MEMORANDUM

Date: October 22, 2001

Subject: Cost Estimates of Long-Term Options for Addressing Boutique Fuels

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To: The Record

This memorandum provides our analysis supporting the costs estimates described in the EPA draft report entitled, "Study of Unique Gasoline Fuel Blends ("Boutique Fuels"), Effects on Fuel Supply and Distribution and Potential Improvements", hereafter referred to as "the report." The report presents four options for addressing boutique fuels in the long term. These options are:

- Three-Fuel Option for 49-State Program
  - With RFG or federal CBG
  - With or without a fuel benzene standard for conventional gasoline
- Two-Fuel Option for 49-State Program
  - With RFG or federal CBG
  - With or without a fuel benzene standard for conventional gasoline
- 49-State Federal Cleaner Burning Gasoline (CBG)
- 50-State California CBG

Federal CBG is defined in the report as a fuel meeting all of the requirements for federal reformulated gasoline, but without the oxygen requirement. It assumes the simultaneous existence of a nationwide renewable oxygenate mandate as discussed in the report.

The first two options presume that states would choose to select from a more limited set of fuel programs. Under these two options, we assumed that states and localities would choose a fuel type with the same or better emissions performance compared to the fuel they receive today resulting in a fewer number of fuels compared to today. Under the Three-Fuel Option, the 7.2 and 7.0 RVP areas would receive RFG or federal CBG, as applicable. Under the Two-Fuel Option, the 7.8, 7.2 and the 7.0 RVP areas would receive RFG or CBG. Thus, under the three- and two-fuel options, the primary change occurring is the conversion of low RVP fuel to Federal RFG or CBG. The third option would impose the federal CBG fuel requirements and a renewable oxygenate mandate on all non-California States. The fourth option would impose the California CBG program nationwide. Under the 2-fuel and 3-fuel options, we also evaluated cases which would impose a 0.95 percent by volume average benzene standard on conventional gasoline.

This memorandum is divided broadly into three parts. The first part provides the context for the cost analysis by describing the environmental programs in place prior to making this analysis. This section also describes the Phase II RFG program and summarizes the components which make up the program. The second part provides a summary of the component costs that were used to estimate the overall costs for reformulated gasoline programs which supplant the low RVP programs in the Three-Fuel and Two-Fuel long term options, and the conventional gasoline benzene standard. These components include costs for changes to specific fuel properties and costs associated with increasing or decreasing volumes of different gasoline blendstocks including oxygenates and their replacements. The third part of this memorandum provides our cost estimates for the Three-Fuel and Two-Fuel long term options and the benzene standard, based on the component costs, and more general cost estimates for the two nationwide CBG programs.

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I Definition of Base and Reference Cases

Before proceeding with the cost analysis, it was necessary to establish a context for making the analysis. The base year for the analysis is the year 2000. Year 2000 volumes were established for each of the fuel types identified in the Boutique Fuel study using information from the Energy Information Administration (EIA). The treatment of oxygenate use during the base year is discussed in analogous memorandum which addresses the gasoline supply impacts of these fuel control options.

The reference case is year 2006 and includes the environmental programs expected to be in effect by that date. These programs include:

1. The Tier 2 low sulfur gasoline requirements
2. The toxics performance standards recently promulgated as part of the Mobile Source Air Toxics (MSAT) rulemaking
3. Existing and currently proposed State MTBE bans which are scheduled to be in place by 2006

The case is termed a reference case, because all of the long term options were compared to it.

Each of the three programs listed above impacts the cost of producing more RFG (or CBG) in the reference year 2006. For example, the Tier 2 low sulfur requirement of 30 ppm on average will apply to essentially all gasoline, both reformulated and conventional by 2006. For all practical purposes, gasoline with 30 ppm sulfur automatically complies with the RFG NOx performance standard, thus compliance with the RFG NOx standard becomes a moot issue after 2006. While previous RFG cost estimates have included a cost for sulfur control, the cost of additional RFG production in the post-2005 time frame no longer has to include this factor.

Another important factor is the state MTBE bans. We project that the current or proposed state bans will shift all Northern RFG and California CBG currently utilizing MTBE to ethanol. These state bans also affect the cost of any new RFG projected to be used in these areas, as this RFG will have to contain ethanol instead of MTBE.

The cost of Phase II RFG was estimated in the original rulemaking published in 1994[1] as 4-6 ¢/gal using costs representative of 1990 refinery production. This cost range was relative to unreformulated (conventional) gasoline at the nominal RVP of 9.0 psi, and was primarily representative of RFG containing MTBE. In addition to the changes due to Tier 2 sulfur controls and MTBE bans by 2006, several factors have already changed that would impact the costs of RFG. Rather than attempt to make adjustments to the original RFG cost estimates for such factors as crude oil prices, oxygenate prices, and the slate of State-specific low RVP programs, we have instead produced a new estimate of the cost of Phase II RFG for the incremental RFG

[1] Federal Register citation 59 FR 7716, published February 16, 1994

volumes under the 3-fuel and 2-fuel options. This new cost estimate assumes current (nominally 2000) component prices and is described in Section III below.

II Component Costs

The component costs described in this section are the building blocks from which we made our cost estimates for changes to specific fuel categories, and thus for the four long-term fuel control options. In some cases, the component costs are estimated for a single fuel volume, when the affected volume varies between some of the fuel control options. In these cases, the issue of cost versus production volume is addressed in Section III below. Distribution costs related to ethanol use are also addressed separately in the context of the discussion of each of the specific program options in Section III.

By 2006, we also expect that the States which currently have legislation (final or proposed) banning MTBE will have implemented those bans. We project that the current or proposed state bans will shift all Northern RFG and California CBG currently utilizing MTBE to ethanol. New RFG production in these areas is also projected to contain ethanol. Also, new RFG in Texas is projected to contain ethanol, due to that state's limit on expanded MTBE use. Further discussion on future MTBE bans can be found in the report. The in-use ratio of MTBE-blended RFG versus ethanol-blended RFG will depend on the program option, as described in Section III below.

We estimated the total cost of Federal Phase II RFG in the reference year of 2006 by assuming that it is composed of the costs of adding an oxygenate, lowering the RVP, and controlling the benzene content. Based on the toxics overcompliance exhibited by RFG in recent years, the Phase II RFG toxics standard is assumed to be met when controls are applied to oxygenates, RVP, and benzene content. In addition, benzene control was used as the sole means of meeting the requirement of the MSAT rule by reducing benzene down to 0.7 vol%. The need for additional aromatics control was not investigated, and is an issue for further study in the future. We calculated the cost of RVP reduction from three different baselines to represent the fact that, under the first two program options described in the introduction to this memorandum, RFG would replace low RVP programs which currently cap the RVP at either 7.2, or 7.0 psi for the Three-Fuel program, and those RVP programs plus the 7.8 RVP programs for the Two-Fuel program.

The cost of the national Federal CBG program can be estimated using the component costs of the RFG program developed for use in estimating the cost of the Two and Three fuel programs. Meeting the toxics requirement of the MSAT requirements without the use of oxygenate is assumed to be met by further reducing benzene in the gasoline pool. Using these estimated costs may underestimate the costs somewhat because if the Federal CBG program were to be extended nationwide, it would involve many small and higher cost refineries which would not be impacted by an incremental RFG program like the Three and Two-Fuel options.

The cost of a nationwide California CBG program cannot be adequately estimated using the component costs used for estimating the Federal RFG and CBG programs. While the RVP and benzene reduction costs would likely be similar with both programs, the California program also requires deep reductions in aromatics and olefins, and increases in E200 and E300, relative to current nationwide conventional gasoline. Thus a rough estimate of the cost will be made using the program costs estimated by the State of California.

The following four sections describe the cost of reducing gasoline RVP, reducing benzene content, adding and removing oxygenate, and meeting the MSAT standards.

A. *Cost of reducing gasoline RVP*

The following section details our cost analysis for lowering gasoline Reid Vapor Pressure (RVP). This section is divided into several subsections. First the means for reducing RVP are discussed. Then, the capital and operating costs for reducing RVP are presented. Then we present our estimate for downgrading the volatile compounds removed from gasoline and selling them to less valuable markets and also account for the increased energy density for the remaining gasoline pool. Finally, we combine these various costs for each of the long term options presented in the boutique fuel report.

For this analysis, gasoline can be defined as being comprised of light and heavy hydrocarbons. Heavy hydrocarbons, which comprise the majority of the gasoline pool, have six or more carbon molecules (C6+) while light hydrocarbon compounds have a carbon count less than six. The light hydrocarbon components in gasoline are butanes (C4s) and pentanes (C5s).[b] The gasoline produced by more complex refineries is comprised of ten or more different streams produced by refinery processes or streams imported into the refinery. Some of these streams contain significant levels of butanes and pentanes while others do not. A refiner's gasoline pool is the volume of various hydrocarbon streams or components that are added to a refiners gasoline volume before shipment.

Butanes are more volatile than pentanes. Reducing the gasoline pool RVP by one RVP number requires removing 1.5 volume percent of butane, versus 7.5 volume percent of pentane. In either case, value is lost because the butanes or pentanes must be sold to a market with lower prices per volume than gasoline. Thus, reductions in RVP are most cost effectively achieved by removal of butanes. RVP reductions via pentane removal are only undertaken after butanes have been removed to their maximum practical limit. A critical issue here is the level of gasoline RVP level which can be achieved by solely removing butanes, as further RVP reductions become significantly more costly. In doing so, we also consider the possibility that refiners who must remove pentanes from a particular gasoline pool (e.g., for producing RBOB for blending with

[b] These molecules can have single and/or double bonds between their carbon molecules. For this cost analysis referral to butanes and pentanes means inclusion of both single and double carbon bond types molecules.

ethanol) can shift those pentanes to another gasoline pool which does not have such a stringent RVP requirement or selling those pentanes to another refiner which produces gasoline for a higher RVP pool. As will be discussed further below, we expect that all of the fuel control options can be met with only the removal of butane from the gasoline pool, except for the two nationwide CBG programs which apply stringent RVP controls to all U.S. gasoline.[c]

In gasoline, each hydrocarbon compound has its own pure vapor pressure. However, the compounds usually contribute a different or modified vapor pressure when blended into the gasoline pool due to its physical interaction with the other constituents in the pool. For ease of making blending RVP calculations, the modified vapor pressure of a single compound is called the blending RVP and we will be using blending RVP values in this study. The C6+ hydrocarbons in gasoline have relatively low blending RVP values ranging from 9 to near zero. Butane and pentane hydrocarbons have much higher blending RVP's; isobutane's and normal butane's blending RVPs are 71 and 65, respectively, and isopentane's and normal pentane's blending RVPs are 17 and 20, respectively[d]. For gasoline, high RVP blendstocks can only be minimally offset with lower RVP blendstocks streams due to the physical nature of vapor pressure. Thus, the volume fractions of the lightest hydrocarbon streams in the gasoline pool set the lowest obtainable pool RVP.

1. Means for reducing the RVP of gasoline

Since butanes and pentanes have high blending RVP's, refiners control the amount blended into their gasoline pool up to the RVP allowed by the applicable environmental or other RVP control specification.[e] In the summertime low RVP season, refiners are probably not adding butane from non-crude oil sources, but separating some of the butanes from their crude-derived blendstocks and blending back a portion to just meet RVP requirements. To accomplish a current RVP goal of say 9.0 psi, refiners utilize existing distillation columns[f] such as light

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[c] Based on conversations with refiners which produce ethanol-blended RFG, they maximize their gasoline production through their blending practices. When they need to remove pentanes from the RFG pool to make room for ethanol, they put the pentanes in the conventional gasoline pool, or sell them to another refiner who can, and remove a small amount of butane from the conventional pool to balance the RVP.

[d] Maples, Robert, E., Petroleum Refinery Process Economics

[e] Summertime RVP specifications are set by Federal or state environmental regulations, or by ASTM Designation Standard 4814.

[f] Distillation columns are the process equipment used to separate light from heavier hydrocarbons through the process of vaporization and condensing. The addition and removal of heat to the column is what drives the separation process. Heat is added to the column through a heat exchanger called a reboiler while heat is removed from the top of the column with an exchanger called a condenser. The lighter hydrocarbons are vaporized and travel up the column were they are removed as a product while the heavier hydrocarbons move down the column are drawn off the bottom. In a distillation column, there are many distillation trays which provide the mechanism for

straight run naphtha splitters, reformate splitters, FCC debutanizers, stabilizers and other existing process distillation columns to remove butanes. These existing distillation columns are limited in making significant reductions in pool RVP, as they were designed primarily to meet higher RVP levels. After these existing methods and equipment for removing light hydrocarbons from the gasoline pool are fully utilized, further lowering of RVP could require a refiner to add additional distillation column capacity to remove butanes, and in some cases pentanes.

Further control of RVP can most easily be realized by reducing the butane or pentane content of the FCC gasoline blendstock. To accomplish this task, refiners would likely have to add a distillation column, or revamp a currently existing distillation column, called a debutanizer and perhaps add another column called a depentanizer, to separate these light hydrocarbons from the rest of the FCC gasoline blendstock. Debutanizers distill or separate butanes and any remaining lighter hydrocarbons off the top of the distillation column while pentanes and heavier C6+ hydrocarbons largely remain in the bottom.[g] Depentanizers remove the pentanes and any butanes which are left in the depentanized FCC gasoline blendstock stream off of the top of the column, while the heavier C6+ hydrocarbon are removed from the bottom.

