Regulatory Impact Analysis

Control of Hazardous Air Pollutants from Mobile Sources

Chapter 9
Costs of the Gasoline Benzene Standard and Other Control Options Considered

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Chapter 9: Costs of the Gasoline Benzene Program and Other Control Options Considered

This chapter provides a summary of the methodology used and the results obtained from our cost analyses of the benzene control program as well as various other benzene 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 benzene program followed by the results. We present the results from our energy and supply analyses for our benzene program. Finally, we discuss and compare the results of an oil industry cost analysis for various benzene programs, including one which is similar to the benzene program that was submitted as comments to the proposed rulemaking.

9.1 Methodology

9.1.1 Overview

Prior to the proposed rule, 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 initially 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 Chapter 6. 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 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 approximate 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 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 of 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 standard.

This strategy results in the optimum selection of benzene control technologies consistent with how the ABT program would be expected to affect benzene control investments by the refining industry attempting to minimize its costs. For this reason, the refinery-by-refinery cost model was used to estimate the cost for various benzene standards both with and without ABT programs, and the LP refinery model was used for the other air toxics control programs considered. Because certain refinery-specific 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 model used in the refinery-by-refinery cost model is described in Section 9.1.3.

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 was evaluated 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 check on the model was conducted by comparing its cost estimates for benzene control with the same benzene control case evaluated with the LP refinery cost model. Finally, 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. However, their principal comments were addressed prior to undertaking the cost analysis for the final rulemaking. The peer review comments and how we addressed them are summarized at the beginning of Section 9.1.2.

A key assumption associated with the analysis is that the benzene reduction technologies assumed to be used are those which reduce benzene levels from the feed or product streams (the product stream is called "reformate") of the reformer, the unit in the refinery which produces most of the benzene in gasoline.[3] Basing the cost of this program on reformer benzene reduction technologies is reasonable because the reformer 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 reformer benzene levels. Thus, reducing benzene from reformate would be expected to be the most cost-effective means for achieving benzene reductions. 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, but also increasing uncertainty that the benzene reductions that are estimated to occur in each region of the country will actually occur. A detailed discussion on the technologies available for benzene control is discussed in Chapter 6 of the Regulatory Impact Analysis.

A number of benzene programs were considered for the final rulemaking. These include the proposed 0.62 vol% average benzene standard with an ABT program and several variants of the proposed benzene standard. We evaluated some of these alternative benzene standards with a second benzene standard called a maximum average standard. The maximum average 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 maximum average standard would require them to meet or exceed the maximum average standard in each refinery before purchasing credits to show compliance with the average standard. The standard effectively limits the degree to which credits can be used to demonstrate compliance. For example, a refinery with a gasoline benzene level of 2 vol% and faced with a 1.3 vol% maximum average 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 vol% maximum average limit. The addition of a maximum average standard would force several high cost refineries to take additional benzene control steps not required by the 0.62 vol% average standard alone. The addition of a maximum average standard would thus tend to increase the cost of a benzene program over a program without a maximum average standard.

We also evaluated a benzene standard without an ABT program. This type of benzene 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 program without an ABT program would likely result in a national average benzene level that is lower than the standard (albeit far costlier, and with far more negative impact on individual refineries). 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.

After the proposed rule, we eliminated any further consideration of a more stringent average gasoline sulfur standard, a low RVP standard, or any variant of a total air toxics standard. Therefore we limited our cost analysis for the final rule to various benzene programs above and below the proposed 0.62 vol% benzene standard, including variants with a maximum average standard. For the final rule, we adopted a gasoline benzene content standard of 0.62 vol% benzene with a maximum average standard of 1.3 vol%. The benzene standards evaluated for the final rule are summarized in Table 9.1-1 .

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

Average Std.	Avg.-Max Std.	ABT Program
0.50	None	Yes
0.60	1.3	Yes
0.60	None	Yes
0.62	1.1	Yes
0.62	1.2	Yes
0.62	1.3	Yes
0.62	1.4	Yes
0.62	1.5	Yes
0.62	None	Yes
0.65	1.3	Yes
0.65	None	Yes
0.70	1.3	Yes
0.70	None	Yes
0.71	None	No

The final benzene levels and cost results for the benzene program and other benzene standards considered are reported by PADD. This allows one to view the potential impact of the benzene program on a regional 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   Changes to the Cost Analysis since the Proposal

In deriving the cost estimate for the final rule, we identified and made a number of changes to the refinery modeling methodology used for the proposed rule. One of the primary changes was to base the future year fuel prices on the Annual Energy Outlook (AEO) 2006 instead of AEO 2005. Perhaps the most important difference between the two AEO studies is that the AEO 2006 projects a higher crude oil price of $47 per barrel for 2012, the year of the final rule analysis, compared to the crude oil price projected by AEO 2005, which was $27 per barrel. The primary difference caused by the higher crude oil price is that the cost of reduced gasoline supply, such as when benzene is extracted from gasoline, is higher when the removed benzene is replaced by other high octane petroleum compounds. AEO 2006 also projects higher natural gas prices as well.

Another change was to update the refinery modeling base year to 2004 from 2003 – the year used for the proposed rule analysis. The primary purpose for this change was to calibrate each refinery's gasoline benzene levels and gasoline volumes to the most recent year that we have information available. Each refinery's 2004 gasoline benzene level and volume is available from the RFG data base.

The final rule analysis treated natural gasoline differently in the refinery-by-refinery cost model compared to how it was treated in the proposed rule analysis. Natural gasoline contains 1.3 vol% benzene and we assumed for the proposed rule cost analysis that natural gasoline, and other benzene-containing streams, are blended directly into gasoline without being treated to reduce their benzene. For the final rule cost analysis, we assessed the feasibility for treating the benzene in natural gasoline as well as the other benzene containing gasoline streams (these other benzene-containing streams include, light straight run naphtha, light coker naphtha and light hydrocrackate). Of these streams, the only one that we identified that refiners would treat to reduce benzene with certainty is natural gasoline (see Chapter 6 of the RIA for a discussion of the feasibility for treating the benzene of these other streams). The reason why we are confident that refiners would treat the benzene in natural gasoline is because most refiners have rerouted natural gasoline to the front of the refinery and are feeding it into the atmospheric crude tower to facilitate the desulfurization of this stream to achieve compliance with the Tier 2 gasoline sulfur standard. As the benzene of natural gasoline is routed through the refinery, it will be treated by the isomerization unit, when the six carbon benzene compounds are rerouted around the reformer, or by extraction and benzene saturation which post-treat the benzene in the reformate. For some refineries which blend a lot of natural gasoline into their gasoline, this additional benzene reduction can be significant.

The refinery modeling case studies conducted for the final rule were conducted on an annual basis – which is different from the proposed rule, which was conducted on a summer basis. As we acknowledged in the proposed rule, assessing the cost of benzene reductions solely on a summer basis, which was done to allow the cost comparison with low RVP control, would likely lead to a slightly conservative cost estimate for benzene reductions. For example, recovering octane loss associated with benzene reduction is higher in the summer versus the winter. Thus, assessing the cost of benzene reductions on an annual basis is expected to more accurately estimate the cost of benzene reductions.

The cost analysis for the final benzene program excludes the participation of California refineries – which differs from how the analysis was conducted for the proposed rule. After the cost analysis was completed for the proposed rule, but before it was proposed, California state officials decided not to be a part of the Federal benzene program and the state has maintained this point of view. Not including California refineries in our cost analysis increases the cost of benzene control slightly because non-California refiners cannot take advantage of the low-cost benzene control credits that California refineries would provide them if they were included in the program.

In addition to the above changes to our cost analysis that we identified, we also made some adjustments that were based on public comments (from the American Petroleum Institute)

and peer review comments we received on the cost analysis that we conducted for the proposal. Peer reviews on the refinery-by-refinery cost model were conducted by Jacobs Engineering and A Second Opinion.[4, 5] 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 peer reviewers agreed with aspects of the refinery modeling and took issue with other aspects. Both reviewers 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. 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 when benzene saturation is applied. Applying this approach would slightly reduce the cost of the program, but we believe a more conservative approach that results in deeper benzene reductions under the credit trading program is more appropriate, thus relieving the need for some of the benzene control by other refineries.

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 and we did not make any changes to our methodology.

Jacobs commented that using the marginal cost of octane from the LP refinery model (also termed shadow values) might underestimate the cost of making up lost octane since the cost of the amount of additional octane needed might be greater than the marginal octane cost. Our analysis of the octane made available from the Renewable Fuels standard mandated by EPAct reveals that this octane entering into the gasoline pool would make up for the octane loss from this benzene program several times over, and should ensure that many increments of octane recovery could be made available at about the same price. Thus, we did not adjust our octane cost methodology for the final rule analysis.

One of the peer review comments we received from Jacobs was in response to our assumption that refiners assess what strategy they will take to reduce gasoline benzene levels based on their desire to minimize their dollars expended per barrel of benzene reduced (dollars expended includes capital amortized at 10% return on investment (ROI) after taxes). Jacobs countered stating that refiners assess how to move forward on a particular refining strategy solely on the desire to minimize their capital investments. We disagree with Jacob's statement. If minimizing capital investment was a refiner's sole goal, then refiners would not have invested in fluidized catalytic cracker (FCC) feed hydrotreating to reduce gasoline sulfur when lower capital cost FCC naphtha hydrotreating is also available. Similarly, refiners would not opt for hydrocrackers and would instead live with relative inflexibility of FCC units. However, we do

understand a refiner's desire to limit their capital investments. We contacted two refining companies and asked them what payout they expect for their newly invested capital investments. The two refiners said that they move forward with their capital investments when they are better than 15% ROI. Thus for the final rule, we continued to assume that refiners assess benzene control technology based on their dollars expended per barrel of benzene reduced, but we amortized the capital investments involved based on the higher after-tax 15% ROI which values the cost of capital more than the lower ROI.

Jacobs and API, in its comments on the proposed rule, provided capital cost estimates for the benzene control technologies. We summarized our capital costs that we used for the proposed rule analysis and those by Jacobs and API in Table 9.1-2.[6]

Table 9.1-2 EPA Capital Costs used for the Proposed Rule Compared to Jacobs and API Capital Costs

	Reported/Estimated			Adjustment to Standard Size and to 2004 Dollars				2004 Dollars				
	Unit Size (K b/sd)	ISBL Cost ($MM)	$ Year	Scale Factor	Infl. Adj. (%)	Std Size (K b/sd)	ISBL Cost ($MM)	Off-Site Factor	ISBL + OSBL Cost $MM	Contingency	Total Capital Cost ($ MM)	Per Barrel Cost ($/bbl)
LSR Rerouting												
EPA (Abt)	15.0	7.69	2004	0.70	100%	15.0	7.69	12.0%	8.61		8.61	0.57
Jacobs Consult	20.0	9.10	2005	0.65	98%	15.0	7.41	50.0%	11.11		11.11	0.74
API (B&OB)	30.0	7.52	2Q 06	0.39	95%	15.0	5.45	70.2%	9.27	15%	10.66	0.71
Benzene Saturation												
EPA (Abt)												
Conv Saturation												
Reform Spltr	30.0	6.00	2003	0.70	107%	30.0	6.43	25.0%	8.04		8.04	
Saturation Unit	6.3	2.76	2003	0.65	107%	6.3	2.96	25.0%	3.70		3.70	
Total		8.76			107%	30.0	9.39	25.0%	11.74		11.74	0.39
CD Hydro	30.0	7.20	2003	0.70	107%	30.0	7.72	25.0%	9.65		9.65	0.32
Jacobs Consult												
Reform Spltr	20.0	9.10	2005	0.65	98%	30.0	11.62	50.0%	17.43		17.43	
Saturation Unit	9.1	10.12	2005	0.65	98%	13.7	12.91	75.0%	22.60		22.60	
Total		19.22		0.65	98%	30.0	24.53	63.9	40.03		40.03	1.33
API (B&OB)												
Reform Spltr	30.0	7.52	2Q 06	0.39	95%	30.0	7.14	70.2%	12.15	15%	13.97	
Saturation Unit	10.0	9.09	2Q 06	0.67	95%	10.0	8.62	70.2%	14.68	15%	17.68	
Total		16.61		0.67		30.0	15.76	70.2%	26.82		31.65	1.05
Benzene Extr												
EPA (ABT)												
Reform Spltr	30.0	6.00	2003	0.70	107%	30.0	6.43	25.0%	8.04		8.04	
Depentanizer	6.3	1.07	2003	0.70	107%	6.3	1.15	25.0%	1.43		1.43	
Sulfolane	5.4	19.00	2003	0.65	107%	5.4	20.37	40.0%	28.52		28.52	
Total	1.8	26.07		0.65	107%	1.8	27.95	35.9%	38.00		38.00	21.1
Jacobs Conslt												
Reform Spltr	20.0	9.10	2005	0.65	96%	16.2	7.77	50.0%	11.66		11.66	
Sulfolane	10.4	17.05	2005	0.65	96%	8.4	14.56	100.0%	29.11		29.11	
Total	1.0	26.16		0.65	96%	0.8	22.33	82.6%	40.77		40.77	48.54
API (B&OB)												
Aromatics Extr	20.4	134.63	2Q 06	0.67	95%	8.4	70.41				113.18	
Aromatics Extr	14.3	134.63		0.67	95%	5.9	70.41				113.18	19.25

Comparing our capital costs used in our proposed rule analysis to those by Jacobs and API we found that, for the most part, our capital costs were lower. We discovered that one general reason why our capital costs were lower is that the base year for our capital costs is several years ago, and capital costs have increased recently much faster than the rate of inflation. For each benzene control technology, we also compared other aspects of our capital costs, such as the offsite costs, to those used by Jacobs and API, and made additional changes to the capital cost information we used for the proposed rule to update them for our final rule cost analysis.

