality of crude refined from wells on U.S. soil is exempted. Since California's major fuels refineries use U.S. crude too, this hides facility feedstock quality from the public and from publicly verifiable environmental science. The public has a right to know about how U.S. oil creates pollution of our communities and threatens our climate. State and federal officials should ensure that the U.S. crude refined is reported just like the foreign crude refined. This is critical for California now.

2. Benchmark refinery performance against nationwide performance.

   Average California refinery emissions intensity exceeds that of any U.S. refining region. It is at the high-emission extreme of performance, not any acceptable norm. It need not remain so, because the main cause of its high emission intensity, refining lower quality crude, can change. California refining has begun a switch to new sources of crude that will play out in the form of new commitments to lower-carbon, similar, or higher-carbon intensity crude feeds before 2020. Thus, "grandfathering" its high emission intensity is unnecessary and risks excess or increased emissions.

3. The benchmark emission component should be a direct emission measurement.

   Emission estimates based on measurements elsewhere that are applied to unmonitored emission sources are prone to error. Comprehensive direct sampling of emission streams provides more accurate and reliable measurements. It should be used. Until then, emission estimates should be based on publicly verifiable data for fuel types, amounts, and emission factors. Importantly, CO_2 predominates the global warming potential (CO_2e) of refinery emissions, and emission factor-based estimates for CO_2 are prone to smaller errors than those for smaller and proportionately more variable portions of combustion product streams. Those considerations and the need for action are balanced with the need for accuracy in this recommendation.

4. The benchmark must measure the driving cause(s) of emission intensity change.

   Benchmarks that fail to measure a driving cause of emissions performance risk emission control failure and perverse results that worsen emissions. Failing to measure the emission intensity driver may track performance inaccurately, miss problems caused by that unmeasured factor, or even mistakenly assign good performance to poor performance caused by that driving factor. Measuring the causal factor(s) driving differences in refinery emission intensity tracks performance more accurately and identifies (predicts) actions needed to maintain and improve emission performance more reliably. All of these benefits, or all of these problems, could be realized depending on which of the currently available benchmark options is chosen.

5. Benchmark refinery emissions intensity against crude feed quality *and* fuels product.

   Crude feed quality is the major driver of refinery emissions intensity in California and the U.S. It explains 85% of emissions variability among U.S. refining regions, and predicts average California refinery emissions within 1% over six recent years. This metric can be used to separate out the major impact of crude quality so that other factors affecting emissions are better identified and addressed, to reduce emissions via refinery feedstock measures analogous to those limiting electric power generation from coal in California, or both. Crude feed quality and fuels produced is the most powerful and reliable of the metrics assessed for refinery emissions.

6. An equipment capacity (complexity) benchmark should not be used in California.

   Metrics based on a refinery's processing capacity or "complexity" greatly exaggerate California refineries' already-high emission intensity. A major reason is that these equipment capacity-based metrics, which were not designed to measure emission intensity, commit the error of attempting to account for California refineries' extra conversion capacity as if it were the same as emission intensity. As a benchmark, this metric would make California refineries' extreme-high emission intensity appear to be good performance, and encourage refiners to install even more capacity for higher-carbon crude, which could further increase emissions.

7. Products-based benchmarks have reliability problems when crude quality is excluded.

   The most accurate and reliable benchmark option assessed includes fuels product output with crude feed quality and a stable emission intensity term. Product-based metrics that exclude crude quality do not measure and predict emissions accurately or reliably. Including product volume in the emission term makes the emission performance measurement unstable, but this problem is readily resolved by including the fuels product and crude quality drivers in the metric side-by-side (see recs. 5, 8). Asphalt should be separated out from light liquid fuels, as these are different classes of products. Public reporting of each facility's products should be addressed.

8. Establish benchmarks and monitor performance using publicly reported data.

   Refinery performance can be measured and predicted based on publicly reported data. A benchmark that relies on secret data would violate basic scientific principles, be prone to the error secrecy breeds, and ultimately violate the environmental policy test that requirements imposed must have scientific support.

   The crude feed quality and fuels produced metric proposed herein measures and predicts emissions per barrel crude refined based on the density and sulfur content of crude feeds, refinery capacity utilization, and the ratio of light liquids (gasoline, distillate, kerosene and naphtha) to other refinery products. It is based on data for U.S. refining districts 1, 2, 3 and 5 over ten recent years. Energy intensity expected from these parameters is compared with fuels data using CO_2 emission factors developed for international reporting of greenhouse gas emissions in the U.S. Data and methods are freely available at http://pubs.acs.org/doi/abs/10.1021/es1019965.

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Technical Appendix, Oil Refinery CO_2 Performance Measurement

Part 2. Data.

Table 2-1. Oil refining data, California (2004–2009); U.S. PADDs 1, 2, 3 and 5 (1999–2008)

		Refinery crude inputs				Refinery process capacity		
California refineries		Feed volume ($m^3/d \times 10^3$)	Density (kg/m^3)	Sulfur (kg/m^3)	Source countries	Atm. dist. ($m^3/d \times 10^3$)	Vacuum dist. ($m^3/d \times 10^3$)	Coking & therm. ($m^3/d \times 10^3$)
Calif.	2004	285.239	899.23	11.46	20	306.623	177.001	77.331
Calif.	2005	293.702	900.56	11.82	24	309.167	177.621	77.729
Calif.	2006	285.519	899.56	11.73	22	312.028	181.548	77.967
Calif.	2007	278.419	899.84	11.89	26	315.288	183.535	79.573
Calif.	2008	285.636	902.00	12.85	23	313.972	185.093	78.452
Calif.	2009	263.568	901.38	11.70	21	318.010	189.099	78.611
Energy factor		--	--	--	--	--	--	--
CO_2 emission factor (kg/GJ)			--	--	--	--	--	--

		Refinery crude inputs				Refinery process capacity		
U.S. refineries PADD	Year	Feed volume ($m^3/d \times 10^3$)	Density (kg/m^3)	Sulfur (kg/m^3)	Source countries	Atm. dist. ($m^3/d \times 10^3$)	Vacuum dist. ($m^3/d \times 10^3$)	Coking & therm. ($m^3/d \times 10^3$)
1	1999	244.363	858.20	8.24	24	243.648	98.020	14.198
1	2000	247.543	860.18	8.00	23	245.922	97.213	14.404
1	2001	235.460	866.34	7.71	19	249.578	96.577	14.086
1	2002	242.456	865.71	7.45	20	252.217	97.424	14.420
1	2003	251.836	863.44	7.43	21	250.750	99.745	14.484
1	2004	249.610	865.44	7.79	21	250.246	99.741	14.484
1	2005	254.221	863.38	7.17	22	252.631	101.497	14.484
1	2006	236.255	864.12	7.17	21	252.631	101.490	14.484
1	2007	234.188	864.33	7.26	24	252.631	101.490	14.484
1	2008	221.151	863.65	7.08	24	252.631	101.490	14.484
2	1999	536.264	858.25	10.64	15	570.946	232.722	58.801
2	2000	542.147	860.03	11.35	16	569.841	236.251	60.978
2	2001	526.089	861.33	11.37	15	564.271	229.892	61.312
2	2002	511.621	861.02	11.28	20	557.754	225.920	56.983
2	2003	512.575	862.80	11.65	16	555.868	226.693	56.122
2	2004	524.817	865.65	11.86	20	555.281	229.605	58.178
2	2005	526.884	865.65	11.95	23	564.648	236.887	59.623
2	2006	526.089	865.44	11.60	20	565.065	238.954	59.480
2	2007	514.801	864.07	11.84	17	578.730	231.688	60.315
2	2008	515.755	862.59	11.73	16	579.803	234.657	59.226
3	1999	1,116.890	869.00	12.86	33	1,234.340	575.734	154.933
3	2000	1,130.240	870.29	12.97	31	1,234.360	591.069	164.981
3	2001	1,156.000	874.43	14.34	28	1,236.250	581.572	173.182
3	2002	1,127.860	876.70	14.47	33	1,258.170	574.493	187.174
3	2003	1,160.130	874.48	14.43	30	1,268.770	584.170	193.899
3	2004	1,191.450	877.79	14.40	33	1,280.320	604.415	200.467
3	2005	1,145.350	878.01	14.40	36	1,323.230	596.821	198.973
3	2006	1,172.530	875.67	14.36	41	1,333.830	598.501	201.898
3	2007	1,176.820	876.98	14.47	37	1,341.890	610.544	209.377
3	2008	1,118.790	878.66	14.94	36	1,337.700	614.105	210.458
5	1999	419.726	894.61	11.09	24	494.843	231.722	95.944
5	2000	430.856	895.85	10.84	23	498.357	231.523	97.144
5	2001	442.621	893.76	10.99	26	495.424	236.920	97.574
5	2002	447.867	889.99	10.86	27	484.218	234.193	98.337
5	2003	456.612	889.10	10.94	29	489.237	235.966	96.712
5	2004	454.863	888.87	11.20	28	487.232	234.784	96.950
5	2005	460.904	888.99	11.38	27	491.044	235.377	97.348
5	2006	456.930	887.65	10.92	30	494.415	239.304	97.586
5	2007	443.734	885.54	11.07	30	496.090	240.310	100.035
5	2008	447.390	890.16	12.11	30	497.296	244.113	97.928
Energy factor		--	--	--	--	--	--	--
CO_2 emission factor (kg/GJ)			--	--	--	--	--	--

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

		Refinery process capacity, *continued*					
California refineries		Cat. cracking ($m^3/d \times 10^3$)	Hydrocracking ($m^3/d \times 10^3$)	1º hydrotreating ($m^3/d \times 10^3$)[a]	2º hydrotreating ($m^3/d \times 10^3$)[a]	Reforming ($m^3/d \times 10^3$)	Alkylation ($m^3/d \times 10^3$)
Calif.	2004	103.437	68.436	80.384	187.621	63.706	25.470
Calif.	2005	103.437	69.644	80.416	186.762	63.865	25.883
Calif.	2006	105.663	76.020	78.190	198.146	68.380	27.950
Calif.	2007	108.488	77.729	81.608	192.001	69.207	27.950
Calif.	2008	106.866	77.729	80.098	193.848	68.635	27.704
Calif.	2009	104.951	80.233	80.098	193.419	68.635	27.918
Energy factor		--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--

		Refinery process capacity, *continued*					
U.S. refineries PADD	Year	Cat. cracking ($m^3/d \times 10^3$)	Hydrocracking ($m^3/d \times 10^3$)	1º hydrotreating ($m^3/d \times 10^3$)[a]	2º hydrotreating ($m^3/d \times 10^3$)[a]	Reforming ($m^3/d \times 10^3$)	Alkylation ($m^3/d \times 10^3$)
1	1999	104.757	6.662	13.196	128.255	45.667	12.821
1	2000	107.984	6.662	13.196	124.595	44.675	13.457
1	2001	99.240	6.805	7.154	130.303	44.834	12.813
1	2002	98.989	6.024	21.311	122.137	45.276	12.923
1	2003	98.273	6.024	14.729	137.793	45.483	12.899
1	2004	98.270	6.026	14.770	135.131	46.488	12.900
1	2005	99.701	6.026	14.770	132.269	46.806	13.355
1	2006	99.701	6.153	7.043	139.933	46.806	13.347
1	2007	99.701	6.153	7.043	140.569	46.806	13.347
1	2008	99.701	6.153	7.043	140.569	46.806	13.347
2	1999	193.249	25.327	71.258	299.120	135.335	39.270
2	2000	191.890	25.327	60.988	315.480	137.696	39.588
2	2001	188.217	23.864	54.008	329.612	134.351	39.397
2	2002	186.884	24.341	71.767	314.399	133.572	38.922
2	2003	184.753	24.103	73.551	348.438	133.391	38.347
2	2004	182.678	21.908	82.141	351.570	132.471	38.067
2	2005	185.546	27.982	83.301	380.895	133.677	39.844
2	2006	185.375	30.653	79.374	390.126	133.474	39.908
2	2007	180.097	37.012	79.295	385.279	134.603	39.113
2	2008	186.759	36.519	84.398	368.902	129.722	38.707
3	1999	431.654	112.650	186.378	640.377	273.083	86.019
3	2000	434.341	115.131	191.902	658.996	277.296	85.988
3	2001	449.640	118.422	159.000	704.826	268.398	85.139
3	2002	460.097	121.379	185.875	704.153	272.336	98.062
3	2003	458.206	113.588	213.565	763.848	270.876	89.818
3	2004	461.255	118.684	222.562	823.819	275.175	105.136
3	2005	464.750	114.391	221.912	874.860	268.593	91.440
3	2006	466.316	114.471	223.013	906.027	268.569	92.526
3	2007	467.278	120.589	247.174	910.060	274.583	89.071
3	2008	473.112	118.426	229.097	940.388	270.910	91.786
5	1999	126.300	80.888	96.299	215.884	87.627	29.279
5	2000	127.174	81.190	83.468	226.261	88.486	41.806
5	2001	126.951	81.921	86.139	226.419	89.499	29.325
5	2002	127.680	81.921	94.725	218.206	88.330	29.993
5	2003	126.037	80.432	80.527	239.567	88.473	31.138
5	2004	127.166	81.378	81.513	247.651	88.953	31.185
5	2005	127.619	82.586	81.545	246.430	89.462	31.527
5	2006	130.258	88.961	79.319	257.416	94.001	33.594
5	2007	133.322	92.213	82.737	260.238	96.338	33.618
5	2008	131.700	91.243	81.227	261.749	94.733	33.371
Energy factor		--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--

Data sources given in part 1 narrative description of data

(a) Primary processing (1º) of gas oil, residua and cat. cracking feeds or secondary processing (2º) of product streams

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

		Refinery process capacity, *continued*						
California		Pol./Dim.	Aromatics	Isomerization	Lubes	Asphalt	Sulfur	H_2 (total)
refineries		($m^3/d \times 10^3$)	($m^3/d \times 10^3$)	($m^3/d \times 10^3$)	($m^3/d \times 10^3$)	($m^3/d \times 10^3$)	($kg/d \times 10^5$)	($m^3 \times 10^8$)
Calif.	2004	1.542	0.000	24.166	2.862	6.598	37.780	131.542
Calif.	2005	1.653	0.000	24.842	2.862	6.836	38.080	132.523
Calif.	2006	1.956	0.000	26.893	3.180	6.598	41.990	142.094
Calif.	2007	1.442	0.000	25.176	3.180	6.836	39.030	145.030
Calif.	2008	1.442	0.000	24.678	3.180	6.836	42.090	145.030
Calif.	2009	1.442	0.000	24.682	3.180	9.778	44.040	145.030
Energy factor		--	--	--	--	--	--	
CO_2 emission fa		--	--	--	--	--	--	

		Refinery process capacity, *continued*						
U.S. refineries		Pol./Dim.	Aromatics	Isomerization	Lubes	Asphalt	Sulfur	H_2 (total)
PADD	Year	($m^3/d \times 10^3$)	($m^3/d \times 10^3$)	($m^3/d \times 10^3$)	($m^3/d \times 10^3$)	($m^3/d \times 10^3$)	($kg/d \times 10^5$)	($m^3 \times 10^8$)
1	1999	2.836	8.611	4.473	3.685	10.334	9.210	11.783
1	2000	2.836	8.515	4.309	3.005	4.611	9.210	14.056
1	2001	2.121	8.515	5.262	3.005	4.611	8.560	11.576
1	2002	2.121	8.515	6.105	2.989	4.452	12.650	10.232
1	2003	2.121	8.515	8.685	2.989	4.452	13.010	15.090
1	2004	2.121	8.515	8.776	3.005	4.452	13.010	15.090
1	2005	2.121	8.515	8.776	3.005	4.452	13.190	15.297
1	2006	2.121	8.515	8.780	3.005	4.452	13.190	17.364
1	2007	2.121	8.515	8.780	3.005	4.452	12.850	13.333
1	2008	2.121	8.515	8.780	3.005	4.452	12.850	13.333
2	1999	2.083	9.242	27.958	2.639	34.930	44.360	44.237
2	2000	2.083	9.235	27.640	2.639	37.632	44.020	44.030
2	2001	2.083	9.235	27.568	2.639	36.170	44.250	47.751
2	2002	1.361	8.876	26.983	2.766	36.678	46.720	43.926
2	2003	1.359	8.876	28.634	2.766	37.267	48.180	40.619
2	2004	1.289	8.765	29.001	2.766	37.052	46.310	41.032
2	2005	1.278	8.383	29.079	2.687	38.141	51.400	49.611
2	2006	1.278	9.194	29.397	2.687	38.968	52.430	77.000
2	2007	1.278	6.571	29.444	2.687	31.511	46.000	77.931
2	2008	1.304	6.571	27.839	1.351	36.082	52.000	78.551
3	1999	3.100	40.811	45.229	17.862	19.304	140.920	146.456
3	2000	2.973	42.024	43.472	18.013	19.667	152.970	148.833
3	2001	2.973	42.604	42.911	17.719	18.481	152.660	155.655
3	2002	3.530	43.096	45.510	17.449	19.044	165.160	160.512
3	2003	3.545	40.724	45.720	17.926	25.692	171.340	160.512
3	2004	3.784	43.857	44.720	19.818	24.087	193.950	174.362
3	2005	3.466	43.538	43.450	23.435	19.365	191.350	172.398
3	2006	3.450	42.393	43.116	23.514	19.137	193.930	162.269
3	2007	6.458	50.263	39.229	22.818	19.375	190.130	160.822
3	2008	6.458	57.865	42.845	22.815	19.375	192.430	164.233
5	1999	2.242	0.397	20.970	4.372	11.908	41.520	126.301
5	2000	2.337	0.397	21.416	4.372	12.147	41.520	151.934
5	2001	2.337	0.445	21.416	4.372	10.779	41.520	149.247
5	2002	2.337	0.445	21.468	3.418	7.425	42.300	151.004
5	2003	2.353	0.445	27.165	3.418	9.794	43.310	148.523
5	2004	2.385	0.401	26.592	2.862	9.201	42.860	147.903
5	2005	2.496	0.358	27.274	2.862	9.396	45.200	149.557
5	2006	2.798	0.215	29.373	3.180	9.158	49.110	159.169
5	2007	2.285	0.193	32.584	3.180	9.396	45.390	162.786
5	2008	2.285	0.193	31.705	3.180	9.396	50.110	162.786
Energy factor		--	--	--	--	--	--	16.4 MJ/m^3
CO_2 emission fa		--	--	--	--	--	--	52.70

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

		Fuels consumed in refineries						
California refineries		H_2 (purch.) ($m^3 \times 10^8$)	Crude oil ($m^3 \times 10^4$)	LPG ($m^3 \times 10^4$)	Distillate ($m^3 \times 10^4$)	Res. fuel oil ($m^3 \times 10^4$)	Fuel gas (bl) ($m^3 \times 10^4$)	Pet. coke ($m^3 \times 10^4$)
Calif.	2004	14.418	0.000	25.803	0.000	0.000	629.035	185.480
Calif.	2005	14.470	0.000	27.129	0.000	0.000	648.594	197.475
Calif.	2006	14.056	0.000	16.132	1.244	0.000	633.147	251.324
Calif.	2007	29.146	0.000	15.421	1.001	0.000	622.581	241.058
Calif.	2008	29.146	0.000	15.982	1.939	0.000	601.661	227.776
Calif.	2009	29.146	0.000	14.781	2.507	0.000	556.490	210.530
Energy factor		16.4 MJ/m³	38.49 GJ/m³	25.62 GJ/m³	38.66 GJ/m³	41.72 GJ/m³	39.82 GJ/m³	39.98 GJ/m³
CO_2 emission fa		52.70	78.53	65.76	77.18	83.14	67.73	107.74

		Fuels consumed in refineries						
U.S. refineries PADD	Year	H_2 (purch.) ($m^3 \times 10^8$)	Crude oil ($m^3 \times 10^4$)	LPG ($m^3 \times 10^4$)	Distillate ($m^3 \times 10^4$)	Res. fuel oil ($m^3 \times 10^4$)	Fuel gas (bl) ($m^3 \times 10^4$)	Pet. coke ($m^3 \times 10^4$)
1	1999		0.000	2.766	2.035	37.012	323.87	205.380
1	2000		0.000	5.008	4.166	38.904	319.90	190.928
1	2001		0.000	5.819	8.967	44.675	323.22	189.751
1	2002		0.000	4.483	7.631	29.190	339.87	188.050
1	2003		0.000	7.854	9.921	28.014	353.29	196.492
1	2004		0.000	7.870	7.409	18.013	354.19	203.774
1	2005		0.000	11.479	5.819	18.220	354.81	203.695
1	2006		0.000	5.231	0.366	14.627	337.56	175.411
1	2007		0.000	2.941	0.350	13.132	363.92	190.356
1	2008		0.000	0.827	0.461	6.344	339.09	193.933
2	1999		0.000	27.123	0.986	43.531	766.67	296.972
2	2000		0.000	14.484	0.763	34.166	773.41	293.348
2	2001		0.000	13.975	1.288	38.888	766.97	276.431
2	2002		0.000	16.439	1.081	29.747	732.93	276.892
2	2003		0.000	25.804	0.588	9.380	729.70	273.569
2	2004		0.000	17.155	0.588	3.100	792.49	253.394
2	2005		0.000	12.385	0.795	2.592	798.32	275.716
2	2006		0.000	9.015	0.715	3.275	788.34	262.361
2	2007		0.000	13.387	0.747	3.005	785.86	249.626
2	2008		0.000	12.783	0.700	3.084	777.16	238.560
3	1999		0.159	12.560	1.892	0.191	1,812.63	662.230
3	2000		0.000	13.085	2.798	0.032	1,841.63	674.535
3	2001		0.000	11.018	2.178	0.000	1,775.65	668.224
3	2002		0.000	13.450	1.336	0.000	1,811.93	668.907
3	2003		0.000	17.489	0.700	0.000	1,949.71	679.718
3	2004		0.000	5.898	1.304	0.000	1,908.64	695.951
3	2005		0.000	5.708	1.367	0.064	1,777.45	656.602
3	2006		0.000	4.404	1.765	0.016	1,988.07	724.807
3	2007		0.000	3.307	1.828	0.048	1,922.63	679.639
3	2008		0.000	8.204	1.701	0.048	1,819.56	625.981
5	1999		0.000	18.649	4.086	9.015	728.04	211.739
5	2000		0.000	34.151	3.736	11.081	742.82	223.139
5	2001		0.000	47.251	4.436	13.609	770.31	228.274
5	2002		0.000	19.587	3.307	14.341	706.94	226.398
5	2003		0.000	34.484	3.911	11.558	743.54	238.227
5	2004		0.000	24.627	3.657	11.495	739.64	244.411
5	2005		0.000	36.424	4.022	11.558	726.57	244.379
5	2006		0.000	23.339	4.054	12.242	715.43	231.327
5	2007		0.000	22.497	3.752	11.813	724.24	230.865
5	2008		0.000	23.991	4.642	11.845	689.74	196.508
Energy factor			38.49 GJ/m³	25.62 GJ/m³	38.66 GJ/m³	41.72 GJ/m³	39.82 GJ/m³	39.98 GJ/m³
CO_2 emission factor (kg/GJ)			78.53	65.76	77.18	83.14	67.73	107.74

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

		Fuels consumed in refineries *continued* ----------------------					Refinery products yield ——	
California refineries		Other products (petajoules)	Natural gas (m^3 x 10^7)	Coal (Gg)	lectricity pur- :hased (TWh)	Steam pur- chased (Tg)	LPG (%)	Fin. motor gasoline (%)
Calif.	2004	5.112	366.244	0.000	2.972	5.268	2.2	53.4
Calif.	2005	6.461	375.964	0.000	3.107	5.674	2.0	53.3
Calif.	2006	5.583	372.101	0.000	3.257	5.766	1.7	53.9
Calif.	2007	5.583	390.180	0.000	3.113	5.728	1.7	53.7
Calif.	2008	5.583	404.019	0.000	3.304	5.559	1.7	50.6
Calif.	2009	5.583	414.216	0.000	3.059	5.846	1.6	53.5
Energy factor		Million GJ	38.27 MJ/m^3	25.80 MJ/kg	3.60 MJ/kWh	2.18 MJ/kg	--	--
CO_2 emission fa		73.20	55.98	99.58	97.22	91.63	--	--

		Fuels consumed in refineries *continued* ----------------------					Refinery products yield ---	
U.S. refineries PADD	Year	Other products (m^3 x 10^4)	Natural gas (m^3 x 10^7)	Coal (Gg)	lectricity pur- :hased (TWh)	Steam pur- chased (Tg)	LPG (%)	Fin. motor gasoline (%)
1	1999	6.964	115.01	28.123	3.180	1.599	2.5	46.6
1	2000	6.105	125.53	27.216	3.084	1.897	2.8	45.2
1	2001	5.406	99.15	29.030	3.450	1.797	2.9	45.8
1	2002	5.851	110.86	28.123	3.282	1.865	3.0	46.7
1	2003	7.059	80.32	29.030	3.415	1.674	3.0	46.4
1	2004	2.242	91.77	26.308	3.410	2.352	2.6	46.5
1	2005	2.242	100.82	29.937	3.520	2.228	2.4	46.6
1	2006	0.859	102.58	28.123	3.576	2.593	2.6	45.8
1	2007	0.334	81.29	29.030	3.984	2.624	3.2	45.5
1	2008	0.461	78.92	28.123	4.192	2.361	3.3	44.6
2	1999	22.560	263.17	0.000	8.956	1.262	3.7	51.1
2	2000	19.047	300.38	1.814	8.949	0.890	3.7	50.4
2	2001	20.382	265.10	6.350	8.728	2.060	3.6	51.1
2	2002	19.555	272.35	0.000	8.933	2.368	3.5	52.0
2	2003	16.392	267.27	8.165	8.885	2.577	3.3	51.5
2	2004	27.855	292.54	7.258	9.486	2.863	3.3	51.6
2	2005	26.805	301.52	7.258	9.875	2.283	3.1	50.4
2	2006	31.177	324.85	2.722	10.488	3.310	4.0	49.4
2	2007	6.280	339.94	6.350	10.555	4.871	3.9	49.8
2	2008	0.286	393.30	10.886	10.804	5.000	3.5	48.5
3	1999	31.177	1,476.83	0.000	13.762	8.968	6.1	44.8
3	2000	34.405	1,475.41	0.000	14.501	11.455	6.0	44.7
3	2001	30.923	1,383.25	0.000	15.868	13.142	5.6	44.3
3	2002	21.479	1,298.76	0.000	16.145	14.670	5.8	45.4
3	2003	29.874	1,217.06	0.000	15.682	14.456	5.5	44.8
3	2004	22.544	1,118.96	0.000	17.044	14.827	5.3	44.6
3	2005	20.668	1,121.29	0.000	16.620	15.757	4.7	43.8
3	2006	31.336	1,120.29	0.000	18.612	17.690	4.8	43.5
3	2007	24.007	1,027.91	0.000	20.433	28.790	5.0	43.2
3	2008	26.996	1,078.93	0.000	20.675	28.919	5.1	41.6
5	1999	25.851	347.54	0.000	5.389	8.469	2.6	44.7
5	2000	26.185	382.68	0.000	4.809	8.268	3.1	45.7
5	2001	22.576	348.67	0.000	4.695	7.881	2.7	45.5
5	2002	22.672	387.33	0.000	4.780	7.589	2.7	47.3
5	2003	25.740	374.77	0.000	4.520	8.595	2.9	47.2
5	2004	31.305	353.35	0.000	4.871	8.732	2.6	47.3
5	2005	27.028	349.06	0.000	4.978	8.145	2.5	47.3
5	2006	34.961	357.33	0.000	4.973	8.164	2.8	47.7
5	2007	27.282	378.63	0.000	5.113	8.091	2.8	46.6
5	2008	32.227	396.29	0.000	5.125	8.064	2.8	45.6
Energy factor		38.66 GJ/m^3	38.27 MJ/m^3	25.80 MJ/kg	3.60 MJ/kWh	2.18 MJ/kg	--	--
CO_2 emission fa		73.20	55.98	99.58	187.78	91.63	--	--

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

California refineries		Refinery products yield *continued* Aviation gasoline (%)	Kerosene jet fuel (%)	Kerosene (%)	Distillate fuel oil (%)	Residual fuel oil (%)	Naphtha for chem FS (%)	Oth. oils for chem FS (%)
Calif.	2004	0.2	13.7	0.0	17.3	3.7	0.0	0.5
Calif.	2005	0.1	13.6	0.0	18.8	3.4	0.0	0.5
Calif.	2006	0.1	13.3	0.0	18.7	3.4	0.0	0.5
Calif.	2007	0.1	12.9	0.0	19.2	3.9	0.0	0.3
Calif.	2008	0.1	15.7	0.0	20.6	3.2	0.0	0.1
Calif.	2009	0.0	14.3	0.0	18.7	3.1	0.0	0.4
Energy factor		--	--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--	--

