Refining Industry Preparation for California CBG3

An Analysis of Refinery Plans Filed Under the California
Environmental Quality Act
California CBG3 Modifications

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Executive Summary

All gasoline sold in California must satisfy the California Cleaner Burning Gasoline (CBG) Regulation. In certain ozone non-attainment areas, Federal reformulated gasoline (RFG) is required. EPA currently allows California to substitute CBG for RFG in these overlap areas as long as the CBG contains at least 2% oxygen. By January 2003, California refiners will have to produce California Cleaner Burning gasoline (CBG3) without MTBE. Since EPA has not granted California a waiver from the use of oxygenate, ethanol will be used in the overlap areas where oxygen in gasoline is required.

In 1999, California refineries supplied the following products:

- 13.7 billion gallons of California CBG
- 883 million gallons of RFG to Arizona
- 106 million gallons of oxygenated gasoline
- 1.32 billion gallons of conventional gasoline

California is divided into two unconnected refining Districts.

The Southern Refining District includes Los Angeles, San Diego and the eastern desert. The Southern Refineries are connected to Arizona and southern Nevada by pipeline. Southern California refineries supply most of Arizona's RFG requirement. The Southern Refineries are concentrated in the Los Angeles basin near the Port of Los Angeles and total approximately 988,700-barrels/calendar day of refining capacity.

Essentially all gasoline produced by Southern District refiners must be oxygenated. In the Southern District and Arizona, the annual demand for oxygenated gasoline on a 2003 basis is approximately 9.55 billion gallons. To produce this oxygenated gasoline with ethanol would require 550 MM gallons or 35,690 barrels per calendar day.

The Northern refining District includes San Francisco, Sacramento, the San Joaquin Valley and Northern rural California. The Northern Refineries are concentrated near Bakersfield and in greater San Francisco. In the North, there is approximately 909,505-barrels/calendar day of refining capacity.

In the Northern District, under the Phase 3 California regulation, only 2.2 billion gallons or about 28% of total production of gasoline must be oxygenated. To produce this oxygenated gasoline with ethanol would require about 125 MM gallons or 8,180 barrels per calendar day.

In order to undertake major refinery modification projects, refiners must file detailed environmental impact plans that must be made available to the public as required by the California Environmental Quality Act (CEQA). All refiners currently producing MTBE containing CBG in Southern California have filed plans. Northern Refiners have not filed comprehensive plans.

Plans filed by Southern California Refiners describe refinery and terminal modifications necessary to implement Phase 3 CBG by January 1, 2003. All plans indicate that modifications will be completed before the phase out deadline and thus ethanol-containing CBG will be available in the Southern market on time.

Plans are not available for Northern Refiners but could be filed in the future. This suggests that little in the way of modifications are required to switch from MTBE to ethanol in Northern California. This is most likely due to the large fraction of CBG and conventional gasoline produced by these refiners that may be non-oxygenated.

In the South, terminal modifications involve conversion of receiving and storage systems for MTBE to ethanol. Ethanol will be received from Jones Act tankers that currently carry MTBE and by rail. Since ethanol must be blended at the terminal or refinery rack prior to truck delivery to the retail outlet, ethanol-blending equipment is being added at the terminals and tankage for ethanol storage is being allocated or added. Much of the ethanol will be shipped from storage to the terminals through existing pipelines as "neat ethanol". Some ethanol will be trucked to terminals.

The refining changes required for Phase 3 CBG may be broken down into three classifications. These are RVP control, sulfur control, and mid and end point distillation control. The majority of the capital investment required to meet the CBG3 regulation is for sulfur control. Generally RVP control and distillation control involve modernizing existing equipment.

A major issue often cited with ethanol is removal of high RVP light ends consisting of butanes and pentanes. To utilize ethanol, refiners will remove some additional butanes and pentanes during the summer. Plans provided by Southern refiners show that the refinery changes required and the logistical additions for storage and handling of the light ends are modest. A variety of uses are cited for the light ends. Economics will dictate the use. Butanes and pentanes will be stored, exported, used as fuel and hydrogen feedstock, and polymerized to diesel fuel. Pentanes stored in the refinery and offsite will be blended back into gasoline in the winter.

Gasoline demand is expected to grow by about 1.8% per year in the short term. It is assumed that refiners will increase supply to meet the growth in demand regardless of the fate of MTBE. The CEQA filings do not really address supply "creep". Instead, they show how refiners will switch from MTBE to ethanol. Thus, if the net supply gain switching to ethanol is equal to or greater than zero, it is believed that demand will be satisfied.

In the Southern District, about 64,000 barrels per day of MTBE must be removed from gasoline. The changes proposed including ethanol blending appear to be adequate to maintain the summer supply of gasoline in the short term. One refinery is undergoing a major modernization not associated with ethanol use. The net change in supply due to switching to ethanol is estimated to be 7,800 barrels per day. Winter gasoline supply capacity may increase modestly because pentanes will not have to be removed for RVP control.

Arizona consumes more than 6% of the CBG produced in California. Southern District refiners can increase the availability of CBG if there is an increase in imports and transfers of RFG for Arizona.

In the Northern District, about 36,000 barrels per day of MTBE will be removed. Since only about 8,180 barrels per day of ethanol will probably be incorporated back into CBG, some modifications, not disclosed to date, are necessary. At the minimum, refiners may need to convert MTBE capacity to isooctane and to shut down or reconfigure TAME facilities.

There appears to be an opportunity to transfer a portion of the blendstock removed to accommodate ethanol in the Southern District to the Northern District. Of the estimated 21,000 barrels per day of rejected blendstocks, Northern District refineries might use 16,000.

Northern refiners may also incorporate MTBE into their conventional gasoline pool that is distributed to northern Nevada, Oregon and Washington.

Introduction:

In 1999, California banned the use of MTBE in gasoline beginning in January of 2003. Simultaneously, the Air Resources Board entered into a rule making process to modify the existing California Reformulated Gasoline Regulations (CaRFG) to prohibit MTBE use in California, adopt Phase 3 gasoline standards, and establish a new fuel certification tool called the Phase 3 Predictive Model (CPM). The new regulation for CaRFG3, known also as CBG3 (cleaner burning gasoline Phase 3), was adopted in early 2000 providing refiners less than three years to comply with the new rules.

In California, refiners have recently provided the local pollution management agencies with plans regarding major changes as a part of the environmental permitting process as specified in the California Environmental Quality Act (CEQA). Plans for all of the major refineries in the Los Angeles area have been filed. These provide detailed information on the process changes required to meet the new Phase 3 regulatory requirements.

This report provides a summary and analysis of California refiner's response to the new regulation. The report will also attempt to identify changes by category that result for various CBG requirements.

CBG and RFG Rules:

The Clean Air Act Amendments of 1990 established a requirement for use of reformulated gasoline in the worst ozone areas. California established a statewide program that EPA accepted as a substitute for the federal program. California gasoline regulations are published in the California Code of Regulations (CCR)[1].

In the early 1990's, the CBG Phase 1 program established RVP controls and eliminated lead from gasoline. Simultaneously, California established a statewide winter oxygenates program to meet the requirements of the federal carbon monoxide oxygenated fuels program. In 1996, CBG Phase 2 rules were implemented. These required whole reformulation of the gasoline. A 7-psi Reid vapor pressure (RVP) limit was established for all gallons of gasoline produced during the high volatility season[2]. Limits were established for other gasoline properties including aromatics, olefins, sulfur, and the distillation parameters, T50 and T90. Refiners were allowed to produce CBG either by formulas established in the CCR or by establishing their own emission equivalent formula using the Phase 2 CPM that was incorporated as a part of the rule. The model relates key gasoline properties (oxygen, aromatics, olefins, sulfur, T50, T90, benzene) to emissions of NO_X, hydrocarbons (THC) and potency-weighted toxics (PWT). The CPM thus provided the refiner a flexible way to produce gasoline that meets the emissions targets. After the implementation of Phase 2 requirements, the statewide winter

[1] California Code of Regulations, Title 13. Motor Vehicles, Chapter 5. Standards for Motor Vehicle Fuels Article 1. Standards for Gasoline.

[2] See section 2262.4 of California Code of Regulations. The season may start as early as March 1 and end as late as October 31.

oxygenates program was eliminated. Instead, seasonal requirements for the remaining CO non-attainment areas were established in the CCR.

The Clean Air Act requires that RFG contain 2% oxygen on average annually. The CBG rule has no such oxygen requirement. Thus, RFG areas in California that are named in the Clean Air Act must use oxygenated CBG year round. California received approval from EPA to lower the winter oxygen requirement in CO areas from 2.7% to 2%. Thus, oxygenated CBG with 2% oxygen meets all federal program gasoline requirements for ozone and CO.

In California, areas that do not fall under either the federal RFG or CO rules must use CBG, but there is no requirement that CBG contain oxygenates.

New Requirements for CaRFG3:

The Phase 3 rule may significantly alter the composition of CBG. The Phase 3 rule increases limits for aromatics and distillation temperatures and alters the relationship between emissions and sulfur in such a way as to encourage gasoline sulfur reduction. As a part of the rule, a new Predictive Model was established that allowed refiners to incorporate the effects of RVP control specifically into their formulations. Thus, where previously gasoline needed to satisfy both RVP and CPM requirements, the Phase 3 model incorporates an RVP option that provides a hydrocarbon emission (THC) credit to the refiner for formulas with RVP below 6.9 psi. With the Phase 3 predictive model, refiners can lower sulfur and RVP in exchange for increasing T50, T90 and aromatics. This change helps to offset MTBE removal by allowing higher boiling materials like alkylate to replace lower boiling MTBE. Importantly, gasoline supply may be increased by increasing the fraction of heavy boiling materials in the gasoline which otherwise would go to the distillate pool. Octane loss due to removal of MTBE can be partly replaced with octane from aromatics. Ethanol may be valued for its octane and its ability to lower T50.

The Phase 3 model also incorporates a THC credit based upon carbon monoxide reduction when using more than 2% oxygen that allows RVP to be increased to 7.2 psi maximum. The CPM allows refiners to use oxygen contents between 0% and 3.5%. While California regulation allows 10% ethanol blends with 3.5% oxygen, the Phase 3 CPM effectively restricts oxygen to a lower level because NO_X emissions are predicted to increase rapidly as oxygen levels exceed 2.7%.

With the Phase 3 Model, refiners will most likely satisfy the NO_X requirement by setting the sulfur content, the hydrocarbon emission requirement by adjusting RVP and the toxic requirement by the benzene level. Whether refiners use ethanol or no oxygenate, there is an incentive to use the model to take advantage of lowered RVP.

California Air Basins

California is divided into a number of air management basins generally along geographical boundaries. These are shown in figure 1. Recently EPA reclassified the San

Figure 1

Joaquin valley from serious to severe ozone triggering the federal RFG requirement. The federally designated RFG areas are the following:

- Los Angeles (South Coast Air Basin, South East desert, Ventura)
- San Diego County
- Sacramento
- San Joaquin Valley

It is highly unlikely that Los Angeles can meet the 1-hour ozone standard before 2010. In the near future, some of these areas may come into attainment for the one hour ozone standard. For example, San Diego can satisfy the 1-hour requirement by having three or less violations in the summer of 2001.

Los Angeles is also non-attainment for carbon monoxide, and may be so indefinitely. The only part of the South Coast basin that has CO violations is south and east of LAX. The source of the CO pollution is freeway traffic. California is required to provide a clean air plan to EPA by September 2001 to address this problem. According to an EPA official[3] the problem is regional because of the source of the pollution; that is, a local neighborhood solution probably cannot be found. The current winter requirement is for the period October through January. ARB has informally proposed reducing the season by one month by eliminating October because violations do not presently occur during October. No formal request has been made to EPA to shorten the season.