Our proposed light straight run rerouting capital costs are about 80 percent those of Jacobs and API. The inside battery limits (ISBL) portion of our LSR rerouting capital costs are

the highest of the three for a similar sized unit, but our 12% offsite factor is much lower. [a] Our LSR rerouting offsite factor also seems low compared to the 25% offsite factor we assigned to reformate splitters, which is another distillation column and arguably should have a similar offsite factor. The offsite factor for Jacob's and API's LSR rerouting distillation column are much higher at 50% and 70%, respectively. However, we believe that these are too high for a distillation column. According to a presentation by Fluor engineers, the offsite factors for new process units in refineries range from 10% to 80%, with the average being 40%.[7] Distillation columns are simple refinery units that we expect would have lower offsite costs. Thus we don't believe that the higher offsite factor used by Jacobs is justified, and API's offsite factor seems extremely high. In addition to API's very high offsite factor, API also applies a 15% contingency factor. Contingency factors are usually reserved for estimates with significant uncertainty, not for well proven technologies. It appears that API is being excessively conservative in its cost estimate. After considering the different offsite factors, we decided to increase our LSR rerouting offsite factor to 25% to make it consistent with the offsite factor for reformate splitters.

Our proposed benzene saturation capital costs are about one third of those of Jacobs and API. In conducting our capital cost comparison, we compared our capital costs individually for each of the two units which comprise benzene saturation: the reformate splitter and the saturation unit. Reviewing our reformate splitter costs we identified that its ISBL costs are lower than API's and much lower than Jacobs'. After reviewing those costs, we found that our costs are indeed low – perhaps solely because they are older. Updating them with cost information from the year 2006, we increased our reformate splitter ISBL costs from $6.4 to $8.3 million for a 30,000 barrel per day unit expressed in 2004 dollars. As discussed above, our OSBL factor is 25% compared to Jacobs which is 50% and API which is 70%, along with a 15% contingency factor. As discussed above, we have a high level of confidence with our 25% offsite factor for distillation columns so we kept the same factor for reformate splitters.

Our proposed saturation unit capital costs are much lower than those by Jacobs and API. We identified two reasons for our lower costs. First, our ISBL and offsite costs were much lower than those by Jacobs and API. We reviewed our saturation unit ISBL cost and found that it was indeed low. We obtained more recent capital cost information and based our saturation unit ISBL capital costs on this new cost information, increasing them by about a factor of 2 ½. Again our saturation offsite factor was much lower than that used by Jacobs and API. As discussed above, the typical range for offsite costs is 10 to 70 percent. A benzene saturation unit is more complicated than a simple distillation column, but less complicated than fluidized catalytic cracker (FCC) or hydrocracker units, which would arguably have offsite costs at the higher end of this range. For this reason, we believe that the offsite factor for a benzene saturation unit should be about at the middle of the range for an offsite factor, so we assigned it a

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[a] 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.

40% offsite factor. We believe that our 40% factor is more appropriate than the higher offsite factors used by Jacobs and API.

The second reason why our proposed benzene saturation costs were lower is that our ratio of benzene saturation unit capacity to reformate splitter capacity was much lower compared to the same ratios used by Jacobs and API. Benzene saturation units are always of lower capacity than the reformate splitter because the reformate splitter concentrates the benzene into a single stream separate from the rest of the reformate. If at a refinery, the six, seven and eight carbon compounds are sent to the reformer, then the six carbon portion of reformate is likely to be on the order of 33% of the reformate, provided that the mix of hydrocarbons are proportional for each carbon number. However, most refiners also send nine carbon and even some higher carbon number hydrocarbons to the reformer in addition to the six, seven and eight carbon hydrocarbons. Thus, the six carbon hydrocarbons comprise 25% or less of the total mix of hydrocarbons. For our proposed rule cost analysis, our benzene saturation unit capacity was 21% of the reformate capacity, while Jacobs and API assigned the benzene saturation unit capacities which are 46% and 31% of the reformate splitter capacity, respectively. Since refiners usually send (or want the capacity to send) the nine and heavier hydrocarbons to the reformer, then it seems that the benzene saturation unit would only need to be sized to be about 25% of the reformate splitter capacity, depending on whether or not a safety factor is also necessary. Based on this reasoning, our assumption that the benzene saturation unit would be sized to be 21% of the reformate splitter capacity would be low. We contacted a vendor of benzene saturation technology to find out how they size their benzene saturation units relative to reformate splitters. They typically size their benzene saturation units to be 28% of the capacity of the reformate splitters. This relative benzene saturation unit capacity seemed reasonable based on the discussion above, and is only slightly lower than API's but much lower than Jacobs' which seems unnecessarily high. We changed the relative capacity of the benzene saturation unit for our analysis to be 28% of the reformate splitter.

Our proposed benzene extraction capital costs were also lower than Jacobs', but about the same as API's on a per-barrel basis. However, the API capital costs are for a BTX extraction unit which is larger and therefore enjoys a better economy of scale. For a similar sized unit, the per-barrel API capital costs would be $32 per barrel and therefore higher than ours at $21 per barrel. We made several changes to our benzene extraction costs. First, as stated above, we adjusted our reformate splitter ISBL capital costs higher for the benzene saturation unit and we applied those same adjustments to our reformate splitter capital costs for benzene extraction. We had included capital costs for a depentanizer, the purpose of which would be to ensure that no five-carbon hydrocarbons would be sent to the extraction unit. However, after further consideration we realized that that all reformers have a stripper that could be used to separate the five carbon hydrocarbon compounds from the heavier hydrocarbons in reformate. Thus, adding a depentanizer unit would be unnecessary, so we eliminated the depentanizer from our benzene extraction costs. Finally, we assessed our capital costs for the benzene extraction unit, the sulfolane unit. Our sulfolane unit ISBL capital costs are as high as or higher than those by Jacobs and API . Therefore we did not adjust them. The offsite factor that we assigned to the sulfolane unit was 40%, which is much lower than those used by Jacobs and API. Using the reasoning that we used above for estimating the offsite factor, we believe that the offsite factor should be higher than 40%. The offsite costs are usually very high for a benzene saturation unit

because of the need for adding special benzene and extraction chemical storage, offloading facilities and the costly environmental controls necessary to control benzene fugitive emissions. The offsite costs for benzene extraction are usually higher than FCC and hydrocracker units which are other complex refinery units with high offsite factors. We therefore increased benzene extraction unit's offsite factor to 100% of the ISBL capital costs. The last variable in the extraction unit's costs is the relative capacity for the sulfolane unit compared to the reformate splitter. For the saturation unit capital costs, we concluded that the saturation unit capacity should be sized to be 28% of the reformate unit capacity. Since the reformate splitter will be creating the same benzene-rich stream for extraction as it would for saturation, we assigned the same relative ratio of extraction unit capacity to reformate splitter unit capacity, which is 28%. Again, Jacobs used a very conservative ratio for the benzene sulfolate extraction unit capacity compared to the capacity for the reformate splitter unit, which we believe is unjustified.

After making the above adjustments to our capital costs, we summarize our revised capital costs in Table 9.1-3 below, comparing them to the Jacobs and API capital costs. The values in Table 9.1-3 which are in bold are revised from the values presented in the proposed rule.[b]

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b After further reviewing the cost information for the benzene saturation technologies as we adopted the revised capital cost estimates into our refinery cost model, we realized that the differences in capital costs from literature between a Bensat unit and a CDHydro unit were greater than expected compared to how these technologies differ. To remedy this, we conservatively assigned CDHydro's capital costs to be the same as those as Bensat, as described in Section 9.2.3.

Table 9.1-3 Our Revised Capital Costs Compared to Capital Costs Provided by Jacobs and API (values in bold indicated that they were updated since the proposed rule)

	Reported/Estimated			Adjustment to Standard Size and to 2004 Dollars				2004 Dollars				
	Unit Size (K b/sd)	ISBL Cost ($MM)	$ Year	Scale Factor	Infl. Adj. (%)	Std Size (K b/sd)	ISBL Cost ($MM)	Off-Site Factor	ISBL + OSBL Cost $MM	Contingency	Total Capital Cost ($ MM)	Per Barrel Cost ($/bbl)
LSR Rerouting												
EPA (Abt)	15.0	7.69	2004	0.70	100%	15.0	7.69	**25.0%**	**9.61**		**9.61**	0.64
Jacobs Consult	20.0	9.10	2005	0.65	96%	15.0	7.41	50.0%	11.11		11.11	0.74
API (B&OB)	30.0	7.52	2Q 06	0.39	92%	15.0	5.45	70.2%	9.27	15%	10.66	0.71
Benzene Saturation												
EPA (Abt)												
Conv Saturation												
Reform Spltr	30.0	**8.79**	**2006**	0.70	**95%**	30.0	**8.34**	25.0%	**10.42**		**10.42**	
Saturation Unit	**8.4**	**8.67**	**2006**	0.65	**95%**	8.4	**8.22**	**40.0%**	**11.51**		**11.51**	
Total		17.46			**95%**	30.0	**16.56**	25.0%	**21.94**		**21.94**	**0.73**
CD Hydro	30.0	**5.86**	2003	0.70	**110%**	30.0	**6.44**	**40.0%**	**9.01**		**9.01**	**0.30**
Jacobs Consult												
Reform Spltr	20.0	9.10	2005	0.65	98%	30.0	11.62	50.0%	17.43		17.43	
Saturation Unit	9.1	10.12	2005	0.65	98%	13.7	12.91	75.0%	22.60		22.60	
Total		19.22		0.65	98%	30.0	24.53	63.9	40.03		40.03	1.33
API (B&OB)												
Reform Spltr	30.0	7.52	2Q 06	0.39	95%	30.0	7.14	70.2%	12.15	15%	13.97	
Saturation Unit	10.0	9.09	2Q 06	0.67	95%	10.0	8.62	70.2%	14.68	15%	17.68	
Total						30.0	15.76	70.2%	26.82		31.65	1.05
Benzene Extr												
EPA (ABT)												
Reform Spltr	30.0	**8.79**	**2006**	0.70	**95%**	30.0	**8.34**	25.0%	**10.42**		**10.42**	
Sulfolane	**8.4**	**25.20**	2003	0.65	110%	**8.4**	**27.73**	**100.0%**	**55.45**		**55.45**	
Total	1.8	**33.99**		0.65	107%	1.8	**36.07**	**82.7%**	**65.88**		**65.88**	**36.60**
Jacobs Conslt												
Reform Spltr	20.0	9.10	2005	0.65	96%	16.2	7.77	50.0%	11.66		11.66	
Sulfolane	10.4	17.05	2005	0.65	96%	8.4	14.56	100.0%	29.11		29.11	
Total	1.0	26.16		0.65	96%	0.8	22.33	82.6%	40.77		40.77	48.54
API (B&OB)												
Aromatics Extr	20.4	134.63	2Q 06	0.67	95%	8.4	70.41				113.18	
Aromatics Extr	14.3	134.63		0.67	95%	5.9	70.41				113.18	19.25

9.1.3   LP Refinery Modeling Methodology

Although the benzene control costs estimated for the final 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 cost analysis. The information from the LP refinery model used in the refinery-by-refinery model included the average 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 refinery operations information from the LP refinery model was 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.[8] 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). The benzene program was assumed to take effect in 2012. 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 2012 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.[9] 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 benzene program 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 base case. Additionally, we also modeled the implementation of EPAct, which requires a large increase in the amount of ethanol to be blended into gasoline to comply with the renewable fuels standard (RFS). In its AEO 2006, EIA has projected that the volume of ethanol blended into gasoline will exceed the RFS required amounts, resulting in 9.6 billion gallons of ethanol blended into gasoline by 2012. Other provisions of EPAct that we modeled included a nationwide ban on MTBE and rescinding the RFG oxygenate standard.

The third step in conducting the LP refinery modeling was to run the various control cases. The control cases are created by applying a specific fuel control standard to each PADD reference case. The control cases are run with capital costs evaluated at a 15 percent rate of return on investment (ROI) after taxes. The refinery model output for each PADD is 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.

9.1.4   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 2004 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 seven refineries, we had gasoline blendstock volumes and benzene levels which the refining companies shared with us in our previous discussions with them for MSAT1 concerning air toxics control and during our discussions with refiners prior to the proposed rule. This specific

refinery information provided to us was entered into the refinery-by-refinery model avoiding the need to estimate it.

The 2004 gasoline production volumes and refinery operating conditions were projected to 2012, the year that we modeled the cost for gasoline benzene control. We chose the year 2012 for modeling the cost of benzene reductions because it represented a midyear in the range of years that the benzene program is expected to phase in. The phase-in years range from 2007 to 2015 with the major benzene reductions expected to occur in 2015. Based on projections by the Energy Information Administration, gasoline demand is expected to increase by 12.5 percent between 2004 and 2012.[10]

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 15 percent rate of return on investment (ROI) after taxes, but were adjusted post modeling 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 utilized to meet the various benzene standards.

9.1.4.1 Estimating Individual Refinery Gasoline Blendstock Volumes

To calibrate each refinery to its current benzene levels and gasoline volumes, and to provide the best opportunity for estimating the cost and ultimate level of benzene control, it is necessary to understand the benzene levels and volumes of the various blendstocks which make up each refinery's gasoline. Information on the volumes and benzene levels 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.[11] [12] Information from these two sources was reviewed for the year 2004, 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 to each refinery's gasoline pool. The units analyzed include coking, fluidized catalytic cracking (FCC), hydrocracking, alkylation, dimersol, polymerization, isomerization, reforming and aromatics extraction.