In the U.S., 106 of the total of 128 gasoline-producing refineries have FCC units.[1] The FCC unit converts gas oil and sometimes residual gas oil[h] to gasoline, distillate, and a range of lighter hydrocarbons including propane, ethane and methane or fuel gas by reacting or cracking the gas oil over fluidized, heated catalyst. The gasoline volume produced by the FCC unit makes up to 35-50 volume percent of refiner's gasoline pool and is thus the largest contributor to the gasoline pool.[2] FCC unit gasoline contains butanes, pentanes, and C6+ hydrocarbons with the amount of these hydrocarbons being set by each refiner's FCC conversion rate[i] and the FCC unit's gasoline distillation capability. Most of the butanes and lighter hydrocarbons are removed off of the top of an existing debutanizer column. Typical ranges for butanes are 0 to 4 percent and pentanes 5 to 17 volume percent of total FCC debutanized gasoline yield. A higher percentage of butane in FCC gasoline blendstock would be expected for a 9.0 RVP gasoline,

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mixing and separation of the hydrocarbons.

[g] Any distillation column does not make a "perfect" cut and when trying to remove most all the lighter butane stream, some of the components of the heavier stream would also be distilled along with the butane stream. Thus, some pentanes would also be expected to be distilled off the top of the column along with the butanes. However, in the case of depentanizers, if some of the pentane stream can be left behind , the C6 or hexane stream, can be prevented from going overhead.

[h] Residual gas oil is the fraction of crude oil which does not boil off in either the atmospheric crude column or the vacuum tower which distills off low boiling hydrocarbon compounds under a vacuum.

[i] FCC conversion can be defined as the amount of FCC charge that is cracked into gasoline and lighter hydrocarbons.

while a low percentage is consistent with a low RVP gasoline. Each refiners' FCC conversion[j] is set by many process parameters, including the type of FCC unit, the FCC feedstock type, feed throughput, catalyst type, unit constraints, unit bottlenecks, catalyst condition and operational mode. Higher amounts of butanes and pentanes are generated as the FCC unit conversion rate is increased.

As mentioned above, it is necessary to determine the point at which RVP control can not longer made with butane reduction and pentanes would need to be removed. We did this using a variety of means. First, we talked to several distillation vendors who have helped refiners make process changes to lower gasoline pool RVP to meet EPA's low RVP and RFG specifications that were instituted in the 1990's and year 2000. One vendor stated that most refiners currently producing a reformulated federal or low RVP (7.0, 7.2 or lower) gasoline today made modifications to their FCC debutanizers to meet the RVP specification. The modifications were achieved either through revamping the existing debutanizer by installing new high capacity trays and heat exchangers, or through the addition of a new debutanizer column. According to this vendor, approximately 40 percent of refiners producing Phase II RFG revamped their FCC debutanizer while 60 percent installed a new debutanizer column. The vendor stated that a FCC gasoline RVP of about 6.7 to 7.0 is achieved by most refiners when butanes are removed to less than 0.5 volume percent of the FCC gasoline pool. He further stated that these low levels of butanes could typically be attained through FCC debutanizer modifications. Obtaining a FCC gasoline RVP of 7.0 or below would probably allow most refiners to produce a pool RVP less than or equal to 7.0. The distillation vendor also stated that half of the refiners that made debutanizer modifications also installed new FCC depentanizers. Prior to lower RVP requirements, refiners typically did not have depentanizers for removing pentane from their FCC gasoline blendstock. The vendor was not sure as to why the depentanizers were added but thought that refiners only required a FCC debutanizer modification to meet lower RVP specifications (i.e., 7.0-7.8 RVP). The vendor also stated that current refiners producing a 7.8 to 9.0 RVP pool cap may have original unmodified debutanizers and typically do not have FCC depentanizers. The original unmodified debutanizers were designed to remove butanes down to a 1.5 to 2.0 volume percent level in FCC gasoline.

We spoke with several refiners who make low RVP gasoline or RFG about how they reduced the RVP of their gasoline pool. Most of the refiners reported that they had to modify their FCC debutanizer columns and these modifications allowed production of a 7.0 RVP gasoline. Most refiners reported that butanes were removed to less than a 1.0% level with a resulting FCC gasoline RVP at 7.0 or below. One refiner operating their FCCU at a low conversion rate actually made a 6.4 RVP FCC gasoline. Only one out of five refiners reported that during the summertime production season that they had to remove some pentanes to meet the 7.0 RVP specification for their pool. During the summer low RVP gasoline season, this refiner

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[j] Conversion is the shift from the heavy, low value parts of crude oil to the lighter more valuable parts. Thus, gas oil, vacuum gas oil and residual gas oil are converted to lighter compounds which can be used in diesel fuel and gasoline. The rate of conversion is the percentage of the feed converted over to the lighter compounds.

intermittently had to remove about 20 percent of the refinery's pentanes from their 7.0 RVP gasoline pool. The other refiners reported no need to remove pentanes to meet a 7.0 RVP spec. The refiners reported that the new depentanizers the distillation vendor referred to may have been installed for several reasons; to allow segregation of the heavier gasoline C6+ components for sulfur sweetening,[k] to remove pentanes to lower the pool RVP or to segregate the pentanes so that the pentanes may be backblended back into the pool per RVP allowance. Some refiners produce several grades of gasoline with varying RVP specifications, thus segregating pentanes and back blending would allow a refiner to more accurately control each pool's RVP and serve a number of gasoline markets. Backblending of pentanes would be particularly important for refiners producing RBOB (renewable blendstock for oxygenate blending) for blending with ethanol since that RBOB must be very low in RVP (e.g., 5.5-5.7 psi) to accommodate the RVP boost of ethanol. Another refiner reported that he thought that pentanes would have to be removed from gasoline to get the pool below a 7.5 RVP specification.

We also evaluated information from several different refinery models in an attempt to understand the breakpoint between butane and pentane reduction to reduce RVP. For this analysis, we used a typical gasoline blend, which represents the gasoline quality for a notional refinery for PADDs 1, 2 and 3[l]. We used this gasoline blend because it represented the gasoline quality for a large portion of the country where the boutique fuels can be found. This gasoline blend is summarized in Table II.D.1-1.

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[k] Send the C6+ hydrocarbons through a Merox or similar process were mercaptan sulfur molecules are converted to meet odor and corrosion requirements.

[l] Costs for Meeting a 40 ppm Sulfur Content Standard for Gasoline in PADDs 1 - 3, via Mobil and CDTech Desulfurization Processes, Study performed by Mathpro for the American Petroleum Institute, February 1999.

Table II.D.1-1
Baseline 9 RVP Gasoline Composition

Gasoline Blendstocks	***% Volume***
Isobutane	1.3
Normal Butane	4.1
C5s & Isom	5.8
Naphtha C5-160	3.5
Naphtha 160-250	3.7
Alkylate	12.1
Hydrocrackate	4.0
Full Range FCC Naphtha	38.1
Light Reform	5.3
Heavy Reform	21.6
MTBE	0.5
Total	100.0
RVP psi	8.5

We then applied the blending RVPs from different refinery models, which included Mathpro Incorporated's, Oak Ridge National Laboratory's (ORNL) and a refining industry consultant's,[m] to the typical gasoline blend to estimate this butane/pentane breakpoint in RVP. Before proceeding with the analysis, we needed to estimate the amount of butane entrained in the gasoline pool.

Butanes remain entrained in the gasoline pool because distillation of hydrocarbons does not allow a perfect cut between the various hydrocarbons which comprise gasoline and some butanes would be expected to remain in refined streams after distillation to remove them. It is important to know how the various refinery modelers set up the input tables of their refinery models to account for this. Mathpro said that their gasoline blendstocks do not incorporate entrained butane and that they put a lower limit on the amount of butane which can be removed

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[m] Each of these firms have their own refinery model which they use for modeling refinery or refinery product changes for the oil industry and other organizations. The refining industry consultant is also such a firm, but wished to remain anonymous.

from the gasoline pool which is 1.0 percent. We used a lower limit of 1.5 percent butanes in the gasoline blend when using their gasoline blendstocks to evaluate this issue based on refiner comments that this is the lowest practical percentage possible without removing pentanes.[3]

Ensys, which has provided many of the technical inputs to the Oak Ridge National Laboratory (ORNL) refinery model, stated that the gasoline blendstocks in the ORNL refinery model were based on actual refinery streams, but did not know how much butane which was in those streams. Since the blendstock qualities were based on actual refinery blendstocks, we presumed that the blendstocks did contain entrained butane.

The refinery industry consultant felt that their gasoline blendstocks contained entrained butane at the level achievable by existing debutanizers (e.g., around the 1.5 volume percent level) and that they model removing all the additional butane in their low RVP studies..

The blendstock blending RVP levels of these three refinery models are summarized in Table II.D.1-2.

Table II.D.1-2
Estimated Gasoline Component Vapor Pressures

Component	***MathPro***	***ORNL***	***Consultant***
Isobutane	71	71	71
Normal Butane	65	65	65
C5s & Isomerate	13.3	13.3	13.8
Straight Run Naphtha	—	—	8.8
(C5-160 F)	13	12	---
(160-250 F)	2.5	3	---
Alkylate	3.5	6.5	4.9
Hydrocrackate	12.5	14	7.2
Full Range FCC Naphtha	3.7	6.9	7.1
Light Reformate	7.5	6.9	6.4
Heavy Reformate	3.8	3.9	3.3
MTBE	8	8	8

We applied the three sets of blendstock RVPs to the typical gasoline blend and reduced butane content to 1.5 percent. We found that each set of RVPs yielded a different RVP limit via butane reduction. The MathPro, ORNL, and the refinery industry consultant's RVPs produced minimum RVPs of 6.2 RVP, 7.1 RVP, and 6.5 RVP, respectively. Averaging these three values and rounding up yields about a 6.7 RVP as the lower limit for removing butane before pentanes would need to be removed.

The different information sources to determine the breakpoint at which butanes are completely removed and pentanes need to be removed to further reduce RVP provide a range of values for our analysis. Since the refinery models tend to represent a wide range of refineries, we relied most heavily on that analysis. That analysis suggests that MTBE-blended RFG can be produced by only removing butanes,[n] but for producing an RFG blendstock for blending with ethanol, pentanes would have to be removed to account for the RVP boost of ethanol. To take into account the higher RVP values for the butane-pentane breakpoint based on the aforementioned discussions with the vendors and refiners, we considered a higher value as a sensitivity for the Boutique Fuels report. Our sensitivity analysis uses the value of 7.5 RVP for the point at which pentanes would begin to be removed when all the butanes have been removed, but this sensitivity only applied for the nationwide RFG or CBG cases. This other RVP did not apply since the RVP-challenged refineries would not be expected to want to participate in producing low RVP gasoline, except under the two nationwide options.

2. Component costs for RVP reductions

The total cost of RVP control was identified as the combination of three separate cost elements. First, capital and operating costs would be incurred through the revamp of, or the installation of, new debutanizer columns, and if necessary, for the installation of new depentanizer columns. We assume that separating butane and pentane (as necessary) from the rest of the gasoline pool requires these investments. Then, the removed butane or pentane is assumed to incur an opportunity cost based on the next available price for these hydrocarbons on the open market compared to the price of gasoline. Finally, the removal of these lighter hydrocarbons causes the gasoline pool to increase in energy content. Thus, we determined the energy density change and estimated the cost impact for the energy change based on the wholesale price for gasoline. The calculation of each of these cost elements and the resulting total costs are summarized below.

Costs were developed for adding additional distillation column capacity for the removal of butanes and pentanes from FCC gasoline by adding FCCU debutanizer and depentanizer capacity. The debutanizer costs are a combination of revamped and new unit costs. Based on

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[n] RFG has a final RVP of about 6.8 - 6.9 psi. However, MTBE, with a blending RVP of 8.0, raises the RVP of the gasoline blendstock by about 0.1 psi, thus, the RVP for a blendstock for blending with MTBE would have to be reduced to about 6.7 or 6.8 psi. Since ethanol, with a blending RVP of about 25 psi, boosts the RVP of the gasoline blendstock by about 1.1 psi, the base gasoline blendstock would have to be reduced to an RVP of about 5.7 psi.

one distillation vendor's estimate for meeting a low RVP gasoline requirement, 40 percent of refineries revamped their existing debutanizers to meet the RVP requirement while the other 60 percent installed new debutanizers. Whether a debutanizer is revamped or new, the incremental operating costs are the same and they represent the incremental costs of increased vaporization to remove additional butanes. The costs are estimated based on an average size refinery processing 150,000 barrels per day of crude oil with a typical production level of gasoline. Depentanizer costs are based on installing a new unit in a refinery. Assuming additional capital and operating costs for additional debutanization and depentanization may be conservative because, as mentioned above, refiners already have debutanizer distillation columns and a number of refiners have already installed depentanizer columns and these refiners may be able to meet very low RVP gasolines without incurring additional capital cost.

For revamping a debutanizer, the distillation vendor provided guidance as to the type of equipment modifications which would be required to revamp a FCC Unit debutanizer. The vendor stated that for our average refinery, the existing FCC debutanizer column would be approximately fourteen feet in diameter and would have 35 to 50 distillation trays. Costs were developed for this column using a basis of 45 new distillation trays. For the revamp, the vendor stated that new high capacity distillation trays, to replace the existing trays would cost $25.00 per tray. This cost was scaled up to derive a total inside battery limit (ISBL) cost using a 3.4 scale up factor from Perry's Handbook.[o] The vendor also stated that additional heat input to the column would be needed requiring approximately 20 percent more reboiler and condenser heat exchanger surface area. The size of heat exchanger surface area for the existing reboiler and condenser were estimated to be 8,000 and 15,000 square feet, respectively. Costs for 25 percent additional exchanger surface area were developed for these two units using information from Perry's Chemical Engineering Handbook[p] and adjusted for size using the sixth tenth's rule using an exponent of 0.6. The referenced exchanger from Perry's was at 1000 square foot surface area with a cost of $21,700 based on a Swift Index[q] of 1000. Costs for the heat exchangers were multiplied by 3.4 as a scale up to obtain an ISBL cost, also based on Perry's, and then ratioed using the Swift Index to adjust to year 2001 prices.