U.S. refineries PADD	Year	Refinery products yield *continued* Aviation gasoline (%)	Kerosene jet fuel (%)	Kerosene (%)	Distillate fuel oil (%)	Residual fuel oil (%)	Naphtha for chem FS (%)	Oth. oils for chem FS (%)
1	1999	0.2	7.0	0.8	26.3	6.5	0.8	0.0
1	2000	0.2	6.3	0.8	27.9	6.8	0.8	0.0
1	2001	0.2	5.3	0.8	29.1	6.6	0.8	0.0
1	2002	0.3	5.3	0.8	28.1	5.7	0.9	0.0
1	2003	0.2	5.2	0.8	27.2	7.8	0.8	0.0
1	2004	0.4	6.1	0.7	26.6	6.9	0.8	0.0
1	2005	0.3	5.7	0.7	28.8	6.2	0.8	0.0
1	2006	0.0	5.1	0.4	29.2	7.1	1.1	0.0
1	2007	0.1	5.0	0.5	29.4	7.2	1.1	0.0
1	2008	0.0	5.7	0.6	29.6	7.1	1.1	0.0
2	1999	0.1	6.6	0.5	24.8	1.6	0.6	0.7
2	2000	0.1	6.9	0.4	25.7	1.8	0.5	0.4
2	2001	0.1	6.6	0.4	26.0	2.0	0.6	0.0
2	2002	0.1	6.7	0.3	25.4	1.8	0.6	0.0
2	2003	0.1	6.2	0.3	26.0	1.7	0.5	0.0
2	2004	0.1	6.4	0.3	25.7	1.8	0.8	0.3
2	2005	0.1	6.5	0.3	27.1	1.6	0.8	0.3
2	2006	0.1	6.2	0.3	27.3	1.7	0.9	0.2
2	2007	0.1	6.1	0.1	28.2	1.7	0.9	0.2
2	2008	0.1	6.3	0.0	30.0	1.6	0.8	0.2
3	1999	0.2	11.1	0.4	21.1	4.3	2.1	2.5
3	2000	0.1	11.1	0.4	21.9	4.6	2.2	2.3
3	2001	0.1	10.5	0.6	22.8	4.8	1.7	2.1
3	2002	0.1	10.3	0.4	22.3	3.7	2.7	1.9
3	2003	0.1	9.9	0.4	23.0	4.1	2.6	2.3
3	2004	0.1	10.0	0.5	23.5	3.9	2.8	2.4
3	2005	0.1	10.2	0.6	24.5	3.9	2.3	2.1
3	2006	0.2	9.7	0.4	25.2	3.8	1.9	2.4
3	2007	0.1	9.4	0.3	26.0	4.1	1.9	2.4
3	2008	0.1	9.6	0.0	28.4	4.0	1.5	2.3
5	1999	0.1	15.8	0.2	18.3	8.5	0.2	0.3
5	2000	0.1	16.2	0.2	18.5	6.8	0.1	0.3
5	2001	0.1	16.0	0.1	19.2	6.9	0.1	0.3
5	2002	0.1	16.0	0.1	19.0	6.2	0.1	0.3
5	2003	0.1	16.0	0.0	19.5	5.8	0.1	0.3
5	2004	0.1	16.2	0.0	19.5	6.1	0.0	0.3
5	2005	0.1	16.2	0.0	20.4	5.8	0.0	0.4
5	2006	0.1	15.3	0.0	20.3	5.8	0.0	0.4
5	2007	0.1	15.6	0.0	20.8	6.3	0.0	0.3
5	2008	0.1	17.5	0.0	21.6	5.5	0.0	0.1
Energy factor		--	--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--	--

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

California refineries		Refinery products yield *continued* — Special naphtha (%)	Lubricants (%)	Waxes (%)	Petroleum coke (%)	Asphalt & road oil (%)	Fuel gas (%)	Miscellaneous products (%)	Utilization of operable ref. capacity (%)
Calif.	2004	0.0	1.0	0.0	7.4	2.1	6.1	0.4	93.0
Calif.	2005	0.0	1.0	0.0	7.7	1.8	5.7	0.4	95.0
Calif.	2006	0.0	1.0	0.0	7.4	2.0	5.7	0.6	91.5
Calif.	2007	0.0	0.9	0.0	7.1	2.2	5.8	0.6	88.3
Calif.	2008	0.0	1.1	0.0	7.4	1.5	5.5	0.8	91.0
Calif.	2009	0.0	1.1	0.0	7.6	1.5	5.3	0.8	82.9
Energy factor		--	--	--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--	--	--

U.S. refineries PADD	Year	Refinery products yield *continued* — Special naphtha (%)	Lubricants (%)	Waxes (%)	Petroleum coke (%)	Asphalt & road oil (%)	Fuel gas (%)	Miscellaneous products (%)	Utilization of operable ref. capacity (%)
1	1999	0.1	1.0	0.0	3.1	5.4	3.7	0.1	90.9
1	2000	0.1	0.9	0.1	3.0	6.1	3.5	0.1	91.7
1	2001	0.1	0.9	0.0	3.3	6.0	3.8	0.1	87.2
1	2002	0.1	1.0	0.0	3.1	6.0	3.9	0.1	88.9
1	2003	0.1	1.0	0.0	2.9	5.7	3.8	0.1	92.7
1	2004	0.1	1.1	0.0	3.1	6.2	3.9	0.1	90.4
1	2005	0.1	1.0	0.0	2.9	5.7	3.8	0.1	93.1
1	2006	0.1	1.1	0.0	3.0	5.6	3.6	0.2	86.7
1	2007	0.0	1.0	0.0	3.2	5.0	3.9	0.2	85.6
1	2008	0.0	1.1	0.1	3.3	5.1	3.8	0.2	80.8
2	1999	0.7	0.6	0.1	4.2	5.6	3.9	0.3	93.3
2	2000	0.7	0.5	0.1	4.3	5.5	3.9	0.3	94.2
2	2001	0.6	0.4	0.1	4.3	5.1	4.0	0.3	93.9
2	2002	0.5	0.5	0.1	4.1	5.3	4.0	0.4	90.0
2	2003	0.6	0.5	0.1	4.2	5.6	4.1	0.4	91.6
2	2004	0.1	0.4	0.1	4.3	5.7	4.1	0.4	93.6
2	2005	0.2	0.4	0.1	4.5	5.7	4.1	0.5	92.9
2	2006	0.2	0.5	0.1	4.4	6.1	4.1	0.5	92.4
2	2007	0.1	0.4	0.1	4.3	5.3	4.2	0.4	90.1
2	2008	0.1	0.4	0.1	4.3	5.3	4.0	0.4	88.4
3	1999	0.8	1.7	0.2	4.8	1.7	4.1	0.4	94.7
3	2000	0.4	1.7	0.2	4.8	1.8	4.1	0.4	93.9
3	2001	0.4	1.6	0.1	5.3	1.6	4.1	0.5	94.8
3	2002	0.4	1.6	0.1	5.7	1.6	4.2	0.5	91.5
3	2003	0.4	1.5	0.1	5.7	1.6	4.4	0.5	93.6
3	2004	0.5	1.6	0.1	5.9	1.5	4.3	0.4	94.1
3	2005	0.4	1.6	0.1	6.0	1.6	4.3	0.4	88.3
3	2006	0.4	1.7	0.1	6.2	1.5	4.6	0.5	88.7
3	2007	0.5	1.7	0.1	6.0	1.3	4.3	0.5	88.7
3	2008	0.5	1.7	0.1	6.0	1.1	4.4	0.6	83.6
5	1999	0.1	1.0	0.0	6.1	2.4	5.8	0.2	87.1
5	2000	0.1	0.9	-0.1	6.3	2.4	5.6	0.3	87.5
5	2001	0.1	1.0	0.0	6.0	2.1	5.8	0.3	89.1
5	2002	0.1	0.8	0.0	6.0	2.1	5.5	0.3	90.0
5	2003	0.1	0.8	0.0	6.2	1.9	5.6	0.3	91.3
5	2004	0.0	0.7	0.0	6.1	1.9	5.4	0.3	90.4
5	2005	0.0	0.7	0.0	6.2	1.7	5.1	0.3	91.7
5	2006	0.1	0.7	0.0	6.0	1.8	5.2	0.4	90.5
5	2007	0.0	0.6	0.0	5.8	1.8	5.4	0.4	87.6
5	2008	0.0	0.8	0.0	6.1	1.4	5.1	0.5	88.1
Energy factor		--	--	--	--	--	--	--	--
CO_2 emission fa		--	--	--	--	--	--	--	--

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

		Energy consumed/vol. crude feed (GJ/m^3) and CO_2 emitted/vol. crude feed (kg/m^3) for refinery fuels									
California		3rd-party H_2 prod.		Crude oil consmd.		LPG consumed		Distillate consmd.		Res. Fuel Oil cons.	
refineries		(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)
Calif.	2004	0.204	10.77	0.000	0.00	0.063	4.18	0.000	0.00	0.000	0.00
Calif.	2005	0.199	10.50	0.000	0.00	0.065	4.26	0.000	0.00	0.000	0.00
Calif.	2006	0.199	10.49	0.000	0.00	0.040	2.61	0.005	0.36	0.000	0.00
Calif.	2007	0.423	22.31	0.000	0.00	0.039	2.56	0.004	0.29	0.000	0.00
Calif.	2008	0.413	21.75	0.000	0.00	0.039	2.58	0.007	0.55	0.000	0.00
Calif.	2009	0.447	23.57	0.000	0.00	0.039	2.59	0.010	0.78	0.000	0.00
Energy factor		16.4 MJ/m^3		38.49 GJ/m^3		25.62 GJ/m^3		38.66 GJ/m^3		41.72 GJ/m^3	
CO_2 emission fa		--	52.70	--	78.53	--	65.76	--	77.18	--	83.14

		Energy consumed/vol. crude feed (GJ/m^3) and CO_2 emitted/vol. crude feed (kg/m^3) for refinery fuels									
U.S. refineries		Hydrogen prod.		Crude oil consmd.		LPG consumed		Distillate consmd.		Res. Fuel Oil cons.	
PADD	Year	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)
1	1999	0.195	10.28	0.000	0.00	0.008	0.52	0.009	0.68	0.173	14.39
1	2000	0.230	12.10	0.000	0.00	0.014	0.93	0.018	1.38	0.180	14.94
1	2001	0.199	10.48	0.000	0.00	0.017	1.14	0.040	3.11	0.217	18.03
1	2002	0.171	8.99	0.000	0.00	0.013	0.85	0.033	2.57	0.138	11.44
1	2003	0.242	12.77	0.000	0.00	0.022	1.44	0.042	3.22	0.127	10.57
1	2004	0.245	12.88	0.000	0.00	0.022	1.46	0.031	2.43	0.083	6.86
1	2005	0.243	12.82	0.000	0.00	0.032	2.08	0.024	1.87	0.082	6.81
1	2006	0.297	15.66	0.000	0.00	0.016	1.02	0.002	0.13	0.071	5.88
1	2007	0.230	12.13	0.000	0.00	0.009	0.58	0.002	0.12	0.064	5.33
1	2008	0.244	12.85	0.000	0.00	0.003	0.17	0.002	0.17	0.033	2.73
2	1999	0.334	17.58	0.000	0.00	0.036	2.33	0.002	0.15	0.093	7.71
2	2000	0.328	17.31	0.000	0.00	0.019	1.23	0.002	0.12	0.072	5.99
2	2001	0.367	19.34	0.000	0.00	0.019	1.23	0.003	0.20	0.085	7.02
2	2002	0.347	18.30	0.000	0.00	0.023	1.48	0.002	0.17	0.067	5.53
2	2003	0.321	16.89	0.000	0.00	0.035	2.32	0.001	0.09	0.021	1.74
2	2004	0.316	16.66	0.000	0.00	0.023	1.51	0.001	0.09	0.007	0.56
2	2005	0.381	20.07	0.000	0.00	0.017	1.09	0.002	0.12	0.006	0.47
2	2006	0.592	31.19	0.000	0.00	0.012	0.79	0.001	0.11	0.007	0.59
2	2007	0.612	32.26	0.000	0.00	0.018	1.20	0.002	0.12	0.007	0.55
2	2008	0.616	32.46	0.000	0.00	0.017	1.14	0.001	0.11	0.007	0.57
3	1999	0.530	27.94	0.000	0.01	0.008	0.52	0.002	0.14	0.000	0.02
3	2000	0.533	28.06	0.000	0.00	0.008	0.53	0.003	0.20	0.000	0.00
3	2001	0.545	28.70	0.000	0.00	0.007	0.44	0.002	0.15	0.000	0.00
3	2002	0.576	30.33	0.000	0.00	0.008	0.55	0.001	0.10	0.000	0.00
3	2003	0.560	29.49	0.000	0.00	0.011	0.70	0.001	0.05	0.000	0.00
3	2004	0.592	31.19	0.000	0.00	0.004	0.23	0.001	0.09	0.000	0.00
3	2005	0.609	32.08	0.000	0.00	0.004	0.23	0.001	0.10	0.000	0.01
3	2006	0.560	29.49	0.000	0.00	0.003	0.17	0.002	0.12	0.000	0.00
3	2007	0.553	29.12	0.000	0.00	0.002	0.13	0.002	0.13	0.000	0.00
3	2008	0.594	31.28	0.000	0.00	0.005	0.34	0.002	0.12	0.000	0.00
5	1999	1.217	64.13	0.000	0.00	0.031	2.05	0.010	0.80	0.025	2.04
5	2000	1.426	75.15	0.000	0.00	0.056	3.66	0.009	0.71	0.029	2.44
5	2001	1.364	71.86	0.000	0.00	0.075	4.93	0.011	0.82	0.035	2.92
5	2002	1.363	71.85	0.000	0.00	0.031	2.02	0.008	0.60	0.037	3.04
5	2003	1.315	69.32	0.000	0.00	0.053	3.49	0.009	0.70	0.029	2.41
5	2004	1.315	69.29	0.000	0.00	0.038	2.50	0.009	0.66	0.029	2.40
5	2005	1.312	69.15	0.000	0.00	0.056	3.65	0.009	0.71	0.029	2.38
5	2006	1.409	74.24	0.000	0.00	0.036	2.36	0.009	0.73	0.031	2.55
5	2007	1.484	78.18	0.000	0.00	0.036	2.34	0.009	0.69	0.030	2.53
5	2008	1.471	77.54	0.000	0.00	0.038	2.48	0.011	0.85	0.030	2.52
Energy factor		16.4 MJ/m^3		38.49 GJ/m^3		25.62 GJ/m^3		38.66 GJ/m^3		41.72 GJ/m^3	
CO_2 emission fa		--	52.70	--	78.53	--	65.76	--	77.18	--	83.14

Data sources given in part 1 narrative description of data

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

		Energy consumed (GJ/m³) and CO_2 emitted/vol. crude feed (kg/m³) for refinery fuels *continued*									
California		Fuel Gas (bl)		Petroleum coke		Other products		Natural Gas		Coal consumed	
refineries		(GJ/m³)	(kg/m³)	(GJ/m³)	(kg/m³)	(GJ/m³)	(kg/m³)	(GJ/m³)	(kg/m³)	(GJ/m³)	(kg/m³)
Calif.	2004	2.406	162.95	0.712	76.74	0.049	3.59	1.346	75.36	0.000	0.00
Calif.	2005	2.409	163.18	0.736	79.35	0.060	4.41	1.342	75.13	0.000	0.00
Calif.	2006	2.419	163.85	0.964	103.88	0.054	3.92	1.366	76.49	0.000	0.00
Calif.	2007	2.440	165.23	0.948	102.18	0.055	4.02	1.469	82.26	0.000	0.00
Calif.	2008	2.298	155.64	0.873	94.11	0.054	3.92	1.483	83.02	0.000	0.00
Calif.	2009	2.303	156.01	0.875	94.26	0.058	4.25	1.648	92.24	0.000	0.00
Energy factor		39.82 GJ/m³		39.98 GJ/m³		38.66 GJ/m³		38.27 MJ/m³		25.80 MJ/kg	
CO_2 emission fa		--	67.73	--	107.74	--	73.20	--	55.98	--	99.58

		Energy consumed (GJ/m³) and CO_2 emitted/vol. crude feed (kg/m³) for refinery fuels *continued*									
U.S. refineries		Fuel Gas (bl)		Petroleum coke		Other products		Natural Gas		Coal consumed	
PADD	Year	(GJ/m³)	(kg/m³)	(GJ/m³)	(kg/m³)	(GJ/m³)	(kg/m³)	(GJ/m³)	(kg/m³)	(GJ/m³)	(kg/m³)
1	1999	1.446	97.93	0.921	99.19	0.030	2.21	0.494	27.63	0.008	0.81
1	2000	1.410	95.49	0.845	91.02	0.026	1.91	0.532	29.76	0.008	0.77
1	2001	1.498	101.43	0.883	95.10	0.024	1.78	0.442	24.72	0.009	0.87
1	2002	1.529	103.58	0.850	91.53	0.026	1.87	0.479	26.84	0.008	0.82
1	2003	1.530	103.66	0.855	92.08	0.030	2.17	0.334	18.72	0.008	0.81
1	2004	1.548	104.85	0.894	96.34	0.010	0.70	0.386	21.58	0.008	0.74
1	2005	1.523	103.13	0.878	94.56	0.009	0.68	0.416	23.28	0.008	0.83
1	2006	1.559	105.58	0.813	87.62	0.004	0.28	0.455	25.48	0.008	0.84
1	2007	1.695	114.82	0.890	95.92	0.002	0.11	0.364	20.37	0.009	0.87
1	2008	1.673	113.30	0.961	103.49	0.002	0.16	0.374	20.95	0.009	0.90
2	1999	1.560	105.64	0.607	65.35	0.045	3.26	0.515	28.80	0.000	0.00
2	2000	1.556	105.41	0.593	63.85	0.037	2.72	0.581	32.52	0.000	0.02
2	2001	1.591	107.72	0.576	62.01	0.041	3.00	0.528	29.58	0.001	0.09
2	2002	1.563	105.85	0.593	63.87	0.041	2.96	0.558	31.24	0.000	0.00
2	2003	1.553	105.19	0.585	62.99	0.034	2.48	0.547	30.60	0.001	0.11
2	2004	1.647	111.58	0.529	56.98	0.056	4.12	0.584	32.72	0.001	0.10
2	2005	1.653	111.96	0.573	61.76	0.054	3.94	0.600	33.59	0.001	0.10
2	2006	1.635	110.72	0.546	58.85	0.063	4.59	0.647	36.24	0.000	0.04
2	2007	1.665	112.80	0.531	57.22	0.013	0.95	0.692	38.76	0.001	0.09
2	2008	1.644	111.34	0.507	54.59	0.001	0.04	0.800	44.76	0.002	0.15
3	1999	1.771	119.92	0.650	69.97	0.030	2.16	1.386	77.61	0.000	0.00
3	2000	1.778	120.40	0.654	70.43	0.032	2.36	1.369	76.62	0.000	0.00
3	2001	1.676	113.50	0.633	68.22	0.028	2.07	1.255	70.23	0.000	0.00
3	2002	1.753	118.71	0.650	69.99	0.020	1.48	1.207	67.59	0.000	0.00
3	2003	1.834	124.18	0.642	69.14	0.027	2.00	1.100	61.57	0.000	0.00
3	2004	1.748	118.37	0.640	68.93	0.020	1.47	0.985	55.12	0.000	0.00
3	2005	1.693	114.67	0.628	67.65	0.019	1.40	1.027	57.46	0.000	0.00
3	2006	1.850	125.28	0.677	72.95	0.028	2.07	1.002	56.08	0.000	0.00
3	2007	1.782	120.72	0.633	68.15	0.022	1.58	0.916	51.27	0.000	0.00
3	2008	1.774	120.17	0.613	66.03	0.026	1.87	1.011	56.60	0.000	0.00
5	1999	1.892	128.17	0.553	59.53	0.065	4.78	0.868	48.60	0.000	0.00
5	2000	1.881	127.39	0.567	61.12	0.064	4.71	0.931	52.13	0.000	0.00
5	2001	1.899	128.60	0.565	60.86	0.054	3.95	0.826	46.24	0.000	0.00
5	2002	1.722	116.63	0.554	59.66	0.054	3.92	0.907	50.76	0.000	0.00
5	2003	1.777	120.32	0.572	61.57	0.060	4.37	0.861	48.17	0.000	0.00
5	2004	1.774	120.15	0.589	63.41	0.073	5.34	0.815	45.60	0.000	0.00
5	2005	1.720	116.48	0.581	62.57	0.062	4.55	0.794	44.45	0.000	0.00
5	2006	1.708	115.69	0.555	59.75	0.081	5.93	0.820	45.90	0.000	0.00
5	2007	1.781	120.60	0.570	61.40	0.065	4.77	0.895	50.08	0.000	0.00
5	2008	1.682	113.92	0.481	51.83	0.076	5.58	0.929	51.99	0.000	0.00
Energy factor		39.82 GJ/m³		39.98 GJ/m³		38.66 GJ/m³		38.27 MJ/m³		25.80 MJ/kg	
CO_2 emission fa		--	67.73	--	107.74	--	73.20	--	55.98	--	99.58

Data sources given in part 1 narrative

Table 2-1. Oil refining data, Calif. (2004–2009); PADDs 1, 2, 3 and 5 (1999–2008) *continued*

California refineries		Energy consumed & CO_2 emitted/vol. crude feed for refinery fuels *continued* Electricity purchased (GJ/m³)	(kg/m³)	Steam purchased (GJ/m³)	(kg/m³)	Refinery energy intensity *(EI)* (GJ/m³)	Fuel mix emit intensity (CO_2) (kg/GJ)	Refinery emission intensity (CO_2) (kg/m³)
Calif.	2004	0.103	9.99	0.110	10.11	4.994	70.82	353.7
Calif.	2005	0.104	10.14	0.115	10.57	5.032	71.06	357.5
Calif.	2006	0.113	10.94	0.121	11.05	5.280	72.65	383.6
Calif.	2007	0.110	10.72	0.123	11.26	5.611	71.43	400.8
Calif.	2008	0.114	11.09	0.116	10.65	5.397	71.02	383.3
Calif.	2009	0.114	11.13	0.132	12.14	5.628	70.54	397.0
Energy factor		3.60 MJ/kWh		2.18 MJ/kg		--	--	--
CO_2 emission fa		--	97.22	--	91.63	--	--	--

U.S. refineries PADD	Year	Energy & CO_2/vol. crude for fuels *continued* Electricity purchased (GJ/m³)	(kg/m³)	Steam purchased (GJ/m³)	(kg/m³)	Refinery energy intensity *(EI)* (GJ/m³)	Fuel mix emit intensity (CO_2) (kg/GJ)	Refinery emission intensity (CO_2) (kg/m³)
1	1999	0.128	24.10	0.039	3.58	3.451	81.53	281.3
1	2000	0.123	23.07	0.046	4.19	3.430	80.34	275.6
1	2001	0.145	27.14	0.046	4.18	3.518	81.85	288.0
1	2002	0.134	25.07	0.046	4.21	3.426	81.08	277.8
1	2003	0.134	25.11	0.040	3.64	3.364	81.51	274.2
1	2004	0.135	25.30	0.056	5.16	3.416	81.46	278.3
1	2005	0.137	25.64	0.052	4.80	3.404	81.23	276.5
1	2006	0.149	28.03	0.066	6.01	3.440	80.40	276.5
1	2007	0.168	31.51	0.067	6.13	3.499	82.28	287.9
1	2008	0.187	35.11	0.064	5.84	3.551	83.26	295.7
2	1999	0.165	30.93	0.014	1.29	3.368	78.11	263.1
2	2000	0.163	30.57	0.010	0.90	3.361	77.56	260.6
2	2001	0.164	30.73	0.023	2.14	3.396	77.46	263.1
2	2002	0.172	32.34	0.028	2.53	3.393	77.90	264.3
2	2003	0.171	32.10	0.030	2.75	3.298	78.00	257.3
2	2004	0.178	33.48	0.033	2.99	3.376	77.25	260.8
2	2005	0.185	34.71	0.026	2.37	3.496	77.27	270.2
2	2006	0.197	36.92	0.038	3.44	3.738	75.84	283.5
2	2007	0.202	37.97	0.057	5.18	3.800	75.55	287.1
2	2008	0.207	38.80	0.058	5.31	3.858	74.97	289.3
3	1999	0.122	22.82	0.048	4.39	4.546	71.61	325.5
3	2000	0.127	23.76	0.061	5.55	4.563	71.87	327.9
3	2001	0.135	25.42	0.068	6.22	4.348	72.43	315.0
3	2002	0.141	26.51	0.078	7.12	4.434	72.71	322.4
3	2003	0.133	25.04	0.074	6.82	4.381	72.81	319.0
3	2004	0.141	26.49	0.074	6.81	4.204	73.43	308.7
3	2005	0.143	26.88	0.082	7.53	4.205	73.24	308.0
3	2006	0.157	29.40	0.090	8.26	4.367	74.15	323.8
3	2007	0.171	32.16	0.146	13.39	4.226	74.93	316.7
3	2008	0.182	34.23	0.154	14.15	4.361	74.48	324.8
5	1999	0.127	23.78	0.121	11.04	4.908	70.27	344.9
5	2000	0.110	20.67	0.115	10.50	5.189	69.09	358.5
5	2001	0.105	19.65	0.106	9.74	5.039	69.38	349.6
5	2002	0.105	19.77	0.101	9.27	4.881	69.15	337.5
5	2003	0.098	18.33	0.112	10.30	4.885	69.40	339.0
5	2004	0.106	19.83	0.115	10.51	4.861	69.89	339.7
5	2005	0.107	20.00	0.106	9.67	4.774	69.88	333.6
5	2006	0.107	20.16	0.107	9.78	4.862	69.32	337.1
5	2007	0.114	21.34	0.109	9.98	5.091	69.12	351.9
5	2008	0.113	21.22	0.108	9.86	4.939	68.39	337.8
Energy factor		3.60 MJ/kWh		2.18 MJ/kg		--	--	--
CO_2 emission fa		--	187.78	--	91.63	--	--	--

Data sources given in part 1 narrative description of data

Table 2-2. Third-party refinery hydrogen supply data evaluation

Data are totals for California refineries	2008	2009
Hydrogen production capacity data[a]		
Third-party capacity serving refineries ($m^3 \bullet 10^8$)	29.15	29.15
Production at typical (90%) capacity utilization		
Third-party at 90% of capacity ($m^3 \bullet 10^8$)	26.23	26.23
Estimated energy to make hydrogen at 90% capacity[b]		
Third-party at 90% capacity (GJ)	43,019,496	43,019,496
Estimated CO_2 emissions from H_2 at 90% capacity[c]		
Emissions at 90% third-party capacity (tonnes)	2,267,127	2,267,127
Emissions reported (Mandatory GHG Reporting)[d]		
Third-party emissions (tonnes)	2,224,778	2,193,684
Difference from third-party estimate (%)	-2%	-3%
Energy calculated from reported emission (GJ)	42,215,901	41,625,882
Difference from third-party estimate (%)	-2%	-3%

[a] From *Oil & Gas Journal* Worldwide Refining surveys *(6).*

[b] Energy based on 16.4 MJ/m^3 energy factor for natural gas-fed steam reforming *(1).*

[c] Emissions based on a 52.7 kg/GJ factor for natural gas-fed steam reforming *(1).*

[d] Facilityy-reported Mandatory GHG Reporting Rule emissions *(2).*

Table 2-3. Density and sulfur content of average California crude feeds, summary of calculation

Year	Feed source	Feed volume (m^3/year)[a]	Specific gravity	Sulfur (% wt.)	Feed mass (tonnes)	Feed sulfur (tonnes)	Feed *d* (kg/m^3)	Feed *S* (kg/m^3)
2009	California[b]	38,007,186	0.9274	1.12	35,249,004	394,436	927.430	10.378
2009	Alaska (TAPS)[c]	14,491,215	0.8714	1.11	12,627,065	140,160	871.360	9.672
2009	Foreign imports[d]	43,703,065	0.8887	1.52	38,838,914	590,740	888.700	13.517
2009	**Refinery input**	96,202,420	--	--	86,714,984	1,125,337	**901.380**	**11.698**
2008	California[b]	39,745,712	0.9273	1.16	36,855,722	427,895	927.288	10.766
2008	Alaska (TAPS)[c]	13,985,477	0.8714	1.11	12,186,385	135,269	871.360	9.672
2008	Foreign imports[d]	50,526,005	0.8906	1.73	44,997,449	776,206	890.58	15.36
2008	**Refinery input**	104,257,194	--	--	94,039,556	1,339,370	**902.00**	**12.85**
2007	California[b]	39,976,562	0.9269	1.10	37,055,075	407,606	926.92	10.20
2007	Alaska (TAPS)[c]	16,041,819	0.8714	1.11	13,978,199	155,158	871.36	9.67
2007	Foreign imports[d]	45,604,553	0.8861	1.60	40,411,563	645,777	886.13	14.16
2007	**Refinery input**	101,622,933	--	--	91,444,836	1,208,541	**899.84**	**11.89**
2006	California[b]	40,461,950	0.9270	1.10	37,506,204	410,693	926.95	10.15
2006	Alaska (TAPS)[c]	16,802,414	0.8714	1.11	14,640,951	162,515	871.36	9.67
2006	Foreign imports[d]	46,949,904	0.8860	1.56	41,599,493	648,952	886.04	13.82
2006	**Refinery input**	104,214,267	--	--	93,746,648	1,222,160	**899.56**	**11.73**
2005	California[b]	42,298,889	0.9277	1.10	39,240,679	431,255	927.70	10.20
2005	Alaska (TAPS)[c]	21,607,328	0.8714	1.11	18,827,761	208,988	871.36	9.67
2005	Foreign imports[d]	43,295,104	0.8886	1.63	38,472,895	626,723	888.62	14.48
2005	**Refinery input**	107,201,321	--	--	96,541,336	1,266,967	**900.56**	**11.82**
2004	California[b]	43,625,479	0.9279	1.18	40,481,871	476,472	927.94	10.92
2004	Alaska (TAPS)[c]	22,570,950	0.8714	1.11	19,667,423	218,308	871.36	9.67
2004	Foreign imports[d]	37,915,927	0.8828	1.49	33,471,422	498,055	882.78	13.14
2004	**Refinery input**	104,112,356	--	--	93,620,716	1,192,835	**899.23**	**11.46**

[a] Feed volumes from California Energy Commission *(5).*

[b] Weighted average density and sulfur content of California-produced crude from data in Table 2-4.