California Gasoline Usage

Table 1 summarizes information regarding the use of gasoline in California in 1998. Detailed use data by county are provided in Appendix A[4]. In 1998, the total reformulated gasoline usage in California was 13.5 billion gallons, or 880,000 barrels per calendar day. According to EIA (see Appendix E), the total CBG product supplied to California in 1999 was near 13.696 billion gallons. EIA projects that gasoline will grow by about 1.8% per year for the period 2000 through 2004 and by 1.4% per year from 2005 through 2010[5]. The California Energy Commission[6] has also projected the growth in gasoline demand. The expected demand in 2000, 2001, 2002 and 2003 are 14.037, 14.378, 14.722 and 15.046 billion gallons per year respectively. These estimates are slightly higher than those based on national averages as projected by EIA. According to CEC, the growth in demand will have to be accommodated by increased imports and product transfers from PAD 3 and by the normal expansive “creep” in refinery capacity that results from improved technology and debottlenecking. The greater dependence on purchased

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[3] Jesson, David, EPA Region 9, Private Communication.
[4] See California Energy Commission Website http://38.144.192.166/statistics/gasoline-stations/index.html
[5] Lidderdale, T., Bohn, A, “Demand and price Outlook for Phase 2 reformulated Gasoline, 2000”, EIA, www.eia.doe.gov/emeu/steo/pub/special/rfg4.html
[6] California Energy Commission Staff report, “California Energy Outlook 2000 Volume II Transportation Energy Systems”, P200-00-001V2, August 2000. See Table D.1 page D1 appendix D.

gasoline and blendstocks as well as the high stream factor required to meet future demand means that price volatility will be a concern.

Table 1
Gasoline Use in Federal and State Areas
For 1998

Los Angeles	Gallons/year
LA County	3,660,156,000
Ventura County	295,425,000
Orange County	1,246,735,000
San Bernadino County (assume all)	620,606,000
Riverside County (assume all)	547,176,000
Total, LA	6,370,098,000
San Diego	
San Diego County	1,136,281,000
Sacramento	
Sacramento County	465,152,000
El-dorado County (assume all)	62,376,000
Placer County (assume all)	111,623,000
Solano County	150,374,000
Sutter County	26,829,000
Yolo County	68,588,000
Total Sacramento	884,942,000
San Joaquin (assume whole air shed)	
Fresno County	268,328,000
Kern County (Western, all assumed)	240,859,000
Kings County	34,073,000
Madera County	37,451,000
Merced County	69,511,000
San Joaquin County	202,140,000
Stanislaus County	153,774,000
Tulare County	108,878,000
Total San Joaquin Valley	1,115,014,000
Total w/o San Joaquin V.	8,391,321,000
Total with San Joaquin V.	9,506,335,000
Total California RFG	13,496,000,000
% Oxygenated W/O San Joaquin V.	62.2%
% Oxygenated W San Joaquin V.	70.4%

In 1998, oxygenated gasoline as required under the Clean Air Act totaled about 8.4 billion gallons or 62% of total gasoline use. After January 2001, the San Joaquin valley will become a federal RFG area. Based upon 1998 data, oxygenated gasoline use will rise to about 70.4% of total consumption in California.

Refinery Production

California refiners are net exporters of gasoline. Table 2 presents a summary of finished motor gasoline production from California refineries[7]. It was assumed that the difference between total CBG consumption in California and total CBG production was exported to Arizona. In addition, California refineries exported gasoline blendstock. The table shows that very little of the gasoline produced in California is not reformulated.

Table 2
Gasoline Production by Type In California (1999)

Gasoline type	Quantity, GPY
California RFG	13,696,000,000
RFG to Arizona	883,302,000
Oxygenated Gasoline	106,596,000
Conventional Gasoline	1,322,664,000
Total Production	16,008,762,000

Supply and Demand for Gasoline in PAD 5

PAD 5 encompasses Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington. Refining capacity [8] to produce gasoline exists in all states but Arizona, Nevada and Oregon. California is the major gasoline producer in PAD 5. Washington has significant refining capability but is not self-sufficient. In addition to refining, a significant quantity of conventional gasoline as well as lesser amounts of oxygenated gasoline and reformulated gasoline are imported from foreign sources or brought into the PAD from the gulf coast by pipeline and ship.

Gasoline supply and demand data for PAD 5 for 1999 have been reported by EIA[9]. These data are analyzed in detail in Appendix E. The data strongly suggest that Southern California refineries supply Arizona with CBG (RFG). Arizona oxygenated gasoline and conventional gasoline primarily come from PAD 3 (Gulf Coast) and foreign imports by pipeline from Texas to Arizona and by water to Los Angeles and then by pipeline. The

[7] California Energy Commission, " (1999) Monthly California Refining Industry Output Report". This report divides gasoline production into reformulated, oxygenated and other finished. It is assumed that reformulated means both CBG and federal RFG. The CBG output used was 347,131 M bbls per year in agreement with EIA instead of 346,365 as reported by CEC.
[8] See Oil and Gas Journal Special December 20, 1999 page 49 for a list of refining capacities by States for 2000.
[9] EIA 1999 Petroleum Supply Annual, Table 12 and EIA 1999 Petroleum Marketing Annual, Table 44.

small amount of oxy-fuel produced in California refineries probably goes by pipeline to Arizona and Southern Nevada. Additional oxygenated gasoline is field blended.

The data also suggest that Northern California refiners supply Reno (and Northern Nevada) by pipeline and Oregon and Washington by water with conventional gasoline. Oxygenated gasoline is field blended.

MathPro[10] examined the ability of the California refining industry to produce gasoline without MTBE in the "intermediate term" when production will be 965,000 barrels per day or 14.8 billion gallons per year. Using the growth estimates provided by EIA and CEC, the intermediate term corresponds to about 2003. The case that most parallels the scenario allows for a mixture of oxygenated and non-oxygenated CBG to be produced in the State. *According to the study, refiners will be able to supply this quantity of CBG with MTBE or ethanol without major expansion of refining capability.* With ethanol, crude input would decrease by 52,000 barrels per day. 94,000 bbls/day of MTBE would be replaced with 44,000 barrels per day of ethanol and alkylate imports would increase by 100,000 barrels per day. As described in the CEQA filings and discussed subsequently, while some alkylate and isooctane will be imported, refiners will likely attempt to expand domestic refining capability to increase crude, and maximize production of alkylate and other clean low sulfur blendstocks within refineries.

California Refining Regions, Product Distribution and Markets:

California is divided into two main refining districts. These are Southern California and Northern California. Table 3 is a list of California Oil Refinery Locations and atmospheric crude distillation capacities [11]. A more detailed list showing processing capability is provided in Appendix C.

The two districts are not connected by pipeline. A small quantity of product is moved by ship between LA and San Francisco.

The Southern Refining District

The southern refining district is comprised of those refineries located in the greater LA area. These refineries are not connected by pipeline to the northern California markets so distribution emphasis is in the southern half of California and adjacent markets. The southern refineries are connected by pipeline to both Nevada and Arizona. There are 8" and 14" CalNev Pipelines originating in Colton (near LA). These lines, which have interconnect capabilities with the Kinder Morgan system, serve the air force bases and terminals in Santa Fe, Daggett, and Coolwater and then continue on to Las Vegas, Nevada. Kinder Morgan has a pipeline (16" to 10") from LA that runs south to San Diego and a 20" pipeline running from LA south to a terminal in Niland (with 6"

[10] See reference 18 Tables A5, A7, A19 for the flat limit intermediate mode.
[11] www.energy.ca.gov/fuels/oil/refineries.html

breakout line to the Imperial terminal) continuing on to Yuma, Arizona and then to Phoenix. Refineries in the southern refining district represent 988,700 bbl/day of the state's crude refining capacity. There are 36 major terminals[12] servicing the greater LA market, which offer gasoline, and 6 servicing the San Diego market. The CEQA filings describe changes to 20 of the LA terminals. There are also common carrier terminals in Niland and Imperial (southeast of greater LA).

Northern Refining District

The northern refining district includes greater San Francisco as well as those refineries that are concentrated in and around the Bakersfield/McKittirick/Santa Maria area. Kinder Morgan has pipelines running south out of San Francisco (8" and 12") to Atwater. From there a 12" pipeline runs south to Fresno. An 8" pipeline runs north from Bakersfield to Fresno. There are no pipelines to the Southern markets so refiners in the northern district tend to direct their distribution emphasis to the northern half of California. There are 30 terminals servicing the greater San Francisco area that offer gasoline. There is also a common carrier terminal in Fresno that is supplied from both San Francisco refiners and from Bakersfield. There is also a line running west to Sacramento (4 major terminals) and continuing on to Reno Nevada. A line splitting near Sacramento runs north to Chico allowing northern refineries to service terminals in that market. There is also a terminal in Eureka (northwest corner of the state) but this terminal is not connected by pipeline to other markets. Cargo is delivered by waterborne transport. This distribution infrastructure results largely in northern refineries marketing in the northern half of the state as well as Oregon, Washington, and the Reno Nevada markets. The northern district represents 909,505 bbl/day of the state's crude refining capacity.

Use of Oxygenated Gasoline

Table 4 summarizes the required use of oxygenated gasoline as well as other forms of gasoline in the Northern and Southern Districts. The usage has been adjusted to a 2003 basis to reflect the time at which a full phase out of MTBE has taken place.

The California Energy Commission[13] is currently required to report the use of MTBE by refinery. Table 5 indicates which refiners are producing finished RFG and summarizes MTBE consumption data for 2000. Statewide, 10.4% MTBE was blended on average in all RFG produced. Comparing Table 3 capacity data and Table 5 suggests that the only refinery producing significant amounts of non-oxygenated RFG is Chevron Richmond. All of the other refineries are most likely blending at the 11% level in RFG.

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[12] The Use of Ethanol in California Clean Burning Gasoline Ethanol Supply/Demand and Logistics, (prepared for the Renewable Fuels Association) Downstream Alternatives Inc., February 5, 1999

[13] California Energy Commission, Quarterly Reports Concerning MTBE Use in California Gasoline, Q1,Q2,Q3 2000.

Southern District:

Southern District refineries supply Southern California, part of Arizona and southern Nevada.

In 1999, LA, San Diego and Arizona required 8.558 billions of gallons per year of oxygenated RFG. This represents 80% of all the oxygenated gasoline that must be supplied by California refineries for Federal clean air programs. Including the low desert, the total Southern Region demand is estimated to be 8.604 billion gallons per year.

Table 3
California Crude refining Capacity, bbls/Calendar day Atmospheric Distillation Capacity

Company	Location	District	Capacity, bbl/day
Large Refineries			
BP Arco	Carson	South	255,000
Chevron	El Segundo	South	260,000
	Richmond	North	225,000
Equilon	Wilmington	South	90,600
	Martinez	North	154,000
	Bakersfield	North	63,000
Exxon-Mobil	Torrance	South	130,000
Tosco	Wilmington	South	125,000
	Rodeo (SF)	North	73,200
	Santa Maria	North	41,800
UDS	Wilmington	South	68,000
	Martinez	North	156,000
Valero	Benicia	North	129,500
Small Refineries			
Paramount	Paramount	South	42,500
Kern Oil Refinery	Bakersfield	North	24,700
San Joaquin	Bakersfield	North	24,300
Huntway	Wilmington	South	5,500
	Benecia	North	8,505
Santa Maria Refining Co	Santa Maria	North	9,500
Golden Bear Oil[1]	Oildale	North	0
Lunday-Thagard Oil	South Gate	South	8,100
Tenby Inc	Oxnard	South	4,000
Total			1,898,205
Total South			988,700
Total North			909,505

Note 1: 10,000 bbl/day vacuum still

Using the MTBE data for the LA refineries, and assuming that 11% MTBE was blended in every gallon, the 1999 production of oxygenated gasoline was near 8.956 billion gallons.

These data suggest that essentially all gasoline produced and used in the Southern region is oxygenated. At 5.7% ethanol in CBG and 10% ethanol in oxy-fuel, the oxygenated and reformulated gasoline supplied by LA refiners in 2003 will require 547,172,000 gallons per year or 35,693 barrels per day of ethanol[14].

Northern District:

In the northern portion of the state, the greater Sacramento area and the San Joaquin Valley require about 2.2 billion gallons per year of oxygenated CBG in 2003. The Northern Region will also produce 4.35 billion gallons of non-oxygenated CBG and 1.44 billion gallons of CG. The quantity of ethanol required to meet oxygen needs in Northern California is 125,400,000 gallons per year or 8,180 barrels per day. Thus about 28% of the gasoline produced must be oxygenated CBG, 52% non-oxygenated CBG and 20% CG. Compared to the Southern District, the Northern District has much more flexibility in gasoline manufacture because it can put less desirable blendstocks into conventional gasoline as long as RFG anti-dumping requirements are satisfied.

Process Changes for CBG3:

A brief discussion of refining technology is provided in Appendix B. The refinery modifications required for CBG3 include RVP control to facilitate ethanol blending, sulfur control and benzene control. The following section categorizes the processing changes required to satisfy the CBG3 regulation.