The feed rate for an average FCC debutanizer column was determined to be 47,400 BPSD based on information from a FCC technology licensor and confidential refinery data. According to the licensor an average FCC converts 55 percent of its feed to FCC gasoline (not depentanized), thus the amount of debutanized gasoline is 33,400 BPSD. Confidential data obtained from a refiner with a similar sized FCC to our average unit, determined that 14,000

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[o] The 4.5 figure is a standard scale-up factor from Perry's Chemical Engineer's Handbook and this is designed to capture additional costs due to foundations, new piping, valves, pumps and instrumentation.

[p] Perry's Chemical Engineering Handbook, sixth edition.

[q] The Swift Index is used to adjust equipment costs for inflation. The index is used to adjust equipment costs determined at an earlier year basis to the current year. The swift index for the year 2001 is 1155 relative to 1000 for the base year in Perry's.

BPSD of alkylation feedstock will be removed as overhead from the debutanizer, thus setting the debutanizer and depentanizer column throughput volumes. The costs for a revamped debutanizer column based on the specified feed rate are summarized in Table II.D.2-1.

Table II.D.2-1
Capital Cost and Process Operation Information for Revamping an Existing Debutanizer

	FCC Debutanizer Revamp
Capacity (bbl/day)	47,400
Capital Cost Trays ISBL	$780,000
Capital Cost Exchangers ISBL	$240,000
Total Capital ISBL	$1,020,000
Electricity* (kWh/bbl)	0.02
Additional Steam* (lb/bbl)	11.6

*Additional steam and electricity are 20% of those for a naphtha splitter from of ORNL's refinery model

Capital and operating costs for a new debutanizer and depentanizer were based on the capital and operating cost of a naphtha splitter from the Oak Ridge National Laboratory (ORNL) refinery model. The costs for a naphtha splitter are expected to be similar to that of a debutanizer and depentanizer because it distills butanes, pentanes along with heavier compounds. The feed rates to the debutanizer and depentanizer are 47,400 BPSD and 33,400 BPSD, respectively. As described above, utilities for a new debutanizer are 20 percent of the values of the ORNL naphtha splitter value representing incremental debutanization. Depentanizer utility requirements are 100 percent of ORNL FCC fractionator values for separation of pentanes from gasoline. The cost information for these two distillation columns is summarized in Table II.D.2-2.

Table II.D.2-2
Process Operations Information for New Debutanizer and New Depentanizer

	Naphtha Splitter for Debutanizer	***Naphtha Splitter for Depentanizer***
Capacity (bbl/day)	20000	20000
Capital Cost, ISBL (MM$)	7	7
Electricity (kWh/bbl)	0.02 *	0.17
Steam (lb/bbl)	11.6 *	98
Other Variable Operating Cost ($/bbl)	0.012	0.045

* Steam and electricity rate for the debutanizer are 20% of ORNL refinery model naphtha splitter values and represent incremental debutanization.
** Steam rate of 98 lbs/bbl used for the new depentanizer taken from ORNL refinery model FCC fractionator value for separation of pentanes from gasoline.

a. Capital costs

Capital costs are the one-time costs incurred by purchasing and installing new hardware in refineries. Capital costs for a particular processing unit are supplied by vendors or estimated from other sources at a particular volume capacity, and these costs are adjusted to match the volume of the particular case being analyzed using the "sixth tenths rule" as described by Gary and Handewerk.[r]

The capital costs are adjusted to account for the off-site costs and differences in labor costs relative to the Gulf Coast using Gary and Handewerk estimates. Cost factors for off-sites and location for the average refinery were determined by volume weighting each PADD's factor by each PADD's respective total refinery gasoline production. Table II.D.2-3 contains the cost factors for each PADD and a weighted average set of values for PADD's 1 - 3 using the weighting factors in the table..

The offsite factor for PADD's 1 - 3 for new units is 1.22 but was reduced to 1.11 for debutanizer estimations since these modifications would utilize a large portion of existing debutanizer offsite facilities (only 20% more incremental offsite are required for the debutanizer modifications over existing offsite demands). For the debutanizer revamp, the costs after adjusting for off-site and location were increased by 15% to account for any unknown contingency costs.

[r] Gary, James, H., Handewerk, Glenn E., Petroleum and Refining Technology and Economics

Table II.D.2-3
Offsite and Location Factors Used for Estimating Capital Costs

Factor	***PADD 1***	***PADD 2***	***PADD 3***	***PADD's 1-3 Average***
New Unit Offsite	1.25	1.25	1.2	1.22
Revamped Unit Offsite	1.125	1.125	1.1	1.11
Location	1.5	1.3	1.0	1.16
Weighting Factors	0.16	0.28	0.56	1.0

The capital costs were amortized over the volume of FCC gasoline produced. The assumptions and the resulting capital amortization cost factors are summarized in Table II.D.2-4. For debutanizer amortization, it was assumed that 14,000 BPSD of the FCC debutanizer charge volume is distilled as alkylation feed and is not included in the FCC gasoline amortization volume. For depentanizer amortization, it was assumed that 3000 BPSD of the pentanes are removed from the feed to get the produced depentanized FCC gasoline volume. The capital costs were amortized based on equipment use of 168 days per year, reflecting that the equipment would be utilized only for the low RVP summer season. The economic factors used for amortizing the capital costs and the resultant capital cost factor is summarized in Table II.D.2-4.

Table II.D.2-4
Economic Factors Used in Deriving the Capital Cost Amortization Factor

Amortization Scheme	***Depreciation Life***	***Economic and Project Life***	***Federal and State Tax Rate***	***Return on Investment (ROI)***	***Resulting Capital Amortization Factor***
Societal Cost	10 Years	15 Years	0%	7%	0.11

b. Fixed costs

Operating costs which are based on the cost of capital are called fixed operating costs. Fixed costs are incurred to maintain the unit in good working order, insure the unit against accidental damage, and for a number of other factors. These are fixed because the cost is normally incurred even when the unit is temporarily shutdown. These costs are incurred each and every year after the unit is installed and operating.

Maintenance cost is estimated to be four percent of capital cost after adjusting for location and offsites. This factor is based on the maintenance factor used in the ORNL refinery model. Other fixed operating costs are also from the ORNL refinery model. These factors are: 0.2 percent for land, one percent for supplies which must be inventoried such as catalyst, and two percent for insurance. These factors sum to 6.2 percent which is applied to the total capital cost (after adjusting for offsite costs and labor factor) to generate a perennial fixed operating cost. Annual labor costs are estimated using the cost equation in the ORNL model. Labor cost is very small; on the order of one ten thousandth of a cent per gallon.

c. Variable operating costs

Variable operating costs are the costs incurred to run the unit on a day-to-day basis are based completely on unit throughput. Thus, when the unit is operating, variable operating costs are not being incurred.

An average electricity and fuel oil equivalent (FOE) cost factor for the debutanizer and depentanizer was developed to represent the average refinery based on volume weighting each of PADD's 1-3 total refinery gasoline production to each PADD's costs factor. The electricity and FOE costs are for year 2000 and are summarized in Table II.D.2-5.

Table II.D.2-5
Summary of Costs Taken from EIA and NPC Data Tables 1999*

	PADD 1	***PADD 2***	***PADD 3***	***PADD's1-3 Average****
Electricity (¢/kWh)	5.9	3.9	4.2	4.4
Fuel Gas ($/FOE)	22.5	22.5	18	20

*¢/kWh is cents per kilowatt-hour, $/FOE is dollars per fuel oil equivalent. The average utility costs for PADDs 1 - 3 were calculated by volume weighting each PADD's utility costs.

The additional heat exchangers for the revamped and new debutanizer will use 20% more energy than the existing equipment to meet lower RVP specifications. This increased energy requirement was calculated by using 20% of ORNL Naphtha splitter energy requirement. Energy for the depentanizer was estimated using ORNL Model FCC Fractionator steam requirement for separation of pentanes from gasoline.

For the various RVP reduction scenarios that require either removal of butanes or butanes and pentanes, costs developed for additional FCCU debutanizer and depentanizer capacity per treated gallon of FCC gasoline were multiplied by 0.39 to get costs per gallon for refinery gasoline. This was based on the determination that for the average refinery used in this analysis, FCC gasoline represents 39% of the total refinery gasoline pool for PADD's 1-3. This determination was based on the 1996 API/NPRA survey data. For each PADD, the PADD's FCC gasoline volume was divided by the PADD's total refinery gasoline volume to determine the percent contribution of FCC gasoline to the total gasoline pool. Next, the PADD FCC fractions for PADDs 1 - 3 were volume weighted to derive the PADD 1 - 3 average. This is summarized in Table II.D.2-6.

Table II.D.2-6
Fraction FCC Gasoline to Total Refinery Gasoline*

Factor	***PADD 1***	***PADD 2***	***PADD 3***	***PADD's 1-3 Average***
FCC Gasoline (bbl/day)	21,452	17,622	33,335	24,136
Total Refinery Gasoline (bbl/day)	46,345	66,348	75,907	62,866
Fraction of FCC Gasoline to Total Refinery Gasoline	0.46	0.27	0.44	0.39

* Based on 1996 API/NPRA Refinery Survey.

Estimating the cost of RVP control was based on the estimated actual changes in RVP which would be necessary. The in-use RVP levels of the various gasolines being evaluated is summarized in the following table. The in-use RVP levels are derived by evaluating survey data from the Association of Automobile Manufactures for gasoline which meets the applicable environmental fuel program. These RVPs are summarized in Table II.D.2-7.

Table II.D.2-7
Actual RVP Levels Associated with Various RVP Standards

Nominal RVP Level	***9.0 RVP Limit***	***9.0 with splash blended EtOH***	***7.8 RVP Limit***	***7.2 RVP Limit***	***7.0 RVP Limit***	***MTBE RFG***	***RBOB for 5.7 vol% Ethanol***
Actual RVP Level	8.8	9.8	7.6	7.05	6.85	6.85	5.75

The average refinery costs per volume of FCC gasoline and per volume of total refinery gasoline pool for debutanizer and depentanizer modifications are shown in Table II.D.2-8.

Table II.D.2-8
Average Refinery Capital Costs, Operating Costs and Total Costs for Debutanizer and Depentanizer Modifications (cents per gallon)

	*Debutanizer**			*Dependanizer*		
	Capital Cost	***Operating Cost***	***Total Cost***	***Capital Cost***	***Operating Cost***	***Total Cost***
Cost per FCC gasoline volume	0.47	0.24	0.71	0.72	1.45	2.17
Cost per total Refinery Gasoline Volume	0.18	0.09	0.27	0.27	0.55	0.82

* 40/60 mix of revamped debutanizer versus new debutanizer

The costs for debutanizing FCC gasoline contained in Table II.D.2-8 are for reducing the RVP of a 9.0 gasoline blend to meet the VOC requirement of RFG. The costs for removing pentane from FCC gasoline contained in Table II.D.2-8 are for reducing the RVP of a RFG gasoline for blending with ethanol. However, it is necessary to estimate the costs for different RVP reductions which would occur under the 3 Fuel option (7.0 and 7.2 RVP areas go to RFG) and 2 Fuel option (7.0, 7.2 and 7.8 RVP areas go to RFG). Since starting at a lower RVP reduces the cost of lowering RVP, we estimated the cost of these other RVP reductions. Debutanizing a 7.8 RVP gasoline is estimated to require two-thirds of the cost of a 9.0 RVP gasoline. Although a 7.8 RVP gasoline is about 50% of the way between a 9.0 RVP gasoline and RFG in terms of RVP, the most significant portion of the distillation cost is incurred in the effort to distill the last portion of a compound. Using two-thirds of the cost respects this aspect of distillation cost. Debutanizing a 7.2 RVP gasoline is estimated to cost half of the operating cost of a 9.0 RVP gasoline and require no capital cost since producing a gasoline meeting a 7.2 RVP fuel, which would be 7.05 RVP in practice, is only 0.2 RVP away from the average RVP of RFG. Refiners likely would invest sufficiently to give them adequate headroom with their debutanizing column to meet an RVP cap standard, so no capital cost is presumed to be incurred for producing RFG from a 7.2 RVP gasoline. Meeting a 7.0 RVP standard requires essentially the same in-use RVP level as meeting the Phase 2 RFG specifications. Thus no debutanization cost would be incurred in this case. The adjusted debutanization and dependanization costs for producing MTBE-blended RFG and ethanol-blended RFG from gasoline meeting various RVP standards are summarized in Section III. below.

d. Opportunity costs and fuel economy improvement benefits

When butanes, and sometimes pentanes, are removed from the gasoline pool, they are sold off in markets which bring a lower return than gasoline. The lost opportunity of blending and selling these petroleum components in gasoline is called the opportunity cost. The opportunity cost is merely the price difference between higher valued gasoline and the price for these petroleum compounds on the open market. We obtained prices for butane, pentane and gasoline from a recent Pace Consulting report for a study of the cost of banning the use of MTBE completed under contract to EPA[s]. The prices used to estimate the opportunity cost are based on historical prices and are projected to year 2005. The prices are summarized in Table II.D.2-9, while the impact of opportunity cost on the price of gasoline is summarized in the next sub-section.

