United States Environmental Protection Agency
Office of Transportation and Air Quality
EPA420-D-06-004
February 2006

Draft Regulatory Impact Analysis: Control of Hazardous Air Pollutants from Mobile Sources

Chapter 9

EPA420-D-06-004
February 2006

Draft Regulatory Impact Analysis: Control of Hazardous Air Pollutants from Mobile Sources

Chapter 9

Assessment and Standards Division
Office of Transportation and Air Quality
U.S. Environmental Protection Agency

Chapter 9: Table of Contents

Chapter 9: Cost of Proposed Gasoline Benzene Standard and Other Control Options Considered

This chapter provides a summary of the methodology used and the results obtained from our cost analyses of the proposed benzene standard as well as various other control options considered. We start by summarizing the refinery models used for our analysis. We then describe our detailed methodology for estimating the benzene control costs for our proposed rule followed by the results. We present the results from our energy and supply analyses for our proposed benzene control program. Finally, we summarize the results of other cost estimates for toxics control.

9.1 Methodology

9.1.1 Overview

We retained the services of Abt Associates, Inc., (Mathpro) under subcontract to ICF, Inc., to assess the cost of potential air toxics emissions control programs. Abt Associates ran their linear program (LP) refinery cost model to investigate various air toxic emissions control programs for gasoline. LP refinery models are proven tools for estimating the costs for fuels programs which control fuel quality.[1] A series of gasoline quality control programs were evaluated using the LP refinery model including benzene, total toxics and sulfur and RVP control.

While the LP refinery models are necessary and appropriate for many analyses, they also have several important limitations of relevance here. When used to model the cost of nationwide fuel control programs on the entire refining industry, LP refinery models are usually used to model groups of refineries in geographic regions called PADDs which are defined above in the feasibility section. The LP refinery model averages the costs over the refineries represented in the PADDs, however, the technology chosen by the refinery model would normally be the lowest cost technology found by the refinery model. This may represent an unreasonable choice of technologies for individual refineries cases because of how refineries are configured and the technologies to which they have access. While the choice of technologies can be limited based on an analysis of what mix of technologies would best suit the group of refineries modeled in each PADD, this would only provide an approximate estimate of the technologies which should be used and the cost incurred. Also the LP refinery model would not be a sensible tool for estimating the credit averaging between PADDs. The PADD trading issue could be partially overcome by iterating between PADD refinery model runs, thus estimating the number of credits traded between PADDs and estimating the level off benzene control in each PADD. However, the need to make multiple runs for each PADD for each case coupled with the need to run multiple control cases for different benzene standards would be very time consuming, costly and still would only result in approximate estimates of the benzene levels achieved and the cost incurred.

For this reason, EPA contracted Abt Associates to develop a refinery-by-refinery cost model which models the capability for each refinery to install the available benzene control

technologies available to them to reduce their gasoline benzene levels.[2] The advantages that this form of cost model has over the LP refinery model are that:

1. The cost for applying the benzene control technologies available to each refinery can be modeled for each refinery;
2. The benzene level achievable by applying each benzene control technology can be estimated for each refinery which allows estimating the benzene level achievable in each PADD and across the entire refining industry;
3. The benzene control cost-effectiveness (cost per amount of benzene reduction achieved) for each benzene control technology modeled in each refinery can be compared to that of the others;
4. The most cost-effective benzene control strategy for each refinery can be chosen after considering the cost-effectiveness of benzene control technologies available at all the refineries and considering the level of the benzene control standard.

This strategy results in the optimum selection of benzene control technologies consistent with how the cost of a benzene standard under an ABT program would be expected to affect benzene control investments by the refining industry. For this reason, the refinery-by-refinery cost model was used to estimate the cost for various benzene control standards both with and without ABT programs, and the LP refinery model was used for the other air toxics control programs considered. Because certain information necessary for estimating the cost of benzene control with the refinery-by-refinery cost model was not publicly available, it was necessary to find a way to estimate this information. The inputs and outputs from the LP refinery cost model provide this needed information and it was utilized in the refinery-by-refinery cost model. The information from the LP refinery used in the refinery-by-refinery cost model is described in the section describing the methodology used with the refinery-by-refinery cost model.

Newly creating the refinery-by-refinery modeling tool raises questions about its viability. For example, the LP refinery model has been used by Abt Associates for dozens, if not hundreds, of refinery modeling studies for a variety of clients, including the oil industry, the automobile industry, and government. These modeling studies have exposed this LP refinery modeling tool to many opportunities for internal and external review and continued adjustment to better model fuel quality changes imposed on the refining industry. Even though refinery modeling expertise was relied upon during the creation of the refinery-by-refinery model, it still has not been exposed to multiple opportunities for scrutiny. For this reason the refinery-by-refinery cost model evaluated in three different ways. First, the model was reviewed by EPA's refining modeling expert who has been conducting cost analyses on fuel programs for nearly 15 years. Another sort of review was conducted on the model by comparing its cost estimates for benzene control with a benzene control case evaluated with the LP refinery cost model. Two peer reviews were conducted on the refinery-by-refinery cost model by two refinery industry consulting firms. These two refining industry consultant peer reviews were conducted late in the proposal process which did not allow for adjustments to the refinery model in time for the proposal. The peer review comments are summarized later on in this section and appropriate adjustments will be made for the final rule. Waiting to address the peer review comments until the final rule is judged to be acceptable because the changes are not expected to cause a significant difference in the benzene control cost estimates. This judgment is partially based on

our review of the peer review comments, and partially based on the fact that the refinery-by-refinery cost model's benzene control costs agree well with those from the LP refinery cost model. Finally, many of the inputs used in the refinery-by-refinery cost model are from the LP refinery model, a dependable source.

A key assumption associated with the analysis is that the benzene reduction technologies being considered are those which reduce benzene levels from the feed or product streams of the reformer, the unit in the refinery which produces most of the benzene in gasoline.[3] Basing the cost of this program on reformate benzene reduction technologies is reasonable because reformate contains the highest concentrations of benzene and reformate comprises a large portion of the gasoline pool. More importantly, essentially all the benzene reduction technologies which have been developed to date and used around the world are designed to reduce reformate benzene levels. Thus, reducing benzene from reformate would be expected to be the most cost-effective means for achieving benzene control. In some unique situations additional benzene reduction might be available from other refinery units. Despite considering the possibility for such reductions, we have not assumed this to be the case here. Should it occur, it would only be at refineries where such control would be more economical than reformate benzene control at other refineries– reducing the costs of the program. A detailed discussion on the technologies available for benzene control is discussed in Chapter 6 of this Regulatory Impact Analysis.

A number of potential air toxics control programs were considered for this proposed rulemaking. These include the proposed benzene control program and several variants of the benzene standard. We also modeled several air toxics control standards that would regulate total air toxics. Finally we modeled two different low RVP programs and a lower sulfur standard. We evaluated some of these alternative benzene control standards with a second benzene control standard called a maximum-average (max-avg) standard. The max-avg standard would place an additional constraint on refiners beyond the average standard. Under this option, refiners would still be able to meet the average standard using credits; however, the max-avg standard would require them to meet or exceed the max-avg standard in each refinery before purchasing credits to show compliance with the average standard. For example, a refinery with a gasoline benzene level of 2 volume percent and faced with a 1.3 vol% max-avg standard and a 0.62 vol% average standard under a nationwide ABT program would have to at least reduce its benzene level below 1.3 vol% to comply with this program. It could remain above the 0.62 volume percent standard and comply with the standard through the purchase of credits. However, its actual production would have to meet the 1.3 volume percent max-avg limit. The addition of a max-avg standard would force several high cost refineries to take additional benzene control steps not required by the 0.62 volume percent average standard alone. This in turn would allow other low-cost refiners who would have been generating credits for sale to these refineries to back off on control. The addition of a max-avg standard would thus tend to increase the cost of a benzene control program over a program without a max-avg standard.

We also evaluated a benzene control standard without an ABT program. This type of benzene control program would require that the benzene levels of every refinery be reduced down to the benzene standard. Because a number of refineries currently produce gasoline with very low benzene levels, the average benzene level of a benzene control program without an

ABT program would likely result in a national average benzene level that is lower than the standard.

The air toxics performance standards studied were various extrapolations on the existing RFG, Anti-dumping and MSAT1 standards, based on toxics performance as estimated by the Complex Model. The low RVP programs studied would expand the volume of already existing low RVP programs. The low sulfur program studied would more stringently regulate the sulfur content of gasoline nationwide.

The proposed benzene control program and other benzene control standards evaluated are summarized in Table 9.1-1 and 9.1-2.

Table 9.1-1. Benzene Control Standards Modeled using Refinery-by-Refinery Model

Average Std.	Avg.-Max Std.	ABT Program
0.52	None	Yes
0.60	1.3	Yes
0.60	None	Yes
0.62	1.3	Yes
0.62	None	Yes
0.65	1.3	Yes
0.65	None	Yes
0.70	1.3	Yes
0.70	None	Yes
0.73	None	No

Table 9.1-2. Air Toxics and Other Standards Modeled using LP Refinery Model

Total Air Toxics with and without Benzene Standards	21.5 Total Toxics Reduction std. on CG[a]
	25% and 35% Total Toxics Reduction std. on CG and RFG, respectively 0.5 vol% avg. Bz std. on CG and RFG[b]
Low RVP	7.8 maximum RVP std on CG[c]
	7.0 maximum RVP std on CG[d]
Sulfur	10 ppm average std on CG and RFG

[a] The 21.5 percent reduction in total air toxics standard applied to CG is the air toxics standard which was established for RFG in the RFG rulemaking. The reduction is measured relative to average gasoline quality in 1990 (CAA baseline) the quality of which was codified in the Clean Air Act.

[b] This set of air toxics case reduction standards was designed to cost out a maximum total air toxics reduction with a slightly less stringent standard for CG, and proportionally more stringent standard for RFG. The benzene standard was picked to be consistent with the stringency of the total air toxics standard, ensuring benzene content reduction in both CG and RFG.

[c] The 7.8 RVP standard already applies to a part of CG in the U.S. This case modeled a volume of CG lowered to 7.8 RVP equivalent to 50% of the volume of RFG in each PADD.

[d] The 7.0 RVP standard applies to a part of CG in the U.S. This case modeled the same volume affected as the 7.8 RVP standard.

All the refinery modeling case studies were conducted on a summer only basis. This is commonplace for refinery modeling studies since it captures what is generally accepted as the higher cost season for complying with gasoline quality controls. Summertime is also the

appropriate season for studying RVP controls. Studying the costs of gasoline benzene and toxics control only during the summer can lead to somewhat conservative cost estimates.

The cost analysis of the benzene control program includes the participation of California refineries. At the time that the analysis was conducted the decision not to cover California gasoline under the proposed benzene standard had not yet been made. If for the final rule California gasoline is still not covered, the California refineries will not be modeled along with the rest off the U.S. refineries for estimating the cost of the final benzene control program. Not including California refineries in our cost analysis is not expected to have a significant impact on costs since California RFG already averages about the same benzene level as the level we are proposing.

The cost results for the proposed benzene control standard and other air toxics control cases are reported by PADD. This allows one to view the potential impact of the proposed standard on a region-by-region basis. Moreover, since the PADD regions are the smallest geographical unit of analysis for the LP refinery modeling case studies, reporting the cost results for the benzene control cases also on a PADD-by-PADD basis allows a straightforward comparison to the LP refinery modeling results which are reported on a PADD-basis. Agreement of certain outputs between the refinery-by-refinery and LP models increases our confidence in the results of both.

9.1.2 LP Refinery Modeling Methodology

The LP refinery model was used for estimating the cost for various total air toxics standards, decreasing the RVP of conventional gasoline and lowering the sulfur content of gasoline. Although the benzene control costs considered for this proposed rule were estimated using the refinery-by-refinery cost model, certain inputs into that model were taken from the input tables or from the results of the refinery modeling output from the LP refinery model – hence its importance for the proposal. The information from the LP refinery model used in the refinery-by-refinery model included the benzene content of the various streams which make up gasoline, the price of hydrogen, the cost for making up the octane-barrel loss of octane, and the price of gasoline. Certain output factors from the LP refinery model were used for estimating the volume of gasoline produced in the refinery-by-refinery model, including the utilization factors of individual refinery units, and the percentage that straight run naphtha, FCC naphtha and hydrocrackate comprises of the feed volume of their respective units. The means for using the specific inputs from the LP refinery model discussed here in the refinery-by-refinery model are summarized below in the section discussing the refinery-by-refinery model methodology.

LP refinery models are detailed mathematical representations of refineries. They are used by individual refining companies to project how best to operate their refineries. They are also used by government agencies, such as EPA and DOE, as well as by refining industry associations and individual companies, to estimate the cost and supply impacts of fuel quality changes. LP refinery models have been used for these purposes for decades and a certain protocol has been established to conduct these studies. For estimating the cost and other impacts of a future gasoline quality standard, the refinery modeling work is conducted in three steps.

The first step in conducting an LP refinery modeling analysis is the development of a base case. The base case is a refinery modeling case that calibrates the refinery model based on actual refinery unit capacity and input and output data. The base year for this study was the year 2000. Because much of the information available for establishing the base case is only available for PADDs of refineries, the LP refinery modeling is conducted on a PADD-wide basis. Refinery capacity information from the Oil and Gas Journal is aggregated by PADD and entered into the LP refinery model.[4] The year 2000 feedstock volumes including crude oil, oxygenates, and gasoline blendstocks, were obtained from the Energy Information Administration and entered into each PADD's model. Similarly, year 2000 product volumes such as gasoline, jet fuel and diesel fuel, were obtained from EIA and entered into the cost model. The environmental and ASTM fuel quality constraints in effect by 2000 are imposed on the products. This includes the Reformulated Gasoline program and the 500 ppm highway diesel fuel sulfur standard. This information was input into the LP refinery cost model for each PADD and each PADD model was run to model the U.S. refinery industry for the year 2000, which is the base year. The gasoline quality for each PADD refinery model was then compared to the actual gasoline quality which is available from the RFG data base. Each model was calibrated to closely approximate the gasoline quality of each PADD.

The next step in modeling is the development of a reference case. The purpose of the reference case is to model the refining industry operations and cost in a future year, which is the year that the air toxics cases are modeled to be in effect (serving as a point of reference to the modeled air toxics cases for estimating costs). At the time that the LP refinery modeling work was being conducted, the air toxics program was assumed to take effect in 2010. The reference case is created by starting with the 2000 base cases for each PADD and adjusting each base case to model the future year, accounting for the changes between the two years.

Two different types of adjustments were made to the base case refinery models to enable modeling the refining industry in 2010 for the reference case. First, the change in certain inputs such as product volumes and energy prices need to be accounted for. U.S. refinery gasoline, diesel fuel and jet fuel demand are projected by EIA to grow to meet increased demand.[5] This growth in demand is used to project refinery production for each PADD to meet that increased demand. This projected growth in U.S. refinery production is entered into the reference case version of the LP refinery model. Another adjustment is made to account for changes in energy prices which are projected by EIA for future years.

The second adjustment made to model the reference cases is the application of fuel quality changes. Environmental programs which have been implemented or which will largely be implemented by the time that the prospective air toxics programs would take effect were modeled in the reference case. These fuel quality changes include limits such as the 30 ppm average gasoline sulfur standard, and 15 ppm caps on highway and nonroad diesel fuel, in addition to the environmental programs which were already being modeled in the basecase. At the time that the LP refinery modeling was being conducted, the House and Senate were both considering passing their own Energy Bills. Because no Energy Bill was passed at that time, we modeled a reference case which only contained the state MTBE bans. However, an eventual Energy Bill seemed likely so we also established a reference case with an Energy Bill. For the second reference case, the leading Senate energy bill at that time was assumed to be in effect for

the second reference case. The energy bill modeled included a nationwide ban on MTBE, rescinding the RFG oxygenate standard, and a Renewable Fuels Standard which required 5 billion gallons of ethanol to be blended into gasoline in 2012.[6] Based on the yearly RFS schedule for blending in ethanol, the reference cases modeled the usage of 4.3 billion gallons of ethanol for 2010.