Table 4

Type of Gasoline Use by Refining District Projected to 2003
Millions of gallons

District	CBG	RFG	Oxygenated	CG
Northern, oxygenated	2,200	0	0	0
Non-oxygenated	4,347	0	0	1,437
Southern, oxygenated	8,437	959	116	0
Non-oxygenated	0	0	0	0
Total	14,984	959	116	1,437

[14] From table 4, at 5.7% ethanol, Southern CBG 31,370 bbls/day, oxy fuel 757 bbls/day, Arizona RFG 3,566 bbls/day.

RVP Control:

During the high ozone season, to either take advantage of the Phase 3 CPM to raise T50, T90 and aromatics or produce oxygenated CBG3 with ethanol, refiners must fully remove butanes and some pentanes and/or pentenes. Pentenes are present in coker naphtha and light fluid catalytically cracked (FCC) gasoline. The distillation towers used for these separations are commonly called debutanizers and depentanizers. To control RVP, refiners will primarily increase the efficiency and capacity of separation of these units for their gasoline blending streams boiling below about 180F.

The lighter materials removed, including pentanes, must be used elsewhere or be disposed. To facilitate storage and handling of the pentanes, refiners can construct pressurized storage. The pentanes and/or pentenes can be used as refinery fuel, winter gasoline blendstock, or can be sold into other markets. Pentanes, but not pentenes, can be used instead of natural gas as feedstock to manufacture refinery hydrogen. Pentenes can also be alkylated or polymerized. The quality of alkylate is poor since the octane number is low (about 89) and the T50 adversely impacts the final gasoline T50. The polymer can be used as a blendstock for jet fuel and diesel.

Table 5
MTBE Use in California for 2000
(Assumed to be MTBE plus TAME)

		Q1	Q2	Q3	Annual
			1000 bbls		bbls/day
BP Amoco	Carson	1,902	1,659	2,028	20,416
Chevron	El Segundo	1,066	1,139	1,098	12,066
Equilon	Wilmington	564	573	541	6,130
Exxon-Mobil	Torrance	668	707	669	7,467
Tosco	Wilmington	778	853	769	8,767
UDS	Wilmington	845	877	857	9,421
6 LA refineries		5,823	5,808	5,962	64,267
Equilon	Bakersfield	220	231	228	2,480
Kern oil	Bakersfield	89	80	81	913
Tosco	Santa Maria	315	405	532	4,574
3 Bakersfield refineries		624	716	841	7,967
Chevron	Richmond	262	193	142	2,181
Equilon	Martinez	648	731	807	7,985
Tosco	Rodeo	235	473	453	4,241
Valero	Benecia	1,112	1,131	1,176	12,489
4 SF Refineries		2,257	2,528	2,578	26,897
State Total		8,704	9,052	9,381	99,131
State Total RFG		82,085	88,962	89,204	347,001

Sulfur Control:

CBG3 sulfur levels could be substantially below 20 ppm. Since the vast majority of the gasoline sulfur (80% or more) is present in the heavier FCC naphtha, refiners will concentrate on removing sulfur from this material but also be careful to ensure that the efficiency of removal of traces of sulfur in other streams is maintained or increased.

To cost effectively lower the sulfur content of the FCC naphtha, the medium and heavy naphtha may be processed and as much as 95 to 99% of the sulfur will be removed along with some or all of the heavy olefins. The octane number of the medium and heavy desulfurized FCC naphtha may be adversely affected as a result of the deep hydrotreating.

Benzene Control:

Generally, refiners in California have already lowered benzene sufficiently to produce CBG3. To gain flexibility to increase aromatics in gasoline, they may concentrate benzene by distillation and then catalytically destroy it.

Ethanol Blending:

Since oxygen is required in gasoline principally in the Southern District, refiners must include facilities to receive, transport and terminal blend ethanol.

Refinery Modification Plans Submitted by Refiners

Plans have been filed under the California Environmental Quality Act (CEQA) that describe how refiners are planning to address the new CBG3 requirements. Refiners in the Northern District are essentially silent regarding refinery modifications. This suggests that there are only minor changes required to satisfy CBG3 in this region.

In the Southern Region, all of the large refiners have filed plans to address the new regulation. In general, and as discussed in the next sections, these plans demonstrate the technical feasibility and timeliness of producing and distributing oxygenated CBG3 without MTBE.

Plans Filed in the Southern California Refining District

LA refiners have filed necessary plans to obtain construction permits for refinery modifications to meet the CBG3 regulation that requires the removal of MTBE from gasoline. At a minimum because of the winter oxygen requirement, refiners have included ethanol receiving, storage and terminal blending capability. Also, since EPA has not granted the California waiver request to lift the oxygen requirement, refiners have proposed changes to control RVP and add storage capacity for pentanes. Since California CBG3 requires a substantial reduction in gasoline sulfur, much of the refinery modifications and expenditures address desulfurization.

Overall, refiners do not propose to modify their refineries very much to satisfy the new regulations. One exception is UDS who plans a major modernization of the Wilmington refinery to improve its economics by eliminating the need to purchase distillate blendstocks.

The crude distillation capacity of the LA Basin refineries is currently about 988,700 barrels per calendar day. In order to satisfy California RFG3 requirements and the Federal oxygenate requirement, refiners have filed refinery and terminal modifications plans with AQMD as required under CEQA. To date, preliminary or final plans have been filed covering 928,600 barrels of refining capacity. These refineries are the only ones reporting MTBE use in 2000 and thus are assumed to be the only refineries that will produce CBG3. 17,000 barrels of remaining capacity are for topping refineries that will probably not make CEQA filings. A small California refiner, Paramount, owns the remaining 42,500 barrels of capacity. Paramount is believed to be supplying UDS with gas oil distillates.

Plans Filed in the Northern Refining District:

At this time, northern district refiners have made no plans public that detail major refinery modifications required to meet CBG3 rules. Thus, it is assumed that these refiners have the capability to replace MTBE with a mixture of ethanol oxygenated and non-oxygenated gasoline.

Even though plans are not available, there are 10,600 barrels per day of oxygenate capacity which will need to be converted or shut down unless these refiners plan to blend the MTBE and TAME into non-California gasoline. 8,100 barrels per day of this capacity is for MTBE. The MTBE capacity could be converted to 5,600 barrels per day of isooctane.

To be completely free of MTBE in Northern gasoline, refiners will need to remove 34,864 barrels per day of MTBE and replace it with 7,550 barrels per day of ethanol. Pace Consultants[15] estimates that 11,800 barrels per day of Canadian isooctane will replace the MTBE produced and imported from Canada.

Other Modifications:

Throughout the distribution system, there may be need for additional modifications of terminals not cited in available CEQA filings. These modifications may not be significant enough to trigger CEQA.

[15] Pace Consultants, "Analysis and Refinery Implications of Gasoline Aromatics Limits in 2005 and the Impact on Ethanol Demand", for Renewable Fuels Assoc and the National Corn growers Assoc. , 2000.

Analysis of Individual Southern District Refiner Plans:

Tosco:

Ethanol Distribution:

Tosco proposes to modify its Branded "76" gasoline distribution system to replace MTBE with ethanol before December 31, 2002. Branded "76" stations are serviced through their LA and Colton Terminals. Unbranded gasoline will continue to be blended with MTBE through 2002.

To handle ethanol, modifications and conversions will be made to the LA Marine Terminal MTBE system, Wilmington refinery MTBE storage, Tosco tank farm transfer system, LA terminal and the Colton terminal.

Ethanol will be received by tanker. 14 fewer vessels will be received per year due to the volume reduction of oxygenate (5.7% ethanol versus 11% MTBE). The existing MTBE storage and handling system will be converted to ethanol service.

Handling system modifications will permit neat ethanol to be transferred by pipeline from the Marine Terminal to the Wilmington Refinery storage.

From Wilmington, neat ethanol will be directed through existing interconnecting pipelines to the Tosco tank farm and LA Terminal where a portion will be used for gasoline blending.

Neat ethanol (8 trucks per day) will be transported to the Colton Terminal from the LA Terminal for gasoline blending.

In both terminals, existing above ground storage will be converted to ethanol service and the systems will be modified to facilitate receiving, storing and blending of ethanol.

Wilmington Refinery Upgrades:

The Wilmington refinery is rated at 131,000 barrels per day.

No new process units will be required for RFG3.

Alkylation capacity will be increased by more efficient recovery of propylene and butylenes from the FCC. Modifications will be made to the existing Catalytic Light Ends Fractionation Unit (CLEF unit) to recover the incremental C3 and C4 olefins. This may lower overall gasoline RVP and olefin content. Apparently there is sufficient capacity in existing alkylation equipment to accommodate the increase in alkylate feedstock. The alkylate volume increase is not specified but cannot exceed one or two thousand barrels per day based upon the FCCU size and nameplate alkylation capacity. It is assumed that the increase is 1,000 bbls/day. Alkylate storage and handling will be upgraded to handle the increased production of alkylate.

The increase in alkylation will result in increased use of isobutane. The Butamer unit (butane isomerization) will require minor pump and piping changes to meet the increase demand for isobutane. Railcar unloading and tankage modifications will be made to facilitate receipt of additional butane for isomerization.

FCC naphtha splitting flexibility will be increased to allow changes in the boiling ranges of the naphtha streams produced to facilitate blending for T50 and T90 without MTBE and to concentrate sulfur to facilitate the optimization of the desulfurization units. Heavy naphtha rejected from the gasoline pool will be used for distillate blending.

Final deep gasoline and diesel desulfurization capability will be improved through minor modifications of the existing hydrotreating units.

Carson Refinery Upgrades:

A modification plan for the L.A. Carson refinery was not provided but Tosco indicates that some changes will need to be made at the refinery. A plan may be submitted in the near future.

Schedule:

A schedule is not provided in the CEQA filing but Tosco is committed to removing MTBE at the earliest date and ahead of the governor's schedule.

Shell/Equilon:

Ethanol Distribution:

Equilon plans to use ethanol as an oxygenate in LA. Ethanol will be received by rail at the Carson Terminal. Ethanol will also be delivered by tanker to the Mormon Island Marine Terminal and pumped through an existing pipeline to the Carson Terminal where it will be stored in four existing above ground tanks. A new truck loading rack will be installed. Ethanol will be supplied from Carson to other LA terminals by truck.

The Wilmington, Signal Hill, Colton, Rialto and Van Nuyes terminals will be modified. New ethanol storage tanks and off-loading equipment will be installed and piped into the system.

Wilmington Refinery Upgrades:

Equilon operates a 98,500-barrel per day refinery in Wilmington.

Considerable modifications are planned to reduce gasoline RVP. Distillation towers will be retrayed and operation will be modified so as to alter cut points. The towers to be modified for RVP control are the Hydrocracker main fractioner, the depentanizer and the FCC debutanizer. The reformer feed prep tower is being modified for RVP control and to minimize the amount of benzene precursors in the reformer feed. The alkylation debutanizer and de-isobutanizer are being modified for RVP control and to permit the most efficient use of isobutane.

Equilon will install a new 60,000 bbl pentane storage sphere along with pentane blending and loading systems.

The FCC feed hydrotreating capability will be increased increasing FCC yields including olefins for alkylation as well.

Equilon plans a 3,500-bbl/day increase in alkylation capacity. A new alkylation reactor (mixer settler) and auxiliary equipment will be installed. Equilon currently exports butane and imports isobutane. 7,500 bbl/day of isobutane isomerization capacity for alkylation that will be added through the conversion of an existing idled catalytic reforming unit. This unit will provide sufficient isobutane for alkylation.

The 29,500 bbl/day catalytic reforming capacity of the Equilon Wilmington refinery is relatively large compared to its crude capacity. The catalytic reforming system will be substantially modified. The reformer feed is a mixture of hydrogenated delayed coker naphtha, heavy straight run and hydrocracker naphtha. The delayed coker unit is oversized for the crude input to the refinery, and Equilon purchases additional stocks for use as coker feed. The coker naphtha hydrotreater and olefin saturator capacity will be increased from 13,000 to 20,000 barrels per day suggesting that Equilon may modify their purchases of coker feedstocks to maximize naphtha production. A new reactor will be added to the catalytic reforming unit feed desulfurizing unit.

A new 16,000-bbl/day CD Tech HDS unit will be installed to treat medium and heavy FCC gasoline. Additional naphtha desulfurization is being considered.

