THE AMERICAN PETROLEUM INSTITUTE

AN ASSESSMENT OF THE IMPACT OF POTENTIAL MOBILE SOURCE AIR TOXIC II REGULATIONS ON REFINERY OPERATIONS, COSTS, AND GASOLINE SUPPLY

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BAKER & O'BRIEN
INCORPORATED

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I. INTRODUCTION

Baker & O'Brien, Inc. (Baker & O'Brien) has been retained by the American Petroleum Institute (API) to provide an assessment of the potential impact of Mobile Source Air Toxics II (MSAT 2) regulations being considered by the United States (U.S.) Environmental Protection Agency (EPA). This study was initiated prior to the EPA's March 29, 2006, publication of proposed MSAT 2 rules.[1] Among other changes, the proposed MSAT 2 rules limit the benzene content of gasoline. This report focuses on the potential impacts of benzene limits on gasoline cost and supply.

General industry conditions, corporate profiles, geographic considerations, and unique refinery characteristics can influence potential responses to regulatory requirements. Therefore, Baker & O'Brien undertook a refinery-by-refinery approach in evaluating the potential impacts of MSAT 2 regulation. Likely compliance strategies were developed and production estimates calculated for each refinery using Baker & O'Brien's *PRISM*™ Refining Industry Analysis modeling system. The *PRISM* model is based on publicly available information, and incorporates Baker & O'Brien's industry experience and knowledge.

Baker & O'Brien conducted this analysis and prepared this report with reasonable care and skill, utilizing methods we believe to be consistent with normal industry practices. No other representations or warranties, expressed or implied, are made by Baker & O'Brien. All results and observations are based on information available at the time of this report. To the extent that additional information becomes available or the factors upon which our analysis is based change, our opinions could be subsequently affected.

II. EXECUTIVE SUMMARY

In March 2001, the EPA published a final rule (MSAT 1)[2] specifically identifying 21 mobile source air toxic, and revising toxic limits that had been established in 1994. In MSAT 1, the EPA also committed to evaluate the need for and feasibility of additional controls. The proposed MSAT 2 rule addresses that commitment.

We undertook a study of three potential MSAT 2 regulations (the Study Cases). Most of our analytical work was completed prior to the March 29, 2006, publication of the EPA's proposed MSAT 2 rule. None of the Study Cases exactly match the proposed rule, but one (Study Case C) is reasonably close.

Refinery modeling work was performed using our proprietary *PRISM* refinery analysis system. The *PRISM* system allows us to model the responses and costs incurred by individual refineries to changes in fuel specification.

CONSUMPTION FORECAST

We developed a gasoline consumption forecast for 2012 based on data from the Energy Information Administration's (EIA) Petroleum Supply Monthly (PSM)[3] and the 2005 Annual Energy Outlook (AEO).[4]

The following table shows a comparison by Petroleum Administration Defense District (PADD), of June though August 2004 gasoline consumption from PSM versus projected 2012 consumption in the same four month period.

U.S. Gasoline Consumption[1]

(Thousands of Barrels Per Day)

	TOTAL U.S.	*PADD 1 [2]*	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5*
2004 June through August PSM						
Conventional	6,186	2,078	2,340	950	304	514
Reformulated	2,030	1,235	363	380	-	52
CARB	1,026	-	-	-	-	1,026
TOTAL	**9,242**	**3,313**	**2,703**	**1,330**	**304**	**1,592**
2012 June through August Projection						
Conventional	7,111	2,333	2,686	1,115	364	613
Reformulated	2,407	1,550	407	450	-	-
CARB	1,285	-	-	-	-	1,285
TOTAL	**10,803**	**3,883**	**3,093**	**1,565**	**364**	**1,898**
2004 to 2012 Average Annual Increase						
Conventional	1.8%	1.5%	1.7%	2.0%	2.3%	2.2%
Reformulated	2.2%	2.9%	1.4%	2.1%	-	-
CARB	2.9%	-	-	-	-	2.9%
TOTAL	**2.0%**	**2.0%**	**1.7%**	**2.1%**	**2.3%**	**2.2%**

NOTES:

(1) Includes finished gasoline, CBOB, RBOB, and CARBOB produced from crude oil refineries and ethanol added to refinery CBOB, RBOB, and CARBOB production. Gasoline blender production, based on blendstock sources other than from domestic refiners, is not included.

(2) The disproportional increase in PADD 1 RFG consumption is due to the assumption that Atlanta moves from the CG to RFG category.

BASE CASE

Starting with our most current *PRISM* data regarding existing refinery capacity and configurations, we projected capacity expansions based on announced projects and our own assumptions about capacity creep. In 2012, we estimated total U.S. crude distillation capacity of approximately 18.6 million barrels per day (MMB/D).

We assumed the following about gasoline blending for 2012:

- All other reformulated gasoline (RFG) rules remain in place (including MSAT 1);
- Methyl-tertiary-butyl-ether (MTBE) blending would be eliminated;
- The renewable fuels standard (RFS) would result in seven billion gallons of ethanol being blended; and
- Tier 2 sulfur limits would be fully implemented.

We assumed the 7.5 billion gallons per year of renewable fuels (RFS) for 2012, would result in 7.0 billion gallons of ethanol being blended to gasoline in 2012. We assumed biodiesel, cellulosic ethanol credits, and other renewables would make up the difference.

We assumed that all California Air Resources Board (CARB) and RFG markets, except Texas, would continue to blend ethanol. After accounting for ethanol blending to RFG and CARB, the remainder of the 7.0 billion gallons was blended into conventional gasoline (CG), primarily in PADD 2. Our estimate for the Base Case 2012 domestic gasoline supply balance is shown below.

2012 Base Case Supply Balance

(Thousands of Barrels Per Day)

	TOTAL U.S.	*PADD 1*	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5*
Domestic Production by Refiners[1]						
Conventional (non-ox)	4,336	312	507	2,802	281	434
Conventional (w/EtOH)	1,762	60	1,468	137	34	62
Reformulated (non-ox)	334	-	-	334	-	-
Reformulated (w/EtOH)	1,933	516	277	1,140	-	-
CARB (non-ox)	-	-	-	-	-	-
CARB (w/EtOH)	1,194	-	-	-	-	1,194
TOTAL	**9,559**	**888**	**2,252**	**4,413**	**315**	**1,690**
Total Ethanol Included Above[2] (MM gals/yr	6,708	883	2,675	1,958	52	1,139
Gasoline Consumption						
Conventional	7,111	2,333	2,686	1,115	364	613
Reformulated	2,407	1,550	407	450	-	-
CARB	1,285	-	-	-	-	1,285
TOTAL	**10,803**	**3,883**	**3,093**	**1,565**	**364**	**1,898**
Domestic Over/(Under) Supply						
Conventional	(1,013)	(1,961)	(711)	1,824	(49)	(117)
Reformulated (w/EtOH)	(140)	(1,034)	(130)	1,024	-	-
CARB (w/EtOH)	(91)	-	-	-	-	(91)
TOTAL	**(1,244)**	**(2,995)**	**(841)**	**2,848**	**(49)**	**(208)**
Total Ethanol Included Above (MM gals/yr)	294	1,585	200	(1,570)	-	79

NOTES:

(1) Includes finished gasoline, CBOB, RBOB and CARBOB produced from crude oil refineries and ethanol added to refinery CBOB, RBOB and CARBOB production. Gasoline blender production, based on blendstock sources other than from domestic refiners, is not included.

(2) Ethanol blended into RBOB and CBOB is shown in the PADD that produces the BOB, not necessarily the PADD in which it is consumed.

STUDY CASES

The three Study Cases assumed the benzene limits shown below.

Study Case Benzene Limits
(Volume Percent)

	RFG		***Conventional***		
	Pool Avg.	***Per Gallon Cap***	***Pool Avg.***	***Per Gallon Cap***	***Credit Trading***
Case A	0.60	0.90	0.95	1.30	No
Case B	0.60	0.90	0.60	0.90	No
Case C	0.60	none	0.60	none	Yes

Faced with these limits, refineries not already meeting the potential standard could:

- Modify cutpoints to remove benzene precursors from reformer feed (this may or may not require capital expenditures);
- Build or expand benzene saturation units;
- Build or expand aromatics extraction units;
- Build or expand pentane/hexane (C_5/C_6) isomerization units;
- Stop making gasoline; or
- Shutdown.

We considered each refinery's unique situation, and drew a few general conclusions. First, all refineries already have the opportunity to invest in aromatics extraction capacity. Those that have chosen not to produce aromatics have done so in light of economic and strategic business considerations that could change if tighter gasoline benzene restrictions are imposed. We concluded that refineries probably would not choose to build grassroots aromatics extraction capacity as a result of the potential benzene limits. We concluded that refineries that have existing aromatics extraction capacity might expand this capacity. In a limited number of cases, we concluded that a company not already doing so might decide to produce a benzene concentrate product that would be extracted at an affiliated refinery.

For refineries not currently producing benzene as a product, or which are not affiliated with such a refinery, we generally selected the compliance option that minimized capital investment requirements. For Study Cases A and B, there were two small specialty product refineries where we concluded that the owners might choose to discontinue manufacturing gasoline, but would continue producing other products. In Study Case C, we assumed these two refineries would be able to purchase benzene credits that would allow them to continue making gasoline. We did not project that any currently operating refineries would shutdown as a result of any Study Case benzene limits.

In several refineries, we did assume isomerization units would be built or expanded in combination with installation or expansion of benzene saturation units. These isomerization units were needed because the removal of benzene from the blend pool left these refineries extremely short of octane.

INVESTMENT REQUIREMENTS

Our conclusions about the types and magnitude of capital investment required for each of the Study Cases is shown on the following page.

Compliance Strategies
(Number of Refineries)

	Study Case		
	A	***B***	***C***
Quit Making Gasoline	2	2	0
New Units			
Naphtha or Reformate Splitters	49	69	64
Benzene Saturation	45	68	68
C_5/C_6 Isomerization	3	3	3
Revamps and Expansions			
Naphtha or Reformate Splitters	5	8	8
Aromatics Extraction	8	9	9
Benzene Saturation	2	2	2
C_5/C_6 Isomerization	1	1	1
Total Investment Cost, millions of 2006 US$	**899**	**1,737**	**1,476**

NOTE:

Individual refineries appear in multiple categories for each case. For example, a refinery that installed a reformate splitter and a benzene saturation unit would appear in both categories.

OTHER COSTS

Although the investment requirements are significant, operating costs are even more significant in the calculation of compliance costs. Natural gas costs are the largest single factor in determining the total compliance cost. Our estimates of potential compliance costs are based on a 2012 natural gas price of 5.38 dollars ($) per million British thermal units (MMBtu). This is the price taken from the 2006 AEO for natural gas delivered to industrial users, but recently, natural gas prices have been much higher. Fluctuations in natural gas prices would have a significant impact on our cost calculations.

Each of the compliance strategies considered in this study impact not only the benzene content of the gasoline, but other gasoline qualities and the quantities of gasoline and other products produced or consumed. The following table shows our estimate of total compliance costs for each of the Study Cases.