The third step in conducting the LP refinery modeling was to run the various control cases. The control cases are created by inserting the specific fuel control standards into each PADD reference case. The control cases are run with capital costs evaluated at a 10 percent rate of return on investment (ROI) after taxes. The refinery model output for each PADD are then compared to the reference case output and the changes in refining operations, fuel quality and costs are reviewed and reported. In the reported results the capital costs are adjusted to a 7 percent rate of ROI before taxes. For each case modeled, the energy density of each finished gasoline type is reported. The cost of each case is adjusted for changes in energy density using the wholesale gasoline price estimated by the refinery model.

9.1.3 Summary of Refinery-by-Refinery Model Methodology

The methodology used for estimating costs with the refinery-by-refinery cost model has some similarities with the methodology used with the LP refinery cost model. Although the refinery-by-refinery cost model is a separate cost estimation tool, the means for using the mathematical representation of the benzene control technologies for estimating the cost and the final gasoline benzene level by reducing benzene levels is very similar. The principal difference is that the refinery-by-refinery cost model estimates the gasoline production and benzene level for each refinery, while the LP refinery model estimates the benzene levels of the aggregate gasoline produced by each PADD of refineries. As discussed above, the modeling of each refinery is important to understanding the impact of the ABT program on compliance and cost. However, attempting to model the refinery operations for each refinery has its own set of challenges. This section presents various steps used in our methodology for estimating the operations and benzene control costs for individual refineries.

The first step was to estimate year 2003 baseline operating conditions for each refinery. This involves estimating the volumes and benzene levels of the gasoline blendstocks that comprise each refinery's gasoline. As a final adjustment to our estimated gasoline volumes and benzene levels, we calibrate them against actual refinery gasoline volume and benzene levels. For four refineries, we had gasoline blendstock volumes and benzene levels which the refining companies shared with us in our previous discussions with them concerning air toxics control. This specific refinery information provided to us was entered into the refinery-by-refinery model avoiding the need to estimate it.

The next step involves applying the various benzene control technologies as appropriate in each refinery. This allows us to make a cost estimate for using each benzene control technology in each refinery. The capital costs for installing the various benzene control technologies in each refinery were evaluated based on a 10 percent rate of return on investment (ROI) after taxes, but were adjusted after-the-fact to a 7 percent ROI before taxes for reporting the results. We also report the cost estimates based on capital costs amortized at 6 and 10

percent ROI after taxes, to represent the typical return on investments experienced by refiners. A key part of illustrating this step is a summary of the cost inputs for the various benzene control technologies. We also describe how the four benzene control strategies were prioritized to meet the various benzene control standards. This provides us a cost estimate as if the program were taking effect in 2003

Finally, we adjusted the cost results from 2003 to 2010 based on the projected increase in volume between those two years.[a] EIA projects gasoline demand for 2010 to be 15 percent greater over 2003.[7] Aggregate total costs are increased by 15 percent to reflect this increased volume. Capital costs are also adjusted higher but by only 9 percent which takes into account the economies of scale of larger capital investments.

9.1.3.1 Individual Refinery Gasoline Blendstock Volumes

Information on the volumes of each gasoline blendstock contained in each refinery's gasoline is not publicly available, so it was necessary to estimate them. This is accomplished by adjusting published refinery unit capacity information to estimate the extent that each refinery unit is utilized followed by a unit-specific analysis for estimating how each refinery unit produces material for blending into gasoline. After the unit-by-unit estimates are completed, we do an overall check by comparing our estimated gasoline volumes with actual gasoline volume. We force the estimated gasoline volumes to match the actual gasoline volume using a factor which adjusts the estimated gasoline volume of each refinery unit.

The Oil and Gas Journal publishes, and the Energy Information Administration reports, unit capacities for the principal refinery units for each refinery in the U.S.[8] [9] Information from these two sources was reviewed for the year 2003, the base year for the cost model, and the information judged best overall from the two sources was entered into the refinery-by-refinery cost model. This information was used as a first step in the process to estimate the volumetric contribution of each of the gasoline producing units, including coking, fluidized catalytic cracking (FCC), hydrocracking, alkylation, dimersol, polymerization, isomerization, reforming and aromatics extraction.

An initial assumption was made that each unit is being operated at the percent of capacity available for that group of refineries based on the basecase conditions in the LP refinery model. The initial assumptions of the percent of capacity utilization that each unit is estimated to be operating by the LP refinery model at is presented in Table 9.1-3.

[a] For the final rule, the costs will be adjusted to the represent the costs in the year that the benzene control program is projected to start.

Table 9.1-3. Initial Percent of Refinery Unit Capacity used in Refinery-by-Refinery Cost Model

	PADD 1	PADD 2	PADD 3	PADD 4 & 5 Outside of CA	CA
Crude	101	100	96	92	101
Coking	89	134	76	90	96
FCC	106	104	94	96	89
Hydrocracker	100	101	80	111	96
Isomerization	89	75	83	102	100
Polymerization	120	117	0	46	0
Alkylation	113	100	96	98	96
Reforming	88	84	82	73	81
Aromatics	53	62	77	0	0

The estimates of refinery unit capacity utilized in Table 9.1-3 are a product of how the LP refinery model models the use of refinery units in each PADD of refineries. Normally, we would expect refinery unit utilization to be 80 to 95 percent of listed capacity. For some units this is the case, but for many of the units this is not the case. There are two reasons for this. First, listed refinery unit capacity can be wrong. For past refinery modeling efforts, we have compared the listed unit capacity for specific refinery units between EIA and the Oil and Gas Journal and have seen significant differences between the two sources. We have no idea which source is right, or if either of the sources is right. The second reason why there may be a discrepancy is because LP refinery models attempt to model PADDs of refineries based on average operating characteristics, which can vary substantially between refineries, and can vary between PADDs based on regional differences in how the units are being operated. If such average operating characteristics are not capturing the refining characteristics adequately, then this could lead to over and underestimating refinery unit utilization. Since a number of the average operating characteristics are taken from the LP refinery model, we chose to use the LP refinery model's estimated refinery utilization factors to be internally consistent.

Estimating refinery unit capacity and utilization of that capacity may or may not translate directly into the gasoline blendstock volume produced by a specific refinery unit because some of the refinery units produce more than one refinery product or they may affect the density of the feedstock to that unit. How the refinery unit capacity and its utilization are used to estimate gasoline blendstock volume is described in detail for each major refinery unit.

For the polymerization and alkylation units listed in Table 9.1-3, the actual capacity of the unit coupled with its estimated utilization does establish the initial volume of gasoline blendstock volume produced by those units. For example, a particular refinery unit in PADD 1 might have a 10,000 barrel per day alkylation unit. Table 9.1-3 shows that the alkylation units in

PADD 1 are estimated to be operating at 113 percent of its listed capacity, thus, alkylate production is 11,300 barrels per day.

Other gasoline blendstocks require additional steps to estimate their volumes, including light straight run naphtha, FCC naphtha, coker naphtha and hydrocrackate. Each of these other gasoline blendstocks are produced based on a portion of the unit capacities for the units used to produce them. To illustrate the methodology used to estimate the volumes, we will use light straight run naphtha as an example. Light straight run naphtha is principally comprised of five carbon hydrocarbons which come directly from crude oil. Thus to model the volume of the light straight run naphtha, it was necessary to estimate the volume of crude oil as well as the percentage that light straight naphtha comprises of crude oil. The Oil and Gas Journal contains reported capacities of the atmospheric crude oil towers for each refinery. The reported crude oil tower capacity is adjusted using the percent of unit utilization estimates for the crude unit contained in Table 9.1-3 applying the same adjustment to each refinery in each PADD. These calculations provided us an estimate of the volume of crude oil processed by each refinery. The fraction of light straight run naphtha in each refinery's crude oil was estimated from the percentage that light straight run comprises of crude oil for each PADD in the LP refinery model. This percentage is based on the types and quality of crude oil processed by all the refineries in each PADD – information obtained from the Energy Information Administration.[10] The percentage that light straight run naphtha comprises of crude oil is applied to each refinery in the refinery-by-refinery cost model. As summarized below in Table 9.1-4, the volume of light straight run naphtha is estimated to be 3 to 5 percent of the crude oil volume processed depending on the PADD.

Light straight run has three possible different fates depending on the refinery. Except for PADD 1, a portion is designated to be sold into the petrochemicals market. For PADDs 2-5, although primarily in PADD 3, a portion of straight run naphtha is processed and sold to petrochemical companies which use the material to make other hydrocarbon compounds. EIA publishes the volume of naphtha which is sold into the petrochemicals market in each PADD.[11] Since no source of information is publicly available that specifies the volume of naphtha sold by each refinery to the petrochemicals market, the volume of light straight run naphtha sold into the petrochemicals market by each refinery was assumed to be proportional to the percentage that its crude oil processing capacity comprises of the total crude oil processing capacity in the PADD. After accounting for the volume of light straight run naphtha sold to the petrochemicals market, the balance of straight run naphtha is blended directly into gasoline for those refineries without an isomerization unit. For refineries with an isomerization unit, the volume of light straight naphtha not sent to the petrochemicals market is sent to the isomerization unit up to the capacity of that unit, and the balance is blended directly into gasoline.

The hydrocracker and coker units produce some light naphtha material which plays a role in blending up gasoline. The light naphtha material produced by the hydrocracker and coker are termed light hydrocrackate and light coker naphtha, respectively. The portion of the material processed by each of these units converted to light coker naphtha and light hydrocrackate is 5 percent for coker units across all the PADDs, and ranges from 21 to 29 percent for hydrocracker units depending on the PADD. Table 9.1-4 below summarizes the percentage of total material processed by these units into light naphtha.

The volume of isomerate, the product produced by the isomerization unit, is based on the feed of to the isomerization unit up to its capacity. As described above, the volume of light straight run is estimated and that volume which is not assumed to be sold into the petrochemical markets to assumed to be sent to the isomerization unit. An additional source of feed to the isomerization unit, as described below, is a portion of the six carbon hydrocarbons which is estimated in the basecase to be sent to the isomerization unit to calibrate a refinery's benzene levels. This is one of the strategies used by refiners to reduce their benzene levels today, although in a limited way since the refinery-by-refinery model estimates that only 12 refineries in the U.S. are sending their six carbon hydrocarbons to the isomerization unit. The six carbon hydrocarbons have priority to the light straight run which is sent to the isomerization unit. In all cases, the volume of isomerate produced by isomerization units is estimated to be 1.6 volume percent less than its feed.

The volume of reformate was estimated based on the feed to the unit as limited by each unit's capacity. The feed to the reformer comes from various sources depending on the refinery configuration. For virtually all refineries, part of the naphtha from the atmospheric crude tower is sent to the reformer. Those refineries with a hydrocracker or a coker will send part of the naphtha from these units to the reformer as well. The naphtha sent to the reformer from these various units is that portion that is heavier than the light naphtha which is either sent to the isomerization unit or blended directly to gasoline. This reformate feed naphtha contains the six, seven, eight and usually the nine carbon compounds from these various sources. In some cases, the six carbon compounds are separated from the rest of the reformate feedstock to reduce the benzene in the final reformate. As discussed above, this rerouted six carbon stream is either blended directly into gasoline or is sent to the isomerization unit for further benzene control. The volume of the feed to the reformer is estimated on a PADD basis and is based on fractions of the material processed in the atmospheric crude tower, hydrocracker and coker.

The fraction of crude oil that is fed to the reformer ranges from about 13 to 16 percent depending on the PADD. About 18 percent of the material processed in the coker unit is estimated to end up as feedstock to the reformer. Of the feed processed in the hydrocracker, a range of 40 to 80 percent is estimated to end up as feed to the reformer unit, depending on the PADD. The variance in the fraction of hydrocracker material sent to the reformer is due to the significant flexibility that the hydrocracker has for producing either gasoline or diesel fuel. In certain PADDs, such as PADD 4 and 5, there is a higher relative demand for diesel fuel compared to gasoline so there is a lower conversion to naphtha than in other PADDs. The product from the reformer experiences a volume decrease of about 22 percent relative to the volume of feed due to the conversion of straight chain hydrocarbons to energy dense aromatics and other light products. This volume shrinkage and conversion to lighter products increases with the severity and thus the conversion of the reformer unit. All the refineries in each PADD are assumed to be operating their reformers at the same severity as estimated by the LP refinery model. The severity of reformer operations for California refineries is estimated to be a very low 93 research octane number (RON)[b] reflecting the stringent benzene and aromatics standards

[b] The severity of reformers is measured by the research octane number (RON) of its product. RON together with motor octane number (MON) makes up the total octane ((R+M)/2) of any gasoline blendstock or the gasoline pool.

which apply there. For the rest of the PADDs, the reformer severity falls within a narrow range of 99 to 100 RON.

The FCC unit contributes a substantial volume to gasoline. We estimated the utilization of each refinery FCC unit by adjusting the nameplate capacity of each unit using the utilization factors listed in Table 9.1-3. Like a number of other gasoline producing units, only a portion of the feedstock of the FCC unit is converted to naphtha. Again, we used PADD-average estimates used in the LP refinery model for estimating the portion of the FCC feed volume converted to naphtha. The conversion percentage to naphtha is affected by the conversion severity of the individual unit. The PADD-average conversion severity is estimated to be fairly consistent across the PADDs, so the portion of FCC feedstock converted to naphtha is quite consistent at about 56 percent.

Some gasoline blendstocks are purchased and blended directly into gasoline. The typically purchased gasoline blendstocks include natural gasoline, alkylate, and oxygenates. We did not have information on the volume of these gasoline blendstocks purchased and blended into gasoline by each refinery, so we again relied on the information from EIA which reports the consumption of these blendstocks on a PADD basis. We assumed that each refinery in the PADD purchased a portion of the total amount of gasoline blendstocks purchased in that PADD in proportion to that refinery's crude oil consumption within the PADD.

Another impact on gasoline volume is the volume of aromatics extracted from gasoline. Refiners extract aromatics to comply with the RFG toxics standards and also to take advantage of the higher price of aromatics, such as xylene and benzene, earns over the price of gasoline. The volume of aromatics, including benzene, extracted from gasoline was initially based on the nameplate capacity of each refinery's extraction unit listed in the Oil and Gas Journal. Unlike other refinery units, the extraction unit capacity is based on the volume of aromatics produced instead of the unit's feed volume. This production volume is estimated based on the unit capacity and aromatics plant utilization estimated by the LP refinery model as summarized in Table 9.1-3. This strategy was effective for the refineries in PADD 2 because it resulted in estimated gasoline benzene levels which closely matched the actual benzene levels for those refineries. However, this method was ineffective at matching the level of benzene for individual refineries in PADDs 1 and 3. One reason why the calibration method did not work so well for the extraction units in PADDs 1 and 3 is because a number of the refiners there are likely purchasing reformate for other refineries and processing them in their extraction units. For those PADDs, the degree to which their extraction units were being utilized was based solely on the need to calibrate each refinery's benzene levels to match year 2003 benzene levels. Each extraction unit had sufficient capacity to supply the needed extraction estimated, and when averaged across each PADD, this method did match the LP refinery model's estimated PADD utilization for extractions units reasonably well.

The various assumptions associated with estimating gasoline blendstocks and the volumes of purchased and sold blendstocks are summarized in Table 9.1-4.