[c] Density and sulfur content, Alaska North Slope blend, TAPS terminus at Valdez, 2002 *(16).*

[d] Weighted average density and sulfur content of all foreign crude imports processed in California *(14).*

Table 2-4. California-producted crude data by field, area, and pool, formation or zone

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Aliso Canyon	Field	Field total			23.084	23.396	21.997	20.707	21.005	23.987
Aliso Canyon	Field	Not matched to pool/*OQ*	0.917 *b*	0.80 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Aliso Canyon		Aliso	0.969 *c*	0.94 *c*	1.512	1.297	1.036	0.307	0.690	0.481
Aliso Canyon		Aliso, West	0.993 *c*	0.80 *b*	0.604	0.490	0.454	0.378	0.201	0.166
Aliso Canyon		Porter-Del Aliso A-36	0.913 *c*	0.80 *b*	5.749	5.060	4.881	5.433	8.133	8.474
Aliso Canyon		Porter, West	0.911 *c*	0.80 *b*	0.000	0.000	0.000	0.000	0.010	0.028
Aliso Canyon		Mission-Adrian	0.882 *c*	0.80 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Aliso Canyon		Monterey	0.917 *b*	0.80 *b*	0.000	0.000	0.000	0.000	0.000	0.018
Aliso Canyon		Sesnon-Frew A/	0.840 *c*	0.80 *b*	15.219	16.550	15.626	14.589	11.970	14.820
Aliso Canyon		Faulted Sesnon	0.922 *c*	0.80 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ant Hill	Field	Field total			12.225	12.145	15.664	17.945	12.714	9.251
Ant Hill	Field	Not matched to pool/*OQ*	0.898 *b*	0.48 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ant Hill		Olcese	0.968 *b*	0.68 *b*	12.225	12.145	15.664	17.945	12.714	9.251
Ant Hill		Jewett	0.828 *b*	0.28 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Antelope Hills	Field	Field total			37.514	31.996	27.777	25.870	26.880	24.872
Antelope Hills	Field	Not matched to pool/*OQ*	0.946 *c*	0.69 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Antelope Hills	Hopkins Area	Phacoides	0.871 *c*	0.69 *c*	0.363	0.339	0.251	0.222	0.254	0.210
Antelope Hills	Hopkins Area	Eocene	0.953 *c*	0.69 *c*	0.560	0.560	0.486	0.469	0.543	0.382
Antelope Hills	Williams Area	No breakdown by pool	0.957 *c*	0.69 *c*	0.000	0.000	0.000	0.000	0.006	1.967
Antelope Hills	Williams Area	Gas Zone	0.946 *c*	0.69 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Antelope Hills	Williams Area	Upper	0.986 *c*	0.69 *c*	1.311	2.208	0.951	0.695	1.550	0.676
Antelope Hills	Williams Area	East Block-Button Bed	0.953 *c*	0.69 *c*	12.877	7.884	6.092	0.695	5.371	4.259
Antelope Hills	Williams Area	East Block-Agua	0.947 *c*	0.69 *c*	4.322	2.483	3.335	6.243	4.232	4.220
Antelope Hills	Williams Area	W. Blk-Button Bed & Agua	0.947 *c*	0.69 *c*	6.421	5.543	4.724	3.582	6.344	5.548
Antelope Hills	Williams Area	Point of Rocks	0.953 *c*	0.69 *c*	11.659	12.979	11.938	8.977	8.580	7.627
Antelope Hills	Nepple Area Gas	All	0.946 *c*	0.69 *c*	0.000	0.000	0.000	0.000	0.000	3.602
Antelope Hills, North	Field	Field total			12.912	13.516	13.064	12.349	22.827	35.157
Antelope Hills, North	Field	Not matched to pool/*OQ*	0.953 *d*		0.000	0.000	0.000	0.000	0.005	0.386
Antelope Hills, North		Miocene-Eocene	0.974 *c*		12.912	13.516	13.064	11.733	11.885	14.800
Antelope Hills, North		Point of Rocks	0.959 *c*		0.000	0.000	0.000	0.616	10.937	23.572
Arroyo Grande	Field	Field total			97.925	92.775	92.838	87.130	75.491	71.809
Arroyo Grande	Field	Not matched to pool/*OQ*	0.969 *c*	1.30 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Arroyo Grande	Oak Park Area	Martin-Elberta	0.966 *c*	1.30 *b*	0.069	0.003	0.016	0.000	0.000	0.394
Arroyo Grande	Tiber Area	Dollie	0.973 *c*	1.30 *b*	97.856	92.772	92.822	87.130	75.491	71.415
Asphalto	Field	Field total			21.839	21.726	19.621	31.842	41.838	38.404
Asphalto	Field	Not matched to pool/*OQ*	0.845 *c*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Asphalto		Etchegoin	0.973 *c*	0.42 *b*	0.000	0.000	0.000	1.120	0.866	0.703
Asphalto		Olig	0.789 *c*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Asphalto		Antelope Shale	0.846 *c*	0.42 *b*	2.978	2.804	0.363	1.349	3.153	4.903
Asphalto		Stevens	0.849 *b*	0.42 *b*	17.510	17.959	18.539	28.593	37.315	31.671
Asphalto		1st Carneros	0.805 *c*	0.42 *b*	1.352	0.962	0.719	0.780	0.504	1.019
Asphalto		Carneros	0.805 *c*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Bandini	Field	Field total			2.647	3.271	3.476	3.432	3.123	1.571
Bandini	Field	Not matched to pool/*OQ*	0.841 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Bandini		Pliocene	0.837 *c*		2.647	3.271	3.476	3.432	3.123	1.571
Bandini		Miocene	0.845 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Barham Ranch	Field	Field total			17.622	16.373	18.360	15.201	14.908	13.026
Barham Ranch	Field	Not matched to pool/*OQ*	0.918 *c*	1.30 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Barham Ranch	La Laguna	Monterey	0.868 *c*	1.30 *c*	17.065	15.520	14.194	11.915	11.872	9.833
Barham Ranch	Old Area		0.968 *c*	1.30 *c*	0.558	0.853	4.166	3.285	3.037	3.193
Barsdale	Field	Field total			14.820	11.247	8.792	9.916	8.542	7.176
Barsdale	Field	Not matched to pool/*OQ*	0.881 *c*	0.83 *b*	14.820	11.247	8.792	9.916	6.032	5.237
Barsdale		Deep	0.857 *c*	0.83 *b*	0.000	0.000	0.000	0.000	2.510	1.939
Beer Nose	Field	Field total			0.949	0.937	0.905	0.569	0.306	0.433
Beer Nose	Field	Not matched to pool/*OQ*	0.871 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Beer Nose		Bloemer	0.871 *c*		0.949	0.937	0.905	0.569	0.306	0.433
Belgian Anticline	Field	Field total			11.077	8.739	9.653	9.303	8.523	8.563
Belgian Anticline	Field	Not matched to pool/*OQ*	0.850 *b*	0.41 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Belgian Anticline	Main Area	No breakdown by pool	0.838 *c*	0.41 *b*	9.176	7.123	7.185	8.166	7.535	6.893
Belgian Anticline	Main Area	Oceanic	0.850 *b*	0.59 *b*	0.000	0.000	0.000	0.206	0.000	0.000
Belgian Anticline	Main Area	Point of Rocks	0.800 *c*	0.41 *c*	0.385	0.449	0.589	0.931	0.247	0.328
Belgian Anticline	Northwest Area	No breakdown by pool	0.885 *c*	0.59 *b*	1.516	1.167	1.880	0.931	0.741	1.342
Belgian Anticline	Northwest Area	Miocene	0.860 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Belgian Anticline	Northwest Area	Eocene	0.846 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Bellevue	Field	Field total			6.161	5.617	5.639	6.320	5.521	5.073
Bellevue	Field	Not matched to pool/*OQ*	0.850 *c*	0.36 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Bellevue	Main Area	Stevens	0.855 *c*	0.36 *b*	5.333	4.890	4.804	5.515	4.782	4.341
Bellevue	South Area	Stevens	0.845 *c*	0.36 *b*	0.828	0.727	0.835	0.805	0.738	0.731
Bellevue, West	Field	Field total			4.724	3.766	4.310	3.823	4.897	4.620
Bellevue, West	Field	Not matched to pool/*OQ*	0.868 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Bellevue, West		Stevens	0.868 *c*		4.724	3.766	4.310	3.823	4.897	4.620
Belmont Offshore	Field	Field total			51.407	66.657	108.201	12.418	114.889	106.080

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Belmont Offshore	Field	Not matched to pool/*OQ*	0.883 *b*	0.90 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Belmont Offshore	Old Area	Upper	0.926 *c*	0.90 *b*	0.000	22.183	53.991	57.897	59.375	56.347
Belmont Offshore	Old Area	Intermediate	0.899 *c*	0.90 *b*	0.000	0.000	0.000	4.088	11.400	6.554
Belmont Offshore	Old Area	Lower	0.899 *c*	0.90 *c*	5.408	5.008	15.576	25.943	18.030	26.106
Belmont Offshore	Old Area	237	0.883 *b*	0.90 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Belmont Offshore	Old Area	Schist	0.883 *b*	0.90 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Belmont Offshore	Surfside Area		0.897 *c*	0.14 *c*	45.999	39.465	38.634	36.734	26.084	17.073
Belridge, North	Field	Field total			609.344	591.421	540.598	525.997	563.581	519.432
Belridge, North	Field	Not matched to pool/*OQ*	0.854 *b,c*	0.66 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Belridge, North		Tulare	0.972 *b*	1.14 *b*	29.653	21.937	150.161	18.346	23.115	19.580
Belridge, North		Diatomite	0.890 *c*	1.14 *b*	559.721	548.835	502.891	492.418	525.835	486.952
Belridge, North		Temblor	0.825 *c*	0.69 *c*	2.260	1.186	2.557	2.211	2.373	1.781
Belridge, North		R Sand	0.771 *c*	0.17 *c*	1.055	1.179	5.091	3.607	2.522	2.311
Belridge, North		Belridge 64	0.828 *c*	0.17 *c*	16.655	18.284	15.037	9.414	9.735	8.809
Belridge, North		Y Sand	0.835 *c*	0.65 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Belridge, South	Field	Field total			6,301.301	5,907.403	5,645.857	5,360.766	5,159.343	4,652.846
Belridge, South	Field	Not matched to pool/*OQ*	0.906 *b,c*	0.70 *b,c*	0.000	0.000	0.000	0.000	0.644	0.671
Belridge, South		Tulare	0.966 *b*	0.23 *b*	2,504.036	2,288.377	2,155.501	2,139.089	2,009.493	1,785.617
Belridge, South		Diatomite	0.890 *c*	0.86 *b*	3,768.569	3,593.228	3,466.721	3,197.425	3,129.365	2,849.268
Belridge, South		Diatomite-Antelope Shale	0.886 *c*	0.86 *b*	2.074	2.567	3.163	7.187	6.114	6.784
Belridge, South		Antelope Shale	0.882 *c*	0.86 *b*	26.622	23.231	20.472	17.065	13.728	10.664
Beta Offshore	Field	Field total			135.378	144.755	132.025	144.490	173.583	231.143
Beta Offshore	Field	Not matched to pool/*OQ*	0.959 *d*	3.80 *c*	135.378	144.755	132.025	144.490	173.583	231.143
Beverly Hills	Field	Field total			175.960	178.745	173.359	153.548	140.515	137.987
Beverly Hills	Field	Not matched to pool/*OQ*	0.869 *c*	2.41 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Beverly Hills	East Area	Pliocene	0.850 *c*	2.30 *c*	11.382	13.489	11.618	10.314	10.037	9.221
Beverly Hills	East Area	Miocene	0.855 *c*	2.45 *b*	131.046	3.572	125.216	109.708	99.962	98.761
Beverly Hills	West Area	Pliocene	0.944 *c*	2.45 *b*	0.522	0.290	0.338	0.750	0.675	0.726
Beverly Hills	West Area	Miocene	0.827 *c*	2.45 *b*	33.010	34.205	36.188	32.775	29.841	29.280
Big Mountain	Field	Field total			5.287	3.486	4.818	5.460	5.778	5.622
Big Mountain	Field	Not matched to pool/*OQ*	0.901 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Big Mountain		Sespe	0.932 *c*		5.287	3.486	4.818	5.460	5.778	5.622
Big Mountain		Eocene	0.876 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Bitterwater	Field	Field total			0.364	0.346	0.356	0.339	0.311	0.297
Bitterwater	Field	Not matched to pool/*OQ*	0.896 *c*		0.364	0.346	0.356	0.339	0.311	0.297
Blackwells Corner	Field	Field total			1.423	1.162	1.290	3.022	2.016	1.661

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific		Sulfur		Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity		% wt.		2004	2005	2006	2007	2008	2009
Blackwells Corner	Field	Not matched to pool/*OQ*	0.973	*b*			1.423	1.162	1.290	3.022	2.016	1.661
Bowerbank	Field	Field total					0.893	0.033	0.000	0.000	0.000	0.000
Bowerbank	Field	Not matched to pool/*OQ*	0.865	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Bowerbank		Gas Zone	0.865	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Bowerbank		Stevens	0.865	*c*			0.893	0.033	0.000	0.000	0.000	0.000
Brea-Olinda	Field	Field total					200.487	196.035	196.141	187.882	179.099	190.006
Brea-Olinda	Field	Not matched to pool/*OQ*	0.917	*c*	1.43	*b*	200.487	196.035	196.141	187.882	179.099	190.006
Brentwood	Field	Field total					0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Field	Not matched to pool/*OQ*	0.823	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	Prewett	0.830	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	First Massive	0.820	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	First Massive Block IA	0.820	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	First Massive Block III	0.820	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	Second Massive	0.830	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	Main Area	Third Massive	0.830	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	West Area	First Massive	0.797	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	West Area	Second Massive	0.835	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Brentwood	West Area	Third Massive	0.830	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Buena Vista	Field	Field total					122.660	114.225	113.420	118.835	153.799	169.786
Buena Vista	Field	Not matched to pool/*OQ*	0.886	*b,c*	0.56	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Buena Vista	Buena Vista Front		0.917	*c*	0.59	*b*	12.847	10.922	10.969	9.058	9.846	8.646
Buena Vista	Buena Vista Hills	No breakdown by pool	0.894	*b*	0.59	*b*	0.000	0.000	0.000	0.000	0.015	1.762
Buena Vista	Buena Vista Hills	Gas Zone	0.873	*b*	0.59	*b*	0.256	0.323	0.126	0.066	0.069	0.184
Buena Vista	Buena Vista Hills	Gas Zone-Upper	0.873	*b*	0.59	*b*	0.738	0.721	0.585	0.416	0.264	0.226
Buena Vista	Buena Vista Hills	Upper Undifferentiated	0.893	*c*	0.59	*b*	59.805	54.252	53.708	59.124	71.357	88.160
Buena Vista	Buena Vista Hills	Sub-Scalez & Mulinia	0.893	*c*	0.59	*b*	0.426	0.497	0.302	0.605	0.286	0.481
Buena Vista	Buena Vista Hills	27B Undifferentiated	0.888	*c*	0.59	*b*	1.049	1.415	1.577	1.467	2.702	4.156
Buena Vista	Buena Vista Hills	Reef Ridge	0.876	*c*	0.50	*b*	0.655	0.474	0.662	1.360	1.748	1.253
Buena Vista	Buena Vista Hills	Antelope Shale-E. Dome	0.877	*c*	0.50	*b*	8.047	7.995	10.666	12.381	16.400	16.619
Buena Vista	Buena Vista Hills	Antelope Shale-W. Dome	0.877	*c*	0.50	*b*	7.874	7.625	6.993	7.121	9.801	12.946
Buena Vista	Buena Vista Hills	555 Stevens	0.882	*c*	0.50	*b*	30.962	30.000	27.832	27.236	41.311	35.353
Bunker Gas	Field	Field total					0.978	0.089	0.060	0.150	0.093	0.073
Bunker Gas	Field	Not matched to pool/*OQ*					0.000	0.000	0.000	0.000	0.000	0.000
Bunker Gas		No breakdown by pool					0.978	0.089	0.060	0.150	0.093	0.073
Bunker Gas		Oil Zone					0.000	0.000	0.000	0.000	0.000	0.000
Burrel	Field	Field total					0.162	0.164	0.168	0.086	0.155	0.140

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Burrel	Field	Not matched to pool/*OQ*	0.876	*c*	0.90	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Burrel		Miocene	0.876	*c*	0.90	*c*	0.162	0.164	0.168	0.086	0.155	0.140
Cabrillo	Field	Field total					0.000	0.000	1.613	4.450	7.997	7.714
Cabrillo	Field	Not matched to pool/*OQ*					0.000	0.000	0.000	0.000	0.000	0.000
Cabrillo		Topanga					0.000	0.000	1.613	4.450	7.997	7.714
Cal Canal Gas	Field	Field total					3.554	3.198	3.899	3.803	3.576	3.933
Cal Canal Gas	Field	Not matched to pool/*OQ*	0.820	*c*	0.16	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Cal Canal Gas		Etchegoin	0.820	*c*	0.16	*c*	0.028	0.023	0.000	0.000	0.000	0.008
Cal Canal Gas		Stevens	0.820	*c*	0.16	*c*	3.526	3.175	3.899	3.803	3.576	3.925
Calders Corner	Field	Field total					0.000	0.000	0.000	0.000	0.000	0.000
Calders Corner	Field	Not matched to pool/*OQ*	0.850	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Calders Corner		Stevens	0.850	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Camden	Field	Field total					0.181	0.216	0.197	0.179	0.196	0.215
Camden	Field	Not matched to pool/*OQ*	0.860	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Camden		Miocene	0.860	*c*			0.181	0.216	0.197	0.179	0.196	0.215
Canada Larga	Field	Field total					0.000	0.000	0.000	0.000	0.047	0.356
Canada Larga	Field	Not matched to pool/*OQ*	0.904	*c*			0.000	0.000	0.000	0.000	0.000	0.356
Canal	Field	Field total					5.283	4.238	3.664	4.367	4.166	5.189
Canal	Field	Not matched to pool/*OQ*	0.845	*c*	0.50	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Canal	Main Area	Gas Zone	0.845	*c*	0.50	*b,c*	0.000	0.000	0.000	0.000	0.000	0.045
Canal	Main Area	Upper Stevens	0.850	*c*	0.41	*c*	0.555	0.395	0.425	0.411	0.354	0.299
Canal	Main Area	Middle Stevens	0.850	*c*	0.41	*b*	1.938	1.458	1.708	1.643	1.415	1.197
Canal	Main Area	Lower Stevens	0.850	*c*	0.70	*c*	0.000	0.000	0.000	0.000	0.060	0.523
Canal	Pioneer Canal	Upper Stevens	0.833	*c*	0.26	*b*	1.141	0.869	0.442	0.626	0.608	0.740
Canal	Pioneer Canal	Lower Stevens	0.844	*c*	0.70	*b*	1.641	1.517	1.088	1.687	1.728	2.430
Canfield Ranch	Field	Field total					41.285	38.025	28.738	24.287	19.103	18.590
Canfield Ranch	Field	Not matched to pool/*OQ*	0.877	*b,c*	0.37	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Canfield Ranch	Gosford East	Stevens	0.855	*b*	0.37	*b*	35.342	32.939	24.698	20.720	16.583	16.483
Canfield Ranch	Gosford East	Larimer Equiv.	0.877	*b,c*	0.37	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Canfield Ranch	Gosford South	Stevens	0.868	*c*	0.37	*c*	5.696	4.713	3.697	3.238	2.180	1.791
Canfield Ranch	Gosford West	Stevens	0.930	*c*	0.37	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Canfield Ranch	Old Area	Etchegoin	0.877	*b,c*	0.37	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Canfield Ranch	Old Area	Stevens	0.887	*c*	0.37	*c*	0.247	0.374	0.343	0.329	0.340	0.316
Canfield Ranch	Old River Area	Stevens	0.845	*c*	0.37	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Careaga Canyon	Field	Field total					0.273	0.303	0.139	2.943	1.872	1.811
Careaga Canyon	Field	Not matched to pool/*OQ*	0.853	*c*	0.34	*c*	0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Careaga Canyon	Old Area	Monterey	0.855 *c*	0.20 *c*	0.273	0.303	0.139	0.065	0.000	0.000
Careaga Canyon	San Antonio Crk.	Monterey	0.850 *c*	0.47 *c*	0.000	0.000	0.000	2.878	1.872	1.811
Carneros Creek	Field	Field total			5.693	5.261	6.588	7.321	8.155	5.688
Carneros Creek	Field	Not matched to pool/*OQ*	0.913 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Carneros Creek		Button Bed	0.979 *c*		0.607	0.677	0.733	0.744	0.770	0.773
Carneros Creek		Carneros	0.916 *c*		0.096	0.086	0.073	0.069	0.057	0.045
Carneros Creek		Phacoides	0.871 *c*		0.472	0.407	0.251	0.243	0.368	0.216
Carneros Creek		Point of Rocks	0.885 *c*		4.517	4.091	5.530	6.265	6.960	4.671
Carpinteria Offshore	Field	Field total			82.509	80.415	82.592	83.660	78.051	73.980
Carpinteria Offshore	Field	Not matched to pool/*OQ*	0.895 *c*	1.88 *e*	82.509	80.415	82.592	83.660	78.051	73.980
Cascade	Field	Field total			67.505	64.173	51.856	43.285	33.814	30.889
Cascade	Field	Not matched to pool/*OQ*	0.910 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Cascade		No breakdown by pool	0.885 *c*		1.846	1.446	2.124	3.479	2.732	3.197
Cascade		Deep	0.885 *c*		65.659	62.727	49.731	39.806	31.082	27.692
Casmalia	Field	Field total			24.997	21.850	22.615	21.323	27.163	29.030
Casmalia	Field	Not matched to pool/*OQ*	0.959 *c*	2.80 *b*	24.997	21.850	22.615	21.323	27.163	29.030
Castaic Hills	Field	Field total			1.207	2.096	2.517	2.875	2.829	2.861
Castaic Hills	Field	Not matched to pool/*OQ*	0.937 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Castaic Hills		Golden	1.007 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Castaic Hills		Sterling	0.863 *c*	0.51 *b*	0.976	1.846	2.369	2.658	2.541	2.595
Castaic Hills		Sterling East	0.863 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Castaic Hills		Rynne-Fisher	0.860 *c*	0.51 *b*	0.232	0.250	0.148	0.218	0.288	0.266
Castaic Hills		Upper Radovich	1.014 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Castaic Hills		Lower Radovich	1.014 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cat Canyon	Field	Field total			61.406	54.220	56.314	57.354	36.675	45.823
Cat Canyon	Field	Not matched to pool/*OQ*	0.988 *b,c*	4.74 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Cat Canyon	Central Area	Sisquoc	0.985 *b*	4.96 *b*	0.581	0.110	0.688	1.015	0.782	0.502
Cat Canyon	East Area		1.001 *c*	5.05 *c*	0.560	0.159	0.064	0.000	0.000	0.000
Cat Canyon	Gato Ridge Area		0.986 *c*	5.87 *c*	12.842	11.677	12.117	12.200	11.564	11.054
Cat Canyon	Olivera Canyon	Monterey	0.960 *b*	4.10 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cat Canyon	Sisquoc Area		1.006 *c*	4.50 *c*	27.110	27.415	23.985	23.848	12.142	19.625
Cat Canyon	Tinaquaic Area	Monterey	1.022 *c*	4.96 *b*	0.000	0.000	0.304	3.158	3.155	2.823
Cat Canyon	West Area	No breakdown by pool	0.953 *c*	3.74 *c*	20.313	14.859	19.157	17.132	9.031	11.819
Cat Canyon	West Area	S6-S6A-Gas Zone	0.988 *b,c*	4.74 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Chaffee Canyon	Field	Field total			0.406	0.328	0.366	0.374	0.288	0.282
Chaffee Canyon	Field	Not matched to pool/*OQ*	0.845 *c*		0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \cdot 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
Chaffee Canyon		Pliocene-Gas Zone	0.845 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Chaffee Canyon		Eocene	0.845 *c*		0.406	0.328	0.366	0.374	0.288	0.282
Cheviot Hills	Field	Field total			12.047	11.644	9.944	9.194	9.096	8.489
Cheviot Hills	Field	Not matched to pool/*OQ*	0.869 *b*	0.70 *b*	0.000	0.000	0.000	0.000	9.096	0.000
Cheviot Hills		Pliocene	0.889 *b*	0.87 *b*	11.000	10.553	9.069	8.209	7.745	7.212
Cheviot Hills		Miocene	0.849 *b*	0.53 *b*	1.047	1.091	0.875	0.985	1.351	1.277
Chico-Martinez	Field	Field total			1.393	1.534	0.598	0.882	0.719	0.476
Chico-Martinez	Field	Not matched to pool/*OQ*	0.948 *c*		1.393	1.534	0.598	0.882	0.719	0.476
Chino-Soquel	Field	Field total			0.120	0.116	0.296	0.313	0.216	0.100
Chino-Soquel	Field	Not matched to pool/*OQ*	0.928 *c*		0.120	0.116	0.296	0.313	0.216	0.100
Cienaga Canyon	Field	Field total			0.835	0.715	1.167	1.526	3.093	1.809
Cienaga Canyon	Field	Not matched to pool/*OQ*	0.934 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Cienaga Canyon		Temblor	0.934 *c*		0.835	0.715	1.167	1.526	3.093	1.809
Coalinga	Field	Field total			953.461	936.150	913.298	893.683	913.671	934.137
Coalinga	Field	Not matched to pool/*OQ*	0.887 *c*	0.37 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Coalinga		Temblor	0.931 *c*	0.64 *c*	953.461	936.150	913.298	893.683	913.671	934.137
Coalinga		Cretacious	0.843 *c*	0.10 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Coalinga East Ext.	Field	Field total			6.825	6.010	2.788	4.748	4.772	3.550
Coalinga East Ext.	Field	Not matched to pool/*OQ*	0.865 *b,c*	0.26 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Coalinga East Ext.	Coalinga Nose	Vaqueros	0.845 *c*	0.22 *c*	1.823	1.528	1.747	1.213	0.877	0.373
Coalinga East Ext.	Coalinga Nose	Gatchell	0.868 *b*	0.25 *b*	5.002	4.482	1.041	3.536	3.895	3.177
Coalinga East Ext.	Northeast Area	Gatchell	0.883 *b*	0.31 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Coles Levee North	Field	Field total			25.506	25.106	23.549	23.388	26.236	24.788
Coles Levee North	Field	Not matched to pool/*OQ*	0.805 *b,c*	0.49 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Coles Levee North		Gas Zone	0.805 *b,c*	0.49 *b,c*	0.006	0.000	0.000	0.000	0.000	0.000
Coles Levee North		Stevens Undifferentiated	0.859 *b*	0.58 *b*	25.500	25.106	23.549	23.388	26.236	24.788
Coles Levee North		Miocene-Eocene	0.751 *c*	0.39 *c*	0.000	0.000	0.000	0.000	0.000	3.482
Coles Levee South	Field	Field total			14.511	15.111	15.375	15.098	14.667	10.912
Coles Levee South	Field	Not matched to pool/*OQ*	0.834 *b,c*	0.38 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Coles Levee South		Gas Zone	0.834 *b,c*	0.38 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Coles Levee South		Stevens	0.840 *b*	0.38 *b*	14.511	15.111	15.375	15.098	14.667	14.393
Coles Levee South		Nozu	0.829 *c*	0.38 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Comanche Point	Field	Field total			0.551	0.586	0.723	0.576	0.976	0.868
Comanche Point	Field	Not matched to pool/*OQ*	0.954 *c*	1.16 *c*	0.551	0.000	0.000	0.000	0.000	0.000
Comanche Point		No breakdown by pool	0.966 *c*	1.16 *c*	0.000	0.586	0.723	0.576	0.324	0.336
Comanche Point		Santa Margarita	0.966 *c*	1.16 *c*	0.000	0.000	0.000	0.000	0.652	0.532