Total Potential Compliance Cost
(Millions of 2006 dollars per year)

	Study Case		
	A	***B***	***C***
Product Quantity and Quality Changes	481	647	563
Purchased Hydrogen	75	87	79
Other Variable Operating Expenses	567	620	532
Fixed Operating Expenses	13	13	11
Capital Recovery	151	293	246
TOTAL COST	**1,286**	**1,660**	**1,431**

DOMESTIC GASOLINE SUPPLY/DEMAND BALANCES

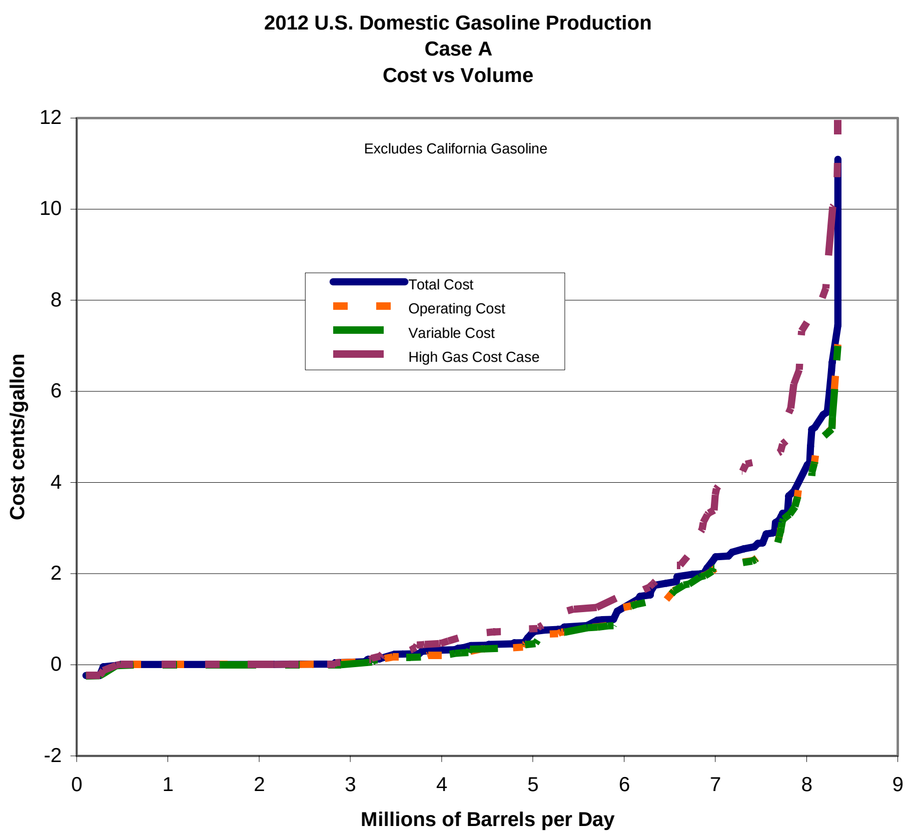
The Base Case supply balance was presented above. While there were variations in gasoline production between the Base Case and the Study Cases, they were not significant. Gasoline consumption was held constant in all cases.

PER GALLON COMPLIANCE COSTS

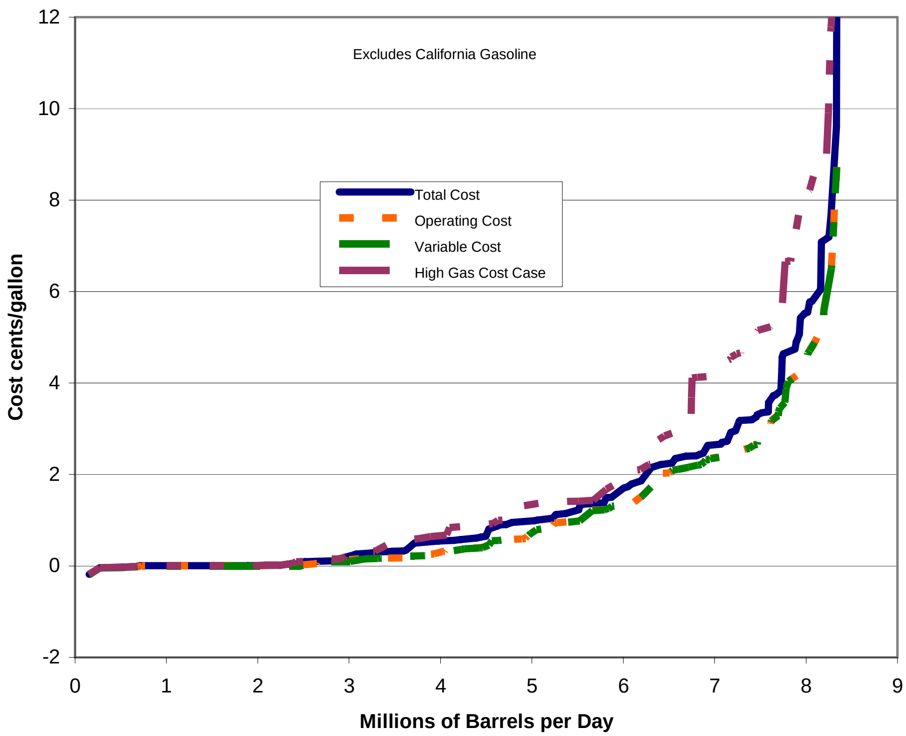
We allocated the compliance costs shown above on a refinery-by-refinery basis to gasoline production to yield the cost curves shown below for each Study Case. Some refineries show small negative compliance costs as a result of the credit they receive for producing aromatics. The analysis indicates that these refineries have an incentive to implement aromatics extraction expansion projects, even with no change in gasoline benzene limits. Since they have already made these investments, our assumptions about the cost and profitability of aromatics extraction may be optimistic. If so, the total implementation costs we have calculated may be somewhat understated.

The graphs also show that there is substantial variation in costs. Some refiners have zero or negative costs, and some have very high costs. When comparing on this basis, relative to Study Case B, the credit trading program in Study C appears to mitigate these variations only slightly. This type of comparison tends to dilute the capital efficiencies and flexibility of the credit program.

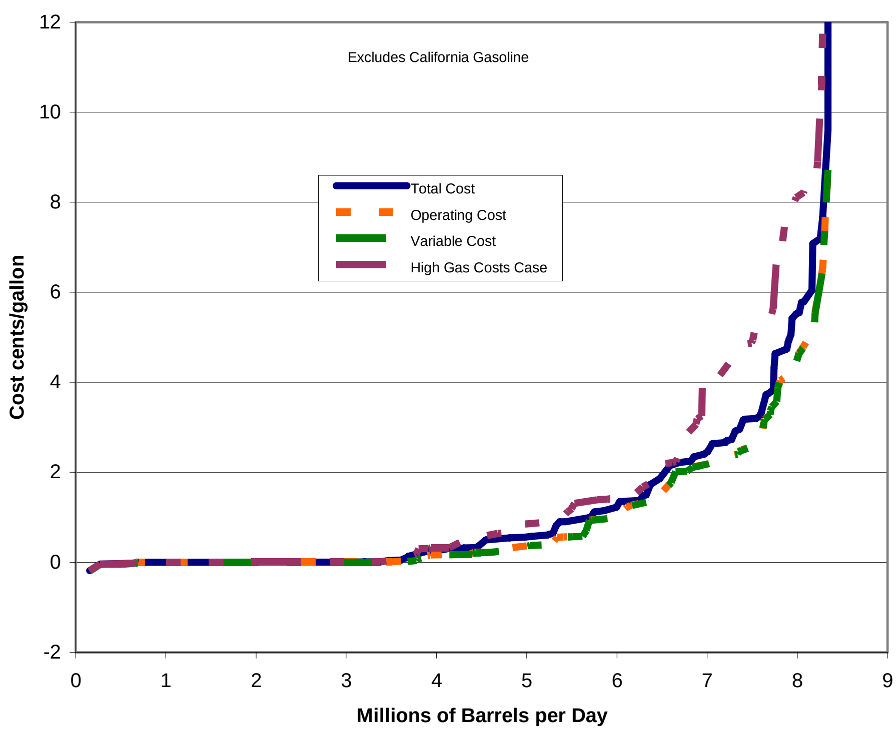
As noted above, natural gas prices have recently been much higher than the $5.38/MMBTU that we assumed in the Study Cases. Each of the cost curves has a "High Gas Cost" line that shows what the total compliance cost would be if natural gas prices doubled.



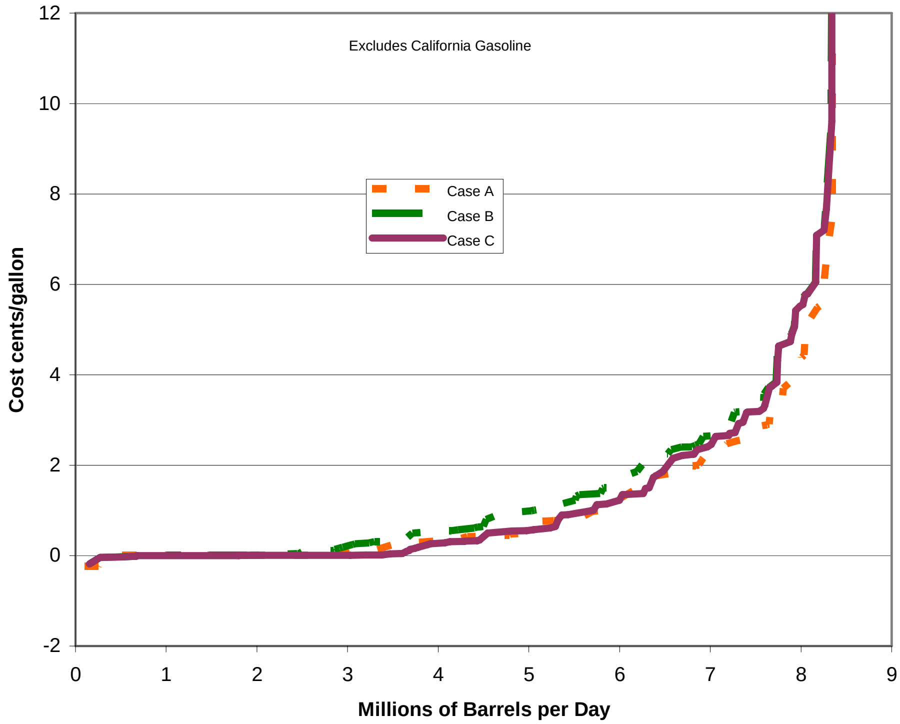
2012 U.S. Domestic Gasoline Production
Case B
Cost vs Volume



2012 U.S. Domestic Gasoline Production
Case C
Cost vs Volume



2012 U.S. Domestic Gasoline Production
Total Cost vs Volume



III. REGULATORY ASSUMPTIONS

Section 202(l) of the Clean Air Act required the Environmental Protection Agency (EPA) to set standards to limit hazardous air pollutants from motor vehicles, motor vehicle fuels, or both. In its February 1994 reformulated gasoline (RFG) and anti-dumping rules, the EPA established limits on toxics in both conventional gasoline (CG) and RFG. Limits were also placed on benzene in RFG. In March 2001, the EPA published a final rule, Mobile Source Air Toxics I (MSAT 1), specifically identifying 21 mobile source air toxics, and revising the toxics limits established in 1994. In MSAT 1, the EPA also committed to evaluate the need for and feasibility of additional controls. The proposed MSAT 2 rule addresses that commitment.

United States (U.S.) gasoline is also subject to EPA sulfur limits (Tier 2), and a variety of other State imposed requirements, including ethanol mandates, volatility restrictions, and others. During the proposed implementation period for the MSAT 2 rule, U.S. refiners will also be implementing compliance strategies for ultra low sulfur diesel (ULSD) and renewable fuels standard (RFS).

REGULATORY SCENARIOS CONSIDERED IN THIS STUDY

Most of the analytical work in this study was completed prior to the release of the EPA's proposed MSAT 2 rule. We considered three regulatory scenarios. None of these exactly match the proposed rule, but one (Study Case C) is reasonably close. In the Base Case and all three Study Cases, we assumed the following about gasoline blending for 2012:

- All RFG rules remain in place (including MSAT 1);
- Methyl-tertiary-butyl-ether (MTBE) blending would be eliminated;

- The renewable fuels standard (RFS) would result in 7 billion gallons of ethanol being blended; and
- Tier 2 sulfur limits would be fully implemented.