In order to desulfurize light naphthas by removing mercaptans, an idled 11,000 barrel per day caustic extraction unit may be revamped.

Schedule:

A schedule was not provided in the CEQA filing. However, modifications must be completed by January 2003 to meet the MTBE phase out requirements set by the State of California.

Exxon-Mobil:

Ethanol Distribution:

The Port of Los Angeles Marine Terminal will be modified to accept ethanol. Ethanol will be distributed by truck from the Marine terminal to the distribution terminals. Two existing above ground storage tanks holding 160,000 barrels total will be converted to ethanol. A new ethanol truck loading rack will be installed.

Ethanol will also be delivered by rail to the Vernon Terminal and the Torrance Refinery and trucked to the distribution terminals.

Ethanol will be blended at the Torrance Refinery rack. Rail and off-loading facilities will be expanded at the Prairie avenue tank farm. Two new above ground storage tanks of undefined size will be constructed at the tank farm.

The Vernon terminal will be modified to off-load and store ethanol. In addition to rail, new truck unloading capability is to be added. At Vernon, 80,000 barrels of existing above ground storage capacity will be converted to ethanol and a new 50,000 barrel above ground ethanol storage tank will be installed. Exxon-Mobil intends to distribute ethanol by truck to the Atwood terminal and third party terminals located in Colton and Mission valley.

Modifications will be made to the Torrance Refinery loading rack, and the Vernon and Atwood (Anaheim) terminal loading racks to allow inline ethanol blending. At Atwood, 10,000 to 15,000 barrels of existing above ground storage will be dedicated to ethanol.

Mobil owns numerous common carrier pipelines in the area. As an alternative, Mobil plans to examine using these to distribute ethanol to terminals in the area.

Torrance Refinery Upgrades:

The Torrance refinery is rated at 148,500 barrels per day of crude.

Refinery modifications are proposed for three areas. These are as follows: RVP control, sulfur reduction, and T50/90-aromatics caps adjustments. Terminal and tank farm modifications are proposed to provide blending flexibility and accommodate ethanol use.

Ethanol will be accommodated by RVP control of light FCC gasoline and light hydrocrackate by deeper removal of butanes and pentanes. The Unsaturated Gas Plant debutanizer will be upgraded. The light hydrocracker gasoline stabilizer distillation tower will be modified to improve separation efficiency. These modifications generally involve upgrading existing equipment and will provide enhanced separation of butanes and pentanes.

In addition, due to the increased volume of light ends being removed, butane handling will be improved. An existing deisobutanizer will be upgraded to recover additional isobutane for alkylation. A new depentanizer will be installed in the saturated gas plant.

Because ethanol will be blended at a lesser volume than MTBE, there will be some loss in gasoline octane. Alkylation feed hydrotreating will be upgraded to improve octane. A new hydrotreating reactor (like IFP Alkyfining) that is used to hydrogenate diolefins to olefins and isomerize 1-butene to cis and trans 2-butenes will be installed. The result is higher quality C4 alkylate with 1.5 R+M/2 octane number increase.

Minor changes will be made to the crude unit and saturated gas plant to eliminate gaseous sulfur contamination in the natural gasoline stream.

The removal of sulfur from FCC gasoline will be increased by raising the hydrotreater severity (The reactor temperature and hydrogen pressure will be increased). Currently, 95% of the sulfur is removed. No equipment changes are required.

The existing light naphtha Merox sulfur extraction system will be modified to increase extraction of sulfur containing mercaptans.

The refinery piping will be modified to better isolate sulfur free light hydrocrackate to prevent sulfur cross-contamination.

A new light FCC gasoline splitter and Merox sulfur extraction system will be installed to provide flexibility for CARB 3 distillation and sulfur specifications. The Unsaturated Gas Plant Re-Run tower will be modified to separate the heavy FCC naphtha into mid and heavy streams. A new stripping tower will be added to remove light ends in the mid-boiling FCC naphtha stream.

Terminal and Tank Farm Changes:

To handle additional volumes of C4 and C5, the refinery will install new LPG rail facilities and associated equipment. One butane and two isopentane storage vessels will be installed. The sizes are not specified. 100,000 barrels of pentane storage is assumed. Exxon-Mobil plans to either store for subsequent winter blending or sell the excess butanes and pentanes into the market. Butanes may also be used as refinery fuel. One option is to export butanes and pentanes to New Mexico for winter fuel use.
Exxon Mobil plans to import a variety of blending streams including alkylate, raffinate, and isooctane and may have to export heavy FCC and straight run naphthas. Pipeline modifications will be made to optimize storage tanks and rail spur modifications will be made.

Schedule:

Construction will occur between June 2001 and January 2003.

Ultramar Diamond Shamrock (UDS):

Ethanol Distribution:

UDS does not distribute finished gasoline from the refinery and owns no terminals in the LA area. UDS will produce CARBOB for ethanol blending and distribute it through third party terminals that will be responsible for ethanol blending. Currently, UDS uses third party terminals at Carson, Colton, Orange, and Wilmington.

Wilmington Refinery Modifications:

The current UDS refinery in Wilmington is rated at 78,000 bbl/cd of crude. In addition, UDS currently purchases 50,000 bbl/day of distillates including gas oils. The refinery will be modified to increase crude capacity to 160,000 bbl/cd while eliminating outside purchases. These modifications are unrelated to the removal of MTBE under phase 3 gasoline. The modifications will greatly increase the flexibility of the Wilmington refinery and probably its ability to compete economically. This revamp can be expected to significantly increase UDS's Gasoline production at Wilmington. Because of the existing equipment in the refinery, UDS has elected to maximize alkylate production in its revamped facility.

A new crude train consisting of atmospheric crude (82,000 bbls/cd), vacuum crude (60,000 bbls/cd) and coker (37,000 bbls/cd) will be installed.

The existing Gas Oil hydrotreater that is used to remove sulfur from the FCC feed will be modified to increase FCC feed desulfurization capacity from 55,000 barrels per day to 73,000. The existing FCC unit capacity will be increased 5,000 bbl/day to 60,000 bbls. The FCC catalyst will be changed and a maximum olefin catalyst will be utilized to increase C3 and C4 olefins for alkylation.

A new diolefin selective hydrogenation unit will be installed to pretreat the alkylation feed. A new 15,000 bbl/day Hydrofluoric Acid alkylation unit will be installed.

The Butamer butane isomerization will be modified to produce additional isobutane to satisfy the increase needed for alkylation.

Product gasoline hydrotreating capability will be significantly increased.
Naphtha hydrotreating will be increased from 30,000 bbl/d to 34,000 bbl/d to desulfurize straight run gasoline and jet, and possibly increase reformer feed.

An existing Olefin treater will be converted to desulfurize and remove olefins from heavy FCC gasoline.

The existing Platformer (Reformer) will be modified to include an 18,000 bbl/d depropanizer to separate propane and improve RVP control of the reformate. Since the reformer is reported to have a 16,000-barrel/day capacity, little if any increase in reformate production is expected.

RVP modifications will be made to more completely debutanize light ends and provide a more exact butane-pentane separation. A new debutanizer will be installed in the FCC gas plant. The existing debutanizer will be converted to a depentanizer.

The plan does not address the fate of light ends removed for RVP control. No new handling systems and storage for pentanes is proposed.

Schedule:

No schedule was provided in the CEQA filing. However, modifications must be completed by January 2003 to meet the MTBE phase out requirements set by the State of California.

BP ARCO:

Ethanol Distribution:

The Marine Terminal will be modified to receive ethanol by ship. Existing storage tanks will be converted to use for ethanol. BP ARCO may ship pentanes by water.

BP ARCO has numerous pipelines within the LA Basin. Some may be used to transport ethanol. Some will be upgraded to increase the ability to move pentanes and butanes to and from storage as well.

BP ARCO operates terminals at East Hynes, Vinvale, Hathaway, Colton and Carson. will be modified to receive ethanol by truck, and store and blend ethanol. In each case, two existing above ground storage tanks will be converted to ethanol service

Carson Refinery Modifications:

BP ARCO will make no major refinery modifications to its 260,000 bbl/d LA refinery.

The existing 2,500-bbl/day MTBE facility will be converted to either a alkylation feed hydrotreating unit or to produce isooctene.

The 2,800-barrel per day cat poly unit will be converted to a C5 olefin dimerization unit. This will lower gasoline RVP by removing pentenes from the light FCC gasoline while providing non-aromatic jet and diesel blendstock.

A mid-barrel hydrotreater will be modified to become a gasoline hydrotreater. BP ARCO has two "distillate hydrotreaters". These are a 10,000-bbl/day unit for jet and a 20,000-bbl/day unit for diesel.

Fractionation changes will be made for FCC heavy gasoline to enhance T90 control and concentrate sulfur for desulfurization. A new FCC bottoms distillation tower will be installed or an existing depentanizer will be converted to a bottoms splitter. The Light hydro and ISO SIV units will be revamped to remove sulfur in FCC heavy gasoline and saturate olefins.

Ethanol will be accommodated by modifying distillation units in the reformer and gasoline fractionator areas to better separate pentanes and butanes. The reformer distillation unit will be modified to remove butanes and pentanes. The gasoline fractionator area debutanizer will be upgraded for butane removal.

The North hydrogen plant would be modified to accept pentanes as hydrogen feedstock in summer.

Terminal and Tank Farm Changes:

The existing pentane spheres at the refinery will receive a pump upgrade.

New equipment will be installed in the existing pentane railcar loading facility to facilitate shipping of pentanes in summer and receipt of pentanes in winter for gasoline blending. Pentanes not used for hydrogen production may be shipped from the refinery in summer to be stored offsite or sold outside the LA basin.

Pentanes may be directed to the Marine terminal storage and loading facility. A new 100,000 bbl refrigerated storage tank for pentanes will be constructed at the Marine terminal.

Schedule:

Construction is expected to begin January 1, 2001 and be completed December 2002**.**

Chevron:

Ethanol Distribution:

Chevron intends to purchase ethanol from a third party source. The ethanol will be trucked to the Chevron terminals located in Van Nuys, Montebello, and Huntington Beach.

The Van Nuyes terminal will be modified to unload ethanol for storage in two existing above ground tanks that will be converted to ethanol use. In-line blending systems will be upgraded.

The Huntington Beach and Montebello terminals will be upgraded with new ethanol off-loading facilities and single new above ground storage tanks.

El Segundo-Refinery Modifications:

Chevron operates the 260,000 El Segundo refinery in LA.

The existing 1,700-barrel per day MTBE facility will be converted to produce isooctene. The 2,660-barrel per day TAME facility will be shutdown.

The alkylation plant will be increased by adding two new contactors and a single settler to handle the increase in FCCU olefins. According to Stratco[16], two contactors will produce at least 4,000 bbl/day of alkylate, and more likely 6,000 bbl/day. Other modifications including product distillation will be made as necessary.

To produce the alkylation feed and replace some of the loss in gasoline capacity due to MTBE removal, the FCCU will be modified to increase the feed rate capacity. The size of the increase is not stated. For normal operation, it is estimated that about 0.25 bbl alkylate are produced per barrel of FCC feed[17]. Thus, the expansion might be 16,000 bbl/day to 24,000 bbl/day. Comparing El Segundo to BP ARCO LA, it is evident that El Segundo cracking can be considerably expanded. With the estimated expansion, FCC at El Segundo would increase to 78,000 to 86,000 bbl/day compared to 96,000 at BP ARCO LA.

No major changes are required for the cracking reactor and regenerator except to increase air flow to the regenerator and upgrade the gas compressors. The FCC expansion will be accommodated by increasing the capacity of the deethanizer, adding a new and larger depropanizer and debutanizer and making other modifications as required to handle increased flow rates.

FCC gasoline sulfur control will be enhanced. The existing depentanizer will be upgraded. A new FCC gasoline splitter will be installed. The bottoms from the depentanizer (light FCC naphtha), will be split into light and medium streams. The medium FCC gasoline will be hydrotreated to remove sulfur and saturate olefins in an existing hydrotreater

A new depentanizer will be installed as a part of the "Isomax complex". The streams treated by this unit will be straight run naphtha and naphtha from the hydrocracker, and reformer.

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[16] Stratco, private communication. Stratco is a major supplier of alkylation equipment.
[17] Gary and Handwerk reference 9. Using tables 11.5 and 6.6 to relate mixed alkylate production to FCC feed rate.