An initial assumption was made that each unit in each refinery is being operated at the percent of capacity for the respective unit's percent of operating capacity for the PADD of refineries being modeled by the LP refinery model. The initial percent of capacity utilization for each unit as estimated by the LP refinery model for 2004 and 2012 is presented in Table 9.1-4.

Table 9.1-4. Initial 2004 and 2012 Percent of Refinery Unit Capacity used in Refinery-by-Refinery Cost Model

		PADD 1	PADD 2	PADD 3	PADD 4 & 5 exCA
Crude	2004	101	94	97	89
	2012	103	97	100	98
Coking	2004	97	90	96	100
	2012	88	87	104	100
FCC	2004	94	97	95	100
	2012	96	97	96	111
Hydrocracker	2004	100	102	77	100
	2012	100	111	100	110
Isomerization	2004	98	100	100	103
	2012	98	72	100	100
Polymerization	2004	90	86	64	10
	2012	101	98	87	71
Alkylation	2004	100	92	71	89
	2012	103	96	75	95
Reforming	2004	88	82	85	85
	2012	93	82	96	72
Aromatics	2004	100	65	88	-
	2012	100	67	94	-

The estimates of refinery unit capacity utilized in Table 9.1-4 are a product of how the LP refinery model models the use of refinery units in each PADD of refineries. Normally, we would expect year 2004 (baseyear) 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 do not know 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. Despite the occasional apparent anomaly in percent of operating capacity estimated by the LP refinery model, we chose to use the LP refinery model's estimated refinery utilization factors.

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 9.1-4, 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 9.1-4 shows that the alkylation units in PADD 1 are estimated to be operating at 103 percent of its listed capacity in 2012, thus, alkylate production is projected to be 10,300 barrels per day at that refinery.

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 9.1-4 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.[13]   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 9.1-5, the volume of light straight run naphtha is estimated to be 4 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 2, a portion is designated to be sold into the petrochemicals market. For PADDs 1, 3, 4 and 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.[14] 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 23 to 32 percent for hydrocracker units depending on the PADD. Table 9.1-5 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 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 is 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 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 26 refineries in the U.S. in 2012 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 30 to 50 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 18 percent relative to the volume of feed due to the conversion of straight chain and cyclical 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. For PADDs 1 through 5, the reformer severity in 2012 falls within a range of 92 to 96 research octane number RON. [c] This range of reformer severity is projected to be lower than the reformer severity common today because of the projected increase in ethanol use and the high octane that it provides.

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 9.1-4. 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 55 to 57 percent.

Some gasoline blendstocks are purchased and blended into gasoline. The typically purchased gasoline blendstocks include natural gasoline, alkylate, isooctane and ethanol. 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, and our contractor who estimated the volume of isooctane which will be available from the conversion of MTBE plants. Based on the work we conducted for the Renewable Fuels Proposed rule, we provided to our contractor the volume of ethanol projected to be used in each PADD. 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 9.1-4. This strategy was effective for the few refineries in PADD 2 with extraction units 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

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[c] 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.

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.

A series of inputs are made to the refinery-by-refinery cost model which are necessary to estimate the cost for certain aspects of the cost modeling. These inputs are from the LP refinery model and EIA.

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 $47 dollar per barrel.[15]

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 reduce 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.[16]

The various assumptions associated with estimating gasoline blendstocks and the volumes of purchased and sold blendstocks and cost factors in 2012 are summarized in Table 9.1-5.

Table 9.1-5. Information used with the Refinery-by-Refinery Cost Model
(Projected Year 2012 Operating Conditions and Year 2004 dollars)

		PADD 1	PADD 2	PADD 3	PADDs 4, 5
Hydrogen Cost ($/foeb)		121	108	82	93
Octane Cost ($/oct-bbl)		0.28	0.20	0.30	0.27
RVP Cost ($/rvp-bbl)		0.36	0.26	0.25	0.28
Gasoline Price ($/bbl)		54	55	52	51
Light Straight Run Naphtha (% of Crude Oil)		4.5	5.0	4.4	4.4
Medium and Heavy Straight Run Naphtha (% of Crude Oil)		13.8	16.2	14.0	13.6
Reformate Severity (RON)		94.7	92.1	96.2	96.2
Average Reformate Yield (vol%)		82	83	82	81
Light Coker Naphtha (% of Unit Feed)		5	5	5	5
Medium and Heavy Coker Naphtha (% of Unit Feed)		18.4	18.4	18.4	18.4
Light Hydrocrackate (% of Unit Feed)		28.7	32.0	23.3	27.2
Medium and Heavy Hydrocrackate (% of Unit Feed)		35.4	43.4	50.2	33.3
FCC Naphtha (% of Feed)		56.6	56.9	54.9	56.4
Aromatics (% of Unit Capacity)		As necessary	0.62	As necessary	-
Inputs	Isooctene Purchased (Kbbl/d)	20	0	0	0
	Alkylate Purchased (Kbbl/d)	0	0	0	0
	Natural Gasoline (Kbbl/d)	0	48	117	35
	Ethanol (Kbbl/d)	73	203	150	59
Outputs	Naphtha to Petrochem. (Kbbl/d)	2	0	134	1
	Gasoline Blendstocks Kbbl/d	0	0	0	8

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, although for the case of steam are calculated based on fuel oil costs, 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 9.1-6 summarizes the various cost factors used in the refinery-by-refinery cost model by PADD.

Table 9.3-1. 2012 Cost Factors by PADD (2004 dollars)

	PADD 1	PADD 2	PADD 3	PADDs 4 & 5
Natural Gas $/foeb	48.3	43.0	32.9	37.0
Electricity $/kw-hr	0.069	0.044	0.056	0.057
Steam $/lb	0.010	0.0091	0.0070	0.0079
Capital Cost Adjustment Factors	1.25	1.15	1.00	1.40

9.1.4.2 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 9.1-7.

Table 9.1-7. 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)	9.8
Light Reformate (with complete benzene precursor rerouting)	0.90
Light Reformate (with benzene extraction)	0.58
Light Reformate (with benzene saturation)	0.39
Heavy Reformate – Semi-Regen (High Press.)	1.7-2.2
Cyclical (Medium Press.)	1.6-2.0
Continuous (Low Press.)	0.78-1.1
Heavy Reformate – High Press.	0.09 - 0.11
(with benzene Medium Press.	0.08 – 0.10
Extraction) Low Press.	0.040 – 0.050
Heavy Reformate – High Press.	0.07-0.09
(with benzene Medium Press.	0.06-0.08
Saturation) Low Press	0.03-0.04

9.1.4.3 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.[17] 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 2004 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 9.1-8.

Table 9.1-8. Calibrated 2004 and Projected 2012 Consumption and Production Volumes for Crude Oil and Gasoline by PADD (kbbl/day)

	Year	PADD 1	PADD 2	PADD 3	PADDs 4, 5
Crude Oil Consumed (Kbbl/d)	2004	1590	3297	7537	1433
	2012	1574	3403	7789	1589
Gasoline Produced (Kbbl/d)	2004	841	1872	3741	652
	2012	879	2081	4148	718

The initial summertime benzene level of each refinery's gasoline estimated with the refinery-by-refinery model was also calibrated against the reported annual average benzene content of gasoline in 2004 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 2004 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.

In Table 9.1-9, the refinery-by-refinery 2004 PADD-average benzene levels are compared to the actual PADD-average benzene levels for 2004. We also show the projected PADD-average benzene levels for 2012.

Table 9.1-9 Refinery-by-Refinery Model 2004 Calibrated and 2012 Projected
Benzene Levels by PADD versus 2004 PADD-actual Benzene Levels (vol%)

	Year	PADD 1	PADD 2	PADD 3	PADDs 4, 5
Actual Benzene Levels	2004	0.67	1.26	0.85	1.68
Refinery-by-Refinery Benzene Levels	2004	0.68	1.23	0.84	1.58
	2012	0.66	1.10	0.85	1.44

9.2   Cost Inputs for the 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 or from the literature. This information was updated from the proposed rule reflecting the detailed analysis we conducted to update the capital costs. Information is presented for routing benzene precursors around the reformer, routing that rerouted benzene precursor stream to an isomerization unit, and installing either of two reformer post-treat technologies, which are benzene saturation and benzene extraction.

9.2.1   Benzene Precursor Rerouting

Routing benzene precursors around the reformer requires that a refinery add a naphtha splitter distillation column, or modify an existing column, to 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 added or 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. A new unit would require the addition of a new naphtha splitter distillation column. 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 adding a naphtha splitter to facilitate routing benzene precursors around the reformer is summarized in Table 9.2-1.[18] 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.[19]

Table 9.2-1. Cost Inputs for Rerouting Benzene Precursors (2004 dollars)

Capital Costs – onsite and offsite ($MM)	9.6
Capital Cost Unit Size (bbl/day feedstock)	15,000
Catalyst ($/bbl)	0.01
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 95 RON 2004 dollars)

Catalyst Cost ($/bbl)	0.354
Fuel Gas (foeb/bbl)	0.044
Electricity (kwh/bbl)	2.6
Steam (lb/bbl)	75
Hydrogen (foeb/bbl feed)	0.036
Plant Gas (foeb/bbl feed)	0.029
Propane (bbl/bbl feed)	0.036
Isobutane (bbl/bbl feed)	0.017
Butane (bbl/bbl feed)	0.028

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 offsets some of the octane loss by producing branched chain compounds from the saturated benzene. The isomerized six carbon stream is estimated to have an octane value of 77.4 (R+M)/2, compared to a similar octane value for the rerouted benzene precursor stream before it. 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 reductions 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.

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[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.

Therefore, for some 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.[20]

Table 9.2-3. Cost Inputs for Sending the Rerouted Benzene Precursors to an Isomerization Unit (2004 dollars)

Catalyst ($/bbl)	0.25
Hydrogen (foeb/bbl)	0.002
Natural Gas (foeb/bbl)	0.009
Plant Gas (bbl/bbl)	-0.024
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 to benzene 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 the benzene-rich stream is sent to 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, potentially lowering the capital costs. A review of the capital cost inputs of the two benzene saturation technologies shows much lower capital costs. When we considered the

difference in capital costs, the CDHydro capital costs seemed much lower than expected considering the efficiency provided by the combined units. For this reason, we assigned the CDHydro unit the same capital costs as the conventional benzene saturation unit. 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.[21] [22] [23]

Table 9.2-4. Cost Inputs for Benzene Saturation (2004 dollars)

Inputs	Bensat	CDHydro
Capital Cost – onsite and offsite ($MM)	20.9	20.9
Capital Cost Unit Size (bbl/day feedstock)	8,400	8,400
Capital Cost Scaling Factor	0.65	0.65
Hydrogen (foeb/bbl)	0.046	0.046
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 final 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 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 for the benzene extraction unit assumes 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. 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 benzene extraction units. Table 9.2-5 contains the capital and utility cost inputs to the refinery-by-refinery cost model for benzene extraction.[24]

Table 9.2-5. Cost Inputs for Benzene Extraction (2004 dollars)

Capital Costs – onsite and offsite ($MM)	65.9
Capital Cost Unit Size* (bbl/day product)	1800
Capital Cost Scaling Factor	0.65
Catalyst ($/bbl)	0.354
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 2004 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

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[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.

unit would process the benzene rich reformate of other refineries to comply with the benzene program.

9.3   Benzene Market and Prices

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 are 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.[25] 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 9.3-1.

Table 9.3-1. 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 suggests that if refiners extract benzene from reformate, they will be able to and sell the concentrated benzene into the chemicals market. We considered this information below when we estimated the impact on benzene price when additional benzene is extracted from gasoline.

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 from the CMAI report are summarized in Table 9.3-2.

Table 9.3-2. 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. 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. Also, it is the relative price of benzene to gasoline which established the economics of extracted benzene. Since the proposal, we contacted CMAI and they provided us with more recent benzene and gasoline price information than that contained in their 2004 report.[26] The U.S. historical prices for benzene, gasoline and the difference between them for the nine years prior to 2005 are summarized in Table 9.3-3.

Table 9.3-3. Historical U.S. Benzene Price

Year	Benzene Price ($/bbl)	Gasoline Price ($/bbl)	Benzene Price above Gasoline Price ($/bbl)
1996	40.95	25.02	15.93
1997	42.00	24.60	17.40
1998	33.78	17.39	16.38
1999	36.36	21.79	14.57
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
2004	120.94	49.16	71.78
2005	121.75	67.47	54.71

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 2004 consistent with increasing demand as the economies of many countries 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. This demand increase continued in 2004 with a sharp increase in benzene price relative to gasoline

prices. Benzene prices remained about the same in 2005, but gasoline prices increased therefore decreasing benzene's relative price compared to gasoline's price.

CMAI used its economic model to project the benzene market in the medium term during the future years from 2006 through 2015. CMAI starts by establishing a basecase which was based on the information on the benzene market in 2005. 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 future benzene 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. In its 2004 report, CMAI projected that World benzene and U.S. benzene demand would increase annually at a very robust rate of 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 continued high benzene prices in 2007. As additional benzene production capacity comes on line, benzene prices are expected to come down to more moderate 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 9.3-4 summarizes the projected benzene and gasoline prices obtained from CMAI's 2005 benzene market projections through 2015. For 2011 through 2015, CMAI provided their projected benzene prices, but not the gasoline prices. We projected the gasoline prices for 2011 through 2015 using the crude oil prices provided by CMAI using the relationship of crude oil prices to gasoline prices from the previous years.