OXYGENATE BLENDING

The RFS requires that 7.5 billion gallons per year of renewable fuels be consumed in 2012, but not all of that will be ethanol blended into gasoline. Taking into account other renewables such as biodiesel and the RFS credits that are generated by cellulosic ethanol, we concluded that 7.0 billion gallons of ethanol blending was a reasonable assumption.

We assumed that all California Air Resources Board (CARB) and RFG markets, except Texas, would continue to blend ethanol. We assumed that the “less stringent” RFG volatile organic compounds (VOC) standard for RFG with ethanol sold in the Chicago-Milwaukee market would continue, but that other RFG areas would not receive the same adjustment. After accounting for ethanol blending to RFG and CARB, the remainder of the 7.0 billion gallons was blended into CG, primarily in Petroleum Administration Defense District (PADD) 2.

BENZENE LIMITS

The Study Cases included three different benzene regulation scenarios as shown below:

Study Case Benzene Limits
(Volume Percent)

	RFG		*Conventional*		
	Pool Avg.	***Per Gallon Cap***	***Pool Avg.***	***Per Gallon Cap***	***Credit Trading***
Case A	0.60	0.90	0.95	1.30	No
Case B	0.60	0.90	0.60	0.90	No
Case C	0.60	none	0.60	none	Yes

CREDIT TRADING PROGRAM

In Study Case C, we included a benzene credit trading program. Credits were generated based on the Study Case B results. Credits were generated using the formula:

Credits = (Pool Average Benzene – 0.6) * (Volume of Gasoline Produced)

The 0.6 pool average limit used here is less than that proposed by the EPA. This, in addition to the assumption of little to no overinvestment, resulted in less credit generation than may otherwise be the case under the proposed EPA program.

In addition, compliance margin and assumed marketplace efficiency in credit utilization provides for a 10 percent (%) underutilization of credits in our analyses.

IV. GASOLINE CONSUMPTION FORECAST

We developed a gasoline consumption forecast for 2012 based on data from the Energy Information Administration's (EIA) Petroleum Supply Monthly (PSM) and 2005 Annual Energy Outlook (AEO). The AEO data do not match well with those of the PSM, and do not include PADD and seasonal breakdowns needed for our analysis. We based our consumption forecast on the AEO growth rate projections, but applied them to the average actual demand calculated from June through August 2004 based on PSM data.

Using this methodology, we estimated that total U.S. gasoline demand in the Study Period would average 10.80 million barrels per day (MMB/D). The 2005 AEO gasoline consumption forecast for the calendar year 2012 is 10.64 MMB/D. The 2004 actual June to August consumption was 9.24 MMB/D versus an annual average of 9.06 MMB/D, a 2.0% increase. Applying a 2.0% increase for summer demand to the AEO annual projection of 10.64 MMB/D yields an estimated summer consumption of 10.85 MMB/D. We believe that our calculation basis using actual 2004 data and AEO growth rates makes proper use of updated information and yields an estimate within the range that might be projected by using only the 2005 AEO estimates.

The following table shows a comparison by PADD of June though August 2004 gasoline consumption from PSM versus projected 2012 consumption in the same four month period.

U.S. Gasoline Consumption[1]

(Thousands of Barrels Per Day)

	TOTAL U.S.	*PADD 1* [2]	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5*
2004 June through August PSM						
Conventional	6,186	2,078	2,340	950	304	514
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TOTAL	**9,242**	**3,313**	**2,703**	**1,330**	**304**	**1,592**
2012 June through August Projection						
Conventional	7,111	2,333	2,686	1,115	364	613
Reformulated	2,407	1,550	407	450	-	-
CARB	1,285	-	-	-	-	1,285
TOTAL	**10,803**	**3,883**	**3,093**	**1,565**	**364**	**1,898**
2004 to 2012 Average Annual Increase						
Conventional	1.8%	1.5%	1.7%	2.0%	2.3%	2.2%
Reformulated	2.2%	2.9%	1.4%	2.1%	-	-
CARB	2.9%	-	-	-	-	2.9%
TOTAL	**2.0%**	**2.0%**	**1.7%**	**2.1%**	**2.3%**	**2.2%**

NOTES:

(1) Includes finished gasoline, CBOB, RBOB, and CARBOB produced from crude oil refineries and ethanol added to refinery CBOB, RBOB, and CARBOB production. Gasoline blender production, based on blendstock sources other than from domestic refiners, is not included.

(2) The disproportional increase in PADD 1 RFG consumption is due to the assumption that Atlanta moves from the CG to RFG category.

V. TECHNOLOGY COSTS

Reformate is the largest source of benzene in the gasoline pool. In our 2012 Base Case, reformate represented 30.2% of the total gasoline pool (including California), and had an average benzene content of 3.31%. In our Base Case, the volume of benzene contained in reformate (before existing benzene extraction and saturation processing), exceeded the total volume of benzene in finished gasoline. Controlling reformate benzene levels is the most practical method of achieving benzene reductions in finished gasoline.

There are three ways to control reformate benzene levels: 1) removing benzene precursor compounds from the reformer feed by fractionation; 2) extracting benzene from reformate for sale into petrochemical markets; and 3) hydroprocessing the benzene to convert it to cyclohexane and other saturates. In the three Study Cases, we were able to meet the finished gasoline benzene specifications using various combinations of these approaches. The costs associated with each are discussed below.

REFORMER FEED FRACTIONATION

The benzene content of reformate can be reduced by removing compounds that are converted into benzene in the reformer (benzene precursors), and benzene itself from the reformer feed. This is done by fractionating the reformer feed into a lighter fraction containing benzene (and the precursors methylcyclopentane and cyclohexane), and a heavier fraction that goes on to the reformer. Depending on the refinery and the level of benzene in the lighter fraction, it can either go directly to gasoline blending, to a benzene saturation unit, to an isomerization unit, or possibly to an aromatics extraction unit.

The other impacts of reformer feed fractionation on a refinery gasoline blending pool include an increase in the volume of the pool (unless the light fraction is sent to an aromatics extraction unit), and a decrease in the average octane level of the pool. There will be a reduction in reformer throughput and associated operating costs, but an increase in operating costs for the fractionator and other units. If the refinery is in a location where reformer feed can be purchased, it may be possible to maintain the reformer operating rate. Isomerizing the light fraction may mitigate the octane loss, but also results in a vapor pressure increase. All of these factors were considered in our analysis.

BENZENE EXTRACTION

In the extraction process, a solvent is mixed with the reformate stream. Aromatics including benzene, toluene, and xylenes, are extracted by the solvent from reformate and the aromatic/solvent mixture ("extract") is separated from the non-aromatic portion of the reformate ("raffinate"). The extract is then fractionated to separate the solvent from the aromatics.

Most refiners that extract aromatics from reformate, extract more than just benzene. We assumed that any refineries that expanded aromatics extraction units in response to changing gasoline regulations, would expand production of all aromatics in the same proportion in which they currently produce them. An alternative strategy would have been to change the fraction of extractor feed to exclude heavier products such as xylenes and produce more benzene at the expense of xylenes. We concluded that existing xylene producers would want to maintain their current market position, and did not use this second alternative.

BENZENE SATURATION

Benzene saturation involves hydrogenating the benzene over a catalyst. The primary product of this process is cyclohexane. Commercial processes for benzene saturation include UOP's Bensat, CD Tech's CDHydro, and Axen's Benfree. Feeds to a benzene saturation unit can include light straight-run naphthas, light hydrocrackate, and light reformate. The adjective "light" in all of these potential feed streams implies fractionation. In the CD Tech process, the benzene saturation reactor is built into the upper section of the fractionator. In the other two processes, the reactor is external to the fractionator. For the Study Cases, we choose to use cost estimates for the UOP process as the basis for our calculations. This is not an endorsement of their process and we did not do any competitive analysis of the three processes.

The impact of benzene saturation on the gasoline pool is an increase in volume (cyclohexane is 12% less dense than benzene) and a loss of octane. We used an average octane blending ([R+M]/2 method) value of 97.5 for benzene and 80.1 for cyclohexane.

ISOMERIZATION

Isomerization units convert benzene into other compounds, but are not designed for that purpose, and have a limited ability to handle benzene and other cyclic compounds. We did not assume isomerization units would be built or expanded for the purpose of hydrogenating benzene. In several refineries, we did assume isomerization units would be built or expanded in combination with installation or expansion of benzene saturation units. These isomerization units were needed because the removal of benzene from the blend pool left these refineries extremely short of octane.

CAPITAL COSTS

Inside the battery limits (ISBL) capital costs for the technologies used in this study were estimated using the formula:

$$\text{ISBL Cost} = \text{Base Cost} * (\text{Actual Capacity}/\text{Base Capacity})^{SF}$$

The following table shows the base cost, base capacity, and scale factor (SF) coefficients for each technology. These coefficients are our own figures based on published vendor estimates, other published information, and our experience.

Process Unit Capital Cost Assumptions
Inside the Battery Limits (ISBL)
Second Quarter 2006

	Aromatics Extraction [(1)]	*Benzene Saturation*	*C_5/C_6 Isomerization*	*Naphtha/ Reformate Fractionation*
Base Capacity, B/SD[(2)]	14,300	10,000	30,000	30,000
Base Cost, 000 US$	134,625	9,091	15,252	7,522
Capacity Scale Exponent	0.67	0.67	0.52	0.39
Initial Catalyst & Chemical, 000 US$/B/SD	0.90	0.08	0.08	-

NOTES:
(1) The Aromatics extraction cost is based on aromatics extracted. The others are based on feed rate.
(2) Barrels per stream day (B/SD)

REVAMP/EXPANSION COSTS

To calculate the cost of revamps and expansions for any of the units listed above, we assumed the investment cost would be 150% of the difference in ISBL replacement cost between the Base Case and the Study Case.

OFF-SITE CAPITAL COSTS

In the cases involving unit expansion, no additional investment was assumed for off-sites. Where new units or new equipment were installed (i.e., a reformate splitter), process off-site investment costs were estimated at 44% of the ISBL cost. Non-process off-sites were estimated at 25% of the ISBL, and spare parts and catalyst at 1.2% of ISBL.

CONTINGENCY ALLOWANCE

Because of the considerable uncertainty associated with actual capital costs, it is prudent to apply some reasonable "contingency" allowance to capture unidentified costs that can be expected to arise during construction. For this study, we chose to apply a contingency allowance of 15% of the combined ISBL and outside the batter limits (OSBL) costs. Other studies have used contingency factors in the range of 15% to 25%.[5,6,7,8,9]

CAPITAL INVESTMENT CHARGE

Estimated capital costs were converted into a unit charge based on the barrels of product produced and some assumed return on total investment. It is assumed for planning purposes that refiners will not enter into investments unless they anticipate some rate of return commensurate with the opportunity cost of capital. For this analysis, we assumed that refiners would require a 10% after-tax rate of return based on a 15-year operating life, a 10-year accelerated depreciation schedule, a 38% tax rate, and a two-year construction period. This results in approximately 17% of the total capital investment being “charged” for each year of product production.

VI. INPUT COSTS

All costs in this report are expressed in constant 2006 U.S. dollars. Hydrocarbon costs, return of capital, and construction costs are all important factors in the cost of reducing gasoline benzene levels.