Table 9.1-4. Information used with Refinery-by-Refinery Cost Model (2003)

		PADD 1	PADD 2	PADD 3	PADDs 4, 5	CA
Hydrogen Cost ($/foeb)		66.3	75.6	63.8	56.6	65.2
Octane Cost ($/oct-bbl)		0.21	0.21	0.18	0.48	0.73
Gasoline Price ($/bbl)		31.0	32.7	29.2	32.7	37.2
Light Straight Run Naphtha (% of Crude Oil)		4.5	5.0	4.0	4.5	3.0
Medium and Heavy Straight Run Naphtha (% of Crude Oil)		13.7	16.2	13.4	13.5	9.4
Reformate Severity (RON)		99	100	100	100	93
Average Reformate Yield (vol%)		78	77.5	77.5	76	82
Light Coker Naphtha (% of Unit feed)		5	5	5	5	5
Medium and Heavy Coker Naphtha (% of Unit Feed)		18.4	18.4	18.4	18.4	18.4
Light Hydrocrackate (% of Unit feed)		28.5	28.5	26.3	20.5	20.5
Medium and Heavy Hydrocrackate (% of unit feed)		79	79	69	40.5	40.5
FCC Naphtha (% of feed)		56.3	56.6	56.8	56.4	56.4
Aromatics (% of Unit Capacity)		As necessary	0.62	As necessary	-	-
Inputs	Alkylate Purchased (Kbbl/d)	0	0	0	0	40
	Natural Gasoline (Kbbl/d)	0	37	69	37	0
	Ethanol (Kbbl/d)	0	79	0	8	8
Outputs	Naphtha to Petrochem. (Kbbl/d)	0	6	119	4	4
	Gasoline Blendstocks Kbbl/d)	0	0	52	8	8

9.1.3.2 Refinery Blendstock Benzene Levels

It is necessary to estimate the benzene levels of individual gasoline blendstocks to model the benzene levels of gasoline today and for estimating the benzene levels attainable by additions of benzene control technology. The benzene levels of individual gasoline blendstocks for each refinery were also not available so they were they were estimated using the average benzene levels in the LP refinery model. The benzene level of reformate was estimated using average reformate benzene levels adjusted for the PADD-average severity and also adjusted by the benzene characteristics of the type of reformer. As the severity of the reformer increases, it produces a greater concentration of benzene in reformate. The Oil and Gas Journal contains information on the type of reformer for each refinery in the U.S. The types of reformers are semi-regenerative (semi-regen) reformers, cyclical reformers, and continuous reformers. Semi-regen reformers operate the highest pressure of the three and as a result this type of reformer tends to crack more of the higher molecular weight aromatics to benzene, resulting in a higher benzene level in reformate. The second type of reformer is the cyclical reformer which operates at a lower pressure than semi-regen reformers, and therefore causes less cracking of heavier aromatic compounds to benzene. Continuous reformers are the lowest pressure reformers and as a result cause relatively little cracking of heavier aromatic compounds to benzene. The benzene level of heavy reformate varies based on presence of the heaviest portion of straight run naphtha, which are the nine carbon compounds. Depending on the refinery, the nine carbon hydrocarbons in straight run is either sent to the reformer, or is blended into jet fuel or diesel fuel. The inclusion of the nine carbon hydrocarbons in reformer feed depends on the gasoline volume calibration as described below. The inclusion of the nine carbon hydrocarbons in the feed to the reformer tends to lower the concentration of benzene in the heavy part of reformate. The

assigned benzene content of gasoline blendstocks, including reformate, is summarized in Table 9.1-5.

Table 9.1-5. Estimated Benzene Content of Gasoline Blendstocks

	PADDs 1 – 5 including CA
Light Straight Run	1.10
Light Coker Naphtha	2.0
Light Naphtha (rerouted benzene precursors)	8.10
Natural Gasoline	1.30
Hydrocrackate	2.40
Alkylate	0.05
FCC Naphtha	0.80
Isomerate	0.20
Ethanol	0.05
Light Reformate (no benzene precursor rerouting)	10.8
Light Reformate (with complete benzene precursor rerouting)	1.00
Light Reformate (with benzene extraction)	0.10
Light Reformate (with benzene saturation)	0.44
Heavy Reformate – Semi-Regen (High Press.) Cyclical (Medium Press.) Continuous (Low Press.)	1.9-2.4 1.75-2.2 0.87-1.1
Heavy Reformate – High Press. (with benzene Medium Press. Extraction) Low Press.	0.02 0.02 0.01
Heavy Reformate – High Press. (with benzene Medium Press. Saturation) Low Press	0.075-0.095 0.07-0.09 0.035-0.04

9.1.3.3 Calibration of the Refinery-by-Refinery Cost Model

The gasoline volume and benzene levels in the refinery-by-refinery cost model were calibrated against actual gasoline volume and benzene levels. Refiners report their conventional and reformulated gasoline volumes and benzene levels to EPA to comply with the reporting provisions of the Reformulated Gasoline program. The 2003 gasoline quality was used for calibrating the refinery model, which is consistent with the baseyear of the refinery-by-refinery cost model. However, we could not begin to estimate how the various gasoline blendstocks were used to blend up RFG and CG for those refineries which produce both, so we aggregated them together for each refinery and calibrated both the gasoline volume and benzene levels for each refinery's entire gasoline pool. Also, since most of the information used to develop the refinery-by-refinery cost model was from summertime refinery modeling runs from the LP refinery model, summertime gasoline volumes and benzene levels were used to calibrate the refinery-by-refinery cost model.

Two different adjustments were used to calibrate the gasoline volumes in the refinery-by-refinery cost model. The first adjustment increased or decreased the utilization of each gasoline producing unit to adjust the gasoline volume higher or lower, respectively. The second adjustment factor is applied when the gasoline volume is too high and it is used to reduce the amount of nine carbon straight run naphtha processed by the reformer. The default in the

refinery model is that the nine carbon straight run naphtha is being sent to the reformer unit. Therefore, if the initial gasoline volume in the refinery-by-refinery cost model is higher than actual, adjustment factors are applied to decrease the utilization of each gasoline-producing unit and reduce the volume of nine carbon feedstock sent to the reformer unit, thus adjusting each refinery's estimated volume in the refinery-by-refinery cost model to equal the actual gasoline volume.

To show the effects of these volumetric calibrations on the PADD volumes, the calibrated crude oil consumption feed and the gasoline production volumes for each PADD are summarized in Table 9.1-6.

Table 9.1-6. Calibrated Consumption and Production volumes for Crude Oil and Gasoline by PADD (kbbl/day)

	PADD 1	**PADD 2**	**PADD 3**	**PADDs 4, 5**	**CA**
Crude Oil Consumed (Kbbl/d)	1489	3227	6880	1228	1858
Gasoline Produced (Kbbl/d)	1017	1805	3389	536	1083

The initial summertime benzene level of each refinery's gasoline estimated with the refinery-by-refinery model was also calibrated against the reported benzene content of summertime gasoline in 2003 from the RFG database. Unlike the straightforward adjustment used for calibrating gasoline volume, adjusting each refinery's benzene level required one or more of a series of different methods depending on the level of adjustment needed, the direction of the adjustment and the processing units in each refinery. If the benzene level for a refinery in the refinery-by-refinery cost model is higher than actual, and that refinery did not have a benzene extraction nor a benzene saturation unit, then an adjustment was made to bypass benzene precursors around the reformer. This is a likely strategy being employed today at refineries producing RFG. However, we are aware that some conventional gasoline- producing refineries are also using benzene precursor rerouting to comply with MSAT1. We therefore utilized this strategy to calibrate the benzene levels for refineries producing either RFG or conventional gasoline. If routing all the benzene precursors around the reformer did not lower the refinery benzene level sufficiently to match the actual benzene level, then an additional step was taken depending on the refinery. Refineries with isomerization units are assumed to route the rerouted benzene precursor stream to that unit to the extent necessary to reduce the benzene down to the actual level. The benzene levels of refineries without isomerization units are adjusted lower by applying an adjustment factor to straight run and FCC naphtha benzene levels, thus lowering the benzene content of each of these streams until the actual benzene level is achieved. If a refinery had a benzene saturation or extraction unit and its benzene level is too high, the straight run and FCC naphtha levels were adjusted lower until the actual benzene level is achieved.

If a refinery's initial benzene level in the refinery-by-refinery model is too low when compared to its 2003 actual benzene level, two different adjustments were made depending on

the refinery's configuration. For a refinery without a benzene saturation unit or a benzene extraction unit, its benzene level is adjusted higher by adjusting the straight run and FCC naphtha benzene levels higher until the refinery's gasoline benzene level matched its actual benzene level. For a refinery with a benzene saturation unit or a benzene extraction unit, its gasoline benzene level is adjusted higher by reducing the utilization of its benzene saturation or its extraction unit until its refinery gasoline benzene level matched its actual benzene level.

9.2 Cost Inputs for Benzene Control Technologies

To estimate the cost of reducing refinery benzene levels, it was necessary to identify the cost inputs of the identified benzene control technologies. This information was obtained from vendors of these benzene control technologies. Information was obtained for routing benzene precursors around the reformer, routing that rerouted benzene precursor stream to an isomerization unit, installing two technologies for benzene saturation, and installing benzene extraction.

9.2.1 Benzene Precursor Rerouting

Routing benzene precursors around the reformer requires that the refinery's naphtha splitter distillation column make a distillation separation between the six carbon and seven carbon hydrocarbons. As discussed in the RIA Section 6.2 above presenting our assessment of the feasibility of complying with this rulemaking, in a refinery where most of the benzene precursors are not currently being routed around the reformer, the naphtha splitter would need to be modified to be able to make a fairly clean cut between the six and seven carbon molecules. Making this cut efficiently is important in separating as much of the six carbon compounds (which include benzene) from the rest of the heavy straight run naphtha as possible, so that the seven carbon and heavier straight run hydrocarbons can continue to be sent to the reformer. Modifying the naphtha splitter distillation column involves increasing the height of the existing column and adding additional distillation trays or replacing the distillation tower with a taller unit. The naphtha splitter modification would also mean that the utility demands of that unit would increase. Conversely, the utility demands of the reformer decreases as the six carbon compounds are withdrawn from that unit. The estimated capital cost and increased utility costs for modifying the naphtha splitter to facilitate routing benzene precursors around the reformer is summarized in Table 9.2-1.[12] We also summarized the utility demands of the reformer in Table 9.2-2 because this information is used to calculate the reduced utility demands when the benzene precursors are withdrawn from that unit.[13]

Table 9.2-1. Cost Inputs for Rerouting Benzene Precursors

Capital Costs – onsite and offsite[c] ($MM)	7.3
Capital Cost Unit Size (bbl/day feedstock)	15,000
Natural Gas (foeb/bbl)	0.010
Electricity (kwh/bbl)	2.80

Table 9.2-2. Cost Inputs and Light Gas Outputs for the Reformer (Severity 100 RON)

Catalyst Cost ($/bbl)	0.357
Fuel Gas (foeb/bbl)	0.049
Electricity (kwh/bbl)	2.6
Steam (lb/bbl)	75
Hydrogen (foeb/bbl feed)	0.048
Plant Gas (foeb/bbl feed)	0.062
Propane (bbl/bbl feed)	0.061
Isobutane (bbl/bbl feed)	0.021
Butane (bbl/bbl feed)	0.036

9.2.2 Isomerizing Rerouted Benzene Precursors

Sending the rerouted benzene precursors to an existing isomerization unit is another technology identified for further reducing gasoline benzene levels. The rerouted benzene precursor stream contains naturally occurring benzene from crude oil. The isomerization unit saturates the benzene in this stream, causing a further reduction in gasoline benzene levels. The saturation occurs in the isomerization reactor which is designed to convert straight chain compounds to branched chain compounds. So while the isomerization unit reduces the octane of this stream by saturating benzene, it also increases the octane by producing branched chain compounds. The isomerized six carbon stream is estimated to have an octane value of 77.4 (R+M)/2. Many refineries have isomerization units today and for this analysis, refiners are assumed to only rely on these existing units at their present capacity for benzene control and not build a new isomerization unit nor increase an existing unit's capacity.[d] In this analysis the rerouted benzene precursors are sent to the isomerization unit which has been treating five carbon hydrocarbons. If the isomerization unit does not have sufficient capacity to treat the volume of both the five and six carbon hydrocarbons, the preference is given to benzene reduction and treating the six carbon hydrocarbons, and the five carbon hydrocarbons are removed as necessary to make room for the six carbon hydrocarbons. Therefore, for some

[c] Onsite costs are for the primary unit including the distillation column, heat exchangers, pumps, heaters, piping, valves and instrumentation. Offsite costs are for administration and control buildings, cooling tower, electrical substation and switchgear, water and waste treatment facilities, feedstock and product storage and loading and offloading, spare equipment kept onsite and catalysts. Normally refiners estimate offsite costs for each project which can vary from zero to a factor several times greater than the onsite costs. For national fuel control programs, cost estimation is averaged and a factor is used to indicate the fraction that offsite costs comprise of onsite costs. This factor is applied for all the technologies requiring capital investment and is expressed as a single onsite and offsite capital cost estimate.

[d] Isomerizing straight run naphtha increases its vapor pressure. Many refiners today are vapor pressure limited and face having to substantially cut its gasoline production volume if its gasoline were to increase in vapor pressure. Since we do not know which refineries are in this situation, we assume that additional isomerization capacity beyond that already present in the refinery would not be tolerated.

refineries the increased utility costs for treating the rerouted benzene precursors is based on the capacity of the isomerization unit instead of the total volume of five and six carbons hydrocarbons fed to the unit, since some of the five carbon hydrocarbons are backed out of the unit. Table 9.2-3 shows cost figures used in modeling isomerization of rerouted benzene precursors.[14]

Table 9.2-3. Cost Inputs for Sending the Rerouted Benzene Precursors to an Isomerization Unit

Hydrogen (foeb/bbl)	0.002
Natural Gas (foeb/bbl)	0.009
Electricity (kwh/bbl)	0.90
Steam (lb/bbl)	50

9.2.3 Benzene Saturation

Benzene saturation is another technology which reduces the benzene content of gasoline. The advantage that benzene saturation has for benzene reduction is that it treats the naturally occurring benzene as well as the benzene formed in the reformer. The benzene formed in the reformer includes the benzene formed from the cracking of heavy aromatics as well as that formed by the conversion of six carbon hydrocarbons. The benzene saturation technology involves the addition of a distillation column called a reformate splitter and then a benzene saturation unit.

The distillation column creates a benzene rich stream which prevents other aromatics, such as toluene, from being sent to the benzene saturation unit. Keeping the toluene and xylenes out of the benzene saturation unit preserves the octane level of the seven carbon and heavier reformate. Based on information we received from vendors who are experts on benzene saturation technology, the reformate splitter is typically optimized to capture 96% of the benzene, while only capturing 1% of the toluene. We programmed our refinery-by-refinery cost model so that the reformate splitter captures benzene and toluene consistent with this information. For those refineries estimated to be currently routing some or all of the benzene precursors around the reformer, for modeling the cost of benzene saturation, those benzene precursors are sent to the reformer before the costs of applying benzene saturation are estimated.

The benzene-rich stream is sent to the benzene saturation unit. In the benzene saturation reactor, hydrogen is reacted with benzene which converts the benzene to cyclohexane. There are two benzene saturation technologies. One is called Bensat and is licensed by UOP. This technology maintains the reformate splitter and benzene saturation units as separate discrete units. The other benzene saturation technology is licensed by CDTech and is called CDHydro. The CDHydro technology combines the distillation column and benzene saturation reactor together into a single unit. The advantage of this approach is that it eliminates the need for the second unit, lowering the capital costs. A review of the capital cost inputs of the two benzene saturation technologies confirms this. For both benzene saturation technologies, the capital costs are scaled using a 0.65 scaling factor which increases the per-barrel capital costs for smaller extraction units than the standard size, and decreases the per-barrel capital costs for larger

extraction units than the standard size. The capital and utility costs and scaling factor used for both Bensat and CDHydro are summarized in Table 9.2-4.[15] [16] [17]

Table 9.2-4. Cost Inputs for Benzene Saturation

Inputs	Bensat	CDHydro
Capital Cost – onsite and offsite ($MM)	10.9	8.7
Capital Cost Unit Size (bbl/day feedstock)	8,000	8,000
Capital Cost Scaling Factor	0.65	0.65
Hydrogen (foeb/bbl)	0.044	0.044
Natural Gas (foeb/bbl)	-	0.016
Electricity (kwh/bbl)	2.5	0.80
Steam (lb/bbl)	197	-

As discussed below in the summary of costs, benzene saturation is the highest cost benzene control technology modeled for this proposed rulemaking. The primary reason for this is that after processing the straight run naphtha in the reformer to create the benzene for blending into gasoline as high octane blendstock, this process converts it back to a low octane blendstock. The process is desirable from the standpoint that it achieves deeper benzene reductions and its cost is acceptable for larger refineries that can take advantage of their better economies of scale.