Table 9.3-4. Projected U.S. Benzene/Gasoline Price Differential

Year	Crude Oil Price ($/bbl)	Benzene Price ($/bbl)	Gasoline Price ($/bbl)	Benzene Price above Gasoline Price ($/bbl)
2007	69	128	79	50
2008	57	102	65	37
2009	52	93	59	35
2010	48	87	55	33
2011	47	85	54	32
2012	48	87	55	32
2013	50	88	56	32
2014	51	90	58	33
2015	52	93	60	34

The CMAI model estimates that the price of benzene in 2007 will be $50 higher than gasoline assuming that crude oil prices will stay high through 2007. CMAI projects that the price of crude oil will decline after 2007. As the projected crude oil price declines, both gasoline and benzene prices are also expected to decline resulting in benzene's price above gasoline to decrease to about $32 per barrel above the price of gasoline. CMAI's projected crude oil price is

$48 per barrel in 2012, which is consistent with the crude oil price assumed for our refinery modeling.

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 12,500 barrels per day, which is 192 million gallons per year, of benzene would be extracted from gasoline and sold to the petrochemical market under the benzene program assuming that it took effect in 2012.

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 192 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 highest cost process for producing benzene. The toluene would remain in the gasoline pool helping to maintain the octane and volume 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.[27] [28] While we don't expect a significant impact on benzene price, we rounded the incremental benzene price down to $30 dollars higher than gasoline. This incremental benzene price is slightly lower than CMAI's projected incremental price to account for a small decrease in benzene price caused by the increased benzene supply caused by this rulemaking.

9.4   Refinery Modeling of Benzene Control Scenarios

For modeling the benzene program, we addressed the costs and benzene impacts of the maximum average standard first. Refineries that the model estimates would be above the maximum average standard are assumed to put in the most cost-effective benzene reduction technology which the model shows would get them below the maximum average standard. Under the ABT program, the benzene control units that the model adds to meet the maximum average standard are assumed to be operated to achieve the maximum possible amount of benzene reduction. The benzene reductions associated with meeting the maximum average standard may or may not be sufficient for meeting the average standard depending on how stringent the maximum average 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.

If additional benzene reductions are needed after application of the maximum average standard, or if we were not modeling a maximum average standard, we modeled benzene reductions to meet the average benzene 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 benzene control cost-effectiveness until the sum of the technologies and refineries chosen results in the U.S. gasoline being produced meeting the benzene program being modeled, giving credit to refineries already below the proposed benzene standard.

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, we assumed the installation of a full sized unit is installed to treat the entire stream being treated, but assumed further that the 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 by comparing its cost output to the cost output of the LP refinery cost model. The LP refinery cost model is a good tool for comparison because it has been used for many years on many different cost studies subjecting it to extensive peer-review.

We evaluated the benzene program with the LP refinery model to estimate the energy and supply impacts of the benzene program. We specified the mix of benzene control technologies that the refinery-by-refinery cost model estimates will be used in each PADD to comply with the benzene program. We trust the refinery-by-refinery cost model's choice of benzene control technologies because of its ability to estimate benzene control costs for each refinery and choose the best mix of benzene control technologies across the refining industry. Because we matched the benzene control technologies and final benzene levels in each PADD a close match in control costs between the two models would confirm that the refinery-by-refinery cost model is sound in its construction. Comparing the cost output of the two cost models, the LP refinery cost model produced very similar costs compared to the refinery-by-refinery cost model, which corroborates the refinery-by-refinery cost model. 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 Benzene Program (2003 dollars, 7% ROI before taxes)

		PADD 1	PADD 2	PADD 3	PADDs 4 & 5	U.S. Average
Refinery-by-Refinery Cost Model	Cost (cents/gal)	0.15	0.34	0.16	0.91	0.27
	Bz Level (vol%)	0.52	0.63	0.61	0.78	0.62
LP Refinery Cost Model	Cost (cents/gal)	0.16	0.27	0.14	0.92	0.24
	Bz Level (vol%)	0.52	0.63	0.61	0.76	0.62

9.6   Refining Costs

This subsection summarizes the estimated costs of the benzene program as well as the other benzene standards considered for this final rulemaking. The estimated cost for the 0.62 vol% benzene standard with 1.3 maximum average standard and ABT program is summarized first, including the sensitivity cases described above. We next summarize the estimated cost for the same and higher and lower average benzene standards, with and without various maximum average standards or which models a benzene program without an ABT program. We adjust our costs from 2004 dollars back to 2003 dollars to make our costs consistent with the gas can and vehicle costs. To make this cost adjustment we used a 0.97 inflation cost factor from the Department of Labor webpage.

The capital costs estimated by the refinery-by-refinery cost model do not include the capital costs associated with hydrogen production and octane recovery. For this reason we believe that the capital costs estimated by the refinery-by-refinery cost model are low. We compared the capital cost estimate by the LP refinery cost model, which includes the hydrogen and octane capital costs, and found them to be about 20 percent higher than those estimated by the refinery-by-refinery cost model. For all the capital cost estimates for all the benzene programs evaluated by the refinery-by-refinery cost model, we adjusted them higher by 20 percent.

9.6.1   Cost of the Benzene Program

The refinery-by-refinery cost model was used to estimate the cost of the benzene program, which puts in place a 0.62 vol% average benzene standard with a 1.3 maximum average standard and an 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 technologies in the refinery-by-refinery cost model is affected by the nature of the stringency of the benzene reduction program being modeled. The refinery-by-refinery cost model indicates that benzene precursor rerouting alone is the most cost effective benzene control technology, followed by routing the benzene precursors to an isomerization unit and extraction. 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 with or without isomerization as the means for achieving benzene reductions. We assume that the ABT program would be fully utilized with credit trading occurring freely within and between refining companies.

The fully phased-in 0.62 vol% benzene standard with 1.3 maximum average standard and ABT program is estimated to cost 0.27 cents per gallon averaged over all U.S. gasoline and with capital costs amortized at 7% ROI before taxes. The total capital cost is estimated to be $1110 million; the total annual cost including amortized capital costs is $330 million/yr estimated in the year 2012.

The 0.27 cents per gallon 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 vol%. When the costs are averaged only over the portion of U.S gasoline which is expected to be reduced in benzene, the fully phased-in benzene program is expected to cost 0.40 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 $14 million and $4.2 million, respectively. These estimated costs for the benzene program are summarized in Table 9.6-1.

Table 9.6-1. Estimated Costs of the Fully Phased in Benzene Program Evaluated in 2012 (2003 dollars, 7% ROI before taxes)

All Refineries	Number of Refineries	104
	Total Capital Cost ($ million)	1110
	Total Annual Cost ($ million/year)	330
	Per-Gallon Cost (cents/gallon)	0.27
Refineries Reducing Their Gasoline Benzene Levels	Number of Refineries	79
	Capital Cost per Refinery ($ million)	14
	Operating Cost per Refinery ($ million/year)	4.2
	Per-Gallon Cost (cents/gallon)	0.40

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 benzene standards, or (with respect to

the 0.62 vol% average benzene standard), 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 and the extent of benzene reduction achieved by them. 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. The figure shows that we project costs to be low for most refineries, representing most of the gasoline production in the country; a relatively few higher-cost refineries contribute significantly to the higher average cost of the program.

Figure 9.6-1. U.S. Refinery Per-Gallon Costs for the Benzene Program
(2003 dollars, 7% ROI before Taxes)
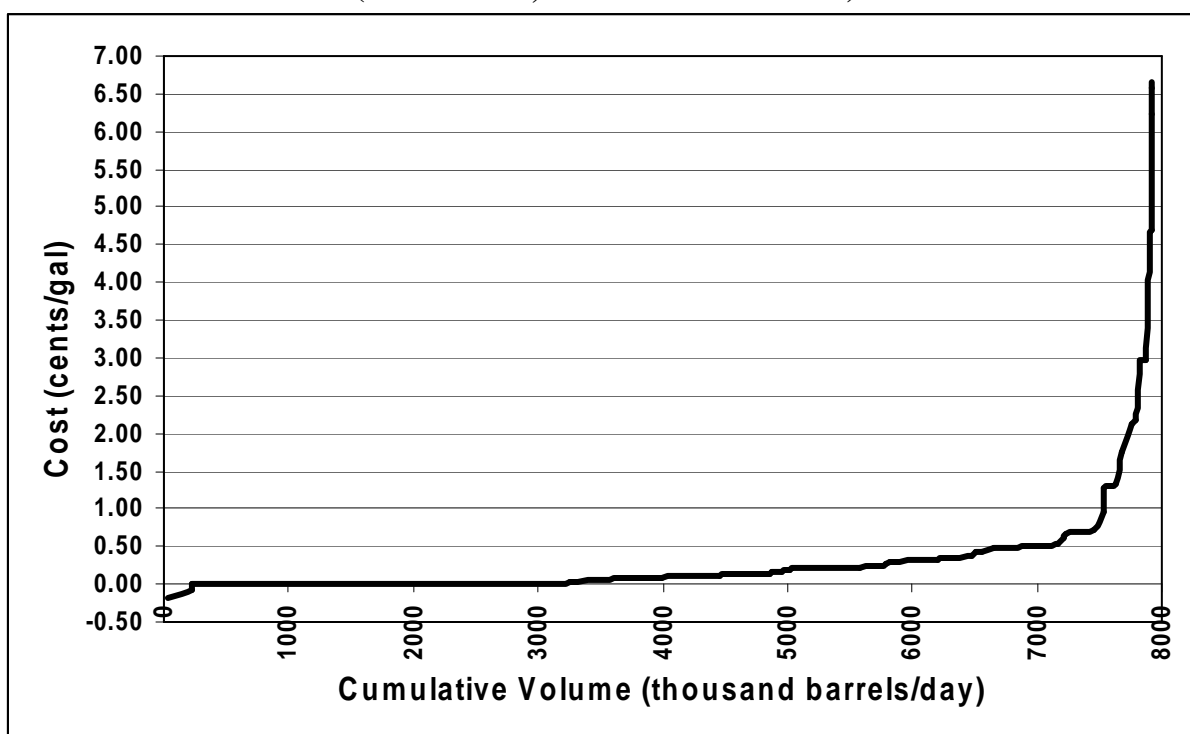
To comply with the benzene program, we expect that all of the control technologies discussed above would be utilized. Of the 79 refineries expected to take steps to reduce their gasoline benzene levels, 17 are expected to route all of the benzene precursors around the reformer, and 28 are expected to send that rerouted stream to their isomerization unit. Of the refineries which take steps to lower their gasoline benzene levels by treating reformate, 16 would install a grassroots benzene extraction unit or revamp their existing extraction units while the another 18 would install benzene saturation units. We project that 52 refineries will continue to produce gasoline with benzene levels greater than the 0.62 vol% average standard and will choose to purchase credits to comply with that standard. Including the refineries with benzene levels currently below 0.62, we project that there will be a total of 50 refineries that will produce gasoline with benzene levels at 0.62 or lower and will generate credits for sale to other refineries.

Finally, based on our modeling, we project that 26 refineries will not take steps to reduce their gasoline benzene levels to comply with the 0.62 and 1.3 vol% benzene standards.

While the estimated per-gallon costs are very low, there is a range in costs depending on the area of the country (again primarily reflecting the degree of benzene reductions as well as the ability to extract and sell the extracted benzene). 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 the rest of the PADDs because extraction was not assumed to be an option due to lack of benzene markets. The average per-gallon benzene control costs for each PADD are summarized in Table 9.6-2.

Table 9.6-2. Per-Gallon Costs by PADD for the Benzene Program
(cents/gal; 2003 dollars; 7% ROI before taxes)

PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 except CA
0.15	0.34	0.16	0.69	1.11