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Coyote East	Field	Field total			44.041	40.007	37.966	35.872	35.938	36.258
Coyote East	Field	Not matched to pool/*OQ*	0.930 *c*	1.16 *c*	44.041	40.007	37.966	35.872	35.938	36.258
Cuyama South	Field	Field total			44.548	44.524	42.754	42.188	40.259	36.443
Cuyama South	Field	Not matched to pool/*OQ*	0.863 *b*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cuyama South	Main Area	No breakdown by pool	0.863 *b*	0.42 *b*	41.633	41.361	38.291	38.915	38.512	32.150
Cuyama South	Main Area	52-1-Gas Zone	0.863 *b*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cuyama South	Southeast Area	Santa Margarita-Gas Zone	0.863 *b*	0.42 *b*	0.000	0.024	0.784	0.630	0.359	0.267
Cuyama South	Southeast Area	Santa Margarita	0.863 *b*	0.42 *b*	2.915	3.140	3.679	2.643	1.387	1.023
Cuyama South	Southeast Area	Cox	0.863 *b*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cuyama South	East Area	L. Miocene	0.863 *b*	0.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Field	Field total			3,007.267	2,835.179	2,934.520	2,923.618	2,861.509	2,787.928
Cymric	Field	Not matched to pool/*OQ*	0.907 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Cymric Flank Area	Cameros	0.842 *c*	0.44 *b*	0.000	0.000	0.000	0.000	0.000	0.220
Cymric	Cymric Flank Area	Phacoides	0.860 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Salt Creek Main	Etchegoin	0.979 *c*	1.16 *b*	0.276	0.336	0.339	0.345	0.557	0.522
Cymric	Salt Creek Main	Cameros West	0.943 *b*	0.69 *b*	1.922	1.876	1.461	0.805	0.854	0.999
Cymric	Salt Creek Main	Cameros Unit	0.937 *c*	0.69 *b*	11.588	10.496	8.999	8.658	6.181	7.259
Cymric	Salt Creek Main	Phacoides	0.922 *c*	0.44 *b*	2.160	2.109	1.996	2.293	2.320	1.488
Cymric	Salt Creek West	Phacoides	0.922 *c*	0.44 *b*	0.000	0.123	0.260	0.145	0.181	0.170
Cymric	Sheep Springs	Tulare	0.990 *c*	1.16 *b*	0.364	0.344	0.299	0.177	0.187	0.221
Cymric	Sheep Springs	Etchegoin	0.959 *c*	0.86 *b*	3.510	3.376	3.709	3.490	3.832	4.454
Cymric	Sheep Springs	Monterey	0.925 *c*	0.69 *b*	0.000	0.000	0.028	0.085	0.267	0.000
Cymric	Sheep Springs	Cameros	0.916 *c*	0.44 *b*	2.269	1.749	1.424	4.160	6.845	7.221
Cymric	Sheep Springs	Phacoides	0.860 *c*	0.44 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Sheep Springs	Oceanic	0.820 *c*	0.23 *b*	0.014	0.012	0.010	0.010	0.008	0.011
Cymric	Welport Area	No breakdown by pool	0.907 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Welport Area	Tulare-Antelope	0.979 *c*	1.16 *b*	145.560	279.075	287.711	253.195	295.886	295.336
Cymric	Welport Area	Tulare	0.979 *c*	1.16 *b*	1,251.681	1,146.959	1,175.553	1,045.810	963.330	892.743
Cymric	Welport Area	Etchegoin	0.887 *c*	0.86 *b*	1,302.987	1,147.315	1,209.081	1,347.150	1,329.735	1,365.377
Cymric	Welport Area	San Joaquin	0.985 *c*	1.38 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Welport Area	Reef Ridge-Antelope	0.960 *c*	0.86 *b*	270.520	226.043	228.528	248.238	240.793	203.307
Cymric	Welport Area	McDonald-Devilwater	0.891 *c*	0.86 *b*	0.016	4.855	2.637	1.481	1.879	1.195
Cymric	Welport Area	Cameros	0.866 *c*	0.44 *b*	2.170	0.715	0.638	1.246	3.196	4.153
Cymric	Welport Area	Agua	0.871 *c*	0.44 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Cymric	Welport Area	Phacoides	0.860 *c*	0.44 *b*	0.161	0.211	2.117	2.321	1.264	0.640
Cymric	Welport Area	Oceanic	0.821 *c*	0.23 *b*	0.000	0.000	0.000	0.000	0.622	0.902

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Cymric	Welport Area	Point of Rocks	0.788	*c*	0.23	*b*	12.068	9.586	9.729	4.010	3.573	1.709
Deer Creek	Field	Field total					6.307	6.694	7.017	7.071	8.049	8.978
Deer Creek	Field	Not matched to pool/*OQ*	0.921	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Deer Creek		Santa Margarita	0.855	*c*			6.307	6.694	7.017	7.071	8.049	8.978
Deer Creek North	Field	Field total					0.000	0.072	0.172	0.159	0.139	0.019
Deer Creek North	Field	Not matched to pool/*OQ*	0.986	*c*			0.000	0.072	0.172	0.159	0.000	0.019
Del Valle	Field	Field total					10.605	8.325	9.465	9.356	9.690	10.434
Del Valle	Field	Not matched to pool/*OQ*	0.887	*c*	1.15	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Del Valle	Kinler Area		0.934	*c*	1.15	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Del Valle	Main Area		0.853	*c*	1.15	*b*	6.646	4.949	6.204	6.145	6.368	7.063
Del Valle	South Area		0.875	*c*	1.14	*b*	3.959	3.377	3.260	3.211	3.322	3.333
Denverton Crk. Gas	Field	Field total					0.189	0.158	0.096	0.052	0.032	0.009
Denverton Crk. Gas	Field	Not matched to pool/*OQ*					0.189	0.158	0.096	0.052	0.032	0.009
Devils Den	Field	Field total					3.040	3.629	4.116	3.761	3.266	3.087
Devils Den	Field	Not matched to pool/*OQ*	0.917	*b,c*	0.41	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Devils Den	Alferitz Area	No breakdown by pool	0.931	*b*	0.37	*b*	2.140	2.890	3.444	3.068	2.734	2.559
Devils Den	Alferitz Area	Eocene Gas Zone	0.887	*c*	0.57	*b*	0.207	0.194	0.172	0.152	0.103	0.132
Devils Den	Bates Area		0.904	*c*	0.14	*c*	0.055	0.081	0.095	0.140	0.112	0.111
Devils Den	Old Area		0.945	*c*	0.57	*b*	0.639	0.464	0.405	0.401	0.317	0.285
Dominguez	Field	Field total					1.421	1.337	1.317	1.286	1.227	1.179
Dominguez	Field	Not matched to pool/*OQ*	0.871	*c*	0.76	*b*	1.421	1.337	1.317	1.286	1.227	1.179
Dos Cuadras OCS	Field	Field total					245.909	227.487	247.484	215.117	220.371	210.282
Dos Cuadras OCS	Field	Not matched to pool/*OQ*	0.881	*c*	1.11	*b*	245.909	227.487	247.484	215.117	220.371	210.282
Dunnigan Hills Gas	Field	Field total					0.000	0.000	0.000	0.000	0.001	0.000
Dunnigan Hills Gas	Field	Not matched to pool/*OQ*					0.000	0.000	0.000	0.000	0.000	0.000
Dunnigan Hills Gas	Main Area						0.000	0.000	0.000	0.000	0.001	0.000
Dunnigan Hills Gas	Southeast Area	Winters					0.000	0.000	0.000	0.000	0.000	0.000
Dutch Slough Gas	Field	Field total					0.097	0.357	0.587	0.408	0.174	0.066
Dutch Slough Gas	Field	Not matched to pool/*OQ*					0.097	0.357	0.587	0.408	0.000	0.066
Edison	Field	Field total					105.532	102.366	107.857	106.296	107.886	107.254
Edison	Field	Not matched to pool/*OQ*	0.914	*c*	0.34	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Edison	Edison Groves		0.970	*c*	0.70	*c*	3.346	3.463	4.555	3.059	3.614	6.797
Edison	Jeppi Area		0.851	*c*	0.42	*b*	1.246	1.713	1.593	1.774	1.907	1.934
Edison	Main Area		0.933	*c*	0.56	*c*	59.822	57.194	58.143	58.630	58.082	53.381
Edison	Portals-Fairfax		0.953	*c*	0.20	*c*	4.989	4.612	5.309	5.352	5.502	9.735
Edison	Race Track Hill		0.905	*c*	0.22	*c*	27.452	27.834	30.109	29.621	31.108	26.896

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
Edison	West Area	No breakdown by pool	0.901 *c*	0.20 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Edison	West Area	Santa Margarita	0.966 *c*	0.20 *c*	0.069	0.043	0.035	0.152	0.179	0.169
Edison	West Area	Chanac-Jewett	0.920 *c*	0.20 *c*	7.766	6.898	7.516	7.033	6.879	6.286
Edison	West Area	Pyramid Hill-Vedder	0.816 *c*	0.20 *c*	0.843	0.608	0.596	0.673	0.615	0.398
Edison, Northeast	Field	Field total			0.138	0.236	0.551	0.000	0.000	0.000
Edison, Northeast	Field	Not matched to pool/*OQ*	0.979 *c*	0.20 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Edison, Northeast		Chanac	0.979 *c*	0.20 *c*	0.138	0.236	0.551	0.000	0.000	0.000
El Segundo	Field	Field total			2.525	2.585	2.394	2.392	3.931	4.146
El Segundo	Field	Not matched to pool/*OQ*	0.949 *b*	4.33 *b*	2.525	2.585	2.394	2.392	3.931	4.146
Elk Hills	Field	Field total			2,952.868	2,867.320	2,732.544	2,602.608	2,371.953	2,005.087
Elk Hills	Field	Not matched to pool/*OQ*	0.882 *c*	0.64 *b*	0.000	0.000	0.000	0.000	0.000	177.090
Elk Hills		No breakdown by pool	0.882 *c*	0.64 *b*	0.000	0.217	0.742	0.790	1.085	1.190
Elk Hills		Tulare	1.000 *c*	1.02 *b*	6.677	6.074	7.999	8.305	6.875	4.004
Elk Hills		Gas Zone	0.924 *b*	0.82 *b*	0.000	0.000	0.648	0.834	0.436	8.212
Elk Hills		4th Mya	0.947 *c*	0.82 *b*	9.931	9.940	7.909	8.230	9.450	5.128
Elk Hills		Upper Undifferentiated	0.905 *c*	0.75 *b*	1,637.570	1,601.698	1,554.117	1,542.450	1,337.456	1,190.117
Elk Hills		Upper Sub-Scalez	0.859 *c*	0.83 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Elk Hills		Reef Ridge	0.882 *c*	0.64 *b*	0.109	0.228	0.007	0.000	0.000	14.471
Elk Hills		Stevens	0.845 *c*	0.49 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Elk Hills		Stevens 29R	0.845 *c*	0.49 *b*	226.734	227.119	226.399	205.279	199.585	178.097
Elk Hills		Stevens Northwest	0.904 *c*	0.49 *b*	153.316	142.235	134.023	120.068	118.314	124.094
Elk Hills		Stevens 31S	0.845 *c*	0.49 *b*	915.403	877.087	797.902	711.270	674.112	597.304
Elk Hills		Cameros	0.780 *c*	0.63 *b*	2.807	2.432	2.587	5.234	24.640	74.029
Elk Hills		Agua	0.840 *c*		0.322	0.290	0.210	0.148	0.000	0.000
Elwood S. Offshore	Field	Field total			188.467	165.575	176.621	179.733	147.853	146.535
Elwood S. Offshore	Field	Not matched to pool/*OQ*	0.870 *c*	1.10 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Elwood S. Offshore	Coal Oil Point		0.870 *c*	1.10 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Elwood S. Offshore	Main Area	Sisquoc	0.880 *c*	2.02 *c*	0.276	0.130	0.214	0.280	0.155	0.144
Elwood S. Offshore	Main Area	Monterey	0.880 *c*	2.02 *c*	188.191	162.407	174.816	177.367	145.882	142.611
Elwood S. Offshore	Main Area	Rincon	0.860 *c*	0.17 *b*	0.000	0.248	1.465	2.087	1.816	3.779
Elwood S. Offshore	Main Area	Sespe	0.860 *c*	0.20 *c*	0.000	2.790	0.126	0.000	0.000	0.000
English Colony	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
English Colony	Field	Not matched to pool/*OQ*	0.855 *c*		0.000	0.000	0.000	0.000	0.000	0.000
English Colony		Stevens	0.855 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Esperanza	Field	Field total			1.468	0.880	1.493	1.559	1.363	1.415
Esperanza	Field	Not matched to pool/*OQ*	0.893 *c*		1.468	0.880	1.493	1.559	1.363	1.415

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
Eureka Canyon	Field	Field total			0.602	0.796	0.867	0.578	0.538	0.493
Eureka Canyon	Field	Not matched to pool/*OQ*	0.899 *c*		0.602	0.796	0.867	0.578	0.538	0.493
Fillmore	Field	Field total			0.091	0.113	0.049	0.024	0.000	0.000
Fillmore	Field	Not matched to pool/*OQ*	0.865 *c*	0.05 *c*	0.091	0.113	0.049	0.024	0.000	0.000
Fruitvale	Field	Field total			66.923	70.502	74.849	78.749	76.198	71.804
Fruitvale	Field	Not matched to pool/*OQ*	0.939 *b*	0.86 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Fruitvale	Calloway Area		0.939 *b*	0.86 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Fruitvale	Greenacres Area	Billington	0.939 *b*	0.86 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Fruitvale	Greenacres Area	Plank	0.939 *b*	0.86 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Fruitvale	Main Area		0.939 *b*	0.86 *b*	66.923	70.502	74.849	78.749	76.198	71.804
Grand Island Gas	Field	Field total			0.008	0.000	0.000	0.000	0.000	0.000
Grand Island Gas	Field	Not matched to pool/*OQ*			0.008	0.000	0.000	0.000	0.000	0.000
Greeley	Field	Field total			19.841	18.241	17.146	16.888	26.587	20.542
Greeley	Field	Not matched to pool/*OQ*	0.839 *b*	0.29 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Greeley		Stevens Undifferentiated	0.841 *b*	0.28 *b*	2.081	1.890	1.800	2.287	8.787	4.514
Greeley		Upper Stevens	0.841 *b*	0.28 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Greeley		Olcese 12-21	0.839 *b*	0.31 *b*	4.692	3.435	3.542	3.103	3.520	3.253
Greeley		Rio Bravo-Vedder	0.837 *b*	0.29 *b*	13.068	12.916	11.645	11.497	14.281	12.775
Guijarral Hills	Field	Field total			0.994	0.689	0.330	0.235	0.108	0.066
Guijarral Hills	Field	Not matched to pool/*OQ*	0.834 *b*	0.61 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Smith	0.847 *c*	0.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Smith & Allison	0.844 *c*	0.63 *b*	0.994	0.689	0.330	0.235	0.108	0.066
Guijarral Hills	Main Area	Allison	0.840 *c*	0.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Leda	0.850 *c*	0.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Leda North	0.841 *b*	0.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Dessel	0.893 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Main Area	Gatchell	0.877 *c*	0.31 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Northwest Area	Leda	0.842 *c*	0.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Polvadero Area	Sanger	0.874 *c*	0.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	Polvadero Area	Bourdieu	0.877 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Guijarral Hills	West Area	Leda	0.842 *c*	0.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Half Moon Bay	Field	Field total			0.000	0.000	0.000	0.000	0.020	0.070
Half Moon Bay	Field	Not matched to pool/*OQ*	0.874 *c*		0.000	0.000	0.000	0.000	0.020	0.070
Hasley Canyon	Field	Field total			6.199	8.127	12.387	13.083	11.413	8.979
Hasley Canyon	Field	Not matched to pool/*OQ*	0.963 *c*	5.49 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Hasley Canyon		Val Verde	0.963 *c*	5.49 *b*	6.199	8.127	12.387	13.083	11.413	8.979

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \cdot 10^3$)[a]					
							2004	2005	2006	2007	2008	2009
Helm	Field	Field total					8.340	5.849	8.923	12.379	15.920	16.010
Helm	Field	Not matched to pool/*OQ*	0.827	*b,c*	0.27	*b,c*	0.000	0.000	0.155	0.000	0.000	0.000
Helm	Main Area	Miocene	0.837	*b*	0.26	*b*	3.864	3.646	6.828	6.101	11.291	11.273
Helm	Main Area	Eocene & Cretaceous	0.808	*c*	0.30	*c*	2.565	1.771	1.794	6.170	4.540	4.663
Helm	Southeast Area	Miocene	0.837	*b*	0.26	*b*	1.911	0.432	0.146	0.108	0.089	0.078
Holser	Field	Field total					4.055	2.816	3.275	3.407	3.071	2.755
Holser	Field	Not matched to pool/*OQ*	0.923	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Holser		Conglomerate	0.953	*c*			0.065	0.042	0.053	0.052	0.046	0.040
Holser		Holser-Nuevo	0.893	*c*			3.990	2.773	3.219	3.354	3.025	2.715
Hondo Offshore	Field	Field total					1,223.927	973.919	894.604	899.656	873.872	753.598
Hondo Offshore	Field	Not matched to pool/*OQ*	0.929	*e*	4.29	*e*	1,223.927	973.919	894.604	899.656	873.872	753.598
Honor Rancho	Field	Field total					10.736	11.837	11.332	14.287	13.931	12.957
Honor Rancho	Field	Not matched to pool/*OQ*	0.842	*c*	0.40	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Honor Rancho	Main Area	Gabriel	0.840	*c*	0.40	*b*	0.107	0.063	0.129	0.229	0.248	0.257
Honor Rancho	Main Area	Rancho	0.850	*c*	0.40	*b*	0.000	0.000	0.000	1.047	1.146	0.525
Honor Rancho	Main Area	Wayside	0.850	*c*	0.40	*b*	2.516	2.193	1.424	2.592	1.980	1.583
Honor Rancho	Southeast Area	Wayside 13	0.830	*c*	0.40	*b*	8.113	9.582	9.779	10.418	10.558	10.592
Hopper Canyon	Field	Field total					1.863	0.364	1.134	1.184	1.321	1.163
Hopper Canyon	Field	Not matched to pool/*OQ*	0.942	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Hopper Canyon	Main Area		0.911	*c*			1.863	0.364	1.134	1.184	1.321	1.163
Hopper Canyon	North Area		0.973	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Howard Townsite	Field	Field total					1.590	1.463	1.032	0.921	1.402	1.104
Howard Townsite	Field	Not matched to pool/*OQ*	0.835	*c*	0.28	*c*	1.590	1.463	1.032	0.921	1.402	1.104
Hueneme Offshore	Field	Field total					17.943	23.187	23.089	21.055	19.300	17.322
Hueneme Offshore	Field	Not matched to pool/*OQ*	0.968	*c*	3.73	*e*	17.943	23.187	23.089	21.055	19.300	17.322
Huntington Beach	Field	Field total					426.468	393.104	354.270	325.566	308.982	292.617
Huntington Beach	Field	Not matched to pool/*OQ*	0.929	*b*	1.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Huntington Beach	Offshore		0.929	*b*	1.60	*b*	337.116	309.991	276.390	251.715	237.291	219.935
Huntington Beach	Onshore		0.929	*b*	1.60	*b*	89.352	83.113	77.880	73.851	71.691	69.945
Hyperion	Field	Field total					1.446	1.681	1.582	1.627	1.657	1.560
Hyperion	Field	Not matched to pool/*OQ*	0.956	*c*			1.446	1.681	1.582	1.627	1.657	1.560
Inglewood	Field	Field total					450.216	458.258	528.095	492.660	493.945	447.759
Inglewood	Field	Not matched to pool/*OQ*	0.929	*b*	2.24	*b*	450.216	458.258	528.095	492.660	493.945	447.759
Jacalitos	Field	Field total					9.944	11.819	15.437	21.410	26.355	20.136
Jacalitos	Field	Not matched to pool/*OQ*	0.832	*b*	0.34	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Jacalitos		Temblor	0.832	*b*	0.34	*b*	9.944	11.819	15.437	21.410	26.355	20.136

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Jasmin	Field	Field total			2.820	3.213	4.120	6.647	13.511	16.997
Jasmin	Field	Not matched to pool/*OQ*	0.973 *b*		0.000	0.000	0.000	0.000	0.000	0.000
Jasmin		Pyramid Hill	0.973 *b*		0.000	0.000	0.000	0.000	0.000	0.000
Jasmin		Cantleberry	0.973 *b*		2.820	3.213	4.120	6.647	13.511	16.997
Kern Bluff	Field	Field total			1.654	1.593	1.456	1.411	1.281	1.353
Kern Bluff	Field	Not matched to pool/*OQ*	0.973 *c*	0.63 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Kern Bluff		Miocene	0.973 *c*	0.63 *c*	1.654	1.593	1.456	1.411	1.281	1.353
Kern Bluff		Transition-Santa Margarita	0.973 *c*	0.63 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Kern Bluff		Vedder	0.973 *c*	0.63 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Kern Front	Field	Field total			260.566	240.570	253.748	270.374	341.787	395.301
Kern Front	Field	Not matched to pool/*OQ*	0.968 *b*	0.89 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Kern Front		No breakdown by pool	0.968 *b*	0.89 *b*	260.566	231.601	229.949	229.821	239.416	223.144
Kern Front		Etchegoin	0.973 *c*	0.94 *b*	0.000	8.969	23.799	40.553	102.370	172.158
Kern River	Field	Field total			5,570.723	5,253.662	4,899.065	4,791.678	4,682.727	4,592.039
Kern River	Field	Not matched to pool/*OQ*	0.979 *b*	1.15 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Kern River		Kern River	0.983 *b*	1.16 *b*	5,570.723	5,253.662	4,897.798	4,790.897	4,680.235	4,590.668
Kern River		Jewett	0.977 *b*	1.14 *b*	0.000	0.000	0.000	0.000	0.000	0.060
Kern River		Vedder	0.823 *c*	0.05 *c*	0.000	0.000	1.267	0.781	2.492	1.311
Kettleman Mid. Dome	Field	Field total			0.094	0.182	0.493	3.775	6.632	5.812
Kettleman Mid. Dome	Field	Not matched to pool/*OQ*	0.842 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Kettleman Mid. Dome		Etchegoin-Jacalitos	0.976 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Kettleman Mid. Dome		Temblor	0.757 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Kettleman Mid. Dome		Vaqueros	0.830 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Kettleman Mid. Dome		Kreyenhagen	0.847 *c*		0.094	0.182	0.493	2.093	2.879	2.374
Kettleman Mid. Dome		Eocene-McAdams	0.797 *c*		0.000	0.000	0.000	1.681	3.753	3.438
Kettleman N. Dome	Field	Field total			13.594	17.166	20.274	11.970	0.585	5.655
Kettleman N. Dome	Field	Not matched to pool/*OQ*	0.771 *b*	0.19 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Kettleman N. Dome		No breakdown by pool	0.771 *b*	0.19 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Kettleman N. Dome		Temblor	0.835 *b*	0.35 *b*	7.731	10.381	14.247	8.045	0.047	3.241
Kettleman N. Dome		Whepley	0.832 *c*	0.13 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Kettleman N. Dome		Vaqueros	0.843 *c*	0.28 *c*	2.084	2.491	1.980	1.146	0.501	0.697
Kettleman N. Dome		Kreyenhagen	0.871 *c*	0.31 *c*	3.447	3.823	3.704	2.515	0.036	1.310
Kettleman N. Dome		Upper McAdams	0.826 *c*	0.31 *c*	0.014	0.229	0.048	0.022	0.000	0.000
Kettleman N. Dome		Lower McAdams	0.859 *c*	0.31 *c*	0.317	0.243	0.295	0.242	0.000	0.407
La Goleta Gas	Field	Field total			0.041	0.035	0.000	0.041	0.109	0.015
La Goleta Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
La Goleta Gas		Vaqueros			0.041	0.035	0.000	0.041	0.109	0.015
La Goleta Gas		Sespe			0.000	0.000	0.000	0.000	0.000	0.000
La Honda	Field	Field total			0.000	0.213	0.300	0.292	0.468	0.458
La Honda	Field	Not matched to pool/*OQ*	0.867 *c*		0.000	0.000	0.000	0.000	0.000	0.000
La Honda	Main Area		0.867 *c*		0.000	0.000	0.000	0.000	0.000	0.000
La Honda	South Area		0.913 *c*		0.000	0.213	0.300	0.292	0.468	0.458
Landslide	Field	Field total			15.938	14.074	12.863	9.399	6.673	5.840
Landslide	Field	Not matched to pool/*OQ*	0.872 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Landslide	Boulder Creek	Stevens	0.872 *c*		1.450	1.418	1.320	1.250	1.373	1.529
Landslide	Main Area	Stevens	0.872 *c*		14.488	12.656	11.543	8.149	5.301	4.311
Las Cienagas	Field	Field total			60.337	67.463	81.534	78.275	79.911	78.139
Las Cienagas	Field	Not matched to pool/*OQ*	0.865 *c*	0.58 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Las Cienagas	Fourth Avenue		0.869 *c*	0.58 *b*	2.845	2.961	6.386	6.348	7.429	10.624
Las Cienagas	Good Shepard		0.871 *c*	0.58 *b*	0.000	0.387	2.317	0.371	0.000	0.000
Las Cienagas	Jefferson Area		0.861 *c*	0.58 *b*	18.804	24.896	32.301	34.795	33.363	29.179
Las Cienagas	Murphy Area	No breakdown by pool	0.862 *c*	0.58 *b*	33.139	31.557	40.531	36.761	37.639	34.781
Las Cienagas	Murphy Area	A,B,C & PE zones, B Block	0.870 *c*	0.58 *b*	5.550	7.662	0.000	0.000	1.480	3.554
Las Cienagas	Pacific Electric		0.855 *c*	0.58 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Las Llajas	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
Las Llajas	Field	Not matched to pool/*OQ*	0.896 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Las Llajas		Las Llajas	0.896 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Las Llajas		Santa Susana	0.896 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Lawndale	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
Lawndale	Field	Not matched to pool/*OQ*	0.882 *c*	1.40 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Lawndale		Upper	0.879 *c*	1.40 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Lawndale		Schist Conglomerate	0.887 *c*	1.40 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Lindsey Slough Gas	Field	Field total			1.479	0.561	0.761	0.943	0.908	0.754
Lindsey Slough Gas	Field	Not matched to pool/*OQ*			1.479	0.561	0.761	0.943	0.908	0.754
Livermore	Field	Field total			1.638	1.794	1.508	2.094	2.934	2.870
Livermore	Field	Not matched to pool/*OQ*	0.905 *c*		1.638	1.794	1.508	2.094	2.934	2.870
Lompoc	Field	Field total			16.338	15.128	24.546	26.179	31.576	34.809
Lompoc	Field	Not matched to pool/*OQ*	0.959 *b*	3.50 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Lompoc	Main Area	Monterey	0.932 *c*	3.50 *b*	9.961	8.524	18.262	20.572	26.510	29.763
Lompoc	Northwest Area	Monterey	0.945 *c*	1.84 *c*	6.377	6.605	6.284	5.607	5.067	5.047
Long Beach	Field	Field total			229.740	238.851	240.859	235.523	238.202	229.985
Long Beach	Field	Not matched to pool/*OQ*	0.918 *b*	1.30 *b*	0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Long Beach	Northwest Ext.		0.959 *c*	1.86 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Long Beach	Old Area	No breakdown by pool	0.918 *b*	1.30 *b*	0.000	0.000	0.029	0.000	0.000	0.000
Long Beach	Old Area	Wardlow	0.865 *c*	1.30 *b*	2.632	2.500	2.186	1.700	1.789	2.304
Long Beach	Old Area	Alamitos	0.918 *b*	1.29 *b*	5.305	5.491	4.809	6.172	6.793	5.739
Long Beach	Old Area	Brown	0.911 *c*	1.06 *b*	0.382	1.378	2.481	2.429	2.089	0.748
Long Beach	Old Area	Deep	0.865 *c*	1.06 *b*	0.084	0.063	0.000	0.000	0.000	0.163
Long Beach	Old Area	Others	0.912 *b*	1.30 *b*	217.170	225.130	227.091	220.565	223.199	216.636
Long Beach	Recreation Park		0.893 *c*	1.30 *b*	4.167	4.289	4.264	4.658	4.331	4.395
Long Beach Airport	Field	Field total			0.175	0.380	1.310	1.917	1.808	1.750
Long Beach Airport	Field	Not matched to pool/*OQ*	0.855 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Long Beach Airport		Deep	0.855 *c*		0.175	0.380	1.310	1.917	1.808	1.750
Los Alamos	Field	Field total			0.000	0.083	0.000	0.375	0.000	0.035
Los Alamos	Field	Not matched to pool/*OQ*	0.845 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Los Alamos		Monterey	0.845 *c*		0.000	0.083	0.000	0.375	0.000	0.035
Los Angeles City	Field	Field total			0.397	0.304	0.255	0.235	0.205	0.202
Los Angeles City	Field	Not matched to pool/*OQ*	0.960 *c*		0.397	0.304	0.255	0.235	0.205	0.202
Los Angeles Downtn.	Field	Field total			15.111	14.233	1.945	0.924	5.319	5.167
Los Angeles Downtn.	Field	Not matched to pool/*OQ*	0.857 *c*	1.58 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Los Angeles Downtn.		No breakdown by pool	0.857 *c*	1.58 *c*	15.111	14.233	1.945	0.924	5.319	5.167
Los Angeles Downtn.		Hill Gas Sands	0.857 *c*	1.58 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Los Angeles East	Field	Field total			8.162	7.492	9.175	6.893	6.144	3.866
Los Angeles East	Field	Not matched to pool/*OQ*	0.853 *c*		8.162	7.492	9.175	6.893	6.144	3.866
Los Lobos	Field	Field total			0.000	0.000	1.299	8.663	2.693	0.000
Los Lobos	Field	Not matched to pool/*OQ*	0.949 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Los Lobos		Etchegoin	0.953 *c*		0.000	0.000	1.299	2.376	0.305	0.000
Los Lobos		Reef Ridge	0.904 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Los Lobos		Monterey	0.990 *c*		0.000	0.000	0.000	6.288	2.388	0.000
Lost Hills	Field	Field total			1,783.149	1,820.338	1,883.906	1,929.043	1,873.020	1,839.112
Lost Hills	Field	Not matched to pool/*OQ*	0.909 *b*	0.71 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Lost Hills		No breakdown by pool	0.909 *b*	0.71 *b*	0.000	0.000	0.000	0.000	0.000	0.872
Lost Hills		Tulare	0.934 *d*	0.83 *b*	14.142	32.613	43.832	55.518	101.136	151.557
Lost Hills		Tulare-Etchegoin	0.892 *b*	0.59 *b*	1,096.131	1,116.993	1,070.442	1,037.618	970.994	860.645
Lost Hills		Etchegoin	0.858 *b*	0.33 *b*	39.465	136.192	291.041	404.895	418.818	456.193
Lost Hills		Etchegoin-Cahn	0.909 *b*	0.71 *b*	145.947	138.768	126.662	113.640	97.778	116.788
Lost Hills		Cahn	0.880 *c*	0.71 *b*	482.263	389.604	345.600	313.022	279.407	226.494
Lost Hills		Devilwater	0.865 *c*	0.71 *b*	3.518	3.152	2.296	4.351	4.886	22.534

