MathPro

FINAL REPORT

REFINING ECONOMICS OF A NATIONAL CLEAN GASOLINE STANDARD FOR PADDS 1-3

A study performed for

The Alliance of Automobile Manufacturers

by

MathPro Inc.

P.O. Box 34404
West Bethesda, Maryland 20827-0404

June 27, 2008

Table A-1: Petroleum Refining Capacity for PADDs 1-3, 2002 & 2006
(K b/calendar day, except as noted)

Type of Process	Process	2002 PADD 1	2002 PADD 2	2002 PADD 3	2006 1	2006 2	2006 3
Crude Distillation	Atmospheric	1,586	3,508	7,684	1,589	3,554	8,390
	Vacuum	613	1,420	3,527	638	1,503	3,815
Conversion	Coking						
	Delayed	44	358	1,074	44	358	1,168
	Fluid	47		14	47	16	63
	Other			38			39
	Fluid Cat Cracking	685	1,175	2,818	692	1,165	2,937
	Hydrocracking						
	Distillate		116	406		160	575
	Resid	18		245	39		102
	Lube			38			46
	Other	20	37	73		33	
	Visbreaking			12			
	Thermal Cracking						10
Upgrading	Alkylation	85	245	545	97	251	581
	Pen/Hex Isomerization	17	157	229	17	172	233
	Reforming	285	840	1,699	294	840	1,718
	Polymerization	18	5	17	18	5	15
	Dimersol		3	4		3	7
Ether Production	MTBE	7	9	73	3	4	27
	TAME	2	0	12			3
Hydrotreating	Naphtha Feed	342	1,002	1,847	348	1,035	2,238
	Naphtha/Aromatics Sat.		10			10	11
	FCC Naphtha	67	22	77	324	332	1,083
	Kerosene & Distillate	381	863	1,979	479	1,067	2,213
	Distillate/Aromatics Sat.	171	344	581		18	26
	FCC Feed/Heavy Gas Oil	89	476	1,121	44	524	1,279
	Resid			224	10		316
	Lube Oil	1	27	73	1	24	89
	Other	14	12	127	16	3	224
Other	BTX Plant	41	48	189	41	50	233
	Other Aromatics	12	8	50	12	8	46
	Butane Isomerization	22	26	108	38	24	109
	Hydrogen (MM scf/d)[1]	99	425	1,508	112	795	1,653
	Lube Oil	19	17	138	19	17	148
	Solvent Deasphalting	19	16	200	20	16	200
	Coke (K t/d)	4	18	63	5	20	70
	Sulfur Recovery (K Sh t/d)	1.3	4.7	16.2	1.3	5.2	19.4
	Asphalt	28	231	125	28	245	125
Complexity		8.4	9.3	10.5	9.0	9.7	10.5

1 Includes production and recovery.

Sources: Capacity derived from 2002 & 2006 "Worldwide Refinery Surveys," *Oil & Gas Journal*, Dec. 23, 2002 & Dec. 18, 2006; and DOE 2002 & 2006 Refinery Capacity Surveys (DOE Website).

Complexity: Derived using Generalized Complexity Index Scores from *Oil & Gas Journal*, March 18, 1996, p. 74-80.

Table A-2a: Refinery Inputs, Process Feeds & Crude Oil Properties, by PADD, 2002
(K b/d)

Inputs	Summer							
	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	PADDs 4&5 ex Calif.	California	U.S.
Refinery Inputs:	**1,946**	**3,499**	**7,772**	**563**	**2,936**	**1,534**	**1,964**	**16,716**
Crude Oil	**1,588**	**3,371**	**7,147**	**530**	**2,665**	**1,406**	**1,790**	**15,301**
Natural Gas Liquids	**3**	**80**	**248**	**13**	**62**	**66**	**10**	**407**
Pentanes Plus		42	139	4	25	29		211
Liquified Petroleum Gases	3	38	109	9	37	37	10	196
Ethane								
Propane								
Normal Butane	0	4	34	4	24	24	4	66
Isobutane	3	34	74	5	13	13	6	130
Other Liquids	**888**	**346**	**617**	**16**	**225**	**76**	**164**	**1,641**
Other Hydrocarbons/H2/Oxy	73	43	127	3	138	36	105	385
Other Hydrocarbons/H2		2	31	1	28	29		61
Oxygenates[1]	73	42	97	2	110	7	105	324
Fuel Ethanol	w	38	w	w	w	w	9	50
Methanol	w	w	w	w	w	w		0
MTBE	69	w	93	w	100	w	96	266
Other	w	w	w	w	w	w		7
Unfinished Oils -- Total	77	33	374	4	38	4	38	526
Naphtha	1		30					
Kerosene	0		2					
Gas Oils	69		232					
Residuum	7		110					
Motor Gasoline Blend. Comp.	332	135	-129	4	24	7	22	366
Input to Refinery/Blenders	208	-28	-125	12	32	22	22	99
Input to Field Blending[2]	124	163	-5	-8	-7	-15		267
Aviation Gasoline Blend. Comp.	-3	0	0					-3
Est. Ethanol in Field-Blnd Gas	5	46	3	4	7	11	0	66
Process Feeds								
Catalytic Cracking	586	1,169	2,743	138	768	-	-	5,404
Catalytic Hydrocracking[3]	39	142	599	3	483	-	-	1,266
Delayed and Fluid Coking	77	328	1,001	39	512	-	-	1,958
Crude Oil Properties								
Sulfur Content (wtg avg %)	0.88	1.30	1.63	1.41	1.21	1.15	1.58	1.40
API Gravity (degrees)	31.7	32.8	29.7	33.0	27.5	30.7	23.7	30.3
Specific Gravity	0.867	0.861	0.878	0.860	0.890	0.872	0.912	0.875

Note: "w" indicates data have been withheld
1 Does not include ethanol not otherwise reported by refineries.
2 Negative number indicates field production.
3 Includes feed to resid and lube hydrocrackers.
Sources: Derived from Tables 16, & 22-25, *Petroleum Supply Annual* 2002, *DOE/EIA;* Tables 2-23 & 28, *2002 Petroleum Supply Monthlys, DOE/EIA; CEC Weekly Refinery Reports; and Table A-7a.*

Table A-2b: Refinery Net Production, by PADD, 2002

(K b/d)

Products	Summer							
	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	PADDs 4&5 ex Calif.	California	U.S.
Refinery Outputs:	**2,081**	**3,729**	**7,889**	**547**	**2,865**	**1,413**	**1,999**	**17,112**
Liquified Refinery Gases	**115**	**276**	**864**	**17**	**150**	**94**	**72**	**1,423**
Ethane/Ethylene			24					24
Ethane			17					17
Ethylene			7					7
Propane/Propylene	48	116	356	8	56	25	40	585
Propane	31	82	178	8	56	25	40	355
Propylene	17	34	178				0	229
Normal Butane/Butylene	24	46	118	2	34	7	30	224
Normal Butane	22	44	111	2	32	7	28	211
Buytlene	1	3	7	0	2	0	2	13
Isobutane/Isobutylene	-4	-3	11	-2	3	-2	3	5
Isobutane	-3	-2	8	-1	2	-1	2	4
Isobutylene	-1	-1	3	-1	1	-1	1	1
Finished Petroleum Products	**1,966**	**3,453**	**7,024**	**531**	**2,715**	**1,319**	**1,927**	**15,689**
Finished Motor gasoline	1,155	2,058	3,658	279	1,499	614	1,164	8,649
Reformulated	610	339	662		1,086	37	1,048	2,697
Oxygenated	11	183	1	12	6	17	0	213
Other	404	1,327	2,996	271	408	564	115	5,406
Field Oxygenated	53	460	33	39	72	112		657
Field Other	77	-251	-34	-43	-72	-116		-324
Finished Aviation Gasoline	0	5	10	0	3	1	2	18
Jet Fuel	87	220	757	25	433	189	269	1,521
Naphtha-Type					0	0		0
Kerosene-Type	87	220	757	25	433	189	269	1,521
Kerosene	11	5	25	0	4	4		44
Distillate Fuel Oil	466	850	1,635	159	507	339	327	3,617
CARB Diesel					210		210	
0.05 % sulfur & under	261	654	1,180	131	200	216	116	2,637
Greater than 0.05 % sulfur	206	195	455	28	97	124	1	980
Residual Fuel Oil	89	57	260	11	160	91	80	577
Less than 0.31 % sulfur	40		22	1	6	4	3	70
0.31 to 1.00 % sulfur	41	8	31	2	53	28	26	134
Greater than 1.00 % sulfur	7	49	207	8	102	58	51	372
Naphtha to Petrochemical	16	21	205		3	3	0	246
Other Oils to Petrochemical		0	137	1	8	1	8	146
Special Naphthas	2	17	29		1	0	2	50
Lubricants	17	15	124		24	0	24	180
Waxes	1	4	11	3		5	-2	17
Petroleum Coke	48	138	423	17	160	31	146	786
Marketable	18	89	305	9	121	15	116	542
Catalyst	31	49	118	7	39	16	30	244
Asphalt and Road Oil	121	190	132	52	64	70	46	560
Still Gas	67	137	329	21	152	56	117	706
Miscellaneous Products	1	12	41	2	7	1	8	63

Note: Refinery Outputs and Finished Petroleum Products exclude petroleum coke and still gas.

Sources: Derived from Tables 17, *Petroleum Supply Annual* 2002, *DOE/EIA; and* Tables 2-23 & 29, *Petroleum Supply Monthly, Feb. 2003, DOE/EIA; and CEC Weekly Refinery Reports.*

Table A-3a: Allocation of Annual Gasoline Use by Region, State, and Gasoline Type, 2002
(K b/d)

Region & State	Gasoline Type: Conven-tional	EtOH Mandate (Minn.)	Low RVP Areas 7.8	7.2	7.0	Federal RFG	California RFG Federal Area	California RFG State Area	Arizona CBG	Total
PADD 1	**1,346**	**0**	**446**	**0**	**170**	**1,184**	**0**	**0**	**0**	**3,146**
Subdistrict 1A	**54**	**0**	**28**	**0**	**0**	**330**	**0**	**0**	**0**	**413**
Connecticut						98				98
Maine	19		28							47
Massachusetts						176				176
New Hampshire	13					32				45
Rhode Island						25				25
Vermont	23									23
Subdistrict 1B	**361**	**0**	**72**	**0**	**0**	**720**	**0**	**0**	**0**	**1,153**
Delaware						26				26
District of Columbia						10				10
Maryland	18					141				159
New Jersey						252				252
New York	166					201				367
Pennsylvania	177		72			88				337
Subdistrict 1C	**931**	**0**	**346**	**0**	**170**	**134**	**0**	**0**	**0**	**1,580**
Florida	269		253							522
Georgia	154				170					324
North Carolina	189		93							282
South Carolina	153									153
Virginia	112					134				246
West Virginia	54									54
PADD 2	**1,653**	**178**	**269**	**17**	**58**	**362**	**0**	**0**	**0**	**2,536**
Illinois	113			17		207				338
Indiana	176		6			26				208
Iowa	105									105
Kansas	62				18					80
Kentucky	106					35				140
Michigan	172		166							337
Minnesota		178								178
Missouri	118				40	48				206
Nebraska	58									58
North Dakota	24									24
Ohio	345									345
Oklahoma	90		27							117
South Dakota	30									30
Tennessee	131		70							202
Wisconsin	122					46				168
PADD 3	**615**	**0**	**353**	**0**	**59**	**283**	**0**	**0**	**0**	**1,310**
Alabama	139				31					170
Arkansas	95									95
Louisiana	74		78							152
Mississippi	106									106
New Mexico	62									62
Texas	140		275		28	283				726
PADDs 4 & 5 ex CA	**471**	**0**	**289**	**0**	**0**	**0**	**0**	**0**	**99**	**859**
Alaska	17									17
Arizona	71								99	170
Colorado	61		76							138
Hawaii	29									29
Idaho	38									38
Montana	29									29
Nevada[1]	57		12							69
Oregon	53		52							105
Utah	14		46							60
Washington	82		102							184
Wyoming	20									20
CALIFORNIA							**731**	**267**		**998**
UNITED STATES	**4,085**	**178**	**1,357**	**17**	**287**	**1,829**	**731**	**267**	**99**	**8,849**

1 Nevada reports a small volume of RFG sales. We assume this is spillover of CaRFG and report it as State Area CaRFG.

Note: Gasoline is classified by the area into which it is sold. Volumes reflect year-long (annual, rather than seasonal) sales to those areas.

Sources: Derived from *Petroleum Marketing Annual 2002* and EPA-provided information on gasoline allociations.

Table A-3b: Estimated Annual Gasoline Use and Supply Sources, by Region and Type of Gasoline, 2002 (K b/d)

Region of Use & Origin of Supply	Gasoline Type								Total
	Conven-tional	EtOH Mandate (Minn.)	Low RVP Areas		Federal RFG	California RFG		Arizona CBG	
			7.8	7.0[1]		Federal Area	State Area		
Use in PADD 1	**1,346**		**446**	**170**	**1,184**				**3,146**
PADD 1 Refineries	212		72		637				921
PADD 2 Refineries	23								23
PADD 3 Refineries	907		346	170	320				1,742
Net Imports	204		28		227				459
Use in Subdistrict 1A	**54**		**28**		**330**				**413**
PADD 1 Refineries	40		0		154				194
PADD 3 Refineries									0
Net Imports	15		28		176				219
Use in Subdistrict 1B	**361**		**72**		**720**				**1,153**
PADD 1 Refineries	152		72		474				698
PADD 2 Refineries	23								23
PADD 3 Refineries	132				198				330
Net Imports	53				48				101
Use in Subdistrict 1C	**931**		**346**	**170**	**134**				**1,580**
PADD 1 Refineries	20				9				29
PADD 3 Refineries	775		346	170	122				1,412
Net Imports	136				3				139
Use in PADD 2	**1,653**	**178**	**269**	**75**	**362**				**2,536**
PADD 1 Refineries	202								202
PADD 2 Refineries	1,206	178	193	46	318				1,940
PADD 3 Refineries	223		76	29	44				372
PADD 4 Refineries	19								19
Net Imports	2								2
Use in PADD 3	**615**		**353**	**59**	**283**				**1,310**
PADD 2 Refineries	18				17				35
PADD 3 Refineries	691		353	59	270				1,373
Net Imports	-94				-4				-98
Use in PADDs 4 & 5 ex CA	**471**		**289**					**99**	**859**
PADD 2 Refineries	24								24
PADD 3 Refineries -- direct	37		29					21	86
-- via Cali	8								8
PADD 4 & 5 (ex CA) Ref.	312		248						560
California Refineries	84		12					78	174
Net Imports	6								6
Use in California	**0**					**731**	**267**		**998**
PADD 4 & 5 (ex CA) Ref.						22			22
California Refineries	2					705	267		975
Net Imports	-2					4			2
TOTAL USE	**4,085**	**178**	**1,357**	**303**	**1,829**	**731**	**267**	**99**	**8,849**
Refinery Production	**3,969**	**178**	**1,329**	**303**	**1,606**	**727**	**267**	**99**	**8,478**
PADD 1	414		72		637				1,124
PADD 2	1,272	178	193	46	334				2,023
PADD 3	1,866		804	257	634			21	3,582
PADDs 4 & 5 ex CA	331		248			22			601
California	86		12			705	267	78	1,149
Net Imports	**116**		**28**		**223**	**4**			**371**

1 Includes small volume (14 K b/d) of gasoline sold to an area in PADD 2 with an RVP limit of 7.2 psi.
Source: Derived from Table A-3a and *Petroleum Supply Annual, 2002* .

Table A-3c: Estimated Gasoline Production Volume, RVP, and Octane, by Type of Gasoline, Destination, and Region 2002

Producing Region, Type of Gasoline, & Destination	Production				RVP		Grade Splits		Pool Octane
	Annual (K b/d)	Share (%)	Summer (K b/d)	Winter (K b/d)	Summer	Winter	Reg	Prem	(R+M)/2
PADD 1 Refineries	**1,124**	**100.0%**	**1,129**	**1,117**	**7.6**	**14.1**	**82%**	**18%**	**87.9**
Conventional	414	36.9%	407	425	8.7	14.0	84%	16%	87.8
Subdistrict 1A	40		39	41	8.7	14.3	84%	16%	
Subdistrict 1B	152		150	156	8.7	14.2	79%	21%	
Subdistrict 1C	20		20	21	8.7	13.0	80%	20%	
PADD 2	202		198	207	8.7	13.8	87%	13%	
7.8 RVP Areas	72	6.4%	71	74	7.6	14.2	79%	21%	88.0
Subdistrict 1A	0		0	0	7.6	14.3	84%	16%	
Subdistrict 1B	72		71	74	7.6	14.2	79%	21%	
PADD 2					7.6	13.8	87%	13%	
RFG	637	56.7%	651	618	6.8	14.2	80%	20%	88.0
Subdistrict 1A	154		158	150	6.8	14.3	84%	16%	
Subdistrict 1B	474		484	459	6.8	14.2	79%	21%	
Subdistrict 1C	9		9	9	6.8	13.0	80%	20%	
PADD 2 Refineries	**2,023**	**100.0%**	**2,059**	**1,991**	**8.2**	**13.8**	**87%**	**13%**	**87.6**
Conventional	1,449	71.7%	1,474	1,428	8.7	13.8	87%	13%	87.6
PADD 1	23		24	23	8.7	14.2	79%	21%	
EtOH Mandate (Minnesota)	178		181	175	8.7	13.8	87%	13%	
PADD 2 other	1,206		1,227	1,189	8.7	13.8	87%	13%	
PADD 3	18		19	18	8.7	12.6	85%	15%	
PADDs 4&5 ex CA	24		25	24	8.7	13.0	83%	17%	
7.8 RVP Areas	193	9.5%	196	190	7.6	13.8	87%	13%	87.6
7.0 RVP Areas[1]	46	2.3%	47	45	6.8	13.8	87%	13%	87.6
RFG	334	16.5%	342	328	6.8	13.7	87%	13%	87.6
PADD 2	318		325	312	6.8	13.8	87%	13%	
PADD 3	17		17	16	6.8	12.6	85%	15%	
PADD 3 Refineries	**3,582**	**100.0%**	**3,649**	**3,525**	**8.0**	**13.0**	**83%**	**17%**	**87.9**
Conventional	1,866	52.1%	1,901	1,836	8.7	13.0	83%	17%	87.9
Subdistrict 1B	132		135	130	8.7	14.2	79%	21%	
Subdistrict 1C	775		789	762	8.7	13.0	80%	20%	
PADD 2	223		227	220	8.7	13.8	87%	13%	
PADD 3	597		608	587	8.7	12.6	85%	15%	
PADDs 4&5 ex CA	45		46	44	8.7	13.0	83%	17%	
Net Exports	94		96	93	8.7	12.6	85%	15%	
7.8 RVPAreas	804	22.4%	819	791	7.6	12.9	83%	17%	87.9
Subdistrict 1B									
Subdistrict 1C	346		352	340	7.6	13.0	80%	20%	
PADD 2	76		77	75	7.6	13.8	87%	13%	
PADD 3	353		360	347	7.6	12.6	85%	15%	
PADDs 4&5 ex CA	29		29	28	7.6	13.0	83%	17%	
7.0 RVP Areas	257	7.2%	262	253	6.8	13.0	82%	18%	87.9
Subdistrict 1C	170		173	167	6.8	13.0	80%	20%	
PADD 2	29		30	29	6.8	13.8	87%	13%	
PADD 3	59		60	58	6.8	12.6	85%	15%	
RFG	634	17.7%	646	625	6.8	13.2	82%	18%	87.9
Subdistrict 1B	198		202	195	6.8	14.2	79%	21%	
Subdistrict 1C	122		124	120	6.8	13.0	80%	20%	
PADD 2	44		45	44	6.8	13.8	87%	13%	
PADD 3	266		271	262	6.8	12.6	85%	15%	
Net Exports	4		4	4	6.8	13.0	85%	15%	
Arizona CBG	21	0.6%	21	20	6.8	11.4	83%	17%	87.8
PADDs 4 & 5 ex CA Refineries	**601**	**100.0%**	**613**	**592**	**8.2**	**13.0**	**83%**	**17%**	**87.8**
Conventional	331	55.1%	329	332	8.7	13.0	83%	17%	87.4
7.8 RVP	248	41.2%	247	249	7.6	13.0	83%	17%	87.4
California RFG	22	3.7%	37	12	6.8	12.6	80%	20%	88.0
California Refineries	**1,149**	**100.0%**	**1,184**	**1,117**	**7.0**	**12.5**	**81%**	**19%**	**88.0**
Conventional	86	7.5%	103	72	8.7	13.0	83%	17%	87.8
PADDs 4&5 ex CA	84		100	70	8.7	13.0	83%	17%	
Net Exports	2		2	2	8.7	12.5	80%	20%	
7.8 RVP Areas	12	1.1%	14	10	7.6	13.0	83%	17%	87.8
California RFG	973	84.7%	974	969	6.8	12.5	80%	20%	88.0
Arizona CBG	78	6.8%	93	65	6.8	11.4	83%	17%	87.8
TOTAL U.S.	**8,478**	**100.0%**	**8,634**	**8,342**	**7.9**	**13.3**	**83%**	**17%**	**87.8**
Conventional	4,146	48.9%	4,214	4,093	8.7	13.4	84.4%	15.6%	87.7
7.8 RVPAreas	1,329	15.7%	1,347	1,314	7.6	13.1	83.4%	16.6%	87.7
7.0 RVP Areas	303	3.6%	309	299	6.8	13.1	82.7%	17.3%	87.9
RFG	1,606	18.9%	1,639	1,570	6.8	13.7	82.4%	17.4%	87.9
California RFG	995	11.7%	1,011	981	6.8	12.5	80.1%	19.9%	88.0
Arizona CBG	99	1.2%	114	85	6.8	11.4	83.3%	16.7%	87.8

Notes: RVPs incorporate typical refinery safety factors of about 0.2 psi

Production of ethanol-blended non-RFG is included in conventional gasoline

Production of gasoline blendstocks not included in totals (i.e., totals include only finished gasoline).