9.2.4 Benzene Extraction

Benzene extraction is the final benzene reduction technology used in our cost analysis for estimating benzene control costs. Benzene extraction physically and chemically separates benzene from the rest of the hydrocarbons, and then concentrates the benzene into a form suitable for sale into the chemicals market. Since this process results in a benzene product stream which must be transported to a buyer, a refiner is unlikely to choose this technology unless there is economical access to a benzene market.

The first step involved in benzene extraction is the separation of a benzene rich stream from the rest of the reformate using a reformate splitter. To maximize the removal of benzene with this technology, any benzene precursor rerouting that is occurring in the basecase is eliminated prior to costing out this technology, allowing the removal of naturally occurring benzene. Not only does this further reduce the benzene in the final gasoline, it improves the cost effectiveness of benzene extraction by improving the economies of scale for the newly installed benzene extraction unit. The benzene-rich stream off the reformate splitter is sent to an extraction unit which separates the aromatic compounds from other hydrocarbons contained in the benzene-rich stream using a chemical extraction agent. While the intent is to have benzene as the only aromatic in the benzene-rich stream, in reality some toluene is also contained in that stream as well. For this reason, a very precise distillation step is conducted concurrently on the product that produces a pure chemical grade benzene product. The desire would be to send only benzene and no toluene to the benzene extraction unit, however, this would require an unreasonably large and expensive reformate splitter. Thus, we used the same assumption used for benzene saturation, which is that 96% of the benzene and 1% of the toluene is captured by the reformate splitter. The concentration process of benzene for the petrochemicals market also assumes the use of a clay treater.

The total capital costs for benzene extraction include the capital costs for the installation of a reformate splitter, a benzene extraction unit and the associated distillation hardware which concentrates the benzene, including a clay treater. The capital costs estimated for this proposed rule, assume that the extraction and distillation step occur in one step, which is called extractive distillation. For new benzene extraction units, additional capital costs are incurred for the installation of benzene storage and loading equipment. We developed an average capital cost for new and revamped extraction units to apply for all refineries eligible for extraction. The capital costs for new extraction units are scaled exponentially using a 0.65 scaling factor. The capital costs for revamped extraction units are not scaled which provides the same per-barrel capital costs regardless of the size of the expansion.[e] Utility costs are incurred for operating the various units. Table 9.2-5 contains the capital and utility cost inputs to the refinery-by-refinery cost model for benzene extraction.[18]

Table 9.2-5. Cost Inputs for Benzene Extraction

Capital Costs – onsite and offsite ($MM)	32.9
Capital Cost Unit Size* (bbl/day product)	2000
Capital Cost Scaling Factor	0.65
Natural Gas (foeb/bbl)	0
Electricity (kwh/bbl)	9.4
Steam (lb/bbl)	1271

* Capital Cost is based on the volume of benzene produced.

A refiner with an extraction unit in one of their refineries has informed us that they frequently extract the benzene from benzene-rich reformate streams provided by other U.S. refineries as well as streams from abroad. This helps offset the high capital costs associated with these units. Because of the high capital costs, other refiners are hesitant to install an extraction unit, but have sufficient octane production capacity to sell benzene-rich reformate to a neighboring refinery which does extract benzene. For our year 2003 basecase analysis, we have deduced that several refineries without an extraction unit or a benzene saturation unit, but with already very low benzene levels (which cannot be easily explained on other bases), are selling benzene-rich reformate to a neighboring refinery with an extraction unit. For modeling the cost of additional benzene control, we also assume that refineries which already have an extraction unit would process the benzene rich reformate of other refineries to comply with the proposed benzene control standard.

9.3 Other Inputs into the Refinery-by-Refinery Cost Model

[e] Typically, the capital costs for revamping an existing refinery unit are not scaled. They are not scaled because small expansions to existing refinery units require the redesign of only a part of an existing refinery unit to realize the usually small increase in production capacity. This is in contrast to very small grassroots units of the same volume as the expansion which requires the design and construction of every piece of equipment involved in the unit being designed. Thus the small grassroots unit needs to be scaled to capture the higher capital costs while the capital costs of revamps are estimated consistent with the per-barrel costs of a full sized unit.

A series of inputs are made to the refinery-by-refinery cost model which are necessary to conduct the cost modeling. These inputs are from various sources including published literature and from the LP refinery model.

As stated above, hydrogen is necessary to saturate the benzene in the isomerization reactor when the rerouted benzene precursors are sent there. Similarly, hydrogen is consumed when benzene is saturated in benzene saturation units. It is also necessary to assign a cost for the lost hydrogen production in the reformer when the benzene precursors are rerouted around the reformer. This lost hydrogen production or additional hydrogen consumption must be made up from somewhere. A price derived from the LP refinery model is assigned for the lost hydrogen production and/or that consumed for saturating benzene. The LP refinery estimates the cost for building new hydrogen plant capacity to provide more hydrogen. The cost for this hydrogen varies somewhat by the region of the country because the typical size of hydrogen plant usually built in each region varies, which affects the economies of scale for the installed capital. Hydrogen costs also tend to vary because the feedstocks to hydrogen plants, which is usually natural gas, also varies by region. To incorporate this variance in regional hydrogen costs, the hydrogen costs are estimated, and entered into the refinery-by-refinery cost model, by PADD. These hydrogen prices may be conservative as they do not consider the economies of scale of producing hydrogen from very large third party hydrogen producers. Conversely, these hydrogen costs may be optimistic as they were based on EIA energy price projections that are lower than today's energy prices; for example, crude oil prices are assumed to be $27 dollar per barrel.[19] Subsequent to this analysis, EIA has revised their energy forecasts upward.[20] These new forecasts will be incorporated into the FRM analysis.

Another input made to the refinery model is a cost factor used for estimating the cost of lost octane. When benzene precursors are routed around the reformer, when benzene is saturated in a benzene saturation unit, or when benzene is extracted from gasoline, the octane of the resulting gasoline is reduced. Similarly, when the rerouted benzene precursors are sent to the isomerization unit, the natural benzene from crude oil which is in that stream is saturated and the high octane of the benzene is lost. However, this resulting low octane stream is then treated in the isomerization unit which offsets some of the lost octane. For all these cases, the cost for the net octane loss is accounted for by assigning an octane-barrel cost to the octane change. The octane-barrel cost is from the LP refinery model which, like for hydrogen, estimates a cost for making up lost octane. There is a regional variance in the type of octane producing units, in the economies of scale for designing and constructing these units and in prices for purchased high octane blendstocks which results in differences in the cost for making up octane loss by PADD. To account for the regional variance in octane costs, octane barrel costs are estimated, and entered into the refinery-by-refinery cost model, by PADD.

Gasoline prices are also a necessary input into the refinery-by-refinery cost model to account for the effects by these various benzene control technologies on changes in gasoline volume. Extracting benzene from gasoline and selling the benzene into the chemicals market will result in a small reduction in gasoline produced by the refineries estimated to use this technology. When the benzene precursors are routed around the reformer, the reduction in feedstock to the reformer will increase gasoline supply. This is because the cracking and aromatization reactions which occur in the reformer reduces the hydrocarbon volume. To

account for the full cost of benzene control, it is necessary to account for the change in gasoline volume. This loss in gasoline volume supply is accounted for by multiplying the change in gasoline volume with the gasoline prices from EIA on a PADD basis.[21]

Utility costs are also an input into the refinery-by-refinery cost model. The benzene reduction technologies consume natural gas, electricity and steam which contribute to the total cost of using these technologies. The consumption of the utilities is converted to per-gallon costs using average cost factors for the individual utilities. The utility costs are from EIA and are represented on a PADD basis.

Another input into the cost model is a cost factor used for adjusting the installed capital costs depending on the PADD in which the capital is being installed. Installing capital in refineries has been shown to vary geographically depending on the region in which the refinery is located. This difference in cost is primarily due to differences in contractor costs used for installing the costs in each region. Installing capital is cheapest in PADD 3 (Gulf Coast), and most expensive in PADDs 4 and 5 with capital costs 40 percent higher than in PADD 3.

Table 9.3-1 summarizes the various cost factors used in the refinery-by-refinery cost model by PADD.

Table 9.3-1. Cost Factors by PADD

	PADD 1	PADD 2	PADD 3	PADDs 4 & 5
Hydrogen $/foeb	66.34	75.6	63.79	56.56
Octane $/octane-bbl	0.21	0.21	0.18	0.48
Wholesale Gasoline Price $/bbl	31.0	32.7	29.18	32.7
Natural Gas $/foeb	36.02	32.14	22.81	27.07
Electricity $/kw-hr	0.065	0.044	0.046	0.043
Capital Cost Adjustment Factors	1.25	1.15	1.00	1.40

Benzene which is generated by benzene extraction and sold into the chemicals market is an important output from the refinery-by-refinery cost model. The economics for benzene extraction is partially dependent on the revenue earned through the sale of chemical grade benzene. To understand the production and demand for benzene and the projected price of benzene, we purchased Chemical Market Associates Incorporated (CMAI) 2004 report entitled the World Benzene Analysis.[22] The CMAI report lists the benzene producers and consumers worldwide and analyzes the economics of benzene production.

Benzene is produced to sell into the chemicals market by 8 different types of benzene production processes. These include extraction from reformers and pyrolysis gasoline at refineries and petrochemical plants, selective toluene disproportionation, paraxylene coproduction, toluene hydrodealkylation and extraction from coke oven naphtha. Except for the production of benzene from coke ovens, the rest of the benzene is sourced from crude oil. The World and U.S. production volumes of benzene for 2002, the most recent year that complete information is available from the CMAI report, are summarized in Table 9.3-2.

Table 9.3-2. 2002 Benzene Supply by Source for U.S. and the World (thousand metric tons)

	Reformate	Pygas	Toluene Disprop.	Selective Toluene Disprop.	Paraxylene Coprod.	Toluene Hydrodealk	Coke Oven	Toluene Transalk.	Imports	Total
U.S.	3,527	2,086	149	810	529	317	163	0	929	8510
World	13,213	12,699	353	1171	1458	2202	1266	980	-	33,342

The benzene production figures show that extraction from reformate is currently a primary source of benzene in the U.S. and the rest of the world. This confirms that lowering gasoline benzene levels by extracting it from reformate and selling the concentrated benzene into the chemicals market is a viable way for reducing gasoline benzene levels. This information is used below as the basis for estimating the price impacts for benzene that would be extracted from gasoline to meet the proposed benzene control standard.

The chief uses for benzene are to use it as a feedstock to produce ethylbenzene, cumene, nitrobenzene, and cyclohexane. Ethylbenzene is used to produce styrene which is a precursor for producing polystyrene. Cumene is used to produce phenol and acetone. Benzene is also reacted to nitrobenzene which is an intermediate in the chain of reactions used for producing urethane. The World and U.S. consumption volumes of benzene by demand market for 2002, the most recent year that complete information is available from the CMAI report, are summarized in Table 9.3-3.

Table 9.3-3. 2002 Benzene Demand by Target Chemical for U.S. and the World (thousand metric tons)

	Ethyl-Benzene	Cumene	Nitrobenzene	Cyclohexane	Chloro-Benzene	Alkylbenzene	Maleic Anhyd.	Exports	Total
U.S.	4050	2291	752	964	131	144	0	27	8450
World	18,201	5872	2200	4257	585	1144	583	-	33,487

Additional information which is useful to consider when projecting the price of benzene is the historical benzene price and demand. Like all hydrocarbons sourced from crude oil, the price of benzene is susceptible to changes in crude oil and other energy prices which complicates the process of projecting the price of benzene. To diminish the effect that changes in energy prices have on benzene prices, we compared the price of benzene to the price of gasoline which would likely be affected in the same way by energy prices as benzene, thus reducing the effects of energy prices as a variable. The U.S. historical prices for benzene, gasoline and the difference between them for the four years prior to 2004 are summarized in Table 9.3-4.

Table 9.3-4. Historical U.S. Benzene Price

Year	Benzene Price ($/bbl)	Gasoline Price ($/bbl)	Benzene Price above Gasoline Price ($/bbl)
2000	57.75	34.99	22.76
2001	42.71	30.83	11.89
2002	49.98	30.28	19.70
2003	64.68	36.67	28.01

The price of benzene dropped in 2001 both absolutely and relative to the price of gasoline. This decrease in price is attributed to a decrease in demand associated with a recession experienced by the U.S. and other parts of the world. Since 2001 the price has tracked upward through 2003 consistent with increasing demand as the economies in recession have emerged from recession. Between 2001 and 2003, benzene demand increased by about 15 percent in the U.S., and about 10 percent for the whole world. This large increase in demand has tightened up the benzene market thus resulting in the increasing benzene price since 2001.

CMAI used its economic model to project the benzene market in the medium term during the future years from 2004 through 2008. CMAI starts by establishing a basecase which was based on the information on the benzene market in 2003. CMAI then projects the benzene market based on anticipated supply, demand and energy prices. The benzene supply which CMAI considers in its cost model includes existing benzene production capacity and announced and planned new benzene plant construction. The near future demand is estimated based on historical demand, the projected U.S. and world economic conditions, and on the anticipated changes in the chemical markets which use benzene as a feedstock. After conducting its benzene market review, CMAI made a series of conclusions. World benzene and U.S. benzene demand are expected to increase annually by 3.8 and 2.4 volume percent, respectively. Imports which satisfied just more than 10 percent of U.S. demand in 2003, is expected to be flat and even decline in the out years. CMAI explains that the robust world benzene demand coupled with new benzene production, which is expected to be slow coming on line, will result in higher benzene prices in 2004. As additional benzene production capacity comes on line, benzene prices are expected to come down to more traditional levels. The projected energy prices which CMAI uses in its economic model are nearly identical with those used by EIA thus making the two analyses consistent in this regard. Table 9.3-5 summarizes the projected benzene and gasoline prices obtained from the CMAI report.

Table 9.3-5. Projected U.S. Benzene Price

Year	Benzene Price ($/bbl)	Gasoline Price ($/bbl)	Benzene Price above Gasoline Price ($/bbl)
2004	73.3	35.2	38.1
2005	56.2	23.6	32.6
2006	50.1	31.3	18.8
2007	50.4	31.2	19.2
2008	51.2	31.8	19.4

The CMAI model estimates that the price of benzene in 2004 will be $38 higher than gasoline. As additional benzene production capacity comes on line, the benzene prices are expected to come down to just under $19 per barrel above gasoline, and then track upwards slightly. The projected prices for 2006 to 2008 are consistent with the historical price for benzene. To select the benzene price to use in our cost analyses, we considered CMAI's projected benzene price and that the benzene prices are trending upward slightly from 2006 to 2008. We therefore rounded the price of benzene to $20 per barrel higher than gasoline.

As we were conducting our cost analysis in 2004 for various possible air toxics control programs, we learned that benzene prices were significantly higher than the already high prices estimated by CMAI for 2004. Early in 2004, benzene prices were $40 to $50 per barrel higher than gasoline. We became concerned that using a benzene price which is $20 per barrel higher than gasoline might be too low. We decided to conduct a sensitivity analysis at the benzene price level estimated by CMAI for 2004, which is $38 per barrel higher than gasoline. Sometime during 2005 we found out from CMAI that benzene prices average over $70 per barrel higher than gasoline for 2004. Thus, even our sensitivity analysis may not bracket the range of benzene prices which could occur considering the very robust demand for benzene.

There may be a concern that the additional benzene that would be extracted from gasoline and sold into the chemical benzene market in response to this rulemaking could depress the benzene price below that projected by CMAI. To address this concern we used the projected volume of benzene extracted from gasoline by the refinery-by-refinery model to evaluate the impact of the additional benzene supply on benzene price. The refinery-by-refinery cost model projects that about 22,000 barrels per day, which is 337 million gallons per year, of benzene would be extracted from gasoline under the proposed benzene control program in 2011.