In each PADD, the average costs in Table 9.6-2 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
Benzene Program
(2003 dollars, 7% ROI before Taxes)
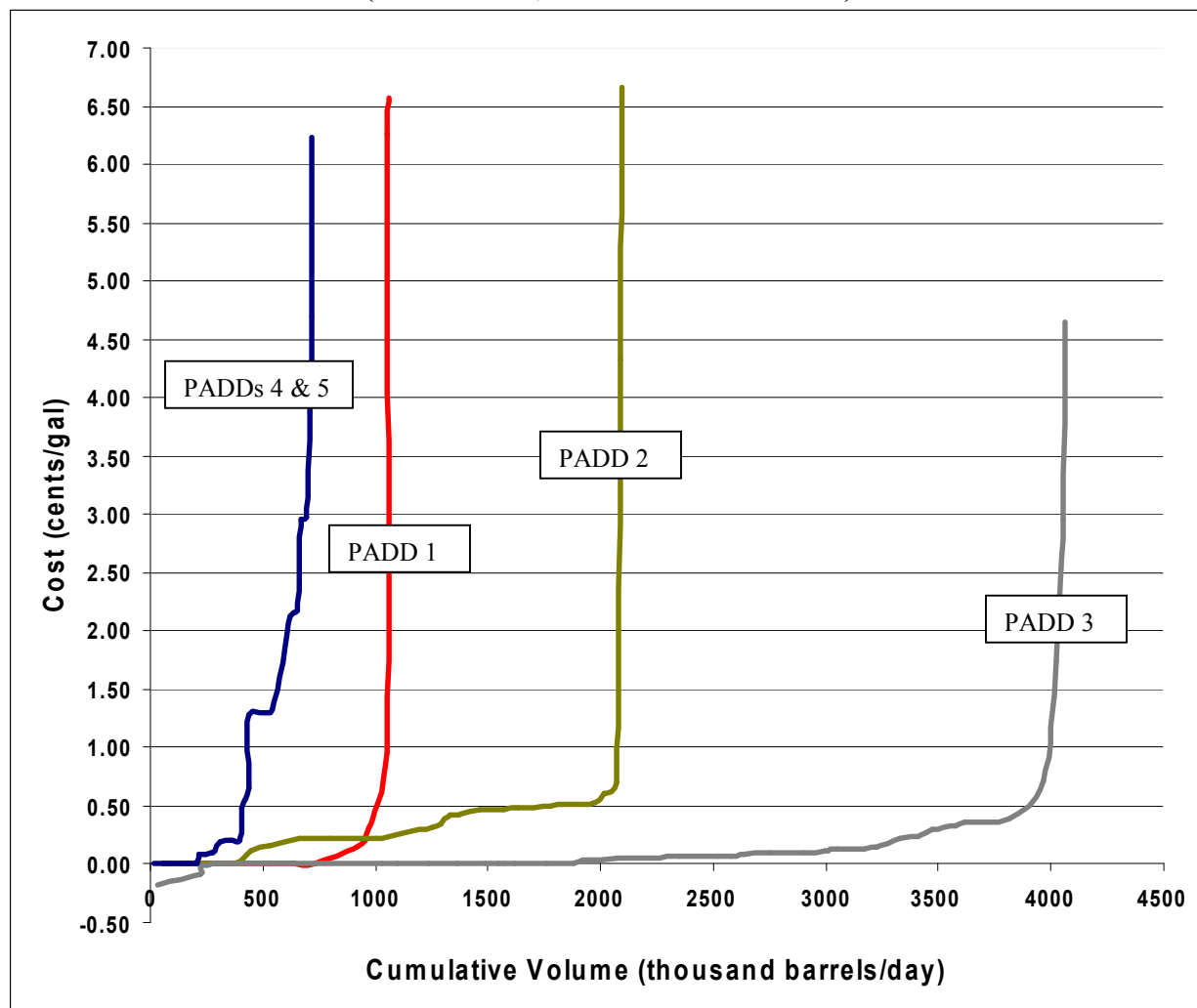
Figure 9.6-2 shows a significant range in costs by the refineries in each PADD. Costs for most refineries in PADDs 1 and 3 are similar with most costs being incurred through extraction which results in near zero (and in a few cases slightly less than zero) costs, as well as zero costs for refineries which do not need to take any action due to already low gasoline benzene levels. Most of the refineries in PADDs 4 and 5 face higher costs, and these costs are significantly higher than the costs for most refineries in the other PADDs due to the generally smaller refineries there and the inability to use extraction. The refinery costs in PADD 2 are more moderate for most of the refineries than those in PADDs 4 and 5, but still more severe than the costs for most of the refineries in PADDs 1 and 3.

In each PADD there are smaller-sized refineries which the model predicts would need to comply with the maximum average standard using benzene saturation, resulting in high per-gallon costs. The costs for these refineries are high because of their poorer economies of scale. The model does not attempt to apply other means likely to be available to these refineries for

avoiding these high per-gallon costs. We believe that these refiners can avoid resorting to benzene saturation and their associated high per-gallon costs by installing a reformate splitter. The reformate splitter is a relatively low capital and operating cost unit that would allow them to remove a benzene-rich stream from the rest of their reformate, resulting in a final gasoline blend that would be in compliance with the maximum average standard. The benzene-rich stream can be sold to another refinery with gasoline benzene levels below the cap standard and so can absorb this small benzene-rich volume. This sort of trading is similar to the credit trading program, except that actual benzene is being traded instead of paper credits.[f]

The rule also includes hardship provisions, available to all refineries, to address extreme hardship situations. The model assumes full compliance without hardship relief, and so may overstate costs for this reason as well.

Our refinery modeling analysis projects that the ABT program will effectively result in a phase-in of the benzene program from 2007 through early 2015. Starting in mid-2007 we believe that using simple operational changes refiners will take the opportunity to achieve modest benzene reductions to generate early credits. We project that these actions taken in mid-2007 will result in a reduction of the average U.S. gasoline benzene level from 1.00 to 0.81 volume percent at an average cost of 0.04 cents per gallon averaged over all U.S. gasoline.

To take full advantage of the flexibility provided to refiners by the ABT program to delay more expensive capital investments, refiners are expected to make additional early benzene reductions to generate more early credits, requiring modest investments in capital. Because of the time it takes to assess, design and install the capital equipment, we believe that these additional early benzene reductions will not occur until the beginning of 2010. These benzene reductions are expected to further reduce the average benzene level of U.S. gasoline to 0.74 volume percent and cost 0.05 cents per gallon averaged over all U.S. gasoline. Refiners are expected to make $324 million of capital investments to achieve this benzene reduction. In 2011 when the 0.62 vol% average benzene standard takes effect, we do not anticipate any further reduction in benzene because we project that the refining industry will be able to comply using early credits.

In mid-2012, when refineries with high benzene levels need to comply with the 1.3 volume percent maximum average standard, we anticipate that U.S. gasoline benzene levels will decline further, to 0.73 vol% benzene and cost an additional 0.04 cents per gallon averaged over all U.S. gasoline. Refiners are expected to make another $153 million in capital investments to comply with the 1.3 vol% maximum average standard which takes effect in mid-2012. Although the early credit use period terminates at the end of 2013, refiners will be able to further delay their most expensive capital investments by using standard credits (which will have been accruing since the start of 2011).[g] Because we expect that refiners will first use their early credits, the standard credits will be banked and will start to be used in 2014 to show compliance

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f Uncertainties in how trading of actual benzene barrels would occur precluded our modeling the cost of this option. For example, we could not anticipate which refiners would be willing to accept this benzene-rich stream which affects its transportation costs.
g Early credits generated or obtained and ultimately used by small refiners may be used through 2017. However, these credits will not affect the overall implementation timeline discussed here.

with the 0.62 vol% average benzene standard. Our analysis suggests that the U.S. refining industry will be able to delay their highest capital investments until May 2015 when the standard credits accumulated since the beginning of 2011 run out. Small refiners must meet the 1.3 vol% maximum-average standard beginning of July 2016 so they also will be reducing their gasoline benzene levels to that standard or below.[h] Small refiners are expected to add an additional 0.01 cents per gallon averaged over all U.S. gasoline when reducing their gasoline benzene levels to comply with their average and cap standards, although the average U.S. gasoline benzene levels do not appear to change due to rounding. This additional benzene reduction is estimated to incur an additional $26 million in capital investments. The nonsmall refiners are projected to fully complete the transition in May 2015 bringing the average gasoline pool down to 0.62 vol% benzene, and incurring a 0.13 cents per gallon cost averaged over all U.S. gasoline and $608 million in capital investments. The estimated cost savings of both the early and ongoing aspects of the ABT program are summarized above in Section 6.5.5.12 where the impacts of the ABT program are discussed.

We estimated the stream of total annual compliance costs for the U.S. refining industry complying with the benzene program from 2007 to 2035, including the phase-in of the ABT program. We used the per-gallon program costs to refiners in 2012 throughout the phase-in period as well as the fully phased-in program, multiplying these estimated costs times the projected gasoline demand by the Energy Information Administration (EIA) contained in the Annual Energy Outlook (AEO) 2006. Since the EIA projections end at 2030, we used the annual average growth rate over the years 2025 to 2030 to extrapolate the growth in demand to 2035. The stream of projected gasoline consumption volume and the total annual costs for complying with the benzene program are summarized in Table 9.6-3.

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h Our analysis included values for small additional costs and emission reductions based on an assumption that the start date for the 1.3 maximum average standard for small refiners would be 2015. Since the final rule sets this date as July 2016, our 2015 results are slightly over-estimated.

Table 9.6-3. Stream of Total Compliance Costs for the Benzene Program
(2003 dollars, 7% ROI before Taxes)

Year	Gasoline Volume (million gallons)	Cost (c/gal)	Total Program Cost (million dollars)
2007	123,719	0.02	28
2008	125,315	0.04	49
2009	127,311	0.04	50
2010	129,705	0.09	101
2011	132,233	0.09	104
2012	134,362	0.11	133
2013	136,224	0.13	164
2014	137,953	0.13	166
2015	139,683	0.27	363
2016	141,412	0.27	379
2017	143,142	0.27	384
2018	144,871	0.27	388
2019	146,733	0.27	393
2020	148,463	0.27	398
2021	150,059	0.27	402
2022	151,656	0.27	406
2023	153,119	0.27	410
2024	154,582	0.27	414
2025	156,179	0.27	419
2026	157,775	0.27	423
2027	159,504	0.27	427
2028	161,234	0.27	432
2029	162,830	0.27	436
2030	164,560	0.27	441
2031	166,156	0.27	445
2032	167,885	0.27	450
2033	169,632	0.27	455
2034	171,397	0.27	459
2035	173,180	0.27	464

9.6.2   Cost of Alternative Benzene Programs

We used the refinery-by-refinery cost model to estimate the cost of other potential benzene standards. This includes analyses of different maximum average benzene standards, different averaging standards, and benzene standards with and without ABT programs.

Table 9.6-4 contains a summary of the national average per-gallon costs and aggregate capital and total annual costs for maximum average benzene standards which range from 1.1 to 1.5 vol% benzene and average benzene standards which range from 0.50 to 0.71 vol%, with and without an ABT program. The 0.50 vol% average benzene standard represents the most stringent benzene 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 0.71 vo% benzene, but without the full ABT program. Each refinery would have to average 0.71 vol% benzene across its own gasoline batches with no ability to average or trade across refineries, or bank credits. This benzene standard is projected to result in a national average benzene level which would equal the 0.62 vol% benzene standard

with full ABT – thus it is an interesting case to study relative to the benzene program. However, the refinery model estimates that two refineries would not be able to achieve the 0.71 vol% benzene standard based on reformate benzene control alone, thus it is not a perfect comparison.

Table 9.6-4. Cost of Other Benzene Standards
(2003 dollars, 7% ROI before taxes)

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)
0.50	Yes	None	0.50	0.74	900	2140
0.60	Yes	1.3	0.60	0.31	380	1250
0.60	Yes	None	0.60	0.30	360	1180
0.62	Yes	1.1	0.62	0.34	410	1120
0.62	Yes	1.2	0.62	0.30	360	1070
0.62*	Yes	1.3	0.62	0.27	330	1110
0.62	Yes	1.4	0.62	0.26	320	1100
0.62	Yes	1.5	0.62	0.25	300	1070
0.62**	Yes	None	0.62	0.24	290	1120
0.65	Yes	1.3	0.65	0.21	250	950
0.65	Yes	None	0.65	0.18	220	960
0.70	Yes	1.3	0.70	0.16	190	740
0.70	Yes	None	0.70	0.11	140	510
0.71***	No	None***	0.62	0.51	620	1670

* Final Rule
** Proposed Rule
*** The 0.71 volume percent benzene standard we modeled could also be thought of being a maximum average standard, because without an ABT program, each refinery would have to meet this level with actual production on an annual average basis.

Our refinery model analysis shows that the reduced flexibility of adding a maximum average benzene standard increases the cost of benzene control over a benzene control program without a maximum average standard. We estimate that the reduced flexibility will require 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. As the table shows, these additional actions by some refiners and the associated cost increases will not affect the in-use benzene level, which will be driven by the 0.62 vol% average standard regardless of the level of maximum average standard.

The benefit to the program of the 1.3 vol% maximum average standard is the increased certainty that the benzene reductions projected by our modeling will in fact be achieved nationwide, especially the significant reductions projected in areas that currently have the highest benzene levels. Implementing a maximum average standard lower than 1.3 vol% would increase the number of refineries that need to install the more expensive benzene reduction equipment. This would diminish the value of the flexibility provided by the ABT program by requiring an increasing number of refineries to make expenditures in benzene control that could otherwise be smaller or avoided entirely, thereby increasing the overall costs of the program. Conversely, a maximum average standard greater than 1.3 vol% would require progressively fewer refineries to take action to reduce their benzene levels. This would in turn provide less assurance that actual

benzene levels would be broadly achieved and would undermine the greater degree of geographic uniformity in benzene reductions achieved by the 1.3 vol% standard.

The 0.71 vol% benzene standard without the ABT program, which results in the same national average gasoline benzene level as the benzene program, is estimated to cost almost two times more than the benzene program. Without any ABT program, this standard offers the least amount of flexibility compared to the benzene program. The lack of flexibility of this benzene standard results in a larger share of benzene reductions occurring through benzene saturation, the most expensive benzene control technology.

We plotted the projected per-gallon costs for each refinery producing gasoline (from lowest to highest cost) versus the cumulative volume of gasoline across the refineries producing gasoline for several benzene programs of interest. Figure 9.6-3 shows the per-gallon costs for the final benzene program and a program with the same standard, but without a maximum average standard. We also included a plot of the 0.50 vol% benzene standard which represents maximum reformate benzene control technically achievable (albeit at significant higher national cost, and with significant adverse economic impact on individual refineries).