1 Includes small volume (14 K b/d) of gasoline sold to an area in PADD 2 with an RVP limit of 7.2 psi.

Source: Derived from Table A-3b, *Petroleum Supply Annual 2002* , and ASTM winter RVP standards.

Table A-3d: Estimated Gasoline Blendstock Use, 2002 (K b/d)

Source & Area of Use	Annual Average	Summer	Winter
Gulf Coast to:	**152**	**149**	**155**
PADD 1	3	7	
PADD 2	123	134	114
PADDs 4&5 ex CA	19	1	35
California	7	8	6
Puget Sound to:			
California[1]	7	8	6
Imports to:	**321**	**365**	**277**
PADD 1	284	313	252
PADD 3	24	37	14
PADDs 4&5 ex CA	2	1	3
California	11	14	8

Note: Imported GTAB contains little, if any, oxygenates, based on refinery production of finished gasoline, oxygen content of RFG and CG, and volume of purchased oxygenates

1 Assumed volume of intra-PADD shipments, not accounted for elsewhere.

Sources: Derived from *Petroleum Supply Annual, 2002* and DOE Company-Level Import Data.

Table A-4a: Crude Oil, Electricity, and Natural Gas Prices, 2002 and Projected 2010
($ 2004)

	2002	2010[5 6]
Crude Oil ($/b)[1]	**25.21**	**50.41**
PADD 1	26.08	51.28
PADD 2	26.42	51.62
PADD 3	24.93	50.13
Electricity (¢/Kwh)[3]	**5.1**	**6.0**
PADD 1	6.9	7.8
PADD 2	4.5	5.4
PADD 3	4.7	5.6
Natural Gas ($/mcf)[3]	**4.18**	**6.64**
PADD 1	5.89	8.35
PADD 2	5.31	7.77
PADD 3	3.76	6.22
Natural Gas ($/foeb)[3 4]	**26.33**	**41.81**
PADD 1	37.11	52.59
PADD 2	33.46	48.94
PADD 3	23.69	39.17
AEO Prices		
World Oil ($/b)		
All Imported Crudes	24.62	49.82
Imported low Sulfur Light Crude		55.93
Electricity to Industrial		
Customers (¢/Kwh)	5.1	6.0
Natural Gas ($/mcf)		
Wellhead	3.07	5.60
Industrial	4.12	6.64

1 Refiner acquisition cost of domestic and imported crude oil.
2 Acquisition cost reported for PADD 4 is assumed for PADDs 4&5 ex CA.
3 Prices to industrial customers.
4 Assumes 6.3 mcf per foeb.
5 Projected regional prices for crude oil estimated as 2012 projected U.S. price plus the 2004 regional price deltas.
6 Projected regional prices for electricity and natural gas estimated as the projected U.S. price plus average regional price deltas estimated over the period 2001 - 2004.

Sources: Derived from:
Table 1A, *Petroleum Marketing Annual 2004* , EIA/DOE;
Tables 1, 8, & 13, "Yearly Tables," *Annual Energy Outlook 2006, Early Release;*
Table 36, *Petroleum Supply Annual, 2004,* EIA/DOE;
Figure 7.7, Electric Power Annuals, 2001 to 2004, EIA/DOE;
Table 32, *Historical Natural Gas Annual 1930 through 1999; and*
Tables 23 & 24, *Natural Gas Annuals 2000 to 2004* , EIA/DOE.

Table A-4b: Crude Oil Acquisition Costs and Product Prices for Refinery Modeling, Summer 2002 & Projected 2010

($/b, $2004)

Region and Product	2002	2010
Crude Oil Acquisition Costs		
PADD 1	26.08	51.28
PADD 2	26.42	51.62
PADD 3	24.93	50.13
Prices for Refinery Modeling		
PADD 1		
Propane	21.79	38.30
Normal Butane	24.46	41.08
Iso-butane	24.86	41.47
Residual Oil: 1 wt% Sulfur	19.50	38.33
PADD 2		
Propane	19.74	37.31
Normal Butane	24.78	41.35
Iso-butane	25.18	41.74
Residual Oil > 3.5 wt% Sulfur	19.75	38.59
PADD 3		
Propane	17.90	39.72
Normal Butane	23.39	43.21
Iso-butane	23.79	43.75
Residual Oil: 1 wt% Sulfur	18.64	37.47

Source:
Crude Oil Prices: Table A-4a.
Other Prices: MathPro projections and ARMS modeling results.

Table A-5: Annual Supply of Major Refined Products, by PADD
(K b/d)

Product/Source	2002 PADD 1	2	3	PDs 4&5 ex Calif	Calif	U.S. Total
Gasoline	**3,146**	**2,536**	**1,309**	**676**	**1,180**	**8,848**
Refinery (& Field) Production	1,120	2,023	3,581	601	1,149	8,474
Net Blndstk Purchases	277	123	-148	12	18	282
Ref Production - Blndstk Pur	843	1,900	3,729	589	1,131	8,192
Net Imports	463	2	-98	6	1	374
Net Inter-PADD Shipments	1,564	511	-2,174	69	30	0
Jet Fuel & Kerosene	**578**	**333**	**207**	**233**	**305**	**1,657**
Refinery Production	99	228	800	189	262	1,578
Net Imports	49	0	-17	10	37	79
Net Inter-PADD Shipments	430	105	-577	35	7	0
Distillate Fuel Oil	**1,356**	**1,101**	**680**	**333**	**307**	**3,776**
Refinery Production	478	829	1,665	333	316	3,621
Net Imports	240	6	-67	-14	-10	155
Net Inter-PADD Shipments	638	266	-918	14	0	0
Residual Oil	**288**	**47**	**193**	**108**	**64**	**700**
Refinery Production	108	58	289	92	81	628
Net Imports	174	-1	-101	16	-17	72
Net Inter-PADD Shipments	7	-11	4		0	0
All Major Products	**5,368**	**4,017**	**2,389**	**1,350**	**1,856**	**14,980**
Refinery Production	1,805	3,138	6,336	1,215	1,808	14,300
Net Imports	926	8	-282	17	12	680
Net Inter-PADD Shipments	2,637	872	-3,665	119	37	0

Notes: Refinery production adjusted to include stock changes.
California includes refined products produced in California but sold in adj
(e.g., Arizona & Nevada)
Source: Derived from Tables 2-23, *Petroleum Supply Monthly, Feb. 2003,* EIA/D(
Weekly Refinery Fuels Reports for 2002, California Energy Commission

Table B-1: Petroleum Supply and Disposition -- Historical 2000-2005 and AEO 2007 Reference Case Forecast for 2010
(K b/d, except as noted)

Supply & Disposition	Historical 2000	2001	2002	2003	2004	2005	AEO Forecast 2010	Projected Growth 2004-2010 Cumulative	Annual
Crude Oil Supply	**14,840**	**15,050**	**14,880**	**15,340**	**15,529**	**15,271**	**15,659**	**0.8%**	**0.1%**
Domestic	5,820	5,740	5,740	5,690	5,468	5,178	5,665	3.6%	0.6%
Alaska	970	960	980	990	910	864	689	-24.3%	-4.5%
Lower 48	4,850	4,780	4,750	4,710	4,558	4,314	4,977	9.2%	1.5%
Net Imports	9,020	9,310	9,140	9,650	10,061	10,093	9,994	-0.7%	-0.1%
Liquids from Natural Gas Plants	**1,910**	**1,870**	**1,880**	**1,720**	**1,809**	**1,717**	**1,801**	**-0.5%**	**-0.1%**
Other Inputs[1]	**350**	**300**	**670**	**440**	**341**	**389**	**1,018**	**198.4%**	**20.0%**
Ethanol					221	255	692	213.3%	21.0%
Liquids from Coal					0	0	0	-	-
Other					120	134	326	170.9%	18.1%
Net Product Imports	**1,400**	**1,590**	**1,420**	**1,640**	**2,098**	**2,508**	**1,797**	**-14.3%**	**-2.5%**
Imports	2,390	2,540	2,390	2,600	3,057	3,578	3,025	-1.0%	-0.2%
Gross Refined Products[2]	2,040	2,080	1,610	1,850	2,069	2,449	1,781	-13.9%	-2.5%
Unfinished Oils	270	380	410	340	490	582	409	-16.5%	-3.0%
Ethers	80	80							
Ethanol					10	7	19	97.1%	12.0%
Gasoline Blending Components[3]			370	410	488	540	816	67.2%	8.9%
Exports	990	950	970	960	959	1,070	1,228	28.1%	4.2%
Refined Petroleum Products Supplied	**19,750**	**19,710**	**19,700**	**20,060**	**20,760**	**20,750**	**21,589**	**4.0%**	**0.7%**
LPG	2,231	2,044	2,163	2,074	2,132	2,030	2,218	4.0%	0.7%
E85	0	0	0	0	0	0	2	-	-
Motor Gasoline[4]	8,500	8,620	8,850	8,940	9,105	9,159	9,531	4.7%	0.8%
Jet Fuel	1,730	1,660	1,610	1,580	1,630	1,679	1,954	19.9%	3.1%
Distillate Fuel & Kerosene	3,670	3,880	3,790	3,930	4,058	4,118	4,532	11.7%	1.9%
Residual Oil	1,050	860	700	770	865	920	786	-9.2%	-1.6%
Other[5]	2,569	2,646	2,587	2,766	2,970	2,844	2,568	-13.5%	-2.4%
Energy Prices ($2004)									
Crude Oil ($/b)									
All Imported Crudes	30.00	23.51	24.62	28.46	36.09	47.87	49.82		
Imported Low Sulfur Light Crudes					41.72	55.24	55.93		
Natural Gas ($/mcf)									
Lower 48 Wellhead	3.90	4.35	3.07	5.08	5.64	7.31	5.60		
Industrial End-Use	4.79	5.28	4.00	5.77	6.68	8.43	6.63		
Electricity, Industrial End-Use (¢/Kwh)	5.0	5.1	5.2	5.3	5.3	5.5	6.0		
Domestic Refining									
Crude Distillation Capacity (K b/d)	16,600	16,800	16,800	16,800	16,947	17,126	17,822		
Capacity Utilization (%)	93.0	93.0	91.0	93.0	93.0	91.0	89.1		

Note: Projected growth rates are calculated using 2004 as the base year because of the impact of hurricane Katrina in 2005.

1 Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, and coal and natural gas converted to liquid fuel.

2 Includes non-ether, gasoline blending components for 1999-2001.

3 Includes imports of ethers in 2002 and thereafter.

4 Includes ethanol and ethers blended into gasoline.

5 Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas petroleum coke, crude oil product supplied, and miscellaneous petroleum products.

Source: Derived from Year-by-Year Tables 1, 8, 11, & 12, *Annual Energy Outlook 2007* (Early Release), EIA/DOE; and Tables A11, A13, and A14, *Annual Energy Outlook 2007* (and previous), EIA/DOE; and Table B-7, *Economic Report of the President, 2006* .

Table B-2: U.S. Imports and Exports of Petroleum Products -- Historical 2000-2006 and Projected 2010 (K b/d)

Commodity	Historical							Projected
	2000	2001	2002	2003	2004	2005	2006[1]	2010
IMPORTS	**2,395**	**2,543**	**2,390**	**2,599**	**3,066**	**3,593**	**3,381**	**3,025**
Gross Refined Products	**1,817**	**1,787**	**1,607**	**1,853**	**2,075**	**2,445**	**2,017**	**1,781**
Natural Gas Liquids	257	250	199	271	306	374	353	330
Pentanes Plus	41	45	16	46	43	47	22	32
Liquefied Petroleum Gases	215	206	183	225	264	328	331	297
Finished Motor Gasoline	428	454	498	518	498	603	502	364
Reformulated	197	217	233	249	213	239	65	0
Other	231	237	265	269	285	364	437	364
Jet Fuel (incl. Kerosene, & Aviation Gas)	165	155	113	115	130	199	187	156
Distillate Fuel Oil	296	344	267	333	326	325	222	185
15 ppm or less sulfur						4	84	139
15 to 500 ppm sulfur	134	129	107	135	149	152	72	0
> 500 ppm sulfur	162	215	161	198	178	173	150	46
Naphthas (for Petrochemical)	119	90	63	87	134	151	115	124
Other Oils (Petrochemical)	143	142	146	146	158	159	183	167
Special Naphthas	11	13	17	11	8	14	14	12
Residual Oil	353	295	249	327	427	530	356	356
< 0.31 wt% Sulfur	112	40	43	50	89	93	30	57
0.31 to 1.00 wt% Sulfur	84	102	52	100	141	175	82	108
> 1.00 wt% Sulfur	156	153	154	178	198	262	244	191
Asphalt & Road Oil	28	26	27	12	43	43	39	42
Lubricants & Waxes	16	10	9	8	12	15	12	13
Miscellaneous Products	0	1	0	1	0	0	0	0
Petroleum Coke	1	6	19	22	33	32	33	33
Unfinished Oils	**274**	**378**	**410**	**335**	**491**	**582**	**689**	**409**
Ethers	**81**	**79**	**61**	**44**	**48**	**55**	**-**	**-**
Ethanol	**0**	**1**	**0**	**1**	**10**	**9**	**-**	**19**
Gasoline Blending Components	**223**	**298**	**311**	**367**	**452**	**510**	**675**	**816**
EXPORTS	**993**	**951**	**975**	**1,014**	**1,024**	**1,133**	**1,319**	**1,228**
Finished Petroleum Products	**866**	**869**	**842**	**897**	**916**	**1,010**	**1,166**	**1,081**
Finished Motor Gasoline	144	133	124	125	125	136	138	128
Special Naphthas	20	23	15	22	27	21	15	14
Jet Fuel , Kerosene, & Aviation Gas	34	31	34	28	44	55	40	38
Distillate Fuel Oil	173	119	112	107	110	138	218	202
15 ppm or less sulfur	0	0	0	0	0	0	0	0
15 to 500 ppm sulfur	47	39	54	50	33	39	65	61
> 500 ppm sulfur	126	80	59	57	77	99	153	142
Residual Fuel Oil	139	191	177	197	205	251	280	260
Asphalt & Road Oil	6	5	6	10	6	11	15	14
Lubricants & Waxes	29	29	37	41	45	45	74	69
Miscellaneous Products	0	0	0	6	3	6	7	7
Petroleum Coke	319	336	337	361	351	347	378	350
Natural Gas Liquids	**78**	**45**	**67**	**59**	**46**	**60**	**69**	**64**
Other Liquids	**49**	**37**	**66**	**59**	**63**	**64**	**84**	**84**
Other Hydrocarbons/H2/Oxygenates	31	27	33	29	30	42	76	76
Motor Gasoline Blending Components	18	10	33	30	33	22	8	8

1 Reflects annualized January through October data.

Table B-2: U.S. Imports and Exports of Petroleum Products -- Historical 2000-2006 and Projected 2010 (K b/d)

Notes on derivation of projections:

IMPORTS -- EIA projection of net product imports plus exports from Table B-1.
Gross Refined Products -- EIA projection from Table B-1
Natural Gas Liquids -- sum of projected pentanes and LPG
Pentanes Plus -- average of 2004 and 2006
Liquified Petroleum Gases -- average of 2004 and 2006
Finished Motor Gasoline -- 2006 imports of conventional gasoline plus pro rata share of estimated additional combined imports of gasolne, jet fuel, and distillate.
Reformulated Gasoline -- assumed to be zero because of ethanol blending (included in imported gasoline blendstocks)
Other Gasoline -- equalt to projected gasoline imports
Jet Fuel -- 2006 imports plus pro rata share of estimated additional combined imports of gasoline, jet fuel, and distillate
Distillate Fuel Oil -- 2006 imports plus pro rata share of estimated additional combined imports of gasoline, jet fuel, and distillate.
Distillate Fuel Oil <= 15 pmm -- assumed to be 75% of total diesel fuel imports with advent of low sulfur diesel standard
Distillate Fuel Oil 15 to 500 pmm -- assumed to be zero
Distillate Fuel Oil > 500 ppm -- difference between projected total distillate fuel imports and imports of ultra low sulfur diesel
Naphthas (for Petrochemcial) -- average of imports in 2004 and 2006
Other Oils (Petrochemical) -- average of last three years
Special Naphthas -- average of last three years
Residual Oil Total -- imports in 2006
Residual Oil by Sulfur Content -- total imports times pro rata share over last three years
Asphalt & Road Oil -- average of last three years
Lubricants & Waxes -- average of last three years
Petroleum Coke -- imports in 2006
Unfinished Oils -- EIA projection from Table B-1
Ethers -- assumed to be zero
Gasoline Blending Components -- EIA projection from Table B-1
Ethanol -- EIA projection from Table B-1

EXPORTS -- EIA projection from Table B-1
Finished Petroleum Products:
Total -- difference between DOE projection of total exports and projected exports of NGL and other liquids
Specific Finished Products -- share in 2006 times the projected total of finished products
Natural Gas Liquids -- average of last two years
Other Liquids -- exports in 2006

Source: Derived from Tables 20 & 27 (2000-2004) and Tables 23 & 29 (2005), *Petroleum Supply Annuals,* EIA/DOE;
Tables 2 & 48, *Petroleum Supply Monthly, Dec. 2006* , EIA/DOE;
DOE Refinery-Level Import Data (for ethanol imports, 2000-2005); and Table B-1.

Table B-3: Projected Growth in Use of Refined Producta, by Region 2004 to 2010

Petroleum Product	Region					Total
	PADD			P 4&5 ex	Calif.[2]	
	1	2	3[1]	AZ/NV/CA		
Total Growth						
Motor Gasoline[1]	4.5%	3.2%	6.9%	6.7%	4.9%	4.7%
Jet & Kerosene	17.2%	17.3%	22.5%	19.7%	21.5%	19.9%
Distillate	7.1%	11.2%	16.3%	16.2%	17.7%	11.7%
Residual Oil	-14.6%	-34.5%	-15.6%	20.5%	26.3%	-9.2%
Petro Feedstock	-5.1%	-5.0%	-2.3%	-7.3%	-8.1%	-3.5%
Other	-23.9%	-26.2%	-12.5%	1.9%	-21.1%	-18.2%
Average Annual						
Motor Gasoline[1]	0.7%	0.5%	1.1%	1.1%	0.8%	0.8%
Jet & Kerosene	2.7%	2.7%	3.4%	3.0%	3.3%	3.1%
Distillate	1.2%	1.8%	2.5%	2.5%	2.8%	1.9%
Residual Oil	-2.6%	-6.8%	-2.8%	3.2%	4.0%	-1.6%
Petro Feedstock	-0.9%	-0.8%	-0.4%	-1.3%	-1.4%	-0.6%
Other	-4.5%	-4.9%	-2.2%	0.3%	-3.9%	-3.3%

1 Includes ethanol blended into finished gasoline.

Note that the regional growth estimates are based on AEO 2006, adjusted for total U.S. growth from AEO2007 (Early Release), as regional energy use is not provided in AEO 2007 (Early Release). We relied on the AEO2006 projections as indicators of the relative growth in petroleum energy demands across regions.

1 Includes 50% of Arizona energy use.

2 Includes 50% of Arizona and 100% of Nevada estimated and projected energy use.

Sources: Derived from Supplement Tables 1-10, *Annual Energy Outlook 2006,* DOE/IEA;
Tables 48, 49, & 50 (Prime Supplier Sales), *Petroleum Marketing Annual 2004* , DOE/EIA;
Table M21, *Federal Highway Statistics 2004* , FHWA; and Census Population Estimates.