NATURAL GAS COST

The most significant cost factor in our analysis was natural gas. Projected 2012 natural gas prices used in our analysis are below current levels, and natural gas prices have recently been much higher than the 2012 price used in this study. Some outer-month natural gas futures prices on the New York Mercantile Exchange (NYME) are currently more than twice our 2012 basis. If natural gas prices in 2012 were to be significantly higher, compliance costs would also be significantly higher. For example, if natural gas prices were twice the AEO estimate, the total costs we have calculated would increase by approximately 40 percent.

HYDROGEN COSTS

In our analysis, we assumed incremental hydrogen requirements would be purchased from outside suppliers. The cost of natural gas usually comprises approximately half the total cost (including capital charges) of manufacturing or purchasing hydrogen from outside sources. Accordingly, we valued hydrogen based on the cost of natural gas used in its production, multiplied by a factor of 2.38. Such a value has historically been adequate to encourage third-party companies to build hydrogen production capacity using steam methane reforming technology, and supply hydrogen to refiners under term-sales contracts. In some situations, refiners may find lower-cost sources for small increases in hydrogen production by making changes to reformer operations, from expansion of existing hydrogen plants, and through recovery of hydrogen from refinery fuel systems. These sources are expected to be limited and we did not include them.

OTHER HYDROCARBON COSTS

Volumes of other hydrocarbons varied between the cases. The reasons for these variations are discussed elsewhere in this report. To calculate the total cost of compliance, it is necessary to assign costs to these other products. In our analysis, the reduced production of a hydrocarbon was treated as a variable operating cost. Increases in production were credited against variable operating costs.

We used prices from the 2006 AEO, the EPA's Draft Regulatory Impact Assessment (RIA) for MSAT 2[10] and various industry publications as the basis for our work. Prices in the 2006 AEO are expressed in 2004 dollars. We choose not to adjust these prices for inflation as an inspection of the AEO price forecast series clearly indicates that the EIA does not expect the energy price increases of 2005 and 2006 to be sustained. Adding the 2004 to 2006 energy price inflation would have increased all of our costs.

Hydrocarbon Costs

(All values in $/B except natural gas in $/MMBtu)

	Value	*Notes*
Published 2004 Values		
Retail Gasoline	79.97	AEO Average of all grades including all taxes
Refinery Netback Gasoline	52.65	Average of all grades
Benzene, FOB USGC	168.00	Jul-Aug average
Butane	37.97	Jul-Aug average
Natural Gasoline	43.51	Jul-Aug average
Naphtha	47.38	Jul-Aug average
AEO 2012 forecasts used in this study		
Natural Gas	5.38	Delivered to industrial users
Average Light Sweet Crude	47.65	Delivered to refinery
Imported Crude	43.59	Delivered to refinery
Retail Gasoline	84.59	Average of all grades including all taxes
Other 2012 forecasts used in this study		
Refinery Netback Gasoline	57.27	Same differential as 2004
Benzene	77.27	Consistent with RIA
Toluene	77.27	Set equal to Benzene
Mixed Xylenes	77.27	Set equal to Benzene
Butane	37.97	Same as published summer 2004
Pentane	40.74	Average of natural gasoline and butane
Natural Gasoline	43.51	Same as published summer 2004
Naphtha	52.00	Same differential as summer 2004

For gasoline, we assumed that the differential between refinery netbacks[1] and pump prices would remain constant. For benzene, we used the EPA's assumption from the MSAT 2 RIA that benzene should be valued at gasoline plus $20 per barrel. We used the same value for toluene and mixed-xylenes, although these products are normally valued below benzene. Reducing the value of toluene and mixed-xylene would increase our cost projections. Butane and natural gasoline were valued at published prices for July and August 2004. The naphtha was valued at a constant differential to gasoline consistent with figures published for July and August 2004.

[1] Refinery netback prices were calculated by subtracting transportation costs from unbranded wholesale rack prices.

OCTANE COSTS

We used published wholesale rack prices from the EIA Petroleum Marketing Monthly[11] for June through August 2005 as the basis for our octane cost. We divided the published differential between premium and regular gasoline by the appropriate octane number difference in each market to calculate an octane cost in each PADD. These values are shown below.

Octane Costs
($/Octane Index Barrel)

	Value
PADD 1	2.19
PADD 2	2.11
PADD 3	1.83
PADD 4	2.14
PADD 5, excluding CA	2.58

VII. ANALYTICAL BASIS

Even without new gasoline benzene rules, compliance with existing fuel quality regulations are placing difficult and expensive burdens on the refining industry. Numerous federal and state regulations are adding to the cost of merely staying in business. State and federal emissions standards at refineries in non-attainment areas necessitate the expenditure of capital on new emissions control equipment. Revisions to new source review standards are currently being challenged in court. Depending upon the outcome, there could be an increase in the cost of investments needed to comply with fuel quality regulations.

Each refinery is unique given its current technology, location, product slate, etc. We therefore examined each refinery's compliance options in each of the three regulatory scenarios, accounting for technical, strategic, market, and economic factors, and then predicted a likely response based on this information. We believe such an approach is superior to aggregate or notional type modeling, given the likely variation in refinery response to regulation, based on each refinery's unique position.

We utilized our own estimate of existing domestic refinery capacities and configurations as a baseline. These estimates have been developed and honed over the 14 years that we have been preparing our quarterly *PRISM*™ Refining Industry Analysis of the U.S. refining industry. We added announced capacity expansions, our own estimate of capacity creep, and our expectation about gasoline desulfurization projects in response to the EPA's Tier 2 regulations to arrive at our 2012 Base Case.

CALIFORNIA GASOLINE

California gasoline is included in the tables summarizing total domestic gasoline production and consumption, but is otherwise excluded from our analysis. This is consistent with the approach the EPA has taken in their proposed MSAT 2 rule.

There are several California refineries that produce non-California gasoline. We modeled these refineries and required them to meet the Study Case benzene limits. In our estimates, several California refineries may be required to make investments as a result of the Study Case benzene limits.

ANNOUNCED CAPACITY EXPANSION

As part of our ongoing *PRISM* data services, we reviewed news reports, company press releases, and trade publications for announcements of new refinery unit construction. Our forecast of 2012 refinery capacity assumes all announced refinery projects will be completed. Other capacity increases are limited to investments required to meet gasoline sulfur regulations and capacity creep, as discussed below. It is assumed that no new grassroots refineries will be constructed in the U.S. during the period covered in the study.

TIER 2 COMPLIANCE

At refineries currently not meeting final Tier 2 sulfur specifications, we added gasoline hydrotreating capacity as needed to meet the regulation requirements.

CAPACITY CREEP

"Capacity creep" occurs when refiners identify and remove capacity constraints (known as "bottlenecks"), through technological advances or other modifications that improve operating efficiency and capacity. Much of the capacity creep over recent years has come in conjunction with investments to comply with new environmental and fuel quality regulations. Generally, the cost of such capacity creep is much lower than the cost of building new grassroots refinery units. It is assumed that a certain amount of capacity creep will continue to be seen in the U.S refining industry over the period of this study. For all refineries that have not announced capacity expansions, we have assumed that capacity creep between 2004 and 2012 will:

- Average 1.15% annually at all refineries with crude distillation capacity of 150,000 barrels per calendar day (B/CD) or more as of January 2002;
- Not apply to small specialty refineries such as asphalt plants, lube oil and solvents plants; and,
- Average 0.85% annually at all other domestic refineries.

The above capacity creep assumptions apply to all refinery processing units, not just crude distillation.

CRUDE SLATE AND CAPACITY UTILIZATION

Except at those refineries with announced projects that impact their crude slates, we assumed that refineries would continue running crude slates comparable to their current slates. We recognize that domestic crude production is declining, but assumed that foreign crudes with equivalent qualities will be purchased to replace the declining domestic crudes. Crude slates are, therefore, the same in the Base and Study Cases.

Based on historical data, we made reasonably optimistic assumptions about refinery capacity utilization for all refineries. Purchases of unfinished intermediates, such as naphtha and vacuum gas oil, were allowed at refineries that typically purchase such feedstocks. Average assumed utilization rates for key processing units that impact gasoline production are shown below. If these utilization rates prove to be unachievable, the need for imported gasoline will increase.

U.S. Capacity and Utilization Rates, 2012

	Capacity *MB/CD*	*Utilization* *%*
Crude Distillation	18,637	96.9%
Fluid Catalytic Cracking	6,187	100.9%
Coking	2,546	100.5%
Catalytic Reforming	3,874	93.8%

COMPLIANCE OPTIONS

In our Base Case, 112 refineries were producing non-California gasoline (including some California refineries). Thirty-one of these refineries were already meeting the Study Case A benzene limits (0.95% pool average for CG, 0.6% pool average for RFG). These included refineries in all PADDs, but were primarily PADD 3 refineries with existing aromatics extraction capacity. Seventeen refineries meet the Study Case B limits (0.6% pool average for all gasoline) in our Base Case. All but one of these refineries have existing aromatics extraction capacity or are in California.

In our estimation, refineries not already able to meet the Study Case limits will have to adopt one or more of the following options:

- Modify cutpoints to remove benzene precursors from reformer feed (this may or may not require capital expenditures);
- Build or expand benzene saturation units;
- Build or expand aromatics extraction units;
- Build or expand butane/hexane (C_5/C_6) isomerization units;
- Stop making gasoline; or
- Shutdown.

After considering each refinery's unique situation, we drew a few general conclusions. First, all refineries already have the opportunity to invest in aromatics extraction capacity. Those that have chosen not to produce aromatics have done so in light of economic and strategic business considerations that could change if tighter gasoline benzene restrictions are imposed. Looking at the new environment presented by the potential gasoline benzene limits, we concluded that refineries probably would not choose to build grassroots aromatics extraction capacity. We concluded that refineries that have existing aromatics extraction capacity might expand this capacity. In a limited number of cases, we concluded that a company might decide to produce a benzene concentrate product that would be extracted at an affiliated refinery.

For refineries not currently producing benzene as a product or which are not affiliated with such a refinery, we generally selected the compliance option that minimized capital investment requirements. For Study Cases A and B, there were two small specialty product refineries where we concluded that the owners might choose to discontinue manufacturing gasoline, but would continue producing other products. In Study Case C, we assumed these two refineries would be able to purchase benzene credits that would allow them to continue making gasoline. We did not project that any currently operating refineries would shutdown as a result of the Study Case benzene limits.

Isomerization units convert benzene into other compounds, but are not designed for that purpose and have a limited ability to handle benzene and other cyclic compounds. We did not assume isomerization units would be built or expanded for the purpose of destroying benzene. In several refineries, we did assume isomerization units would be built or expanded in combination with installation or expansion of benzene saturation units. These isomerization units were needed because the removal of benzene from the blend pool left these refineries extremely short of octane.

Compliance Strategies
(Number of Refineries)

	Study Case		
	A	***B***	***C***
Quit Making Gasoline	2	2	0
New Units			
Naphtha or Reformate Splitters	49	69	64
Benzene Saturation	45	68	68
C_5/C_6 Isomerization	3	3	3
Revamps and Expansions			
Naphtha or Reformate Splitters	5	8	8
Aromatics Extraction	8	9	9
Benzene Saturation	2	2	2
C_5/C_6 Isomerization	1	1	1
Total Investment Cost, millions of 2006 US$	**899**	**1,737**	**1,476**

NOTE:

Individual refineries appear in multiple categories for each case. For example, a refinery that installed a reformate splitter and a benzene saturation unit would appear in both categories.