Table II.D.2-9
Prices for Butane, Pentane and RFG used for Estimating the Opportunity Cost of Debutanizing and Removing pentane from Gasoline (¢/gal)

Butane	Pentane	Reformulated Gasoline
43	53	70

The energy density of the resulting lower RVP gasoline is improved slightly compared with the higher RVP gasoline because both butane and pentane are less energy dense than gasoline. The cost of the energy density increase is calculated using several steps. First, the number of BTU's (British Thermal Units) removed with the volume of lost butane and pentane were subtracted from the number of BTU's in the original gasoline pool. Then the remaining BTU's were divided by the remaining volume of gasoline to calculate the energy density for the reduced RVP gasoline. The value of BTUs in the original gasoline pool was multiplied by the ratio of the increased energy density to the original energy density to calculate the fractional increased energy value of the lower RVP gasoline. The fractional increase in energy density was then multiplied times the wholesale price of gasoline to estimate the cost benefit of lowering RVP. Values for the energy density (BTU's per liquid gallon) of gasoline, butane, and pentane were taken from the API Technical Data Book and the Gas Processors Engineering Data Book. Cost estimates for increases in energy increases for were calculated for the RVP reductions for the scenarios which we are evaluating. The energy contents of gasoline, pentane and butane are summarized in Table II.D.2-10.

[s] The Refining Economics of a MTBE Ban, Pace Consultants under a Southwest Research Institute Contract for EPA, April 2001.

Table II.D.2-10
Energy Content of Butane, Pentane and RFG for Estimating the Fuel Economy Impacts of Reducing the RVP of Gasoline (MMBtu/gal)

Butane	Pentane	Reformulated Gasoline
94,000	102,000	112,000

3. Cost summary

RVP control costs were developed for the 3 Fuel, 2 Fuel, and the nationwide Federal and California clean burning gasoline long term options described in the boutique fuels report. For each of these scenarios, specific fuel programs would be consolidated to other fuel programs to reduce the total number of fuels which would be required. This consolidation of fuels usually required a specific change in RVP and we analyzed the cost for those RVP changes. The opportunity losses due to butane and pentane removal, the gains due to increased energy density and the capital and operating costs for operating debutanizers and depentanizers to meet a specific gasoline RVP reductions are summarized in Table II.D.3-1.

Table II.D.3-1
Summary of the RVP, Opportunity and Fuel Economy Cost of Reducing RVP to Produce RFG (¢/gal)*

	9.0 RVP to RFG		***7.8 RVP to RFG***		***7.2 RVP to RFG***		***7.0 RVP to RFG***	
	MTBE	Ethanol	MTBE	Ethanol	MTBE	Ethanol	MTBE	Ethanol
Butane/Pentane Distillation Cost	0.27	1.27	0.18	1.18	0.05	1.04	0	1.0
Opportunity Cost	0.49	0.79	0.30	0.60	0.08	0.39	0	0.31
Fuel Economy Cost	-0.20	-0.31	-0.12	-0.24	-0.03	-0.16	0	-0.13
Total Cost	0.56	1.75	0.36	1.54	0.10	1.27	0	1.18

* These RVP control costs for producing RFG are for producing incremental volumes for the 3 Fuel and 2 Fuel programs, not for the Nationwide CBG programs. The costs in this table do not include the costs for oxygenate or benzene reductions needed to meet RFG requirements.

E. Cost of reducing gasoline benzene content

The Agency estimated the cost of reducing gasoline benzene levels for the Mobile Source

Air Toxics Rule (MSAT) and is relying on those estimates here. These costs estimates were calculated in year 2000 for projected gasoline volumes in year 2010, but are applicable for year 2006 gasoline volumes used for this study. During January, 2000, the Agency and DOE held meetings with a number of refiners to discuss what their strategy would be for meeting a benzene standard. The refiners that we met with indicated that of all the streams used in blending gasoline, reformate was the stream that contained the most benzene and that the most cost-effective strategy for reducing benzene in gasoline would be to treat the reformate stream.

Reformate is the product stream from the reformer which reacts heavy straight run naphtha over a catalyst at elevated temperatures and low to moderate pressure. Reformers produce a number of aromatic compounds including benzene to form a high octane blendstock and virtually every refinery which produces gasoline has one. Reformate typically contains about 3 to 5 percent benzene and contributes 50 to 75 percent of the benzene in the gasoline pool. The strategy a refiner will choose to reduce benzene levels in reformate is dependent upon the refinery configuration and crude oil source.

The two principal methods refiners may take for reducing benzene in the reformate stream are: 1) "pre-fractionation" to remove benzene precursors before they can be converted to benzene in the reformer, and 2) "post-fractionation" to remove benzene from the reformate stream and either extract it for sale in the petrochemical market or for saturation to cyclohexane. These options are explained more below.

The first benzene reduction method is known as pre-fractionation. There are two options using pre-fractionation. The first pre-fractionation option only involves the use of a naphtha splitter which removes most of the chemical components which would form benzene in the reformer. Since this process removes most of the benzene precursors from the feed to the reformer, benzene content is reduced in the reformate product which results in less benzene in the gasoline. This method does not eliminate all the benzene in the reformate since some is formed in the reformer as other aromatics are converted to benzene due to some light cracking of alkylated benzene compounds. However, routing precursors around the reformer results in a lost opportunity for increasing octane and generating hydrogen in the reformer. The second option is similar to the first option. It begins with fractionating the benzene precursors prior to the reformer. However, this cyclohexane rich stream is then sent to a C5/C6 isomerization unit to increase the octane.

The second method for reducing benzene in gasoline is known as post-fractionation, as the benzene rich portion of the reformate stream is separated from the rest of the reformate after the reformer. There are two options which uses post-fractionation. The first option is benzene extraction which separates and concentrates benzene for sale as a commodity on the petrochemicals market. However, benzene has a very high freezing point (i.e., around 40 degrees F) which requires it to be shipped in heated barges or heated railway cars to prevent it from solidifying during shipment. These physical characteristics of benzene make the transportation costs approximately three times higher than other petrochemicals for the same distance.

Therefore, to make benzene extraction more economically attractive for a refinery, it is important that the refinery be located near a petrochemical market. Benzene extraction involves the use of a reformate splitter to obtain a benzene rich stream from the reformate product. This benzene rich stream is then sent to an aromatic extraction complex which extracts the benzene and sometimes other aromatics by liquid-liquid extraction, and may convert the benzene into other petrochemical feedstocks, for example, para-xylene or mixed xylenes.

The second post-fractionation option involves separating the benzene from the rest of the reformate product and then saturating it to cyclohexane using hydrogen. One method for implementing this post-fractionation technology reduces the octane level of reformate. Two vendors provide benzene saturation technologies, one developed by UOP called BenSat, the other developed by CD Tech called CD Hydro. A similar process by UOP also saturates the benzene after post-fractionation, but the saturation occurs in a special C5/C6 isomerization unit. With this unit, the benzene is saturated in a reactor for saturating benzene, called a Penex unit, and the other compounds other than benzene are isomerized to higher octane, branched chain compounds.

All the technologies mentioned above are commercially proven as they already have been installed and operated in refineries, thus no special adjustments were made in our cost analysis to account for uncertainty. The prefractionation methods are limited in their ability to reduce benzene levels and would be insufficient if a refinery's benzene levels are high, or if benzene must be reduced to a low level.

1. Component costs for fuel benzene reduction

a. Technology and cost inputs

The cost estimates are based on the technologies described above. We estimated costs on a PADD-by-PADD basis, based on gasoline production in each PADD. Each PADD is represented by a single refinery which consists of refining units having the average capacity of all refineries of that PADD and which produces gasoline having the average benzene level for that PADD. The technology mix used in each PADD is based on the configuration of the refineries in the PADD (as described below) and on the gasoline benzene level as reported to EPA for the RFG program. Costs were calculated for three cases:

- A 0.95 vol% benzene average for conventional gasoline
- A 0.70 vol% benzene average for meeting the RFG/MSAT toxics requirements under either the Three-Fuel or Two-Fuel options
- A 0.30 vol% benzene average for federal CBG under either the Two- or Three-Fuel options or the nationwide CBG option

We acquired process operations information on each of the technologies used from technical information sheets provided from UOP or CD Tech, from the Handbook of Petroleum Refining Processes, second edition[t], from information provided to us by refiners, and from the Department of Energy (DOE) Oak Ridge National Laboratory (ORNL) refinery model. The cost input data used in our analysis for extraction are summarized in Table II.E.1-1. The cost input data used in our analysis for technologies other than extraction are summarized in Table II.E.1-2.

Table II.E.1-1
Process Operations Information for Benzene Extraction Processes*

	Benzene + Xylene Extraction	*Sulfolane Benzene Extraction*
Capacity (MMbbl/day)	18,400	10,400
Capital Cost (MM$)	110	13
Hydrogen Consumption (SCF/bbl)	-	-
Electricity (kWh/bbl)	11	0.90
Steam (lb/bbl)	248	140
Fuel Gas (BTU/bbl)	0.22	-
Catalyst Cost ($/bbl)	-	-
Cooling Water (gal/bbl)	340	167
Yield Loss (%) per volume Reformate	12	5
Octane Loss (R+M)/2 per volume Reformate	0.35 - Benzene 5.89 - Xylene	0.35 - Benzene

* Unless noted, all values pertain to the benzene or benzene and xylene rich stream.

[t] Meyers, Robert A, Handbook of Petroleum Refining Processes, second edition, McGraw-Hill, Boston (1997).

Table II.E.1-2
Process Operation Information for Benzene Reduction Technologies other than Extraction

	UOP C5/C6 Post Isomerization Benzene Saturation and Octane Recovery	*UOP BenSat Benzene Saturation*	*CD Hydro Benzene Saturation*	*CD Hydro Benzene Saturation for FCC Naphtha*	*Naphtha Splitter for Routing Benzene Precursors around the Reformer*
Capacity (MMbbl/day)	10,000	10,000	13,950	13,950	20,000
Capital Cost (MM$)	8.1	4.9	3	3	8
Hydrogen Consumption (SCF/bbl)	195	576	160	250	40*
Electricity (kWh/bbl)	2.2	0.4	0.41	0.41	2.5
Steam (lb/bbl)	52	39	53	53	10
Fuel Gas (BTU/bbl)	-	-	-	-	0.011
Catalyst Cost ($/bbl)	0.21	-	0.05	0.05	-
Cooling Water (gal/bbl)	405	75	-	-	-
Yield Loss (%)	-2.15	0	0	0	0
Octane Loss (R+M)/2 **	-3.12	1.63	1.63	2	1.63

* Hydrogen reformer loss from splitting benzene precursors around the reformer.
** Octane gain for UOP C5/C6 Post Isom technology applies to only the isomerized material. Octane losses for other technologies apply to entire reformate stream.

For the benzene reduction technologies described above, we identified distillation or splitting columns which would be necessary to pair up with the appropriate feedstock to the benzene reduction technologies. A reformate splitter would be necessary to separate out a benzene-rich stream, or a stream rich in benzene and other aromatics, from the rest of the reformate to serve as a feedstock for benzene or benzene/xylene extraction technologies. The capital and operating cost inputs for the reformate splitter are based on information from ORNL's refinery model. A reformate splitter would also be needed for the UOP post-fractionation C5/C6 Isomerization technologies. A splitter for making simple cuts in reformate based on information from Mobil Oil was added to UOP BenSat technology. The Mobil naphtha splitter inputs were obtained through the National Petroleum Council (NPC) Technology Workgroup which was active during the writing of the NPC report "U.S. Petroleum Refining, Assuring the Adequacy and Affordability of Clean Fuels." We are assuming that this naphtha splitter may be used for the UOP BenSat technology because only a simple cut is needed for this technology. For the C5/C6 isomerization and extraction technologies, a better cut is needed therefore a full reformate splitter is required. A reformate splitter provides fine cuts in the reformate allowing to significantly concentrate the benzene in the benzene-rich stream separate from the lighter and heavier compounds in the reformate. The process operation information for these various splitters is summarized in Table II.E.1-3.

Table II.E.1-3
Process Operations Information for Additional Units used for Benzene Reduction Cost Analysis

	Simple Splitter (Mobil Oil)	*Reformate Splitter*
Capacity (MMbbl/day)	50000	20000
Capital Cost (MM$)	4.1	7
Electricity (kWh/bbl)	0.17	2.5
Steam (lb/bbl)	36	10
Fuel Gas (FOE/bbl)	-	0.01
Cooling Water (Gal/bbl)	13	-

In the case which existing units in refineries are modified to further reduce benzene in the gasoline pool, the operating costs are applied to the incremental volume of treated gasoline. The capital costs are applied to the incremental volume without using the economies of scale adjustment (called the sixth tenths rule) described above in the above section on RVP costs, because the discussions with a vendor indicate that the cost of this type of splitter do not scale up.

b. Capital Cost Adjustments and Fixed and Variable Operating Costs

The capital costs and the fixed and variable operating costs were calculated using the same economic factors and methodology used above in the RVP control section. Since the extraction, isomerization and prefractionation benzene reduction technologies would be modifications to existing units already having offsite facilities, the offsite factors were reduced by 50 percent. Costs were calculated based on the gasoline volumes contained in Table II.E.1-4.

Table II.E.1-4
Projected Volume of Reformate and Gasoline Produced by an Average Refinery in each PADD in 2010 for the U.S. (Thousand barrels per day)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5*
Reformate Volume	17	34	43	9	14
Gasoline Volume	93	80	91	23	32

* California gasoline not included.

2. The cost of reducing benzene in gasoline for a 0.95 vol% average for CG

We only estimated costs for refineries with benzene levels above 0.95 volume percent as reported to the 1998 RFG database. If a refinery had reported a benzene level above 0.95 volume percent, then its gasoline volume was considered impacted. If a refinery had reported a benzene level below 0.95 volume percent benzene, then its gasoline was not considered impacted. Of course, RFG was not impacted by this scenario. The following table lists the conventional (CG) volumes that were both impacted and not impacted for this scenario.