A new pentanes storage unit will be built to accommodate pentane removal. Pentanes will be sold or used as hydrogen feedstock. It is assumed that it will be comparable in size to that installed at BP ARCO LA, or approximately 100,000 bbl.

Schedule:

Construction is proposed to begin in August 2001, and be completed in November 2002.

Summary of Southern District CEQA Filings by Process Type:

Table 6 (see end of section) provides a summary of refinery and terminal modifications separated into three categories, Ethanol/RVP, Sulfur, and Multiple/Other. These categories are discussed in greater detail below.

Ethanol/RVP:

This category includes those items, which can be clearly identified as being largely necessary to accommodate ethanol blending. Terminal modifications are included here because ethanol blending must be done at the terminal level necessitating listed modifications.

Items related to pentane removal, storage, and use are also included in this category since the removal of pentane is largely a result of the lower RVP requirement for the base CARBOB to accommodate the addition of ethanol.

Sulfur:

This category includes those items, which can clearly be identified as being modifications made primarily to reduce the sulfur content of gasoline, and includes such items as modification to hydrotreating systems and modifications to FCCU gasoline fractionators, olefin treaters, and sulfur recovery units.

Multiple/Other:

This category includes modifications that benefit more than one fuel specification area. Examples include alkylation which benefits, volatility control, sulfur, distillation properties, and olefin/aromatic levels, isooctane plants to increase octane but also convert/reduce olefin content, Cat Poly unit modifications which helps with both aromatic caps and distillation properties, and changes to fractionation columns which reduce RVP but also contribute to octane.

It is relatively clear from Table 6 that investments in modifications that are solely to accommodate the use of ethanol are related primarily to pentane removal and storage and terminal modifications. Conversely investments in modifications for sulfur reductions are more extensive. Investments in equipment and modification that provide multiple benefits are also more extensive although in this case some of these modifications and upgrades do, in fact, also contribute to fuel properties that more readily accommodate ethanol blending. However it certainly appears that investments for sulfur control, distillation properties, aromatics/olefins control, and benzene reduction far exceed those required to accommodate ethanol blending.

Southern District Capacity Changes:

Table 7 presents a summary of major refinery capacity changes estimated from the CEQA filings. Table 8 presents estimated supply and octane-barrel changes.

The CEQA plans demonstrate how refiners will shift from MTBE to ethanol. They do not provide information on how refiners will handle the increased demand for gasoline projected by EIA and CEC which will occur whether MTBE is used or not. In this analysis, the difference in supply for ethanol containing and MTBE containing gasoline can be estimated. It is assumed that this difference can be added on to the necessary "creep" in supply that would otherwise occur to satisfy demand. Thus, if the net change in barrels per day is zero or positive, it would be concluded that refiners have removed MTBE beginning in 2003 while satisfying demand.

Some of the plans are very detailed and present actual capacity changes. Some plans provide information to make estimates of changes in capacity, while some plans provide no quantitative information. According to the plans, all refiners will be prepared in advance of the January 1, 2003 CBG3 deadline to produce oxygenated gasoline with ethanol.

As a part of the plans, refiners have increased their flexibility and capability to receive gasoline blendstocks including alkylate and ethanol.

On a 1999 adjusted basis LA Basin refineries used about 64,150 barrels per day of MTBE. In order to eliminate ethers from the refinery gasoline stream, 6,800 bbl/day of MTBE and TAME capacity will be shutdown. In addition, refiners will cease to purchase approximately 57,350 barrels per day of MTBE.

Ultramar (UDS) plans a major modification of the Wilmington refinery to raise crude distillation by 82,000 barrels per day while forgoing the current purchase of 50,000 barrels per day of distillate blendstock. The changes are being made to better match the refinery upstream processing and catalytic cracking capability. The total potential increase in gasoline supply at UDS Wilmington is approximately 44,500 bbls /day based upon the crude oil feedstock increase[18]. UDS will utilize a high olefin cracking catalyst to maximize alkylate feedstock and expand alkylation by 15,000 barrels per day.

[18] EIA, 1999 Petroleum Supply Annual, "Table 12- PAD V-Supply and Disposition of Crude Oil and Petroleum Products".

Chevron intends to increase FCC capacity by 24,000 bbls/day. This will yield about 13,000 bbls/day of FCC gasoline[19].

In addition, other modifications provided in CEQA plans (exclusive of UDS Wilmington) will net out approximately 8,600 bbl/day of gasoline as alkylate and isooctane.

Refiners will increase alkylation capacity (alkylate and isooctane) by approximately 28,385 barrels per day, while eliminating 9,600 barrels per day of oxygenate and polymer gasoline capacity. The majority of the alkylation capacity increase comes from the UDS refinery modification. The remaining incremental increases in alkylate come from better recovery of olefins produced in FCC units and production of isooctane from isobutylene currently dedicated for MTBE manufacture.

Because the oxygen requirement is in effect, refiners have planned to add ethanol to gasoline in summer and winter. Considerable RVP control in the form of debutanization and depentanization will be added along with about 360,000 barrels of pentane storage capacity.

Southern District Octane Balance Estimate:

It is not possible to accurately estimate how much pentanes and pentenes must be removed from gasoline to permit ethanol blending because this is a strong function of control of propane, propylene and butanes and butylenes in the gasoline pool in individual refineries. MathPro estimated[20] that 71.6% of the volume of ethanol blended might be rejected as blendstocks. Of these, half were composed of low volatility naphthas. The majority of the high volatility material rejected is light FCC gasoline that boils between about 130 and 220F. This material might be rejected based on volatility, but it also contains about 60% olefins by volume. CPM gasoline with ethanol appears to require a very low olefin content.

It is not possible to determine how much aromatics may increase in gasoline based upon the CEQA filings because catalytic reformers are currently underutilized. The reduction in the pool octane due to MTBE removal is estimated to be 1.2 units. Octane-barrels may be increased through improvement in alkylate quality, increased use of C5+ isomerization, and increased reformer utilization. In the Southern District, at least one refiner has plans to add a processing step ahead of alkylation to remove dienes and isomerize butenes. Such a process is reported to raise C4 alkylate octane by 1.5 units. According to the MathPro analysis, C5+ isomerization is currently underutilized and thus, additional octane capacity may be available. Refiners might also elect to lower their

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[19] Gary, J., Handwerk, G., Petroleum Refining Technology and Economics, Third Edition, Marcel Dekker NY, 1994. Table 6.6 page 144 FCC Material Balance for 75% Conversion shows 56.8% yield of C5+ FCC naphtha.

[20] MathPro, "Potential Economic Benefits of the Feinstein-Bilbray Bill", Performed for Chevron Products Co and Tosco Corp, March 18,1999. Table A10 for the intermediate term. Table A10, 100% ethanol use is 75,000 bbl/d. For the 1029 M bbl/d CBG pool, the ethanol blend rate is 7.3%. We reduced the ethanol input to 5.7% and retained the total quantity of rejected stocks at 42 M bbl/d. The ratio of rejected stocks to ethanol input is 0.716.

pool octane slightly, supplying less mid and premium grade gasolines. At 100 severity, catalytic reforming will increase octane by about 35 units while reducing volumetric supply by about 20% based upon the reformer feed rate. If the octane deficit for the new supply is to be completely made up by catalytic reforming, aromatics may have to be increased by as much as 4.5%. The net gain in supply in the Southern District will be 7,800 barrels per calendar day[21].

Some refiners who have planned for pentane control in summer propose to sell the pentanes as gasoline blendstock in non-California markets or use the pentanes as steam reforming-hydrogen plant feedstock. It appears (appendix D), that if natural gas prices exceed about $2.50 per million BTU, pentanes could be used economically to generate hydrogen. The current spot price of natural gas is well above $2.50 per million BTU in California.

[21] The MathPro analysis also examines a case where non-oxygenated CBG is made along with oxygenated CBG in a ratio similar to that expected statewide from this analysis. Comparing the all oxygenated MathPro case to the split case, there is the opportunity to transfer some of the rejected blendstock to Northern District refiners. According to MathPro Table A-7, about 67% of the blendstocks or about 15,950 bbls/day could be transferred.

Table 7 Major Refinery Capacity Changes Identified in CEQA Filings

Company	City	Barrels/ day					
		Crude	Vacuum	Coking	FCC	Reforming	H-crack
Chevron US	El Segundo				24,000		
BP Arco	Los Angeles						
Exxon Mobil Rfg & Supply Co	Torrance						
Tosco Refining Co	Wilmington						
Equilon Enterprises LLC	Wilmington						
UDS Refining	Wilmington	82,000	60,000	37,000	5,000		
Paramount	Wilmington						
Lunday-Thagard	South Gate						
Huntway Refining Co	Wilmington						
Tenby Inc.	Oxnard						
		82,000	60,000	37,000	29,000	0	0

Table 7 Concluded

	Hydrotreating for Gasoline Manufacture				Octane and Olefins Conversion				
Company	Reformer	Other	Feed	Gasoline	Alkylation	Polygas	Oxygenates	Isooctene	Pentanes
	Feed	Naphtha	FCC	FCC				Isooctane	Storage
Chevron US					6,000		-4,300	1,168	100,000
BP Arco				20,000		-2,800	-2,500	1,718	100,000
Exxon Mobil Refg & Supply Co				+					100,000
Tosco Refining Co				+	1,000				
Equilon Enterprises LLC	7,000	11,000		16,000	3,500				60,000
UDS Refining		4,000	18,000	15,000	15,000				
Paramount									
Lunday-Thagard Oil									
Huntway Refining Co									
Tenby Inc.									
	7,000	15,000	18,000	51,000	25,500	-2,800	-6,800	2,885	260,000

Table 8 Possible Octane Barrel Balance Based Upon CEQA Filings

Blendstock		CaRFG2	CaRFG3
(R+M/2)	Barrels/day	Octane bbl/day	
MTBE (110)	64,150	7,056,500	
Ethanol (115)	32,174		3,700,010
Isooctane (99)	2885		285,615
Poly gasoline (90.5)	-2,800		-253,400
Mixed alkylate (92)	25,500		2,346,000
FCC (Chevron, 86)	13,000		1,118,000
FCC and other (UDS 73)[22]	29,500		2,153,500
Rejected Blendstocks (80)[23]	-23,037		-1,842,927
Total	77,222	7,056,500	7,506,798
Pool Octane		110	97.2
Aromatics required for ON balance (35ON /% aromatics, 20% volume loss)	26,297		920,400
Total with aromatic shrinkage	71,963		
Possible Increase in aromatics, %			4.5%
Net capacity Increase	7,813		

[22] The approximate mix of gasoline from increased crude run is 11.1% coker at 63.5 octane, 10.8% LSR at 63.5 octane, 29.4% HSR at 60.5 octane and 48.7% FCC gasoline at 84.6 octane yielding 73 octane.
[23] Quantity estimated from MathPro. Octane estimated from Gary and Handwerk, Table 12-1.

Table 6 Detailed Refinery Modifications

The following table is a summary of detailed changes for Southern refineries.