Table 9.3-3 above shows that the U.S. demand for chemical grade benzene in 2002 was 8450 metric tons, which is equivalent to 2529 million gallons. Based on an annual growth rate of 2.4 percent, the U.S. demand for benzene is expected to be 3,000 million gallons in 2010 and is expected to grow to 3,130 million gallons in 2011. Thus, the increase in U.S. benzene demand from 2010 to 2011 is projected to be 130 million gallons. We expect the extraction of benzene would occur over several years due to the effect of the ABT program. Therefore, the increased production of chemical grade benzene due to extraction would be smaller than the annual growth over the several years that the program phases in and no significant impact on benzene price would be expected. Even if all of the benzene extraction capacity were to be installed in a single

year resulting in all 337 million gallons of benzene coming into the benzene market in one year, the benzene production market could rebalance by the reduced processing of toluene into benzene. The toluene would remain in the gasoline pool helping to maintain the octane lost by benzene extraction. Finally, refining and petrochemical market experts who evaluated the effect of the benzene extraction expected to occur in response to the Reformulated Gasoline Program came to a similar conclusion despite the large volume of benzene extracted back then.[23] [24] For these reasons, we used the projected chemical benzene price of $20 per barrel higher than gasoline for our principal analysis, and $38 per barrel for our sensitivity analysis.

9.4 Refinery Modeling of Benzene Control Scenarios

For the proposed benzene control standard, the national ABT program optimizes the benzene reduction by allowing the refining industry to collectively choose the most cost-effective means of benzene reduction. In the refinery-by-refinery modeling, this is accomplished by ranking the benzene reduction technology available to each refinery and over all the refineries in order from lowest to highest in benzene reduction cost-effectiveness. Then refineries are chosen to implement benzene reduction refinery-by-refinery from the lowest to the next lowest in cost effectiveness until the sum of the technologies and refineries chosen results in the U.S. gasoline being produced averaging 0.62 volume percent benzene, giving credit to refineries already below the proposed benzene standard.

For the cases we modeled that involve a maximum-average (max-avg) standard in addition to an average benzene standard, modeling the costs for such cases requires a different modeling methodology. Refineries that the model estimates would be above the max-avg standard are assumed to put in the most cost-effective benzene reduction technology which the model shows them getting below the max-avg standard. The units that the model adds to meet the max-avg standard are assumed to be operated to achieve the maximum possible amount of benzene reduction. The benzene reductions associated with meeting the max-avg standard may or may not be sufficient for meeting the average standard depending on how stringent the max-avg standard is relative to the average standard. If additional benzene reduction is necessary, it is achieved in the cost model consistent with the methodology used to achieve benzene reductions under the average standard only.

For the benzene control cases we modeled that do not include an ABT program, all the refineries that are below the standard are assumed to maintain their current benzene level, while the refineries with benzene levels above the standard are assumed to take the necessary steps to reduce their benzene levels down to the standard. If the model shows that capital investments need to be made to achieve the necessary benzene reduction, a full sized unit is installed to treat the entire stream being treated, but that unit is only operated to the extent necessary to meet the applicable standard.

9.5 Evaluation of the Refinery-by-Refinery Cost Model

As described in the Overview Portion of this section, the refinery-by-refinery cost model was evaluated to assess its viability. This evaluation was conducted in two ways. The first way involved a comparison of the cost output of the refinery-by-refinery cost model with the cost

output of the LP refinery model for the same benzene control case. The second way was through a thorough a peer review process conducted by two refinery industry consulting firms.

We evaluated a stringent nationwide 0.5 volume percent benzene control standard with the LP refinery model that closely matched the 0.52 volume percent standard modeled with the refinery-by-refinery cost model.[f] As expected, the LP refinery cost model produced higher costs than the refinery-by-refinery cost model. The costs are expected to be higher because the LP refinery model inherently averages costs only across the refineries in each PADD, while the refinery-by-refinery cost model averages costs across the entire country through the national ABT program. The LP refinery model projects deeper benzene reductions in PADDs 4 and 5 than the refinery-by-refinery cost model, which results in higher estimated cost of compliance using the LP refinery model. Estimated costs of compliance for PADDs 1 and 3 are roughly the same under either model. Despite estimated benzene control levels which are identical between the two models for PADD 2, the LP refinery model estimates higher costs for PADD 2. Table 9.5-1 summarizes the cost output and estimated benzene levels for the two refinery modeling analyses.

Table 9.5-1. Comparison of PADD and National Costs and Benzene Levels for the 0.5 Volume Percent Benzene Control Case

		PADD 1	PADD 2	PADD 3	PADDs 4 & 5	U.S. Average
Refinery-by-Refinery Cost Model	Cost (cents/gal)	0.10	0.79	0.10	1.20	0.36
	Bz Level (vol%)	0.48	0.50	0.52	0.62	0.52
LP Refinery Cost Model	Cost (cents/gal)	0.13	1.05	0.07	1.75	0.49
	Bz Level (vol%)	0.50	0.50	0.50	0.50	0.50

Peer reviews on the refinery-by-refinery cost model were conducted by Jacobs Engineering and A Second Opinion.[25, 26] They both are refining industry consulting firms which also have consulted for EPA in the past. Both firms have conducted cost analyses on changes to fuel quality – Jacobs uses a refinery cost LP refinery model while A Second Opinion has used simpler cost estimation techniques. Based on the different experiences they each have in conducting cost analysis, each firm brings a different perspective to the peer review process.

As expected, both reviews agreed with aspects of the refinery modeling and took issue with other aspects. We believe that overall, the two reviews support the refinery-by-refinery cost model and accounting for their comments would not significantly affect the costs estimated by the refinery modeling. Both reviews found that the choices for benzene control technologies, including benzene precursor rerouting with and without isomerizing this stream, benzene saturation and benzene extraction, are sound choices for modeling the reduction in benzene levels. One reviewer found that the cost inputs for the various technologies were about right, while the other reviewer found that some costs differed from what they expect – both higher and lower than expected. Both reviewers thought, contrary to our modeling, that any benzene precursor rerouting assumed to be occurring in the basecase would continue in the control case

[f] We also evaluated a 0.65 benzene control standard with the LP refinery model, however, the choice of benzene control technologies differed which greatly complicated any comparison with the refinery-by-refinery cost model.

when benzene saturation is applied – removing this modeling method should reduce the cost of the program.

Both reviewers found that the calibration of each refinery's benzene level and gasoline volume to their actual levels and volumes is important for establishing a sound refinery-specific analysis, although one reviewer pointed to some anomalies in how a few specific refineries were calibrated. Some anomalies can be expected when attempting to calibrate individual refineries modeled using average gasoline blendstock production and quality information when their operations deviate significantly from the average. Thus, this is not unexpected.

One reviewer commented that using the next increment of octane cost from the LP refinery model might underestimate the cost of making up lost octane since several increments of octane might be necessary, and second and later increments of making up this lost octane could be more expensive. Our analysis of the octane made available from the Renewable Fuels standard mandated by EPAct reveals that the octane forced into the gasoline pool would make up for the octane loss from this proposed program several times over, and should ensure that many increments of octane recovery could be made available at about the same price.

One comment suggested using a scheme for projecting how refiners would choose a benzene control technology based much more heavily on the level of capital costs associated with each technology rather than on overall costs. The commenter suggested that since refiners are somewhat conservative when it comes to spending money on capital for their refineries, that this might be a better basis. Our analysis already values capital costs higher than other costs by assuming that refiners would choose their technology based on a 10 percent hurdle rate-of-return (ROI) after taxes, then we adjust the costs to a 7 percent ROI before taxes to report the costs. An even higher ROI assumption could be used to more highly value new capital investments.

In summary, the peer reviews generally supported the refinery-by-refinery cost model. We will use the comments to focus our review of the refinery-by-refinery cost model for the final rule on certain specific parts of the model. These include the cost inputs for the various technologies, the cost for octane recovery, and the means for estimating the benzene control technology that would be chosen by refiners, especially whether capital costs should play a larger role.

9.6 Refining Costs

This subsection summarizes the estimated costs of the proposed benzene control program as well as the other air toxics control standards considered for this proposed rulemaking. The estimated cost for the proposed 0.62 volume percent benzene standard with ABT program is summarized first, including the sensitivity cases described above. We next summarize the estimated cost for other variations of the 0.62 volume percent benzene standard which includes an average-maximum standard or which models a benzene control program without an ABT program. We then summarize the estimated costs for other benzene control standards that we considered. Finally we summarize the costs for several total air toxics standards and low RVP and sulfur control programs. Although we included California refineries in the modeling of the

proposed benzene control program, their participation and associated costs were minimal so we therefore are not reporting their costs in the following tables.

9.6.1 Cost of the Proposed 0.62 vol% Benzene Standard

The refinery-by-refinery cost model was used to estimate the cost of the proposed 0.62 volume percent average benzene standard under a nationwide ABT program. For each of the refineries which produce gasoline, the methodology described above was applied to estimate the cost of reducing the benzene levels. The projected use of the benzene control technologies in the refinery-by-refinery cost model is (naturally) affected by the nature of the stringency of the benzene reduction program being modeled. The cost model indicates that extraction is the most cost-effective technology followed by benzene precursor rerouting alone, or precursor rerouting coupled with isomerization. Benzene saturation is the least cost-effective benzene control technology, but as the benzene control stringency is increased, for reasons of technical feasibility benzene saturation replaces benzene precursor rerouting as the means for achieving benzene control. We assume that the ABT program would be fully utilized with credit trading occurring freely within and between refining companies.

The proposed 0.62 benzene standard with ABT program is estimated to cost 0.13 cents per gallon averaged over all gasoline and with capital costs amortized at 7% ROI before taxes. The total capital cost is $500 million, the total annual cost including amortized capital costs is $170 million/yr.

The 0.13 cents/gal average cost is calculated by amortizing the costs over all U.S. produced gasoline including that gasoline volume with benzene levels already at or below 0.62 volume percent. When the costs are averaged only over the portion of U.S gasoline which is expected to be reduced in benzene, the proposed program is expected to cost 0.20 cents per gallon. For those refineries which are projected to take some action to reduce their benzene levels, the average capital and total annual operating cost per refinery is $6 million and $1 million, respectively. These estimated costs for the proposed benzene standard are summarized in the Table 9.6-1.

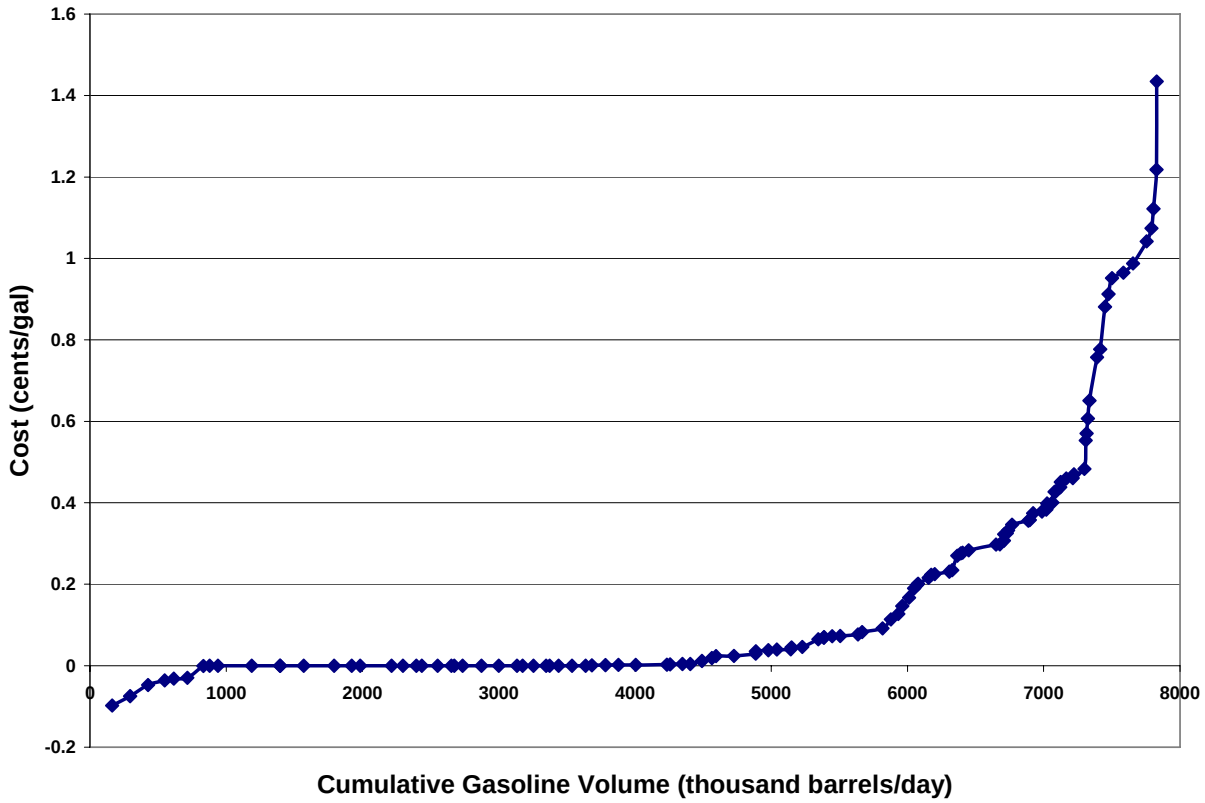
Table 9.6-1. Estimated Costs of the Proposed 0.62 vol% Average Benzene Standard with ABT Program
(2003 dollars, 7% ROI before taxes, benzene priced at $20/bbl higher than gasoline)

All Refineries	Number of Refineries	115
	Total Capital Cost ($ million)	500
	Total Annual Cost ($ million/yr)	170
	Per-Gallon Cost (cents/gallon)	0.13
Refineries Reducing Their Gasoline Benzene Levels	Number of Refineries	88
	Capital Cost per Refinery ($ million)	6
	Operating Cost per Refinery ($ million/yr)	1
	Per-Gallon Cost (cents/gal)	0.20

Reporting the average per-gallon costs in the above table does not provide any indication of the range in costs that we project would occur in different refineries. The costs vary by

refinery for a variety of reasons. First, some refineries experience no cost because either the gasoline produced by those refineries is already below the proposed standard, or our modeling shows that these refineries would experience lower costs by simply purchasing credits. Another reason why refineries are projected to experience differing costs is due to the range in technologies that they would use. The final reason why these refineries are projected to experience differing costs is due to the different refinery economies of scale and cost inputs in different refining regions. Figure 9.6-1 summarizes the projected per-gallon costs by refinery plotted against the cumulative volume of gasoline produced.

Figure 9.6-1. U.S. Refinery Per-Gallon Costs for the Proposed Benzene Control Program (2003 dollars, 7% ROI before Taxes, benzene priced $20/bbl higher than gasoline)



As discussed above, a sensitivity case was run assuming that the price of benzene remains high as it was estimated to be in 2004, at $38/ bbl higher than gasoline. In this case, the cost of the proposed benzene control program decreases to 0.05 cents per gallon. Sensitivity cases were also run for amortizing capital costs at 6 and 10 percent ROI after taxes. These result in per-gallon costs at 0.13 and 0.15 cents per gallon, respectfully. Table 9.6-2 summarizes the per-gallon costs of the ROI sensitivity cases of the proposed benzene control program.

Table 9.6-2. Alternative Capital Amortization Return on Investment (ROI) for the Proposed Benzene Control Program (benzene $20/bbl higher than gasoline)

Capital amortized at 6% ROI after taxes	Capital amortized at 10% ROI after taxes
0.13 cents/gal	0.15 cents/gal

To comply with the proposed benzene standard, we expect that all of the control technologies discussed above would be utilized. Of the 88 refineries expected to take steps to reduce their gasoline benzene levels, 54 are expected to route all of the benzene precursors around the reformer, and 28 of those are expected to send that rerouted stream to their isomerization unit. Of the refineries which take steps to lower their gasoline benzene levels by treating reformate, 23 would install benzene extraction units or revamp their existing extraction units while the other 11 would install benzene saturation units.