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Lost Hills		Carneros	0.865 *c*	0.71 *b*	0.000	0.000	0.000	0.000	0.000	0.354
Lost Hills		Antelope/McDonald	0.909 *b*	0.71 *b*	1.683	3.015	4.032	0.000	0.000	3.789
Lost Hills Northwest	Field	Field total			3.378	3.019	2.831	2.434	3.201	3.407
Lost Hills Northwest	Field	Not matched to pool/*OQ*	0.910 *c*	0.33 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Lost Hills Northwest		Etchegoin	0.885 *c*	0.33 *c*	2.084	1.946	1.866	1.632	2.257	2.566
Lost Hills Northwest		Antelope Shale	0.934 *c*	0.33 *c*	1.293	1.073	0.965	0.803	0.942	0.841
Lynch Canyon	Field	Field total			0.000	4.818	10.225	17.692	20.365	23.877
Lynch Canyon	Field	Not matched to pool/*OQ*	0.993 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Lynch Canyon		Lanigan	0.993 *c*		0.000	4.818	10.225	17.692	20.365	23.877
Mahala	Field	Field total			0.444	0.340	0.416	0.287	0.246	0.105
Mahala	Field	Not matched to pool/*OQ*	0.908 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Mahala	Abacherli Area		0.923 *c*		0.404	0.314	0.327	0.262	0.216	0.079
Mahala	Mahala Area		0.921 *c*		0.040	0.026	0.021	0.025	0.029	0.025
Mahala	Mahala West Area		0.871 *c*		0.000	0.000	0.068	0.000	0.000	0.000
Mahala	Prado Dam Area		0.916 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Maine Prairie Gas	Field	Field total			0.006	0.065	0.004	0.002	0.002	0.004
Maine Prairie Gas	Field	Not matched to pool/*OQ*			0.006	0.065	0.004	0.002	0.002	0.004
McCool Ranch	Field	Field total			0.000	0.000	0.000	0.000	0.618	0.194
McCool Ranch	Field	Not matched to pool/*OQ*	0.988 *c*	1.20 *c*	0.000	0.000	0.000	0.000	0.000	0.000
McCool Ranch		Lombardi	0.988 *c*	1.20 *c*	0.000	0.000	0.000	0.000	0.618	0.194
McDonald Anticline	Field	Field total			11.087	13.129	12.258	12.192	14.821	9.591
McDonald Anticline	Field	Not matched to pool/*OQ*	0.903 *c*		0.000	0.000	0.000	0.000	0.000	0.000
McDonald Anticline	Bacon Hills Area	No breakdown by pool	0.907 *c*		0.000	0.000	0.000	0.000	0.000	0.000
McDonald Anticline	Bacon Hills Area	Antelope	0.979 *c*		0.048	0.163	0.141	0.000	0.373	0.207
McDonald Anticline	Bacon Hills Area	Oceanic	0.835 *c*		0.000	0.000	0.000	0.000	0.000	0.000
McDonald Anticline	Layman Area		0.913 *c*		11.040	12.965	12.118	12.192	14.448	9.384
McKittrick	Field	Field total			404.989	406.531	445.962	434.653	395.041	356.473
McKittrick	Field	Not matched to pool/*OQ*	0.957 *b*	0.96 *b*	0.000	0.000	0.000	0.000	0.000	0.000
McKittrick	Main Area	Tulare	0.962 *b*	0.96 *b*	2.328	3.061	16.439	42.995	40.318	42.625
McKittrick	Main Area	Upper	0.962 *b*	0.96 *b*	40.613	47.795	72.613	88.855	101.789	101.718
McKittrick	Main Area	Olig	0.973 *c*	0.96 *b*	0.000	0.000	0.000	0.000	1.108	11.094
McKittrick	Main Area	Antelope Shale	0.986 *c*	1.18 *c*	0.000	0.000	0.000	0.000	0.000	0.000
McKittrick	Main Area	Stevens	0.903 *c*	1.02 *c*	3.489	6.503	4.058	20.762	13.409	12.499
McKittrick	Northeast Area	Upper	0.949 *c*	0.96 *b*	258.285	259.160	264.895	213.143	174.632	138.170
McKittrick	Northeast Area	Tulare	0.962 *b*	0.96 *b*	5.470	9.659	16.536	14.865	13.971	15.596
McKittrick	Northeast Area	Antelope Shale	0.905 *c*	1.18 *c*	1.119	0.688	0.633	1.856	4.565	2.572

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
McKittrick	Northeast Area	Carneros	0.845 *c*	1.02 *c*	2.563	2.952	3.017	4.430	3.297	7.832
McKittrick	Northeast Area	Phacoides	0.860 *c*	1.02 *c*	31.246	28.859	27.197	21.257	23.673	22.428
McKittrick	Northeast Area	Phacoides/Oceanic	0.853 *c*	1.02 *c*	3.167	2.210	2.052	1.235	1.018	0.682
McKittrick	Northeast Area	Oceanic	0.845 *c*	1.02 *c*	21.512	14.625	8.188	3.733	4.402	4.267
McKittrick	Northeast Area	Point of Rocks	0.910 *c*	1.02 *c*	35.196	31.017	30.332	21.522	12.860	10.584
Medora Lake Gas	Field	Field total			0.013	0.047	0.042	0.030	0.010	0.000
Medora Lake Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Medora Lake Gas		Winters			0.013	0.047	0.042	0.030	0.010	0.000
Merrill Avenue Gas	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
Merrill Avenue Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Merrill Avenue Gas		Blewett			0.000	0.000	0.000	0.000	0.000	0.000
Midway-Sunset	Field	Field total			7,117.798	6,721.020	6,300.516	6,043.567	5,775.550	5,398.648
Midway-Sunset	Field	Not matched to pool/*OQ*	0.945 *b*	1.00 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Midway-Sunset	County Code 029		0.945 *b*	1.00 *b*	2,870.140	2,519.130	2,215.383	2,023.260	1,847.419	1,680.645
Midway-Sunset	County Code 030		0.945 *b*	1.00 *b*	4,244.114	4,198.429	4,080.051	4,014.579	3,923.591	3,711.220
Midway-Sunset	County Code 079		0.945 *b*	1.00 *b*	3.544	3.461	5.088	5.728	4.541	7.419
Millar Gas	Field	Field total			0.164	0.077	0.048	0.047	0.034	0.000
Millar Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Millar Gas	Main Area				0.025	0.001	0.041	0.047	0.034	0.000
Millar Gas	West Area				0.139	0.076	0.007	0.000	0.000	0.000
Monroe Swell	Field	Field total			2.282	2.670	2.233	1.204	1.381	1.148
Monroe Swell	Field	Not matched to pool/*OQ*	0.930 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Monroe Swell	Northwest Area		0.916 *c*		1.255	1.502	1.142	0.524	0.901	0.516
Monroe Swell	Old Area		0.944 *c*		1.027	1.168	1.091	0.680	0.480	0.632
Montalvo West	Field	Field total			49.978	46.838	44.459	40.082	64.931	91.323
Montalvo West	Field	Not matched to pool/*OQ*	0.923 *c*	4.10 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Montalvo West	Offshore	Sespe	0.922 *c*	4.10 *c*	3.805	3.923	3.422	4.796	3.947	3.684
Montalvo West	Offshore	Colonia	0.959 *d*	4.10 *d*	11.691	10.088	7.505	5.678	19.146	17.569
Montalvo West	Onshore	No breakdown by pool	0.923 *c*	4.10 *c*	34.483	32.663	33.533	29.607	30.307	30.132
Montalvo West	Onshore	Gas Zone	0.923 *c*	4.10 *c*	0.000	0.164	0.000	0.000	0.000	0.000
Montalvo West	Onshore	Sespe	0.887 *c*	4.10 *c*	0.000	0.000	0.000	0.000	11.531	20.995
Montalvo West	Onshore	Colonia	0.959 *c*	4.10 *c*	0.000	0.000	0.000	0.000	0.000	18.943
Montebello	Field	Field total			138.173	128.467	122.178	112.687	110.810	117.459
Montebello	Field	Not matched to pool/*OQ*	0.914 *b*	0.91 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Montebello	Any Area		0.914 *b*	0.91 *b*	38.310	33.344	35.102	34.708	32.477	34.788
Montebello	Main Area	No breakdown by pool	0.914 *b*	0.91 *b*	86.152	78.914	71.433	64.732	64.201	67.310

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific		Sulfur		Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity		% wt.		2004	2005	2006	2007	2008	2009
Montebello	Main Area	1st and 2nd	0.919	*c*	1.17	*b*	5.265	4.685	3.781	3.482	1.535	1.696
Montebello	West Area	No breakdown by pool	0.914	*b*	0.91	*b*	0.000	0.000	0.000	0.006	0.115	0.225
Montebello	West Area	1st	0.934	*c*	1.17	*b*	0.000	0.000	0.000	0.063	0.000	0.183
Montebello	West Area	Observation Pool	0.914	*b*	0.91	*b*	0.978	0.000	11.862	0.000	4.663	4.360
Montebello	West Area	8th	0.850	*c*	0.91	*b*	7.468	11.523	0.000	9.696	7.819	8.897
Monument Junction	Field	Field total					25.981	23.598	21.572	21.666	21.044	17.123
Monument Junction	Field	Not matched to pool/*OQ*	0.898	*c*			0.000	0.000	0.000	0.000	0.000	1.461
Monument Junction	Main Area	San Joaquin	0.898	*c*			0.000	0.000	0.000	0.000	0.008	0.000
Monument Junction	Main Area	Reef Ridge	0.898	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Monument Junction	Main Area	Antelope	0.898	*c*			21.957	18.486	16.890	17.690	17.837	15.997
Monument Junction	Mongoose Area	Antelope	0.898	*c*			4.024	5.113	4.682	3.976	3.199	2.586
Moorpark West	Field	Field total					0.262	0.287	0.070	0.288	0.292	0.275
Moorpark West	Field	Not matched to pool/*OQ*	0.973	*c*			0.262	0.287	0.070	0.288	0.292	0.275
Morales Canyon	Field	Field total					0.546	0.395	0.490	0.176	0.597	0.372
Morales Canyon	Field	Not matched to pool/*OQ*	0.850	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Morales Canyon	Clayton Area	Clayton	0.865	*c*			0.546	0.395	0.490	0.093	0.234	0.284
Morales Canyon	Government 18	Covernment 18	0.835	*c*			0.000	0.000	0.000	0.083	0.363	0.088
Mount Poso	Field	Field total					111.179	93.159	88.095	89.413	94.248	87.004
Mount Poso	Field	Not matched to pool/*OQ*	0.965	*c*	0.67	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Mount Poso	Baker-Grover	Vedder	0.963	*c*	0.67	*b*	0.942	1.487	1.495	2.220	2.575	2.103
Mount Poso	Dominion Area	Pyramid Hill	0.979	*c*	0.67	*b*	0.189	0.235	0.136	0.020	0.019	0.045
Mount Poso	Dominion Area	Vedder	0.966	*c*	0.67	*b*	14.429	13.247	14.818	14.187	14.804	15.831
Mount Poso	Dorsey Area	Vedder	0.963	*c*	0.68	*c*	7.924	8.496	7.828	7.963	7.970	7.455
Mount Poso	Granite Canyon	Vedder	0.966	*c*	0.67	*b*	1.772	1.963	1.941	1.801	1.440	1.351
Mount Poso	Main Area	No breakdown by pool	0.964	*c*	0.65	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Mount Poso	Main Area	Pyramid Hill	0.966	*c*	0.65	*c*	0.000	1.481	2.364	3.098	8.527	15.351
Mount Poso	Main Area	Pyramid Hill-Vedder	0.964	*c*	0.65	*c*	84.263	65.555	59.050	59.512	57.794	42.276
Mount Poso	Main Area	Vedder	0.963	*c*	0.67	*b*	0.170	0.043	0.051	0.338	1.049	2.353
Mount Poso	West Area	Vedder	0.959	*c*	0.67	*b*	1.491	0.652	0.412	0.273	0.070	0.235
Mountain View	Field	Field total					28.850	25.917	23.018	23.724	25.010	21.928
Mountain View	Field	Not matched to pool/*OQ*	0.874	*c*	0.44	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Mountain View	Arvin Area		0.873	*c*	0.36	*c*	1.295	1.178	1.050	1.087	1.625	1.405
Mountain View	Arvin West Area	Richards	0.863	*c*	0.44	*b*	0.869	0.949	1.219	1.308	1.311	1.119
Mountain View	Arvin West Area	Chanac-Cattani	0.871	*c*	0.51	*c*	0.240	0.192	0.099	0.152	0.288	0.191
Mountain View	Arvin West Area	Cattani	0.876	*c*	0.44	*b*	0.994	0.976	0.955	0.972	1.024	1.015
Mountain View	Arvin West Area	Houchin Main	0.850	*c*	0.44	*b*	0.287	0.265	0.202	0.178	0.161	0.161

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
Mountain View	Arvin West Area	Houchin Northwest & Brite	0.850 *c*	0.44 *b*	4.639	4.008	3.381	3.415	3.149	2.842
Mountain View	Arvin West Area	Stenderup	0.887 *c*	0.44 *b*	1.694	1.748	1.495	1.581	1.736	1.560
Mountain View	Arvin West Area	Frick	0.893 *c*	0.44 *b*	1.265	1.337	1.521	1.480	1.572	1.240
Mountain View	Digiorgio Area	No breakdown by pool	0.879 *c*	0.44 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Mountain View	Digiorgio Area	Schist	0.898 *c*	0.44 *b*	0.000	0.000	0.000	1.103	0.560	0.002
Mountain View	Main Area	No breakdown by pool	0.882 *c*	0.44 *b*	17.237	14.963	12.749	11.814	13.366	12.204
Mountain View	Main Area	Kern River-Chanac	0.911 *c*	0.36 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Mountain View	Vaccaro Area	Chanac	0.845 *c*	0.51 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Mountain View	Vaccaro Area	Upper Miocene	0.858 *c*	0.44 *b*	0.329	0.301	0.348	0.634	0.219	0.188
Newhall	Field	Field total			0.260	0.237	0.276	0.338	0.228	0.267
Newhall	Field	Not matched to pool/*OQ*	0.918 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Newhall	De Witt Canyon	Kraft	0.928 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Elsmere Area		0.966 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Pico Canyon Area		0.852 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Rice Canyon Area		0.888 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Townsite Area		0.934 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Towsley Canyon		0.935 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Tunnel Area		0.954 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Newhall	Whitney Canyon		0.920 *c*		0.260	0.237	0.276	0.338	0.228	0.250
Newhall	Wiley Canyon		0.888 *c*		0.000	0.000	0.000	0.000	0.000	0.017
Newhall-Potrero	Field	Field total			28.584	32.927	34.651	30.558	27.727	22.335
Newhall-Potrero	Field	Not matched to pool/*OQ*	0.864 *b*	0.60 *b*	0.000	0.000	0.000	0.000	0.000	1.620
Newhall-Potrero		No breakdown by pool	0.864 *b*	0.60 *b*	0.000	0.000	0.000	0.000	0.142	0.084
Newhall-Potrero		Pico Sands	0.864 *b*	0.60 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Newhall-Potrero		1-2-3 pool	0.853 *c*	0.52 *c*	12.402	16.974	13.876	10.755	10.357	9.806
Newhall-Potrero		3 pool	0.850 *c*	0.52 *c*	0.866	1.846	1.253	0.793	0.669	0.618
Newhall-Potrero		5th	0.857 *c*	0.56 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Newhall-Potrero		5th/6th	0.851 *c*	0.56 *c*	10.918	9.417	12.119	11.630	11.269	9.199
Newhall-Potrero		6th	0.846 *c*	0.56 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Newhall-Potrero		7th	0.868 *c*	0.81 *b*	4.397	4.689	7.404	7.374	5.290	4.200
Newhall-Potrero		9th	0.864 *b*	0.60 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Newport West	Field	Field total			17.018	15.415	15.849	17.880	18.547	16.865
Newport West	Field	Not matched to pool/*OQ*	0.946 *b*	2.74 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Newport West	Offshore	Division D-E	0.940 *c*	2.74 *b*	5.328	5.457	5.280	4.782	4.968	4.642
Newport West	Onshore	Bolsa	0.947 *c*	2.74 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Newport West	Onshore	A	0.916 *c*	1.99 *b*	1.369	1.297	1.472	1.552	1.402	1.257

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Newport West	Onshore	B	0.947 *c*	1.99 *b*	7.836	6.568	6.055	6.129	5.444	4.887
Newport West	Onshore	C	0.916 *c*	2.74 *b*	2.473	2.074	3.043	5.416	6.733	6.078
Newport West	Onshore	D	0.916 *c*	2.74 *b*	0.010	0.019	0.000	0.000	0.000	0.000
Oak Canyon	Field	Field total			6.270	6.537	6.133	5.109	5.058	5.031
Oak Canyon	Field	Not matched to pool/*OQ*	0.887 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Oak Canyon		1-A	0.910 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Oak Canyon		3-AB	0.876 *c*	1.03 *c*	0.000	0.000	0.000	0.000	0.000	0.223
Oak Canyon		3-ABCD	0.893 *c*	1.03 *c*	3.237	3.417	3.066	2.510	2.607	2.363
Oak Canyon		3-CD	0.910 *c*	1.03 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Oak Canyon		4-AB	0.876 *c*	0.59 *b*	0.460	0.456	0.408	0.375	0.347	0.368
Oak Canyon		4-AB & 5-A	0.873 *c*	0.59 *b*	0.575	0.580	0.589	0.386	0.141	0.000
Oak Canyon		6-AB, 7, and 8-AB	0.871 *c*	0.59 *b*	1.998	2.084	2.070	1.838	1.963	2.077
Oak Park	Field	Field total			4.270	2.956	3.638	3.095	2.939	2.748
Oak Park	Field	Not matched to pool/*OQ*	0.922 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Oak Park		Sespe	0.922 *c*		4.270	2.956	3.638	3.095	2.939	2.748
Oakridge	Field	Field total			11.779	7.903	11.611	12.425	11.560	10.260
Oakridge	Field	Not matched to pool/*OQ*	0.928 *c*	0.98 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Oakridge		Miocene	0.928 *c*	0.98 *b*	11.779	7.903	11.611	12.425	11.560	10.260
Oat Mountain	Field	Field total			6.385	5.415	9.094	11.369	12.595	19.382
Oat Mountain	Field	Not matched to pool/*OQ*	0.948 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Oat Mountain		Pliocene	0.948 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Oat Mountain		Sesnon-Eocene	0.948 *c*		6.385	5.415	9.094	11.369	12.595	19.382
Oil Creek	Field	Field total			0.459	0.373	0.297	0.170	0.101	0.193
Oil Creek	Field	Not matched to pool/*OQ*	0.820 *c*		0.459	0.373	0.297	0.170	0.101	0.193
Ojai	Field	Field total			52.527	47.341	46.451	45.786	41.782	43.316
Ojai	Field	Not matched to pool/*OQ*	0.921 *c*	1.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ojai	Lion Mountain	Lower Sespe	0.920 *c*	1.63 *b*	0.411	0.314	0.402	0.500	0.157	0.428
Ojai	Lion Mountain	Eocene	0.893 *c*	1.63 *b*	0.265	0.201	0.241	0.260	0.082	0.224
Ojai	N. Sulphur Mtn.	Miocene	0.917 *c*	1.63 *b*	10.697	9.571	8.722	7.619	8.751	10.158
Ojai	Oakview Area		0.865 *c*	1.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ojai	Silverthread Area	Pliocene	0.922 *c*	1.63 *b*	0.063	0.055	0.058	0.054	0.065	0.066
Ojai	Silverthread Area	Miocene	0.893 *c*	1.63 *b*	30.931	26.927	26.980	28.514	24.463	24.177
Ojai	Sisar Creek Area	Saugus	0.973 *c*	1.63 *b*	1.994	1.818	1.830	1.861	1.727	1.703
Ojai	Sisar Creek Area	Saugus-Miocene	0.973 *c*	1.63 *b*	0.220	0.385	0.341	0.356	0.375	0.374
Ojai	Sisar Creek Area	Miocene	0.973 *c*	1.63 *b*	0.638	0.435	0.433	0.461	0.415	0.728
Ojai	Sulphur Crest	Miocene	0.892 *c*	1.63 *b*	6.693	6.878	6.530	5.306	4.896	5.095

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Ojai	Sulphur Mountain	Miocene	0.953 *c*	1.63 *b*	0.545	0.713	0.754	0.703	0.699	0.423
Ojai	Tip Top Area		0.916 *c*	1.63 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ojai	Weldon Canyon		0.882 *c*	1.63 *b*	0.070	0.044	0.159	0.206	0.153	0.257
Olive	Field	Field total			3.303	3.374	3.167	3.171	3.177	3.113
Olive	Field	Not matched to pool/*OQ*	0.973 *c*		3.303	3.374	3.167	3.171	3.177	3.113
Orcutt	Field	Field total			92.217	94.897	101.422	106.258	138.418	175.231
Orcutt	Field	Not matched to pool/*OQ*	0.880 *c*	2.48 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Orcutt	Careaga Area	Monterey	0.919 *c*	2.17 *c*	0.121	0.000	0.000	0.000	0.000	0.000
Orcutt	Careaga Area	Pt Sal	0.882 *c*	0.61 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Orcutt	Careaga Area	Lospe	0.863 *c*	1.65 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Orcutt	Main Area	No breakdown by pool	0.880 *c*	2.48 *b*	91.354	93.450	98.890	104.716	127.504	137.253
Orcutt	Main Area	Diatomite	0.880 *c*	2.48 *b*	0.742	1.447	2.533	1.542	10.914	30.730
Orcutt	Main Area	SX	0.880 *c*	2.48 *b*	0.000	0.000	0.000	0.000	0.000	20.131
Orcutt	Main Area	Monterey Deep	0.855 *c*	2.48 *b*	0.000	0.000	0.000	0.000	0.000	1.517
Oxnard	Field	Field total			16.933	14.789	12.878	11.115	24.040	19.811
Oxnard	Field	Not matched to pool/*OQ*	1.010 *c*	5.77 *b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Oxnard		Pliocene Tar	1.022 *c*	6.00 *c*	15.610	14.061	11.850	9.737	22.544	18.176
Oxnard		Miocene Tar	1.022 *c*	7.54 *b*	0.000	0.016	0.041	0.041	0.041	0.037
Oxnard		Topanga	0.910 *c*	1.72 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Oxnard		McInnes	0.910 *c*	1.72 *b*	1.324	0.712	0.986	1.337	1.454	1.597
Oxnard		Lucas	0.865 *c*	1.72 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Oxnard		Livingston and E-D	0.857 *c*	1.72 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Pacoima	Field	Field total			0.000	1.488	0.830	0.307	0.000	0.000
Pacoima	Field	Not matched to pool/*OQ*	0.855 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Pacoima		Modelo Gas Zone	0.855 *c*		0.000	0.153	0.198	0.000	0.000	0.000
Pacoima		Modelo	0.855 *c*		0.000	1.335	0.632	0.307	0.000	0.000
Paloma	Field	Field total			3.811	4.448	5.421	5.148	4.695	4.312
Paloma	Field	Not matched to pool/*OQ*	0.806 *b*	0.26 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Paloma	Main Area	Gas Zone	0.806 *b*	0.26 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Paloma	Main Area	Paloma	0.804 *c*	0.40 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Paloma	Main Area	Antelope	0.806 *b*	0.26 *b*	0.000	0.000	0.047	0.290	0.123	0.158
Paloma	Main Area	Lower Stevens	0.819 *c*	0.10 *c*	3.304	3.914	4.776	4.052	3.961	3.610
Paloma	Symons Area	Symons	0.792 *c*	0.10 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Paloma	Symons Area	Paloma	0.816 *c*	0.40 *c*	0.507	0.534	0.598	0.805	0.611	0.544
Pescado Offshore	Field	Field total			835.129	794.985	807.051	702.007	770.829	717.512
Pescado Offshore	Field	Not matched to pool/*OQ*	0.917 *f*		835.129	794.985	807.051	702.007	770.829	717.512