Table B-4a: Annual Supply of Major Refined Products, by Region -- 2004

(K b/d)

Product/Source	PADD 1	PADD 2	PADD 3	PDs 4&5 ex Calif	Calif	U.S. Total
Gasoline	3,264	2,622	1,354	723	1,168	9,130
Refinery (& Field) Production	1,243	2,090	3,632	687	1,106	8,757
Net Blndstk Purchases	370	146	-215	16	62	380
Ref Production - Blndstk Pur	872	1,944	3,847	671	1,044	8,378
Net Imports	464	1	-103	8	4	373
Net Inter-PADD Shipments	1,557	532	-2,175	28	58	0
Jet Fuel & Kerosene	650	354	150	251	293	1,699
Refinery Production	121	227	816	200	251	1,614
Net Imports	46	1	-20	21	38	85
Net Inter-PADD Shipments	483	127	-645	31	5	0
Distillate Fuel Oil	1,449	1,202	723	374	321	4,069
Refinery Production	464	867	1,845	362	316	3,853
Net Imports	269	0	-57	0	5	216
Net Inter-PADD Shipments	717	336	-1,065	12	0	0
Residual Oil	480	52	169	112	54	867
Refinery Production	112	57	305	106	65	645
Net Imports	318	1	-90	6	-13	222
Net Inter-PADD Shipments	50	-5	-47		1	0
All Major Products	5,843	4,231	2,396	1,460	1,836	15,766
Refinery Production[1]	1,569	3,094	6,813	1,338	1,675	14,489
Net Imports	1,097	2	-270	34	34	897
Net Inter-PADD Shipments	2,807	989	-3,932	72	64	0

Notes: Refinery production adjusted to include stock changes.
California includes refined products produced in California but sold in adjacent states (e.g., Arizona & Nevada)

1 Includes refinery production of gasoline, less purchased blendstocks.

Source: Derived from Tables 2-12, *Petroleum Supply Annual 2004,* EIA/DOE; and CEC Refinery Reports, 2004, California Energy Commission.

Table B-4b: Projected Supply of Major Refined Products, by Region -- 2010
(K b/d)

Product/Source	PADD 1	PADD 2	PADD 3	PADDs 4&5 ex Calif	Calif[1]	Total	2004 Total	Proj. Growth 2004-2010
Gasoline	**3,401**	**2,697**	**1,443**	**769**	**1,221**	**9,531**	**9,130**	**4.4%**
Refinery (& Field) Production[2]	1,602	2,130	3,736	667	1,159	9,295	8,757	6.1%
Net Blndstk Purchases	730	167	-169	-36	117	808	380	
Imports	706	0	66	4	33	808	380	
From Gulf Coast[3]	24	167	-235	0	44	0		
From Puget Sound[4]				-40	40	0		
Production - Blndstk Pur[5]	872	1,964	3,905	704	1,042	8,487	8,378	1.3%
Net Imports	351	1	-128	8	4	236	373	
Net Inter-PADD Shipments	1,448	566	-2,165	93	58	0	0	
Jet Fuel & Kerosene	**761**	**415**	**184**	**301**	**356**	**2,018**	**1,699**	**18.8%**
Refinery Production	121	245	994	240	301	1,900	1,614	17.7%
Net Imports	62	1	-24	25	55	118	85	
Net Inter-PADD Shipments	579	169	-785	37	0	0	0	
Distillate Fuel Oil	**1,526**	**1,315**	**827**	**428**	**372**	**4,467**	**4,069**	**9.8%**
Refinery Production	464	945	2,264	434	379	4,485	3,853	16.4%
Net Imports	51	-1	-70	9	-7	-17	216	
Net Inter-PADD Shipments	1,011	371	-1,367	-15	0	0	0	
Residual Oil	**408**	**34**	**142**	**134**	**67**	**786**	**867**	**-9.4%**
Refinery Production	112	57	312	128	80	689	645	6.9%
Net Imports	214	1	-112	6	-13	96	222	
Net Inter-PADD Shipments	82	-23	-59	0	0	0	0	
Major Products	**6,096**	**4,461**	**2,596**	**1,631**	**2,017**	**16,801**	**15,766**	**6.6%**
Refinery Production[6]	1,569	3,210	7,474	1,505	1,802	15,560	14,489	7.4%
Net Gas Blndstk Imports	706	0	66	4	33	808	380	
Net Finished Prod. Imports	678	2	-335	48	40	433	897	
Net Inter-PADD Shipments	3,120	1,083	-4,375	115	58	0	0	
Proj.Growth in Refinery Out-turns, 2004-2010	**0.0%**	**3.7%**	**9.7%**	**12.5%**	**7.6%**	**7.4%**		
Gasoline (less Blndstk Pur)	0.0%	1.0%	1.5%	4.8%	-0.1%	1.3%		
Jet Fuel & Kerosene	0.0%	8.0%	21.8%	20.0%	20.0%	17.7%		
Distillate Fuel Oil	0.0%	9.0%	22.7%	20.0%	20.0%	16.4%		
Residual Oil	0.0%	0.0%	2.4%	21.0%	23.3%	6.9%		

1 Includes California refinery out-turns sold in adjacent states; does not include projected shipments of 25 K b/d of EBOB from Pudget Sound refineries to California.
2 Includes net blendstock purchases and "Field Production" of oxygenated gasoline.
3 Assumes 20% growth in PADD 3 out-turns of gasoline blendstocks and allocated pro-rata based on 2002
4 Includes alkylate and isomerate; does not include projected shipments of 25 K b/d of CaRFG to California (which is included in PADD 4&5 refinery production of finished gasoline).
5 Not adjusted for ethanol bending that may occur in the destination-PADD.
6 Calculated as the sum of gasoline production (less blendstock purchases) and production of jet fuel & kerosene, distillate, and resid.
Notes: 2012 totals calculated by multiplying 2004 totals by DOE projected growth from 2004 to 2012.
Numbers in italics for PADD 3 indicate implicit growth in production to balance projected U.S. demand, less imports and production in other refining centers.
Sources: Derived from Tables 2-12 & 32, *Petroleum Supply Annual 2004, EIA/DOE; and* Tables A-5, B-1, B-2, B-3, and B-4a.

Table B-5: Projected Refinery Inputs and Net Production, by Region -- 2010
(K b/d)

Inputs & Outputs	Summer PADD 1	PADD 2	PADD 3	PADDs 4&5 ex Calif.	California	U.S.
Refinery Inputs:	**2,669**	**4,032**	**8,982**			**19,525**
Crude Oil	**1,594**	**3,451**	**8,347**	**1,538**	**1,941**	**16,908**
Natural Gas Liquids	**4**	**83**	**226**	**68**	**11**	**402**
Pentanes Plus		40	110	31		189
Liquified Petroleum Gases	4	42	115	37	11	212
Ethane						
Propane						
Normal Butane	0	3	24	23	5	55
Isobutane	4	40	91	15	6	158
Other Liquids	**1,071**	**497**	**410**			**2,215**
Other Hydrocarbons/H2/Oxy	166	224	236	-	-	782
Other Hydrocarbons/H2		8	44			94
Oxygenates[1]	166	216	192	59	55	689
Unfinished Oils -- Total	48	56	315	-52	94	462
Motor Gasoline Blend. Comp.	831	168	-157	-35	119	925
Aviation Gasoline Blend. Comp.	-7	0	0			-6
Refinery Outputs:	**2,605**	**3,869**	**8,717**	**1,515**	**2,136**	**18,890**
Liquified Refinery Gases	**80**	**160**	**547**	**30**	**75**	**894**
Ethane/Ethylene	0		23			24
Ethane	0		16			16
Ethylene	0		7			7
Propane/Propylene	58	118	389	23	49	639
Propane	34	84	190	21	44	375
Propylene	23	34	199	2	5	264
Normal Butane/Butylene	25	47	137	9	35	253
Normal Butane	25	47	138	9	35	256
Buytlene	0	-1	-2	0	0	-3
Isobutane/Isobutylene	-3	-4	-3	-2	-9	-22
Isobutane	-4	-5	-3	-3	-10	-24
Isobutylene	0	0	0	0	1	2
Finished Petroleum Products	**2,525**	**3,708**	**8,170**	**1,486**	**2,061**	**17,996**
Finished Motor gasoline	1,691	2,162	3,781	620	1,223	9,478
Reformulated	969	421	974	21	1,010	3,394
Other	723	1,741	2,807	600	213	6,083
Finished Aviation Gasoline		5	11	5		22
Jet Fuel	112	242	966	234	303	1,857
Kerosene	9	3	35	2		49
Distillate Fuel Oil	450	961	2,321	430	400	4,559
CARB (& less than 0.0015 % sulfur)					271	271
Less than 0.0015 % sulfur	344	868	1,971	426	128	3,740
Greater than 0.0015 % sulfur	122	90	370	10	0	598
Residual Fuel Oil	103	58	319	127	73	681
Less than 0.31 % sulfur	45		25	6	3	82
0.31 to 1.00 % sulfur	44	4	35	39	23	143
Greater than 1.00 % sulfur	14	54	258	82	47	456
Naphtha to Petrochemical	15	29	205	1	0	249
Other Oils to Petrochemical		9	187	1	9	206
Special Naphthas	2	5	48	1		56
Lubricants & Waxes	19	17	145	0	25	206
Asphalt and Road Oil	129	204	131	69	42	576
Miscellaneous Products	1	12	34	-1	10	57

1 Estimated assuming total ethanol use of 7.5 bgy.
Sources: Derived Petroleum Supply Annual 2004, Vols. 1 &2, EIA/DOE; and Table B-4b.

Table B-6a: Allocation of Annual Gasoline Use by Region, States, and Gasoline Type -- 2010
(K b/d)

Region & State	Gasoline Type									
	Conven-tional	EtOH Mandate (Minn.)	Low RVP Areas 7.8	Low RVP Areas 7.2	Low RVP Areas 7.0	Federal RFG	California RFG Federal Area	California RFG State Area	Arizona CBG	Total
PADD 1	**920**	**0**	**826**	**0**	**164**	**1,491**	**0**	**0**	**0**	**3,401**
Subdistrict 1A	**52**	**0**	**32**		**0**	**375**	**0**	**0**	**0**	**459**
Connecticut						123				123
Maine	16		32							48
Massachusetts						191				191
New Hampshire	13					35				48
Rhode Island						26				26
Vermont	24									24
Subdistrict 1B	**98**	**0**	**354**		**0**	**792**	**0**	**0**	**0**	**1,244**
Delaware						28				28
District of Columbia						10				10
Maryland	16					163				178
New Jersey						290				290
New York	52		128			206				386
Pennsylvania	30		227			94				351
Subdistrict 1C	**771**	**0**	**439**		**164**	**324**	**0**	**0**	**0**	**1,697**
Florida	292		274							567
Georgia	125				63	151				339
North Carolina	118		78		100					296
South Carolina	109		64							173
Virginia	92					173				266
West Virginia	34		23							57
PADD 2	**1,212**	**188**	**527**	**0**	**303**	**466**	**0**	**0**	**0**	**2,697**
Illinois	125					233				357
Indiana	83		104		6	31				223
Iowa	113									113
Kansas	71					22				93
Kentucky	117		2		3	36				158
Michigan	75		99		168					341
Minnesota		188								188
Missouri	121					102				223
Nebraska	60									60
North Dakota	25									25
Ohio	81		281							362
Oklahoma	103		31							134
South Dakota	30									30
Tennessee	85				127					212
Wisconsin	124		9			43				177
PADD 3	**648**	**0**	**330**	**0**	**62**	**403**	**0**	**0**	**0**	**1,443**
Alabama	148				33					182
Arkansas	101				2					103
Louisiana	82		64			22				167
Mississippi	116									116
New Mexico	66									66
Texas	135		266		27	381				810
PADDs 4 & 5 ex CA	**394**	**67**	**391**	**0**	**0**	**0**	**0**	**0**	**119**	**971**
Alaska	23									23
Arizona	79								119	198
Colorado	49		92							140
Hawaii		34								34
Idaho	41									41
Montana		33								33
Nevada	13		76							89
Oregon	59		58							117
Utah	16		52							68
Washington	91		113							204
Wyoming	23									23
CALIFORNIA							**746**	**273**		**1,019**
UNITED STATES	**3,174**	**255**	**2,074**	**0**	**529**	**2,361**	**746**	**273**	**119**	**9,531**

1 We assume spillover of a small volume of CaRFG into Nevada occurs in 2008 and report it as State CBG.

Note: Gasoline is classified by the area into which it is sold. Volumes reflect year-long (annual, rather than seasonal) sales to those areas.

Sources: Derived from *Petroleum Marketing Annual, 2004;* EPA-provided information on gasoline allociations; and Table B-4b.

Table B-6b: Projected Annual Gasoline Use and Supply Sources, By Region and Type of Gasoline -- 2010 (K barrels per day)

Region of Use & Origin of Supply	Gasoline Type: Conven-tional	EtOH Mandate (Minn.)	Low RVP Areas 7.8	Low RVP Areas 7.0[1]	Federal RFG	California RFG Federal Area	California RFG State Area	Arizona CBG	Total
Use in PADD 1	**920**		**826**	**164**	**1,491**				**3,401**
PADD 1 Refineries	78		325		986				1,389
PADD 2 Refineries	7		10						17
PADD 3 Refineries	834		439	164	392				1,828
Net Imports	1		52		113				166
Use in Subdistrict 1A	**52**		**32**		**375**				**459**
PADD 1 Refineries	50		0		295				345
PADD 3 Refineries									0
Net Imports	2		32		80				114
Use in Subdistrict 1B	**98**		**354**		**792**				**1,244**
PADD 1 Refineries	0		325		682				1,007
PADD 2 Refineries	7		10						17
PADD 3 Refineries	0		0		90				90
Net Imports	90		20		20				130
Use in Subdistrict 1C	**771**		**439**	**164**	**324**				**1,697**
PADD 1 Refineries	28				9				37
PADD 3 Refineries	649		439	164	302				1,553
Net Imports	94				13				107
Use in PADD 2	**1,212**	**188**	**527**	**303**	**466**				**2,697**
PADD 1 Refineries	72		141						213
PADD 2 Refineries	967	188	325	171	405				2,055
PADD 3 Refineries	151		61	133	62				407
PADD 4 Refineries	21								21
Net Imports	1				0				1
Use in PADD 3	**648**		**330**	**62**	**403**				**1,443**
PADD 2 Refineries	22				16				37
PADD 3 Refineries	754		330	62	388				1,534
Net Imports	-128				-1				-128
Use in PADDs 4 & 5 ex CA	**394**	**67**	**391**					**119**	**971**
PADD 2 Refineries	21								21
PADD 3 Refineries -- direct	67		0					85	152
-- routed through Calif									0
PADD 4 & 5 (ex CA) Ref.	207	67	315						589
California Refineries	92		76					34	202
Net Imports	8								8
Use in California						**746**	**273**		**1,019**
PADD 4 & 5 (ex CA) Ref.						58			58
California Refineries	0					684	273		957
Net Imports	0					4			4
TOTAL USE	**3,174**	**255**	**2,074**	**529**	**2,361**	**746**	**273**	**119**	**9,531**
U.S. Refinery Production	**3,291**	**255**	**2,022**	**529**	**2,248**	**742**	**273**	**119**	**9,480**
PADD 1	151		465		986				1,602
PADD 2	1,016	188	335	171	420				2,130
PADD 3	1,805		831	358	842			85	3,921
PADDs 4 & 5 ex CA	227	67	315			58			667
California	92		76			684	273	34	1,159
Net Imports	**-117**		**52**		**112**	**4**			**51**

1 Includes small projected volume (15 K b/d) of gasoline sold to an area in PADD 2 with an RVP limit of 7.2 psi.
Sources: Derived from Tables B-4b and B-6a.

Table B-6c: Projected Gasoline Production Volume, RVP, and Octane, by Type of Gasoline, Destination, and Region -- 2010

Producing Region, Type of Gasoline, & Destination	Annual Production Volume (K b/d)	Annual Production Share (%)	Seasonal Production (K b/d) Summer	Seasonal Production (K b/d) Winter	RVP Summer	RVP Winter	Pool Octane (R+M)/2
PADD 1 Refineries	**1,602**	**100.0%**	**1,691**	**1,526**	**7.2**	**14.1**	**88.1**
Conventional	151	9.4%	177	128	8.7	13.8	88.1
Subdistrict 1A	50		59	43	8.7	14.3	
Subdistrict 1B	0		0	0	8.7	14.2	
Subdistrict 1C	28		33	24	8.7	13.0	
PADD 2	72		85	62	8.7	13.8	
7.8 RVP Areas	465	29.0%	546	396	7.6	14.1	88.1
Subdistrict 1A	0		0	0	7.6	14.3	
Subdistrict 1B	325		381	277	7.6	14.2	
PADD 2	141		165	120	7.6	13.8	
RFG	986	61.6%	969	1,001	6.8	14.2	88.1
Subdistrict 1A	295		290	299	6.8	14.3	
Subdistrict 1B	682		670	693	6.8	14.2	
Subdistrict 1C	9		9	9	6.8	13.0	
PADD 2 Refineries	**2,130**	**100.0%**	**2,162**	**2,103**	**8.0**	**13.8**	**88.0**
Conventional	1,204	56.5%	1,226	1,186	8.7	13.8	88.0
PADD 1	7		8	7	8.7	13.8	
EtOH Mandate (Minnesota)	188		191	185	8.7	13.8	
PADD 2 other	967		984	952	8.7	13.8	
PADD 3	22		22	21	8.7	12.6	
PADDs 4&5 ex CA	21		21	20	8.7	13.0	
7.8 RVP Areas	335	15.7%	341	330	7.6	13.8	88.0
7.0 RVP Areas[1]	171	8.0%	174	168	6.8	13.8	88.0
RFG	420	19.7%	421	419	6.8	13.8	88.0
PADD 2	405		406	403	6.8	13.8	
PADD 3	16		16	16	6.8	12.6	
PADD 3 Refineries	**3,736**	**100.0%**	**3,781**	**3,697**	**7.8**	**12.9**	**87.8**
Conventional	1,620	43.4%	1,619	1,621	8.7	12.9	87.7
Subdistrict 1B	0		0	0	8.7	14.2	
Subdistrict 1C	649		648	649	8.7	13.0	
PADD 2	151		151	151	8.7	13.8	
PADD 3	626		626	626	8.7	12.6	
PADDs 4&5 ex CA	67		66	67	8.7	13.0	
Net Exports	128		127	128	8.7	12.6	
7.8 RVPAreas	831	22.2%	830	831	7.6	12.9	87.7
Subdistrict 1B	0		0	0	7.6	14.2	
Subdistrict 1C	439		439	440	7.6	13.0	
PADD 2	61		61	61	7.6	13.8	
PADD 3	330		330	330	7.6	12.6	
PADDs 4&5 ex CA	0		0	0	7.6	13.0	
7.0 RVP Areas	358	9.6%	358	359	6.8	13.2	87.7
Subdistrict 1C	164		163	164	6.8	13.0	
PADD 2	133		133	133	6.8	13.8	
PADD 3	62		62	62	6.8	12.6	
RFG	841	22.5%	884	805	6.8	13.0	88.2
Subdistrict 1B	90		95	86	6.8	14.2	
Subdistrict 1C	302		317	288	6.8	13.0	
PADD 2	62		65	59	6.8	13.8	
PADD 3	388		408	371	6.8	12.6	
Net Exports	1		1	1	6.8	13.0	
Arizona CBG	85	2.3%	89	81	6.8	11.4	88.2
PADDs 4 & 5 ex CA Refiner	**667**	**100.0%**	**620**	**707**	**7.9**	**12.9**	
Conventional	227	34.1%	224	230	8.7	13.0	
EtOH Mandate (MT & HA)	67	10.0%	66	68	7.6	12.6	
7.8 RVP	315	47.2%	310	319	7.6	13.0	
California RFG	58	8.7%	21	90	6.8	12.6	
California Refineries	**1,159**	**100.0%**	**1,223**	**1,105**	**7.0**	**12.5**	
Conventional	92	7.9%	117	71	8.7	13.0	
PADDs 4&5 ex CA	92		117	71	8.7	13.0	
Net Exports	0		0	0	8.7	12.5	
7.8 RVP Areas	76	6.5%	96	58	7.6	13.0	
California RFG	957	82.6%	967	949	6.8	12.5	
Arizona CBG	34	2.9%	43	26	6.8	11.4	
TOTAL U.S.	**9,294**	**100.0%**	**9,478**	**9,138**	**7.7**	**13.3**	
Conventional	3,294	35.4%	3,362	3,236	8.7	13.3	
7.8 RVPAreas	2,022	21.8%	2,124	1,936	7.6	13.3	
7.0 RVP Areas	529	5.7%	532	527	6.8	13.4	
RFG	2,248	24.2%	2,274	2,225	6.8	13.7	
California RFG	1,015	10.9%	987	1,039	6.8	12.5	
Arizona CBG	119	1.3%	133	108	6.8	11.4	

Notes: RVPs incorporate typical refinery safety factors of about 0.2 psi
Production of ethanol-blended non-RFG is included in conventional gasoline
Production of gasoline blendstocks not included in totals (i.e., totals include only finished gasoline).
1 Includes small volume (14 K b/d) of gasoline sold to an area in PADD 2 with an RVP limit of 7.2 psi.
Source: Derived from Tables A-3c and B-6b; 2005 *Petroleum Marketing Monthlys;* and AAM Gasoline Survey, Summer 2004.