While the estimated per-gallon costs are very low, there is a range in costs depending on the area of the country. The estimated costs in PADDs 1 and 3 are lowest due to the expected use of extraction (with sale of the recovered benzene). The estimated benzene control costs are higher for rest of the PADDs because extraction is not an option due to lack of benzene markets. The average per-gallon benzene control costs for each PADD are summarized in Table 9.6-3.

Table 9.6-3. Per-Gallon Costs by PADD for the Proposed 0.62 vol% Benzene Control Program (cents/gal; 2003 dollars; 7% ROI before taxes; benzene priced $20/bbl higher than gasoline)

PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 except CA
0.05	0.25	0.05	0.40	0.72

In each PADD, the average costs in Table 9.6-3 represent a wide range in costs across the refineries in the PADD. However, the nature of the cost range varies in each PADD based on the factors described above. Figure 9.6-2 depicts the estimated per-gallon costs by refinery in each PADD plotted against the cumulative gasoline production.

Figure 9.6-2. U.S. Refinery Per-Gallon Costs by PADD for the Proposed Benzene Control Program (2003 dollars, 7% ROI before Taxes, benzene priced $20/bbl higher than gasoline)

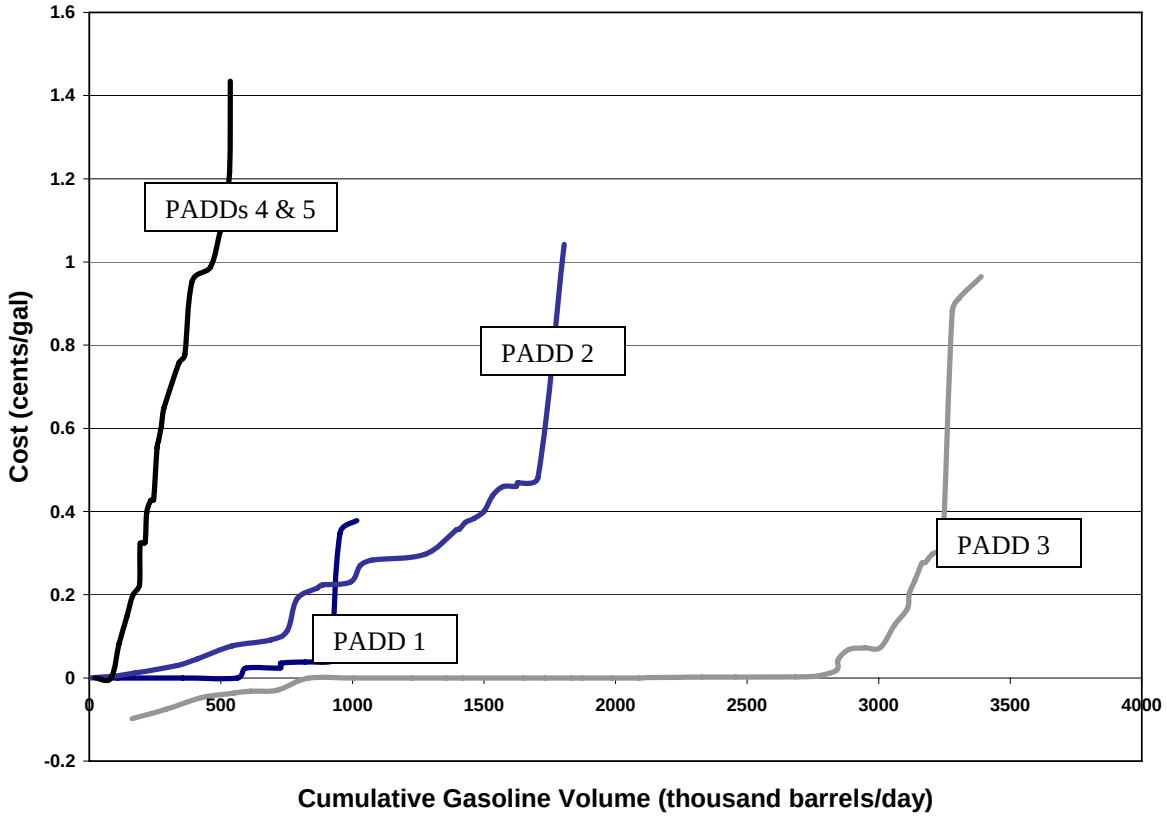


Figure 9.6-2 shows a significant range in costs by the refineries in each PADD. PADD 1 and 3 costs are similar with most costs being incurred through extraction which results in near zero (and in a few cases slightly less than zero) costs, as well as zero costs for refineries which do not need to take any action due to already low benzene levels. The refineries in PADDs 4 and 5 face higher costs, but what differentiates the costs in these two PADDs from the other PADDs is the consistently higher costs across the PADDs. The refinery costs in PADD 2 is more moderate for most of the refineries than those in PADDs 4 and 5, but still more severe than the costs for the refineries in PADDs 1 and 3.

We estimated the stream of total annual compliance costs for the U.S. refining industry complying with the proposed benzene control program from 2011 to 2035. We projected the estimated 2003 total annual program costs to 2011, the proposed start date of the program, using projected gasoline demand by the Energy Information Administration (EIA). The total annual costs for 2012 to 2035 are also projected using the projected growth in demand by EIA. Since the EIA projections end at 2025, we used the annual average growth rate over the years 2020 to 2025 to extrapolate the growth in demand to 2035. The stream of projected gasoline consumption volume and the total annual costs for complying with the proposed benzene control program are summarized in Table 9.6-4.

Table 9.6-4. Stream of Total Compliance Costs for the Proposed Benzene Control Program (2003 dollars, 7% ROI before Taxes, Benzene priced $20/bbl higher than gasoline)

Year	Gasoline Volume (million gallons)	Total Program Cost (million dollars)
2011	156,020	185.5
2012	158,694	188.7
2013	161,352	191.9
2014	164,069	195.1
2015	166,742	198.3
2016	169,230	201.2
2017	171,728	204.2
2018	174,128	207.1
2019	176,490	209.9
2020	178,787	212.6
2021	181,226	215.5
2022	183,780	218.5
2023	186,504	221.8
2024	189,540	225.4
2025	192,638	229.1
2026	195,787	232.8
2027	198,987	236.6
2028	202,239	240.5
2029	205,545	244.4
2030	208,905	248.4
2031	212,319	252.5
2032	215,790	256.6
2033	219,317	260.8
2034	222,901	265.1
2035	226,545	269.4

9.6.2 Cost of Alternative Benzene Control Programs

We used the refinery-by-refinery refinery model to estimate the cost of other potential benzene control standards. This includes analyses of benzene standards which are more and less stringent than the proposal as well as benzene control standards with and without ABT programs. We also evaluated some of these alternative benzene control standards with a second benzene control standard called a maximum-average, or max-avg standard (see Section 9.1.1 above).

Table 9.6-5 contains a summary of the national average per-gallon costs and aggregate capital and total annual costs for average benzene control standards which range from 0.52 to 0.73 and with and without ABT and maximum-average standards. The 0.52 average benzene control standard represents the most stringent benzene control standard technically feasible with maximum reformate control assuming that either benzene extraction or benzene saturation would be used. For comparison, we also modeled an average standard of 0.73 volume percent benzene, but without the full ABT program. Each refinery would have to average 0.73 volume percent benzene across its own gasoline batches with no ability to average or trade across refineries, or bank credits. This benzene control standard would result in a national average benzene level which would equal the proposed 0.62 volume percent benzene standard with full ABT – thus it is

an interesting case to study. The refinery model also estimates that a number of refineries might not be able achieve a tighter standard than this without additional benzene control technology beyond reformate benzene control. The refinery-by-refinery cost model projects that 5 refineries would not be able to achieve the 0.73 volume percent benzene standard based on reformate benzene control alone. All of these refineries could achieve the benzene control standard by either treating or reducing their assumed purchases of natural gasoline, a practice that the refiners operating these refineries would probably view as unacceptable.

Table 9.6-5. Cost of Other Benzene Control Standards
(2002 dollars, 7% ROI before taxes and benzene priced at $20/bbl above gasoline)

Average Benzene Std. (vol %)	ABT Program	Max-Avg Std. (vol %)	Actual In-Use Benzene Level (vol %)	Per-Gallon Cost (cents/gal)	Total Annual Cost ($ million/yr)	Aggregate Capital Cost ($ million)
0.52	Yes	None	0.52	0.36	490	875
0.60	Yes	1.3	0.60	0.16	215	610
0.60	Yes	None	0.60	0.15	210	540
0.62	Yes	1.3	0.62	0.13	180	590
0.62*	Yes	None	0.62	0.13	170	500
0.65	Yes	1.3	0.65	0.10	145	510
0.65	Yes	None	0.65	0.09	123	460
0.70	Yes	1.3	0.70	0.08	110	475
0.70	Yes	None	0.70	0.06	80	365
0.73	No	None**	0.62	0.25	340	660

* Proposed Rule
** The 0.73 volume percent benzene standard could also be thought of being an avg-max standard, because without an ABT program, each refinery would have to meet this level with actual production on an annual average basis.

The reduced flexibility of a max-avg benzene standard increases the cost of benzene control over a benzene control program without a max-avg standard. We estimate that the reduced flexibility forces some refiners to install a benzene saturation unit instead of routing the benzene precursors around the reformer or sending that rerouted stream to an isomerization unit and procuring credits to make up the remaining shortfall.

The 0.73 volume percent benzene control standard without the full ABT program, which results in the same national average gasoline benzene level as the proposed program, is estimated to cost almost two times more than the proposed program. Without any ABT program, this standard offers much less flexibility than the proposed benzene control program. The reason why the national average benzene level for the 0.73 volume percent benzene standard without an ABT program is 0.62 volume percent is that the many refineries with benzene levels below 0.62 volume percent benzene today are assumed to stay at their current levels in the future, which balances out the many refineries which are assumed to come down to 0.73 volume percent benzene in response to the benzene control standard. The lack of flexibility of this benzene control case results in a larger share of benzene reductions occurring through benzene saturation, a more expensive benzene control technology, in lieu of benzene reductions achieved from installing new or revamping existing benzene extraction units or benzene precursor rerouting with and without isomerization.

We plotted the per-gallon costs versus the cumulative volume of gasoline across the refineries producing gasoline for several benzene control programs of interest. Figure 9.6-3 shows the per-gallon costs for the proposed 0.62 volume percent benzene control program and a program with the same standard, but with the addition of a max-avg standard. We also included a plot of the 0.52 volume percent benzene control standard.

Figure 9.6-3.

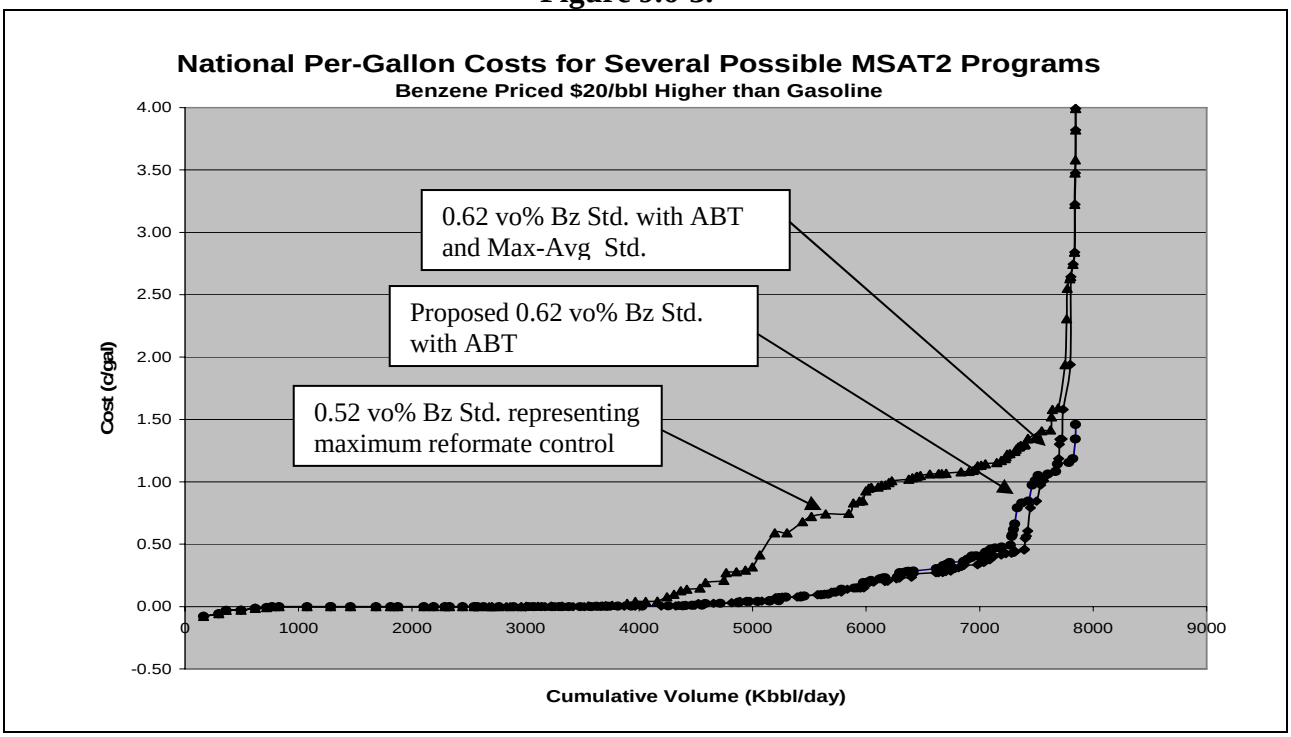


Figure 9.6-3 shows that for roughly half the volume of gasoline, the costs for benzene control are zero or near zero, and for a few extraction refineries even negative. The addition of the max-avg standard forces a small number of refineries to adopt a much more expensive benzene control strategy. Comparing the two programs, the proposed program would cause 9 refineries to exceed 1 cent per-gallon compliance cost compared to the benzene control program with a max-avg standard which would cause 16 refineries to exceed 1 cent per-gallon compliance cost. The 0.52 volume percent benzene standard is much more expensive in this regard causing about 50 refineries to exceed 1 cent per-gallon in compliance costs. The highest cost of compliance under the proposed program would be about 1.5 cents per-gallon, while under the benzene control program with the max-avg standard the highest cost of compliance would be about 4 cents per gallon (same for the 0.52 volume percent control standard).

Table 9.6-6 below summarizes the number refineries which install or adopt each of the four different types of benzene control technologies for:

- the proposed 0.62 volume percent benzene control program with ABT program,

- a 0.62 volume percent benzene control program with a 1.3 volume percent max-avg standard with ABT program, and

- a 0.73 volume percent benzene control standard without an ABT program which results in a 0.62 average benzene level in gasoline.

Table 9.6-6. Projected Number and Type of Benzene Control Technologies Installed for Different Benzene Control Programs

	Routing Benzene Precursors Around Reformer	Sending Rerouted Benzene Precursors to Isom Unit	New and Revamped Benzene Extraction Units	Benzene Saturation
Proposed 0.62 avg Bz std with ABT Program	26	28	23	11
0.62 vol% avg Bz std with 1.3 max-avg std and ABT program	20	28	23	16
0.73 avg Bz std, No ABT Program; 0.62 vol% in-use	7	16	17	45

Imposing a max-avg standard or eliminating the ABT program altogether reduces flexibility available to refiners and is projected to result in a different pattern of benzene reduction across the country. Refineries which find it economically advantageous to use the ABT program to realize only minor benzene reductions and purchase credits to show compliance with the average benzene standard are primarily located in PADD 2, PADD 4 and PADD 5. The refineries which generate credits under the ABT program are primarily located in PADDs 1 and 3. Thus, as the flexibility across the different benzene control programs diminishes, benzene levels decrease in PADD 4 and 5 and increase in PADD 3. Table 9.6-7 summarizes the estimated benzene level by PADD for several different benzene control programs that would result in the same nationwide benzene level, but differing gasoline benzene profiles.