Table II.E.2-1
Volume of CG Gasoline Impacted and not Impacted by PADD for the Stage 2 Scenario in year 1998

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 OC
CG volume impacted (billion gal/yr)	1.0	16.3	21.9	2.6	2.0
CG volume not impacted (billion gal/yr)	3.9	6.4	13.1	0.7	0.3

The application of the benzene reduction technologies to specific refineries was determined based on the technology currently being utilized in those refineries with benzene levels above 0.95 volume percent. If a refinery with sufficiently high benzene already had extraction capabilities, our analysis found that these refineries would expand their extraction capacity by an average of 20 percent to extract the necessary amount of benzene from their reformate. We found that PADD 1 refineries with extraction units already had low benzene levels so there was no need for those refineries to expand their extraction units. Only in PADD 2 and PADD 3 would it be necessary for refineries with extraction units to expand their extraction units to meet a 0.95 volume percent benzene standard. It is not clear if the benzene extraction units in refineries utilize Sulfolane benzene or Sulfolane benzene with xylene technology, so we used an even split of half of one technology and half of the other.

For refiners that have existing C5/C6 isomerization, we projected that these refineries could revamp their isomerization units by adding a UOP Penex reactor at a low cost.

For other refiners that had benzene levels between 0.95 volume percent and 1.05 volume percent benzene, we projected that they could meet a 0.95 volume percent benzene average level by using existing naphtha splitting. For refineries with benzene levels above 1.05 volume percent, we don't believe that these refineries would be able to meet a 0.95 volume percent benzene standard using pre-fractionation.

For the refiners in each PADD that did not have extraction or isomerization capacity and with benzene levels above 1.05 volume percent, the volumes were split equally between CD Hydro and UOP BenSat,. The following table lists the percentages of benzene technology reduction options chosen for each refinery in each PADD under this scenario.

Table II.E.2-2
Utilization of Benzene Reduction Technologies to Achieve
a 0.95% Benzene Average for CG

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Sulfolane Benzene Extraction	0%	8%	1%	0%	0%
Sulfolane Benzene Extraction and Parax Xylene Extraction	0%	8%	1%	0%	0%
UOP Post C5/C6 Isom	2%	40%	17%	35%	64%
UOP BenSat	10%	9%	9%	22%	12%
CD Tech Hydro	10%	9%	9%	22%	12%
Existing Naphtha Splitting	0%	0%	1%	0%	0%
Percentage of CG below 0.95% benzene	78%	26%	62%	21%	12%

The vendor benzene reduction technology information and the various cost inputs described above were combined using the percentages in Table II.E.2-2 to estimate the cost of reducing benzene in gasoline for a 0.95% benzene average in conventional gasoline. To estimate national average costs, we volume weighted the PADD-specific cost estimates. The following table lists the capital cost, operating cost and the total cost for each PADD.

Table II.E.2-3
Capital Costs, Operating Costs and Total Costs
for a 0.95% Benzene Average Standard for CG

	Capital Cost (Cents/gallon)	Operating Cost (Cents/gallon)	Total Cost (Cents/gallon)
PADD 1	0.03	0.11	0.15
PADD 2	0.23	0.34	0.58
PADD 3	0.06	0.19	0.25
PADD 4	0.23	0.71	0.96
PADD 5	0.24	0.61	0.86
National	0.13	0.28	0.41

3. The cost of reducing benzene in gasoline to a 0.70 vol% average for RFG

We also estimated the cost to reduce gasoline benzene levels to an average of 0.70 volume percent and applied this cost to producing RFG for the Three-Fuel and Two-Fuel options complying with the Mobile Source Air Toxics (MSAT) requirements. This cost estimate is likely conservative, especially for the Three-Fuel option, as the 0.70 benzene standard was estimated to be met by a mix of impacted and non-impacted refineries and the costs averaged over the whole pool. If a refinery had reported an average benzene level above 0.70 volume percent benzene, then its gasoline volume was considered impacted. If a refinery had reported a benzene level below 0.70 volume percent benzene, then its gasoline was not considered impacted. However, a significant portion of the gasoline pool, perhaps produced by refineries producing RFG today, already meets such a benzene standard, thus, this incremental volume of reformulated gasoline could potentially be produced by the refineries which would already meet such a benzene standard and incur little or no additional benzene reduction cost. Since we do not know which refineries would ultimately be involved in producing the incremental gallons of RFG, using a mix of costs for both impacted and non impacted costs seemed appropriate.[u] We determined the

[u] Our analysis using an average cost is also appropriate due to the uncertainty of meeting the pool octane requirements, especially considering MSAT. In our analysis, we don't know which refinery has additional capacity

refineries which would be impacted using the benzene levels and the refinery gasoline volumes reported to EPA during 1998 to the RFG database. For this analysis, only gasoline outside of California was considered.

Similar to the benzene cost analysis described above, the benzene technology reduction options used were based on the current refinery configurations in each PADD. If a refinery already had extraction capabilities, we found that it would be cost effective for them to expand their extraction capacity by 20 percent to extract more benzene from their reformate stream. However, only in PADD 2 and PADD 3 did we find it necessary for those refineries to expand their extraction units. The gasoline in PADD 1 produced by refineries with extraction units already would meet a 0.70 average benzene standard. Since no refinery in PADDs 4 and 5 have extraction now, likely because they are not situated near a petrochemical market, it was assumed that none of these refiners would choose the option of extraction.

For refiners that have existing C5/C6 isomerization, our cost analysis found that they would likely fractionate the reformate stream, saturate the benzene using a Penex reactor and isomerate the remainder of the benzene-rich stream for octane recovery. For remainder of refiners that had benzene levels between 0.70 volume percent and 0.80 volume percent benzene, our analysis found that they could meet a 0.70 volume percent benzene average level by using existing naphtha splitting. For the remaining refiners in each PADD that did not have extraction or isomerization capacity, we equally split the volumes among CD Hydro, and UOP BenSat. The following table lists the percentages of benzene technology reduction options chosen for each refinery in each PADD under this scenario.

to make up for a shortfall in octane, and which does not.

Table II.E.2-4
Application of Benzene Reduction Technologies for a
0.70% Benzene Average for converting CG to RFG

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5OC
Sulfolane Benzene Extraction	0%	16%	4%	0%	0%
Sulfolane Benzene Extraction and Parax Xylene Extraction	0%	16%	4%	0%	0%
UOP Post C5/C6 Isom	1%	30%	14%	35%	64%
UOP BenSat	7%	12%	10%	22%	12%
CD Tech Hydro	7%	12%	10%	22%	12%
Existing Naphtha Splitting	17%	0%	5%	0%	0%
Percentage of CG below 0.70% benzene	68%	14%	53%	21%	12%

The costs for the various benzene reducing technologies were combined with their application percentages to estimate the PADD-wide and nationwide costs of reducing conventional gasoline benzene levels to 0.70 percent by volume. The following table summarizes the capital cost, operating cost, and total cost for each PADD in 2010.

Table II.E.2-5
Cost of Reducing CG Benzene Levels to an Average 0.70% by Volume

	Capital Cost (Cents/gallon)	Operating Cost (Cents/gallon)	Total Cost (Cents/gallon)
PADD 1	0.03	0.18	0.21
PADD 2	0.31	0.36	0.67
PADD 3	0.08	0.22	0.30
PADD 4	0.25	0.71	0.96
PADD 5	0.25	0.61	0.86
National	0.14	0.28	0.42

4. The cost of reducing benzene in gasoline to a 0.30 vol% average for federal CBG

Blending in oxygenate to meet the RFG oxygenate mandate is costly for refiners. This is why MTBE use is currently very limited outside of RFG areas, and when it is used it is almost exclusively blended into the premium and mid-grade blends. In our analysis we project that if the RFG oxygen requirement were to be rescinded, MTBE use would be limited to these two pools thus comprising about 2 percent in the gasoline pool not banned from containing MTBE. Ethanol use in gasoline is primarily in the Midwest where it largely enjoys state subsidies in addition to the Federal subsidies. As summarized below, transporting ethanol to the East and West Coasts for blending into RFG is estimated to cost an additional 17 cents per gallon. Coupling ethanol's price increase due to the increased production levels, the transportation cost of shipping ethanol to those two markets, and the cost of blending up an RFG blendstock for blending with ethanol is expected to be a significant cost to refiners. Thus, if given the opportunity, refiners might significantly reduce ethanol use in East Coast RFG areas. The significant constraints of the California CBG program would likely require the blending of significant amounts of ethanol under an MTBE ban in that market, even without the RFG oxygen mandate. [4]

For this analysis we assumed that refiners would largely phase out the use of MTBE and, outside of California, completely phase out ethanol use in RFG in the cases which the RFG oxygen mandate is removed. To allow refiners to phase down or phase out the use of MTBE and ethanol and still meet the anti-backsliding requirements of the MSAT rule, we assumed that refiners would further reduce benzene in their gasoline pool by removing benzene from the FCC gasoline blendstock pool.

Several different technologies could be used for further removing the benzene from the FCC gasoline pool, and these include CD Hydro, BenSat, Penex, and extraction. For this analysis, we based the costs for reducing benzene to the 0.3 volume percent level on the same mix of technologies as those used for the 0.70 volume percent benzene analysis. This is reasonable since these are the technologies expected to be used by the RFG refineries and we would expect these refineries to use the same technologies to further reduce their gasoline benzene levels.

Reducing benzene in the FCC naphtha can be integrated with the FCC naphtha desulfurization unit installed for meeting the Tier 2 gasoline sulfur standard. For desulfurizing gasoline, most refiners using desulfurization units such as Scanfining, Octgain, ISAL, IFP Prime G and CDTech are expected to split the FCC naphtha into light and a heavy naphtha streams. Splitting the FCC naphtha into light and heavy FCC naphtha allows the refiner to most economically treat either stream. The point at which the split occurs could be chosen to segregate virtually all the benzene in the heavier stream. Then a distillation column would be used to create a benzene rich stream to send that stream to the various benzene reduction strategies.

The vendor benzene reduction technology information weighted by the percentages fractions listed under the 0.70 volume percent benzene case plus the various cost inputs described above were combined together to estimate the cost of reducing RFG benzene levels to 0.30 percent by volume to enable removing oxygenate. In this case, all refineries were impacted by this need to further reduce their benzene levels. This cost will be used to under the Two- and Three-Fuel options, thus, the incremental RFG produced under these options would only be produced by refiners in PADDs 1, 2 and 3. Thus, we developed costs only for these three PADDs only. To derive national average costs, we volume-weighted the PADD-specific cost estimates. The following table lists the capital cost, operating cost, and total cost for each PADD which produces Federal RFG. The PADD 1, 2 and 3 weighted cost was used to estimate the cost of the various fuel options in Section III.

Table II.E.2-6
Costs for Reducing RFG Benzene Levels to an Average 0.30% by Volume

	Capital Cost (Cents/gallon)	Operating Cost (Cents/gallon)	Total Cost (Cents/gallon)
PADD 1	0.08	0.57	0.65
PADD 2	0.36	0.42	0.78
PADD 3	0.18	0.48	0.66
Weighted Avg of PADDs 1 - 3	0.21	0.48	0.69

F. Cost of oxygenates and iso-octane

The purpose of this section is to summarize the estimated cost impacts of changes in oxygenate use, ethanol and MTBE, and iso-octane, for the various fuel control options. The fuel control options contained in the Boutique fuel analysis study the impacts of incremental gallons of RFG replacing the gasoline going to certain low RVP areas, and with the RFG oxygen requirement in place, the incremental RFG gallons would require the use of oxygenates. The long term options also investigate the impacts of rescinding the RFG oxygen requirement and putting in place a 2.4% renewable oxygenate requirement. These changes in requirements would involve dramatic changes in both volumes and location of use of oxygenates and this section evaluates the cost impacts of these changes. Also, we are including the estimated cost impacts for the use of iso-octane from converted MTBE plants. In a related analysis of the supply impacts of these options, we present an analysis based on work by Pace Consultants Inc. which describes the likely conversion of MTBE plants to produce either iso-octane or alkylate in the event of a reduction in MTBE demand caused by bans on the use of MTBE. We use that background information to project the volume of iso-octane which would likely be produced to replace the lost MTBE volume. In this analysis, we use the estimated prices of these various gasoline blendstocks as a surrogate for the cost of producing them as described below.