BENZENE CREDIT TRADING AND VALUATION

Credits were generated using the equation:

Credits = (Pool Average Benzene – 0.6) * (Volume of Gasoline Produced)

We assumed credits could be purchased by any refinery and there would be no differentiation between RFG and CG credits. We also assumed that the market would be 90% efficient (i.e., a maximum of 90% of the credits generated would be utilized). To determine which refineries would likely purchase the available credits, we calculated the value of credits to each refinery using the following formula:

Credit Value = (Avoided Total Cost) / (Volume of Gasoline Produced)

We assumed the credits would be used by refineries with the highest credit value with one exception. If the number of credits required by an individual refinery exceeded 15% of the total number of credits generated by all refineries, that refinery was not allowed to buy credits in our scenario. This is based on our assumption that refineries in this situation would probably not choose to be dependent on the availability of such a large quantity of credits. Credits were traded without regard for corporate affiliation. Individual refineries were assumed to operate either in the Base Case or Study Case B mode. Intermediate investment options were not considered.

Using this methodology, we were able to utilize 89% of the credits generated in Study Case C. We used the value to the last refinery that purchased credits as cost of credits to all refineries that used credits and added this cost to the refinery variable cost. We used the value of the credits purchased by the last refinery, as the basis for all the refineries. This cost was added to the refinery variable cost. We subtracted 89% of this credit value from the variable cost of refineries that produced credits in Study Case C. In Study Case C, credits were produced in all PADDs and were also purchased in all PADDs.

VIII. STUDY RESULTS

BASE CASE GASOLINE SUPPLY

Our Base Case assumes full implementation of existing gasoline rules (i.e., Tier 2 sulfur regulations), but no change in benzene rules. Our estimate of the 2012 Base Case domestic gasoline production is 9,559 thousand barrels per day (MB/D) including 438 MB/D of ethanol (6.7 billion gallons per year). We estimate that another 19 MB/D of ethanol (294 million gallons per year) will be blended into imported gasoline blendstocks.

2012 Base Case Supply Balance

(Thousands of Barrels Per Day)

	TOTAL U.S.	*PADD 1*	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5*
Domestic Production by Refiners[1]						
Conventional (non-ox)	4,336	312	507	2,802	281	434
Conventional (w/EtOH)	1,762	60	1,468	137	34	62
Reformulated (non-ox)	334	-	-	334	-	-
Reformulated (w/EtOH)	1,933	516	277	1,140	-	-
CARB (non-ox)	-	-	-	-	-	-
CARB (w/EtOH)	1,194	-	-	-	-	1,194
TOTAL	**9,559**	**888**	**2,252**	**4,413**	**315**	**1,690**
Total Ethanol Included Above[2] (MM gals/yr	6,708	883	2,675	1,958	52	1,139
Gasoline Consumption						
Conventional	7,111	2,333	2,686	1,115	364	613
Reformulated	2,407	1,550	407	450	-	-
CARB	1,285	-	-	-	-	1,285
TOTAL	**10,803**	**3,883**	**3,093**	**1,565**	**364**	**1,898**
Domestic Over/(Under) Supply						
Conventional	(1,013)	(1,961)	(711)	1,824	(49)	(117)
Reformulated (w/EtOH)	(140)	(1,034)	(130)	1,024	-	-
CARB (w/EtOH)	(91)	-	-	-	-	(91)
TOTAL	**(1,244)**	**(2,995)**	**(841)**	**2,848**	**(49)**	**(208)**
Total Ethanol Included Above (MM gals/yr)	294	1,585	200	(1,570)	-	79

NOTES:

(1) Includes finished gasoline, CBOB, RBOB and CARBOB produced from crude oil refineries and ethanol added to refinery CBOB, RBOB and CARBOB production. Gasoline blender production, based on blendstock sources other than from domestic refiners, is not included.

(2) Ethanol blended into RBOB and CBOB is shown in the PADD that produces the BOB, not necessarily the PADD in which it is consumed.

Some domestically produced natural gasoline is blended into gasoline outside of refineries. Assuming 120 MB/D of natural gasoline blending, a total of 1,124

MB/D of finished gasoline and gasoline blendstocks imports are required to balance supply with the projected 2012 gasoline consumption.

STUDY CASE A GASOLINE SUPPLY

Of the 112 refineries that were producing non-California gasoline in the Base Case, we estimate that 31 are already producing gasoline that complies with the Study Case A benzene limits. Our modeling indicated that another 23 refineries could meet the Study Case A standards through operating changes (i.e., changing cut-points or product mix) that did not require new investments. In our supply projection, we assumed that two small gasoline producers would cease producing gasoline. The remaining 56 refineries all required some level of capital investment to meet the Study Case A standards.

2012 Study Case A Supply Balance

(Thousands of Barrels Per Day)

	TOTAL U.S.	*PADD 1*	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5*
Domestic Production by Refiners[1]						
Conventional (non-ox)	4,361	332	506	2,815	282	427
Conventional (w/EtOH)	1,761	60	1,463	141	34	62
Reformulated (non-ox)	319	-	-	319	-	-
Reformulated (w/EtOH)	1,903	490	278	1,135	-	-
CARB (non-ox)	-	-	-	-	-	-
CARB (w/EtOH)	1,202	-	-	-	-	1,202
TOTAL	**9,546**	**881**	**2,248**	**4,410**	**316**	**1,691**
Total Ethanol Included Above[2] (MM gals/yr)	6,667	843	2,670	1,957	53	1,145
Gasoline Consumption						
Conventional	7,111	2,333	2,686	1,115	364	613
Reformulated	2,407	1,550	407	450	-	-
CARB	1,285	-	-	-	-	1,285
TOTAL	**10,803**	**3,883**	**3,093**	**1,565**	**364**	**1,898**
Domestic Over/(Under) Supply						
Conventional	(988)	(1,941)	(717)	1,841	(48)	(124)
Reformulated (w/EtOH)	(186)	(1,060)	(129)	1,004	-	-
CARB (w/EtOH)	(83)	-	-	-	-	(83)
TOTAL	**(1,257)**	**(3,002)**	**(845)**	**2,845**	**(48)**	**(207)**
Total Ethanol Included Above (MM gals/yr)	357	1,626	197	(1,539)	-	72

NOTES:

(1) Includes finished gasoline, CBOB, RBOB and CARBOB produced from crude oil refineries and ethanol added to refinery CBOB, RBOB and CARBOB production.

(2) Ethanol blended into RBOB and CBOB is shown in the PADD that produces the BOB, not necessarily the PADD in which it is consumed.

Our estimate of aggregate domestic gasoline and blendstock production in Study Case A excluding ethanol (not shown in table) is 10 MB/D less than the base case. Including ethanol blended into domestically produced blendstocks, domestic supply from refineries is 13 MB/D less than the Base Case.

Some refineries that were producing reformulated blendstock (RBOB) in the Base Case were able to comply with the Study Case A benzene limits without investment by shifting their production toward CG and CBOB. As a result, total domestic RFG supply in Study Case A is down 45 MB/D versus the Base Case. Since CG typically has a higher vapor pressure than RFG, the shift toward CG and CBOB allowed more pentane or butane to be blended at these refineries, thus increasing total gasoline production.

At refineries that extracted benzene to achieve compliance, the removal of this high-octane, low-vapor pressure component tended to also force pentane out of the gasoline pool compounding the volume loss at these refineries.

In refineries that modified cut-points to reduce benzene precursor in the feed to their reformers, we assumed that if naphtha has been historically available for purchase that these refineries would maintain their reformer rate by purchasing incremental naphtha. As a result, a few of these refineries had gasoline volume increases.

For refineries that were assumed to modify cut-points, but have not historically had access to supplemental naphtha supplies, we assumed reformer rates would be reduced. Because reforming results in a loss of gasoline volume, the gasoline pool at these refineries increased in size, but declined in octane. Saturating benzene to cyclohexane also increases the gasoline pool volume while decreasing its octane level. Generally, this resulted in a shift from premium to regular production. In a few cases, new or additional isomerization capacity was required to compensate for the lost octane. In aggregate, our estimate of the total U.S. gasoline pool octane level declined 0.07 octane number ([R+M]/2 method) between the Base Case and Study Case A.

STUDY CASE B GASOLINE SUPPLY

2012 Study Case B Supply Balance

(Thousands of Barrels Per Day)

	TOTAL U.S.	*PADD 1*	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5*
Domestic Production by Refiners(1)						
Conventional (non-ox)	4,312	311	506	2,786	282	427
Conventional (w/EtOH)	1,763	60	1,466	141	34	62
Reformulated (non-ox)	324	-	-	324	-	-
Reformulated (w/EtOH)	1,937	512	273	1,152	-	-
CARB (non-ox)	-	-	-	-	-	-
CARB (w/EtOH)	1,201	-	-	-	-	1,201
TOTAL	**9,538**	**883**	**2,245**	**4,404**	**317**	**1,691**
Total Ethanol Included Above(2) (MM gals/yr)	6,722	877	2,666	1,982	53	1,145
Gasoline Consumption						
Conventional	7,111	2,333	2,686	1,115	364	613
Reformulated	2,407	1,550	407	450	-	-
CARB	1,285	-	-	-	-	1,285
TOTAL	**10,803**	**3,883**	**3,093**	**1,565**	**364**	**1,898**
Domestic Over/(Under) Supply						
Conventional	(1,036)	(1,962)	(714)	1,812	(47)	(124)
Reformulated (w/EtOH)	(145)	(1,038)	(134)	1,027	-	-
CARB (w/EtOH)	(84)	-	-	-	-	(84)
TOTAL	**(1,265)**	**(3,000)**	**(848)**	**2,839**	**(47)**	**(207)**
Total Ethanol Included Above (MM gals/yr)	296	1,591	205	(1,574)	-	73

NOTES:

(1) Includes finished gasoline, CBOB, RBOB and CARBOB produced from crude oil refineries and ethanol added to refinery CBOB, RBOB and CARBOB production.

(2) Ethanol blended into RBOB and CBOB is shown in the PADD that produces the BOB, not necessarily the PADD in which it is consumed.

Our Base Case modeling indicates that 14 refineries could already be producing non-California gasoline that complies with the Study Case B benzene limits. We estimated that another 15 refineries could adjust operations to meet the benzene limits without capital investment. The two small refineries that were assumed to cease making gasoline in Study Case A were also assumed to do so in Study Case B. Eighty-one refineries required capital investments to comply with the Study Case B limits.

Total gasoline supplied by domestic refineries, including the ethanol added to refinery-produced blendstocks, was estimated to be 22 MB/D less than the

Base Case. CARB and RFG production actually increased by 1 MB/D relative to the Base Case. CG production declined.

STUDY CASE C GASOLINE SUPPLY

The Study Case C balance is only slightly different than the Study Case B balance from which it is derived.

2012 Study Case C Supply Balance

(Thousands of Barrels Per Day)

	TOTAL U.S.	*PADD 1*	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5*
Domestic Production by Refiners(1)						
Conventional (non-ox)	4,305	313	506	2,777	282	428
Conventional (w/EtOH)	1,763	60	1,466	141	34	62
Reformulated (non-ox)	324	-	-	324	-	-
Reformulated (w/EtOH)	1,949	512	273	1,164	-	-
CARB (non-ox)	-	-	-	-	-	-
CARB (w/EtOH)	1,202	-	-	-	-	1,202
TOTAL	**9,543**	**885**	**2,245**	**4,405**	**317**	**1,692**
Total Ethanol Included Above(2) (MM gals/yr)	6,740	877	2,666	2,000	53	1,146
Gasoline Consumption						
Conventional	7,111	2,333	2,686	1,115	364	613
Reformulated	2,407	1,550	407	450	-	-
CARB	1,285	-	-	-	-	1,285
TOTAL	**10,803**	**3,883**	**3,093**	**1,565**	**364**	**1,898**
Domestic Over/(Under) Supply						
Conventional	(1,043)	(1,960)	(715)	1,802	(47)	(123)
Reformulated (w/EtOH)	(134)	(1,038)	(134)	1,038	-	-
CARB (w/EtOH)	(83)	-	-	-	-	(83)
TOTAL	**(1,260)**	**(2,998)**	**(848)**	**2,840**	**(47)**	**(206)**
Total Ethanol Included Above (MM gals/yr)	278	1,591	205	(1,591)	-	73

NOTES:

(1) Includes finished gasoline, CBOB, RBOB and CARBOB produced from crude oil refineries and ethanol added to refinery CBOB, RBOB and CARBOB production.