California Refiner Modification for CaRFG3

Company	Ethanol/RVP	Sulfur	Multiple/Other	Comments
Chevron (El Segundo) (continued)	tions in column in TAME plant. New steam boilers and overhead condensers for both (to facilitate pentane removal), New storage sphere for pentanes (pentanes will be sold or used for refinery fuel or feed for the hydrogen plant).	columns, and overhead condensers, reflux pumps and steam reboiler to split FCC light gasoline. Possible modification to furnaces and new compressor pumps, exchangers, and piping modifications at one furnace (all primarily to facilitate sulfur removal).	(including new condensers, reflux pump and steam reboiler) New larger debutanizer (including new condensers, reflex pump & steam reboiler) Modification to existing deethanizer (including new column plus new pumps & exchangers) Modifications to propylene caustic treating unit (including installation of vessels pumps & exchangers), new equipment (pumps, exchangers, contactors) to caustic treating plant. New Amine Absorber (to remove sulfur from increased propylene stream). Modification to relief system (relief headers, vapor recovery facilities & flair). Modifications to main air blower (to increase capacity) also main motor of air blower Upgrades to wet gas compressor rotor & gearbox. Modifications to wet gas interstage compressor (exchangers & vessels) Alkylation Plant modifications (to handle increased olefin production from FCCU) Add two new contactors and acid	

California Refiner Modification for CaRFG3

Company	Ethanol/RVP	Sulfur	Multiple/Other	Comments
Chevron (El Segundo) (continued)			settlers and restore out of service column as a refinery debutanizer (to handle increased LPG stream from FCCU). Recommissioned column will require new cooling tower. Modifications to convert distillation column will include retraying and new trim coolers. Iso-octene Plant (to improve octane) Convert existing MTBE unit to iso-octane unit (probably new pressure vessels, exchangers, pumps, and modifications to existing columns). Storage Tanks (to store gasoline components) Current MTBE tank converted to gasoline service and addition of two new floating roof tanks.	
Chevron Terminals	Van Nuys New ethanol off loading pumps Convert two tanks to ethanol service New ethanol loading pumps Huntington Beach New piping, ethanol loading & off loading pumps and new ethanol storage tank & foundation. New fire protection on ethanol tank Montebello New piping, new ethanol loading			

California Refiner Modification for CaRFG3

Company	Ethanol/RVP	Sulfur	Multiple/Other	Comments
Chevron Terminals (continued)	loading pumps, new ethanol storage tanks & foundation, two new containment dikes/pads and new ground system for ethanol unloading area.			
Arco (LA Refinery) Modification to seven (of 34) key processing units.	Reformer/fractionator (RVP control) Modifications to R/F unit also modification to overhead condensers and new pumps SFIA Debutanizer modifications (RVP control) No. 1 naphtha splitter converted to a new debutanizer and the SFIA depentanizer converted to a new naphtha splitter. Also new piping & control valves and minor pump modifications North Hydrogen Plant modifications (RVP control) New feed drums, add pumps, vaporizer and piping. Tank Farm Existing MTBE tanks and some finished products tanks would be converted to component storage and would also require minor piping tie ins to the gasoline blending system. Pentane Off-loading & Loading Modifications to existing pentane rail car off-loading to import pentane (winter), add re-pressurizing vaporizer system. Add two new rail car spots.	Light Hydro unit. Modified for additional sulfur removal including adding new heat exchangers, piping, & pumps, also modification or replacement to existing heat exchangers and control systems Iso-SIV/Unit Convert to hydrotreater for sulfur removal including new reactors, exchangers, and pumps and upgrading control systems/ instrumentation. Also modifications to existing heat exchangers and piping. FCCU Gasoline Fractionation (Sulfur) New rerunbottoms splitter including splitting tower, heat exchangers, reboiler, product cooler, overhead accumulator/ reflux drum, piping and control system/instrumentation. Mid Barrel Unit Mid-barrel unit modified to a gasoline hydrotreating system, also modifications to feed and product pumping and hydrogen system, heat exchanger, & assorted instrumentation.	MTBE Unit Conversion Replace MTBE reactor with new reactor, new steam reactor, feed heaters. Add additional new feed exchangers. Convert methanol towers. Heat exchangers to be modified or replaced. Modifications to piping & control system. Cat Poly Unit modifications (process also helps with distillation points & aromatic cap) Modify Cat Poly Unit into a pentane dimerazation Unit. Add new hydrotreating reactor, plus associated piping and control/ instrumentation modifications. (note: not required by Phase 3, dimerate would go to jet fuel but would also help with pentane removal (RVP control). Support Facilities A number of refinery support facilities would be modified to accommodate total changes.	

California Refiner Modification for CaRFG3

Company	Ethanol/RVP	Sulfur	Multiple/Other	Comments
Arco (LA Refinery) (continued)	Pipeline/Marine terminal Pentane transport Add pump near existing pentane spheres and modifications to associated electrical substation. Add new pentane storage tanks at marine terminal. Butane Loading/Off-loading Modifications to existing propylene loading facility to allow butane loading & off-loading from rail cars.			
Arco Terminals	Marine Terminal Convert two existing tanks to store ethanol Modification to piping & metering systems. Tank cleaning/ modifications. Construct new 100m barrel refrigerated tank for pentane storage (requiring demolition of two existing tanks) East Hynes Terminal Conversion of one existing tank to ethanol storage. Modifications to piping, metering for loading/ off-loading & blending of ethanol including two new blending skids. Also new pumps (product shipped to East Hynes from marine terminal via pipeline). Vinvale terminal Convert two existing tanks to ethanol storage. Modifications to piping and metering for off-loading and blending ethanol. Modification to loading rack system to blend ethanol and distribute (product would be shipped via pipeline or tanker truck).			

California Refiner Modification for CaRFG3

Company	Ethanol/RVP	Sulfur	Multiple/Other	Comments
Arco Terminals (continued)	Hathaway Terminal Conversion of several existing tanks to ethanol storage. Tank cleaning & modifications, modification to existing blending skid, modification to piping, metering and off-loading, blending at racks. Modification to truck racks (ethanol piped to Hathaway from marine terminal) Carson Terminal Conversion of one existing tank to ethanol storage. Tank cleaning & modifications. Modification to existing blending skids. Modifications to piping & metering systems for off-loading ethanol & blending at loading racks. Colton Terminal Conversion of one tank to ethanol storage. Tank cleaning & modifications. Modification to existing blending skids. Modifications to piping & metering systems for off-loading ethanol & blending at loading racks.			
Arco Project Alternatives			Pentane storage at refinery. Conversion of MTBE Unit into a Selective Hydrogenation unit	
Equilon LA Refinery	Pentane Sphere (RVP control) New pentane sphere to include blending and loading pumps, piping, valves, & fittings.	Modifications to hydrotreater Unit #2 Install new olefin saturation reactor in series with new pretreat extractor, new charge pumps, new heat exchangers and replacement of the active tray area, also replace stripper reboiler, new control valves & piping modifications. Retube charge heater.	C4 Isomerization Unit (support alkylation unit) Convert idle reformers to C4 isomerization unit (for additional isobutane feed to alkylatation unit) using existing equipment. Also use of existing zinc oxide treater in BenSat Unit of Isomerization Unit. Additional exchangers, stabilizers, gas scrubber, driers, vessels, pumps, and piping	

California Refiner Modification for CaRFG3

Company	Ethanol/RVP	Sulfur	Multiple/Other	Comments
Equilon LA Refinery (continued)		Cat Reformer Unit New reactor (nickel oxide catalyst) Retray debutanizer tower. Hydrotreating Unit #4 Changes to main reactor, add diesel side stripper, add new feed stream preheater, additional heat exchangers and piping modifications. CD Tech Unit New Unit (16 mbd) including columns, reactors, stabilizer, absorber, condensers, exchangers, coolers, pumps, compressors, fired heater & drums Merichem-Thioloex Unit May revamp idle Merichem Unit (11,000 bpd) into an extractive Thiolex Unit. Unit conversion would include a caustic regeneration system and mercaptan oxidation system and would require new equipment to include an oxidation vessel, contactors, exchangers, strainers, piping pumps, valves, flanges, and fittings.	Alkylation Unit (aromatics/ olefins reduction) Increase production from 8500 bpd to 12,000 bpd. Addition of effluent treating vessels, new contactor and settler, refrigeration unit and modifications to existing cooling tower, new exchangers and pumps. Also requires new boiler to provide steam. Fractionation Changes (RVP control, octane) Changes to a number of fractionation columns. Hardware revisions to the HCU main fractionation, FCCU, debutanizer, feed prep tower, depentanizer, Alky Deisobutanizer and the C4 isomerization debutanizer. The aforementioned are predominately undergoing revamps/tray modifications and revisions to cutpoints. The HCU depropanizer and CRU2 splitter will undergo operation revisions. Storage Tanks Modifications Service and throughput of various tanks will be modified.	
Equilon Terminals	Carson Terminal New rail car off-loading facility New truck loading rack and vapor processor. Morman Island Marine Terminal Will receive product & transfer via existing pipeline to Carson Terminal Colton, Rialto, Signal Hill, Van			

California Refiner Modification for CaRFG3

Company	Ethanol/RVP	Sulfur	Multiple/Other	Comments
Equilon Terminals (continued)	Nuys, & Wilmington These five terminals will get new tanks, off-loading pad, and miscellaneous piping.			
Ultramar Diamond Shamrock Wilmington refinery	FCCU Install Debutanizer Modify existing debutanizer to depentanizer New primary absorber stripper, accumulators, pumps, reboiler, distillation column, vessels, & heat exchangers Platformer (RVP) Modification to include new compressor and depropanizer.	Olefin Treater To be converted to hydrotreater including new reactor, new stripper, new compressor, piping changes, and a new catalyst Gas Oil Hydrotreator (Increased capacity/sulfur reduction) Modifications to increase capacity from 55mbpd to 73mbpd. Includes new pumps, new compressors, and modifications to heater Sulfur Recovery Unit Install new third Sulfur recovery Unit. Including a new Amine Regeneration Unit, Tail Gas treating Unit, and thermal oxidizer. Also additional sulfur loading facilities. Merox treater New Merox treater. Sour Water Stripper New Unit	Butamer Unit (Increase production of alkylate) Expand production of alkylate by adding one new column and associated new heat exchangers, vessels, and pumps. New Crude Unit (expand capacity) Includes new crude unit, new vacuum unit, and a new coker complex. Alkylation Unit (multiple specifications) New alkylation unit including columns, vessels, condensers, circulation heaters, heat exchangers, and pumps. New LPG dryer and Selective Hydrogenator Unit will be installed. The FCCU LPG Merox Unit will be modified to remove water, sulfur, & diolifins. An existing column will be converted to a depropanizer. FCCU reactor will be modified to increase feed rates from 55 mbpd to 60 mbpd. Also switching to rare earth metal catalysts * modifications will include a new wet gas compressor, air blower, expander reactor, heat exchangers, and pumps.	*Note that the majority of Ultramars modifications are a result of a capacity increase

California Refiner Modification for CaRFG3

Company	Ethanol/RVP	Sulfur	Multiple/Other	Comments
Ultramar Diamond Shamrock Wilmington refinery (continued)			RVP/Distillation/sulfur/Increase Capacity Light End Recovery Unit/ Naphtha Hydrotreater Unit Modifications to exiting unit to increase capacity from 30 mbpd to 34 mbpd. New butanizer and depropanizer will be added. Existing LERC depropanizer will be modified, new vessels, pumps, and fin fans. The naphtha Hydrotreater would receive modifications to the existing compressor and new heat exchangers and pumps. Storage Tanks Service of several storage tanks will be modified or throughput will be changed. New tanks to be added to store intermediate stream, molten sulfur, and sour water. Pipelines Construction of new pipeline connecting refinery to off-site tanks (still in planning stage) Boiler New 200 million btu unit required to support other refinery modifications. Flare System Modification to existing system to accommodate capacity increase and pressure relief capacity of new units. Cooling Tower New cooling tower to support new refinery unit.	

California Refiner Modification for CaRFG3

Company	Ethanol/RVP	Sulfur	Multiple/Other	Comments
Ultramar Diamond Shamrock Wilmington refinery (continued)			Relocated facilities Maintenance, labs, & operations building will be relocated to provide space for the new refinery units. Other Modifications Includes fire water systems, service (utility) to new units, plant air system and fuel gas system to support new units, and new hydrobin system to support additional production of petro-leum coke.	