Table B-6d: Projected Gasoline Blendstock Use, 2010
K b/d

Source & Area of Use	Annual	Summer	Winter
Gulf Coast to:	**235**	**240**	**231**
PADD 1	24	28	22
RFG	24	28	22
CG	0	0	0
PADD 2	167	168	165
RFG	118	117	119
CG	49	51	46
PADDs 4&5 ex CA: CG	0	0	0
California: RFG	44	44	44
Net Imports to:	**808**	**925**	**708**
PADD 1	706	803	623
RFG	322	335	325
CG	383	467	298
PADD 3: CG	66	83	51
PADDs 4&5 ex CA: CG	4	5	3
California	33	35	30
RFG	3	0	6
CG	29	34	24
Import Share:	**100%**	**100%**	**100%**
Federal RFG	40%	36%	46%
California RFG	0%	0%	1%
CG	60%	64%	53%
Puget Sound to:			
California -- Alky & Isomerate	40	40	40

Note: Imported gasoline blendstocks are assumed to contain no oxygenates.
Source: Derived from Tables 2, 6, 10, 14, 18, & 22, *Petroleum Supply Monthly,* 2006 Issues, EIA/DOE; and Table B-4b.

Table B-7: Projected Ethanol Annual 'Use, by Region and Source of Gasoline Supply, 2010
K b/d

Region/ Source	In Gasoline Consumed in the Region	By Source of Gasoline Supply
PADD 1	340	78
PADD 2	270	194
PADD 3	144	418
PADDs 4&5 ex CA	97	66
California	102	108
Imports[1]	-	88
Total		
K b/d	953	953
Bgy	14.6	14.6

1 Includes ethanol blended with imported finished gasoline and gasoline blendstocks.
Source: Derived from Exhibits B-6a, B-6b, B-6c, and B-6d.

Table C-1: National Average Properties of RFG and CG (ex California), 2000-2004

	RFG					CG[1]					Pool				
	2000	2001	2002	2003	2004	2000	2001	2002	2003	2004	2000	2001	2002	2003	2004
Alliance Surveys															
Rvp (psi)	6.8	6.8	6.8	6.9	6.9	7.9	7.8	7.9	7.8	7.8	7.7	7.6	7.6	7.6	7.6
Oxygen (wt%)	2.2	2.2	2.2	2.3	2.5	0.6	0.6	0.6	0.5	0.5	1.0	1.0	1.0	0.9	1.0
MTBE (vol%)	9.2	9.1	9.2	9.5	8.2	0.5	0.3	0.4	0.4	0.6	2.4	2.3	2.3	2.4	2.2
Tame (vol%)	0.9	0.6	0.6	0.6	0.4	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.1	0.2
Ethanol (vol%)	1.1	1.1	1.3	1.3	2.6	1.5	1.6	1.5	1.3	1.2	1.4	1.5	1.5	1.3	1.5
Aromatics (vol%)	21.5	22.8	21.7	22.5	23.3	30.6	30.6	30.0	30.5	31.1	28.6	28.9	28.2	28.8	29.4
Benzene (vol%)	0.60	0.63	0.55	0.54	0.57	1.21	1.26	1.12	1.13	1.08	1.08	1.12	0.99	1.00	0.97
Olefins (vol%)	11.1	10.1	9.2	10.1	11.3	11.3	10.7	9.6	9.5	9.5	11.3	10.6	9.5	9.7	9.9
Sulfur (ppm)	120	122	140	112	86	276	293	305	249	110	242	256	269	219	105
E200 (%off)	48.5	48.6	48.3	49.1	48.5	44.6	45.1	43.6	43.7	43.5	45.5	45.8	44.6	44.8	44.6
E300 (%off)	84.0	84.0	83.4	82.9	82.2	79.5	80.8	79.5	79.2	80.3	80.5	81.5	80.3	80.0	80.7
DI[2]	1,149	1,147	1,154	1,149	1,159	1,173	1,162	1,182	1,185	1,181	1,168	1,159	1,176	1,177	1,176
Octane (R+M)/2	88.3	88.2	88.1	88.2	88.5	88.1	88.1	88.0	88.0	88.0	88.1	88.1	88.1	88.0	88.1
EPA Refinery & Importer Reports															
Rvp (psi)	6.8	6.8	6.8	6.8		8.0	8.2	8.2	8.2		7.7	7.9	7.9	7.9	
Oxygen (wt%)	2.2	2.1	2.2	2.2		0.2	0.2	0.2	0.2		0.7	0.7	0.7	0.7	
MTBE (vol%)	8.8	8.7	8.7	8.6		0.5	0.6	0.6	0.6		2.6	2.6	2.6	2.5	
Tame (vol%)	0.9	0.9	0.7	0.8		0.1	0.1	0.1	0.1		0.3	0.3	0.3	0.2	
Ethanol (vol%)	1.1	1.1	1.3	1.5		0.3	0.2	0.3	0.3		0.5	0.4	0.5	0.6	
Aromatics (vol%)	19.3	20.1	20.4	20.1		28.4	28.1	27.9	27.5		26.1	26.1	26.0	25.7	
Benzene (vol%)	0.59	0.62	0.59	0.61		1.15	1.16	1.10	1.13		1.01	1.02	0.97	1.00	
Olefins (vol%)	10.6	11.8	10.8	11.0		11.7	12.6	12.0	11.9		11.5	12.4	11.7	11.7	
Sulfur (ppm)	126	127	124	110		317	300	295	299		268	256	252	254	
E200 (%off)	47.7	47.4	47.5	47.9		45.1	44.9	44.8	44.7		45.8	45.6	45.5	45.5	
E300 (%off)	84.7	84.4	84.4	84.4		80.7	80.6	80.3	79.8		81.7	81.5	81.4	80.9	
EPA Federal RFG Area Surveys															
RVP (psi)	6.8	6.8	6.8	6.8	6.9										
Oxygen (wt%)	2.3	2.3	2.4	2.5	2.6										
MTBE (wt%)	8.6	8.4	8.2	8.2	7.3										
TAME (wt%)	0.9	1.0	0.8	0.9	0.5										
Ethanol (wt%)	1.8	1.8	2.1	2.4	3.4										
Aromatics (vol%)	19.2	20.0	20.2	19.8	21.0										
Benzene (vol%)	0.61	0.65	0.62	0.65	0.66										
Olefins (vol%)	9.1	10.0	10.6	10.7	10.5										
Sulfur (ppm)	130	125	120	109	76										
E200 (%off)	48.0	47.6	47.7	48.1	48.2										
E300 (%off)	84.9	84.5	84.0	84.0	83.2										

1 Includes low-RVP gasoline

2 Does not include an adjustment to account for the adverse effects of ethanol on driveability

Table C-2: Average Properties of RFG and CG, by PADD of Origin, 2002-2004

	PADD 1									PADD 2								
	RFG			CG[1]			Pool			RFG			CG[1]			Pool		
	2002	2003	2004	2002	2003	2004	2002	2003	2004	2002	2003	2004	2002	2003	2004	2002	2003	2004
Alliance Surveys																		
Rvp (psi)	6.9	7.0	7.0	7.6	7.6	7.7	7.2	7.2	7.3	6.8	6.8	7.0	8.3	8.3	8.3	8.2	8.1	8.2
Oxygen (wt%)	2.2	2.2	2.7	0.5	0.6	1.0	1.5	1.6	2.0	3.2	3.2	3.3	1.3	1.1	1.0	1.6	1.4	1.3
MTBE (vol%)	11.7	11.3	7.7	0.7	0.8	3.1	7.3	7.2	5.9	0.1	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.0
Tame (vol%)	0.2	0.7	0.0	0.0	0.0	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethanol (vol%)	0.0	0.0	3.8	1.2	1.3	1.3	0.5	0.5	2.8	9.2	9.3	9.6	3.8	3.2	3.0	4.5	3.9	3.8
Aromatics (vol%)	24.0	24.2	24.3	33.4	29.2	30.5	27.7	26.2	26.7	20.5	21.0	20.7	29.3	29.9	29.6	28.3	28.9	28.5
Benzene (vol%)	0.52	0.45	0.52	0.81	0.68	0.71	0.63	0.54	0.60	0.70	0.67	0.76	1.32	1.37	1.18	1.25	1.28	1.13
Olefins (vol%)	10.2	12.4	13.4	9.8	10.2	10.7	10.0	11.5	12.3	5.3	5.6	7.1	8.2	8.1	8.7	7.8	7.8	8.5
Sulfur (ppm)	106	95	93	159	157	111	127	120	100	126	108	96	299	255	153	279	237	146
E200 (%off)	49.1	48.9	48.5	41.9	45.4	43.3	46.3	47.5	46.4	44.8	45.3	46.4	45.7	46.1	44.4	45.6	46.0	44.7
E300 (%off)	83.7	82.6	82.7	79.0	80.4	80.8	81.8	81.8	81.9	84.1	84.3	83.2	80.7	80.6	80.7	81.1	81.1	81.0
DI[2]	1,144	1,149	1,156	1,206	1,176	1,193	1,168	1,160	1,171	1,180	1,178	1,175	1,151	1,150	1,162	1,155	1,153	1,164
Octane (R+M)/2	88.1	88.4	88.6	88.1	88.0	87.9	88.1	88.2	88.3	88.5	88.5	89.2	88.1	87.9	87.9	88.1	87.9	88.1
EPA Refinery Reports																		
Rvp (psi)		6.8			8.3			7.4			6.9			8.5			8.3	
Oxygen (wt%)		2.1			0.8			1.6			2.6			0.3			0.5	
MTBE (vol%)		11.7			1.6			7.7			0.0			0.0			0.0	
Tame (vol%)		0.1			0.0			0.1			0.0			0.0			0.0	
Ethanol (vol%)		0.0			1.4			0.6			7.0			0.7			1.5	
Aromatics (vol%)		21.0			26.5			23.2			19.9			28.7			27.7	
Benzene (vol%)		0.57			0.95			0.72			0.82			1.39			1.32	
Olefins (vol%)		13.0			13.3			13.1			3.7			9.6			8.9	
Sulfur (ppm)		101			230			152			115			351			323	
E200 (%off)		47.3			46.6			47.1			45.4			45.8			45.8	
E300 (%off)		82.8			81.2			82.2			85.1			80.8			81.3	
EPA Federal RFG Area Surveys																		
RVP (psi)	6.8	6.8	6.9							6.8	6.8	6.9						
Oxygen (wt%)	2.1	2.1	2.8							3.3	3.5	3.5						
MTBE (wt%)	10.5	10.7	6.0							0.6	0.1	0.0						
TAME (wt%)	0.9	1.2	0.1							0.0	0.0	0.0						
Ethanol (wt%)	0.0	0.0	4.9							9.2	10.1	10.2						
Aromatics (vol%)	21.5	21.5	21.8							18.6	17.9	18.5						
Benzene (vol%)	0.59	0.67	0.63							0.71	0.70	0.80						
Olefins (vol%)	12.2	12.3	12.8							6.3	6.6	6.2						
Sulfur (ppm)	101	87	83							116	116	84						
E200 (%off)	47.6	47.3	47.5							46.1	46.1	47.1						
E300 (%off)	84.3	84.1	83.7							84.4	84.6	83.9						

1 Includes low-RVP gasoline

2 Does not include an adjustment to account for the adverse effects of ethanol on driveability

Table C-2: Average Properties of RFG and CG, by PADD of Origin, 2002-2004

	PADD 3								
	RFG			CG[1]			Pool		
	2002	2003	2004	2002	2003	2004	2002	2003	2004
Alliance Surveys									
Rvp (psi)	6.8	7.0	6.9	7.5	7.5	7.4	7.4	7.4	7.3
Oxygen (wt%)	2.0	2.1	2.1	0.1	0.1	0.2	0.5	0.6	0.6
MTBE (vol%)	10.1	10.9	10.8	0.6	0.7	0.7	2.7	2.9	2.9
Tame (vol%)	1.0	0.7	0.7	0.0	0.0	0.2	0.2	0.2	0.3
Ethanol (vol%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Aromatics (vol%)	20.7	21.9	23.5	30.4	31.3	31.9	28.3	29.3	30.1
Benzene (vol%)	0.54	0.57	0.54	0.98	0.95	0.98	0.88	0.87	0.89
Olefins (vol%)	9.6	10.0	11.1	10.6	10.4	10.0	10.4	10.3	10.2
Sulfur (ppm)	165	123	78	331	244	90	295	218	87
E200 (%off)	48.9	50.2	49.1	41.7	41.5	42.7	43.2	43.4	44.1
E300 (%off)	83.1	82.7	81.7	78.1	77.7	79.7	79.2	78.8	80.1
DI[2]	1,153	1,141	1,157	1,209	1,214	1,194	1,197	1,198	1,186
Octane (R+M)/2	88.0	88.0	88.2	88.1	88.2	88.3	88.1	88.1	88.3
EPA Refinery Rep									
Rvp (psi)		6.8			8.1			7.8	
Oxygen (wt%)		2.3			0.1			0.6	
MTBE (vol%)		8.9			0.7			2.5	
Tame (vol%)		0.7			0.1			0.2	
Ethanol (vol%)		1.6			0.0			0.3	
Aromatics (vol%)		18.3			26.3			24.6	
Benzene (vol%)		0.55			0.95			0.86	
Olefins (vol%)		10.9			12.8			12.4	
Sulfur (ppm)		131			308			270	
E200 (%off)		49.1			43.8			45.0	
E300 (%off)		84.3			78.4			79.6	
EPA Federal RFG									
RVP (psi)	6.8	6.8	6.9						
Oxygen (wt%)	2.1	2.1	2.1						
MTBE (wt%)	10.5	10.9	11.0						
TAME (wt%)	0.9	0.9	0.8						
Ethanol (wt%)	0.0	0.0	0.0						
Aromatics (vol%)	19.9	19.2	21.0						
Benzene (vol%)	0.59	0.61	0.57						
Olefins (vol%)	11.3	11.3	11.2						
Sulfur (ppm)	147	132	71						
E200 (%off)	48.9	49.9	49.0						
E300 (%off)	83.6	83.6	81.9						

1 Includes low-RVP gasoline

2 Does not include an adjustment to account for the adverse effects of ethanol on driveability

Table D-1a: Estimated Cost of Proposed National Clean Gasoline Standard, by PADD and Study Case

	PADD 1			PADD 2			PADD 3			PADDs 1-3		
Study Case -->	**#1**	**#2**	**#3**	**#1**	**#2**	**#3**	**#1**	**#2**	**#3**	**#1**	**#2**	**#3**
RFG -->	●	●	●	●	●	●	●	●	●	●	●	●
Low RVP -->		●	●		●	●		●	●		●	●
CG -->			●			●			●			●
Refining Cost												
Total ($million/d)	**0.5**	**0.6**	**0.7**	**0.2**	**0.6**	**2.1**	**0.7**	**2.1**	**5.0**	**1.5**	**3.4**	**7.8**
Capital charge & fixed	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.2	1.2	0.1	0.3	1.4
All other	0.5	0.6	0.7	0.2	0.6	2.0	0.6	1.9	3.7	1.4	3.0	6.4
Cents/gal of Affected Gasoline												
Average	2.1	2.0	2.2	2.0	1.8	2.6	1.4	2.0	2.9	1.6	1.9	2.7
Incremental	2.1	1.8	4.6	2.0	1.7	3.1	1.4	2.6	4.6	1.6	2.3	3.9
Refinery Investment ($B)	**0.0**	**0.0**	**0.1**	**0.0**	**0.1**	**0.2**	**0.1**	**0.3**	**1.5**	**0.1**	**0.4**	**1.8**
Affected Gasoline (K b/d)	**565**	**719**	**771**	**292**	**807**	**1,976**	**1,283**	**2,571**	**4,046**	**2,140**	**4,097**	**6,793**
Cost of Change in Gasoline Pool Energy Density ($MM/d)	**-0.1**	**-0.1**	**-0.2**	**0.0**	**-0.1**	**-0.8**	**0.2**	**-0.2**	**-0.6**	**0.1**	**-0.2**	**-0.6**

Note: in $2005.

Table D-1b: Effect of Changes in Energy Prices on the Estimated Cost of Proposed National Clean Gasoline Standard

	Original Study Costs			Crude Price Sensitivity Analysis		
Study Case -->	**#1**	**#2**	**#3**	**#1**	**#2**	**#3**
RFG -->	●	●	●	●	●	●
Low RVP -->		●	●		●	●
CG -->			●			●
Assumed Energy Prices						
Crude ($/b)	51.2			125		
Electricity (¢/Kwh)	6.1			6.6		
Industrial Natural Gas ($/mcf)	6.82			10.5		
Refining Cost						
Total ($million/d)	1.5	3.4	7.8	2.3	5.4	12.9
Cents/gal of Affected Gasoline	1.6	1.9	2.7	2.5	3.2	4.5
Effect on Estimated Refining Cost of a $10/b Crude Price Increase (¢/g)[1]				0.06	0.09	0.15
Affected Gas Volume (K b/d)	2,140	4,097	6,793	2,140	4,097	6,793

1 Assumes electricity and natural gas prices remain as specified.

Table D-2: Operations and New Capacity (K b/d, except as noted)

Type of Process	Process	PADD 1				
				Study Case		
		2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG
USE OF EXISTING CAPACITY						
Crude Distillation	Atmospheric	1,566	1,621	1,621	1,621	1,621
Conversion	Fluid Cat Cracker	590	649	655	655	655
	Hydrocracker	38	30	5	5	7
	Coking	77	66	67	68	68
	Visbreaker					
Upgrading	Alkylation	85	97	97	97	97
	Merchant Iso-Octane/ene					
	Catalytic Polymerization	16	12	10	10	10
	Dimersol					
	Pen/Hex Isomerization	17	17	17	17	17
	Reforming	240	212	232	236	240
Oxygenate Prod.	MTBE -- FCC-based	7				
	MTBE -- Field Butane-based					
	MTBE -- Other					
	TAME	2				
Hydrotreating	Naphtha Desulf.	329	291	312	318	320
	FCC Naphtha Desulfurization	67	351	351	351	351
	Benzene Saturation				0	1
	Distillate Desulfurization	376	427	437	436	435
	FCC Feed Desulfurization	89	44	44	44	44
	Merox (MTBE)					
	Resid Desulfurization					
Hydrogen	Hydrogen Plant (MM scf/d)	74	1,109	1,108	1,106	1,110
Fractionation	Debutanization	100	109	109	109	109
	Lt. Naphtha Spl. (Benz. Prec.)	35	9	9	9	9
Other	Aromatics Plant	29	53	53	53	53
	Benzene Extraction	3	1	1	1	1
	Butane Isomerization		6	10	9	9
	Lubes & Waxes	18	19	19	19	19
	Solvent Deasphalting	14	19	19	19	19
	Sulfur Recovery (K s tons/d)	1	1	1	1	1
	Steam Generation (K lb/hr)	7,849	8,298	8,316	8,363	8,400
NEW CAPACITY						
Upgrading	Alkylation					
	Pen/Hex Isomerization					
Hydrogen	Hydrogen Plant (MM scf/d)				0	0
Fractionation	Debutanization					1
	Depentanization		31		28	44
	Medium Naphtha Splitter					
	Light Gas Processing					
Retrofitting	Captive MTBE to Alkylate					
	Tier 2 Desulfurization		4	15	15	14
OPERATIONS						
Operating Indices	FCC Conversion (Vol %)	74.7	73.1	71.4	71.4	71.4
	Reformer Severity (RON)	96.9	98.0		98.0	98.0
Charge Rates	Fluid Cat Cracker[1]	590	639	645	645	645
	Reformer[1]	241	214	234	239	242
FCC Olefin Max Cat. (%)						
Fuel Use	All Fuels (foeb)	104	109	113	113	114

Table D-2: Operations and New Capacity (K b/d, except as noted)