(2) Ethanol blended into RBOB and CBOB is shown in the PADD that produces the BOB, not necessarily the PADD in which it is consumed.

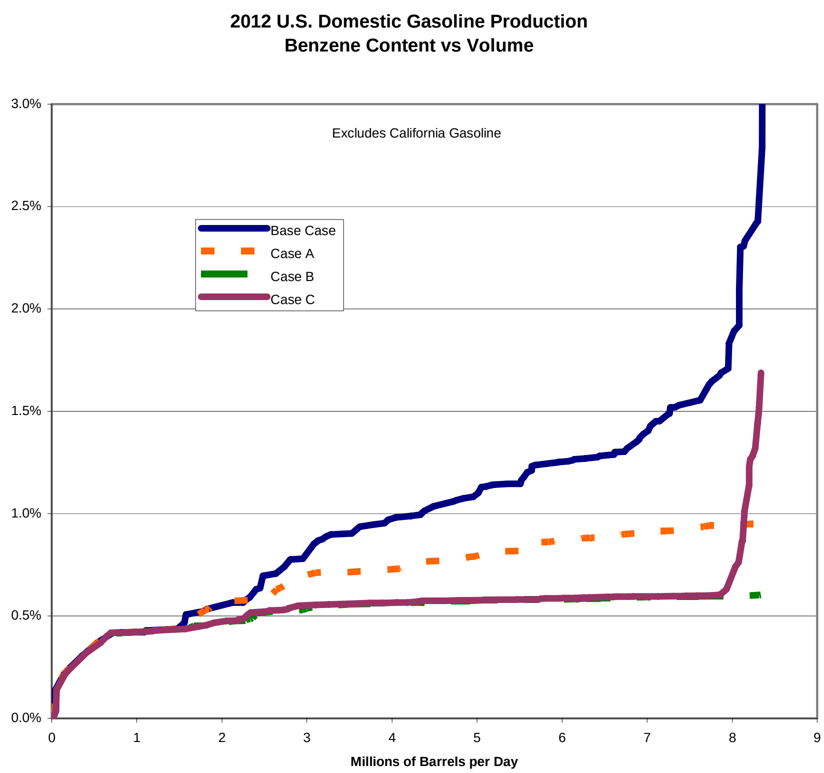
GASOLINE BENZENE LEVELS

The following table compares regional gasoline benzene levels reported by the EPA in their proposed MSAT 2 rule to those from our study. The EPA's data are from their refinery-by-refinery model for 2003 summertime gasoline production. In aggregate, our Base Case model data is slightly below the EPA figure. Part of the difference could be the difference in basis. The EPA modeling effort attempted to reproduce 2003 summertime actual data. Our Base Case includes refinery expansions, increased ethanol blending and Tier 2 gasoline hydrotreating. In PADD 5, our 2012 Base Case is significantly below the EPA's figures indicating potential differences in our respective cost estimates for these refineries or difference in underlying assumptions for the two studies.

Regional Produced Gasoline Benzene Content, vol%

	EPA Summer 2003	***Base Case 2012***	***Study Cases***		
			A	***B***	***C***
PADD 1	0.62	0.75	0.55	0.50	0.54
PADD 2	1.32	1.15	0.80	0.56	0.58
PADD 3	0.86	0.94	0.69	0.52	0.54
PADD 4	1.60	1.38	0.85	0.56	0.59
PADD 5, excluding CA	2.06	1.21	0.70	0.45	0.57
TOTAL U.S.	**0.97**	**0.94**	**0.67**	**0.51**	**0.54**

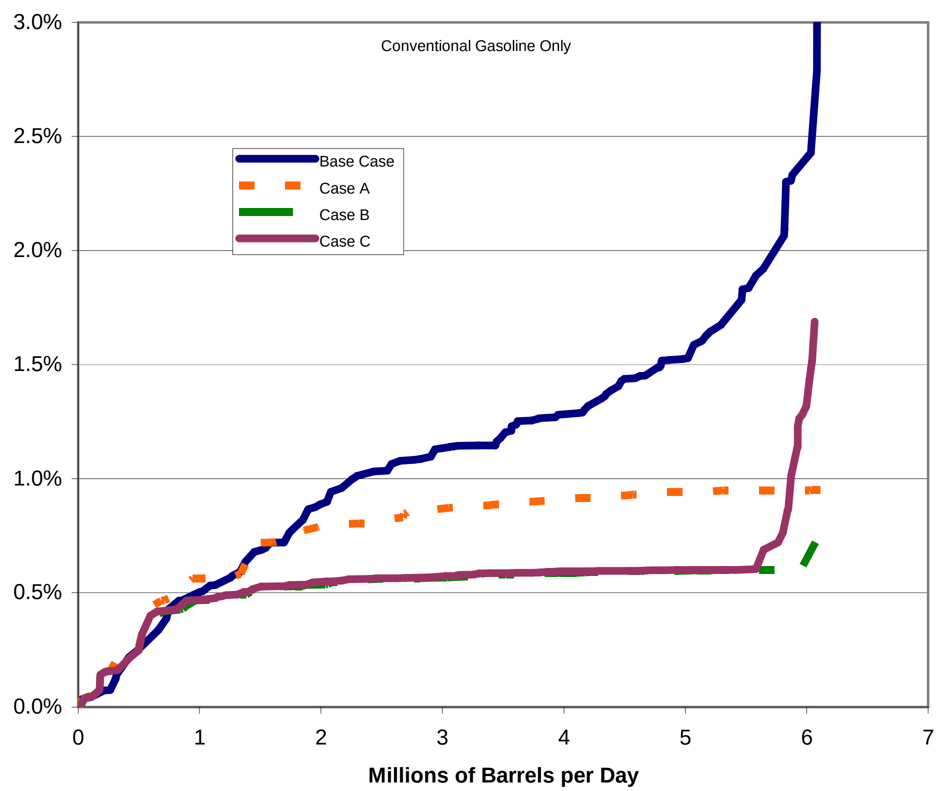
The following graph shows the refinery-by-refinery benzene levels versus cumulative gasoline production for all non-California gasoline.



In Study Case A, the average benzene content of all non-California gasoline produced decreases by 28%. The maximum pool average benzene level for an individual refinery decreases from 3.8% to 0.95%. The Study Case B and Study Case C curves are identical except at the far right side of the graph. Study Case B achieves a 47% reduction in aggregate average benzene concentration and reduces the maximum individual refinery pool average to 0.6%. In Study Case C, an aggregate reduction of 43% is achieved and the maximum individual refinery average is 1.7%.

The next graph shows similar data for CG only.

2012 U.S. Domestic Gasoline Production
Benzene Content vs Volume



In Study Case A, the aggregate average benzene level of CG is reduced by 31%. In Study Cases B and C, the aggregate reductions are 54% and 51%

respectively. The reductions in the individual refinery pool averages are the same as discussed above.

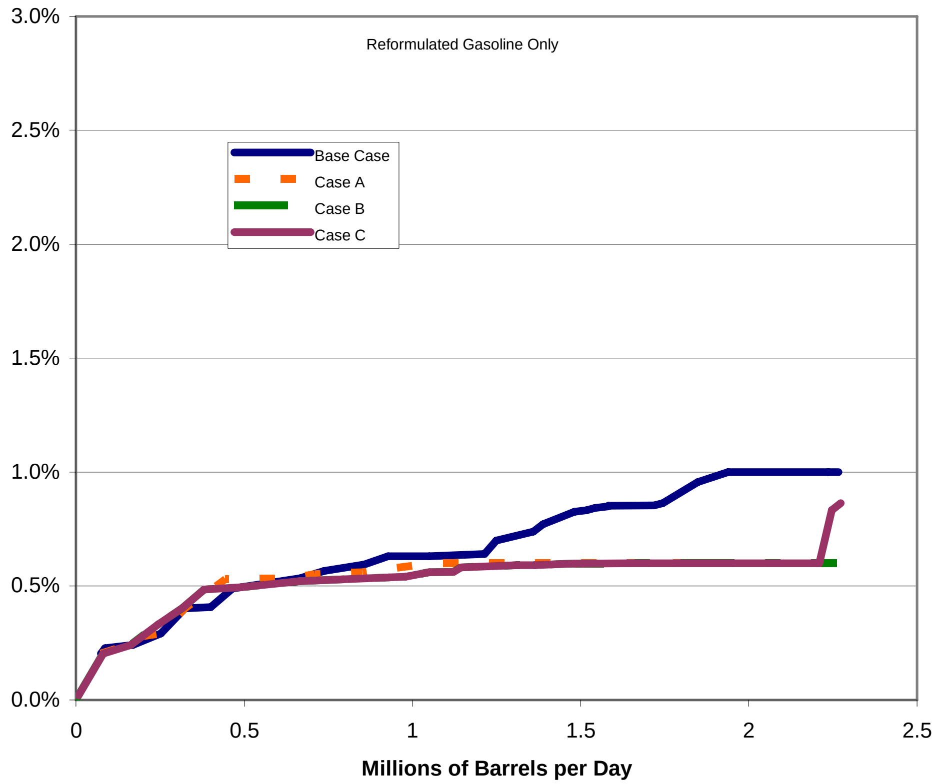
Regional Produced Gasoline Benzene Content, vol%

Conventional Gasoline Only

	Base Case	***Study Cases***		
	2012	***A***	***B***	***C***
PADD 1	0.73	0.52	0.41	0.50
PADD 2	1.24	0.86	0.58	0.60
PADD 3	1.03	0.75	0.51	0.53
PADD 4	1.38	0.85	0.56	0.60
PADD 5	1.23	0.70	0.45	0.57
TOTAL U.S.	**1.12**	**0.77**	**0.52**	**0.56**

Since RFG already has a lower average benzene content, the aggregate reductions are smaller than for CG and are very similar in all three Study Cases, ranging from 22.7% to 24.2%. The individual refinery maximum pool average is reduced from 1.00% in the Base Case to 0.60% in Study Cases A and B, and 0.86% in Study Case C.

2012 U.S. Domestic Gasoline Production
Benzene Content vs Volume



Regional Produced Gasoline Benzene Content, vol%

Non-California Reformulated Gasoline Only

	Base Case	***Study Cases***		
	2012	***A***	***B***	***C***
PADD 1	0.76	0.57	0.57	0.57
PADD 2	0.46	0.41	0.41	0.41
PADD 3	0.72	0.55	0.54	0.55
TOTAL U.S.	**0.70**	**0.54**	**0.53**	**0.54**

INVESTMENT COSTS

Investment costs for the compliance strategies discussed above are tabulated in the following table. For Study Case A, the estimated investment cost is \$899 million (2006 dollars). The cost for Study Case B is almost twice that figure at \$1.737 billion. Study Case C investments are estimated at \$1.476 billion.