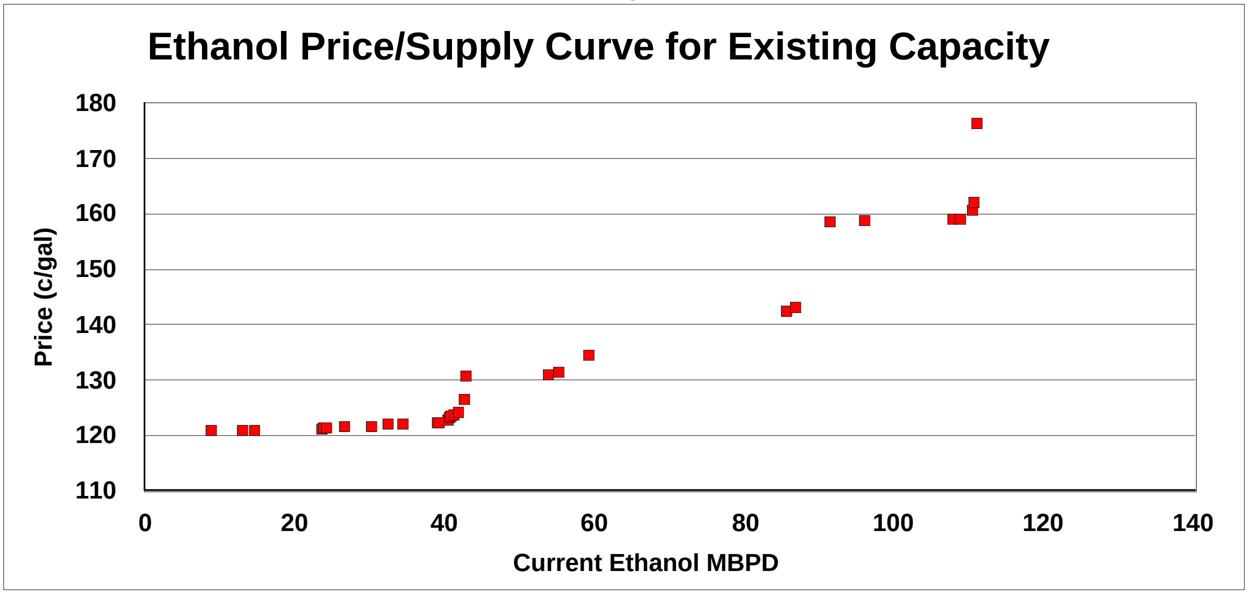
1. Ethanol

Ethanol prices are difficult to project as a variety of factors influence its price. One such factor is that ethanol is produced from corn by two different production processes and each produces different by-products. One process which accounts for approximately 60 percent of the U.S. production of ethanol is called a wet mill operation. In addition to ethanol, wet mills produce corn gluten feed, corn gluten meal, and corn oil. These plants can also be used to produce high fructose corn syrup. The other major process for producing ethanol from corn is called a dry mill operation. At a dry mill facility corn is converted into ethanol and also to distillers dried grains. Distillers dried grains, corn gluten feed and corn gluten meal are all animal feeds. When estimating the price of ethanol based on a particular demand scenario, it would be important to assess if increased production of ethanol would be from wet mill plants or dry mill plants. It also would be important to estimate how the demand of ethanol would impact the price of both the feedstock, corn, and the various byproducts as both their availability and price would probably change with the changing ethanol production.

EPA evaluated some of the studies which estimated the price of ethanol resulting from changes in ethanol demand. Three such studies include a study made by DOE's Energy Information Administration, a study by DOE's Policy Office, and a study by Energy Security Analysis, Inc. (ESAI) for California. After reviewing the various factors which were considered in the price estimates, EPA chose to base the price projections in our cost study on the estimates made by ESAI for California.[5] ESAI's work was particularly relevant because it analyzed the breakeven cost of current ethanol production which enabled us to estimate the price point at which new ethanol production capacity would come on line.

In the first portion of their analysis, ESAI developed a price-supply curve for current ethanol production which indicates the price which would be necessary to pull ethanol from its current markets and redirect it to California. Exhibit II.F.1-1 shows that ethanol from existing capacity could be made available for use in California starting at a price of $1.20 per gallon. The higher price for much of the current ethanol production is due to the existence of substantial state ethanol subsidies which increase ethanol's value in those states. These prices refer to those provided to the ethanol producer (i.e., in the Midwest). As such, they do not include any cost of transporting the ethanol to California.

Exhibit II.F.1-1
Price Curve for Shifting Ethanol to California



ESAI then developed incremental cost or price curves for additional ethanol plant capacity from new ethanol plants. In this case, ESAI estimated how prices of corn would increase with demand, and how byproducts would decrease in value. In Tables I.F.1-1 and I.F.1-2 below the breakeven ethanol prices are given for production increases (above current level) of 10,000, 50,000 and 100,000 barrels per day for the wet and dry mill production processes.

Table II.F.1-1
Ethanol Short Term Breakeven Value from New Wet Mill Operation (¢/gal)

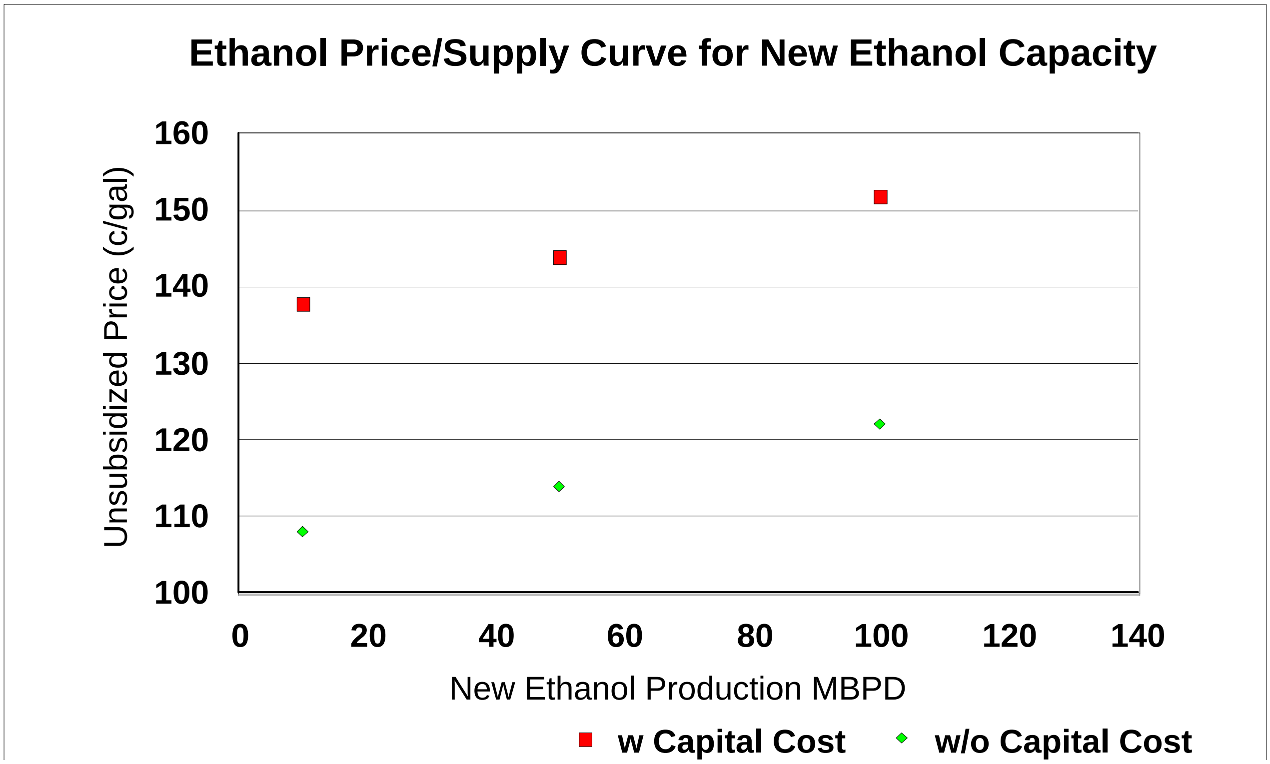
	10,000 BPD	50,000 BPD	100,000 BPD
Raw Material Cost	1.02	1.07	1.15
Operating/Other Costs	0.51	0.51	0.51
Byproduct Credits	0.53	0.53	0.53
Net Production Cost	1.00	1.05	1.13

Table II.F.1-2
Ethanol Short Term Breakeven Value from Dry Mill Operation (¢/gal)

	10,000 BPD	50,000 BPD	100,000 BPD
Raw Material Cost	1.02	1.07	1.15
Operating/Other Costs	0.62	0.62	0.62
Byproduct Credits	0.39	0.39	0.39
Net Production Cost	1.25	1.30	1.38

In developing the tables above it was assumed that the raw material cost (corn) would increase as the demand increases. However, expenses, which include energy, labor, depreciation, chemicals and fixed costs, and credits derived from the sale of byproducts were maintained constant. Furthermore, the study assumed that 67 percent of the ethanol will be produced using wet mill ethanol plants with the remaining 33 percent coming from dry mill ethanol plants. By combining the figures above at the 67/33 ratio, the corresponding ethanol prices are $1.08, $1.14 and 1.22 per gallon for the production of an additional 10,000, 50,000 and 100,000 barrels per day. These figures represent the breakeven value, as calculated in the tables above, without taking into account the capital cost. The lower curve in Exhibit II.F.1-2 represents these figures. The upper curve in Exhibit II.F.1-2 represents the ethanol value increased by 30 cents per gallon to reflect the investment cost. This cost was calculated using the capital cost calculation scheme described above, except that a rate of return (ROI) of 10 percent and a federal income tax rate of 39 percent were used to capture the breakeven price, since these values represent the capital payback and tax rate experienced by the ethanol industry.

Exhibit II.F.1-2
Ethanol Price Curve for New Ethanol Plants



In applying the cost curves, we determined the point at which new ethanol capacity would come on line. New ethanol capacity begins to come available at about 1.35 $/gal. However, Exhibit 3.1.3 shows that existing ethanol capacity is available at ethanol prices from 1.20 to 1.85 $/gal and that existing ethanol production capacity can deliver 60,000 barrels per day of ethanol at less than 1.35 $/gal. Assuming that economics would determine the transition point, it appears that current ethanol plant capacity would supply up to 60,000 bbls/day of the total 112,000 barrels per day available of ethanol to a new market, but beyond that new ethanol plants would come on line to fulfill the need for the new market. The remaining ethanol production from existing plants would remain in the Midwest states with high ethanol subsidies.

We next used the price curves to estimate the ethanol price for the year 2006 reference case and the various boutique fuel long term options. As discussed in our analysis of the supply impacts of these fuel control options, the year 2006 reference case would result in 162,000 barrels per day of ethanol demand and this includes a reduction in 60,000 barrels per day demand in conventional gasoline areas.[6] Examining the two ethanol price curves, there is 112,000 barrels of day ethanol production available from current ethanol plants. Thus, 162,000 barrels per day of ethanol demand would require another 50,000 barrels per day of new ethanol production. The 50,000 barrels per day point in Exhibit 3.1.4 corresponds with $1.44 per gallon. For most of the

Boutique fuel long term cases, ethanol demand is almost identical, so the same ethanol price is used in these cases. However, for the renewable ethanol cases, ethanol demand is expected to be about 200,000 barrels per day which is at the 88,000 barrel per day point in Exhibit 3.1.4 and it corresponds to an ethanol price of $1.50 per gallon. Comparing the reference case and the nonrenewable oxygenate cases to the renewable oxygenate cases, there is a 6 cent per gallon increase in ethanol price for the renewable cases. (This is in addition to the 9 cent per gallon price increase projected for the reference case relative to today.) The subsidized ethanol price was used in the analysis and since these options are several years out, a 51 cents per gallon subsidy was used consistent with the phasing down of the ethanol subsidy in future years.

We also took the cost of distributing ethanol into account in our cost analysis. For ethanol transported down to the Gulf Coast area, we added an ethanol distribution cost of 8 cents per gallon, and for ethanol transported to the East and West coast we added 17 cents per gallon to the price of ethanol.[7]

The fuel economy impact of using ethanol also was added to the cost of using ethanol. Ethanol contains about sixty percent the energy content of gasoline. Thus, this shortfall in energy content is assumed to have to be made up using regular grade reformulated gasoline at its wholesale price, which is 68 cents per gallon.

2. MTBE

For the cost analysis, it was necessary to develop a price for MTBE use as well. However, MTBE feedstocks are less sensitive to MTBE demand compared to the way ethanol affects the price of its feedstock because MTBE is largely manufactured from natural gas liquids which is in large supply. Thus, this analysis used a single price for MTBE which was 77 cents per gallon.[8] This price is 9 cents per gallon higher than the price of regular grade RFG. The fuel economy effect was also taken into account for MTBE as well. MTBE contains about 80 percent the energy of gasoline so the shortfall in energy content was made up using regular grade reformulated gasoline at its wholesale price of 68 cents per gallon.

3. Iso-octane

When MTBE use diminishes in the cases which evaluated rescinding the RFG oxygen requirement but put in place a renewable oxygenate requirement, it was assumed that the lost MTBE volume would be converted over to high octane blendstocks. The basis for this is summarized in the supply analysis. MTBE producers have the choice to convert their MTBE plants to produce either iso-octane or alkylate. The supply analysis conservatively assumed that MTBE removed from the gasoline supply would be replaced by iso-octane, which is produced at slightly less than half the volume should the MTBE plants be converted to alkylate production instead of iso-octane. The price for iso-octane used in the cost analysis was 76 cents per gallon.[9]

The capital cost associated with conversion of an MTBE plant is $30 million for a 15,000 barrel per day MTBE plant.

D. Cost of complying with MSAT requirements

The recently published Mobile Source Air Toxics (MSAT) rulemaking[v] set new standards for toxics emissions from both RFG and conventional gasoline. Separate standards apply to each refinery's reformulated and conventional gasoline and are set equal to the average toxics emissions levels from 1998 - 2000 RFG and conventional gasoline production, respectively, to ensure that toxic emissions over-compliance exhibited during this time frame is not lost in the future. The toxics performance standard for increased volumes of RFG produced by refiners or importers who had produced or imported RFG during 1998-2000 remains at the RFG toxics performance standard of 21.5 percent. However, RFG produced or imported by those who had not produced or imported RFG during 1998-2000 must meet the default MSAT standard of 26.7 percent.

Absent changes in relative RFG and CG production volumes and other applicable fuel quality standards (e.g., no change in MTBE use, no entry into the RFG market by a refinery currently producing just conventional gasoline), the costs associated with compliance with the MSAT rule were estimated to be negligible on a nationwide average basis. However, some of the fuel options being evaluated here involve significant changes to fuel quality standards. Thus, compliance with the MSAT standards could involve greater costs than simply complying with the RFG toxics performance standards.