Appendix A
Table A-1
By County 1998 Gasoline Consumption Data for California

County	Retail Service Stations	County Population	Total Paid County Vehicle Registrations	Miles of Surface Road	Gallons of Gasoline Consumed	Region	FED RFG	CO Gas
	1999	1998	1998	1997	1998			
STATEWIDE TOTALS	9,520	33,226,000	24,281,400	170,496	13,496,210,000			
(summed from below)		33,225,655	23,051,586	172,062	13,515,285,000			
Alameda	3	1,413,400	1,020,402	3,495	610,461,000	N	N	N
A1pine	5	1,190	1474	268	1,020,000	N	N	N
Amador	27	33,300	34135	679	12,714,000	N	N	N
Butte	97	199,100	153,065	2,150	70,829,000	N	N	N
Calaveras	31	38,100	42,917	1,023	13,743,000	N	N	N
Colusa	18	18,600	15,820	959.80	9,494,000	N	N	N
Contra Costa	257	906,500	708,424	3,124	403,581,000	N	N	N
Del Norte	21	28,100	18,620	735.77	8,357,000	N	N	N
El Dorado	67	148,800	135,286	2,119	62,376,000	N	Y	N
Fresno	300	781,900	484,796	7,026	268,328,000	N	Y	N
Glenn	23	26,850	21,412	1,091	10,337,000	N	N	N
Humboldt	74	126,000	104,261	2,481	50,633,000	N	N	N
Imperial	76	143,000	96,610	3,362	45,752,000	S	N	N
Inyo	31	18,300	18,988	4,779	12,436,000	N	N	N
Kern	334	637,200	418,846	6,856	240,859,000	N	Y	N
Kings	55	121,000	66,382	1,418	34,073,000	N	Y	N
Lake	31	55,100	54,362	1,152	18,730,000	N	N	N
Lassen	21	33,650	23,138	2,013	11,537,000	N	N	N
Los Angeles	2,133	9,587,300	5,870,715	20,990	3,660,156,000	S	Y	Y
Madera	64	114,100	77,198	2,114	37,451,000	N	Y	N
Marin	60	244,100	214,212	1,245	122,557,000	N	N	N
Mariposa	15	16,000	17,696	911.03	6,445,000	N	N	N

Mendocino	51	86,100	77,777	1,909	37,897,000	N	N	N
Merced	81	203,200	131,317	2,414	69,511,000	N	Y	N
Modoc	12	9,975	8,307	1,969	4,226,000	N	N	N
Mono	14	10,550	10,777	1,471	8,000,000	N	N	N
Monterey	131	381,000	261,640	2,257	149,558,000	N	N	N
Napa	29	121,900	101,651	851.63	52,879,000	N	N	N
Nevada	35	89,200	85,278	1,173	38,738,000	N	N	N
Orange	588	2,734,500	2,015,296	7,056	1,246,735,000	S	Y	Y
Placer	96	219,400	201,956	2,048	111,623,000	N	Y	N
Plumas	26	20,450	22,656	1,833	9,021,000	N	N	N
Riverside	443	1,441,000	944,054	7,541	547,176,000	S	Y	Y
Sacramento	295	1,156,500	832,090	4,339	465,152,000	N	Y	N
San Benito	18	46,950	36,835	986.63	16,244,000	N	N	N
San Bernardino	565	1,631,500	1,058,681	10,970	620,606,000	S	Y	Y
San Diego	704	2,795,800	1,981,345	8,621	1,136,281,000	S	Y	N
San Francisco	110	783,400	427,884	892.13	381,425,000	N	N	N
San Joaquin	183	546,900	360,360	3,221	202,140,000	N	Y	N
San'Luis Obispo	103	236,400	191,275	2,520	104,344,000	N	N	N
San Mateo	186	716,500	657,263	2,057	371,087,000	N	N	N
Santa Barbara	118	402,900	293,475	2,002	163,412,000	N	N	N
Santa Clara	370	1,686,400	1,317,476	4,854	816,048,000	N	N	N
Santa Cruz	78	249,000	198,230	1,137	101,902,000	N	N	N
Shasta	122	164,100	133,879	2,761	65,798,000	N	N	N
Sierra	8	3,340	3,547	781.44	1,637,000	N	N	N
Siskiyou	35	44,200	44,298	3,578	20,305,000	N	N	N
Solano	128	382,000	272,260	1,779	150,374,000	N	Y	N
Sonoma	136	436,700	373,910	2,664	192,938,000	N	N	N
Stanislaus	173	428,300	297,937	2,744	153,774,000	N	Y	N
Sutter	31	76,400	58,562	1,072	26,829,000	N	Y	N
Tehama	32	54,900	41,918	1,643	21,705,000	N	N	N
Trinity	23	13,200	13,036	2,110	4,415,000	N	N	N

Tulare	**193**	**359,900**	**226,889**	**4,780**	**108,878,000**	**N**	**Y**	**N**
Tuolumne	**37**	**52,500**	**50,725**	**1,147**	**20,161,000**	**N**	**N**	**N**
Ventura	**198**	**732,700**	**565,087**	**2,684**	**295,425,000**	**S**	**Y**	**Y**
Yolo	**73**	**155,500**	**113,681**	**1,414**	**68,588,000**	**N**	**Y**	**N**
Yuba	**27**	**60,800**	**41,475**	**791.79**	**18,584,000**	**N**	**N**	**N**
Northern Counties					**5,963,154,000**			
Southern Counties					**7,552,131,000**			
					13,515,285,000			

Appendix B

Brief Discussion of Refining:

Refineries process crude oil into a range of hydrocarbon products including those that are used to make gasoline. The figure in Appendix F shows a block diagram of a typical refinery. Crude oil contains hydrocarbons that boil from less than –200F to well over 1000F. The gasoline fraction (called straight run gasoline) boils between about 100F and 400F and represents less than 20% of the crude. Distillates like diesel fuel, jet fuel and heating oil boil between about 400F and 650F. Typically the gasoline demand amounts to between 50 and 60% of the crude supplied to the refinery. Typically, 50% or more of the crude oil boils above 650F and has little commercial value. To balance gasoline supply and demand, refiners use conversion processes such as catalytic cracking, and coking to produce gasoline and distillates from the +650F fraction of the barrel.

Straight run gasoline processing:

The octane quality of the "straight run" gasoline distilled from crude is poor. The light straight fraction is often "isomerized" to increase the octane from about 65 to 82 or more and remove benzene and sulfur. The heavy straight run fraction is desulfurized and catalytically "reformed". Heavy coker naphtha and heavy hydrocracked gasoline may also be reformed. During reforming, the octane of the stream is raised from 60 to above 95 and the aromatic content of the straight run gasoline is raised from less than 10 or 20% to 70% or more.

Conversion:

In the FCC unit, the crude fraction boiling between about 650F and 1050F is heated to a high temperature and contacted with a catalyst. The heavy oil is "cracked" to produce lower boiling gases and liquids that are highly olefinic and heavier gasoline and distillate liquids that are aromatic. The gasoline produced, called FCC naphtha, contains most of the sulfur and olefins found in gasoline. This gasoline stream is often hydrotreated to lower both the sulfur and olefin content. The octane number of FCC gasoline is lower than the octane number of finished gasoline, being typically about 84 compared to 89. About one third of the gasoline produced in the refinery comes from the FCC unit.

In the coker unit, very high boiling material, typically above 1050F, is destroyed thermally producing gases and liquids similar to those from catalytic cracking along with petroleum coke.

In addition to gasoline, heavier highly aromatic products that boil in the range of diesel and residual fuel oil are produced in the FCCU and coker. A portion of these may be hydrocracked to produce additional gasoline with a lesser sulfur and aromatic content.

Hydrocracking is also sometimes used to process a portion of the crude that could be directly processed in the FCC.

Certain light olefins are not directly included in gasoline because of their high volatility and usefulness as a feed material to make high quality gasoline. Propylene and four different butylenes including isobutylene are byproducts of catalytic cracking and coking. These are processed to gasoline by alkylation, polymerization and etherification.

MTBE is currently produced in the refinery by reacting methanol with the isobutylene. A number of studies suggest that refiners will instead polymerize isobutylene and hydrogenate the isooctene product to isooctane. Isooctane has a 100 octane number, and like alkylate is free of sulfur, olefins and aromatics.

In alkylation, isobutane (4 carbons) is added to propylene (3 carbons) and butenes (4 carbons) in a catalytic process to produce larger branched paraffins (mostly 7 and 8 carbons) called alkylate which boils between about 200F and 300F and has an octane number between 89 and 96. It is also possible to alkylate or polymerize C5 olefins produced in the FCCU to remove the highly photochemically reactive olefins but the boiling range of C5 alkylate is high and the octane is only about 89. Alkylate contains no sulfur, olefins or aromatics. A byproduct of alkylation is the respective saturated paraffin of the olefin converted. Thus, propylene alkylation produces propane by-product and butene alkylation produces n-butane as a by-product. The RVP of alkylate depends upon how thoroughly propane and butane are separated in the alkylation distillation section.

The quantity of isooctane and alkylate produced is limited to the amount of light olefins generated in the refinery. Typically refineries have just enough alkylation capacity to process all of the light olefins. A typical refinery might produce an amount of alkylate equal to 15% of its gasoline.

In California refineries, many grades and types of gasoline are produced. These include regular and premium CBG, RFG or CBG for Arizona, and conventional gasoline. CBG must satisfy the Predictive Model, RFG the EPA complex model, and all gasoline must satisfy ASTM specifications.

To be able to satisfy the emissions and ASTM requirements and meet demand for the various types and grades, refiners further process the gasoline streams. This generally involves additional distillation steps. To aid in satisfying distillation criteria and compositional requirements, the various wider boiling streams are separated into two or three narrower boiling cuts.

- The saturated light gases from the crude unit, reformer, and hydrocracker and straight run gasoline are collected and may be separated into several streams including fuel gas, LPG, butanes, pentanes, light and heavy naphtha. Pentanes may be removed for RVP control or isomerized to increase their octane content.

- The unsaturated light gases from the FCC and coker are collected and separated into fuel gases, C3 and C4 light olefins for alkylation, and debutanized FCC gasoline. This stream can also be depentanized to control the RVP and olefin content of the FCC gasoline stream.
- FCC naphtha might be cut into light (to 220F), medium (220 to 320F) and heavy (300F to 400+F). To allow for RVP control, the most volatile streams are carefully distilled to remove the last traces of butanes and to concentrate pentanes. The majority of the olefins are present in the light FCC gasoline while the majority of the aromatics and sulfur are present in the heavy FCC gasoline.

Because of toxics restrictions, control of benzene in refinery streams is important. Benzene boils at about 180F. Its concentration can be lowered by a variety of pretreatment and post treatment steps for the various streams. In California, benzene is destroyed instead of recovered as there is a limited petrochemical market.

Appendix C

Table C-1 Summary of California Refinery Capacity from 2000 Oil and Gas Journal Worldwide Refining Survey
Note: Capacities may differ from Table 3 reported by the CEC

Company	City	Unit Capacity bbl/cd					
Southern District		Crude	Vacuum	Coking	FCC	Catalytic Reforming	H-cracking
Chevron US	El Segundo	260,000	120,000	64,000	62,000	40,000	45,000
Arco Products Co	Los Angeles	260,000	130,000	65,000	96,000	52,000	43,000
ExxonMobil Refg & Supply Co	Torrance	148,500	98,000	50,500	88,500	19,000	23,000
Tosco Refining Co	Wilmington & Carson	131,000	78,000	48,000	45,000	35,200	24,750
Equilon Enterprises LLC	Wilmington	98,500	58,000	41,000	35,000	29,500	29,000
UDS Refining	Wilmington	78,800	44,000	28,000	52,000	16,000	0
Wilmington	Paramount	45,000	26,500	0	0	7,500	0
World oil	South Gate	7,000	7,125	0	0	0	0
Huntway Refining Co	Wilmington	6,000	5,000	0	0	0	0
Tenbyinc.	Oxnard	4,000	0	0	0	0	0
		1,038,800	566,625	296,500	378,500	199,200	164,750
Northern District							
Chevron	Richmond	225,000	110,000	0	65,000	45,000	109,000
Equilon	Martinez	154,800	102,400	44,600	68,700	28,200	33,800
Equilon	Bakersfield	61,750	37,050	19,800	0	13,200	18,900
Golden Bear	Oildale	12,500	11,500	0	0	0	0
Santa Maria Refining Co	Santa Maria	10,000	6,000	0	0	0	0
Huntway	Benecia	10,000	7,500	0	0	0	0
Kern Oil	Bakersfield	25,000	0	0	0	3,000	0

San Joaquin Refining	Bakersfield	24,300	14,300	10,000	0	0	0
Tosco	Rodeo and Santa Maria	115,000	70,400	42,200	0	30,600	32,000
UDS	Martinez	168,000	102,000	42,000	66,500	40,000	32,000
Valero	Benecia	135,000	68,500	29,000	72,000	36,000	35,000
		941,350	529,650	187,600	272,200	196,000	260,700

Table C-1 Continued

	Unit Capacity bbl/cd								
Company	Hydrotreating for gasoline manufacture					Octane and Olefins Conversion			
Southern District	Reformer feed	Naphthas	Aromatics Saturation	FCC Feed	FCC Gasoline	Alkylation	Polygas	C5+ Isom	Oxygenates
Chevron US	52,000	0	0	90,000	18,000	21,000	0	19,000	4,300
Arco Products Co	40,000	27,000	0	90,000	0	15,000	2,800	20,000	2,500
ExxonMobil Refg & Supply Co	22,000	0	0	99,000	0	23,000	0	0	0
Tosco Refining Co	50,850	0	0	0	0	9,450	0	12,200	0
EQUILON ENTERPRISES LLC	0	0	8,500	30,000	0	8,700	0	0	0
UDS Refining	30,000	0	0	62,000	0	15,000	0	0	0
Wilmington	0	9,500	0	0	0	0	0	0	0
World oil	0	0	0	0	0	0	0	0	0
Huntway Refining Co	0	0	0	0	0	0	0	0	0
Tenbyinc.	0	0	0	0	0	0	0	0	0
	194,850	36,500	8,500	371,000	18,000	92,150	2,800	51,200	6,800
Northern District									
Chevron	55,000	0	0	0	0	20,000	1,800	25,000	4,800
Equilon Martinez	26,000	0	17,600	45,200	0	10,200	2,300	14,400	0
Equilon Bakersfield	11,250	0	0	0	0	0	0	0	0

Golden Bear	0	0	0	0	0	0	0	0	0
Santa Maria Refining Co	0	0	0	0	0	0	0	0	0
Huntway	0	0	0	0	0	0	0	0	0
Kern Oil	4,500	0	2,000	0	0	0	0	0	0
Tosco	20,700	0	0	0	0	0	0	9,000	0
UDS	23,000	0	7,000	0	0	15,000	0	0	2,300
Valero	29,000	44,000	11,000	21,000	0	15,000	2,500	0	3,500
Northern Total	169,450	44,000	37,600	66,200	0	60,200	6,600	48,400	10,600

Appendix D
Analysis of Pentane Economics:

1. Economics of substituting Pentanes for Methane in hydrogen manufacture. Assume for equal hydrogen production, only cost difference is feedstock cost for both hydrogen production and reformer firing. We assume $11 per barrel loss for sale of pentanes to market compared to sale in gasoline blend value.