Compliance Strategies
(Number of Refineries)

	Study Case		
	A	***B***	***C***
Quit Making Gasoline	2	2	0
New Units			
Naphtha or Reformate Splitters	49	69	64
Benzene Saturation	45	68	68
C_5/C_6 Isomerization	3	3	3
Revamps and Expansions			
Naphtha or Reformate Splitters	5	8	8
Aromatics Extraction	8	9	9
Benzene Saturation	2	2	2
C_5/C_6 Isomerization	1	1	1
Total Investment Cost, millions of 2006 US$	**899**	**1,737**	**1,476**

NOTE:

Individual refineries appear in multiple categories for each case. For example, a refinery that installed a reformate splitter and a benzene saturation unit would appear in both categories.

TOTAL COMPLIANCE COSTS

Capital investment costs are an important part of the total compliance cost, but operating costs related to natural gas prices are the largest cost component. The total compliance cost for each of the Study Cases is shown on the following page.

Total Potential Compliance Cost

(Millions of 2006 dollars per year)

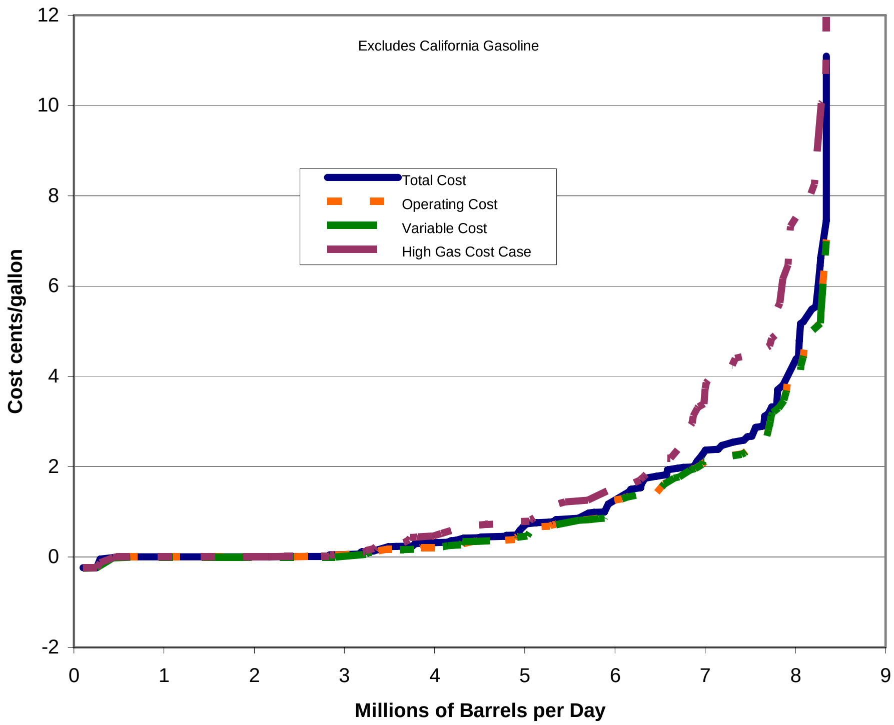
	Study Case		
	A	***B***	***C***
Product Quantity and Quality Changes	481	647	563
Purchased Hydrogen	75	87	79
Other Variable Operating Expenses	567	620	532
Fixed Operating Expenses	13	13	11
Capital Recovery	151	293	246
TOTAL COST	**1,286**	**1,660**	**1,431**

In the graphs that follow, the individual refinery compliance costs are plotted in cents per gallon of gasoline for the three Study Cases. All three show significant volumes of gasoline with zero or negative costs. The negative cost refineries all have existing aromatics extraction capacity, which was assumed to be expanded to reduce benzene levels. The negative cost is a result of the assumed profitability of aromatics extraction. If aromatics extraction is as profitable as indicated, it is unclear why these refineries would not implement aromatics extraction projects even without new benzene regulations. The implication is that our expense or margin assumptions may be optimistic and the compliance costs may be understated.

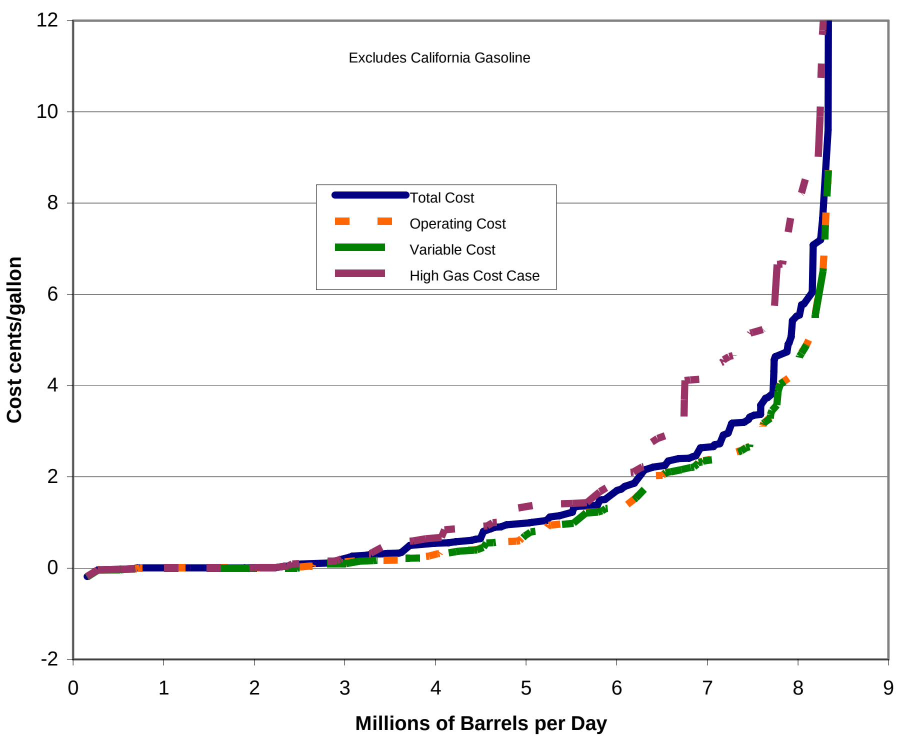
The zero cost refineries, i.e., those that can already meet the benzene limits, were mostly located in PADD 1, 2, and 3, and are already extracting aromatics from reformate. Several other refineries where RFG is the main gasoline formulation also have no compliance cost.

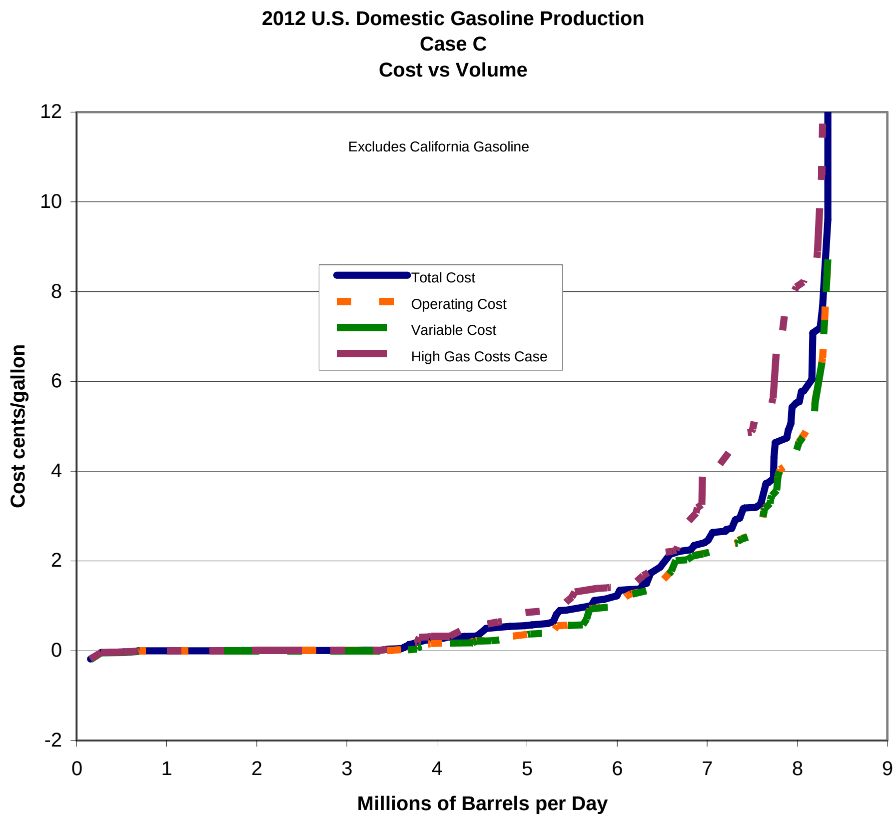
The variable cost line on each graph includes product quantity and quality changes, purchased hydrogen, and other variable operating expenses. In Study Case C, the variable cost line also includes the purchase or sale of benzene credits. A sensitivity case was run assuming natural gas costs at twice that used in this study, as discussed in Section VI.

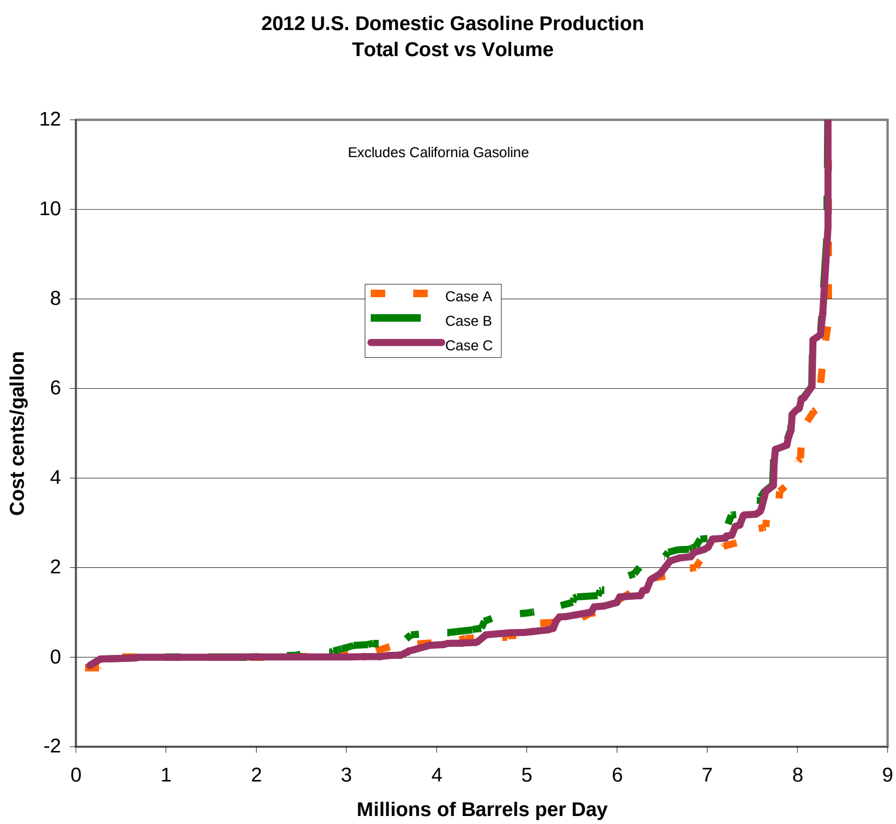
2012 U.S. Domestic Gasoline Production
Case A
Cost vs Volume



2012 U.S. Domestic Gasoline Production
Case B
Cost vs Volume




2012 U.S. Domestic Gasoline Production
Case C
Cost vs Volume
Excludes California Gasoline
Total Cost
Operating Cost
Variable Cost
High Gas Costs Case
Cost cents/gallon
Millions of Barrels per Day
12
10
8
6
4
2
0
-2
0
1
2
3
4
5
6
7
8
9


2012 U.S. Domestic Gasoline Production
Total Cost vs Volume
Excludes California Gasoline
Case A
Case B
Case C
Cost cents/gallon
Millions of Barrels per Day
12
10
8
6
4
2
0
-2
0
1
2
3
4
5
6
7
8
9

IX. CONCLUSIONS

It does not appear that any of the considered benzene reduction scenarios would have a significant impact on the volume of gasoline produced by domestic refiners. We do not expect benzene restrictions at the levels included in the Study Cases to cause any refineries to shutdown, although a couple of refineries that only produce small volumes of gasoline may discontinue its production. The requirement for imported gasoline is substantial in the Base Case, but it may not be affected significantly by changes in benzene regulations. However, tighter benzene standards could make it more difficult to obtain the needed imports of gasoline in the future.