Type of Process	Process	PADD 2: 2002 Calib-ration	PADD 2: 2010 Refer-ence	Study Case #1 RFG	Study Case #2 RFG+ Low RVP	Study Case #3 RFG+ Low RVP+ CG
USE OF EXISTING CAPACITY						
Crude Distillation	Atmospheric	3,324	3,328	3,331	3,344	3,402
Conversion	Fluid Cat Cracker	1,169	1,141	1,140	1,140	1,117
	Hydrocracker	148	160	160	160	160
	Coking	319	306	307	309	320
	Visbreaker					
Upgrading	Alkylation	236	251	251	251	251
	Merchant Iso-Octane/ene					
	Catalytic Polymerization	5	5	5	5	5
	Dimersol		3	3	3	
	Pen/Hex Isomerization	119	172	172	172	172
	Reforming	687	515	522	534	601
Oxygenate Prod.	MTBE -- FCC-based	9				
	MTBE -- Field Butane-based					
	MTBE -- Other					
	TAME					
Hydrotreating	Naphtha Desulf.	768	841	842	845	909
	FCC Naphtha Desulfurization	22	647	647	647	643
	Benzene Saturation	10	9	9	9	9
	Distillate Desulfurization	890	934	937	945	952
	FCC Feed Desulfurization	464	462	463	465	474
	Merox (MTBE)					
	Resid Desulfurization					
Hydrogen	Hydrogen Plant (MM scf/d)	1,467	1,793	1,805	1,816	1,820
Fractionation	Debutanization	217	208	209	209	210
	Lt. Naphtha Spl. (Benz. Prec.)	91	266	266	266	266
Other	Aromatics Plant	35	50	50	50	50
	Benzene Extraction		1	1	1	1
	Butane Isomerization	2	5	6	16	24
	Lubes & Waxes	19	17	17	17	17
	Solvent Deasphalting	16	16	16	16	16
	Sulfur Recovery (K s tons/d)	3	4	4	4	4
	Steam Generation (K lb/hr)	16,939	17,103	17,160	17,289	17,853
NEW CAPACITY						
Upgrading	Alkylation					
	Pen/Hex Isomerization					
Hydrogen	Hydrogen Plant (MM scf/d)				0	0
Fractionation	Debutanization					6
	Depentanization					43
	Medium Naphtha Splitter					
	Light Gas Processing					
Retrofitting	Captive MTBE to Alkylate					
	Tier 2 Desulfurization		0	2	10	0
OPERATIONS						
Operating Indices	FCC Conversion (Vol %)	76.3	75.2	75.1	74.8	72.2
	Reformer Severity (RON)	98.1	93.6	93.9	94.5	95.3
Charge Rates	Fluid Cat Cracker[1]	1,145	1,141	1,142	1,147	1,169
	Reformer[1]	700	574	576	583	649
FCC Olefin Max Cat. (%)						
Fuel Use	All Fuels (foeb)	255	269	272	276	287

Table D-2: Operations and New Capacity (K b/d, except noted)

Type of Process	Process	PADD 3				
				Study Case		
		2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG
USE OF EXISTING CAPACITY						
Crude Distillation	Atmospheric	7,038	8,387	8,385	8,390	8,390
Conversion	Fluid Cat Cracker	2,742	2,744	2,750	2,697	2,748
	Hydrocracker	455	575	575	575	575
	Coking	1,001	1,199	1,200	1,201	1,218
	Visbreaker	12				
Upgrading	Alkylation	518	581	581	581	581
	Merchant Iso-Octane/ene					
	Catalytic Polymerization	10	11	11	11	11
	Dimersol					
	Pen/Hex Isomerization	146	233	233	233	233
	Reforming	1,352	1,231	1,212	1,271	1,370
Oxygenate Prod.	MTBE -- FCC-based	72	0	0	0	0
	MTBE -- Field Butane-based	69				
	MTBE -- Other	60				
	TAME					
Hydrotreating	Naphtha Desulf.	1,242	1,655	1,655	1,653	1,705
	FCC Naphtha Desulfurization	77	1,506	1,506	1,506	1,506
	Benzene Saturation					
	Distillate Desulfurization	1,951	2,458	2,458	2,458	2,458
	FCC Feed Desulfurization	1,074	1,119	1,120	1,135	1,201
	Merox (MTBE)					
	Resid Desulfurization	56	170	171	172	177
Hydrogen	Hydrogen Plant (MM scf/d)	1,776	2,680	2,680	2,680	2,680
Fractionation	Debutanization	511	542	542	542	542
	Lt. Naphtha Spl. (Benz. Prec.)	126	192	192	192	192
Other	Aromatics Plant	150	196	202	233	233
	Benzene Extraction	21	10	10	10	10
	Butane Isomerization	65	84	86	95	94
	Lubes & Waxes	135	145	145	145	145
	Solvent Deasphalting	200	200	200	200	200
	Sulfur Recovery (K s tons/d)	10	13	13	13	13
	Steam Generation (K lb/hr)	42,704	48,154	48,316	48,753	50,149
NEW CAPACITY						
Upgrading	Alkylation					
	Pen/Hex Isomerization					
Hydrogen	Hydrogen Plant (MM scf/d)				180	302
Fractionation	Debutanization		0	0	0	52
	Depentanization					291
	Medium Naphtha Splitter					
	Light Gas Processing					
Retrofitting	Captive MTBE to Alkylate		3	5	4	7
	Tier 2 Desulfurization			1		48
OPERATIONS						
Operating Indices	FCC Conversion (Vol %)	75.7	72.9	72.9	71.5	69.0
	Reformer Severity (RON)	98.0	97.6	96.7	98.0	96.9
Charge Rates	Fluid Cat Cracker[1]	2,685	2,797	2,800	2,837	3,003
	Reformer[1]	1,380	1,261	1,276	1,296	1,433
FCC Olefin Max Cat. (%)		22	17	17	22	21
Fuel Use	All Fuels (foeb)	667	772	782	799	828

Table D-3a: Refinery Inputs[1] (K b/d)

Inputs	PADD 1					PADD 2					PADD 3				
			Study Case					Study Case					Study Case		
	2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG	2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG	2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG
Crude Oil	**1,566**	**1,621**	**1,622**	**1,627**	**1,631**	**3,324**	**3,328**	**3,331**	**3,344**	**3,402**	**7,038**	**8,387**	**8,385**	**8,396**	**8,483**
Gasoline Blendstocks						**42**	**40**	**40**	**40**	**40**	**184**	**155**	**155**	**155**	**155**
Natural Gas Liquids						42	40	40	40	40	139	110	110	110	110
Alkylate															
PyGas											45	45	45	45	45
Oxygenates	**63**	**77**	**77**	**77**	**77**	**85**	**198**	**198**	**198**	**198**	**37**	**405**	**405**	**405**	**405**
MTBE	58														
Ethanol	2	77	77	77	77	82	198	198	198	198	13	405	405	405	405
Methanol	3					3					24				
Other Refinery Inputs	**77**	**48**	**48**	**48**	**48**	**60**	**97**	**95**	**84**	**77**	**381**	**321**	**323**	**319**	**315**
Iso-butane						23	38	36	25	21	7				
Normal butane						4	3	3	3			6	8	4	
Naphtha	1					33	56	56	56	56	30	25	25	25	25
Kerosene											2	2	2	2	2
Heavy Gas Oil	69	44	44	44	44						232	196	196	196	196
Residual Oil	7	4	4	4	4						110	92	92	92	92
Merchant Plant Inputs											**155**				
Field Butanes											64				
Butylenes											48				
Methanol											44				
Purchased Energy															
Electricity (K Kwh)	5,867	6,107	6,193	6,222	6,270	15,038	16,552	16,695	16,871	17,302	39,190	47,835	48,335	48,960	50,322
Natural Gas (K foeb/d)	77	84	87	88	88	197	233	236	239	248	546	683	696	715	746
Total (ex. Purch En)	**1,706**	**1,746**	**1,747**	**1,752**	**1,756**	**3,511**	**3,662**	**3,663**	**3,666**	**3,716**	**7,640**	**9,268**	**9,267**	**9,275**	**9,357**

1 Includes inputs to merchant producers of MTBE

Table D-3b: Refinery Outputs[1]
(K b/d)

Outputs	PADD 1					PADD 2					PADD 3				
			Study Case					Study Case					Study Case		
	2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG	2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG	2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG
Total[2]	**1,713**	**1,761**	**1,756**	**1,761**	**1,765**	**3,481**	**3,657**	**3,657**	**3,659**	**3,701**	**7,741**	**9,250**	**9,250**	**9,252**	**9,340**
BTX	32	54	54	54	54	35	46	46	47	48	171	206	206	206	206
MTBE - Merchant											100				
Ethane											24	23	23	23	23
Propane	38	37	36	37	37	92	80	80	82	84	224	232	232	234	237
Propylene	18	23	23	23	23	44	34	34	34	34	178	199	199	199	199
Butane/Butylene	3	15	16	16	17	2				30	10				35
Mixed C45s		5		5	8					7					50
Naphtha	18	17	17	17	17	38	34	34	34	34	174	253	253	253	253
Aviation Gas						5	5	5	5	5	10	11	11	11	11
Gasoline[3]	810	771	771	771	771	1,914	1,976	1,976	1,976	1,976	3,756	4,172	4,172	4,172	4,172
Conventional	238	52	52	52		1,429	1,169	1,169	1,169		1,908	1,601	1,601	1,601	126
7.8 RVP	82	154	154			196	341	341			819	930	930		
7.0 RVP				154	206	47	174	174	515	1,684	262	358	358	1,288	2,763
RFG, ethanol blended		565	565	565	565	225	292	292	292	292	100	1,283	1,283	1,283	1,283
RFG, MTBE	490					17					667				
Jet Fuel	98	121	121	121	121	225	245	245	245	245	782	1,001	1,001	1,001	1,001
Distillate Fuel															
On -road diesel <0.05 wt%	261					664					1,168				
On-road diesel<0.0015 wt%		344	344	344	344		868	868	868	868		1,971	1,971	1,971	1,971
Off-road diesel/Heating Oil	206	122	122	122	122	195	90	90	90	90	455	370	370	370	370
Unf. Oil to PetroChem											137	187	187	187	187
Carbon Black Feed											25	31	31	31	31
Residual Oil	90	103	103	103	103	57	58	58	58	58	260	318	318	318	318
Asphalt	121	129	129	129	129	190	204	204	204	204	132	131	131	131	131
Lubes & Waxes	18	19	19	19	19	19	17	17	17	17	135	145	145	145	145
Coke	11	9	9	9	9	74	70	70	71	73	265	299	299	300	304
Sulfur (s tons/d)	1.0	1.0	1.0	1.0	1.0	3.3	3.6	3.6	3.6	3.7	9.8	12.8	12.8	12.8	13.1

1 Includes outputs of merchant producers of MTBE
2 Excludes coke & sulfur
3 Includes production of gasoline blendstocks

Table D-4a: Average Gasoline Properties -- PADD 1

Property / Octane & Volume	2002 Calibration					2010 Reference					Study Case 1: RFG					Study Case 2: RFG+Low RVP				Study Case 3: RFG+Low RVP+CG		
	CG	7.8 RVP	7.0 RVP	MTBE RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG/ Nat'l Gas	Pool	CG	Nat'l Gas	RFG/ Nat'l Gas	Pool	Nat'l Gas	RFG/ Nat'l Gas	Pool
Property																						
RVP (psi)	8.7	7.6		6.8	7.4	9.7	7.6		7.0	7.3	9.7	7.6		6.8	7.2	9.7	6.8	6.8	7.0	7.1	6.8	6.9
Oxygen (wt%)	0.9	0.7		2.1	1.6	3.5	3.5		3.5	3.5	3.5	3.5		3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Aromatics (vol%)	27.9	30.0		19.3	22.9	26.2	27.0		17.9	20.3	20.1	30.5		18.4	21.0	24.7	34.4	17.4	21.3	33.0	17.3	21.5
Benzene (vol%)	0.94	0.94		0.59	0.73	0.62	0.62		0.59	0.60	0.62	0.62		0.59	0.60	0.62	0.62	0.59	0.60	0.62	0.59	0.60
Olefins (vol%)	14.0	14.0		12.6	13.2	18.0	18.0		12.1	13.6	14.9	9.2		10.7	10.7	15.7	3.8	11.9	10.5	9.1	10.8	10.4
Sulfur (ppm)	217	300		102	156	30	30		30	30	17	5		4	5	18	4	5	5	4	5	4
E130 (vol% off)	9.3	7.9		8.2	8.5	11.0	8.0		7.1	7.6	11.4	6.5		7.1	7.2	9.7	5.4	7.1	6.9	5.8	7.0	6.7
E200 (vol% off)	45.3	41.1		47.0	45.9	42.6	41.6		47.6	46.1	53.1	43.8		44.6	45.0	50.8	45.4	43.9	44.7	45.7	44.0	44.5
E300 (vol% off)	75.1	75.0		83.6	80.2	72.4	73.9		82.3	79.9	81.3	73.4		80.2	78.9	78.3	76.5	79.4	78.8	75.4	79.9	78.7
Estimated DI[1]	1,185	1,220		1,147	1,165	1,207	1,220		1,151	1,169	1,100	1,213		1,180	1,181	1,134	1,195	1,187	1,185	1,195	1,185	1,188
En. Den. (MM Btu/bbl)	5.187	5.225		5.108	5.143	5.097	5.123		5.039	5.060	5.012	5.097		5.066	5.069	5.052	5.116	5.065	5.074	5.128	5.059	5.078
Emission Red (%)[2]																						
VOCs	-1.5	10.3		28.8					28.1					28.0				28.0			28.1	
NOx	0.3	-1.5		9.2					13.6					15.4				15.3			15.8	
Toxics	14.3	14.5		35.5					33.7					33.6				33.7			34.0	
Octane ((R+M)/2)	**88.2**	**88.2**		**88.2**	**88.2**	**88.1**	**88.1**		**88.1**	**88.1**	**88.1**	**88.1**		**88.1**	**88.1**	**88.1**	**88.1**	**88.1**	**88.1**	**88.1**	**88.1**	**88.1**
Volume (K b/d)	**238**	**82**		**490**	**810**	**52**	**154**		**565**	**771**	**52**	**154**		**565**	**771**	**52**	**154**	**565**	**771**	**206**	**565**	**771**

1 ASTM Driveability Index; calculated using modeling results for E130, E200, & E300.
2 As estimated by reduced-form of the Complex Model in ARMS.

Table D-4b: Average Gasoline Properties -- PADD 2

Property / Octane & Volume	2002 Calibration						2010 Reference					Study Case 1: RFG					Study Case 2: RFG+Low RVP				Study Case 3: RFG+Low RVP+CG		
	CG	7.8 RVP	7.0 RVP	EOH RFG	MTBE RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG/ Nat'l Gas	Pool	CG	Nat'l Gas	RFG/ Nat'l Gas	Pool	Nat'l Gas	RFG/ Nat'l Gas	Pool
Property																							
RVP (psi)	8.7	7.6	6.8	6.8	6.8	8.3	9.7	7.8	7.3	7.0	8.8	9.7	7.8	7.3	6.8	8.7	9.7	6.8	6.8	8.5	7.5	6.8	7.4
Oxygen (wt%)	1.5	0.4	0.7	3.5	2.1	1.6	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Aromatics (vol%)	26.7	37.1	31.0	18.7	18.0	26.8	23.0	8.0	32.2	16.0	20.2	19.9	22.8	24.9	16.3	20.3	22.8	18.5	16.0	20.7	23.2	16.0	22.1
Benzene (vol%)	1.37	1.37	1.37	0.82	0.82	1.30	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
Olefins (vol%)	10.1	6.0	10.3	5.2	5.2	9.1	10.3	8.0	7.9	8.3	9.4	8.5	6.8	5.0	13.7	8.7	7.0	8.8	11.4	8.1	7.4	2.8	6.7
Sulfur (ppm)	350	84	350	200	170	304	30	30	30	30	30	26	20	20	5	21	23	5	5	15	4	5	4
E130 (vol% off)	9.7	5.1	5.0	6.7	8.5	8.7	10.8	9.1	5.9	7.3	9.6	10.9	8.1	6.6	7.5	9.5	10.1	8.0	6.7	9.1	7.0	7.6	7.1
E200 (vol% off)	46.7	40.4	49.9	52.0	52.0	46.8	53.1	53.4	42.9	44.0	50.9	53.2	45.7	46.8	50.2	50.9	55.1	43.9	44.1	50.5	49.5	41.9	48.4
E300 (vol% off)	79.5	79.4	78.0	88.4	90.7	80.6	77.8	90.2	91.3	88.4	82.7	83.2	85.7	78.1	79.6	82.7	85.7	76.4	80.4	82.5	80.7	85.2	81.4
Estimated DI[1]	1,158	1,220	1,159	1,100	1,085	1,157	1,115	1,074	1,156	1,153	1,117	1,094	1,148	1,174	1,142	1,118	1,075	1,195	1,184	1,122	1,144	1,179	1,149
En. Den. (MM Btu/bbl)	5.125	5.237	5.185	5.032	5.094	5.126	5.017	4.973	5.101	5.033	5.019	4.994	5.049	5.073	5.060	5.020	4.993	5.080	5.059	5.025	5.056	5.030	5.052
Emission Red (%)[2]																							
VOCs	1.3	14.4	17.2	28.1	28.1					28.0					29.9				28.6			28.0	
NOx	0.0	0.4	7.2	9.4	9.6					16.3					14.1				16.0			18.3	
Toxics	8.4	8.4	8.4	31.0	33.8					34.9					34.6				34.3			35.5	
Octane ((R+M)/2)	**88.9**	**87.8**	**87.8**	**87.8**	**87.8**	**88.6**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**
Volume (K b/d)	**1,429**	**196**	**47**	**225**	**17**	**1,914**	**1,169**	**341**	**174**	**292**	**1,976**	**1,169**	**341**	**174**	**292**	**1,976**	**1,169**	**515**	**292**	**1,976**	**1,684**	**292**	**1,976**

1 ASTM Driveability Index; calculated using modeling results for E130, E200, & E300.
2 As estimated by reduced-form of the Complex Model in ARMS.

Table D-4c: Average Gasoline Properties -- PADD 3

Property	2002 Calibration						2010 Reference					Study Case 1: RFG					Study Case 2: RFG+Low RVP				Study Case 3: RFG+Low RVP+CG			
Octane & Volume	CG	7.8 RVP	7.0 RVP	EOH RFG	MTBE RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG/ Nat'l Gas	Pool	CG	Nat'l Gas	RFG/ Nat'l Gas	Pool	Export CG	Nat'l Gas	RFG/ Nat'l Gas	Pool
Property																								
RVP (psi)	8.7	7.6	6.8	6.8	6.8	7.9	9.7	7.6	7.0	6.8	8.1	9.7	7.6	7.0	6.8	8.1	9.7	6.8	6.8	7.9	8.7	7.3	6.8	7.2
Oxygen (wt%)	0.2	0.2	0.2	3.5	2.1	0.6	3.2	3.5	3.5	3.5	3.4	3.2	3.5	3.5	3.5	3.4	3.2	3.5	3.5	3.4		3.5	3.5	3.4
Aromatics (vol%)	26.9	29.0	35.0	20.0	20.0	26.5	24.6	21.5	26.0	16.0	21.4	26.0	13.9	16.5	22.0	21.2	17.9	27.6	20.6	21.7	29.9	24.2	16.2	21.9
Benzene (vol%)	1.00	0.94	0.56	0.60	0.58	0.87	0.62	0.62	0.62	0.60	0.61	0.62	0.62	0.62	0.60	0.61	0.62	0.62	0.60	0.61	0.62	0.62	0.60	0.61
Olefins (vol%)	12.8	11.5	15.0	8.5	12.5	12.5	11.0	7.0	9.9	10.2	9.8	12.1	10.2	13.2	2.5	8.8	6.8	11.6	4.3	7.5	0.9	5.4	11.3	7.1
Sulfur (ppm)	320	320	320	150	150	285	30	30	30	30	30	22	25	25	5	18	14	5	5	8	5	5	5	5
E130 (vol% off)	9.0	6.3	4.7	7.1	6.8	7.7	10.2	7.1	6.5	7.6	8.4	10.6	8.2	7.4	6.2	8.4	11.1	6.6	6.0	8.1	10.5	6.8	6.6	6.8
E200 (vol% off)	41.7	47.9	40.8	52.0	51.4	45.0	53.0	50.6	43.0	42.2	48.3	51.6	45.2	50.3	47.4	48.7	50.9	45.1	47.8	48.2	54.9	48.8	44.4	47.6
E300 (vol% off)	79.0	79.0	79.0	83.0	83.0	79.8	78.5	87.7	88.4	81.1	82.2	77.5	85.9	82.9	85.2	82.2	86.0	75.6	83.2	81.9	95.2	79.9	87.6	82.7
Estimated DI[1]	1,197	1,165	1,220	1,118	1,123	1,176	1,116	1,111	1,164	1,191	1,142	1,127	1,151	1,129	1,146	1,138	1,099	1,195	1,151	1,145	1,040	1,153	1,156	1,151
En. Den. (MM Btu/bbl)	5.179	5.226	5.264	5.051	5.086	5.175	5.029	5.023	5.082	5.061	5.042	5.061	4.988	5.030	5.050	5.038	5.014	5.099	5.033	5.046	5.127	5.066	5.020	5.054
Emission Red (%)[2]																								
VOCs	0.2	14.2	18.4	28.0	28.9					28.0					28.0				28.2				30.1	
NOx	-1.1	-1.8	0.0	10.3	7.4					15.5					15.8				16.1				16.3	
Toxics	12.1	15.3	11.0	34.0	35.6					34.0					33.7				33.9				35.1	
Octane ((R+M)/2)	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**88.0**	**87.7**	**87.7**	**87.7**	**88.2**	**87.9**	**87.7**	**87.7**	**87.7**	**88.2**	**87.9**	**87.7**	**87.7**	**88.2**	**87.9**	**87.7**	**87.7**	**88.2**	**87.9**
Volume (K b/d)	**1,908**	**819**	**262**	**100**	**667**	**3,756**	**1,601**	**930**	**358**	**1,283**	**4,172**	**1,601**	**930**	**358**	**1,283**	**4,172**	**1,601**	**1,288**	**1,283**	**4,172**	**126**	**2,763**	**1,283**	**4,172**

1 ASTM Driveability Index; calculated using modeling results for E130, E200, & E300.
2 As estimated by reduced-form of the Complex Model in ARMS.