A thorough assessment of the impact of the MSAT standards on the cost of producing gasoline under the various fuel control options is beyond the scope of this study. Unlike VOC and NOx emission performance, which are dominated by RVP and sulfur, respectively, toxics emission performance is affected by a number of fuel parameters, primarily benzene and aromatic contents, but also sulfur, olefin and oxygen contents. Changes to most of these fuel parameters involve changes to gasoline octane, as well as volume and involve numerous refinery streams. While it is not possible here to completely assess the impact of the MSAT standards on the cost of the various fuel options, it is possible to qualitatively discuss the primary factors involved in complying with the MSAT standards and possible strategies available to refiners.

The primary factor which affects MSAT-related compliance costs actually occurs in the reference case, as opposed to the fuel control options. This factor is the set of state MTBE bans which are scheduled for the most part to occur prior to 2006. Under these bans, refiners would substitute ethanol for MTBE in order to comply with the RFG oxygen mandate. Ethanol would likely be used at levels which provide 2.0, 2.7 or 3.5 weight per oxygen, as the ethanol excise tax credit is available at these specific levels. Simply substituting ethanol for MTBE (plus iso-octane

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[v] Federal Register reference 66 FR 17230, published March 29, 2001.

for the remaining MTBE volume) results in a loss of toxics emission performance.[w] This occurs, because MTBE is a relatively unique property of depressing the vapor pressure of benzene and thereby reducing non-exhaust emissions of benzene. For refiners who had been using MTBE in the past, for the few years prior to full Tier 2 sulfur compliance, compliance with the MSAT standards without MTBE will require additional toxics emission control beyond substituting ethanol and iso-octane or alkylate, with some modification to refinery operation and its attendant cost.

As discussed in the previous sub-section, reducing benzene levels further appears to be the most likely avenue for incremental toxics control. Reducing benzene in FCC naphtha and producing an RFG with 0.3-0.4 volume percent benzene would compensate for the loss of toxics performance when substituting ethanol for MTBE. However, this would entail a capital investment for most refiners. The need for this investment will likely disappear with full compliance with the Tier 2 sulfur standards. Thus, it is somewhat uncertain whether a refiner would make this capital investment for just 1-2 years of operation. As these costs occur in the reference case and are not associated with any of the fuel control options, they are not a direct part of this cost analysis. However, the means that refiners would use to comply with the MSAT standards in the context of the state MTBE bans still forms an important baseline from which further fuel modifications are evaluated. While it is possible that refiners would have to reduce benzene levels further in areas with MTBE bans, that was not assumed here. To do so could reduce the cost of complying with the MSAT standards under the fuel options with a renewable fuel mandate, since these options also involve benzene reductions to the 0.3 volume percent level. Since this analysis is primarily focused on the fuel control options and not changes occurring prior to 2006, it seems inappropriate to assume that certain costs occur in the reference case and not in the fuel control options being assessed.

Once the Tier 2 sulfur standards apply, the effects of lower sulfur and associated lower olefin levels, combined with ethanol and iso-octane use, produce essentially equivalent toxics performance. This assumes that the refinery's baseline RFG sulfur level was 130 ppm or higher. If it was significantly lower, then the effect of complying with the Tier 2 sulfur standards would be smaller and toxics performance could still drop relative to current levels. In general, however, once the Tier 2 sulfur standards are fully met, compliance with the MSAT performance standard should not be costly for most refiners, even without MTBE.

Under the Three-Fuel option requires only a small increase in nationwide RFG production. In this case, this incremental production would likely be primarily by refiners who already produce RFG. As discussed above, the toxics performance standard for this incremental

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[w] At the lower levels of ethanol, iso-octane is assumed to replace that volume of MTBE not replaced by ethanol. As converted MTBE plants would produce 70% of the original MTBE volume in the form of iso-octane, there would be more than enough iso-octane available to combine with ethanol use to fully compensate for MTBE's volume.

production would be 21.5 percent.[x] This performance standard is easily achievable with 6.8 RVP, 0.7 volume percent benzene, and 30 ppm sulfur, with or without the use of oxygenate and regardless of oxygenate type.

The Two-Fuel option involves a 50 percent increase in the production of Federal RFG outside of California. Thus, it is less clear that all of this incremental RFG production would come from refineries already producing RFG. To the extent that this occurred, this new RFG would only have to meet a 21.5 percent toxics performance standard. As was the case with the three-fuel option, reductions in RVP to 6.8 and benzene to 0.7 volume percent, along with already required sulfur reductions and accompanying olefin reductions would be sufficient to meet the 21.5 percent toxics performance standard. However, to the extent that some refineries began making RFG (or CBG under the renewable fuel mandate), their RFG or CBG would have to meet a 26.7 percent toxics performance standard.

Refiners which had to comply with the tighter 26.7 percent standard could still comply if MTBE or ethanol were used. However, further benzene control to 0.3 volume percent (or other similar toxics reducing strategies), at least, would be required in the absence of MTBE or ethanol, as could be the case under the cases with a renewable fuel mandate. In all these cases, careful management of aromatics and octane would be required, which again is beyond the scope of this analysis. Iso-octane should be available in significant quantities from converted MTBE plants to facilitate this management. Iso-octane has relative high motor and research octanes of 100. However, its blending octane ((R+M)/2) is still lower than that of either MTBE or ethanol. Thus, simply replacing oxygenate with iso-octane is not sufficient from an octane perspective.

Overall, then, uncertainty exists regarding refiners plans for compliance with the MSAT standards in areas which have banned MTBE prior to the full implementation of the Tier 2 sulfur standards. Beyond this, for the Three-fuel option, under either the RFG oxygen mandate or the renewable fuel mandate, RVP control and a benzene level of 0.7 volume percent should be sufficient for the new RFG or CBG to comply with applicable toxics performance standards. For the Two-Fuel option, with the RFG oxygen mandate in place, the same level of benzene control should be sufficient. However, under the renewable oxygen mandate, further benzene control to 0.3 volume percent would likely be needed. Under either national fuel options, further benzene control to 0.3 volume percent would likely be needed. Again, these projections should only be considered to be indicative of the types of fuel modifications which would be necessary to comply with the MSAT standards until a more thorough refining analysis can be conducted.

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[x] The actual standard that refiners must comply with is volume-weighted average of their 1998 - 2000 toxics performance and the "existing" toxics performance standard, which for RFG is the regulatory value of 21.5 percent reduction with respect to the statutory baseline fuel. Thus incremental volumes of RFG are not, strictly speaking, compared directly to the regulatory value of 21.5 percent. However, for the purposes of estimating costs associated with the MSAT rule, this simplification is deemed appropriate and is not expected to materially affect the cost estimates.

III. Fuel Program Option Costs

This Section describes the cost estimation process used for the four program options presented in the report. Table III-1 summarizes the program options analyzed in this study.

Table III-1
Matrix of Cases Analyzed

	Case #	RFG Oxy Mandate	Renewable Oxy Mandate	Benzene Standard for Conventional Gasoline
2000 Base Case*		Yes	No	No
2006 Reference Case**		Yes	No	No
3-Fuel Options				
	1	Yes	No	No
	2	Yes	No	Yes
	3	No	Yes	No
	4	No	Yes	Yes
2-Fuel Option; 9.0 RVP CG				
	5	Yes	No	No
	6	Yes	No	Yes
	7	No	Yes	No
	8	No	Yes	Yes
49-State Fed CBG	9	No	Yes	NA
50 State Cal CBG	10	No	Yes	NA

A. Three-fuel option for 49-State program

This option represents the smallest change from the current slate of fuel programs in existence, both in terms of total cost to the nation and in terms of the practical and logistical ramifications. In this option, States with 7.0 and 7.2 RVP areas would choose to upgrade to a cleaner fuel program and 7.8 and 9.0 psi RVP conventional gasoline would continue to be used where it is used today. Thus a total of three fuel programs would be in existence, in addition to the California CBG program and any other State-specific programs created for non-air quality reasons.

In addition to an RVP program at 7.8 psi, the two cleaner fuel programs available to States under this option would be either RFG or federal CBG. We also analyzed the cost of an average fuel benzene content standard applied to conventional gasoline. The result is that there are four possible Cases for this program option, as described in Table III-1. A summary of the costs for each Case is given in Table III.A-2, and the costs of each of these four Cases are addressed below.

Table III.A-2
Summary of Costs for Three Fuel Option (¢/gal except where noted)

	vol%	Case 1	Case 2	Case 3	Case 4
Program description					
RFG with oxygen requirement		Yes	Yes	No	No
Renewable oxygen mandate		No	No	Yes	Yes
Benzene standard for CG		No	Yes	No	Yes
Conventional gasoline - MTBE blends					
9.0 psi RVP areas	31		0.4		0.4
7.8 psi RVP areas	9.1		0.4		0.4
7.2 psi RVP areas	0	2.73	2.73	1.2	1.2
7.0 psi RVP areas	2.1	2.63	2.63	1.1	1.1
Conventional gasoline - Ethanol blends					
9.0 psi RVP areas	9.3		0.4		0.4
7.8 psi RVP areas	3.9		0.4		0.4
7.2 psi RVP areas	0.2	4.73	4.73	1.2	1.2
7.0 psi RVP areas	0.9	4.75	4.75	1.1	1.1
Other state-specific programs					
California CBG in federally covered areas	7.0				
California CBG in the rest of the state	4.5				
Arizona CBG program	1.0				
Ethanol mandate in Minnesota	2.0		0.4		0.4
Additional oxygenate, iso-octane, or compliance with MSAT				0.10	0.10
Nationwide average cost		0.11	0.35	0.13	0.38
Investment cost ($ million)		90	1040	510	1460

Case 1: *9.0 psi RVP conventional gasoline*
7.8 psi RVP conventional gasoline
Federal RFG

In this Case, the only areas that would change from their current fuel program are those that have conventional gasoline RVP standards of less than 7.8 psi. These areas account for less than 4 percent of nationwide gasoline. These areas are assumed to adopt RFG to ensure that no air quality benefits are lost (by otherwise dropping back to the default programs of 7.8 or 9.0 psi RVP). Since the increase in RFG volume would be small, we expect no increase in oxygenate prices due to increased volumes, nor adverse cost impacts due to the MSAT rule. We can therefore use the reference case costs of RFG without adjustment for increased production volumes.

Areas that currently have a 7.0 psi RVP cap and which would change to RFG under this Case are expected to continue to use MTBE and ethanol based on the State MTBE bans which may apply and also based on their relative location to oxygenate production capacity (70 percent of the new RFG would use MTBE while the remaining 30 percent would use ethanol). The area currently having a 7.2 psi cap is expected to use only ethanol. Therefore, the costs given in Section II for RVP control, benzene control, and oxygenates can be weighted together to produce an average cost of 3.3 cents per gallon for the additional volume of RFG that would be produced under this Case. For the nation as a whole, the costs of this Case would be extremely small since it would only affect approximately four percent of nationwide fuel. The net result is that nationwide costs for this case would be approximately 0.1 cents per gallon. The refining industry would be expected to invest about $90 million in new capital.

Case 2: *9.0 psi RVP conventional gasoline with 0.95 vol% benzene standard*
7.8 psi RVP conventional gasoline with 0.95 vol% benzene standard
Federal RFG

This Case differs from Case 1 only in that an annual average fuel benzene content standard of 0.95 volume percent has been applied to all conventional gasoline. Per the discussion of benzene control costs in Section II.B above, the cost of this control is approximately 0.4 cents per gallon of conventional gasoline. This additional cost would apply to the 64 percent of nationwide fuel that would remain conventional gasoline under the Three-Fuel option. This represents an additional nationwide average cost increase of approximately 0.25 cents per gallon relative to Case 1. If this cost is added to the costs associated with replacing low RVP control programs in the U.S. with RFG in Case 1, the nationwide average cost of this Case is approximately 0.35 cents per gallon. The refining industry would be expected to invest about $1037 million in new capital.

Case 3: *9.0 psi RVP conventional gasoline*
7.8 psi RVP conventional gasoline
Federal Cleaner-Burning Gasoline
Renewable oxygenate mandate

This Case differs from Case 1 in that the oxygen requirement for RFG is removed, and a renewable oxygenate mandate applicable to all gasoline is implemented. For the purposes of estimating costs for this Case, we have separately evaluated the cost of federal CBG without oxygen and the cost of increased nationwide use of ethanol use associated with the renewable oxygenate mandate.

We expect that, under the renewable oxygenate mandate, nationwide use of MTBE will change from 1.5 volume percent to 0.8 volume percent, while ethanol use will increase from 1.9 volume percent to 2.4 volume percent. The price of ethanol changes due to changes in volume and changes in transportation cost. Increasing the volume of ethanol demanded increases the price of ethanol by 6 cents per gallon, however, the lower transportation cost caused by using it more where it is produced instead of far away results in a 9 cents per gallon decrease in price, or a net 3 cents per gallon decrease in delivered price. Simultaneous with these changes, iso-octane use will increase as some precursors to MTBE production are diverted to iso-octane production to replace lost octane and volume. These changes occur in addition to 7.2 and 7.0 psi RVP areas converting over to new CBG areas.

Refiners must also comply with the MSAT toxics standard for CBG. Our preliminary projection is that this would require benzene reductions to roughly 0.3 volume percent if oxygen were removed from CBG. A shift of ethanol from CBG to conventional gasoline would reduce RVP reduction costs on average, since the RVP boost associated with ethanol blending can be ignored in 9 psi RVP gasoline. Overall, the flexibility of being able to meet the RFG performance standards with whatever level of oxygenate is most economic, coupled with the ability to add ethanol to 9 psi RVP gasoline without adjusting for RVP in lieu of producing 5.7 psi RVP blendstock for ethanol blending into RFG, leads to net lower ethanol blending costs.