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Pioneer	Field	Field total			0.286	0.308	0.387	0.394	0.351	0.366
Pioneer	Field	Not matched to pool/*OQ*	0.825 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Pioneer		Miocene	0.825 *c*		0.286	0.308	0.387	0.394	0.351	0.366
Pitas Point Offshore	Field	Field total			0.117	0.000	0.000	0.059	0.112	0.059
Pitas Point Offshore	Field	Not matched to pool/*OQ*	0.835 *e*	0.61 *e*	0.117	0.000	0.000	0.059	0.112	0.059
Placerita	Field	Field total			196.527	172.576	162.715	152.629	134.848	114.907
Placerita	Field	Not matched to pool/*OQ*	0.927 *b*	1.30 *b*	196.527	0.000	0.000	0.000	134.848	0.000
Placerita		No breakdown by pool	0.927 *b*	1.30 *b*	0.000	172.576	162.715	152.629	0.000	18.667
Placerita		Upper Kraft	0.986 *c*	1.30 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Placerita		Lower Kraft	0.925 *c*	1.30 *b*	0.000	0.000	0.000	0.000	0.000	96.240
Playa Del Rey	Field	Field total			6.641	5.623	7.144	6.106	7.822	7.497
Playa Del Rey	Field	Not matched to pool/*OQ*	0.907 *b*	2.65 *b*	0.000	0.000	0.000	0.000	0.000	0.363
Playa Del Rey	Del Rey Hills Area		0.907 *b*	3.20 *c*	0.783	0.649	1.424	1.443	1.378	0.822
Playa Del Rey	Kidson Area		0.876 *c*	2.65 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Playa Del Rey	Venice Area		0.924 *c*	2.65 *b*	5.859	4.974	5.720	4.663	6.444	6.700
Pleasant Valley	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
Pleasant Valley	Field	Not matched to pool/*OQ*	0.866 *c*	0.35 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Pleasant Valley		Temblor	0.850 *c*	0.35 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Pleasant Valley		Kreyenhagen	0.866 *c*	0.35 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Pleasant Valley		Gatchell	0.882 *c*	0.35 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Pleito	Field	Field total			36.092	32.269	30.230	29.978	43.034	39.634
Pleito	Field	Not matched to pool/*OQ*	0.935 *c*	1.18 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Pleito	Creek Area		0.953 *c*	1.18 *c*	2.197	2.279	2.002	1.988	11.106	14.054
Pleito	Ranch Area		0.916 *c*	1.18 *c*	33.895	29.990	28.228	27.990	31.928	25.580
Point Arguello OCS	Field	Field total			576.230	453.842	414.619	426.343	388.670	366.854
Point Arguello OCS	Field	Not matched to pool/*OQ*	0.934 *c*	2.90 *c*	576.230	453.842	414.619	426.343	388.670	366.854
Pt. Pedernales OCS	Field	Field total			379.534	404.059	472.821	440.090	426.093	364.590
Pt. Pedernales OCS	Field	Not matched to pool/*OQ*	0.960 *c*	1.40 *e*	379.534	404.059	472.821	440.090	426.093	364.590
Poso Creek	Field	Field total			45.343	75.121	114.511	206.274	320.456	356.434
Poso Creek	Field	Not matched to pool/*OQ*	0.979 *c*	0.94 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Poso Creek	Enas Area		0.983 *c*	0.98 *c*	1.125	1.493	1.057	1.395	2.645	2.041
Poso Creek	McVan Area		0.973 *c*	0.80 *c*	12.682	34.283	62.896	131.810	207.814	210.001
Poso Creek	Premier Area	No breakdown by pool	0.978 *c*	0.98 *c*	31.536	39.345	50.558	73.069	109.931	140.919
Poso Creek	Premier Area	Etchegoin-Chanac	0.981 *c*	0.98 *c*	0.000	0.000	0.000	0.000	0.066	3.429
Pyramid Hills	Field	Field total			10.547	11.282	10.089	10.377	10.652	9.084
Pyramid Hills	Field	Not matched to pool/*OQ*	0.903 *c*		0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Pyramid Hills	Dagany Area	KR	0.959	*c*			3.861	3.902	3.067	3.320	3.708	3.187
Pyramid Hills	Dagany Area	Canoas	0.804	*c*			0.039	0.024	0.036	0.041	0.045	0.022
Pyramid Hills	Norris Area	Miocene	0.986	*c*			0.177	0.226	0.180	0.407	0.232	0.141
Pyramid Hills	Norris Area	Eocene	0.899	*c*			1.320	2.000	1.661	1.609	1.408	0.681
Pyramid Hills	Orchard Ranch	Canoas	0.814	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Pyramid Hills	West Area	Gas Zone	0.903	*c*			0.000	0.000	0.000	0.000	0.000	0.000
Pyramid Hills	West Slope Area	KR	0.953	*c*			5.150	5.130	5.144	5.000	5.260	5.053
Railroad Gap	Field	Field total					5.975	2.892	2.173	5.545	14.498	23.035
Railroad Gap	Field	Not matched to pool/*OQ*	0.867	*c*	0.86	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Railroad Gap		No breakdown by pool	0.867	*c*	0.86	*b*	0.000	0.000	0.000	0.038	0.839	2.729
Railroad Gap		Gas Zone	0.867	*c*	0.86	*b*	0.136	0.104	0.069	0.707	0.466	0.638
Railroad Gap		Amnicola	0.979	*c*	1.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Railroad Gap		Olig	0.816	*c*	0.67	*c*	0.000	0.000	0.000	0.000	0.000	0.000
Railroad Gap		Antelope Shale	0.867	*b*	2.00	*c*	2.206	1.690	1.059	3.742	6.935	6.737
Railroad Gap		Antelope Shale/Carneros	0.867	*c*	0.86	*b*	0.000	0.000	0.000	0.000	0.000	0.503
Railroad Gap		Valv	0.866	*c*	0.64	*c*	0.000	0.136	0.124	0.080	0.176	0.331
Railroad Gap		Carneros	0.857	*b*	0.44	*b*	0.213	0.105	0.117	0.226	5.447	11.499
Railroad Gap		Phacoides	0.810	*c*	0.22	*b*	3.421	0.857	0.804	0.751	0.635	0.597
Raisin City	Field	Field total					22.096	21.648	29.737	33.951	29.059	29.161
Raisin City	Field	Not matched to pool/*OQ*	0.906	*b*	0.43	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Raisin City		Zilch	0.897	*c*	0.70	*c*	19.856	17.398	15.523	16.320	16.136	18.098
Raisin City		Eocene	0.888	*c*	0.41	*c*	2.240	4.251	14.214	17.433	12.923	11.063
Raisin City		Moreno	0.906	*b*	0.43	*b*	0.000	0.000	0.000	0.198	0.000	0.000
Raisin City		Panoche	0.906	*b*	0.43	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Ramona	Field	Field total					11.443	10.820	12.257	11.956	12.092	11.430
Ramona	Field	Not matched to pool/*OQ*	0.911	*b*	2.45	*b*	11.443	10.820	12.257	11.956	12.092	11.430
Ramona North	Field	Field total					0.028	0.000	0.000	0.020	0.055	0.104
Ramona North	Field	Not matched to pool/*OQ*	0.947	*c*			0.028	0.000	0.000	0.020	0.055	0.104
Richfield	Field	Field total					68.862	63.458	59.648	56.549	54.999	60.205
Richfield	Field	Not matched to pool/*OQ*	0.946	*c*	1.56	*c*	68.862	63.458	59.648	56.549	54.999	60.205
Rincon	Field	Field total					76.299	59.580	60.614	63.305	54.573	51.790
Rincon	Field	Not matched to pool/*OQ*	0.873	*c*	0.70	*b,c*	0.000	0.000	0.000	0.000	0.000	0.000
Rincon	Offshore		0.865	*c*	0.20	*c*	16.591	7.408	7.189	4.869	2.413	1.852
Rincon	Onshore		0.880	*c*	1.20	*b*	59.708	52.172	53.426	58.436	52.160	46.282
Rio Bravo	Field	Field total					26.751	27.674	29.116	27.838	29.858	30.102
Rio Bravo	Field	Not matched to pool/*OQ*	0.849	*c*	0.29	*b*	0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Rio Bravo		No breakdown by pool	0.849 *c*	0.29 *b*	0.000	0.000	0.000	0.010	0.022	2.672
Rio Bravo		Gas Zone	0.849 *c*	0.29 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Rio Bravo		Round Mountain	0.849 *c*	0.29 *b*	0.000	0.129	0.174	0.177	0.194	0.183
Rio Bravo		Olcese	0.860 *c*	0.29 *b*	5.866	1.327	1.831	1.821	2.490	2.741
Rio Bravo		Round Mt-Olcese	0.849 *c*	0.29 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Rio Bravo		R. Brvo-Mn Vedder-Osborn	0.838 *c*	0.35 *c*	20.885	26.218	27.111	25.830	27.153	24.506
Rio Bravo		Osborn-Helbling	0.849 *c*	0.29 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Rio Bravo		Helbling	0.850 *c*	0.29 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Rio Viejo	Field	Field total			15.632	15.142	14.273	13.869	13.221	12.189
Rio Viejo	Field	Not matched to pool/*OQ*	0.879 *c*	0.90 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Rio Viejo		Stevens	0.879 *c*	0.90 *c*	15.632	15.142	14.273	13.869	13.221	12.189
Rio Vista Gas	Field	Field total			2.348	2.481	2.742	4.412	4.928	2.210
Rio Vista Gas	Field	Not matched to pool/*OQ*			2.348	2.481	2.742	4.412	4.928	2.210
River Island Gas	Field	Field total			0.000	0.182	0.539	0.189	0.100	0.073
River Island Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		No breakdown by pool			0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Markley-Nortonville			0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Nortonville			0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Domengine-Capay			0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Mokulumne River			0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Starkey			0.000	0.000	0.000	0.000	0.000	0.000
River Island Gas		Winters			0.000	0.182	0.539	0.189	0.100	0.073
Riverdale	Field	Field total			4.617	5.907	6.286	5.628	6.032	14.486
Riverdale	Field	Not matched to pool/*OQ*	0.832 *b*	0.25 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Riverdale		Miocene	0.825 *b*	0.22 *b*	2.814	3.947	4.596	3.671	3.841	8.826
Riverdale		Eocene	0.839 *b*	0.27 *b*	1.803	1.960	1.690	1.956	2.192	5.613
Rocky Point Offshore	Field	Field total			24.235	125.927	113.716	50.316	29.825	0.000
Rocky Point Offshore	Field	Not matched to pool/*OQ*			24.235	125.927	113.716	50.316	29.825	0.000
Rose	Field	Field total			39.785	46.649	40.802	37.673	34.009	29.466
Rose	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Rose		McClure			39.785	46.649	40.802	37.673	34.009	29.466
Rosecrans	Field	Field total			29.175	30.476	29.771	29.732	27.545	27.829
Rosecrans	Field	Not matched to pool/*OQ*	0.838 *b*	0.54 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Rosecrans	Main Area		0.838 *b*	0.54 *b*	27.910	28.617	27.778	27.448	25.236	25.624
Rosecrans	Athens Area		0.838 *b*	0.54 *b*	0.000	0.532	0.836	1.012	1.109	1.060
Rosecrans	Central Area		0.838 *b*	0.54 *b*	1.265	1.327	1.157	1.272	1.199	1.145

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Rosecrans East	Field	Field total			0.423	0.281	0.269	0.273	0.231	0.007
Rosecrans East	Field	Not matched to pool/*OQ*	0.876 *c*	0.52 *b*	0.423	0.281	0.269	0.273	0.231	0.007
Rosecrans South	Field	Field total			2.365	2.371	2.312	2.072	1.983	1.826
Rosecrans South	Field	Not matched to pool/*OQ*	0.857 *c*	0.52 *b*	2.365	2.371	2.312	2.072	1.983	1.826
Rosedale	Field	Field total			4.351	4.159	3.840	3.206	3.234	2.851
Rosedale	Field	Not matched to pool/*OQ*	0.873 *c*	0.75 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Rosedale	East Area	Stevens	0.887 *c*	0.75 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Rosedale	Main Area	Stevens	0.870 *c*	0.75 *c*	4.243	3.917	3.630	3.031	3.077	2.676
Rosedale	North Area	Stevens	0.871 *c*	0.75 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Rosedale	South Area	Stevens	0.865 *c*	0.75 *c*	0.107	0.242	0.210	0.175	0.157	0.175
Rosedale Ranch	Field	Field total			16.283	16.480	18.188	26.072	29.861	31.335
Rosedale Ranch	Field	Not matched to pool/*OQ*	0.934 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Rosedale Ranch	Main Area	Etchegoin	0.966 *c*		2.441	2.056	1.037	2.312	2.825	3.290
Rosedale Ranch	Main Area	Lerdo-Chanac	0.932 *c*		12.817	13.344	16.277	17.078	18.215	16.584
Rosedale Ranch	Main Area	Chanac	0.922 *c*		0.000	0.000	0.000	5.892	8.108	11.035
Rosedale Ranch	Northeast Area	Lerdo-Chanac	0.934 *c*		0.615	0.647	0.525	0.474	0.370	0.137
Rosedale Ranch	Northeast Area	Chanac	0.917 *c*		0.410	0.431	0.350	0.316	0.343	0.290
Round Mountain	Field	Field total			205.980	251.643	222.346	214.102	219.044	304.064
Round Mountain	Field	Not matched to pool/*OQ*	0.956 *c*	0.59 *b*	0.000	0.000	0.000	0.000	0.000	4.036
Round Mountain	Alma Area	Vedder	0.979 *c*	0.60 *b*	0.000	0.072	0.046	0.144	0.198	0.210
Round Mountain	Coffee Canyon	Pyramid Hill	0.943 *c*	0.59 *b*	0.399	0.454	0.446	0.290	0.315	0.384
Round Mountain	Coffee Canyon	Pyramid Hill-Vedder	0.956 *c*	0.71 *c*	6.031	6.073	7.946	7.386	6.685	5.890
Round Mountain	Main Area	No breakdown by pool	0.943 *c*	0.49 *c*	0.000	0.474	8.631	19.596	20.961	10.784
Round Mountain	Main Area	Jewett-Vedder	0.943 *c*	0.54 *b*	198.829	243.861	194.472	163.863	173.850	230.360
Round Mountain	Main Area	Vedder	0.959 *c*	0.60 *b*	0.000	0.000	1.857	5.686	3.943	6.892
Round Mountain	Main Area	Pyramid Hill	0.947 *c*	0.43 *c*	0.000	0.000	8.231	16.505	12.253	44.840
Round Mountain	Pyramid Hill	Vedder	0.959 *c*	0.60 *b*	0.721	0.710	0.636	0.626	0.742	0.710
Round Mountain	Sharktooth Area	Vedder	0.979 *c*	0.60 *b*	0.000	0.000	0.082	0.005	0.097	0.017
Russell Ranch	Field	Field total			7.048	8.636	10.559	10.958	10.592	10.718
Russell Ranch	Field	Not matched to pool/*OQ*	0.778 *c*	0.31 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Russell Ranch	Main Area		0.726 *c*	0.36 *c*	6.953	8.544	10.502	10.956	10.451	10.716
Russell Ranch	Southeast Area	Dibblee	0.830 *c*	0.29 *b*	0.095	0.092	0.057	0.002	0.141	0.002
Ryer Island Gas	Field	Field total			0.055	0.018	0.018	0.105	0.068	0.090
Ryer Island Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Ryer Island Gas	Offshore				0.000	0.000	0.000	0.000	0.000	0.000
Ryer Island Gas	Onshore				0.055	0.018	0.018	0.105	0.068	0.090

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Sacate Offshore	Field	Field total					470.309	598.889	654.297	612.861	501.797	475.563
Sacate Offshore	Field	Not matched to pool/*OQ*	0.868	*c*			470.309	598.889	654.297	612.861	501.797	475.563
Salt Lake	Field	Field total					17.538	9.032	7.933	8.851	8.221	7.886
Salt Lake	Field	Not matched to pool/*OQ*	0.954	*c*	2.73	*b*	17.538	9.032	7.933	8.851	8.221	7.886
Salt Lake South	Field	Field total					8.688	8.474	8.739	7.203	5.401	5.642
Salt Lake South	Field	Not matched to pool/*OQ*	0.910	*c*			8.688	8.474	8.739	7.203	5.401	5.642
San Ardo	Field	Field total					634.214	558.932	500.897	546.406	662.852	838.089
San Ardo	Field	Not matched to pool/*OQ*	0.985	*b*	2.20	*b*	0.000	0.000	0.000	0.000	0.000	0.000
San Ardo	Main Area	Lombardi	0.985	*b*	2.14	*b*	572.288	496.403	447.748	483.180	583.547	763.518
San Ardo	Main Area	Auriguac	0.985	*b*	2.25	*b*	61.926	62.530	52.977	51.027	43.023	55.308
San Ardo	North Area	Lombardi	0.990	*c*	2.37	*c*	0.000	0.000	0.172	12.200	36.282	19.263
San Emidio Nose	Field	Field total					5.987	5.327	4.643	5.148	4.376	3.058
San Emidio Nose	Field	Not matched to pool/*OQ*	0.866	*c*	0.93	*b*	0.000	0.000	0.000	0.000	0.000	0.000
San Emidio Nose	Main Area	Reef Ridge	0.868	*c*	0.83	*c*	0.000	0.000	0.000	0.000	0.000	0.000
San Emidio Nose	Main Area	Stevens	0.865	*c*	0.93	*b*	4.455	3.947	3.307	3.808	3.310	2.916
San Emidio Nose	Northwest Area	Stevens	0.863	*c*	0.93	*b*	1.532	1.380	1.336	1.341	1.066	0.142
San Joaquin	Field	Field total					0.569	0.508	0.555	0.476	0.543	0.578
San Joaquin	Field	Not matched to pool/*OQ*	0.876	*c*			0.000	0.000	0.000	0.000	0.000	0.000
San Joaquin		Eocene	0.876	*c*			0.569	0.508	0.555	0.476	0.543	0.578
San Miguelito	Field	Field total					101.467	87.233	79.298	89.552	87.439	106.832
San Miguelito	Field	Not matched to pool/*OQ*	0.876	*c*	0.90	*b*	101.467	87.233	0.000	0.000	0.000	0.000
San Miguelito		Grubb 1-3	0.871	*c*	0.87	*c*	0.000	0.000	10.072	25.301	40.036	57.045
San Miguelito		Grubb 4-5	0.888	*c*	0.90	*b*	0.000	0.000	43.121	41.983	39.550	41.871
San Miguelito		Grubb D	0.871	*c*	0.87	*c*	0.000	0.000	1.165	7.728	7.852	7.916
San Vicente	Field	Field total					109.898	93.731	76.938	67.028	63.297	57.065
San Vicente	Field	Not matched to pool/*OQ*	0.912	*c*			0.000	0.000	0.000	0.000	0.000	0.000
San Vicente		Clifton, Dayton and Hay	0.912	*c*			109.898	93.731	76.938	67.028	63.297	57.065
Sansinena	Field	Field total					43.991	42.390	45.511	44.600	41.504	29.622
Sansinena	Field	Not matched to pool/*OQ*	0.925	*c*	0.87	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Sansinena	12-G Area		0.949	*c*	0.87	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Sansinena	Central Area		0.905	*c*	0.87	*b*	2.863	3.482	3.916	3.989	4.135	3.755
Sansinena	Curtis Area		0.925	*c*	0.87	*b*	1.508	0.929	0.736	0.269	0.367	0.408
Sansinena	East Area		0.897	*c*	0.87	*b*	13.343	11.719	12.694	11.617	11.014	7.814
Sansinena	New England Area		0.932	*c*	0.87	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Sansinena	West Area		0.940	*c*	0.87	*b*	26.277	26.261	28.165	28.725	25.988	17.646
Santa Clara Avenue	Field	Field total					11.258	10.644	10.691	11.276	11.604	12.201

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \bullet 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
Santa Clara Avenue	Field	Not matched to pool/*OQ*	0.914 *c*	2.00 *c*	11.258	10.644	10.691	11.276	11.604	12.201
Santa Clara Offshore	Field	Field total			108.134	92.569	96.149	85.175	95.437	98.940
Santa Clara Offshore	Field	Not matched to pool/*OQ*	0.887 *c*	2.85 *e*	108.134	92.569	96.149	85.175	95.437	98.940
Santa Fe Springs	Field	Field total			98.086	113.841	108.169	101.717	102.800	100.605
Santa Fe Springs	Field	Not matched to pool/*OQ*	0.861 *b*	0.41 *b*	98.086	113.841	108.169	101.717	102.800	100.605
Santa Maria Valley	Field	Field total			31.291	23.323	20.581	19.320	13.833	20.823
Santa Maria Valley	Field	Not matched to pool/*OQ*	0.987 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Bradley Area	Foxen	0.987 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Bradley Area	Basal Sisquoc	0.973 *c*	4.13 *c*	6.843	2.969	2.476	3.298	1.511	5.276
Santa Maria Valley	Bradley Area	Monterey	0.973 *c*	4.35 *b*	1.236	0.699	1.214	1.031	0.083	0.744
Santa Maria Valley	Clark Area	Foxen	1.000 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Clark Area	Sisquoc	1.011 *c*	4.35 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Clark Area	Clark	0.987 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Main Area		0.965 *c*	3.00 *c*	7.980	9.062	7.902	5.912	8.720	7.112
Santa Maria Valley	North Area	Foxen	0.979 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Southeast Area	Foxen	1.000 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Southeast Area	Sisquoc	0.990 *c*	4.35 *b*	10.036	5.598	4.001	4.679	0.592	3.035
Santa Maria Valley	Southeast Area	Houk	0.990 *c*	4.35 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Santa Maria Valley	Southeast Area	Monterey	1.014 *c*	4.35 *b*	1.730	1.818	1.826	1.362	0.000	1.510
Santa Maria Valley	West Area		0.964 *c*	0.60 *c*	3.466	3.177	3.162	3.037	2.926	2.939
Santa Susana	Field	Field total			5.646	3.556	4.525	4.349	3.612	3.107
Santa Susana	Field	Not matched to pool/*OQ*	0.821 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Santa Susana		Sespe	0.821 *c*		0.979	0.642	0.652	0.943	0.786	0.882
Santa Susana		First Sespe	0.806 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Santa Susana		Second and Third Sespe	0.835 *c*		4.668	2.914	3.873	3.406	2.826	2.225
Sargent	Field	Field total			3.285	2.848	2.954	3.825	4.486	4.007
Sargent	Field	Not matched to pool/*OQ*	0.952 *b*	0.86 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Sargent		No breakdown by pool	0.952 *b*	0.86 *b*	3.285	2.848	2.954	3.032	2.571	2.473
Sargent		Purisma Sand	0.932 *c*	0.62 *c*	0.000	0.000	0.000	0.792	1.915	1.534
Saticoy	Field	Field total			7.596	7.182	8.792	8.326	7.076	6.566
Saticoy	Field	Not matched to pool/*OQ*	0.854 *c*	0.94 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Saticoy	Main Area		0.854 *c*	0.94 *b*	7.029	6.990	8.284	7.741	6.597	5.937
Saticoy	South Area		0.854 *c*	0.94 *b*	0.568	0.192	0.508	0.586	0.479	0.629
Sawtelle	Field	Field total			38.476	33.490	33.706	29.285	28.826	28.695
Sawtelle	Field	Not matched to pool/*OQ*	0.902 *b*	1.99 *b*	38.476	33.490	33.706	29.285	28.826	28.695
Seal Beach	Field	Field total			74.059	70.371	76.528	77.406	78.039	74.269

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Seal Beach	Field	Not matched to pool/*OQ*	0.867 *b*	0.55 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Seal Beach	Alamitos Area		0.886 *c*	0.55 *b*	4.439	4.324	4.068	4.406	3.873	6.394
Seal Beach	Marine Area	Wasem	0.888 *c*	0.55 *b*	0.197	0.472	0.331	0.432	0.405	0.268
Seal Beach	Marine Area	McGrath	0.904 *c*	0.55 *b*	6.223	6.196	7.177	7.425	7.402	6.676
Seal Beach	North Block	No breakdown by pool	0.898 *c*	0.55 *b*	31.606	30.164	31.712	32.274	33.351	31.777
Seal Beach	North Block	Selover	0.893 *c*	0.55 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Seal Beach	N. Block-East Ext.	Recent	0.867 *b*	0.55 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Seal Beach	N. Block-East Ext.	Wasem	0.887 *c*	0.55 *b*	1.775	1.500	1.419	1.371	1.447	1.401
Seal Beach	N. Block-East Ext.	McGrath	0.877 *c*	0.55 *b*	2.048	2.159	1.954	1.897	2.161	2.048
Seal Beach	South Block		0.896 *c*	1.00 *c*	27.770	25.557	29.867	29.590	29.401	28.241
Semitropic	Field	Field total			6.478	6.442	6.175	5.660	5.896	4.797
Semitropic	Field	Not matched to pool/*OQ*	0.846 *c*		0.000	0.000	0.000	0.000	0.000	0.438
Semitropic		Gas Zone	0.846 *c*		0.022	0.045	0.181	0.000	0.043	0.128
Semitropic		Randolph	0.876 *c*		6.456	6.397	5.994	5.660	5.853	5.120
Semitropic		Vedder	0.816 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Sespe	Field	Field total			71.285	61.951	62.307	61.906	62.563	54.681
Sespe	Field	Not matched to pool/*OQ*	0.887 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Sespe	Foot of the Hills	Middle Sespe	0.934 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Sespe	Foot of the Hills	Basal Sespe	0.910 *c*		1.322	1.018	1.206	1.080	1.151	0.448
Sespe	Foot of the Hills	Eocene	0.910 *c*		0.052	0.054	0.056	0.052	0.057	0.049
Sespe	Little Sespe Creek	Upper Sespe	0.887 *c*		1.150	0.745	0.698	0.654	0.499	0.135
Sespe	Little Sespe Creek	Basal Sespe	0.871 *c*		0.644	0.667	0.729	0.720	0.731	0.570
Sespe	Tar Crk-Topatopa	No breakdown by pool	0.875 *c*		4.600	3.189	4.393	4.218	4.391	5.485
Sespe	Tar Crk-Topatopa	Rincon-Vaqueros	0.865 *c*		0.163	0.078	0.276	0.633	0.575	0.223
Sespe	Tar Crk-Topatopa	Vaqueros	0.865 *c*		0.922	1.116	1.008	1.185	1.221	1.346
Sespe	Tar Crk-Topatopa	Upper Sespe	0.887 *c*		1.676	1.288	1.225	1.076	0.717	0.931
Sespe	Tar Crk-Topatopa	Middle Sespe	0.887 *c*		2.015	2.034	2.205	1.745	1.319	1.227
Sespe	Tar Crk-Topatopa	Basal Sespe	0.871 *c*		56.577	49.781	48.420	48.362	49.174	42.028
Sespe	Tar Crk-Topatopa	Coldwater	0.876 *c*		2.164	1.981	2.091	2.180	2.729	2.236
Shafter North	Field	Field total			122.413	113.215	103.849	103.572	107.392	91.598
Shafter North	Field	Not matched to pool/*OQ*	0.890 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Shafter North		McClure	0.890 *c*		122.413	113.215	103.849	103.572	107.392	91.598
Shiells Canyon	Field	Field total			9.511	10.536	10.608	10.747	13.778	12.902
Shiells Canyon	Field	Not matched to pool/*OQ*	0.866 *c*	0.78 *c*	9.511	0.000	0.000	0.000	13.778	5.125
Shiells Canyon	Main Area	No breakdown by pool	0.866 *c*	0.78 *c*	0.000	10.536	10.608	10.747	0.000	0.670
Shiells Canyon	Main Area	Sespe	0.865 *c*	0.78 *c*	0.000	0.000	0.000	0.000	0.000	0.960

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Shiells Canyon	Main Area	Eocene	0.860 *c*	0.78 *c*	0.000	0.000	0.000	0.000	0.000	6.147
Simi	Field	Field total			0.069	0.122	0.132	0.146	0.123	0.114
Simi	Field	Not matched to pool/*OQ*	0.900 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Simi	Old Area	No breakdown by pool	0.882 *c*	0.68 *b*	0.069	0.122	0.132	0.146	0.123	0.114
Simi	Old Area	Gas Zone	0.900 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Simi	Old Area	Llajas	0.876 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Simi	Strathearn Area		0.860 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Simi	Canada da la Brea		0.948 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Simi	Alamos Canyon		0.931 *c*	0.68 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Sockeye Offshore	Field	Field total			270.434	278.630	234.778	245.710	239.933	243.032
Sockeye Offshore	Field	Not matched to pool/*OQ*	0.917 *c*	3.26 *e*	270.434	278.630	234.778	245.710	239.933	243.032
South Mountain	Field	Field total			79.072	74.778	74.022	71.815	72.153	76.341
South Mountain	Field	Not matched to pool/*OQ*	0.886 *b*	1.73 *b*	79.072	74.778	74.022	71.815	72.153	76.341
Stockdale	Field	Field total			14.895	16.045	15.150	15.203	15.381	15.514
Stockdale	Field	Not matched to pool/*OQ*	0.893 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Stockdale	Old Area	Chanac	0.898 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Stockdale	Panama Lane	Nozu	0.887 *c*		14.895	16.045	15.150	15.203	15.381	15.514
Strand	Field	Field total			1.127	0.715	0.648	0.647	0.622	0.785
Strand	Field	Not matched to pool/*OQ*	0.855 *c*	0.47 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	East Area	Stevens	0.855 *c*	0.41 *c*	0.418	0.067	0.000	0.000	0.000	0.264
Strand	Main Area	Gas Zone	0.855 *c*	0.47 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	Main Area	Upper Stevens	0.850 *c*	0.43 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	Main Area	Lower Stevens	0.860 *c*	0.45 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	Main Area	Vedder	0.835 *c*	0.47 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	Northwest Area	Gas Zone	0.855 *c*	0.47 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Strand	Northwest Area	Stevens	0.857 *c*	0.54 *c*	0.709	0.648	0.648	0.647	0.622	0.521
Strand	South Area	Stevens	0.871 *c*	0.43 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Suisun Bay Gas	Field	Field total			0.000	0.000	0.000	0.000	0.000	0.000
Suisun Bay Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Tapia	Field	Field total			1.863	6.186	8.391	7.641	9.042	9.108
Tapia	Field	Not matched to pool/*OQ*	0.953 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tapia		No breakdown by pool	0.953 *c*		1.863	6.186	8.391	7.641	9.042	9.108
Tapia		Saugus	0.953 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tapo Canyon South	Field	Field total			1.992	1.799	2.374	2.375	2.117	1.773
Tapo Canyon South	Field	Not matched to pool/*OQ*	0.926 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tapo Canyon South		No breakdown by pool	0.926 *c*		1.636	1.427	1.908	1.950	1.712	1.354