Table D-5a: Average Gasoline Composition (Volume Percent) -- PADD 1

Gasoline Blendstock	2002 Calibration					2010 Reference					Study Case 1: RFG					Study Case 2: RFG+Low RVP				Study Case 3: RFG+Low RVP+CG		
	CG	7.8 RVP	7.0 RVP	MTBE RFG	Pool	CG	7.8 RVP	7.0 RVP	EOH RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG/ Nat'l Gas	Pool	CG	Nat'l Gas	RFG/ Nat'l Gas	Pool	Nat'l Gas	RFG/ Nat'l Gas	Pool
Total (%)	**100.0**	**100.0**		**100.0**	**100.0**	**100.0**	**100.0**		**100.0**	**100.0**	**100.0**	**100.0**		**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
C4s	7.4	5.4		3.5	4.8	8.0	4.2		1.0	2.1	6.4	2.0		1.2	1.7	6.2	0.5	1.3	1.5	0.5	1.5	1.3
Natural Gas Liquids																						
C5s & Isomerate	6.1	0.3		0.4	2.1				3.0	2.2	7.3	0.1		2.3	2.2	10.5		2.0	2.2		3.0	2.2
Raffinate				2.5	1.5		2.7		3.8	3.3		16.0			3.2		13.4	0.8	3.2	5.7	2.4	3.2
Naphthas (C5-250°)	10.7			13.2	11.1	12.1	7.3		9.4	9.2	3.2	7.7		9.1	8.4	12.5	20.2	5.0	8.5	17.3	5.3	8.5
Hydrocrackate		11.5			1.2				1.9	1.4		1.2		0.4	0.5		2.6		0.5	2.3		0.6
Alkylate	4.1	4.4		14.6	10.5				17.2	12.6	2.2			16.9	12.6		0.9	16.9	12.6	0.5	17.0	12.6
Merchant Alkylate																						
Iso-Octane/Octene																						
Poly Gas	3.7	5.5			1.6	10.6	4.0			1.5		6.7			1.3	8.8	3.7		1.3	5.0		1.3
FCC Naphtha	36.3	30.1		43.8	40.2	26.6	53.5		45.0	45.5	64.8	14.1		52.3	45.5	27.7		59.1	45.2	19.4	54.2	44.9
Reformate - Light	6.0	13.2		4.0	5.5	10.2	0.7		1.1	1.6	6.2	0.1		0.9	1.1	4.5	4.0		1.1	4.1	0.2	1.2
Reformate - Med&Hvy	21.7	25.5		6.6	13.0	22.5	17.7		7.7	10.7		42.0		6.9	13.5	19.9	44.6	5.0	13.9	35.2	6.4	14.1
Aromatics																						
Py Gas																						
Oxygenates																						
MTBE	2.2	4.0		11.5	8.0																	
TAME	0.8				0.2																	
Ethanol	1.0				0.3	10.0	10.0		10.0	10.0	10.0	10.0		10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Volume (K b/d)	**238**	**82**		**490**	**810**	**52**	**154**		**565**	**771**	**52**	**154**		**565**	**771**	**52**	**154**	**565**	**771**	**206**	**565**	**771**

Table D-5b: Average Gasoline Composition (Volume Percent) -- PADD 2

Gasoline Blendstock	2002 Calibration						2010 Reference					Study Case 1: RFG					Study Case 2: RFG+Low RVP				Study Case 3: RFG+Low RVP+CG		
	CG	7.8 RVP	7.0 RVP	EOH RFG	MTBE RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG/ Nat'l Gas	Pool	CG	Nat'l Gas	RFG/ Nat'l Gas	Pool	Nat'l Gas	RFG/ Nat'l Gas	Pool
Total (%)	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
C4s	6.5	3.2	2.0	1.4	5.4	5.4	5.8	4.2	2.3	2.0	4.7	5.9	4.0	2.0	2.0	4.6	5.3	3.0	1.5	4.1	1.9	2.8	2.0
Natural Gas Liquids	2.4	4.0				2.2																	
C5s & Isomerate	5.8	7.9	16.0	4.0		6.0	14.3			0.6	8.6	10.6	7.3	11.7		8.6	13.9		2.3	8.6	10.1		8.6
Raffinate		1.3		2.4		0.4	2.0				1.2	1.8	0.6	0.5		1.2	1.9		0.9	1.2	0.4	6.2	1.3
Naphthas (C5-250°)	3.4	3.0	8.2	20.2	24.5	5.7	2.2	15.1	4.1	13.4	6.2	6.7	8.9	7.5	0.3	6.2	6.7	6.2	4.6	6.2	7.4	0.3	6.3
Hydrocrackate	3.4					2.6	2.7	3.8	4.2	4.1	3.2	2.9	4.6	5.0	2.3	3.3	4.1	4.3		3.5	1.3	16.6	3.6
Alkylate	11.7	1.4		23.9	25.9	11.9	2.7	39.6		26.5	12.4	10.2	14.6	14.2	17.2	12.4	6.1	22.4	19.8	12.4	9.5	29.0	12.4
Merchant Alkylate																							
Iso-Octane/Octene																							
Poly Gas								0.4		0.6	0.2		0.9			0.2	0.3			0.2			
FCC Naphtha	37.9	23.8	41.3	18.7	16.7	34.1	36.7	27.0	27.1	27.1	32.7	29.7	20.9	16.8	68.1	32.7	23.3	41.1	56.2	32.8	35.4	14.6	32.3
Reformate - Light	7.0	26.9	8.6	9.7	8.0	9.4	4.8		52.2	11.2	9.1	10.3	17.2			9.1	14.6	0.6	1.9	9.1	9.0	9.9	9.1
Reformate - Med&Hvy	17.6	26.3	20.2	9.7	8.1	17.6	18.2			4.6	11.5	11.3	11.0	32.4		11.4	13.5	12.4	2.8	11.6	14.8	10.5	14.1
Aromatics							0.4				0.3	0.4				0.3	0.4			0.3	0.3		0.3
Py Gas																							
Oxygenates																							
MTBE	0.1	2.2	3.7		11.5	0.5																	
TAME																							
Ethanol	4.2			10.0		4.3	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Volume (K b/d)	**1,429**	**196**	**47**	**225**	**17**	**1,914**	**1,169**	**341**	**174**	**292**	**1,976**	**1,169**	**341**	**174**	**292**	**1,976**	**1,169**	**515**	**292**	**1,976**	**1,684**	**292**	**1,976**

Table D-5c: Average Gasoline Composition (Volume Percent) -- PADD 3

Gasoline Blendstock	2002 Calibration						2010 Reference					Study Case 1: RFG					Study Case 2: RFG+Low RVP				Study Case 3: RFG+Low RVP+CG			
	CG	7.8 RVP	7.0 RVP	EOH RFG	MTBE RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG	Pool	CG	7.8 RVP	7.0 RVP	RFG/ Nat'l Gas	Pool	CG	Nat'l Gas	RFG/ Nat'l Gas	Pool	Export CG	Nat'l Gas	RFG/ Nat'l Gas	Pool
Total (%)	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
C4s	6.5	3.9	2.2	2.1	2.0	4.7	5.4	2.7	2.0	2.0	3.5	5.6	3.0	2.2	1.5	3.4	6.8	1.2	0.5	3.1	7.7	1.8	1.1	1.8
Natural Gas Liquids	5.9				4.0	3.7		2.4			0.5	1.3	7.1	1.6		2.2		3.8	2.3	1.9		1.9	4.5	2.6
C5s & Isomerate		2.6	17.3	22.1	8.3	3.8	14.1	0.3			5.5	2.7			14.5	5.5	1.2	0.5	15.9	5.5		8.3		5.5
Raffinate	0.3			3.0	2.0	0.6	2.9	5.4			2.3	1.1	0.9	4.5	0.5	1.2	1.0	2.8		1.3	17.2	0.8		1.1
Naphthas (C5-250°)	0.7	13.7		3.7	3.2	4.0	5.2	11.2	9.4	14.3	9.7	9.0	6.8	2.3	14.8	9.7	13.6	3.5	11.4	9.8	19.0	12.3	3.1	9.7
Hydrocrackate	8.3					4.2	2.9		2.9		1.4	1.6	1.1	2.9		1.1		1.6	1.9	1.1	8.2	1.3		1.1
Alkylate	13.4	19.5	0.8	16.1	10.1	13.4		20.4	10.0	27.1	13.8	1.8	26.3	21.9	17.5	13.8	21.8		17.6	13.8	16.9	11.8	18.0	13.9
Merchant Alkylate																								
Iso-Octane/Octene																								
Poly Gas																								
FCC Naphtha	40.8	30.0	45.7	24.6	42.5	38.7	39.9	25.4	36.9	36.2	35.3	48.6	40.4	51.1	10.5	35.3	31.5	56.4	18.8	35.3		25.8	54.3	33.8
Reformate - Light	8.3	7.6	18.3		10.4	9.0	2.0	12.8	28.8	0.1	6.1	1.5	1.2		14.8	5.4	9.6	7.7		6.1		5.1	6.5	5.4
Reformate - Med&Hvy	14.8	21.9	2.9	4.5	6.0	13.7	18.3	9.3		6.7	11.2	17.6	2.6	3.5	12.3	11.4	5.3	9.5	18.1	10.6		20.4		13.5
Aromatics													0.6			0.1		2.9		0.9	21.5	0.4		0.9
Py Gas			11.8	14.0		1.2				3.5	1.1				3.5	1.1			3.5	1.1	9.4		2.6	1.1
Oxygenates																								
MTBE	0.8	0.8	0.8		11.5	2.7																		
TAME																								
Ethanol	0.2			10.0		0.3	9.2	10.0	10.0	10.0	9.7	9.2	10.0	10.0	10.0	9.7	9.2	10.0	10.0	9.7		10.0	10.0	9.7
Volume (K b/d)	**1,908**	**819**	**262**	**100**	**667**	**3,756**	**1,601**	**930**	**358**	**1,283**	**4,172**	**1,601**	**930**	**358**	**1,283**	**4,172**	**1,601**	**1,288**	**1,283**	**4,172**	**126**	**2,763**	**1,283**	**4,172**

Table D-6: Shadow Values of Complex Model Parameters & Driveability Index and Cost of Octane

Gasoline		PADD 1					PADD 2					PADD 3				
				Study Case					Study Case					Study Case		
Property	Type	2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG	2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG	2002 Calib-ration	2010 Refer-ence	#1 RFG	#2 RFG+ Low RVP	#3 RFG+ Low RVP+ CG
RVP (psi)	CG	-0.277	-0.744	-0.875	-0.932		-0.228	-0.430	-0.435	-0.437		-0.178	-0.339	-0.368	-0.523	-0.802
	7.8 RVP	-0.277	-0.744	-0.882			-0.228	-0.430	-0.435			-0.178	-0.339	-0.368		
	7.0 RVP	-0.277					-0.228	-0.430	-0.435			-0.178	-0.339	-0.368		
	RFG	-0.277	-0.744	-0.877	-0.934	-0.934	-0.228	-0.430	-0.435	-0.437	-0.818	-0.178	-0.339	-0.357	-0.522	-0.802
	Nat'l Gas				-0.934	-0.934				-0.437	-0.818				-0.522	-0.802
Oxygen (wt%)	CG								0.000					0.000		
	7.8 RVP								0.000					0.000		
	7.0 RVP								0.000					0.000		
	RFG															
	Nat'l Gas															
Aromatics (vol%)	CG															
	7.8 RVP															
	7.0 RVP															
	RFG													-0.017		
	Nat'l Gas															
Benzene (vol%)	CG	-0.388	-0.666	-0.616	-0.838		-0.041	-1.023	-1.027	-1.029			-0.978	-1.041	-0.553	-1.217
	7.8 RVP	-0.388	-0.666	-0.623			-0.041	-1.023	-1.027				-0.978	-1.041		
	7.0 RVP	-0.388					-0.041	-1.023	-1.027				-0.978	-1.041		
	RFG	-0.388	-0.666	-0.619	-0.841	-0.841	-0.041	-1.023	-1.027	-1.029	-1.383		-0.978	-1.354	-0.864	-1.217
	Nat'l Gas				-0.841	-0.841				-1.029	-1.383				-0.864	-1.217
Olefins (vol%)	CG	-0.005														
	7.8 RVP	-0.005														
	7.0 RVP	-0.005														
	RFG	-0.005														
	Nat'l Gas															
Sulfur (ppm)	CG	0.000	-0.005	-0.031	-0.032			-0.003	-0.003	-0.003		0.000	-0.002	-0.004	-0.002	-0.953
	7.8 RVP	0.000	-0.005	-0.032				-0.003	-0.003			0.000	-0.003	-0.004		
	7.0 RVP	0.000						-0.003	-0.003			0.000	-0.003	-0.004		
	RFG	0.000	-0.005					-0.003				0.000		-0.387	-0.499	-0.953
	Nat'l Gas														-0.499	-0.953
E200 (vol% off)	CG															
	7.8 RVP															
	7.0 RVP															
	RFG															
	Nat'l Gas															
E300 (vol% off)	CG															
	7.8 RVP															
	7.0 RVP															
	RFG															
	Nat'l Gas															
ASTM Driveability Index	CG															
	7.8 RVP															
	7.0 RVP															
	RFG															
	Nat'l Gas															
Cost of Octane (¢/oct-gal)	CG		1.0	1.1	1.2			0.5	0.5	0.5			0.4	0.4	0.4	0.9
	7.8 RVP		1.0	1.1				0.5	0.5				0.4	0.4		
	7.0 RVP							0.5	0.5				0.4	0.4		
	RFG		1.0	1.1	1.1	1.1		0.5	0.5	0.5	0.7		0.4	0.7	0.7	0.9
	Nat'l Gas				1.1	1.1				0.5	0.7				0.7	0.9

Note: A negative shadow value indicates that limits imposed on a Complex Model parameter constrained "refinery operations," i.e., a cost was incurred to meet the parameter limit. A positive shadow value on the oxygen paramter indicates the "refinery" would prefer to blend less oxygenate (and vice versa). The shadow value indicates the cost of changing a given parameter by one unit (percent point) on the last barrel of gasoline produced. Alternatively, it indicates the cost of making a small reduction for a given parameter that, when summed over all barrels of a given gasoline class, equals a change of one unit (percent point).

Table D-7: Selected 2002 Calibration Results vs. Reported Information

	PADD 1		PADD 2		PADD 3	
	Reported	Calibration	Reported	Calibration	Reported	Calibration
Crude Inputs (K b/d)	1588	1,566	3371	3,324	7147	7,038
Operations						
Charge Rates (K/b/d)						
Fluid Cat Cracking	586	590	1169	1,145	2743	2,685
Hydrocracking[1]	39	38	142	148	599	455
Coking	77	77	328	319	1001	1,001
Operating Indices						
FCC Conversion		74.7		76.3		75.7
Reformer Severity		96.9		98.1		98.0
Prices/Marginal Cost ($/b)[2]						
Gasoline[3]						
Conventional	32.3	31.43		31.60	32.4	29.28
Federal RFG	34.3	32.11		32.05	33.9	29.74
Distillates						
Jet Fuel	31.2	29.00		29.89	30.1	28.15
On-road Diesel	30.3	28.93		30.00	29.4	28.12
Off-road Diesel	29.6	28.69		29.56	28.6	27.63
Pool Gasoline Properties[4]						
RVP (psi)	7.4	7.4	8.3	8.3	7.8	7.9
Oxygen (wt%)	1.6	1.6	0.5	1.6	0.6	0.6
Aromatics (vol%)	23.2	22.9	27.7	26.8	24.6	26.5
Benzene (vol%)	0.72	0.73	1.32	1.30	0.86	0.87
Olefins (vol%)	13.1	13.2	8.9	9.1	12.4	12.5
Sulfur (ppm)	152	156	323	304	270	285
E130 (vol% off)	*7.0*	8.5	*8.0*	8.7	*7.0*	7.7
E200 (vol% off)	47.1	45.9	45.8	46.8	45.0	45.0
E300 (vol% off)	82.2	80.2	81.3	80.6	79.6	79.8
DI	*1156*	1165	*1164*	1157	*1,180*	1,176

1 EIA reported charge rate includes charges to "lube hydrocracking."

2 In $2004.

3 Reported prices are for regular grade gasoline, whereas ARMS marginal costs are for pool gasoline.

4 Reported pool gasoline properties are based on PADD-level data provided by EPA for 2003, except for E130, which is based on data from the Alliance "North American Fuels Survey," Summer 2002. DI is estimated by formula using E130, E200 & E300.

1. INTRODUCTION

The Alliance of Automobile Manufacturers (the Alliance) retained MathPro Inc. to analyze the technical and economic effects of a contemplated new federal standard for a national "clean gasoline" (NCG) for use throughout the United States (ex California). The NCG standard would augment the federal standard for reformulated gasoline, and NCG would replace special gasolines ("boutique fuels") and conventional gasoline. This report deals with the technical approach and the results of the analysis.

1.1 Background

We understand that the Alliance advocates an NCG program because it would reduce emissions by gasoline-powered vehicles in the U.S. in three ways.

- In the existing vehicle fleet, NCG would offer better emissions performance than the boutique fuels and conventional gasoline (CG) that it would replace; the NCG standards also would improve the emissions performance of federal reformulated gasoline (RFG).

- In future vehicles, general availability of NCG would allow automobile manufacturers to tailor engine designs to a narrow and predictable range of gasoline properties, thereby enabling more economical and effective compliance with new emissions standards.

- In future vehicles, NCG would enable use of improved emission control technology that is sensitive to the sulfur content of gasoline.

The contemplated NCG program would phase in over time. Initially, for example, the NCG standards might be superimposed on the RFG program – gasoline sold in RFG areas would have to meet both sets of standards. Next, NCG could become the gasoline of choice in areas choosing to use a cleaner gasoline for meeting the 8-hour ozone standard. Ultimately, the NCG program could result in the U.S. gasoline pool (ex California) comprising no more than two gasoline types: NCG and federal RFG/NCG.

NCG would be a cleaner burning gasoline than either CG or low-RVP gasoline; but it would have higher refining costs, with the magnitude of the cost increase depending on the NCG standard and its phase-in sequence. The refining cost and investment requirements for NCG production would tend to increase with NCG's volume share of the U.S. gasoline pool.

1.2 Proposed NCG Standard

For purposes of this study, NCG is defined in terms of a set of gasoline properties, shown in **Table 1** on the next page.

Table 1: Proposed Standards for National Clean Gasoline (NCG)

Property	Units	Spec.	Type	Comments
Octane ((R+M)/2)				
Regular		87	Min.	
Premium		93	Min.	
Complex Model				
RVP	psi	7	Max.	Set at *6.8 psi* in the refinery models
Sulfur	ppm	10	Max.	Set at *5 ppm* in the refinery models
Benzene	vol.%	0.62	Avg.	EPA's new benzene standard
Aromatics	vol.%	----		No Aromatics limit for NCG
Olefins	vol.%	----		No Olefins limit for NCG
E200	vol.%	----		No E200 requirement for NCG
E300	vol.%	----		No E300 requirement for NCG
Oxygen	wt.%	----		No oxygen required in NCG, but the entire U.S. gasoline pool (including NCG) is assumed to be E10
Driveability Index		1250	Max.	Set at *1220* in the refinery models

The *Driveability Index (DI)* standard in Table 1 applies to the Driveability Index definition recently adopted by ASTM[1]:

$$DI\ (^oF) = 1.5*T_{10} + 3.0*T_{50} + 1.0*T_{90} + 2.403*(Vol\%\ EtOH).$$

The last term in the equation adjusts the DI upwards by about 24 numbers when ethanol is blended at 10%, to reflect ethanol's observed adverse effects on driveability.

The study considered a phased introduction of NCG into the U.S. gasoline pool, with the following assumed sequence of NCG volume additions: (1) augmentation of the RFG standards with the NCG standard (that is, introduction of NCG in current RFG areas); (2) replacement of all low-RVP (7.0 and 7.8 RVP gasoline); and (3) replacement of all CG. This sequence begins with the least-cost replacement and moves on to progressively more costly ones.

1.3 Technical Approach

We analyzed the refining economics of the proposed NCG standard at each step in the phase-in sequence by means of regional refinery LP modeling, using our proprietary refinery modeling system. In particular, we applied three models, representing aggregate refining operations in PADD 1, PADD 2, and PADD 3, respectively.[2] The target time period for the analysis was the 2010 summer season, as specified by the Alliance.