The net result is that nationwide costs for this case would be approximately 0.13 cents per gallon. The refining industry would be expected to invest about $510 million in new capital.

Case 4: *9.0 psi RVP conventional gasoline with 0.95 vol% benzene standard*
7.8 psi RVP conventional gasoline with 0.95 vol% benzene standard
Federal Cleaner-Burning Gasoline
Renewable oxygenate mandate

This Case differs from Case 3 only in that an annual average fuel benzene content standard of 0.95 volume percent has been applied to all conventional gasoline. Per the discussion of benzene control costs in Section II.B above, the cost of this control is approximately 0.4 ¢/gal. This additional cost would apply to the 64 percent of nationwide fuel that would remain conventional gasoline under this option. This represents a nationwide average cost of approximately 0.25 cents per gallon. If this cost is added to the costs associated with replacing low RVP control programs in the U.S. with federal CBG, the nationwide average cost of this Case is approximately 0.38 cents per gallon. The refining industry would be expected to invest about $1460 million in new capital.

B. *Two-fuel option for 49-State program*

Under this fuel control option, States are assumed to adopt an alternative cleaner fuel program instead of the default 7.8, the 7.2 and the 7.0 psi RVP conventional gasoline programs. As for the three-fuel program option, we assumed that the California CBG program and any other State-specific programs created for non-air quality reasons would continue. Similar to the three fuel option, the cleaner fuel program available to States under this option would be RFG or federal CBG, and an average fuel benzene content standard may or may not be applied to conventional gasoline. The result is that there are four possible Cases for this program option, as described in Table III-1. The costs of each of these four Cases are summarized in Table III.B-1, and described below.

Table III.B-1
Summary of Costs for Two Fuel Option (¢/gal)

	vol%	Case 5	Case 6	Case 7	Case 8
Program description					
RFG with oxygen requirement		Yes	Yes	No	No
Renewable oxygen mandate		No	No	Yes	Yes
Benzene standard for CG		No	Yes	No	Yes
Conventional gasoline - MTBE blends					
9.0 psi RVP areas	31		0.4		0.4
7.8 psi RVP areas	9.1	2.99	2.99	1.46	1.46
7.2 psi RVP areas	0	2.73	2.73	1.2	1.2
7.0 psi RVP areas	2.1	2.63	2.63	1.1	1.1
Conventional gasoline - Ethanol blends					
9.0 psi RVP areas	9.3		0.4		0.4
7.8 psi RVP areas	3.9	5.34	5.34	1.46	1.46
7.2 psi RVP areas	0.2	4.73	4.73	1.2	1.2
7.0 psi RVP areas	0.9	4.75	4.75	1.1	1.1
Other state-specific programs					
California CBG in federally covered areas	7.0				
California CBG in the rest of the state	4.5				
Arizona CBG program	1.0				
Ethanol mandate in Minnesota	2.0		0.4		0.4
Additional oxygenate, isooctane, or compliance with MSAT				0.10	0.10
Nationwide cost		0.59	0.78	0.32	0.52
Investment cost ($ million)		610	1360	1030	1780

Case 5: *9.0 psi RVP conventional gasoline*
Federal RFG

In this Case, the areas that would change from their current fuel program are those that have conventional gasoline RVP standards of less than 9.0 psi (i.e. 7.8, 7.2 and 7.0 psi RVP areas). These areas account for less than 17 percent of nationwide gasoline, and would affect 13 percent more gasoline than Case 1. These low RVP areas are assumed to adopt RFG in this Case to ensure that no air quality benefits are lost (by dropping back to the default program of 9.0 psi RVP). As a result, RFG would account for a total of 49 percent of nationwide gasoline. This represents an RFG production increase outside of

California of approximately 50 percent.

Under this Case, the increase in RFG production volume could potentially increase the per-gallon costs of RFG. These potential adjustments would include the fact that the MSAT "incremental volume" provisions become important in this Case, oxygenate demand will increase, and there will be a greater need to produce lower-RVP blendstocks for use in producing RFG with ethanol. However, we cannot determine with certainty how many current RFG-producing refineries would produce additional RFG under this Case. For refineries that did produce RFG in 1998 - 2000, RFG accounted for only 30 - 35 percent of their total gasoline production on average. As a result, it appears reasonable to assume that much of the 50 percent increase in RFG production could come from current RFG-producing refineries. However, some of this new RFG could also come from "new" RFG refiners or importers and must meet more stringent MSAT toxics performance standards.

As shown in Section II.C, the production cost of oxygenates is largely independent of production level for low production levels. Thus the per gallon cost of both MTBE and ethanol remains essentially the same in this Case as compared to Case 1. However, due to an increase in MTBE demand under this case, some iso-octane plants would likely switch back to MTBE production. Also, ethanol use would increase to just above 2.4 percent of non-California gasoline. Thus, ethanol prices (as opposed to cost) would be expected to increase to those expected under the renewable fuel standard, or an estimated 6 cents per gallon relative to the reference case.

The 7.0 and 7.2 psi RVP cap areas are expected to use MTBE and ethanol in the same ratio as that described under Case 1. The 7.8 psi RVP areas are assumed to use 60 percent MTBE and 40 percent ethanol. Therefore, the component costs can be weighted together with the new RFG costs for the 7.8 RVP areas to produce an average cost of 3.6 cents per gallon for the volume of RFG that would be produced under this Case. For the nation as a whole, the costs of this Case would be approximately 0.6 cents per gallon. The refining industry would be expected to invest about $610 million in new capital.

Case 6: *9.0 psi RVP conventional gasoline with 0.95 vol% benzene standard*
Federal RFG

This Case differs from Case 5 only in that an annual average fuel benzene content standard of 0.95 volume percent has been applied to all conventional gasoline. Per the discussion of benzene control costs in Section II.B above, the cost of this control is approximately 0.4 cents per gallon of CG. This additional cost would apply to the 51 percent of nationwide fuel that is currently conventional gasoline with an RVP of 9.0. This represents an additional nationwide average cost of approximately 0.2 cents per gallon. If this cost is added to the costs associated with replacing low RVP control programs in the U.S. with RFG in Case 5, the nationwide average cost of this Case is approximately 0.8 cents per gallon. This represents an average cost of 1.2 cents per gallon for all affected gasoline under this Case. The refining industry would be expected to invest about $1360 million in new capital.

Case 7: *9.0 psi RVP conventional gasoline*
Federal Cleaner-Burning Gasoline
Renewable oxygenate mandate

This Case differs from Case 5 and is similar to Case 3 in that the oxygen requirement for RFG is removed, and a renewable oxygenate mandate applicable to all gasoline is implemented. For the purposes of estimating costs for this Case, we have separately evaluated the cost of federal RFG without oxygen (thus as CBG) and the cost of increased nationwide use of ethanol use associated with the renewable oxygenate mandate.

We expect that, under the renewable oxygenate mandate, nationwide use of MTBE will change from 1.5 volume percent to 0.8 volume percent, while ethanol use would increase from 1.9 volume percent to 2.4 volume percent. The price if ethanol changes due to changes in volume and changes in transportation cost. Increasing the volume of ethanol demanded increases the price of ethanol by 6 cents per gallon, however, the lower transportation cost caused by using it more where it is produced instead of far away results in a 9 cents per gallon decrease in price, or a net 3 cents per gallon decrease in price. Simultaneous with these changes, iso-octane use will increase as some precursors to MTBE production are diverted to iso-octane production to replace lost octane and volume. These changes occur in addition to 7.8, 7.2 and 7.0 psi RVP areas converting over to new CBG areas.

Refiners must also comply with the MSAT toxics standard for CBG. Our preliminary projection is that this would require benzene reductions to roughly 0.3 volume percent if oxygen were removed from CBG. A shift of ethanol from CBG to conventional gasoline would reduce RVP reduction costs on average, since the RVP boost associated with ethanol blending can be ignored in 9 psi RVP gasoline. Overall, the flexibility of being able to meet the RFG performance standards with whatever level of oxygenate is most economic, coupled with the ability to add ethanol to 9 psi RVP gasoline without adjusting for RVP in lieu of producing 5.7 psi RVP blendstock for ethanol blending into RFG, leads to net lower ethanol blending costs.

The net result is that nationwide costs for this case would be approximately 0.32 cents per gallon. The refining industry would be expected to invest about $1030 million in new capital.

Case 8: *9.0 psi RVP conventional gasoline with 0.95 vol% benzene standard*
Federal Cleaner-Burning Gasoline
Renewable oxygenate mandate

This Case differs from Case 7 only in that an annual average fuel benzene content standard of 0.95 volume percent has been applied to all conventional gasoline. Per the discussion of benzene control costs in Section II.B above, the cost of this control is approximately 0.4 cents per gallon of CG. This additional cost would apply to the 51 percent of nationwide fuel that would still be conventional gasoline with an RVP of 9.0 psi. This represents a nationwide average cost of approximately 0.2 cents per gallon. If this cost is added to the costs associated with replacing low RVP control programs in the U.S. with federal CBG, the nationwide average cost of this Case is approximately 0.52 cents per gallon. The refining industry would be expected to invest about $1780 million in new capital.

C. 49 State federal CBG program option

Federal Cleaner-Burning Gasoline would meet all the existing RFG emission performance requirements, but would not specify an oxygen requirement; oxygenates could be used in federal CBG, but would not be required. Under the assumptions made in the report, a federal CBG program would only be implemented if a national renewable fuels requirement applicable to all gasoline were implemented at the same time.

The cost of federal CBG is difficult to estimate without the use of a refinery model. Even then, the estimates may be soft due to the difficulty in understanding the capability of the U.S. refining industry, as the sum of over 100 different refineries, to produce CBG. The supply analysis showed a potential reduction of 3 - 6 percent by volume, and it is not clear how much of this volume loss would be made up by domestic refining capacity versus imports. The cost estimate made in the early 90's for RFG was 4-6 cents per gallon. However, as described above, there are several differences today which complicates the use of that cost estimate for this program. First, refiners will not need to make any investments to meet the NOx standard since gasoline sulfur will already be at 30 ppm. Second, in recent years, the price of oxygenate has been less expensive than when the RFG cost estimate was made, although under a renewable requirement, the price of ethanol would be as high if not higher. Also, under a CBG program, refiners can choose whether they would use oxygenate or not so refiners with complex refineries may be able to meet the program’s requirements without oxygen, while others less well suited can choose to use oxygenate. Finally, much of the country is already meeting RFG requirements, or low RVP program requirements, today which would lower the cost of meet the CBG requirements. Conversely, a couple of factors would cause this program to be more expensive than past estimates for the RFG program. First, this is a nationwide program so that more expensive and less complex refineries would have to participate. Also, because the program applies nationwide, refiners do not have the option of blending back and forth between a reformulated gasoline pool and a conventional gasoline pool. The net conclusion to be drawn from this discussion is that there is a large degree of uncertainty in estimating the cost of such a fuel program. We believe that the nationwide program cost would ultimately fall within the 3 - 7 cents per gallon range.

D. 50 State California CBG program option

California has estimated that their Phase 2 CBG with oxygen costs from 5 - 15 ¢/gal. By 2006, California CBG will represent both the recent Phase 3 modifications and California's MTBE ban. These elements are expected to add an additional 4 - 5 ¢/gal to the cost of California CBG. The vast majority of this incremental cost is associated with the California MTBE ban scheduled to go into effect in 2003. The removal of MTBE from California CBG will be accompanied by the addition of ethanol (for fuel sold in the federal RFG areas, comprising about 70 percent of the fuel sold in California) and potentially other fuel modifications to compensate for the accompanying impacts of the oxygenate change on emission performance. Outside of federal RFG areas in California where oxygen is not required to be present in the fuel, the additional cost of the Phase 3 modifications would be much lower, possibly 1 cent per gallon.

There is no current federal legislation to ban the use of MTBE nationwide, but several States will have banned MTBE by the reference year of 2006. The additional cost associated with the California MTBE ban are applicable only to those States expected to have implemented MTBE bans by 2006. However, the number of States falling into this category would not meaningfully change California's estimated cost range of 5 - 15 cents per gallon on a nationwide average basis. As a result, the cost of Phase 3 CBG is assumed to be 5 - 15 cents per gallon as we consider its use in the nation as a whole (we have not included the possible 1 cents per gallon additional cost of the Phase 3 requirements incremental to Phase 2, since it also would not materially affect the range). The cost of Phase 3 CBG will rise above this base cost as the total production volume increases.

Absent detailed refinery modeling, we cannot precisely estimate the cost of California Phase 3 CBG if all refineries in the U.S. were required to produce it. The cost of California Phase 3 CBG is currently estimated at 5 - 15 cents per gallon. Under this program option, we would also implement a renewable oxygenate mandate. However, based on refinery modeling for California refineries, refiners might choose to use more ethanol in order to meet the California Phase 3 CBG specifications than would be required under the renewable fuel mandate. Detailed refinery modeling would be required to confirm this, however, as the decision to use ethanol versus other technology and blendstocks would be based on economics, which have not been assessed on a nationwide basis. Also, opportunity costs associated with butane and pentane removal would change substantially, raising the cost of the RVP reductions required for all gasoline under this Case. Other factors would also undoubtedly increase production costs as well. However, we do not at this time have the means for estimating the costs of Phase 3 CBG under a nationwide program. Therefore, it appears reasonable to project that the cost of this option would be at least 5 to 15 cents per gallon on average, with higher costs in many areas.

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