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \cdot 10^3$)[a] 2004	2005	2006	2007	2008	2009
Tapo Canyon South		Sespe	0.947 *c*		0.356	0.372	0.467	0.426	0.405	0.418
Tapo North	Field	Field total			0.072	0.148	1.023	0.931	1.029	0.940
Tapo North	Field	Not matched to pool/*OQ*	0.930 *c*		0.072	0.148	1.023	0.931	1.029	0.940
Tapo Ridge	Field	Field total			0.465	0.379	0.557	0.535	0.451	0.316
Tapo Ridge	Field	Not matched to pool/*OQ*	0.956 *c*		0.465	0.379	0.557	0.535	0.451	0.316
Tejon	Field	Field total			53.970	53.910	48.997	54.131	93.381	84.936
Tejon	Field	Not matched to pool/*OQ*	0.879 *b*	0.27 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon	Central Area		0.879 *b*	0.28 *c*	7.095	9.593	9.124	12.926	11.118	9.129
Tejon	Eastern Area		0.947 *c*	0.27 *b*	2.658	2.566	2.428	1.935	2.449	2.369
Tejon	Southeast Area		0.943 *c*	0.27 *b*	2.988	3.143	2.881	3.000	2.834	2.675
Tejon	Western Area		0.944 *c*	0.40 *c*	41.229	38.608	34.563	36.270	76.979	70.763
Tejon Hills	Field	Field total			2.434	1.767	1.950	1.945	1.671	2.241
Tejon Hills	Field	Not matched to pool/*OQ*	0.866 *b*	0.26 *b*	2.434	1.767	1.950	1.945	1.671	2.241
Tejon North	Field	Field total			9.579	10.009	9.313	8.882	7.395	6.739
Tejon North	Field	Not matched to pool/*OQ*	0.846 *b*	0.20 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon North		No breakdown by pool	0.846 *b*	0.20 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon North		Fruitvale	0.917 *c*	0.20 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon North		Olcese	0.845 *c*	0.20 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon North		Olcese-Eocene	0.811 *c*	0.20 *c*	3.468	3.844	3.056	3.076	2.803	2.547
Tejon North		JV-Basalt	0.797 *c*	0.16 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Tejon North		Vedder-Eocene	0.810 *c*	0.24 *c*	6.111	6.165	6.257	5.805	4.592	4.191
Temblor Ranch	Field	Field total			0.221	0.141	0.138	0.064	0.033	0.023
Temblor Ranch	Field	Not matched to pool/*OQ*	0.959 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Temblor Ranch		Miocene	0.959 *c*		0.221	0.141	0.138	0.064	0.033	0.023
Temescal	Field	Field total			4.834	5.118	5.337	5.348	4.819	3.891
Temescal	Field	Not matched to pool/*OQ*	0.920 *b*	0.55 *b*	4.834	5.118	5.337	5.348	4.819	3.891
Ten Section	Field	Field total			19.630	18.551	18.466	19.041	14.455	14.692
Ten Section	Field	Not matched to pool/*OQ*	0.845 *b*	0.41 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ten Section	Main Area	Gas Zone	0.845 *b*	0.41 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ten Section	Main Area	Upper Stevens	0.845 *c*	0.41 *b*	17.533	17.205	17.120	17.423	12.811	13.159
Ten Section	Main Area	Lower Stevens	0.860 *c*	0.41 *b*	2.098	1.346	1.346	1.617	1.644	1.533
Ten Section	Northwest Area	No breakdown by pool	0.845 *b*	0.41 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Ten Section	Northwest Area	Stevens	0.852 *c*	0.41 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Thornton WWG Gas	Field	Field total			0.000	0.000	0.038	0.153	0.014	0.000
Thornton WWG Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.038	0.153	0.014	0.000
Timber Canyon	Field	Field total			6.187	3.250	6.000	5.497	4.888	6.278

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Timber Canyon	Field	Not matched to pool/*OQ*	0.847 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Timber Canyon	Loel-Maxwell Area		0.840 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Timber Canyon	Main Area		0.855 *c*		6.187	3.250	6.000	5.497	4.888	6.278
Tisdale Gas	Field	Field total			0.000	0.000	0.000	0.000	0.008	0.000
Tisdale Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.000	0.000	0.000	0.000
Tisdale Gas	Main Area	Forbes			0.000	0.000	0.000	0.000	0.008	0.000
Tisdale Gas	Southeast Area	Forbes			0.000	0.000	0.000	0.000	0.000	0.000
Tisdale Gas	Southeast Area	Guinda			0.000	0.000	0.000	0.000	0.000	0.000
Torrance	Field	Field total			60.768	58.047	61.020	61.287	61.560	59.173
Torrance	Field	Not matched to pool/*OQ*	0.934 *b*	2.26 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Torrance	Offshore	Del Amo	0.887 *c*	2.42 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Torrance	Offshore	Others	0.930 *c*	2.43 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Torrance	Onshore	Tar-Ranger & Main, East	0.936 *c*	1.37 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Torrance	Onshore	Others	0.934 *b*	2.26 *b*	57.219	54.931	57.893	58.047	58.323	55.642
Torrance	Onshore	Del Amo	0.887 *c*	2.42 *b*	3.549	3.116	3.127	3.240	3.237	3.531
Torrey Canyon	Field	Field total			13.830	10.938	14.342	14.046	13.976	12.720
Torrey Canyon	Field	Not matched to pool/*OQ*	0.896 *c*	2.74 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Torrey Canyon		Sespe	0.896 *c*	2.74 *b*	1.686	1.417	1.757	1.691	1.664	1.621
Torrey Canyon		First Sespe	0.910 *c*	2.74 *b*	0.828	0.626	0.871	0.876	0.733	0.526
Torrey Canyon		Second Sespe	0.882 *c*	2.74 *b*	0.836	0.727	1.007	0.935	0.945	0.873
Torrey Canyon		Third Sespe	0.896 *c*	2.74 *c*	1.172	1.187	1.452	1.479	1.343	1.333
Torrey Canyon		Deep	0.896 *c*	2.74 *b*	9.308	6.982	9.255	9.065	9.291	8.367
Tulare Lake	Field	Field total			2.518	0.391	0.000	0.000	0.000	0.000
Tulare Lake	Field	Not matched to pool/*OQ*	0.843 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tulare Lake		Salyer	0.771 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tulare Lake		KCDC	0.826 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tulare Lake		54-8U	0.865 *c*		1.521	0.283	0.000	0.000	0.000	0.000
Tulare Lake		54-8M	0.850 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Tulare Lake		54-8L	0.865 *c*		0.507	0.094	0.000	0.000	0.000	0.000
Tulare Lake		Boswell	0.876 *c*		0.490	0.015	0.000	0.000	0.000	0.000
Tulare Lake		Vaqueros	0.845 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Union Avenue	Field	Field total			0.812	1.077	0.848	0.600	0.888	2.902
Union Avenue	Field	Not matched to pool/*OQ*	0.966 *c*	2.25 *c*	0.812	1.077	0.848	0.600	0.888	2.902
Union Station	Field	Field total			2.358	0.651	0.225	0.000	0.000	0.000
Union Station	Field	Not matched to pool/*OQ*	0.829 *c*		2.358	0.651	0.225	0.000	0.000	0.000
Vallecitos	Field	Field total			1.159	1.161	0.857	0.829	0.825	1.161

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

			Specific	Sulfur	Production by year ($m^3 \cdot 10^3$)[a]					
Field	Area	Pool, formation or zone	gravity	% wt.	2004	2005	2006	2007	2008	2009
Vallecitos	Field	Not matched to pool/*OQ*	0.877 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Vallecitos	Ashurst Area	Domengine-Yokut	0.900 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Vallecitos	Cedar Flat Area	San Carlos	0.921 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Vallecitos	Central Area	Ashurst	0.840 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Vallecitos	Central Area	Domengine-Yokut	0.850 *c*		0.699	0.716	0.585	0.567	0.653	0.755
Vallecitos	Franco Area	Yokut	0.860 *c*		0.195	0.244	0.215	0.232	0.056	0.247
Vallecitos	Griswold Canyon	San Carlos	0.845 *c*		0.035	0.021	0.035	0.028	0.031	0.028
Vallecitos	Los Pinos Canyon		0.898 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Vallecitos	Silver Creek Area	San Carlos	0.904 *c*		0.230	0.179	0.022	0.003	0.085	0.132
Vallecitos	Pimental Cn. Gas	Yokut	0.877 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Valpredo	Field	Field total			0.000	0.000	0.000	0.006	0.003	0.000
Valpredo	Field	Not matched to pool/*OQ*	0.898 *c*	1.80 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Valpredo		Miocene	0.898 *c*	1.80 *c*	0.000	0.000	0.000	0.006	0.003	0.000
Van Ness Slough	Field	Field total			0.398	0.199	0.176	0.131	0.071	0.020
Van Ness Slough	Field	Not matched to pool/*OQ*	0.845 *c*		0.000	0.000	0.000	0.000	0.000	0.000
Van Ness Slough		Miocene	0.845 *c*		0.398	0.199	0.176	0.131	0.071	0.020
Van Sickle Island Gas	Field	Field total			0.000	0.000	0.120	0.350	1.297	1.254
Van Sickle Island Gas	Field	Not matched to pool/*OQ*			0.000	0.000	0.120	0.350	1.297	1.254
Ventura	Field	Field total			697.753	627.288	675.084	671.198	664.385	666.861
Ventura	Field	Not matched to pool/*OQ*	0.866 *b*	1.08 *b*	697.753	627.288	675.084	671.198	664.385	666.861
Walnut	Field	Field total			1.688	1.554	1.347	1.391	1.304	1.277
Walnut	Field	Not matched to pool/*OQ*	0.959 *c*		1.688	1.554	1.347	1.391	1.304	1.277
Wasco	Field	Field total			0.083	0.049	0.000	0.000	0.000	0.006
Wasco	Field	Not matched to pool/*OQ*	0.836 *c*	0.21 *b*	0.083	0.049	0.000	0.000	0.000	0.006
Wayside Canyon	Field	Field total			2.874	2.959	2.728	2.639	1.978	1.457
Wayside Canyon	Field	Not matched to pool/*OQ*	0.925 *c*		2.874	2.959	2.728	2.639	1.978	1.457
West Mountain	Field	Field total			1.560	1.621	1.610	1.533	1.268	1.169
West Mountain	Field	Not matched to pool/*OQ*	0.934 *c*		1.560	1.621	1.610	1.533	1.268	1.169
Wheeler Ridge	Field	Field total			16.243	15.655	15.391	16.355	12.306	11.231
Wheeler Ridge	Field	Not matched to pool/*OQ*	0.884 *b*	0.46 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Central Area	No breakdown by pool	0.884 *b*	0.46 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Central Area	Coal Oil Canyon	0.916 *c*	0.69 *c*	1.690	1.417	1.787	1.581	1.186	0.473
Wheeler Ridge	Central Area	Coal Oil Canyon-Main	0.896 *c*	0.69 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Central Area	Miocene-Oligocene	0.852 *c*	0.55 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Central Area	Main	0.876 *c*	0.69 *c*	0.698	0.633	0.616	0.750	1.526	0.887
Wheeler Ridge	Central Area	Valv	0.898 *c*	0.40 *c*	0.763	0.427	0.247	0.288	0.065	0.113

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity		Sulfur % wt.		Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Wheeler Ridge	Central Area	2-38 pool	0.825	*c*	0.40	*c*	0.311	0.351	0.475	0.483	0.493	0.551
Wheeler Ridge	Central Area	Olcese	0.825	*c*	0.40	*b*	0.284	0.232	0.236	0.460	0.919	0.517
Wheeler Ridge	Central Area	Oligocene-Eocene	0.827	*c*	0.46	*b*	0.536	0.479	0.523	0.400	0.173	0.080
Wheeler Ridge	Central Area	ZA-5	0.806	*c*	0.46	*b*	0.000	0.000	0.000	0.045	0.283	0.134
Wheeler Ridge	Central Area	ZB-3	0.884	*b*	0.46	*b*	0.771	0.636	0.377	0.329	0.190	0.199
Wheeler Ridge	Central Area	ZB-5	0.806	*c*	0.46	*b*	0.810	0.710	0.668	0.564	0.437	0.459
Wheeler Ridge	Central Area	Refugian Eocene	0.847	*c*	0.29	*c*	4.224	5.508	5.403	6.270	2.911	4.342
Wheeler Ridge	Northeast Area	FA-2	0.947	*c*	0.69	*b*	0.880	1.010	1.046	0.852	0.716	0.973
Wheeler Ridge	Northeast Area	Hagood	0.953	*c*	0.46	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Northeast Area	ZB-1	0.830	*c*	0.46	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Northeast Area	Vedder	0.830	*c*	0.46	*b*	1.552	1.197	0.915	1.267	0.732	0.348
Wheeler Ridge	Southeast Area	Olcese	0.811	*c*	0.46	*b*	0.037	0.049	0.684	0.991	1.206	0.516
Wheeler Ridge	Telegraph Canyon	Eocene	0.780	*c*	0.29	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Windgap Area	No breakdown by pool	0.826	*c*	0.46	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Wheeler Ridge	Windgap Area	Reserve	0.928	*c*	0.69	*b*	3.688	3.005	2.413	2.072	1.466	1.676
Wheeler Ridge	Windgap Area	Olcese	0.724	*c*	0.40	*b*	0.000	0.000	0.000	0.000	0.000	0.000
White Wolf	Field	Field total					0.814	0.744	0.863	1.650	2.553	2.252
White Wolf	Field	Not matched to pool/*OQ*	0.968	*c*			0.814	0.744	0.863	1.650	2.553	2.252
Whittier	Field	Field total					13.743	8.347	9.841	14.217	19.606	17.754
Whittier	Field	Not matched to pool/*OQ*	0.922	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Whittier	Central Area	Upper	0.945	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Whittier	Central Area	6th, 184 Anticline	0.874	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Whittier	Central Area	184 Anticline	0.845	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Whittier	La Habra Area		0.931	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Whittier	Rideout Heights	No breakdown by pool	0.952	*c*	0.60	*b*	0.000	0.000	0.000	0.000	0.584	0.454
Whittier	Rideout Heights	Pliocene	0.969	*c*	0.60	*b*	11.565	7.064	8.074	12.863	17.201	15.427
Whittier	Rideout Heights	Miocene	0.936	*c*	0.53	*c*	2.178	1.283	1.767	1.354	1.821	1.873
Wilmington	Field	Field total					2,381.235	2,387.980	2,358.855	2,366.217	2,319.053	2,173.822
Wilmington	Field	Not matched to pool/*OQ*					0.000	0.000	0.000	0.000	0.000	0.000
Wilmington	Offshore		0.908	*b,c*	1.54	*b,c*	1,874.608	1,870.824	1,812.232	1,757.379	1,710.736	1,618.035
Wilmington	Onshore		0.914	*b,c*	1.39	*b,c*	506.626	517.156	546.624	608.839	608.317	555.787
Yorba Linda	Field	Field total					10.795	0.000	0.000	0.000	0.000	0.000
Yorba Linda	Field	Not matched to pool/*OQ*	0.963	*c*	1.90	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Yorba Linda		Shallow	0.979	*c*	1.86	*b*	10.795	0.000	0.000	0.000	0.000	0.000
Yorba Linda		Main	0.966	*c*	1.68	*b*	0.000	0.000	0.000	0.000	0.000	0.000
Yorba Linda		Shell	0.957	*c*	1.99	*b*	0.000	0.000	0.000	0.000	0.000	0.000

Table 2-4. California-producted crude data by field, area, and pool, formation or zone, *continued*

Data sources: *Cal. Div. Oil , Gas & Geothermal Res. (a, c); U.S. DOE (b, d); Environment Canada (e); Santa. Barbara County (f).*

Field	Area	Pool, formation or zone	Specific gravity	Sulfur % wt.	Production by year ($m^3 \bullet 10^3$)[a] 2004	2005	2006	2007	2008	2009
Yorba Linda		F Sand	0.957 *c*	1.99 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Yorba Linda		E Sand	0.957 *c*	1.99 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Yorba Linda		Miocene Contact	0.966 *c*	1.90 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Yowlumne	Field	Field total			54.905	43.902	37.742	37.305	31.424	26.902
Yowlumne	Field	Not matched to pool/*OQ*	0.865 *c*	0.42 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Yowlumne		Etchegoin	0.865 *c*	0.42 *c*	0.680	0.599	0.419	0.632	0.042	0.489
Yowlumne		Stevens	0.868 *c*	0.60 *c*	54.225	43.303	37.324	36.672	31.382	26.412
Yowlumne		South Yowlumne	0.871 *c*	0.42 *c*	0.000	0.000	0.000	0.000	0.000	0.000
Zaca	Field	Field total			35.787	28.823	24.952	24.608	12.486	31.853
Zaca	Field	Not matched to pool/*OQ*	1.008 *b*	5.65 *b*	0.000	0.000	0.000	0.000	0.000	0.000
Zaca		Monterey North Block	1.008 *b*	5.65 *b*	11.778	9.395	8.658	8.552	4.047	10.975
Zaca		Monterey South Block	1.008 *b*	5.65 *b*	24.009	19.428	16.294	16.055	8.439	20.878
Grand total crude and condensate production reported by Cal. Div. Oil & Gas[a]					**42,567**	**40,685**	**39,649**	**38,686**	**37,956**	**36,583**

[a] *Annual Report of the State Oil & Gas Supervisor, 2004–2008, and Monthly Oil and Gas Production and Injection reports 2009*. Reports PR06; PR04. California Department of Conservation, Division of Oil, Gas, & Geothermal Resources: Sacramento, CA. Production and reserves.

[b] *California Oil and Gas Fields*. Cal. Dept. Conservation, Division of Oil, Gas, & Geothermal Resources: Sacramento, CA. 1998. Three volumes. http://www.conservation.ca.gov/dog/pubs_stats/Pages/technical_reports.aspx; accessed 2 June 2011.

[c] *Crude Oil Analysis Database*. U.S. Department of Energy, National Energy Technology Laboratory: Bartlesville OK. Summary of Analyses; www.netl.doe.gov/technologies/oil-gas/Software/database.html; Crude Oil Analysis Database. Accessed 19 May 2011.

[d] *Heavy Oil Database*. U.S. Department of Energy, National Energy Technology Laboratory: Bartlesville OK. Composite of databases; www.netl.doe.gov/technologies/oil-gas/Software/database.html; Heavy Oil Database. Accessed 19 May 2011.

[e] *Oil Properties Database*. Environment Canada: Canada. www.etc-cte.ec.gc.ca/databases/oilproperties. Accessed 13 June 2011.

[f] *Fields/Production History*. County of Santa Barbara Planning and Development, Energy Division: Santa Barbara, CA. http://www.countyofsb.org/energy/projects/exxon.asp; Fields Production/History. Accessed 4 June 2011.

Table 2-5. Facility-level capacity data, California refineries[a]

Barrels/calendar day: (b/cd)

Facility	Year	Atm. dist. (b/cd)	Vacuum dist. (b/cd)	Coking & therm. (b/cd)	Cat. cracking (b/cd)	Hydrocracking (b/cd)
Chevron El Segundo	2008	265,000	147,000	59,000	65,000	46,000
Chevron El Segundo	2009	269,000	147,000	67,500	65,000	46,000
BP Carson	2008	252,225	133,000	63,450	91,800	45,000
BP Carson	2009	252,225	133,000	63,450	92,250	45,000
Chevron Richmond	2008	243,000	110,000	0	80,000	154,250
Chevron Richmond	2009	243,000	110,000	0	80,000	151,000
Tesoro Avon	2008	161,000	144,000	42,000	66,500	32,000
Tesoro Avon	2009	161,000	144,000	42,000	66,500	32,000
Shell Martinez	2008	158,600	91,100	46,500	68,870	37,900
Shell Martinez	2009	145,000	91,100	46,500	68,870	37,900
ExxonMobil Torrance	2008	149,500	98,500	52,500	96,000	20,500
ExxonMobil Torrance	2009	149,500	98,000	52,000	83,500	20,500
Valero Benicia	2008	139,500	78,500	28,000	69,000	36,000
Valero Benicia	2009	139,500	78,500	28,000	69,000	36,000
ConocoPh. Carson & Wilmington[b]	2008	138,700	80,000	48,000	45,000	24,750
ConocoPh. Carson & Wilmington[b]	2009	138,700	80,000	48,000	45,000	24,750
Tesoro Wilmington & Carson[b]	2008	100,000	62,000	40,000	36,000	32,000
Tesoro Wilmington & Carson[b]	2009	100,000	62,000	40,000	36,000	32,000
Ultramar-Valero Wilmington	2008	80,000	46,000	28,000	54,000	0
Ultramar-Valero Wilmington	2009	80,000	46,000	28,000	54,000	0
ConocoPhillips Rodeo[c]	2008	76,000	59,600	25,700	0	37,000
ConocoPhillips Rodeo[c]	2009	76,000	59,600	25,700	0	56,000
Paramount	2008	53,000	33,800	0	0	0
Paramount	2009	88,000	59,800	0	0	0
Big West Bakersfield	2008	65,000	39,000	22,000	0	23,500
Big West Bakersfield	2009	65,000	39,000	22,000	0	23,500
ConocoPhillips Santa Maria[c]	2008	44,200	27,400	21,100	0	0
ConocoPhillips Santa Maria[c]	2009	44,200	27,400	21,100	0	0
Kern Oil & Refining	2008	25,000	0	0	0	0
Kern Oil & Refining	2009	25,000	0	0	0	0
San Joaquin Refining	2008	24,300	14,300	10,000	0	0
San Joaquin Refining	2009	24,300	14,000	10,000	0	0

[a] Data from *Oil & Gas Journal* Worldwide refining *(6)* except as noted. Includes all large California fuels refineries. Some small facilities limited to other products, such as asphalt blowing plants, are not shown.

[b] Capacity data for separate closely located facilities are aggregated as reported by *Oil & Gas Journal* (6).

[c] Facilities reported b/cd capacities in aggregate *(6)* but stream-day capacities separately *(14)* and are ~250 miles apart. Capacities were disaggregated by comparison of b/cd and b/sd data *(6, 14).* Data shown are in b/cd.

Table 2-5. Facility-level capacity data, California refineries, *continued*[a]

Barrels/calendar day: (b/cd) Facility	Year	1º hydrotreating of gas oil, resid. & cracking feeds (b/cd)	2º hydrotreating of hydrocarbon product streams (b/cd)	Reforming (b/cd)	Alkylation (b/cd)	Pol./Dim. (b/cd)
Chevron El Segundo	2008	65,000	136,000	44,000	30,000	0
Chevron El Segundo	2009	65,000	136,000	44,000	30,000	0
BP Carson	2008	85,500	134,730	46,800	13,950	0
BP Carson	2009	85,500	132,030	46,800	15,300	0
Chevron Richmond	2008	0	197,340	69,000	24,000	3,700
Chevron Richmond	2009	0	197,340	69,000	24,000	3,700
Tesoro Avon	2008	62,000	110,500	42,000	14,000	0
Tesoro Avon	2009	62,000	110,500	42,000	14,000	0
Shell Martinez	2008	0	117,950	29,400	11,000	2,470
Shell Martinez	2009	0	117,950	29,400	11,000	2,470
ExxonMobil Torrance	2008	102,000	41,500	19,000	23,500	0
ExxonMobil Torrance	2009	102,000	41,500	19,000	23,500	0
Valero Benicia	2008	37,000	109,000	36,000	17,100	2,900
Valero Benicia	2009	37,000	109,000	36,000	17,100	2,900
ConocoPh. Carson & Wilmington[b]	2008	50,000	85,850	35,200	14,200	0
ConocoPh. Carson & Wilmington[b]	2009	50,000	85,850	35,200	14,200	0
Tesoro Wilmington & Carson[b]	2008	38,000	63,250	32,500	12,000	0
Tesoro Wilmington & Carson[b]	2009	38,000	63,250	32,500	12,000	0
Ultramar-Valero Wilmington	2008	62,500	77,000	17,500	14,500	0
Ultramar-Valero Wilmington	2009	62,500	77,000	17,500	14,500	0
ConocoPhillips Rodeo[c]	2008	0	73,000	31,000	0	0
ConocoPhillips Rodeo[c]	2009	0	73,000	31,000	0	0
Paramount	2008	0	35,250	11,600	0	0
Paramount	2009	0	35,250	11,600	0	0
Big West Bakersfield	2008	21,900	0	14,700	0	0
Big West Bakersfield	2009	0	21,900	14,700	0	0
ConocoPhillips Santa Maria[c]	2008	0	0	0	0	0
ConocoPhillips Santa Maria[c]	2009	0	0	0	0	0
Kern Oil & Refining	2008	0	13,000	3,000	0	0
Kern Oil & Refining	2009	0	13,000	3,000	0	0
San Joaquin Refining	2008	1,800	3,000	0	0	0
San Joaquin Refining	2009	1,800	3,000	0	0	0

[a] Data from *Oil & Gas Journal* Worldwide refining *(6)* except as noted. Includes all large California fuels refineries. Some small facilities limited to other products, such as asphalt blowing plants, are not shown.

[b] Capacity data for separate closely located facilities are aggregated as reported by *Oil & Gas Journal* (6).

[c] Facilities reported b/cd capacities in aggregate *(6)* but stream-day capacities separately *(14)* and are ~250 miles apart. Capacities were disaggregated by comparison of b/cd and b/sd data *(6, 14)*. Data shown are in b/cd.

Table 2-5. Facility-level capacity data, California refineries, *continued*[a]

Barrels/calendar day: (b/cd)

Facility	Year	Aromatics (b/cd)	Isomerization (b/cd)	Lubes (b/cd)	Asphalt (b/cd)	Sulfur (tonnes/d)
Chevron El Segundo	2008	0	27,000	0	0	544
Chevron El Segundo	2009	0	27,000	0	0	544
BP Carson	2008	0	28,170	0	0	446
BP Carson	2009	0	28,193	0	0	446
Chevron Richmond	2008	0	36,600	16,000	0	600
Chevron Richmond	2009	0	36,600	16,000	0	600
Tesoro Avon	2008	0	0	0	0	140
Tesoro Avon	2009	0	0	0	0	140
Shell Martinez	2008	0	15,000	0	15,000	360
Shell Martinez	2009	0	15,000	0	15,000	360.0
ExxonMobil Torrance	2008	0	0	0	0	400
ExxonMobil Torrance	2009	0	0	0	0	380
Valero Benicia	2008	0	0	0	5,000	275
Valero Benicia	2009	0	0	0	5,000	275
ConocoPh. Carson & Wilmington[b]	2008	0	17,500	0	0	340
ConocoPh. Carson & Wilmington[b]	2009	0	17,500	0	0	340
Tesoro Wilmington & Carson[b]	2008	0	8,000	0	0	265
Tesoro Wilmington & Carson[b]	2009	0	8,000	0	0	265
Ultramar-Valero Wilmington	2008	0	10,200	0	0	250
Ultramar-Valero Wilmington	2009	0	10,200	0	0	250
ConocoPhillips Rodeo[c]	2008	0	9,000	0	0	310
ConocoPhillips Rodeo[c]	2009	0	9,000	0	0	472
Paramount	2008	0	3,750	0	16,500	40
Paramount	2009	0	3,750	0	35,000	40
Big West Bakersfield	2008	0	0	0	0	103
Big West Bakersfield	2009	0	0	0	0	103
ConocoPhillips Santa Maria[c]	2008	0	0	0	0	120
ConocoPhillips Santa Maria[c]	2009	0	0	0	0	120
Kern Oil & Refining	2008	0	0	0	0	5
Kern Oil & Refining	2009	0	0	0	0	5
San Joaquin Refining	2008	0	0	4,000	6,500	6
San Joaquin Refining	2009	0	0	4,000	6,500	6

[a] Data from *Oil & Gas Journal* Worldwide refining *(6)* except as noted. Includes all large California fuels refineries. Some small facilities limited to other products, such as asphalt blowing plants, are not shown.

[b] Capacity data for separate closely located facilities are aggregated as reported by *Oil & Gas Journal* (6).

[c] Facilities reported b/cd capacities in aggregate *(6)* but stream-day capacities separately *(14)* and are ~250 miles apart. Capacities were disaggregated by comparison of b/cd and b/sd data *(6, 14).* Data shown are in b/cd.