---

[1] ASTM Subcommittee D02.A Section 3 adopted the new standard, ASTM D4814-06a, in November 2006.

[2] We did not consider PADDs 4 and 5 in the analysis, because (i) the total gasoline volume produced and consumed in PADDs 4 and 5 ex California is small and (ii) the NCG standard would not apply in California.

The refinery modeling reflected the following assumptions regarding national and state policies affecting gasoline quality.

- All gasoline is ethanol-blended at 10 vol% in 2010 ("*National E10*"), resulting in national ethanol use of about 14½ bgy. (By contrast, the Department of Energy's Annual Energy Outlook 2007 (*AEO 2007*) projected ethanol use of about 10.8 bgy in 2010);

- No use of MTBE in gasoline;

- Implementation of the 8-hour ozone standard;

- Continuation of the 1 psi RVP waiver for ethanol blended CG and for low-RVP gasoline in those states (mostly in the Midwest) now granting the waiver (which does not apply for low-RVP gasoline during the peak ozone months, July and August);

- Continuation of the RVP waiver for NCG that replaces CG, but not for NCG that replaces low-RVP gasoline, even in the Midwest; and

- No increase in the number of distinct gasoline types, per Title 15 Subtitle C of EPAct2005.

We developed regional (i.e., PADD-level) projections based on price and national volume projections from *AEO 2007* (Reference Case) and on prior MathPro studies of

- Demand for and refinery production of gasoline;

- Additional volumes of special gasolines – 7 RVP, 7.8 RVP, and RFG – that would be called out (i.e., specified in SIPs) in response to the 8-hour ozone standard; and

- Ethanol use consistent with national E10.

The refinery modeling encompassed a 2002 Calibration Case, a 2010 Reference Case, three 2010 Study Cases and three DI Sensitivity Cases. The three Study Cases represented the staged introduction of NCG in the aforementioned sequence. The three DI Sensitivity Cases represented the introduction of NCG in the same sequence, but with a maximum Driveability Index of 1200, rather than 1250 as in the Study Cases. Each case encompassed separate modeling runs for PADD 1, PADD 2, and PADD 3.

All of these cases incorporated a crude oil price of $51.2/Bbl ($2006), the *AEO 2007* Reference case projection for 2010. Because the recent run-up in crude oil prices calls that projection into question, we conducted a brief sensitivity analysis in which we estimated the effects of a much higher crude oil price for 2010 – $125/Bbl ($2006) – on the refining economics of NCG production (with DI capped at 1250).[3]

---

[3] We used projections from *AEO 2007* in the refining analysis because we conducted the analysis in the third quarter of 2007, prior to the publication of *AEO 2008*. By way of comparison, the *AEO 2008* Reference Case projects a crude price of $XX/Bbl in 2010.

This sensitivity analysis did not involve additional refinery modeling. Rather, we estimated a set of prices for other refinery inputs and refined products consistent with a crude oil price of $125/Bbl and then applied these prices to the refinery input and output volumes returned by the various Study Cases.

1.4 Summary of Results

Table D-1a (Appendix D) summarizes the primary economic results of the original Study Cases in the refining analysis (with AEO 2007's projected crude oil price). The table shows the estimated average refining cost of the proposed NCG standard, by PADD, in ¢/gal of NCG and billions of dollars of refinery investment, at each of the various NCG phase-in stages.

Averaged over PADDs 1, 2, and 3, the estimated *average cost* of producing NCG at the assumed maximum market coverage – with NCG augmenting all RFG and replacing all low-RVP gasoline and CG in the three PADDs – is about *2¾¢/gal*. The corresponding estimated average *incremental cost* for the last increment of NCG introduced (to replace CG) is about *4¢/gal*.

The results of the DI Sensitivity Cases in the refining analysis (not shown in Table D-1a) indicate that lowering the DI standard to 1200 in the NCG program would (i) increase the average refining cost of NCG in PADD 1 (only) by about *1¢/gal* and the incremental cost (for displacing CG) by about *5¢/gal* (given AEO 2007's projected crude oil price) and (ii) have no effect on average refining costs in the other PADDs. However, as discussed later in this report, the DI 1200 standard would likely impose additional costs on some individual refineries, costs not captured in our aggregate refinery modeling.

Table D-1b (Appendix D) summarizes the estimated effects of increasing crude price on the primary economic results of the refining analysis. At a projected crude oil price of $125/Bbl ($2006), the estimated *average cost* of producing NCG (averaged over PADDs 1, 2, and 3) at the assumed maximum market coverage – with NCG augmenting all RFG and replacing all low-RVP gasoline and CG in the three PADDs – is about *4½¢/gal*. That is, we estimate that the increase in crude oil price from $50/Bbl to $125/Bbl increases the *average* refining cost of the NCG program by about *1¾¢/gal* and the corresponding average *incremental cost* for the last increment of NCG introduced (to replace CG) by about *2¾¢/gal* (relative to the results of the original Study Cases.)

Table D-1b also indicates that, for crude prices in the vicinity of $125/Bbl, a $10/Bbl change in crude price would lead to a change of about ¼¢/gal in the average cost of producing NCG (assuming no change in electricity and natural gas prices).

1.5 Organization of the Report

The following sections of the report describe the development of the regional refining models for analyzing prospective effects of the NCG program, present the results of the analysis, and discuss analytical issues that emerged in the refinery modeling.

- Section 2 shows the boundary conditions (refining capacity, refining inputs & outputs, etc.) developed for calibrating our refinery models.
- Section 3 discusses the projections of refinery inputs and refined product out-turns developed to establish the baseline (Reference case) for 2010, the target year for the analysis.
- Section 4 provides information on average properties of the U.S. gasoline pool, developed from data provided by the Alliance and EPA.
- Section 5 presents results of the refinery modeling analysis for the Calibration, Reference, and Study Cases.
- Section 6 presents results of the refinery modeling analysis for the DI Sensitivity Cases, in which the DI standard is lowered from 1250 to 1200.
- Section 7 discusses the sensitivity analysis to estimate the effect of higher crude oil prices on the economics of NCG production.
- Section 8 discusses analytic issues that arose in the refinery modeling and that influence the study results.
- Section 9 discusses the results and findings of the analysis.

2. BOUNDARY CONDITIONS FOR REFINERY MODELING

Boundary conditions are the constraints in a refinery model that represent actual or forecast market and technical conditions to which refinery operations must conform. They are used in the development and calibration of refinery models representing the operations of a specific refinery or group of refineries – for this study the aggregate operations of refineries in PADDs 1, 2, and 3. Boundary conditions include refining capacity; refinery inputs of crude oil, unfinished oils, and blendstocks; refinery out-turns of finished products, such as gasoline and diesel fuel; specifications for the properties of refined products (e.g., octane, RVP, and sulfur for gasoline); and certain regulatory standards that constrain refining operations (e.g., RFG standards implemented through the Complex Model and MSAT standards).

Calibration of a refinery model involves adjusting technical data elements in the model such that the model yields solution values that match with sufficient precision certain key measures of refinery operations in the calibration period, in this case Summer 2002. In this study, matching the properties of the gasoline pool "produced" by the refinery models to the actual PADD-level pool properties estimated from Alliance or EPA data is of particular importance. This requirement is discussed in Section 4.

Tables A-1 through A-5 show the boundary conditions developed for this study for the calibration period, Summer 2002.

- **Table A-1** shows petroleum refining capacity by PADD for 2002 and 2006. We used refining capacity reported for 2002 to calibrate the PADD 3 refining model to operations in the summer of 2002. We used refining capacity reported for 2006 to develop the models representing refinery operations in Summer 2010.

- **Tables A-2a and A-2b** show refinery inputs, volumes of feed going to specific refinery processes, crude oil properties, and net production of refined products, by PADD.

- **Tables A-3a, A-3b, A-3c**, and **A-3d** show PADD-level estimates of refinery production of gasoline, by type (conventional, low-RVP, and RFG), and gasoline blendstock use.

- **Table A-4** shows average prices for refining inputs of crude oil, electricity, and natural gas for 2002, and projected prices for 2010.

- **Table A-5** shows the supply of major refined products by PADD.

  Information on refined product supply from this table, in combination with EIA projections of aggregate energy supply and regional energy use, was used to develop projections of PADD-level energy supply, as discussed in Section 3.

Not shown in this set of tables are other boundary conditions – including various constraints on the average properties of refined products, Complex Model constraints, and MSAT standards –

used in configuring and calibrating the 2002 regional models. Constraints on the average properties of refined products bear on the RVP of gasoline, the benzene and sulfur content of gasoline (based on gasoline properties discussed in Section 3), and the sulfur content of on-road and off-road diesel fuel (based on previous MathPro studies). The Complex Model and MSAT constraints are based on analyses in previous MathPro studies.

3. Projected Baseline Refinery Operations for 2010

Tables B-1 through B-7 show our projections of refinery inputs and outputs for the target period, Summer 2010. We developed the projections primarily using data from the Department of Energy's *Petroleum Supply Annual 2004* in combination with aggregate energy forecasts and regional energy demand forecasts from *AEO 2007*.

- **Tables B-1 to B-3** show projections for 2010 of total U.S. petroleum supply and disposition, imports and exports of petroleum products, and regional growth in energy consumption. We used these projections in developing the PADD-level projections shown in subsequent tables.

- **Table B-4** shows projected supply of major refined products, by PADD.

- **Table B-5** shows refinery inputs and refined product out-turns, by PADD.

- **Tables B-6a, B-6b, B-6c, and B-6d** show projections of gasoline out-turns, by PADD and by type of gasoline, and the corresponding projected pattern of use of gasoline blendstocks.

  These projections assume implementation of the 8-hour ozone standard by 2010, and consequent increases in the shares of low-RVP and reformulated gasoline in the gasoline pool. Our estimates of the effects of the 8-hour ozone standard on gasoline markets come from MathPro Inc.'s earlier published work for the American Petroleum Institute (API).[4]

- **Table B-7** shows projected national ethanol use of about 14½ bgy, allocated by PADD, consistent with blending ethanol at 10 vol%.

Tables A-1 (2006 data), A-4 (2010 projection), B-5, B-6c, B-6d, and B7 establish the primary boundary conditions for the 2010 Baseline (Reference) case.

The 2010 Reference and Study cases reflect an increase in refined product out-turns (net of purchased gasoline blendstocks), relative to the 2002 Calibration cases, of about 8% for PADD 1, 10% for PADD 2, and 20% for PADD 3 (which includes projected increases in shipments of refined products to the other PADDs). The 2010 regional refined product out-turns reflect about a 16% projected aggregate increase in U.S. refinery out-turns (including ethanol) over those in 2004.

[4] "*Potential Effects of 8-Hour Ozone Standard on Gasoline Supply, Demand, and Production Costs*"; Prepared for the American Petroleum Institute by MathPro Inc.; March 2005

4. Estimated Average Properties of the U.S. Gasoline Pool

Tables C-1 and C-2 show estimated average gasoline properties, by gasoline type, for the years 2000 through 2004. We derived these property sets from gasoline sampling data from the Alliance's *North American Fuel Surveys* and from data in EPA refinery and importer reports and federal RFG Area Surveys. The Alliance surveys are taken at the retail level[5]; the EPA reports are at the refinery and blender level.

Table C-1 shows the average properties of RFG and CG for the U.S. (ex California) derived from the Alliance surveys and reported by EPA. The average gasoline properties derived from the two sources are in good agreement, except for the pool averages for aromatics and olefins content.

> The Alliance-derived estimate for pool aromatics for 2003 is 28.8 vol%, whereas the EPA survey data indicate pool aromatics at 25.7 vol%, about 3 percent points lower. The Alliance-derived estimates of aromatics in both RFG and CG are higher than the corresponding estimate in the EPA reports. Likewise, the Alliance-derived estimate for aromatics in RFG is higher than the estimate derived from the EPA RFG Area Surveys.
>
> The Alliance-derived estimates for the olefins content of RFG are generally within a percent point of the values in the EPA reports and the estimates derived from the EPA RFG Area Surveys. However, the Alliance-derived estimates of olefins for CG are about 2 percent points lower than the values in the EPA reports.

Table C-2 shows estimated average properties for RFG and CG by PADD of *origin*, not consumption. We estimated average properties for both the Alliance surveys and the EPA federal RFG Area Surveys by assigning the surveyed cities to specific PADDs, according to the sourcing of their gasoline supplies. For example, cities assigned to PADD 3 included all of those located in PADD 3, along with the Washington metropolitan area and all cities in the southeast. Cities assigned to PADD 1 included Pittsburgh and all cities in the northeast, except those in New England (e.g., Boston), because the latter areas are supplied largely by imports. All cities in PADD 2 were assigned to PADD 2.

Because the EPA data sources encompass more of the national gasoline pool than the Alliance fuel surveys, we chose to rely more heavily on the EPA sources than on the Alliance surveys with respect to the target aromatics and olefin contents in the Calibration Case. In particular, we used average gasoline properties derived from the 2003 EPA reports (reflecting refinery-level reporting) as the gasoline property targets for the 2002 Calibration model run. (The average gasoline properties reported in the Alliance surveys are stable between 2002 and 2003,

[5] Excluding California and Nevada (areas supplied exclusively by California refineries) and Fairbanks, AK, the Alliance Survey reports the properties of retail gasoline samples taken in twenty-one cities: eight RFG cities, eight low-RVP cities, two ethanol-blended CG cities, and three CG cities. The Surveys provide nearly complete coverage for RFG areas, broad coverage of low-RVP areas, and thin coverage of CG areas.

suggesting that average gasoline properties in 2002 were similar to those we have available for 2003 from EPA data.)

For each PADD, we adjusted E_{130} for most blendstocks, E_{200} and E_{300} for FCC naphtha and reformate, and olefin content for FCC naphtha. In addition, for PADDs 1 and 2, we adjusted the olefins and sulfur content of FCC naphtha. **Table D-7** (discussed below) compares the average gasoline pool properties returned by models in the Calibration Case, which reflect these adjustments in blendstock properties, with the average gasoline pool properties estimated from the 2003 EPA data. For PADD 3, the average aromatic contents are about 2 percent points higher than indicated by the 2003 EPA data.

We elected not to adjust the aromatics contents of the primary aromatics-containing blendstocks in the refining models (reformate and FCC naphtha), because these aromatics contents are consistent with information from various industry sources on the aromatics content of PADD 3 gasoline blendstocks. The divergence in aromatics content may arise from the way we handled gasoline blendstock production in this study, versus how refiners report such production. We include in the finished gasoline volume all gasoline blendstock volumes produced, rather than treating these volumes as a separate category. The other average gasoline properties from the Calibration case for PADD 3, along with those for PADDs 1 and 2, are close to the reported average gasoline properties.

5. Results of the Calibration, Reference, and Study Cases[6]

As described in Section 1.3, we developed and analyzed a series of refinery modeling cases to assess the effects of the contemplated NCG program. Each case encompassed separate modeling runs for each PADD of interest.

- The **2002 Calibration Case** serves to calibrate the model to historical data for Summer 2002.

- The **2010 Reference Case** establishes the Summer 2010 baseline case to which the Study Cases are compared.

  The Reference Case incorporates refining capacity sufficient to produce projected refined product out-turns, meet the Tier 2 sulfur standards for gasoline, and supply the volumes of low-RVP gasoline and RFG to meet the (projected implementation of the) 8-Hour Ozone Standard. The Reference Case assumes that all gasoline is E10.

- **Study Cases 1 through 3** assess the effects of progressively increasing the share of the gasoline pool meeting a NGC standard.

  - In **Study Case 1: RFG,** the federal RFG standards are augmented by the NCG standard -- specifically, the NCG standards for 7.0 RVP, 5 ppm sulfur content, and DI 1250 are overlaid on the RFG standards.

  - In **Study Case 2: Low-RVP**, all 7.0 and 7.8 RVP gasoline is replaced by NCG (with all RFG also conforming to the NCG standard).

  - In **Study Case 3: CG**, all CG (except for a small export volume in PADD 3) is replaced by NCG (in addition to all RFG and low-RVP gasoline).

Tables **D-1 through D-7** show the results of the Calibration, Reference, and Study cases, for each PADD.

- **Table D-1** summarizes the economic results of our analysis. The table shows the estimated refining costs of the NCG standard in ¢/gal of NCG and in billions of dollars of refinery investment, at the various phase-in stages.

  Average per-gallon costs increase progressively as the NCG standard covers first RFG, then low-RVP gasoline, and finally CG. The estimated average per-gallon cost of NCG for the aggregate of PADDs 1-3 increases from about *1½¢/gal* in Study Case 1 to about *3¢/gal* in Study Case 3.

[6] Results of the Sensitivity cases are discussed in Section 6.

Incremental per-gallon cost of NCG (the cost of the last increment of NCG volume) likewise increases to about *4¢/gal* in Study Case 3.

Aggregate refinery investments in new process capacity increase progressively with increasing NCG share to about *$2 billion* in Study Case 3. Capital charges and fixed costs associated with this investment represent slightly less than 20% of total per-gallon costs in Study Case 3.

Finally, the proposed NCG program would induce small improvements in the energy density of the gasoline pool in Study Cases 2 and 3. This would reduce the national cost of NCG, by about ½¢/gal, but not the refining industry's costs.

- **Table D-2** shows refining operations and, for the Study cases, new capacity additions.

  The 2010 Reference case is configured such that *Existing Capacity* in Table D-1 includes any capacity added by the refinery model (beyond that reported in 2006) to produce the projected refinery out-turns and to meet regulatory standards.[7] Results returned by the refinery models show progressively more (but still relatively small amounts of) new capacity as the NCG share of the gasoline pool increases.

  Additional capacity in the Study cases is needed mostly for RVP control (debutanization and depentanization). Some minor additions of crude distillation and fractionation capacity also are made in Study Cases 2 and 3. Overall, DI control called for no investment in new capacity, because of the effects of blending ethanol at 10 vol% on the distillation curves of gasoline, notwithstanding the ethanol adjustment factor in the DI equation.

- **Tables D-3a and D-3b** show estimated refinery inputs and outputs.

  The refinery models are constrained to respond to requirements for progressively increasing volumes of NCG by adjusting refinery inputs, capacity, and operations, not by adjusting outputs of gasoline and other finished refined products. That is, output volumes of all refinery products are fixed, except for certain light gases (propane, butane, and mixed C4/C5s).

  The volumes of certain refinery inputs, such as pyrolysis gasoline (an ethylene plant by-product), ethanol, naphtha, kerosene, heavy gas oil, and residual oil, are held constant across the Reference and Study cases. Other inputs, such as crude oil, iso-butane, and normal butane, are priced and their volumes are allowed to vary across cases.

- **Tables D-4a, 4b, and 4c** shows the estimated average properties of each gasoline type, by PADD, in each case, as well as the Complex Model emission reductions for RFG (as

[7] Merchant MTBE plants operating in 2002 are represented in the 2002 Calibration case. No merchant MTBE plants are represented in the 2010 Reference and Study cases, but retrofitting refinery-based MTBE units operating in PADD 3 in 2006 to alkylate production was allowed.

calculated by the reduced-form of the Complex Model embedded in the refinery model, not by the actual Complex Model).

In the Calibration Case, we adjusted properties of some gasoline blendstocks such that the weighted average properties of the gasoline pool closely approximated those estimated from the EPA data, as discussed in Section 4.

In Study Case 1, the average pool aromatics content and DI increase somewhat for PADD 2, but remain about the same for PADDs 2 and 3.[8] The (small) effect on gasoline properties arising in PADD 1 from augmenting the RFG standards with the NCG standard occurs for several reasons. A larger fraction of the gasoline pool is RFG in PADD 1 than in the other PADDS, and (as discussed in more detail in Section 8) the NCG sulfur standard would lead to reduction in the sulfur content of most of the non-NCG gasoline produced in PADD 1.

In Study Case 2, there generally are small increases in aromatics and DI, reflecting still greater geographic coverage of NCG's low sulfur and RVP standards (and the loss of the 1 psi ethanol RVP waiver) as low-RVP gasoline is replaced by NCG. Olefins levels also decline due to more extensive treatment of FCC naphtha to reduce the sulfur content of NCG.

In Study Case 3, these trends to increased aromatics content and DI and reduced olefins content DI continue as the NCG standard expands to cover all gasoline (except for some exports in PADD 3).

With respect to the 2010 Reference Case, the net effect of full imposition of the NCG standard a gasoline is to (1) lower pool average RVP, sulfur, and olefins and (2) raise somewhat average aromatics and DI. However, pool average aromatics and DI would remain lower than in gasoline produced in 2003/2004, as shown in Exhibit C-2.

- **Tables D-5a, 5b, and 5c** show the estimated composition of the various gasoline types produced and of the entire gasoline pool.

  The primary changes in the estimated composition of the total gasoline pool are that the volume fractions of: (1) C4s decline somewhat (because of RVP control); (2) FCC naphtha declines slightly (due to the cost of sulfur control); and (3) medium and heavy reformate increases (to make up the octane lost in desulfurizing FCC naphtha to 5 ppm). These changes are rather small, but become more noticeable as the share of NCG in the gasoline pool expands.