Figure 9.6-3.
Cost Comparison between Final Benzene Standards and Two Other Options
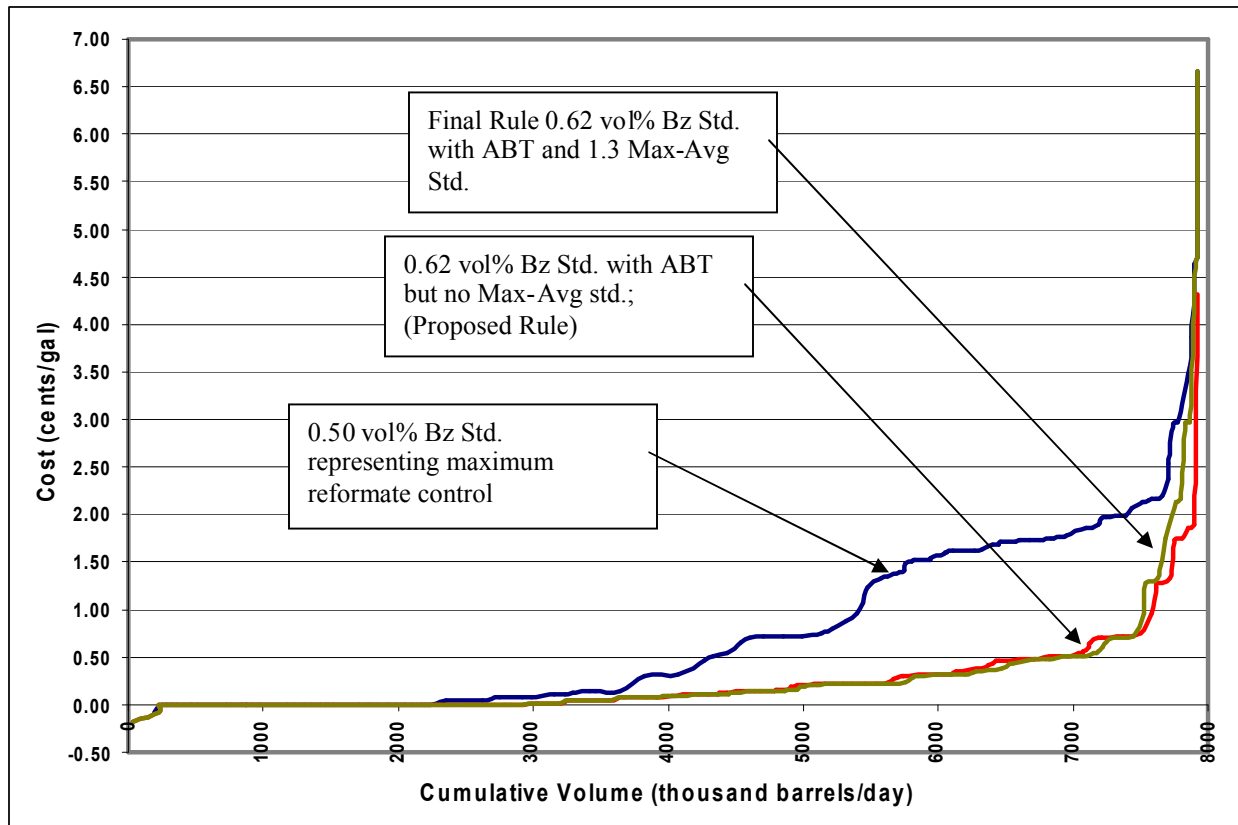**(2003 dollars, and 7% ROI before taxes)**

Figure 9.6-3 shows that for nearly half the volume of gasoline, the costs for benzene control are zero or near zero, and for a few extraction refineries even negative. The model projects that the addition of the maximum average standard will require a small number of refineries to adopt more expensive benzene control strategies. Comparing the proposed and final programs, the final rule benzene program would cause 16 refineries to exceed 1 cent per-gallon compliance cost compared to 8 refineries that would exceed 1 cent per gallon without a maximum average standard. The 0.50 vol% benzene standard would be much more expensive in this regard as it is estimated to cause about 60 refineries to exceed 1 cent per gallon in compliance costs. Although it is difficult to determine this from the above figure, the refinery with the highest cost of compliance under the final benzene program is estimated to incur about a 6.5 cents per gallon cost (same for the 0.50 vol% standard) while under the benzene program without the maximum average standard the refinery with the highest cost of compliance would be about 4 cents per gallon.

Table 9.6-5 below summarizes the number refineries which install or adopt each of the four different types of benzene control technologies for:

- the final benzene program (0.62 vol% average benzene standard with 1.3 maximum average standard and ABT program,

- a 0.62 vol% benzene standard program with ABT program, but no maximum average standard (proposed rule),

- a 0.71 vol% benzene standard without an ABT program which results in a 0.62 vol% average benzene level in gasoline, and

- a 0.50 vol% benzene standard with ABT program (maximum reformate benzene control).

Table 9.6-5. Projected Number and Type of Benzene Control Technologies Installed for the Final Benzene Standards and Other Options

	Routing Benzene Precursors Around Reformer	Sending Rerouted Benzene Precursors to Isom Unit	New and Revamped Benzene Extraction Units	Benzene Saturation
Final Rule 0.62 vol% avg Bz std with 1.3 Max-Avg std and ABT program	17	28	16	18
0.62 avg Bz std with ABT Program , no max-avg std (proposed rule)	19	28	17	8
0.71avg Bz std, No ABT Program; 0.62 vol% in-use	1	12	25	52
0.50 avg Bz std with ABT (maximum reformate benzene control)	0	0	63	24

Adding a maximum average standard or eliminating the ABT program altogether is projected to result in a different pattern of benzene reduction across the country. Refineries which we project will find it economically advantageous to realize only minor benzene reductions and to primarily purchase credits to comply with the average benzene standard are primarily located in PADD 4 and PADD 5. The refineries which we project will generate credits under the ABT program are primarily located in PADDs 1 and 3. The model assumes perfect trading of credits, so if an alternate program is projected to increase benzene reductions in one area, the model would project that this increase would be offset by decreased benzene reductions in other areas. For example, as shown in Table 9.6-6, the model projects that adding a 1.3 vol% maximum average standard should result in significant additional benzene reductions in PADDs 4 and 5 and a small increased reduction in PADD 1, all of which would appear to be offset by small decreases in benzene reductions in PADDs 2 and 3.

We note that the design of the refinery model and its inherent trading assumptions is such that we can be much more certain that large projected changes will actually occur than we can about small projected changes. Thus, while we are confident that adding the 1.3 vol% maximum average standard will result in greater benzene reductions in PADDs 4 and 5 than would a program without the 1.3 vol% standard, we cannot be certain that the small changes projected for PADDs 1, 2, and 3 will occur or occur in the ways that the model projects. In addition to this uncertainty about small modeled changes in benzene, some refiners may behave differently than the model predicts. For example, it is not unlikely that some refiners in PADDs 2 and 3 will choose to "over-comply" with the 0.62 vol% average standard (to provide a greater margin of safety for compliance) regardless of the state of the benzene credit market. Yet the model would tend to project that these refiners would reduce benzene levels as little as necessary. Thus, the projected benzene levels achieved in PADDs 2 and 3 under a 0.62 vol% benzene standard without a maximum average standard may well be achieved (or even exceeded) under the final

rule program with a maximum average standard if refiners choose to comply with a safety margin. Table 9.6-6 summarizes the estimated benzene level by PADD for several different benzene programs that would result in the same nationwide benzene level, but differing gasoline benzene profiles because of the addition of the maximum average standard. We also show the pattern of benzene control across the country for the 0.50 vol% benzene standard with ABT program.

Table 9.6-6. Comparison of the 2004 and Modeled Gasoline Benzene Levels by PADD for the Final Benzene Program and Other Options (vol% benzene)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 excluding CA	U.S. Average
Current Benzene Levels	0.67	1.26	0.85	1.56	1.80	1.00
Final Rule 0.62 vol% avg Bz std with 1.3 Max-Avg std and ABT program	0.52	0.63	0.61	0.90	0.69	0.62
0.62 vol% avg Bz std with 1.1 Max-Avg std and ABT program	0.55	0.61	0.63	0.83	0.55	0.62
0.62 vol% avg Bz std with 1.5 Max-Avg std and ABT program	0.52	0.63	0.60	0.90	0.82	0.62
0.62 avg Bz std with ABT Program No Max-Avg (Proposed Rule)	0.53	0.61	0.60	0.94	0.88	0.62
0.71 avg Bz std, No ABT Program*	0.53	0.70	0.59	0.71	0.70	0.62
0.50 avg Bz std with ABT (maximum reformate benzene control)	0.50	0.45	0.52	0.53	0.48	0.50

* The cost analysis shows that 2 refineries would not be able to meet a 0.71 vol% benzene standard. These two refineries would need to achieve the 0.71 vol% standard by reducing benzene levels in another gasoline stream.

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 programs with average national benzene levels of 0.62 vol% benzene. A review of the refinery-by-refinery output shows that the benzene levels of the refineries in PADD 4 and PADD 5 (excluding California) are most likely to remain above the average standard with a nationwide ABT program in place. The plots of the refinery benzene levels against cumulative gasoline production for all U.S. refineries, and for all refineries in PADDs 4 and 5 (excluding California), are contained in Figure 9.6-4, and Figure 9.6-5, respectively.

Figure 9.6-4. U.S. Final Rule Benzene Levels Compared to Benzene Levels for 2004 and Other Control Options
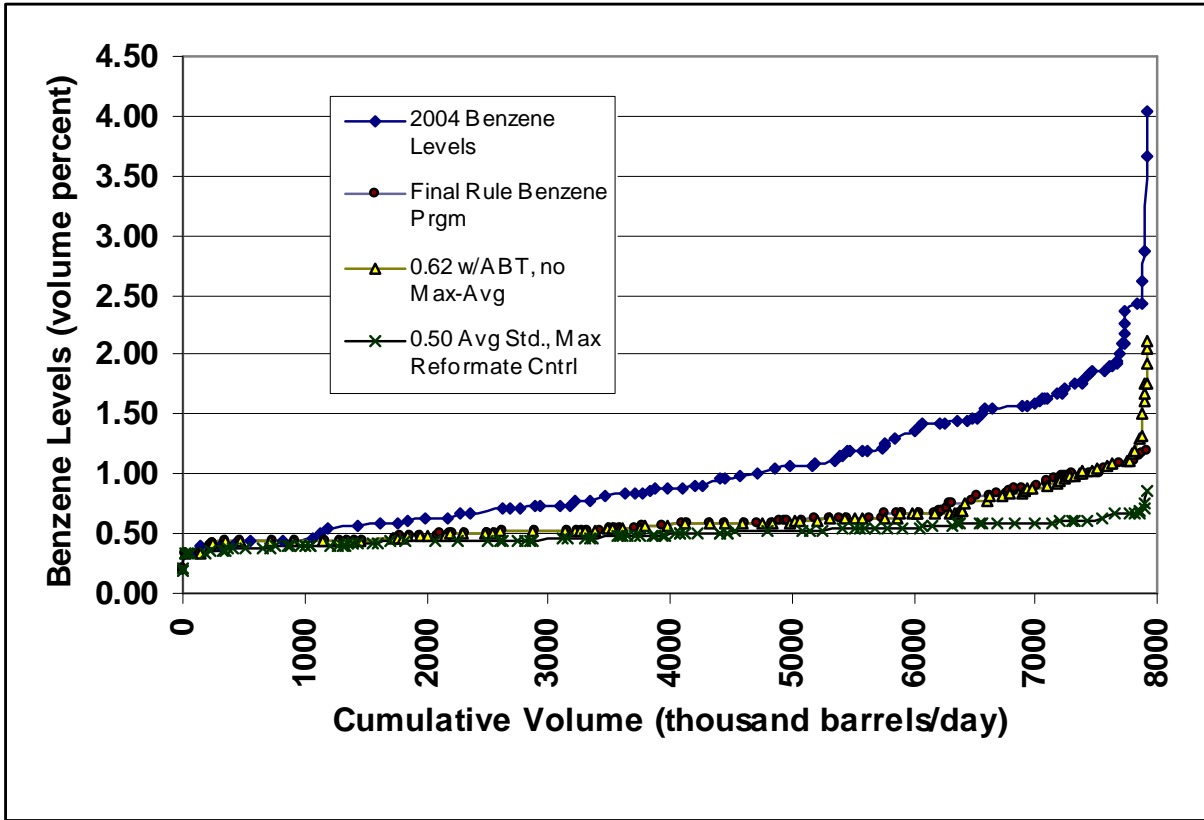
**Figure 9.6-5. PADD 4 and 5 Estimated Final Rule Benzene Levels Compared
to Benzene Levels for 2004 and Other Control Options**
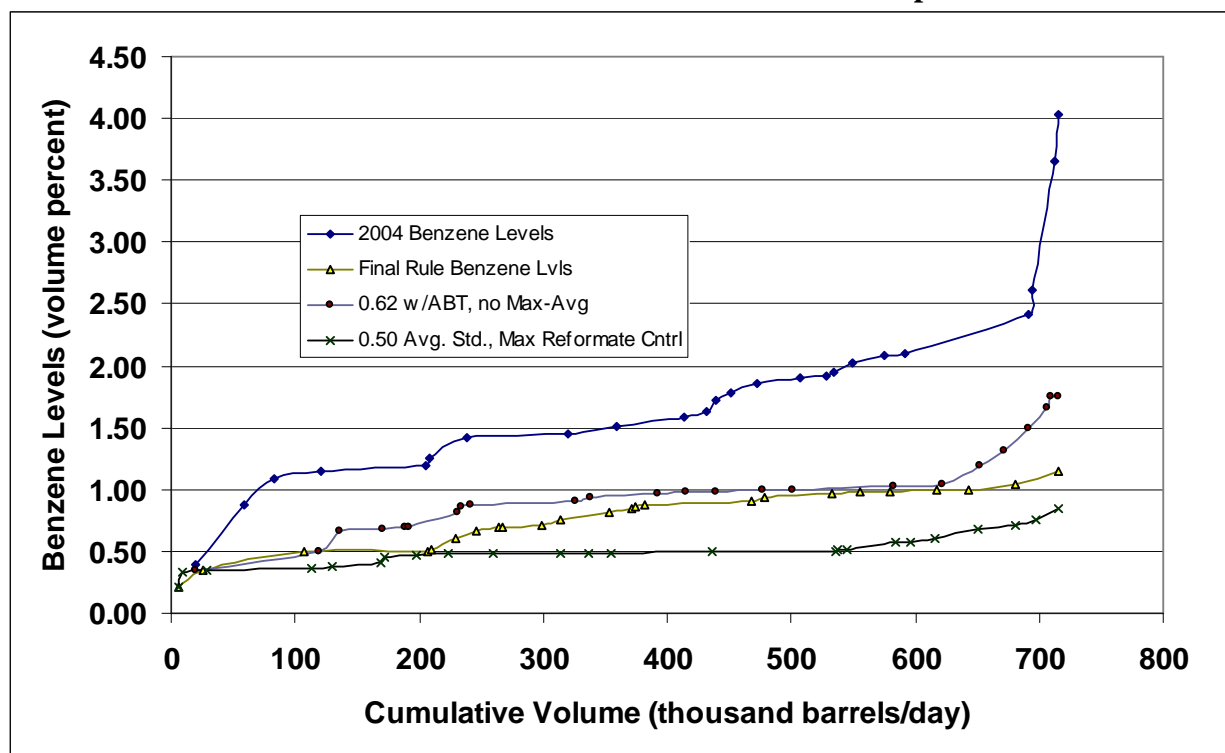
All of the benzene standards represented in Figure 9.6-4 and Figure 9.6-5 would realize
substantial benzene reductions in all parts of the country compared to today's benzene levels. As
the benzene control standard is tightened or as flexibility is reduced, the curve for gasoline
benzene levels becomes flatter.