Table 9.6-7. Estimated Gasoline Benzene Levels by PADD for Several 0.62 volume percent Benzene Control Programs and a 0.52 volume percent Benzene Control Standard with ABT Program Representing Maximum Reformate Control (volume percent benzene)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 excluding CA	U.S. Average
Current Benzene Levels (summertime)	0.66	1.32	0.86	1.54	1.87	0.97
Proposed 0.62 avg Bz std with ABT Program	0.51	0.73	0.55	0.95	1.04	0.62
0.62 vol% avg Bz std with 1.3 max-avg std and ABT program	0.50	0.75	0.56	0.90	0.88	0.62
0.73 avg Bz std, No ABT Program*	0.49	0.72	0.58	0.71	0.75	0.62
0.52 avg Bz std with ABT (maximum reformate benzene control)	0.48	0.50	0.52	0.56	0.67	0.52

* The cost analysis shows that 5 refineries would not be able to meet a 0.73 volume percent benzene standard, including three in PADD 5 which results in the modeled PADD-average benzene level to exceed the standard. All these refineries would achieve the 0.73 standard by reducing or eliminating the natural gasoline they are assumed to purchase.

One concern with proposing a benzene control program with a national ABT program is that there may be refineries that could produce gasoline with benzene levels higher than the average standard on an ongoing basis while using credits to comply, thus potentially exposing people using that gasoline to higher benzene emissions. To gain a sense of the relative benzene levels among all U.S. refineries, we plotted the individual refinery benzene levels projected to result from several of the benzene control programs with average national benzene levels of 0.62 volume percent benzene. A review of the refinery-by-refinery output reveals that the benzene levels of the refineries in PADD 4 and PADD 5 (excluding California) are most likely to remain above the standard with a nationwide ABT program in place. The plot of the refinery benzene levels against cumulative gasoline production for all U.S. refineries, and all refineries in PADDs 4 and 5 (excluding California), is contained in Figure 9.6-4, and Figure 9.6-5, respectively.

Figure 9.6-4. National Benzene Levels Under Different Benzene Reduction Levels

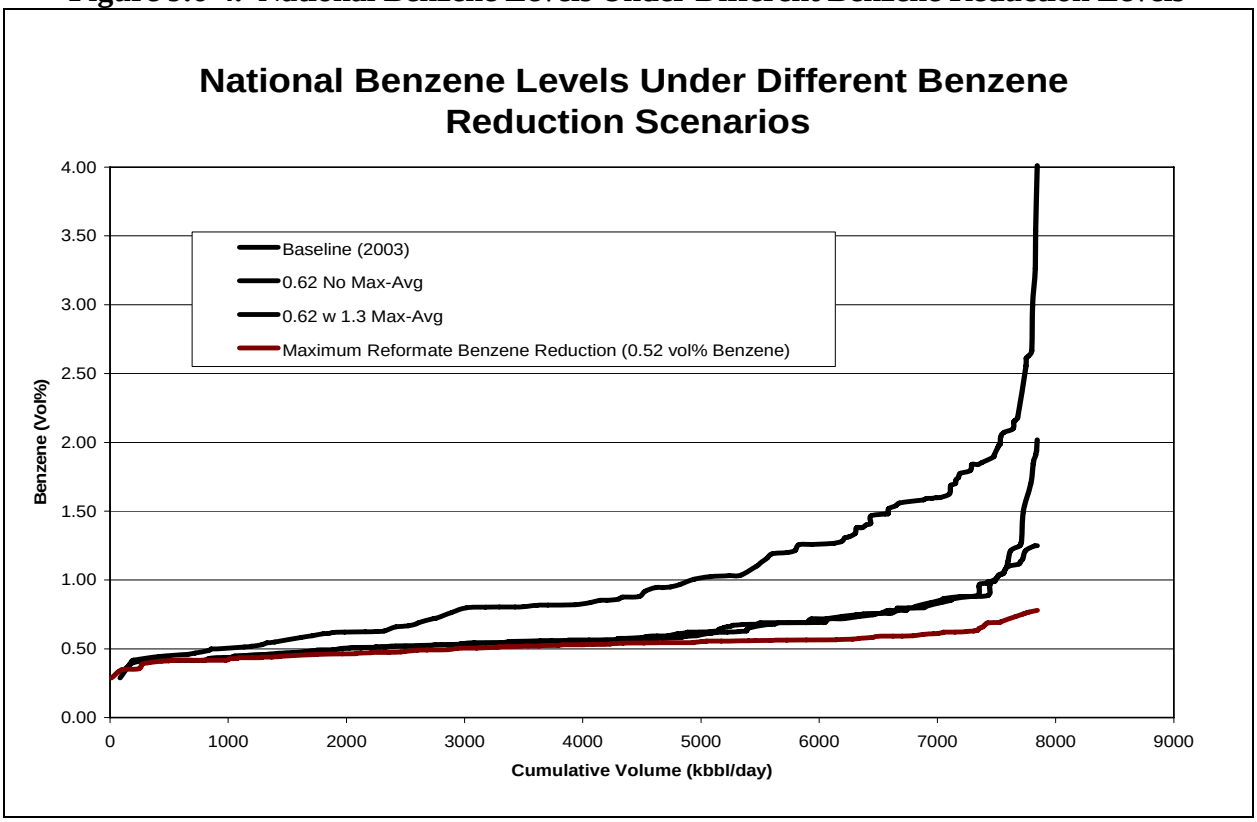
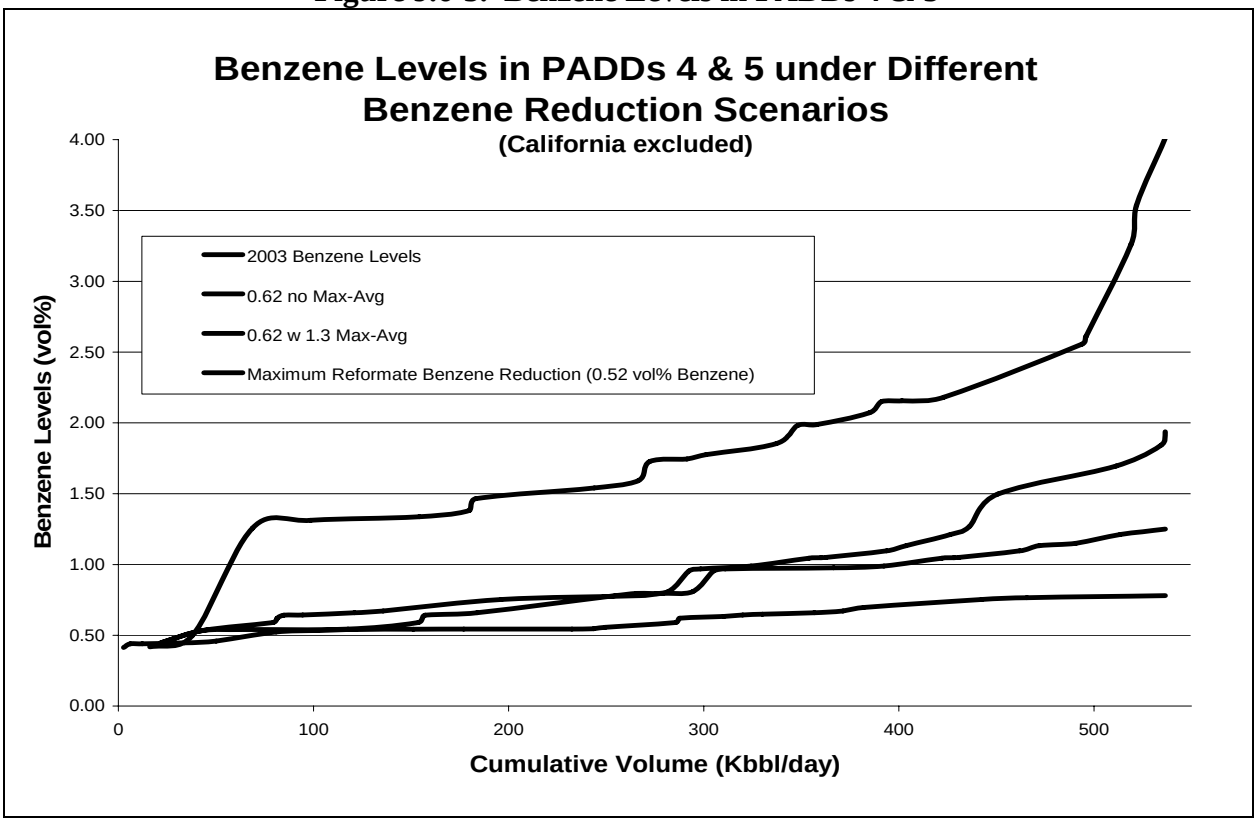


Figure 9.6-5. Benzene Levels in PADDs 4 & 5



All of the benzene control standards represented in Figure 9.6-4 and Figure 9.6-5 would realize substantial benzene reductions in all parts of the country compared to today's benzene levels. As the benzene control standard is tightened or as flexibility is reduced, the curve for gasoline benzene levels becomes flatter.

We also assessed the costs of the various benzene control programs based on the projected 2004 benzene price, which is $38 per barrel instead of the $20 per barrel upon which the proposed program cost estimates are based. Table 9.6-8 contains a summary of costs for the proposed and other benzene control standards based on benzene priced $38 per barrel above gasoline.

Table 9.6-8. Cost of Other Benzene Control Standards
(2000 dollars, 7% ROI before taxes and benzene priced at $38/bbl above gasoline)

Average Benzene Std. (vol %)	ABT Program	Avg.-Max Std. (vol %)	Actual In-Use Benzene Level (vol %)	Per-Gallon Cost (cents/gal)	Total Annual Cost ($ million/yr)	Aggregate Capital Cost ($ million)
0.52	Yes	None	0.52	0.28	380	870
0.60	Yes	1.3	0.60	0.09	125	630
0.60	Yes	None	0.60	0.07	96	530
0.62	Yes	1.3	0.62	0.05	66	580
0.62*	Yes	None	0.62	0.05	64	500
0.65	Yes	1.3	0.65	0.03	35	560
0.65	Yes	None	0.65	0.01	15	460
0.70	Yes	1.3	0.70	0.00	6	530
0.70	Yes	None	0.70	-0.02	-26	415
0.73	No	None	0.62	0.19	260	660

* Proposed Rule

9.6.3 Costs Used to Estimate Price Impacts of the Proposed Benzene Standard

In Chapter 13 of the RIA, we estimate the increase in gasoline prices for the proposed benzene control standard. To facilitate that analysis, certain cost information was obtained from the refinery-by-refinery cost model and presented to the contractor conducting that analysis. The cost information provided is consistent with specific macroeconomic principals that form the basis for estimating price impacts.

When modeling macroeconomic effects, the price in any market can be assumed to be based on the cost for the last, highest cost increment of supply which meets demand. We do not know which refineries are the highest cost producers of gasoline, so we have estimated three different cost breakpoints to capture the costs experienced by these price setter refineries. For the first set of costs provided, we assumed that the highest cost gasoline producers also experience the highest benzene control costs. The refinery-by-refinery cost model estimates the compliance cost for individual refineries so we simply sorted through the list of individual refinery costs and picked the highest cost of compliance in each PADD, which is the market area we chose to use for evaluating price effects.

We developed other cost information to capture other ways that this program could impact prices. Perhaps, the price setting refineries are not experiencing the maximum benzene control costs, or maybe they are affected by other factors. Refineries produce in a wide range of markets. Since the products are produced from the same feedstock with limited flexibility for changing the product slate, market prices for individual products are not independent of each other. Being the highest cost producer for one product does not mean they are the highest cost producer for all products, and market prices won't necessarily reflect their costs. To capture these other possible market effects, two other sets of cost information are provided to our contractor for estimating price effects.

The second set of costs we developed is based on the maximum variable costs experienced in each PADD. These costs do not include the capital costs and could also represent

another situation based on claims made by the representatives of the oil industry. They have said that after complying with the 500 ppm highway diesel fuel sulfur standard, the price increase in highway diesel fuel after that rule went into effect did not support their recovering their capital costs. We could not confirm this claim, but providing the maximum variable costs would attempt to model this situation.

For the third set of costs, we provided the average cost of compliance in each PADD. Since the highest benzene control costs may not necessarily correlate to the refineries with the highest overall gasoline production costs this case simply assumes the highest cost gasoline producer experiences average benzene control costs. Estimating the average cost of compliance for the fuel consumed is more complicated because the gasoline consumed in any area is a function of the imports and transfers into the PADD as well as the gasoline produced there. The methodology for how we generated average compliance costs for the gasoline consumed in a PADD from the average costs for the gasoline produced in a PADD is summarized in the RIA Section 6.1.2. Table 9.6-9 summarizes the maximum total and variable costs and the average per-gallon consumption costs for each PADD for estimating the price impacts of the proposed benzene control program.

Table 9.6-9. Summary of Potential Price Increases by PADD for the Proposed Benzene Control Program Based on Three Methods, Cents per Gallon (2002 dollars, 7% ROI before taxes)

Price Estimating Methodology	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 (excluding CA)	CA
Max-Total Cost (cents/gal)	0.41	1.15	1.06	1.46	1.14	0.15
Max-Variable Cost (cents/gal)	0.35	1.07	0.98	1.46	1.14	0.08
Average Cost for Gasoline Consumed (cents/gal)	0.05	0.20	0.05	0.36	0.39	0.15

9.6.4 Projected Fuel Supply and Energy of the Proposed Benzene Program

EPA has evaluated the potential impact on U.S. fuel supply of the proposed gasoline benzene control program. As discussed in detail elsewhere in this chapter, refiners are expected to utilize a variety of approaches to control benzene. Other than extraction these do not impact gasoline production appreciably. Extraction physically removes benzene from the refinery reformate stream, usually for sale into the petrochemical market. In extracting benzene, the volume of reformate available for gasoline production is reduced.

We estimate that in response to the proposed program, refiners would extract about 21,700 barrels of benzene per day in 2010. Because benzene has a slightly higher energy density than gasoline (about 7 percent higher), the projected extracted benzene is equivalent to about 23,500 barrels per day of gasoline, or about 0.2 percent of U.S. gasoline production. However, for two main reasons the net effect on gasoline supply of the rule will be far less, potentially zero.

First, gasoline volume reduced through benzene extraction would be largely made up through other processes that otherwise would produce this benzene. As shown in Table 9.3-2 of this RIA, about 41 percent of benzene supply for the petrochemical market is already extracted from the refinery reformate stream. Another 21 percent comes from a process that uses toluene as a feedstock. Both of reformate and toluene are components of gasoline, and so a large fraction of benzene on the market would be supplied directly from gasoline production even in the absence of the proposed program. Another approximately 25 percent of benzene comes from extraction from pyrolysis gasoline, which results from ethylene production for such things as plastics manufacture. The primary feedstock for pyrolysis gasoline is atmospheric gas oil which, although not directly a gasoline feedstock, would otherwise be processed in an FCC unit and mainly produce gasoline. Thus, nearly 90 percent of benzene is produced from gasoline blendstocks or from intermediate streams refineries normally use to produce gasoline. The reduced volume of gasoline from benzene extraction would largely be made up by increased production from processes currently used to produce benzene. Thus, overall, there would be little or no net reduction in gasoline.

Second, this increase in extraction of benzene from gasoline is expected to occur with or without the proposed benzene standard. Using CMAI's estimate of a 2.4 percent annual growth in benzene demand, we would expect that demand for benzene would increase by 650 million gallons from 2006 to 2011. This increased demand is expected to come from gasoline and crude oil, since roughly 90% of benzene is produced today from gasoline feedstocks, and 95% from crude oil. This compares with the projected new supply of benzene from extraction to meet the proposed standard of about 337 million gallons per year. Because the industry would be using the ABT program to effectively phase in the use of extraction over a period of several years, the amount of benzene extracted from benzene in any given year could easily be less than the increased annual demand, resulting in no net impact of the rule.