However, total compliance costs for all three Study Cases are expected to be significant. There may also be a wide disparity in compliance costs between different refiners, but the credit trading program has the potential to mitigate those differences.

This study did not evaluate the complexity additions to refineries for meeting more constraining product quality specifications. Therefore, no attempt was made to adjust for potential changes in utilization rates and/or reblending needs (minimized with no caps) and their potential effect on supply.

APPENDIX A. REGIONAL GASOLINE QUALITIES

2012 Base Case Regional Gasoline Qualities

	TOTAL U.S.	*PADD 1*	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5*
Domestic Production by Crude Oil Refiners[1]						
Total Pool (w/EtOH)						
RVP, psi	7.9	7.4	8.7	7.7	8.6	7.5
Olefins, Vol %	9.6%	11.1%	9.1%	10.6%	10.5%	6.7%
Aromatics, Vol %	26.3%	27.1%	26.5%	26.7%	26.9%	24.2%
Benzene, Vol %	0.94%	0.75%	1.15%	0.94%	1.38%	0.66%
Sulfur, wppm	24.2	27.2	27.6	27.3	27.8	9.3
Conventional (non-ox)						
RVP, psi	8.2	8.2	8.2	8.1	8.4	8.8
Olefins, Vol %	11.4%	14.4%	9.3%	11.7%	10.3%	10.0%
Aromatics, Vol %	31.3%	35.0%	31.7%	31.4%	27.3%	30.4%
Benzene, Vol %	1.10%	0.71%	1.47%	1.02%	1.44%	1.22%
Sulfur, wppm	23.8	19.8	21.2	25.9	27.2	14.0
Conventional (w/EtOH)[2]						
RVP, psi	9.3	9.4	9.2	8.9	9.8	10.5
Olefins, Vol %	10.1%	20.0%	9.4%	8.7%	12.0%	19.0%
Aromatics, Vol %	25.4%	26.4%	25.5%	29.3%	22.7%	16.7%
Benzene, Vol %	1.16%	0.87%	1.16%	1.35%	0.80%	1.14%
Sulfur, wppm	31.3	31.8	31.4	26.2	32.5	38.4
RFG (non-ox)						
RVP, psi	6.8	-	-	6.8	-	-
Olefins, Vol %	11.5%	-	-	11.5%	-	-
Aromatics, Vol %	16.3%	-	-	16.3%	-	-
Benzene, Vol %	0.69%	-	-	0.69%	-	-
Sulfur, wppm	22.0	-	-	22.0	-	-
RFG (w/EtOH)						
RVP, psi	6.8	6.7	6.8	6.8	-	-
Olefins, Vol %	7.5%	7.8%	6.7%	7.5%	-	-
Aromatics, Vol %	19.0%	21.9%	21.6%	17.0%	-	-
Benzene, Vol %	0.70%	0.76%	0.46%	0.73%	-	-
Sulfur, wppm	31.2	31.7	22.0	33.3	-	-

NOTES:

(1) Includes ethanol added to refinery CBOB, RBOB and CARBOB production.

(2) Conventional gasoline with ethanol production in PADDs 3 and 4 are less than five percent of the total gasoline production and comparison of its quality to other formulations is not meaningful.

2012 Study Case A Regional Gasoline Qualities

	TOTAL U.S.	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Domestic Production by Crude Oil Refiners[1]						
Total Pool (w/EtOH)						
RVP, psi	7.9	7.5	8.7	7.7	8.6	7.5
Olefins, Vol %	9.8%	11.3%	9.2%	10.8%	10.6%	6.7%
Aromatics, Vol %	26.0%	27.0%	26.2%	26.5%	26.1%	24.0%
Benzene, Vol %	0.67%	0.55%	0.80%	0.69%	0.85%	0.49%
Sulfur, wppm	24.2	27.3	27.6	27.4	27.9	9.2
Conventional (non-ox)						
RVP, psi	8.2	8.2	8.2	8.1	8.4	8.8
Olefins, Vol %	12.1%	15.6%	10.8%	12.4%	11.5%	9.9%
Aromatics, Vol %	30.2%	33.9%	29.0%	30.4%	27.1%	29.6%
Benzene, Vol %	0.74%	0.47%	0.82%	0.76%	0.87%	0.67%
Sulfur, wppm	25.3	26.0	25.4	26.9	28.4	12.4
Conventional (w/EtOH)						
RVP, psi	9.3	9.4	9.2	8.9	9.8	10.5
Olefins, Vol %	9.4%	26.1%	9.0%	4.6%	2.5%	19.0%
Aromatics, Vol %	25.7%	18.3%	26.0%	32.4%	16.9%	15.5%
Benzene, Vol %	0.84%	0.90%	0.87%	0.50%	0.70%	0.85%
Sulfur, wppm	27.6	33.4	28.0	16.6	22.6	40.1
RFG (non-ox)						
RVP, psi	6.8	-	-	6.8	-	-
Olefins, Vol %	11.5%	-	-	11.5%	-	-
Aromatics, Vol %	20.6%	-	-	20.6%	-	-
Benzene, Vol %	0.59%	-	-	0.59%	-	-
Sulfur, wppm	16.9	-	-	16.9	-	-
RFG (w/EtOH)						
RVP, psi	6.8	6.7	6.8	6.8	-	-
Olefins, Vol %	7.0%	6.3%	7.5%	7.1%	-	-
Aromatics, Vol %	19.1%	22.8%	21.7%	16.8%	-	-
Benzene, Vol %	0.53%	0.57%	0.41%	0.54%	-	-
Sulfur, wppm	31.9	27.6	31.4	33.9	-	-
CARB (w/EtOH)						
RVP, psi	6.8	-	-	-	-	6.8
Olefins, Vol %	4.8%	-	-	-	-	4.8%
Aromatics, Vol %	22.3%	-	-	-	-	22.3%
Benzene, Vol %	0.40%	-	-	-	-	0.40%
Sulfur, wppm	6	-	-	-	-	6

NOTE:

(1) Includes ethanol added to refinery CBOB, RBOB and CARBOB production.

2012 Study Case B Regional Gasoline Qualities

	TOTAL U.S.	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Domestic Production by Crude Oil Refiners[1]						
Total Pool (w/EtOH)						
RVP, psi	7.9	7.4	8.7	7.7	8.6	7.5
Olefins, Vol %	9.6%	11.1%	9.2%	10.6%	10.5%	6.7%
Aromatics, Vol %	25.8%	26.9%	26.0%	26.3%	25.7%	23.9%
Benzene, Vol %	0.51%	0.50%	0.56%	0.52%	0.56%	0.41%
Sulfur, wppm	24.2	27.0	28.0	27.4	27.6	8.9
Conventional (non-ox)						
RVP, psi	8.2	8.2	8.2	8.1	8.4	8.8
Olefins, Vol %	11.8%	14.8%	11.4%	11.9%	10.4%	10.2%
Aromatics, Vol %	30.1%	34.4%	27.9%	30.4%	26.0%	29.6%
Benzene, Vol %	0.51%	0.37%	0.66%	0.51%	0.55%	0.42%
Sulfur, wppm	25.8	22.2	28.6	27.3	26.8	14.2
Conventional (w/EtOH)						
RVP, psi	9.3	9.4	9.2	8.9	9.8	10.5
Olefins, Vol %	9.5%	22.8%	8.6%	10.3%	11.3%	14.2%
Aromatics, Vol %	26.2%	23.6%	26.2%	32.0%	23.3%	18.8%
Benzene, Vol %	0.55%	0.61%	0.55%	0.47%	0.66%	0.62%
Sulfur, wppm	27.6	32.7	28.0	17.0	35.4	33.2
RFG (non-ox)						
RVP, psi	6.8	-	-	6.8	-	-
Olefins, Vol %	11.5%	-	-	11.5%	-	-
Aromatics, Vol %	20.4%	-	-	20.4%	-	-
Benzene, Vol %	0.59%	-	-	0.59%	-	-
Sulfur, wppm	12.7	-	-	12.7	-	-
RFG (w/EtOH)						
RVP, psi	6.8	6.7	6.8	6.8	-	-
Olefins, Vol %	7.1%	7.3%	7.4%	7.0%	-	-
Aromatics, Vol %	18.5%	22.2%	21.1%	16.3%	-	-
Benzene, Vol %	0.52%	0.57%	0.41%	0.52%	-	-
Sulfur, wppm	31.9	29.6	28.2	33.8	-	-

NOTE:

(1) Includes ethanol added to refinery CBOB, RBOB and CARBOB production.

2012 Study Case C Regional Gasoline Qualities

	TOTAL U.S.	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Domestic Production by Crude Oil Refiners[1]						
Total Pool (w/EtOH)						
RVP, psi	7.9	7.4	8.7	7.7	8.6	7.5
Olefins, Vol %	9.6%	11.1%	9.2%	10.6%	10.5%	6.7%
Aromatics, Vol %	25.9%	27.0%	26.0%	26.3%	25.8%	24.0%
Benzene, Vol %	0.54%	0.54%	0.58%	0.54%	0.59%	0.45%
Sulfur, wppm	24.2	26.8	28.0	27.4	27.6	8.9
Conventional (non-ox)						
RVP, psi	8.2	8.2	8.2	8.1	8.4	8.8
Olefins, Vol %	11.8%	14.7%	11.4%	12.0%	10.4%	10.2%
Aromatics, Vol %	30.1%	34.7%	27.9%	30.4%	26.1%	29.9%
Benzene, Vol %	0.55%	0.48%	0.66%	0.55%	0.58%	0.52%
Sulfur, wppm	25.7	21.7	28.6	27.3	26.8	13.9
Conventional (w/EtOH)						
RVP, psi	9.3	9.4	9.2	8.9	9.8	10.5
Olefins, Vol %	9.3%	22.8%	8.6%	8.4%	11.3%	14.1%
Aromatics, Vol %	26.4%	23.6%	26.2%	33.7%	23.3%	19.0%
Benzene, Vol %	0.58%	0.61%	0.58%	0.44%	0.66%	0.89%
Sulfur, wppm	27.7	32.7	28.1	17.3	35.4	33.3
RFG (non-ox)						
RVP, psi	6.8	-	-	6.8	-	-
Olefins, Vol %	11.5%	-	-	11.5%	-	-
Aromatics, Vol %	20.2%	-	-	20.2%	-	-
Benzene, Vol %	0.62%	-	-	0.62%	-	-
Sulfur, wppm	12.5	-	-	12.5	-	-
RFG (w/EtOH)						
RVP, psi	6.8	6.7	6.8	6.8	-	-
Olefins, Vol %	7.2%	7.3%	7.4%	7.1%	-	-
Aromatics, Vol %	18.6%	22.2%	21.1%	16.4%	-	-
Benzene, Vol %	0.52%	0.57%	0.41%	0.53%	-	-
Sulfur, wppm	31.8	29.6	28.2	33.6	-	-

NOTE:

(1) Includes ethanol added to refinery CBOB, RBOB and CARBOB production.

APPENDIX B. REFERENCES

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