9.6.3   Costs Used to Estimate Price Impacts of the Benzene Program

In Chapter 13 of the RIA, we estimate the increase in gasoline prices for the benzene
program. 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 principles 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. Tables 9.6-7,8 and 9 summarize gasoline consumption volumes and average per-gallon consumption costs and per-gallon maximum total and maximum variable costs for each PADD for estimating the price impacts of the benzene program.

Table 9.6-7. Summary of Yearly Volumes and Potential Price Increases by PADD for the Benzene Program Based on Average Total Costs
(2003 dollars, 7% ROI before taxes)

Year	PADD 1 Gasoline Consumption (million gals)	Cost (c/gal)	PADD 2 Gasoline Consumption (million gals)	Cost (c/gal)	PADD 3 Gasoline Consumption (million gals)	Cost (c/gal)	PADD 4 Gasoline Consumption (million gals)	Cost (c/gal)	PADD 5 except CA Gasoline Consumption (million gals)	Cost (c/gal)
2004	49,193	0	38,790	0	20,615	0	4542	0	7918	0
2005	49,517	0	39,045	0	20,751	0	4572	0	7971	0
2006	50,274	0	39,642	0	21,068	0	4642	0	8092	0
2007	50,923	0.008	40,154	0.053	21,340	0.013	4702	0.019	8197	0.004
2008	51,734	0.014	40,793	0.091	21,680	0.022	4777	0.033	8327	0.007
2009	52,707	0.014	41,560	0.091	22,088	0.022	4867	0.033	8484	0.007
2010	53,734	0.027	42,370	0.194	22,518	0.042	4962	0.099	8649	0.035
2011	54,599	0.027	43,052	0.194	22,881	0.042	5042	0.099	8788	0.035
2012	55,355	0.051	43,649	0.308	23,198	0.075	5111	0.213	8910	0.140
2013	56,058	0.048	44,203	0.227	23,492	0.065	5176	0.227	9023	0.244
2014	56,761	0.048	44,757	0.227	23,787	0.065	5241	0.227	9137	0.244
2015	57,464	0.147	45,311	0.307	24,081	0.154	5306	0.501	9250	0.997
2016	58,167	0.147	45,866	0.307	24,376	0.154	5371	0.501	9363	0.997
2017	58,869	0.147	46,420	0.307	24,670	0.154	5436	0.501	9476	0.997
2018	59,626	0.147	47,016	0.307	24,987	0.154	5506	0.501	9598	0.997
2019	60,329	0.147	47,571	0.307	25,282	0.154	5571	0.501	9711	0.997
2020	60,978	0.147	48,082	0.307	25,554	0.154	5631	0.501	9815	0.997
2021	61,626	0.147	48,594	0.307	25,826	0.154	5691	0.501	9920	0.997
2022	62,221	0.147	49,063	0.307	26,075	0.154	5745	0.501	10,015	0.997
2023	62,816	0.147	49,531	0.307	26,324	0.154	5800	0.501	10,111	0.997
2024	63,464	0.147	50,043	0.307	26,596	0.154	5860	0.501	10,215	0.997
2025	64,113	0.147	50,554	0.307	26,868	0.154	5920	0.501	10,320	0.997
2026	64,816	0.147	51,109	0.307	27,162	0.154	5985	0.501	10,433	0.997
2027	65,518	0.147	51,663	0.307	27,457	0.154	6050	0.501	10,546	0.997
2028	66,167	0.147	52,174	0.307	27,729	0.154	6110	0.501	10,651	0.997
2029	66,870	0.147	52,728	0.307	28,023	0.154	6175	0.501	10,764	0.997
2030	67,519	0.147	53,240	0.307	28,295	0.154	6235	0.501	10,868	0.997
2031	68,221	0.147	53,794	0.307	28,589	0.154	6299	0.501	10,981	0.997
2032	68,931	0.147	54,354	0.307	28,887	0.154	6365	0.501	11,095	0.997
2033	69,648	0.147	54,919	0.307	29,187	0.154	6431	0.501	11,211	0.997
2034	70,373	0.147	55,491	0.307	29,491	0.154	6498	0.501	11,328	0.997
2035	71,105	0.147	56,068	0.307	29,798	0.154	6566	0.501	11,445	0.997

Table 9.6-8. Summary of Yearly Volumes and Potential Price Increases by PADD for the Benzene Program Based on Maximum Total Costs
(2003 dollars, 7% ROI before taxes)

Year	PADD 1 Gasoline Consumption (million gals)	PADD 1 Cost (c/gal)	PADD 2 Gasoline Consumption (million gals)	PADD 2 Cost (c/gal)	PADD 3 Gasoline Consumption (million gals)	PADD 3 Cost (c/gal)	PADD 4 Gasoline Consumption (million gals)	PADD 4 Cost (c/gal)	PADD 5 except CA Gasoline Consumption (million gals)	PADD 5 except CA Cost (c/gal)
2004	49,193	0	38,790	0	20,615	0	4542	0	7918	0
2005	49,517	0	39,045	0	20,751	0	4572	0	7971	0
2006	50,274	0	39,642	0	21,068	0	4642	0	8092	0
2007	50,923	0.026	40,154	0.243	21,340	0.323	4702	0.609	8197	0.334
2008	51,734	0.026	40,793	0.243	21,680	0.323	4777	0.609	8327	0.334
2009	52,707	0.026	41,560	0.243	22,088	0.323	4867	0.609	8484	0.334
2010	53,734	0.189	42,370	0.473	22,518	0.424	4962	0.176	8649	0.334
2011	54,599	0.189	43,052	0.473	22,881	0.424	5042	0.176	8788	0.334
2012	55,355	5.67	43,649	3.54	23,198	4.10	5111	2.46	8910	3.37
2013	56,058	5.67	44,203	3.54	23,492	4.10	5176	2.46	9023	3.37
2014	56,761	5.67	44,757	3.54	23,787	4.10	5241	2.46	9137	3.37
2015	57,464	5.80	45,311	5.89	24,081	4.10	5306	5.62	9250	4.29
2016	58,167	5.80	45,866	5.89	24,376	4.10	5371	5.62	9363	4.29
2017	58,869	5.80	46,420	5.89	24,670	4.10	5436	5.62	9476	4.29
2018	59,626	5.80	47,016	5.89	24,987	4.10	5506	5.62	9598	4.29
2019	60,329	5.80	47,571	5.89	25,282	4.10	5571	5.62	9711	4.29
2020	60,978	5.80	48,082	5.89	25,554	4.10	5631	5.62	9815	4.29
2021	61,626	5.80	48,594	5.89	25,826	4.10	5691	5.62	9920	4.29
2022	62,221	5.80	49,063	5.89	26,075	4.10	5745	5.62	10,015	4.29
2023	62,816	5.80	49,531	5.89	26,324	4.10	5800	5.62	10,111	4.29
2024	63,464	5.80	50,043	5.89	26,596	4.10	5860	5.62	10,215	4.29
2025	64,113	5.80	50,554	5.89	26,868	4.10	5920	5.62	10,320	4.29
2026	64,816	5.80	51,109	5.89	27,162	4.10	5985	5.62	10,433	4.29
2027	65,518	5.80	51,663	5.89	27,457	4.10	6050	5.62	10,546	4.29
2028	66,167	5.80	52,174	5.89	27,729	4.10	6110	5.62	10,651	4.29
2029	66,870	5.80	52,728	5.89	28,023	4.10	6175	5.62	10,764	4.29
2030	67,519	5.80	53,240	5.89	28,295	4.10	6235	5.62	10,868	4.29
2031	68,221	5.80	53,794	5.89	28,589	4.10	6299	5.62	10,981	4.29
2032	68,931	5.80	54,354	5.89	28,887	4.10	6365	5.62	11,095	4.29
2033	69,648	5.80	54,919	5.89	29,187	4.10	6431	5.62	11,211	4.29
2034	70,373	5.80	55,491	5.89	29,491	4.10	6498	5.62	11,328	4.29
2035	71,105	5.80	56,068	5.89	29,798	4.10	6566	5.62	11,445	4.29

Table 9.6-9. Summary of Yearly Volumes and Potential Price Increases by PADD for the Benzene Program Based on Maximum Operating Costs
(2003 dollars)

	PADD 1		PADD 2		PADD 3		PADD 4		PADD 5except CA	
Year	Gasoline Consumption (million gals)	Cost (c/gal)	Gasoline Consumption (million gals)	Cost (c/gal)	Gasoline Consumption (million gals)	Cost (c/gal)	Gasoline Consumption (million gals)	Cost (c/gal)	Gasoline Consumption (million gals)	Cost (c/gal)
2004	49,193	0	38,790	0	20,615	0	4542	0	7918	0
2005	49,517	0	39,045	0	20,751	0	4572	0	7971	0
2006	50,274	0	39,642	0	21,068	0	4642	0	8092	0
2007	50,923	0.026	40,154	0.243	21,340	0.323	4702	0.609	8197	0.334
2008	51,734	0.026	40,793	0.243	21,680	0.323	4777	0.609	8327	0.334
2009	52,707	0.026	41,560	0.243	22,088	0.323	4867	0.609	8484	0.334
2010	53,734	0.096	42,370	0.351	22,518	0.342	4962	0.609	8649	0.334
2011	54,599	0.096	43,052	0.351	22,881	0.342	5042	0.609	8788	0.334
2012	55,355	4.56	43,649	3.02	23,198	3.41	5111	2.01	8910	2.75
2013	56,058	4.56	44,203	3.02	23,492	3.41	5176	2.01	9023	2.75
2014	56,761	4.56	44,757	3.02	23,787	3.41	5241	2.01	9137	2.75
2015	57,464	4.56	45,311	4.42	24,081	3.41	5306	4.27	9250	3.34
2016	58,167	4.56	45,866	4.42	24,376	3.41	5371	4.27	9363	3.34
2017	58,869	4.56	46,420	4.42	24,670	3.41	5436	4.27	9476	3.34
2018	59,626	4.56	47,016	4.42	24,987	3.41	5506	4.27	9598	3.34
2019	60,329	4.56	47,571	4.42	25,282	3.41	5571	4.27	9711	3.34
2020	60,978	4.56	48,082	4.42	25,554	3.41	5631	4.27	9815	3.34
2021	61,626	4.56	48,594	4.42	25,826	3.41	5691	4.27	9920	3.34
2022	62,221	4.56	49,063	4.42	26,075	3.41	5745	4.27	10,015	3.34
2023	62,816	4.56	49,531	4.42	26,324	3.41	5800	4.27	10,111	3.34
2024	63,464	4.56	50,043	4.42	26,596	3.41	5860	4.27	10,215	3.34
2025	64,113	4.56	50,554	4.42	26,868	3.41	5920	4.27	10,320	3.34
2026	64,816	4.56	51,109	4.42	27,162	3.41	5985	4.27	10,433	3.34
2027	65,518	4.56	51,663	4.42	27,457	3.41	6050	4.27	10,546	3.34
2028	66,167	4.56	52,174	4.42	27,729	3.41	6110	4.27	10,651	3.34
2029	66,870	4.56	52,728	4.42	28,023	3.41	6175	4.27	10,764	3.34
2030	67,519	4.56	53,240	4.42	28,295	3.41	6235	4.27	10,868	3.34
2031	68,221	4.56	53,794	4.42	28,589	3.41	6299	4.27	10,981	3.34
2032	68,931	4.56	54,354	4.42	28,887	3.41	6365	4.27	11,095	3.34
2033	69,648	4.56	54,919	4.42	29,187	3.41	6431	4.27	11,211	3.34
2034	70,373	4.56	55,491	4.42	29,491	3.41	6498	4.27	11,328	3.34
2035	71,105	4.56	56,068	4.42	29,798	3.41	6566	4.27	11,445	3.34

9.6.4   Projected Fuel Supply and Energy Impacts of the Benzene Program

EPA has evaluated the potential impact on U.S. fuel supply of the benzene 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 benzene program, refiners will extract about 12,500 barrels of benzene per day, or 192 million gallons per year, when the benzene program is fully phased-in. Because benzene has a slightly higher energy density than gasoline (about 7 percent higher), the projected extracted benzene is equivalent to about 13,375 barrels per day of gasoline,

or about 0.1 percent of U.S. gasoline production. However, we believe that the net effect on gasoline supply of the rule will be far less, potentially zero.