Projected Energy Impacts of the Proposed Benzene Program

We used the LP and refinery-by-refinery models to estimate the changes in energy use that would result from the implementation of the proposed benzene control program. For this analysis, we used the refinery-by-refinery model to select the range of technologies we believe would be likely to be used across the industry by PADD in 2010, both with and without a benzene program. We then used the resulting array of technologies as input data for the LP model. This data then became the starting point for runs of the LP model, which we used to produce estimates of the net change in energy use due to increased refinery processing and changes to inputs into the refinery. In these runs, the LP model maintains the same volume of gasoline production in the reference and control cases. The model makes up the loss of gasoline volume due to benzene extraction by assuming additional purchases of crude oil. To the extent that this benzene extraction would be made up by swapping gasoline blendstocks or increases to refinery intermediate streams that could then be used to produce gasoline, this analysis is somewhat conservative. Table 9.6-10 presents the results of the energy use evaluation.

Table 9.6-10. Estimated Changes in Energy Use (2010)
(in Thousands of Fuel Oil Equivalent Barrels per Day (Kfoeb/d)

	PADD 1	PADD 2	PADD 3	PADDs 4&5 (except CA)	All PADDs (except CA)
Total Benzene Control-Related	0.4	3	8	3	14
Light Naphtha Splitting	-0.1	1.3	-1.0	-0.1	0
Reforming	0.1	-1.9	3.1	0.1	1
Isomerization	0	1.5	0	0.3	2
Benzene Saturation	0	0	0.3	1.1	1
Benzene Extraction	0.4	0	5.2	0	6
Hydrogen Production	0	1.6	0.3	1.9	4
All Other	0	-1	3	0	3
Net Process Energy Change	**0.4**	**2**	**11**	**3**	**17**
% Change in Process Energy	*0.4*	*0.6*	*1.3*	*2.8*	*1.2*
Non-Process Energy Change	0.8	1	2	2	6
Net Total Energy Change	**1.2**	**3**	**13**	**5**	**23**
% Change in Total Energy	*0.07*	*0.08*	*0.14*	*0.28*	*0.13*

As shown in the table, our modeling projects that increases refinery process energy (fuel, steam, and electricity) would contribute most to the total change in energy use (17 of the total increase of 23 Kfoeb/d). This process energy increase would represent about one percent of all energy used in refinery processes. When all energy involved in producing gasoline is considered, including the energy in crude oil and other feedstocks, we project that the proposed benzene control program would increase overall energy use by refineries by about one tenth of one percent.

Of the nationwide increase in process energy, most would be due to processes directly related to benzene control (14 of 17 Kfoeb/d). Benzene extraction would be the largest contributor to this process energy increase (6 of 14 Kfoeb/d). It is important to note as discussed above that the increase in benzene production through greater extraction, and thus the increase in energy used in this process, would likely occur regardless of whether the proposed benzene control program was in place. Thus, the increase in energy used to extract benzene could be attributed to meeting the increased demand for benzene rather than attributed to the proposed program. (Projected increases in energy use due to the other benzene-related processes would be appropriately attributed to the proposed program.)

The variation in energy impacts from PADD to PADD shown in the table results from the expected differences in the technological approaches refiners would pursue in different parts of the country, as discussed in Chapter 6. For example, for PADDs 2, 4, and 5, we do not expect that the proposed program would result in an increase in benzene extraction, and thus the table shows no increase in energy for this process. However, we project that the largest energy increases in PADD 1 and PADD 3 would be due to increased benzene extraction. (Refiners in these regions would be near benzene markets and would tend to invest in benzene extraction equipment.) Overall, we project that PADD 3 would contribute more than half of the nationwide

increase in energy use, both due to the emphasis on extraction by refiners there as well as the large volume of gasoline produced in that region.

9.6.5 Costs of Other Air Toxics Control Programs

We used the linear program (LP) refinery model to estimate the cost of total air toxics control standards and total air toxics standards coupled with benzene standards. Use of the LP refinery model is necessary to express the wide-ranging impacts of one fuel change on others. This is less important if the fuel change has limited ripple effects (eg. benzene) but is critical for fuel changes expected to have significant ripple effects (eg. aromatics, sulfur, RVP).

The total air toxics standards modeled included (percent reductions in air toxics emissions are projected using the Complex Model):

- a minimum 21.5 percent reduction in total air toxics applied to conventional gasoline for each PADD,

- a minimum 25% total air toxics reduction applied to conventional gasoline for each PADD, and a minimum 35% total air toxics reduction applied to reformulated gasoline for each PADD and a 0.5 vol% average benzene standard applied to both conventional and reformulated gasoline.

We also evaluated the cost of several ozone/total air toxics control programs which would reduce the Reid vapor pressure (RVP) of conventional gasoline, and would further reduce the sulfur content of all gasoline. These ozone/air toxics control programs modeled include:

- a 7.8 RVP standard applied to a portion of the conventional gasoline pool, the volume of which is equivalent to 50% of the volume of reformulated gasoline consumed in each PADD,

- a 7.0 RVP standard applied to a portion of the conventional gasoline pool, the volume of which is equivalent to 50% of the volume of reformulated gasoline consumed in each PADD, and

- a 10 ppm sulfur standard applied to all U.S. gasoline.

As discussed in the preamble for this rule (section VII.C.1), we considered addressing MSATs in several ways other than reducing benzene emissions. Our decision to address MSAT emissions through gasoline benzene content reductions was not based exclusively on an analysis of costs, but strongly considered other factors. We discussed our reasoning for deciding not to propose to address MSAT emissions through a total toxics performance standard, as well as through further reductions in gasoline sulfur content and gasoline volatility.

For example, our experience with past toxics control programs has shown that, because reducing gasoline benzene content is by far the least expensive approach, we believe that regardless of the form of the standard, refiners would almost exclusively respond to a standard of equivalent stringency by reducing gasoline benzene. At the same time, a toxics performance

standard would introduce complexities and uncertainties that we believe would be unnecessary and could prove to be costly in the future. Regarding the value of controlling gasoline sulfur and volatility for MSAT purposes, sufficient data about the potential impact of such fuel changes on the toxics emissions of today's generation of vehicles does not yet exist.

Although we did not base these decisions on cost factors, we present for general information purposes the results of several limited modeling exercises that may be of interest. Table 9.6-11 presents LP modeling runs of two hypothetical toxics performance and benzene content standards. As discussed above in Section 9.1.1, there are strengths and weaknesses to the use of the LP model in evaluating fuel control programs. There are also important similarities and differences between EPA's refinery-by-refinery model (used to evaluate the proposed benzene control program) and the LP model (used in the case of other programs). We do not draw specific conclusions from these modeling results, but clarify some of the results below.

Table 9.6-11 contains a summary of the national average per-gallon costs and aggregate capital and total annual costs for the various total air toxics standards which we modeled. Much more information for these LP refinery modeling cases are contained in submissions to the docket.

Table 9.6-11. Detailed Cost Information by PADD for Air Toxics, Low RVP and Sulfur Control Cases
(2000 dollars, 7% ROI before taxes and benzene priced $20/bbl above gasoline)

		21.5% Tox Std CG	25% Tox Std CG 35% Tox Std RFG; 0.5 vol% Bz std for RFG & CG	7.8 RVP	7.0 RVP	10 ppm Sulfur CG & RFG
PADD 1	Volume (kbbl/day)	428	1067	64	64	1067
	Capital Cost ($MM)	-7	260	-27	-65	-15
	Total Annual Cost ($MM/yr)	33	190	8	14	145
	Per-Gallon (cents/gal)	0.50	1.17	0.86	1.45	0.90
PADD 2	Volume (Kbbl/day)	1864	2169	206	206	1864
	Capital Cost ($MM)	480	560	15	37	236
	Total Annual Cost ($MM/yr)	240	300	14	17	229
	Per-Gallon Cost (cents/gal)	0.84	0.90	0.45	0.54	0.69
PADD 3	Volume (Kbbl/day)	3399	4198	612	612	4198
	Capital Cost ($MM)	580	1840	133	222	574
	Total Annual Cost ($MM/yr)	170	850	9	22	201
	Per-Gallon Cost (cents/gal)	0.33	1.32	0.10	0.24	0.31
PADD 4 & 5	Volume (Kbbl/day)	724	724	-	-	724
	Capital Cost ($MM)	185	300	-	-	530
	Total Annual Cost ($MM/yr)	130	175	-	-	66
	Per-Gallon Cost (cents/gal)	0.51	1.60	-	-	0.06
Total and Average Costs	Volume (Kbbl/day)	6415	8158	882	882	8158
	Capital Cost ($MM)	1240	2960	121	184	1325
	Total Annual Cost ($MM/yr)	570	1520	32	54	643
	Per-Gallon Cost (cents/gal)	0.58	1.21	0.23	0.40	0.51
Total Air Toxics Reduction Compared to Clean Air Act Baseline (percent) See Note A		26.7	29.7	See Note B	See Note B	See Note B

Note A – Volume-weighted toxics reduction for CG and RFG.
Note B – The potential for air toxics emissions reductions with additional RVP and gasoline sulfur controls is uncertain, therefore no estimates are provided for these control programs. While the tendency is for these programs to provide some sort of reduction in air toxics emissions, without additional emissions testing, the VOC and toxics emissions impacts of these programs would need to be based on older correlations between fuel quality and emissions which may no longer apply as vehicle technology has changed. In addition, the reductions may be partially or completely offset by the means which refiners adjust the fuel quality secondarily (i.e., recover octane loss).

The projected costs for the total air toxics control programs presented in Table 9.6-11 are much higher than those for the proposed benzene control program. To understand the reasons for this difference, we compared the 21.5 percent total air toxics reduction case (since it is closest scenario in the existing modeling to the proposed benzene control program) with the proposed

benzene control program case. There are three primary reasons why the 21.5 total air toxics reduction case is more costly than the proposed benzene control standard.

The primary reason why the 21.5 percent reduction case is higher in cost is because when the contractor was setting up the LP refinery modeling work, it established the types of benzene control technologies that could be used for the total air toxics control cases, and it specified that benzene saturation be the primary technology used.[g] Since benzene control is the primary means picked by the refinery model for controlling total air toxics, benzene saturation provides a significant portion of the total air toxics control costs for the 21.5 percent toxics reduction case. However, for nearly the same level of total air toxics control, the refinery-by-refinery cost model, to achieve benzene control, relies mostly on benzene precursor rerouting with or without isomerization, and secondarily relies on extraction. As a result, benzene saturation plays a very small role in achieving benzene control in the refinery-by-refinery cost model. Yet benzene saturation costs average about 5 times higher than either benzene precursor rerouting or extraction for the average refinery (the difference is much less if only large refineries rely on benzene saturation). The reason why different benzene control strategies were relied upon for the two refinery modeling studies is that the total air toxics control cases modeled with the LP refinery model were completed early on in the development of the program and the choice of benzene control technologies was not a focal point of the cost analysis at that time.

Another reason why our modeling projects the 21.5 total air toxics reduction case to be higher in cost than the proposed benzene control standard is that it is a more severe toxics control case. RFG is assumed to maintain its MSAT1 performance, and CG is assumed to achieve 21.5 total air toxics reduction in each PADD. As a result, the refinery modeling of the 21.5 percent reduction case projects that all gasoline produced by U.S. refineries would achieve on average a 26.7 percent reduction in total air toxics compared to an estimated 25.1 percent reduction for the proposed benzene control case.[h] It is costlier to achieve a higher level of total air toxics control.

Finally, while the LP refinery modeling does tend to optimize the total air toxics reduction costs across the refineries in each PADD (partially emulating an ABT program within each PADD), it does not optimize total air toxic control costs nationwide. Thus, this restriction in program cost optimization increases the projected compliance cost compared to the proposed benzene control case which optimizes benzene control costs nationwide.

---

g It is typical for the contractor to limit or specify certain control technologies in LP refinery modeling to prevent the LP refinery model from choosing control technologies that are obviously unreasonable choices for a subset of refineries affected by a fuel quality control standard.

h To estimate the total air toxics emission reductions for the 21.5 percent toxics reduction case and proposed benzene control case, we needed to insert the relevant gasoline qualities (i.e., RVP, volume percent benzene, aromatics, olefins, percent evaporated at 200 and 300 F, and RVP) into the Complex Model to estimate the total air toxics emission reductions. This is easily obtainable from the LP refinery modeling reports since the necessary gasoline qualities are estimated for the control cases in each PADD. Since the refinery-by-refinery cost model does not estimate these various gasoline qualities, the reference case gasoline qualities for the LP refinery modeling reference cases were used for most of the gasoline qualities, and we then substituted the benzene levels from the refinery-by-refinery model output to estimate the final total air toxics reductions for the proposed benzene control standard.

The other total air toxics control case is even more stringent than the 21.5 percent reduction in total air toxics case and therefore achieves even deeper reductions in air toxics emissions at a higher cost, but was developed using the same assumptions. Therefore, these results can best be compared among the two air toxics control cases, but not relative to the proposed benzene control case.

References for Chapter 9

[1] Refinery Modeling: Legislative and Regulatory Developments: Effects on Gasoline Supply, Prepared for U.S. Environmental Protection Agency by Abt Associatiates Inc under subcontract from ICF Incorporated, January 14, 2003; Appendices A, B and D.

[2] Evaluation of Refinery Gasoline Benzene Reduction Options – Part 2, Prepared for U.S. Environmental Protection Agency by Abt Associates Inc. under contract from ICF Consulting Inc., November 30, 2004.

[3] Keesom, William H., et al, Benzene Reduction Alternatives, Technical Paper presented to the 1991 National Petroleum Refiners Association Annual Meeting.

[4] Worldwide Refining/Worldwide Production, Oil and Gas Journal, Volume 98.51, December 18, 2000.

[5] Annual Energy Outlook 2002, Energy Information Administration, Department of Energy.

[6] Senate Bill S.791, 108th Congress, April 3, 2003.

[7] Annual Energy Outlook 2005, Energy Information Administration, Department of Energy.

[8] Worldwide Report , Oil and Gas Journal, www.ogjonline.com, December 22, 2003.

[9] Capacity of Operable Petroleum Refineries by State as of January 1, 2003, Table 38 of Petroleum Supply Annual 2002, Volume 1, Energy Information Administration, Department of Energy.

[10] Inputs of Crude Oil and Petroleum Products by Country of Origin, 2003, Tables 22 – 25, Petroleum Supply Annual 2003 Volume 1, Energy Information Administration, Department of Energy, Department of Energy.

[11] Refinery Net Production of Finished Petroleum Products by PAD, and Refining Districts, 2003, Petroleum Supply Annual, Table 17, Petroleum Supply Annual 2003, Volume 1, Energy Information Administration, Department of Energy.

[12] Information in the LP refinery model from literature and provided by vendors of refining technologies.

[13] Information in the LP refinery model from literature and provided by vendors of refining technologies.

[14] Information in the LP refinery model from literature and provided by vendors of refining technologies.

[15] Information in the LP refinery model from literature and provided by vendors of refining technologies including new information.

[16] Rock, Kerry L., Manager CDTECH, Low Cost Benzene Reduction for RFG, Technical Paper presented at the 1995 National Petroleum Refiners Association Annual Meeting.

[17] Rock, Kerry L., Manager CDTECH, Cost Effective Solutions for Reducing the Benzene in Gasoline, Technical Paper presented at the 1997 National Petroleum Refiners Association Annual Meeting.

[18] Information in the LP refinery model from literature and provided by vendors of refining technologies including new information.

[19] Annual Energy Outlook 2005, Energy Information Administration, Department of Energy.

[20] Annual Energy Outlook 2006 (early release), Energy Information Administration,

Department of Energy.

[21] Annual Energy Outlook 2004, Energy Information Administration, Department of Energy.

[22] World Benzene Analysis 2004, Chemical Market Associates Incorporated, Houston Texas, 2004.

[23] Fisler, Mark, Vice President, Chemical Market Associates Incorporated, Benzene Outlook in the Era of Reformulated Gasoline, Presented at the NPRA Annual Meeting, March 1992.

[24] Stellman, Richard, President, The Pace Consultants Incorporated, Reformulated Gasoline and the Petrochemical Industry, Presented at the NPRA Annual Meeting, March 1992.

[25] DiVita, Vince, Group Manager, Jacobs Consultancy, Peer Review of a Refinery-By-Refinery Cost Model for the U.S. Refining Industry, January 9, 2006.

[26] Hodge, Cal, President, A 2nd Opinion, Peer Review: Cost of Benzene Control Model, January 8, 2006.