- **Table D-6** shows the shadow values (marginal costs) of Complex Model parameters, DI, and octane for each gasoline type. Non-zero values in this table for Complex Model parameters

[8] In general, the properties shown in Tables 4a, 4b, and 4c and the gasoline compositions in Tables 5a, 5b, and 5c may change within Study Cases for individual types of gasolines without affecting the refinery model's objective function, i.e., the refining models may have multiple alternate optima with respect to gasoline properties and compositions across different types of gasoline.

and DI indicate the limits on specific gasoline properties and on DI that constrain refinery operations, i.e., impose additional costs.

The two Complex Model parameters whose shadow values progressively increase across the Study Cases are RVP and benzene. The shadow value of RVP increases because it is controlled directly by the NCG standard and the extent of RVP control increases as NCG expands its share of the gasoline pool. The shadow value of benzene increases because of the indirect effect of the NCG standards on gasoline pool octane. FCC naphtha desulfurization, required to achieve the sulfur standard, leads to some octane loss. The lost octane is replaced by an increased volume share of reformate, a high-octane blendstock that contains benzene. The shadow value on sulfur also would have increased across the Study Cases, except for a special modeling procedure that we employed to directly control the sulfur content of FCC naphtha and other sulfur-containing blendstocks to 5 ppm or lower. Finally, the cost of octane progressively increases because of the octane lost via FCC naphtha desulfurization and the reductions in high-octane C4 blendstocks due to RVP control.

- **Table D-7** compares the results of the Calibration Case with reported refinery operating data for Summer 2002. As discussed earlier, the gasoline pool properties closely match reported data, with the exception of aromatics content. With respect to process throughput volumes, computed crude throughput and FCC and coker feed rates are within 2% of volumes reported by EIA. Reported and modeled hydrocracker feed rates for PADD 3 differ considerably, primarily because EIA defines hydrocracking feed to includes volumes fed to lube plants and resid hydrocrackers, whereas we include only feed to distillate hydrocrackers.

  The marginal costs of gasoline and distillate production returned in the Calibration Case are lower than reported market prices in 2002. However, the marginal costs have the same general relationship as market prices, i.e., gasoline marginal costs are higher than distillates, etc. In our experience, small changes in process capacity constraints can move the marginal cost estimates arbitrarily close to reported prices. We did not pursue making such changes because this study focuses not on 2002 but on 2010, a period defined by a different set of process capacities and refined product out-turns.

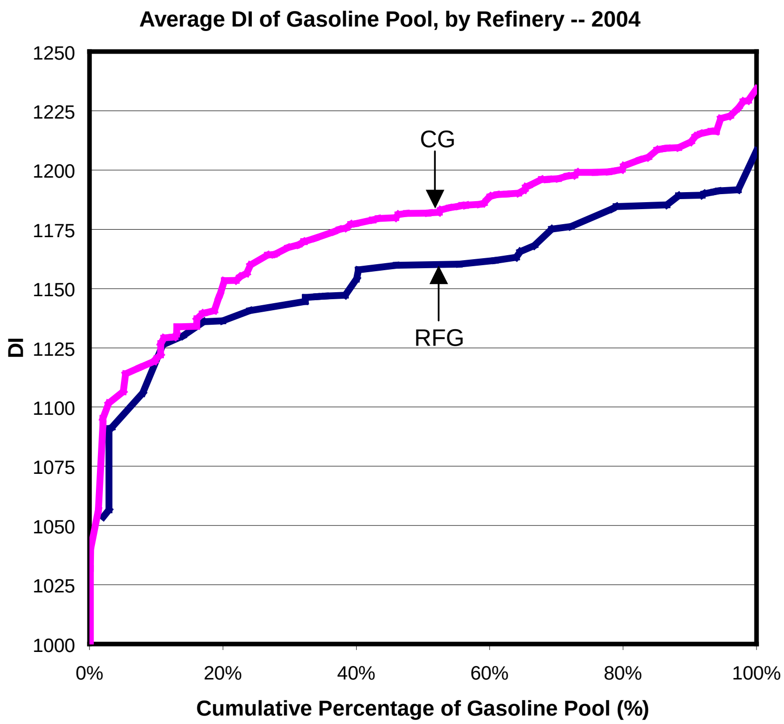
6. Results of the DI Sensitivity Cases

As described in Section 1.3, we analyzed a set of refinery modeling cases to assess the effects of a more stringent DI standard on the estimated cost of the contemplated NCG program. The results of the DI Sensitivity Cases indicated that a DI 1200 standard, rather than DI 1250, would affect average refining costs only in the PADD 1 refining sector. Average refining costs in PADD 1 would increase by about *0.1¢/gal* in Sensitivity Case 1 (relative to Study Case 1), *½¢/gal* in Sensitivity Case 2, and *1¢/gal* in Sensitivity Case 3. Likewise, investments in new refining process capacity also increased – by about *$0.3 billion* and *$0.4 billion* in Sensitivity Cases 2 and 3, respectively, relative to the corresponding Study Cases.

The lower DI standard would affect the PADD 1 refining sector because the average DI of the gasoline pool produced in that PADD is > 1200 in the Study Cases assessing the 1250 DI standard. PADD 1 refineries would have to produce a gasoline with average DI below 1200 (around 1175) in order to insure compliance with a maximum DI of 1200 at the pump. To meet the lower DI standard PADD 1 refineries would have to back out heavy, high-octane gasoline blendstocks, such as reformate, and replace them with lighter, high-octane blendstocks, mainly alkylate and isomerate. The refineries would have to compensate for the resulting RVP increase by increasing depentanization. PADDs 2 and 3 produce gasoline pools with average DI below or close to the 1175 refinery-gate DI target in the Study Cases, in which NCG has a DI 1250 standard.

However, results from aggregate refinery modeling, as conducted in this study, can significantly understate the effects of imposing the lower DI standard, because of the significant refinery-to-refinery variation in average DI of the gasoline pool. Aggregate refinery models represent refinery operations in which all blendstocks produced in the region are available for blending in all gasoline batches, whereas individual refineries have a smaller pool of blendstocks from which to draw. Those refineries having high pool average DI likely would have to modify their refining operations, rather than simply trading high-DI blendstocks for low-DI blendstocks from another refinery, as is done implicitly in the aggregate refining models.

The chart on the next page shows the distribution of estimated pool average DI, separately for RFG and CG (including low-RVP gasoline) produced by individual refineries (ex-California) in 2004. (The effect on DI of ethanol blending at terminals is not captured in the data underlying this chart.) Clearly, significant variation exists in average pool DI across refineries. The higher the average DI of a refinery's current gasoline pool, the higher the likely difficulty and cost of the refinery's meeting a tighter DI standard.


Average DI of Gasoline Pool, by Refinery -- 2004
1250
1225
1200
1175
1150
1125
1100
1075
1050
1025
1000
DI
CG
RFG
0%
20%
40%
60%
80%
100%
Cumulative Percentage of Gasoline Pool (%)

7. Results of the Crude Price Sensitivity Analysis

As described in Section 1.3, we conducted a brief analysis to estimate the effects of crude oil price on the refining economics of NCG production (with DI capped at 1250). In particular, we considered a 2010 crude oil price of $125/Bbl ($2006) in place of the $51.2/Bbl value used in the primary analysis.

We conducted this sensitivity analysis using a simple approach that did not involve additional refinery modeling. On the basis of historical price series, we estimated average prices for all refinery inputs (other than crude oil) and refined products that would be consistent with a crude oil price of $125/Bbl. We applied these estimated prices to the refinery input and output volumes returned by the refinery model in each Reference Case and Study Case, to obtain the indicated cost differentials for each case, with crude oil at $125/Bbl (and commensurate prices for purchased electricity and natural gas). For each Study Case, the estimated refining cost of the NCG program with crude oil at $125/Bbl is the difference in the gross refining margin (GRM)[9] plus the difference in purchased energy costs between the Study Case and its Reference Case.

Table D-1b (Appendix D) summarizes the results of this analysis. With crude oil price at $125/Bbl ($2006), the estimated *average cost* of producing NCG (averaged over PADDs 1, 2, and 3) at the assumed maximum market coverage – with NCG augmenting all RFG and replacing all low-RVP gasoline and CG in the three PADDs – is about *4½¢/gal*. In other words, increasing the crude oil price from ≈ $50/Bbl to $125/Bbl increases the estimated *average* refining cost of the NCG program by about *1¾¢/gal*. Similarly, increasing the crude price increases the corresponding average *incremental cost* for the last increment of NCG introduced (to replace CG) to about *6½¢/gal*; that is, by about *2¾¢/gal* (relative to the original Study Cases).

Table D-1b also indicates that each additional $10/Bbl increase in crude price would increase the average refining cost of the NCG program by about 0.24¢/gal (at constant natural gas and electricity prices).

The refining cost of any regulatory program affecting refined product quality – in this instance, the contemplated NCG program – is the sum of the *changes* (relative to a baseline) induced by that program in (i) gross refining margin (as defined here), (ii) the cost of refinery energy purchases (mainly natural gas and electricity), and (iii) other refinery operating costs (e.g., catalysts and chemicals, etc.) plus the capital charges associated with investments in new refining capacity called out by the program. Refinery LP modeling, such as we conducted in this study, considers all of these factors. The crude price sensitivity analysis that we conducted considers only the first and second: the changes in GRM and in the cost of refinery energy purchases.

---

[9] Gross refining margin is the total revenue from refined product sales minus the total cost of crude oil and other refinery inputs (excluding natural gas and electricity).

Because the sensitivity analysis did not involve refinery modeling – an optimization technique that identifies minimum cost refining operations – the results of the analysis may embody some overstatement of the effect of increasing crude price. In particular, the sensitivity analysis did not consider changes in refinery capital investments (which refinery modeling would have). Refinery modeling might have revealed some additional investment called out to partially counteract higher energy prices.

8. Analytical Issues

Various study assumptions and premises merit discussion and should be considered in assessing the results of the refinery modeling.

- The proposed NCG standard has a 10 ppm cap on sulfur content. To meet this limit, refineries would have to desulfurize FCC naphtha to $\leq$ 5 ppm. FCC naphtha is usually the largest single constituent of a refinery's gasoline pool (typically comprising about 35% of pool volume) and the primary source of sulfur in gasoline (accounting for about 95% of the sulfur content of untreated gasoline).

  We understand that many of the FCC naphtha treating units that have been or will be installed to meet the Tier 2 sulfur standard are capable of producing a treated FCC naphtha with sulfur content < 10 ppm. However, some units (particularly retrofitted units) may not have this capability and may need an additional treatment stage to achieve the 10 ppm sulfur cap contemplated for NCG. Retrofitting an additional treatment stage would entail some additional investment. To estimate the potential impact of retrofitting on our cost estimates, we postulated that all FCC naphtha hydrotreaters would have to be retrofitted at a cost equal to 30% of the estimated grassroots ISBL cost of a new unit (about $1500 K/Bbl/day). This investment raises the estimated total investment in new process capacity by about $1.5 billion (to a total of about $3 billion) and the estimated cost of fully implementing the NCG standard by about 0.2–0.3¢/gal.

- As noted above, NCG production would entail desulfurizing the FCC naphtha blended to NCG to about 5 ppm sulfur. If a refinery opted to produce NCG, it would probably desulfurize *all* of its FCC naphtha to 5 ppm (not just the portion blended to NCG), because of constraints on tankage and the difficulty of segregating ultra-low sulfur from low sulfur blendstocks. Thus, NCG production could lead to very low sulfur levels in the non-NCG gasoline produced by refineries opting to produce some NCG.

  We captured this effect in Study Case 1 by requiring all FCC naphtha produced by RFG refineries judged likely to continue producing RFG when NCG is first phased in to be desulfurized to 5 ppm and blended in co-produced low-RVP gasoline and CG. (The RFG/other gasoline splits in these refineries range from about 40/60 to 60/40). In Study Case 2, we assumed that non-RFG refineries producing low-RVP gasoline would produce CG in about the same volume (i.e., a 50/50 split), leading to FCC naphtha desulfurization of twice the amount necessary solely for low-RVP gasoline. (The exception is for PADD 1, where larger coastal RFG refineries also produce the bulk of low-RVP gasoline and where we assume that small inland refineries would forego producing low-RVP gasoline as the NCG program was phased in).

  This analytical procedure shifts part of the cost of desulfurizing low-RVP gasoline and CG to RFG and of desulfurizing CG to low-RVP gasoline as the NCG program is phased in; it does not change the cost of fully implementing the NCG standard. It also leads to improvement in estimated emissions performance of some low-RVP gasoline and CG during the phase-in of NCG by virtue of the early reductions in their sulfur levels.

- Typically, the investment for expanding existing units is about half to two-thirds of the cost of adding the same capacity in grassroots units. The investment costs shown in Table D-6 reflect grassroots investment economics. We specified grassroots investment economics in the Study cases and Sensitivity cases, rather than expansion economics, as a simple means of dealing with various investment considerations.

  On one hand, most additional capacity in crude distillation, alkylation, and isomerization likely would come about by expansion of existing units, rather than construction of new units, and would therefore incur investment costs consistent with expansion economics. On the other hand, we did not include any ancillary refining costs that could be incurred to control the sulfur content of gasoline blendstocks that need not be treated in order to meet the Tier 2 gasoline sulfur standard.[10] We assumed in the Reference Case that gasoline blendstocks likely to have high sulfur content relative to the Tier 2 standard, such as straight run naphtha, coker naphtha, natural gas liquids, and pyrolysis gasoline, would be treated to reduce sulfur to low levels (5 ppm or less). In the end, because estimated investment costs are low, modifying the procedure to use expansion, rather than grassroots, investment economics for some units would have only a minor effect on our cost estimates.

- We allowed DI "quality shifting" to occur from NCG to co-produced low-RVP gasoline and CG (i.e., low-RVP gasoline and CG produced by NCG refineries), subject to an arbitrary refinery gate, upper limit on DI of 1220. That is, we constrained the DI for other low-RVP gasoline and CG to Reference Case levels. Presently, no regulatory mechanism exists to prevent quality shifting in response to a NCG standard.

- As customary, our analysis does not address additional costs incurred downstream of the refinery – from the refinery gate to the pump – in moving, storing, and distributing NCG. However, we think any such costs would be low because NCG would replace existing gasoline types and, under EPAct2005, could not lead to an increase in the number of distinct gasoline types in commerce.

- Capital charges in the refinery model and in the cost analysis reflect a rate of return on investment of 10%. EPA uses lower rates of return when estimating the "social" (national) costs of regulations; refiners often use higher rates of return when evaluating refinery investment opportunities.

---

[10] *Ancillary refining costs* are refining costs that are not registered in the refinery model, such as those discussed here that refineries may incur in meeting a 5 ppm sulfur standard. Refinery LP models do not register ancillary costs not because they are imaginary, but because it is hard to express them as explicit functions of refinery operating variables.

9. COMMENTS ON STUDY RESULTS AND FINDINGS

9.1 Magnitude of the Estimated Average and Incremental Costs

Averaged over PADDs 1, 2, and 3, the estimated *average* cost of producing NCG at the assumed maximum market coverage – that is, with NCG augmenting/replacing all RFG, low-RVP gasoline, and CG in the three PADDs – is about 3¢/gal of NCG (for a crude oil price of ≈ $51 ($2006)). The corresponding estimated *incremental* cost for the last increment of NCG at maximum market coverage (that is, replacing CG) is about 4¢/gal. (Table D-1)

To provide some perspective for these estimates, note that the estimated *average* and *incremental* refining costs are in the same range as most corresponding estimates for federal Phase 1 RFG, prior to its implementation in 1995. After implementation, and prior to the institution of state MTBE bans, spot price differentials between CG and federal RFG usually were usually in the range of 2¢ to 4¢/gal, except in periods of temporary supply disruption. The estimated refining costs for NCG are below estimates of the cost of the California MTBE ban, prior to its implementation in 2004, and of the cost of a national MTBE ban.

In summary, the results of the analysis indicate that NCG would be a relatively costly gasoline program, but not necessarily more costly than some other gasoline programs that U.S. consumers have accepted.

This finding applies over the entire range of crude oil prices considered in this study. (Note that the estimated refining costs indicated by the crude price sensitivity analysis (Section 7) are not directly comparable to the results obtained in any prior studies of proposed regulatory standards affecting gasoline, because all prior studies incorporated crude prices very much lower than $125/Bbl.)

9.2 NCG Costs Depend on Phase-In Sequence

Except for the average refining cost at full market coverage, the average and incremental refining costs of NCG would be a function of its phase-in sequence (that is, the sequence in which other gasoline types would be augmented/replaced by NCG). In particular, the estimated costs shown in Table D-7 apply only to the assumed phase-in sequence: RFG first, low-RVP gasoline second, and CG third, simultaneously in all PADDs.

Other sequences, with or without regional variations, would lead to different cost progressions for NCG's introduction, but the average cost of the NCG program at full market coverage would be unaffected by the phase-in sequence.

9.3 Capabilities of Foreign Refiners to Produce NCG Were Not Considered

We project imports of finished gasoline and blending components to constitute more than 12% of total U.S. gasoline supply in 2010. Most gasoline imports come into PADD 1, where imports constitute about 31% of total gasoline supply (including inter-regional transfers from PADD 3).

Imports of gasoline into PADD 1 in 2010 will be in the form of blendstocks (CBOBs, RBOBs, etc.) subsequently blended with ethanol at 10 volume% to make finished gasoline. A handful of refineries in eastern Canada, the Virgin Islands, and Venezuela are consistent suppliers, accounting for most of PADD 1's gasoline imports. The rest of the imports come from "opportunity" suppliers, refineries in northern Europe, Africa, the Middle East, and Asia.

An important assumption in the analysis was that gasoline production in each PADD of interest would remain unchanged with the introduction of NCG. This assumption implies that (1) the total volume of gasoline imports would remain unchanged with the introduction of NCG and (2) imported low-RVP gasoline and CG would be replaced by imported NCG in step with the shift in domestic gasoline production.

We assumed that foreign refineries, collectively, would supply the indicated amounts of NCG imports, and do so at delivered prices consistent with the marginal production costs of the U.S. refining sector. In practice, that may or may not be the case. However, analysis of the capabilities and economics of foreign suppliers is far beyond the scope of this study.

9.4 Other Factors Could Affect Refining Costs of NCG

As noted in Section 8, many FCC naphtha desulfurization units installed to meet the Tier 2 sulfur standard already have the capability of desulfurizing FCC naphtha to the extent needed to produce gasoline containing $\leq$ 10 ppm sulfur. However, some units (particularly retrofitted units) may not have this capability. They would require some additional investment in order to achieve the NCG sulfur standard.

Meeting the NCG sulfur standard could also require desulfurization of other gasoline blendstocks that (unlike FCC naphtha) did not require treatment to meet the Tier 2 gasoline sulfur standard (30 ppm average). We did not attempt to capture these investments in the Study Cases and Sensitivity Cases. Rather, we assumed that these desulfurization costs were embodied in the Reference Case, in which total refining capacity includes the process capacity installed to meet the Tier 2 gasoline sulfur standard. Hence, the results of the analysis do not reflect the costs that would be incurred if some refineries had to install new desulfurization capacity expressly to produce NCG in the specified volumes.

9.5 Logistics System Effects Were Not Considered

Consistent with the ground-rules established for the study, we did not consider the technical and economic effects of an NCG program on the gasoline distribution system, from the refinery to the pump.

These effects would likely be minimal. As EPAct2005 dictates, NCG would have to replace another gasoline type at each step of the phase-in, and NCG could not lead to any increase in the number of distinct gasolines in commerce in the U.S.[11] During periods of supply shortfall or supply interruption, the widespread use of a standard NCG would tend to enhance the distribution system's flexibility in responding and mitigating the price spikes that often occur in such situations.

9.6 Aggregate Refinery Modeling and Possible Over-Optimization

We conducted the refinery modeling using regional aggregate refining models. Such models essentially pool all regional refining capacity and intermediate and final gasoline blendstocks, as though all refining capacity in the region were fully integration. Consequently, all aggregate refining models have a tendency to "over-optimize" – that is, to return operating results better than the refining sector could achieve in practice under the conditions represented in the models.

The results returned by the PADD-level refining models in this analysis may embody some over-optimization in representing the phase-in of NCG – most notably with respect to quality shifting. An aggregate model can practice quality shifting among gasoline types to a greater extent than can individual refineries. As noted in Section 8, quality shifting from NCG to other gasoline types would, directionally, reduce the cost of NCG production but impair emissions performance of the gasoline types that were the "quality sinks." In practice, as NCG phased in, some refineries might produce NCG and others might not, further limiting the extent to which quality shifting could occur.

[11] The assumed phase-in sequence satisfies the EPAct2005 requirements in PADDs 1, 2, and 3. For purposes of this study, we ignored the small volumes of low-RVP gasolines currently used in PADD 4.