This increase in extraction of benzene from gasoline is expected to occur with or without the benzene program. Using CMAI's estimate of a 2.4 percent annual growth in benzene demand, we expect that U.S. demand for benzene will increase by 600 million gallons from 2007 to 2015, the years that the benzene program is expected to phase-in. Assuming that reformate extraction continues to supply about 40 percent of the supply, then reformate extraction is expected to supply about 250 million gallons additional benzene over the 8 year program phase-in period. Thus, increased reformate extraction expected to occur to meet increased benzene demand would exceed the projected benzene extraction expected to occur to comply with the benzene program, provided that the benzene extraction occurs throughout the entire phase-in period. If all the benzene extraction occurs to comply with the benzene program in a single year, then the increased benzene supply would be greater than two times the yearly increase in total benzene demand.

Even if all the projected benzene extraction occurs in a single year, the benzene market could adjust to rebalance both the benzene market and the gasoline supply. Selective toluene disproportionation and toluene hydrodealkylation are benzene production technologies which are higher benzene production cost technologies. These two marginal benzene production processes would likely reduce their benzene production which would rebalance the benzene supply/demand market. Presuming that these two benzene production processes temporally reduce their output to rebalance benzene supply, the toluene would presumably stay in the gasoline pool and the effect on gasoline supply would be minimal.

Projected Energy Impacts of the 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 benzene program.[29] 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 2012, 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 by 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 (2012)
(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)
Refinery Process Energy Use					
Total Benzene Control-Related	0.4	2.0	3.4	2.1	8.0
Light Naphtha Splitting	-0.1	1.1	0.1	-0.1	1.1
Reforming	0.2	-0.6	0.6	0.4	0.6
Isomerization	0	-0.5	0	0.1	-0.5
Benzene Saturation	0	0.2	0.3	0.9	1.5
Benzene Extraction	0.4	1.1	1.9	0	3.4
Hydrogen Production	-0.2	0.8	0.5	0.8	1.8
All Other	-0.2	0.5	0.2	-0.1	0.4
Net Process Energy Change	**0.2**	**2.5**	**3.6**	**2.0**	**8.3**
% Change in Process Energy	*0.2*	*0.9*	*0.4*	*1.8*	*0.6*
Net Total Energy Change	**0.9**	**3.2**	**5.1**	**3.4**	**12.7**
% Change in Total Energy	*0.05*	*0.09*	*0.06*	*0.21*	*0.08*

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 (8.3 of the total increase of 12.7 Kfoeb/d). This process energy increase would represent about 0.6 percent of all energy used in refinery processes. When all energy involved in refining crude oil is considered, including the energy in crude oil and other feedstocks, we project that the benzene program would increase overall energy use by refineries by less than 0.1 percent.

Of the nationwide increase in process energy, most would be due to processes directly related to benzene control (8 of 8.3 Kfoeb/d). Benzene extraction would be the largest contributor to this process energy increase (3.4 of 8.3 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 benzene 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 benzene program. (Projected increases in energy use due to the other benzene-related processes would be appropriately attributed to the benzene 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 benzene 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 a significant portion of the nationwide increase in energy use because of its very large production volume as well as because of its reliance on extraction. PADDs 4 and 5 provide a significant portion of the energy demand

despite the lower gasoline production in these two PADDs because of the large reduction in benzene levels in these two PADDs.

9.7   Refinery Industry Cost Study

The American Petroleum Institute (API) conducted its own refinery modeling study to evaluate the cost of benzene control.[30] The API study, conducted by Baker and O'Brien Incorporated, analyzed the cost of three different benzene programs, and these were Case A: a 0.60 vol% average benzene standard and 0.90 per-gallon cap standard applicable to RFG, and a 0.95 average vol% benzene standard and 1.30 per-gallon cap standard applicable to CG, but no credit trading program; Case B: a 0.60 vol% average benzene standard and 0.90 per-gallon cap standard applicable to both RFG and CG, but no credit trading program; and Case C: a 0.60 vol% average benzene standard for both CG and RFG with no cap standard and with a credit trading program.[i] API made some very conservative assumptions regarding credit generation and use for Case C. API assumed that when credits are being generated that each refinery will hold onto 10 percent of the generated credits as a safety margin which resulted in a lower benzene level than that required.

The API study also assumed that MTBE is no longer blended into the U.S. gasoline pool, that the Tier 2 gasoline sulfur program is fully implemented, that the renewable fuels standard is implemented resulting in 7 billion gallons of ethanol blended into the gasoline pool and that MSAT1 is still in effect. The three cases modeled by API are summarized in Table 9.7-1. We also included the final U.S. gasoline pool benzene levels for the base case and each case in the last column of the table. We adjusted the benzene levels to exclude California gasoline because it is not assumed to be regulated by the API refinery modeling study consistent with our analysis.

Table 9.7-1. Summary of the Three Refinery Modeling Case Studies by API

	Gasoline Pool	Avg Std	Cap Std	Credit Trading	Benzene Level (vol%)
Basecase	Total Pool	-	-	-	1.00
Case A	RFG	0.60	0.90	No	0.70
	CG	0.95	1.30		
Case B	RFG	0.60	0.90	No	0.52
	CG	0.60	0.90		
Case C	RFG	0.60	None	Yes	0.56
	CG	0.60	None		

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i In the refinery modeling report, Baker and O'Brien states that the benzene program modeled for Case C is a 0.60 vol% benzene standard, and that credits are calculated based on benzene reductions below that value. However, in its comments to the proposed rule summarizing the results of its refinery modeling study, API stated that it modeled a 0.62 vol% average benzene standard with a 0.02 vol% compliance margin. It appears that API was trying to adapt its refinery modeling cost study to mirror the proposed standard, but that the refinery modeling study actually modeled a 0.60 benzene control standard. For the purposes of our review of the API study we will assume that the modeled standard was the 0.60 vol% benzene standard, not a 0.62 vol% benzene standard as indicated in its comments.

The types of benzene control technologies modeled in the API study include modifying the cutpoints to remove benzene precursors from reformer feed, build or expand benzene saturation units, expand aromatics extraction units, and build or expand pentane/hexane isomerization units. These are the same technologies that we used in our cost study, except that API did not allow refineries to install grassroot extraction units. Similar to our study, API did allow refineries with aromatics extraction units to expand their units to extract the aromatics from the gasoline of other refineries, although in our study we only assumed the extraction of benzene, not xylene and toluene – the other aromatic compounds that can be extracted from gasoline.

The total costs for each of the refinery modeling cases analyzed by API were summarized in their report. The API refinery modeling report did not calculate the per-gallon costs so we made the necessary calculations based on the total annual capital costs provided by API which are based on a 10 percent return on investment (ROI). We summarize those costs and adjust them to a 7 percent ROI – the basis for how we express the per-gallon costs – to express the API costs on the same basis as ours. The total annual costs, per-gallon and adjusted per-gallon costs for each case are summarized in Table 9.7-2.

Table 9.7-2. Total and Per-Gallon Costs for API's Refinery Modeling Study

Case #	Total Cost ($MM/yr)	2012 Gasoline Volume (Kbbl/day)	Investment (Million dollars)	Per-Gallon Cost (c/gal)	Capital Charge 10% after tax ROI ($MM/yr)	Capital Charge 7% before tax ROI ($MM/yr)	Adjusted Per-Gallon Cost (c/gal)
A	1286	8365	899	1.00	151	97	0.96
B	1660	8365	1737	1.29	293	188	1.21
C	1431	8365	1476	1.12	246	158	1.05

Of the four cases modeled by API, Case C is the closest to our final benzene program, thus we will compare API's cost estimate for that case to our estimated benzene program costs. It is immediately apparent that there is a large difference in estimated cost between our estimated cost, which is 0.27 cents per gallon, compared to API's Case C, which is 1.05 cents per gallon. We identified numerous reasons for the most of the difference in cost.

One of the most important differences between the two cost estimates is that API assumed a much larger benzene reduction than our study. The starting benzene level for the API study was 1.0 vol% benzene. After control, the API study assumed a slightly more stringent benzene standard – modeling a 0.60 vol% average standard instead of a 0.62 vol% average benzene standard - and a much more conservative approach to how refiners use credits. API assumed that credits would not be traded freely, but instead that refining companies would hold onto 10 percent of their credits in case they have a future problem with their benzene control unit. Due to the more stringent benzene standard and the 10 percent credit margin, the API study estimated that the U.S. refining industry would average 0.56 vol% benzene compared to our 0.62 vol% benzene control level. From the base case to the final benzene level, the API study analyzed a 0.44 vol% benzene reduction. However, our study estimated the impacts of a 0.33

vol% benzene reduction. The API study estimated a 33 percent greater benzene reduction than that analyzed in our analysis.

EPA does not believe that refiners will find it necessary to consistently and significantly overcomply with the 0.62 vol% average benzene standard and hold onto a significant amount of credits as assumed by API. This is because this benzene standard is an average standard, not a cap standard, and can be met by the accumulation of gasoline batches with benzene levels higher or lower than the standard. Thus, if a refinery tended to produce gasoline with lower or higher gasoline benzene levels over the first part of the year, the operations could be adjusted to balance out the gasoline benzene levels for the rest of the year. Also, our program includes several provisions which give refiners significant flexibility for compliance with average benzene standard. For example, refiners could overcomply slightly with the standard early on in the program's implementation and hold onto the credits for up to five years before they expire. If a refinery's benzene control unit goes down, the refiner would be able to use those accumulated credits, the refiner could purchase credits from other refineries, or the refiner could create a benzene reduction deficit at that refinery and make it up the deficit following year. With this degree of flexibility, there will be little need for a refining company to control its refineries' benzene level on an ongoing basis at a lower level than the standard to have a substantial supply of credits on hand. Even if they did feel the need to accumulate some benzene credits, the company could do so the first year, but then would not likely do so for each year after since the first year's credits would be sufficient for the next five years. For these reasons, we believe that the overcompliance modeled by API is unnecessary.

The second reason why the API estimated costs are higher than our estimates is that API used a more restrictive assumption with respect to benzene extraction – a more cost-effective benzene control technology than benzene saturation which was the principal benzene control technology relied upon by the API study. API assumed that no new grassroots benzene extraction capacity would be installed in the future, but that existing extraction units could be expanded. We agree that existing units will likely be expanded. However, we also believe that new grassroots extraction units will be installed as well. Our premise is supported by CMAI projections of a continued robust benzene market in the future with benzene priced higher than its historical margin above gasoline. CMAI estimates a benzene price which is $30/bbl higher than gasoline, which is higher than its historical margin. Higher benzene price margins will provide an incentive to refiners to add grassroots benzene extraction units, even in areas where benzene markets have been smaller. For example, one refiner has indicated to us that if the proposed gasoline benzene standard was to be finalized, it would install a grassroots benzene extraction unit at one of its refineries in the Midwest, where the benzene market is currently small. This is a strong indicator that new grassroots benzene extraction units will also be installed on the Gulf and East Coasts, where benzene markets are already strong.

API's cost of aromatics extraction is likely to be higher than our extraction costs because of the differences in benzene prices. For the final rule, we used the most recent CMAI benzene price projection, which prices benzene at $30/bbl above that of gasoline. API used an incremental benzene price of $20 per barrel above that of gasoline, which is what we used for the proposed rule. A likely primary reason for CMAI's higher incremental benzene price is that CMAI is assuming a higher future crude oil price.

The third reason why the API benzene control costs are higher than ours is the very large difference in octane control costs. For both studies, the cost associated with the octane loss that occurs through the use of the various benzene control technologies is accounted for by assigning a dollar per octane-barrel cost to the octane loss. However, API's costs for restoring octane are about an order of magnitude higher than the octane recovery costs that we are projecting. The octane costs used by API and those we use are summarized in Table 9.7-3.

Table 9.7-3. Octane Costs used in the API and EPA Benzene Cost Studies ($/octane-barrel)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
API	2.19	2.11	1.83	2.14	2.58
EPA	0.28	0.20	0.30	0.27	0.27

The octane costs used by API are high because API used the rack price differential between premium and regular grade gasoline as summarized by the Energy Information Administration. Using the rack price differential between premium and regular grade gasoline results in high octane costs because they reflect a significant amount of profit. For example, the cost difference to produce premium gasoline is usually only a few cents per gallon more than for producing regular grade gasoline, yet refiners and marketers usually charge 20 to 30 cents per gallon higher price for premium gasoline at retail. Much of this marked up price appears at the rack price differential between regular and premium grades of gasoline. A review of octane prices shows that the rack price differential between premium and regular grade gasoline is 50% higher then when estimating octane cost using bulk prices. Bulk prices are closer to the actual costs incurred by refiners with respect to the cost of octane. However, our linear programming cost analysis shows that refinery octane costs are much lower than bulk prices.

Another reason why the API octane costs are higher than ours is because they used the premium-regular grade gasoline price differential for the summer of 2005, when the octane costs are likely higher than in the future due to the very large volume of ethanol that is expected to enter the gasoline market by then under the Renewable Fuels Standard. In addition to the large volume of ethanol, ethanol has very high octane (115 (R + M)/2) which contributes to the large impact on octane costs. The large impact that ethanol will have on octane costs is reflected in the octane costs that we use in our analysis.

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