Table 2-5. Facility-level capacity data, California refineries, *continued*[a]

Barrels/calendar day: (b/cd)

Facility	Year	Total hydrogen excpt. CCR H_2 (MMcfd)	Hydrogen purchased (MMcfd)	Pet. coke production (tonnes/d)
Chevron El Segundo	2008	71.0	146.0	4,064
Chevron El Segundo	2009	71.0	146.0	4,064
BP Carson	2008	133.0	0.0	2,108
BP Carson	2009	133.0	0.0	2,108
Chevron Richmond	2008	170.0	0.0	0
Chevron Richmond	2009	170.0	0.0	0
Tesoro Avon	2008	74.0	31.0	1,500
Tesoro Avon	2009	74.0	31.0	1,500
Shell Martinez	2008	101.0	0.0	1,150
Shell Martinez	2009	101.0	0.0	1,150
ExxonMobil Torrance	2008	160.0	0.0	3,050
ExxonMobil Torrance	2009	160.0	0.0	3,050
Valero Benicia	2008	131.5	0.0	1,080
Valero Benicia	2009	131.5	0.0	1,080
ConocoPh. Carson & Wilmington[b]	2008	100.8	0.0	2,000
ConocoPh. Carson & Wilmington[b]	2009	100.8	0.0	2,000
Tesoro Wilmington & Carson[b]	2008	55.0	55.0	1,615
Tesoro Wilmington & Carson[b]	2009	55.0	55.0	1,615
Ultramar-Valero Wilmington	2008	0.0	50.0	1,700
Ultramar-Valero Wilmington	2009	0.0	50.0	1,700
ConocoPhillips Rodeo[c]	2008	91.0		1,127
ConocoPhillips Rodeo[c]	2009	91.0		1,127
Paramount	2008	0.0	0.0	0
Paramount	2009	0.0	0.0	0
Big West Bakersfield	2008	29.7	0.0	1,200
Big West Bakersfield	2009	29.7	0.0	1,200
ConocoPhillips Santa Maria[c]	2008	0.0	0.0	1,053
ConocoPhillips Santa Maria[c]	2009	0.0	0.0	1,053
Kern Oil & Refining	2008	0.0	0.0	0
Kern Oil & Refining	2009	0.0	0.0	0
San Joaquin Refining	2008	4.2	0.0	0
San Joaquin Refining	2009	4.2	0.0	0

[a] Data from *Oil & Gas Journal* Worldwide refining *(6)* except as noted. Includes all large California fuels refineries. Some small facilities limited to other products, such as asphalt blowing plants, are not shown.

[b] Capacity data for separate closely located facilities are aggregated as reported by *Oil & Gas Journal* (6).

[c] Facilities reported b/cd capacities in aggregate *(6)* but stream-day capacities separately *(14)* and are ~250 miles apart. Capacities were disaggregated by comparison of b/cd and b/sd data *(6, 14)*. Data shown are in b/cd.

Table 2-6. Re-assignment of emissions from hydrogen production refiners rely upon from co-located third-party hydrogen plants that are reported separately under California Mandatory GHG Reporting.

		Reported emissions[a]	Reported H_2 purchased[b]	Regional purch. shares		Corrected emissions	
				H_2 cap.[c]	H_2 emit[d]	Mass	Intensity[e]
Fuels refineries	Year	(tonnes)	($m^3 \bullet 10^7$)	(%)	(tonnes)	(tonnes)	(kg/m^3)
S.F. Bay Area							
Chevron Richmond	2008	4,792,052	0.000	0.00	0	4,792,052	339.8
Shell Martinez	2008	4,570,475	0.000	0.00	0	4,570,475	496.6
Valero Benicia	2008	2,796,057	0.000	0.00	0	2,796,057	345.4
Tesoro Avon	2008	2,703,145	32.040	100.00	220,179	2,923,324	312.9
ConocoPhillips Rodeo	2008	1,888,895	0.000	0.00	0	1,888,895	428.3
Chevron Richmond	2009	4,522,383	0.000	0.00	0	4,522,383	320.7
Shell Martinez	2009	4,322,192	0.000	0.00	0	4,322,192	513.7
Valero Benicia	2009	2,889,104	0.000	0.00	0	2,889,104	356.9
Tesoro Avon	2009	2,291,909	32.040	100.00	285,442	2,577,351	275.9
ConocoPhillips Rodeo	2009	1,873,464	0.000	0.00	0	1,873,464	424.8
L.A. Area							
BP Carson	2008	4,504,286	0.000	0.00	0	4,504,286	307.7
Chevron El Segundo	2008	3,603,446	150.900	58.17	1,116,950	4,720,396	307.0
CP Carson & Wilmington	2008	2,924,503	0.000	0.00	0	2,924,503	363.3
ExxonMobil Torrance	2008	2,852,374	0.000	0.00	0	2,852,374	328.8
Tesoro Wilm. & Carson	2008	1,761,136	56.846	21.91	420,770	2,181,906	376.0
Ultramar-Valero Wilm.	2008	951,913	51.678	19.92	382,516	1,334,429	287.4
BP Carson	2009	4,425,697	0.000	0.00	0	4,425,697	302.4
Chevron El Segundo	2009	3,205,873	150.900	58.17	1,061,092	4,266,965	273.3
CP Carson & Wilmington	2009	2,578,050	0.000	0.00	0	2,578,050	320.3
ExxonMobil Torrance	2009	2,694,574	0.000	0.00	0	2,694,574	310.6
Tesoro Wilm. & Carson	2009	1,577,507	56.846	21.91	399,727	1,977,234	340.7
Ultramar-Valero Wilm.	2009	994,536	51.678	19.92	363,387	1,357,923	292.5
Third-party hydrogen plants supplying purchased H_2							
S.F. Bay Area							
Air Products Martinez	2008	220,179					
Air Products Martinez	2009	285,442					
L.A. Area							
Air Products Wilmington	2008	674,672					
Air Liquide El Segundo	2008	667,096					
Air Products Carson	2008	578,468					
Air Products Wilmington	2009	693,003					
Air Liquide El Segundo	2009	540,999					
Air Products Carson	2009	590,204					
Other areas[f]							
Air Products Sacramento	2008	43,168					
Praxair Ontario	2008	41,195					
Air Products Sacramento	2009	45,545					
Praxair Ontario	2009	38,491					

[a] California Mandatory GHG Reporting Rule public facility reports by Cal. Air Resources Board *(2)*.

[b] Third-party hydrogen production capacity, as reported by *Oil & Gas Journal* for each refinery *(6)*.

[c] Percentage share of total third-party hydrogen capacity in the region held by a refinery in a given year.

[d] Emission increment (from "c") of third-party H_2 emissions in region & year added back to refinery emissions.

[e] CO_2 emitted per cubic meter crude refined estimated from atm. distillation capacities in Table 2-5.

[f] Not co-located with refineries: Emissions from "other" H_2 plants are not added to refinery emissions.

Table 2-7. Estimate calculation, 2008 San Francisco Bay Area crude feed quality

	Crude feed component streams			
Parameter, facility or region	Foreign[a]	SJV[b]	ANS[c]	Crude feed[d]
Crude volume (m^3/day)				
Valero Benicia	8,870	5,323	7,986	22,179
Tesoro Avon	9,683	7,935	7,979	25,597
Shell Martinez	4,837	19,920	458	25,215
Chevron Richmond	29,921	0	8,713	38,634
ConocoPhillips Rodeo	1,611	9,183	1,289	12,083
SFBA total	54,922	42,361	26,425	123,708
Crude mass (tonnes/day)				
Valero Benicia	8,108	4,965	6,958	20,031
Tesoro Avon	8,664	7,401	6,953	23,018
Shell Martinez	4,524	18,580	399	23,503
Chevron Richmond	25,566	0	7,592	33,159
ConocoPhillips Rodeo	1,409	8,565	1,123	11,098
SFBA total	48,271	39,511	23,026	110,808
Sulfur mass in crude (tonnes/d)				
Valero Benicia	111	43	77	230
Tesoro Avon	110	64	77	251
Shell Martinez	84	160	4	249
Chevron Richmond	442	0	84	526
ConocoPhillips Rodeo	13	74	12	99
SFBA total	759	340	256	1,355

Estimated crude feed quality (kg/m^3)	density	sulfur
Valero Benicia	903.15	10.39
Tesoro Avon	899.24	9.80
Shell Martinez	932.08	9.86
Chevron Richmond	858.28	13.61
ConocoPhillips Rodeo	918.45	8.22
SFBA total	895.72	10.95

[a] Foreign crude feed volume, density and sulfur content reported for each plant *(14).* in 2008. Density and sulfur are weighted averages for foreign crude processed.

[b] San Joaquin Valley pipeline crude volume based on SJV percentage of refinery feed reported *(27),* and crude charge capacities (Table 2-5). Weighted average density (0.9327 SG) and sulfur (0.861 % wt.) calculated for all crude streams produced in the SJV (Districts 4 and 5) during 2008 from data in Table 2-4.

[c] Alaskan North Slope (ANS) volume estimated by difference of other streams from . charge capacity given in note d. ANS density (0.8714 SG) and sulfur (1.11 % wt.) as reported for the TAPS pipeline terminus at Valdez *(16).*

[d] Crude feed volume from atmospheric distillation charge capacities in Table 2-5. Crude feed mass and mass of sulfur in feed are the sums of component streams. Crude feed density and sulfur content estimates are from data in this column.

Table 2-8. Simplified mixing analysis for potential effects of anomalous oils on average California crude feeds

Year	Refinery crude feed volume data reported[a] Potentially anomalous streams[b] Stream 1 (% vol.)	Stream 2 (% vol.)	Stream 3 (% vol.)	Other streams (% vol.)	Anomalous oil assumption[c] Predicted by density, sulfur (factor)	Excess in anomalous oil (factor)	Potential crude feed effect[d] Crude feed predicted (factor)	Crude feed with anomaly (factor)
2004	29.28	21.68	13.13	35.91	1	2	1.00	1.43
2005	27.16	20.16	14.12	38.57	1	2	1.00	1.41
2006	26.93	16.12	13.27	43.68	1	2	1.00	1.38
2007	26.98	15.79	11.31	45.92	1	2	1.00	1.38
2008	25.72	13.41	12.65	48.21	1	2	1.00	1.36
2009	26.44	15.06	11.29	47.21	1	2	1.00	1.37

PADDs 1-3, 5 range 2003–2008: 1.26–1.40
PADDs 1-3, 5 range 1999–2008: 1.26–1.40

Legend: Density and sulfur content predict unreported characteristics of crude oils more reliably in well-mixed crude feeds than in poorly mixed crude feeds. Anomalies in one oil stream have less potential to affect total feed quality when that stream is mixed with many others of equal or greater volume. This table presents results from a simplified four-component mixing analysis for potential effects of anomalous oils on the crude feeds processed in California each year. It is adapted from recent published work using the same method to validate crude feed quality data among U.S PADDs *(1)*.

a. Refinery crude feed component streams represent a foreign country from which California refiners import and process crude *(14),* the Alaska North Slope (ANS) stream, or California-produced crude from either the San Joaquin Valley (Calif. Div. of Oil & Gas districts 4 and 5), California's coastal and offshore reserves (districts 1–3) or northern California (District 6). Stream values are shown as percentages of total crude feed volume *(5)*.

b. Potentially anomalous streams might be dominated by oils in which unreported characteristics that affect processing occur in anomalously high amounts *(1)*. The streams are ranked based on their volume and the assumption that oils from a single country of origin, region in California, or the ANS, may originate from similar geology and have similar anomalies. Note that this assumption may be overly conservative for purposes other than checking the reliability of predictions based on density and sulfur for these crude feeds.

   Stream 1 in the table represents the San Joaquin Valley, the largest of the streams (as designated above) refined by California refineries in all years. Stream 2 was from the ANS in all years. The third largest stream was from Saudi Arabia during 2004–2008 and from California's coastal region in 2009. Other streams were from 20–26 other countries or regions in California and comprised 36–48% of the crude feed.

c. It was assumed that an unreported charactistic of crude which affects processing was twice as abundant in the anomalous oil as predicted by density and sulfur. This assumption appears plausible as an extreme case *(1)*.

Table 2-8 ***continued***
Table legend continued

d. Results estimate the potential for crude feeds to have anomalous high content for unreported characteristics that are not predicted by crude feed density and sulfur. They do not show that any such anomaly actually occurred. Potential effects in the total refinery crude feed assume that the anomalous oil is 100% of stream 1, 50% of stream 2, and 25% of stream 3 for each district and year. This reflects the decreasing likelihood of the same anomaly in multiple separate streams. The predicted factor is assigned to the balance of the streams for each year. Results are show increases from the predicted crude feed factor of 1.00 on the right of Table 2-8.

   Relatively well-mixed crude feeds limit the effect of the anomaly to less than half of its assumed magnitude in the anomalous oil stream. For context, crude sulfur content exceeds that of other process catalyst poisons by eight times in the case of nitrogen and by 160 to 500 times in the cases of nickel and vanadium *(1, 28).* The range of annual estimates for California overlap with those from U.S. PADDs 1, 2, 3 and 5 reported from the original use of this check on crude feed mixing. Those U.S. regions were found to have reasonably well mixed crude feeds for purposes of predicting crude feed quality based on density and sulfur content *(1).* The ranges for PADDs 1, 2, 3 and 5 from that study *(1)* are shown at the bottom right of Table 2-8.

   This check is limited to a simple blending analysis, and the anomalous oil stream assumptions described above. It represents an extreme and unlikely scenario for California given the number of its crude sources and the relatively well-understood refining characteristics of the San Joaquin Valley and ANS streams.

Table 2-9. Preliminary results discarded from the assessment.

[a] Results for annual data among U.S. PADDs 1, 2, 3 and 5 1999–2008 (N = 40) *(1)*.
[b] Subsample including California refining 2004–2009 from Table 2-1 in place of PADD 5 (N =24).
"CA Sub." results potentially unreliable due to small sample size: reported for transparency only.

y	*x*	*R*-squared U.S.[a]	*R*-squared CA Sub.[b]	standardized coefficient of *x* U.S.[a]	standardized coefficient of *x* CA Sub.[b]
energy intensity *(EI)*	crude feed quality *(OQ)*	0.90	0.95		
	density			**0.80**	**0.89**
	sulfur			**0.23**	**0.18**
	refinery capacity utilized			0.05	**−0.18**
	refinery products ratio			−0.10	0.04
energy intensity *(EI)*	crude processing intensity *(PI)*	0.92	0.97		
	vacuum distillation			**0.35**	**0.35**
	conversion capacity			**0.35**	**0.37**
	hydrotreating gas oil & residua			**0.22**	**0.29**
	refinery capacity utilized			**−0.16**	**−0.15**
	refinery products ratio			−0.14	-0.08
crude processing intensity *(PI)*	crude feed quality *(OQ)*	0.94	0.99		
	density			**0.73**	**0.94**
	sulfur			**0.42**	**0.11**
	refinery capacity utilized			**0.09**	0.03
	refinery products ratio			−0.02	**0.09**
hydrogen production capacity	crude feed quality *(OQ)*	0.91	0.97		
	density			**1.09**	**0.96**
	sulfur			−0.01	−0.06
	refinery capacity utilized			0.05	−0.05
	refinery products ratio			**0.35**	**0.27**
sulfur recovery capacity	crude feed quality *(OQ)*	0.94	0.97		
	density			−0.01	**0.44**
	sulfur			**0.95**	**0.71**
	refinery capacity utilized			−0.06	−0.03
	refinery products ratio			**−0.15**	**−0.17**
pet. coke + fuel gas yield	crude feed quality *(OQ)*	0.95	0.98		
	density			**0.80**	**0.83**
	sulfur			**0.34**	**0.30**
	refinery capacity utilized			−0.04	−0.01
gasoline + distillate yield	crude feed quality *(OQ)*	0.75	0.39		
	density			**−0.85**	**−0.37**
	sulfur			−0.07	**−0.38**
	refinery capacity utilized			−0.04	0.03
light liquids/other products ratio	crude feed quality *(OQ)*	0.26	0.05		
	density			**−0.40**	0.05
	sulfur			−0.12	−0.08
	refinery capacity utilized			0.17	0.22
hydrogen production capacity	hydrocracking	0.97	0.97		
	hydrocracking			**1.02**	**1.04**
	refinery capacity utilized			−0.06	0.01
	refinery products ratio			**0.14**	**0.16**
hydrogen production capacity	product stream hydrotreating	0.18	0.37		
	product stream hydrotreating			**−0.33**	**0.49**
	refinery capacity utilized			−0.09	0.03
	refinery products ratio			**−0.17**	−0.19
energy intensity *(EI)*	Yield	0.93	0.92		
	pet. coke + fuel gas yield			**0.59**	**0.81**
	gasoline + distillate yield			**−0.42**	**−0.26**
	refinery capacity utilized			−0.01	−0.11
	refinery products ratio			−0.02	**0.22**
energy intensity *(EI)*	product stream processing	0.91	0.95		
	product stream hydrotreating			**−0.17**	0.08
	reforming			**−0.19**	−0.01
	asphalt			**−0.30**	**−0.29**
	aromatics			**−0.33**	**−0.27**
	polymerization/dimerization			**−0.25**	−0.02
	lubricants			0.04	**0.20**
	alkylation			**0.30**	**0.43**
	isomerization			**0.24**	**0.35**
	refinery capacity utilized			−0.06	−0.10
	refinery products ratio			**-0.33**	−0.08
observed emissions (CO_2)	emissions predicted by oil quality	0.85	0.93		
	EI predicted by crude feed quality			**0.88**	**1.28**
	fuel mix emission intensity			−0.04	0.18

Table 2-10. Energy and emission intensity drivers, nonparametric regressions on all data.

		Observed values (analysis inputs)[a]							
All data		*EI* GJ/m³	FMEI kg/GJ	emit kg/m³	density kg/m³	sulfur kg/m³	cap. util. %	products ratio	1° proc. cap.
PADD 1	1999	3.451	81.53	281.3	858.20	8.24	90.9	3.668	0.972
PADD 1	2000	3.430	80.34	275.6	860.18	8.00	91.7	3.489	0.974
PADD 1	2001	3.518	81.85	288.0	866.34	7.71	87.2	3.479	0.897
PADD 1	2002	3.426	81.08	277.8	865.71	7.45	88.9	3.605	0.944
PADD 1	2003	3.364	81.51	274.2	863.44	7.43	92.7	3.321	0.930
PADD 1	2004	3.416	81.46	278.3	865.44	7.79	90.4	3.397	0.932
PADD 1	2005	3.404	81.23	276.5	863.38	7.17	93.1	3.756	0.936
PADD 1	2006	3.440	80.40	276.5	864.12	7.17	86.7	3.522	0.906
PADD 1	2007	3.499	82.28	287.9	864.33	7.26	85.6	3.443	0.906
PADD 1	2008	3.551	83.26	295.7	863.65	7.08	80.8	3.400	0.906
PADD 2	1999	3.368	78.11	263.1	858.25	10.64	93.3	4.077	1.018
PADD 2	2000	3.361	77.56	260.6	860.03	11.35	94.2	4.132	1.010
PADD 2	2001	3.396	77.46	263.1	861.33	11.37	93.9	4.313	0.988
PADD 2	2002	3.393	77.90	264.3	861.02	11.28	90.0	4.345	1.015
PADD 2	2003	3.298	78.00	257.3	862.80	11.65	91.6	4.281	1.017
PADD 2	2004	3.376	77.25	260.8	865.65	11.86	93.6	4.167	1.035
PADD 2	2005	3.496	77.27	270.2	865.65	11.95	92.9	4.207	1.051
PADD 2	2006	3.738	75.84	283.5	865.44	11.60	92.4	3.907	1.051
PADD 2	2007	3.800	75.55	287.1	864.07	11.84	90.1	4.161	1.017
PADD 2	2008	3.858	74.97	289.3	862.59	11.73	88.4	4.333	1.038
PADD 3	1999	4.546	71.61	325.5	869.00	12.86	94.7	3.120	1.184
PADD 3	2000	4.563	71.87	327.9	870.29	12.97	93.9	3.120	1.213
PADD 3	2001	4.348	72.43	315.0	874.43	14.34	94.8	3.128	1.199
PADD 3	2002	4.434	72.71	322.4	876.70	14.47	91.5	3.251	1.215
PADD 3	2003	4.381	72.81	319.0	874.48	14.43	93.6	3.160	1.232
PADD 3	2004	4.204	73.43	308.7	877.79	14.40	94.1	3.228	1.255
PADD 3	2005	4.205	73.24	308.0	878.01	14.40	88.3	3.316	1.207
PADD 3	2006	4.367	74.15	323.8	875.67	14.36	88.7	3.176	1.203
PADD 3	2007	4.226	74.93	316.7	876.98	14.47	88.7	3.205	1.233
PADD 3	2008	4.361	74.48	324.8	878.66	14.94	83.6	3.229	1.230
PADD 5	1999	4.908	70.27	344.9	894.61	11.09	87.1	2.952	1.275
PADD 5	2000	5.189	69.09	358.5	895.85	10.84	87.5	3.160	1.245
PADD 5	2001	5.039	69.38	349.6	893.76	10.99	89.1	3.231	1.271
PADD 5	2002	4.881	69.15	337.5	889.99	10.86	90.0	3.460	1.315
PADD 5	2003	4.885	69.40	339.0	889.10	10.94	91.3	3.487	1.267
PADD 5	1999	4.908	70.27	344.9	894.61	11.09	87.1	2.952	1.275
PADD 5	2000	5.189	69.09	358.5	895.85	10.84	87.5	3.160	1.245
PADD 5	2001	5.039	69.38	349.6	893.76	10.99	89.1	3.231	1.271
PADD 5	2002	4.881	69.15	337.5	889.99	10.86	90.0	3.460	1.315
PADD 5	2003	4.885	69.40	339.0	889.10	10.94	91.3	3.487	1.267
Calif.	2004	4.994	70.82	353.7	899.23	11.46	93.0	3.631	1.652
Calif.	2005	5.032	71.06	357.5	900.56	11.82	95.0	3.800	1.646
Calif.	2006	5.280	72.65	383.6	899.56	11.73	91.5	3.846	1.665
Calif.	2007	5.611	71.43	400.8	899.84	11.89	88.3	3.814	1.684
Calif.	2008	5.397	71.02	383.3	902.00	12.85	91.0	4.088	1.682
Calif.	2009	5.628	70.54	397.0	901.38	11.70	82.9	4.043	1.676
Calif.	2004	4.994	70.82	353.7	899.23	11.46	93.0	3.631	1.652
Calif.	2005	5.032	71.06	357.5	900.56	11.82	95.0	3.800	1.646
Calif.	2006	5.280	72.65	383.6	899.56	11.73	91.5	3.846	1.665
Calif.	2007	5.611	71.43	400.8	899.84	11.89	88.3	3.814	1.684
Calif.	2008	5.397	71.02	383.3	902.00	12.85	91.0	4.088	1.682
Calif.	2009	5.628	70.54	397.0	901.38	11.70	82.9	4.043	1.676

EI: energy intensity. ***FMEI:*** fuel mix emission intensity. **Pratio:** light liquids/other products ratio. **Primary processing capacity:** the ratio of vacuum distillation, conversion and gas oil/residua hydrotreating to atm. crude distillation capacity.

[a] Data from Table 2-1. 2004–2008 PADD 5 data excluded to avoid errors due to inclusion of Calif. in PADD 5. Calif. data (2004–2009), and PADD 5 data (1999–2003) resampled to balance data counts among regions for regression analyses.

Table 2-10. Energy and emission intensity drivers, nonparametric regressions, continued.

		Predicted *EI* (GJ/m³) and emissions (kg/m³) values[b]						Observation vs prediction %Δ					
All data		1 (GJ/m³)	2 (kg/m³)	3 (kg/m³)	4 (kg/m³)	5 (kg/m³)	6 (kg/m³)	1	2	3	4	5	6
PADD 1	1999	3.208	271.5	265.1	265.1	273.9	339.3	8%	4%	6%	6%	3%	-17%
PADD 1	2000	3.316	272.5	270.5	272.8	271.4	321.7	3%	1%	2%	1%	2%	-14%
PADD 1	2001	3.598	286.7	282.6	288.1	275.7	321.6	-2%	0%	2%	0%	4%	-10%
PADD 1	2002	3.532	282.8	283.4	284.1	278.8	339.6	-3%	-2%	-2%	-2%	0%	-18%
PADD 1	2003	3.478	282.6	278.3	281.2	256.7	320.7	-3%	-3%	-1%	-2%	7%	-14%
PADD 1	2004	3.558	285.3	283.0	284.3	274.5	320.9	-4%	-2%	-2%	-2%	1%	-13%
PADD 1	2005	3.132	267.9	277.4	257.4	255.2	334.1	9%	3%	0%	7%	8%	-17%
PADD 1	2006	3.427	276.7	285.6	283.3	284.5	325.9	0%	0%	-3%	-2%	-3%	-15%
PADD 1	2007	3.463	282.9	285.0	284.6	281.9	316.5	1%	2%	1%	1%	2%	-9%
PADD 1	2008	3.540	287.1	295.8	295.8	281.9	349.1	0%	3%	0%	0%	5%	-15%
PADD 2	1999	3.279	266.3	252.8	260.6	275.7	295.2	3%	-1%	4%	1%	-5%	-11%
PADD 2	2000	3.327	267.3	266.0	259.5	273.0	279.2	1%	-3%	-2%	0%	-5%	-7%
PADD 2	2001	3.141	258.5	270.4	248.4	267.7	236.4	8%	2%	-3%	6%	-2%	11%
PADD 2	2002	3.573	277.5	275.8	274.2	285.0	288.6	-5%	-5%	-4%	-4%	-7%	-8%
PADD 2	2003	3.531	276.2	276.3	271.0	280.0	278.6	-7%	-7%	-7%	-5%	-8%	-8%
PADD 2	2004	3.556	275.9	285.7	272.1	279.1	277.0	-5%	-5%	-9%	-4%	-7%	-6%
PADD 2	2005	3.558	275.2	284.1	271.5	283.0	274.7	-2%	-2%	-5%	0%	-5%	-2%
PADD 2	2006	3.777	287.2	279.9	284.4	283.0	327.4	-1%	-1%	1%	0%	0%	-13%
PADD 2	2007	3.716	286.0	278.4	280.9	281.7	319.6	2%	0%	3%	2%	2%	-10%
PADD 2	2008	3.592	282.9	278.0	275.4	297.0	298.6	7%	2%	4%	5%	-3%	-3%
PADD 3	1999	4.516	325.7	293.0	324.3	303.7	314.4	1%	0%	11%	0%	7%	4%
PADD 3	2000	4.534	326.5	297.9	325.0	315.3	313.3	1%	0%	10%	1%	4%	5%
PADD 3	2001	4.403	322.2	326.5	320.1	311.1	319.1	-1%	-2%	-4%	-2%	1%	-1%
PADD 3	2002	4.236	311.7	318.7	312.0	320.5	319.0	5%	3%	1%	3%	1%	1%
PADD 3	2003	4.321	317.4	321.6	315.7	323.1	315.9	1%	1%	-1%	1%	-1%	1%
PADD 3	2004	4.441	324.6	334.3	323.1	334.7	320.1	-5%	-5%	-8%	-4%	-8%	-4%
PADD 3	2005	4.397	321.9	324.6	324.8	331.4	324.1	-4%	-4%	-5%	-5%	-7%	-5%
PADD 3	2006	4.322	314.2	313.6	318.7	326.9	338.0	1%	3%	3%	2%	-1%	-4%
PADD 3	2007	4.343	313.7	317.9	319.5	334.8	335.8	-3%	1%	0%	-1%	-5%	-6%
PADD 3	2008	4.220	307.3	333.6	319.2	340.1	315.7	3%	6%	-3%	2%	-4%	3%
PADD 5	1999	5.001	352.7	359.6	348.1	347.2	361.4	-2%	-2%	-4%	-1%	-1%	-5%
PADD 5	2000	5.125	353.7	359.8	357.0	337.1	331.5	1%	1%	0%	0%	6%	8%
PADD 5	2001	4.973	345.1	351.6	346.4	339.6	330.1	1%	1%	-1%	1%	3%	6%
PADD 5	2002	4.987	346.5	337.8	345.2	350.9	312.1	-2%	-3%	0%	-2%	-4%	8%
PADD 5	2003	4.796	333.9	333.2	333.0	332.2	315.2	2%	2%	2%	2%	2%	8%
Calif.	2004	5.061	359.8	361.5	358.3	368.3	322.6	-1%	-2%	-2%	-1%	-4%	10%
Calif.	2005	4.967	353.1	356.4	355.2	351.7	311.7	1%	1%	0%	1%	2%	15%
Calif.	2006	5.298	389.3	368.6	379.0	376.1	333.3	0%	-1%	4%	1%	2%	15%
Calif.	2007	5.411	386.0	379.7	383.8	394.6	336.2	4%	4%	6%	4%	2%	19%
Calif.	2008	5.422	386.3	394.2	386.6	382.5	311.6	0%	-1%	-3%	-1%	0%	23%
Calif.	2009	5.683	403.2	394.8	401.7	396.5	371.4	-1%	-2%	1%	-1%	0%	7%

Obs–pred %Δ: percent by which observed value exceeds central prediction of nonparametric analysis.

[b] Central predictions from the following analyses:

1 (R^2 0.97): Observed *EI* vs observed crude density, crude sulfur, products ratio and refinery capacity utilization.
2 (R^2 0.96): Observed emit vs *EI* predicted by analysis 1, and observed fuel mix emission intensity (FMEI).
3 (R^2 0.92): Observed emit vs observed crude density, crude sulfur content, and refinery capacity utilization.
4 (R^2 0.96): Observed emit vs observed crude density, crude sulfur, products ratio and refinery capacity utilization.
5 (R^2 0.92): Observed emit vs observed primary processing capacity and refinery capacity utilization.
6 (R^2 0.29): Observed emit vs observed light liquids/other products ratio and refinery capacity utilization.