Case 1: Pentanes sold at market value of blendstock and NG purchased for hydrogen
Case 2: Pentanes fired at gasoline value.

For hydrogen manufacture, assume 67% thermal efficiency.
1 BBL of pentanes is 0.63*8.33*42 = 220.4 #.
By stoichiometry, 72 # pentane produces 32 # H2.
Adjusting for efficiency, 1 bbl produces 65.63 # H2/2# per mole* 379 SCF/mole
1 bbl of pentanes produces 12,400 scf of hydrogen.
By stoichiometry, 1 mole of methane produces 4 moles of hydrogen.
Adjusting for efficiency, 4*1000*0.67
1000 scf of methane produces 2,680 scf of hydrogen.
Therefore, 12,400/2680*1000 =4.627 Mscf of natural gas produces the same hydrogen as a barrel of pentane.
Thus, the breakeven price of gas is $11/4.627 = $2.38. If gas exceeds $2.38 per MSCF (per MM BTU), it is more economical to generate hydrogen from pentanes.

Appendix E:

PAD 5 Supply and demand for 1999

In order to understand the structure of the California refining industry, data were analyzed from the EIA 1999 Petroleum Supply Annual (PSA), the 1999 Petroleum Marketing Annual (PMA) and the Oil and Gas 2000 refinery survey. Additionally, data presented specifically for California refinery production were utilized from the California Energy Commission "Monthly California Refining Industry Operating Report" for 1999. Table E-1 summarizes supply data in thousands of barrels per year with Hawaii and Alaska removed.

Table E-1
Supply of Gasoline in PAD 5
(from Table 12, 1999 PSA)
Quantities in Thousands of Barrels

	Stocks	Exports	Product Supplied Entire PAD	Product Supplied w/o Ak, Hawaii	Total
RFG	89	120	350,225	350,225	350,434
Oxy	42	390	40,041	38,736	40,473
CG	(842)	1,958	134,969	120,499	136,085
Total	(711)	2,468	525,235	509,460	526,992

	Field	Refinery	Imports	Net Receipts	Total
RFG	-	347,131	3,263	40	350,434
Oxy	18,554	16,238	-	5,681	40,473
CG	(13,365)	115,230	8,517	25,703	136,085
Total	5,189	478,599	11,780	31,424	526,992

In Table E-1, imports (exports) refers to material received (sent to) from foreign suppliers. Net receipts are materials that enter the PAD from other US refining districts by barge, rail and pipeline. Field production represents production of oxygenated gasoline (most likely at terminals) by addition of oxygenate and other blendstock to conventional gasoline.

Table E-2 provides gasoline use data by state, type and grade of gasoline in thousands of gallons per day. The last column provides total demand in thousands of barrels per year. Because of data sampling errors, there is a slight difference between total supply and demand. In order to further analyze the data, the demand data were normalized to the supply by type of gasoline.

The refining capacity in Hawaii and Alaska were examined and it was estimated that these two states were essentially self-sufficient in terms of gasoline production capability based upon the state demands. In terms of the contiguous states, California, Washington Arizona, Nevada, and Oregon, only the first two have any refining capacity.

California is a net exporter of reformulated gasoline to Arizona and conventional gasoline to the remaining states. Washington's refining capacity is inadequate to meet the state gasoline demand.

The gasoline use in Northern and Southern Nevada is estimated using census population data for the nine metropolitan areas in the state. 70.3% of the gasoline is estimated to be used in Southern Nevada.

Figure E-3 represents supply and demand in PAD 5. In the picture, it is assumed that all Arizona and Southern Nevada gasoline not produced in California refineries comes directly from stocks, imports and net receipts either from Texas or from the Port of Los Angeles by pipeline. In addition, Southern California refineries ship the necessary reformulated gasoline and all the oxygenated gasoline produced in California by pipeline. No conventional gasoline beyond that derived from imports and net receipts is required. The additional oxygenated gasoline required in Arizona and Southern Nevada is produced by field terminal blending.

California uses a small quantity of conventional gasoline. The remaining conventional gasoline produced in California is nearly sufficient to satisfy the demand in Washington, Oregon and Northern Nevada. In these states, all oxygenated fuel is produced by field blending conventional gasoline with oxygenate and other blendstock. A small quantity of imported or net receipt conventional gasoline, shown as an input to California, is passed directly through to Oregon and Washington. This gasoline could also be directly shipped to those states.

This picture supports the idea that Northern California refineries are responsible for producing and distributing most of the California conventional gasoline.

Table E-2
Demand for Gasoline in PAD 5

Source; Table 48 1999 Petroleum marketing Annual

Thousands of gallons /day

State	Conventional Gasoline			Oxygenated Gasoline			Reformulated Gasoline			Total Gasoline			MBBL
	REG	MID	PREM	REG	MID	PREM	REG	MID	PREM	REG	MID	PREM	
Alaska	622.40	14.25	-	51.30	14.25	82.30		-	-	673.70	28.50	82.30	6,818
Arizona	1,336.60	125.90	187.00	851.50	102.20	148.10	2,170.40	330.40	401.40	4,358.50	558.50	736.50	49,132
California	469.50	-	-	-	-	-	27,954.00	4,972.70	6,302.70	28,423.50	4,972.70	6,302.70	345,002
Hawaii	598.30	111.70	262.50	-	-	-	-	-	-	598.30	111.70	262.50	8,451
Nevada	1,409.40	123.95	248.00	494.20	123.95	125.00	-	-	-	1,903.60	247.90	373.00	21,939
Oregon	2,824.60	208.70	357.10	738.10	57.50	83.40	-	-	-	3,562.70	266.20	440.50	37,103
Washington	4,578.20	659.70	871.80	1,399.80	121.70	141.70	-	-	-	5,978.00	781.40	1,013.50	67,550
Total	11,839.00	1,244.20	1,926.40	3,534.90	419.60	580.50	30,124.40	5,303.10	6,704.10	45,498.30	6,966.90	9,211.00	535,996

Figure E-3 1999 Supply and Demand Balance for PAD 5 (R= reformulated, O=oxygenated, C=conventional)
Quantities are 1000 Barrels

Oregon & Washington

Type	Inputs	Field	Refinery	Supply	Demand
R			-		-
O	0	10,051	12,395	22,446	22,446
C	23,399	(7,240)	69,268	85,427	85,427

California

Type	Inputs	Refinery	Demand	Transfers
R	0	347,131	326,100	21,031
O	0	2,538	-	2,538
C	2,282	31,492	4,222	29,552

Reno

Type	Inputs	Field	Supply	Demand
R	-	-	-	-
O	-	1,946	1,946	1,946
C	6,154	(1,402)	4,752	4,752

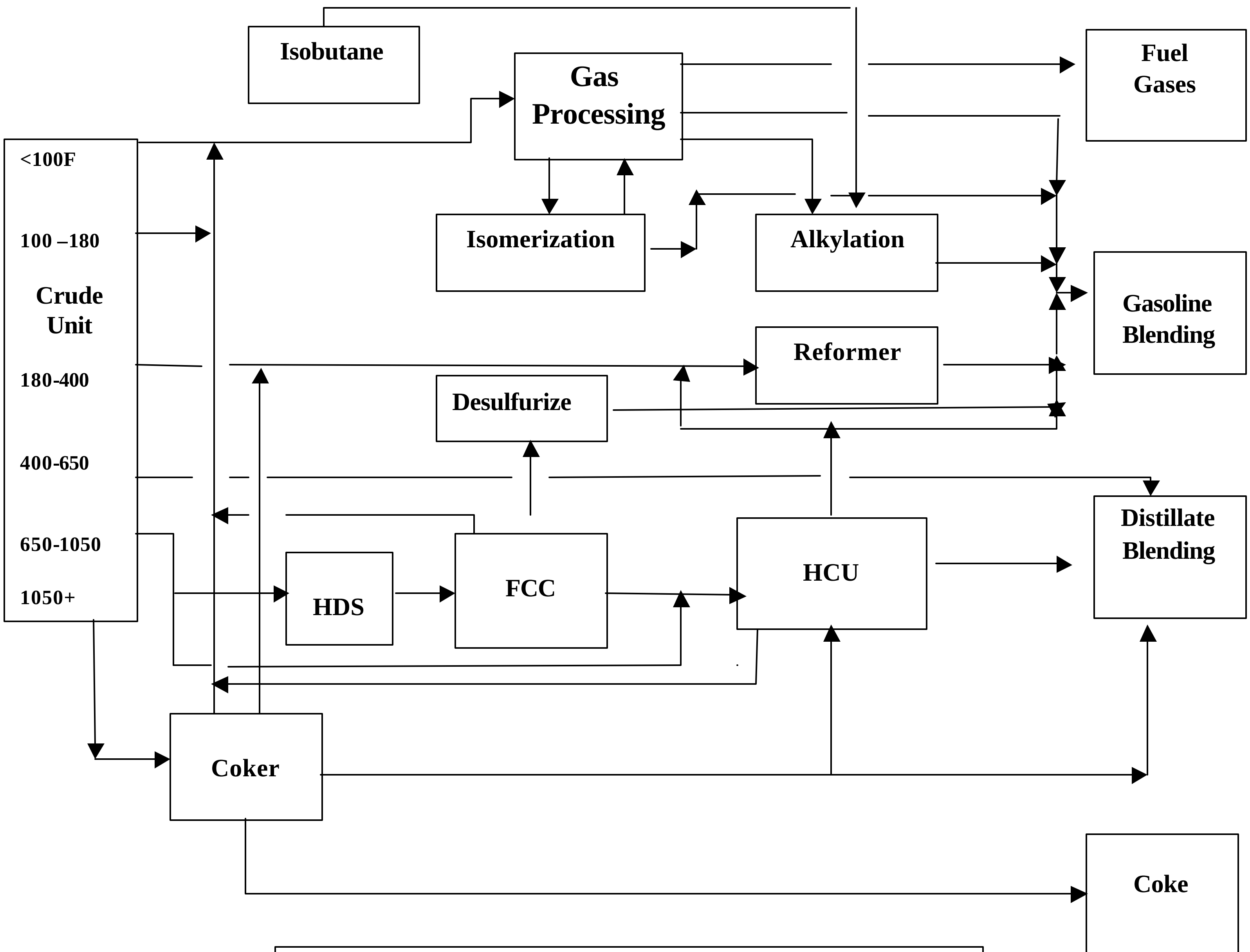
Stocks, Imports and Receipts

TYPE	Stocks	Imports	Receipts	Total
R	-89	3143	40	3094
O	-42	-390	5681	5249
C	842	6559	25703	33104

Arizona & Las Vegas

Type	Inputs	Field	Supply	Demand
R	24,125	0	24,125	24,125
O	7,787	6,556	14,343	14,343
C	30,822	(4,723)	26,099	26,099

Appendix F:
Refinery Flow Diagram



Refinery Process Flow Diagram