comply with the fleet average standard. We also cannot reasonably assume that an ICI that certifies and produces vehicles one year, will certify or even be in business the next. Consequently, we are finalizing the proposed provision barring ICIs from utilizing the deficit carry forward provisions of the ABT program.

VI. Gasoline Benzene Control Program

A. Description of and Rationale for the Gasoline Benzene Control Program

We received comments on a wide range of issues regarding our proposal of a gasoline benzene control program. We have considered these comments carefully. This notice finalizes a gasoline benzene control program that is very similar to the proposed program, with the inclusion of an upper limit benzene standard on which we sought comment.

The gasoline benzene control program has three main components, each of which is discussed in this section:

—*A gasoline benzene content standard.* In general, refiners and importers will be subject to an annual average gasoline benzene standard of 0.62 volume percent (vol%), beginning January 1, 2011. This single standard will apply to all gasoline, both reformulated gasoline (RFG) and conventional gasoline (CG) nationwide (except for gasoline sold in California, which is already covered by a similar state program).

—*An upper limit benzene standard.* In general, this ''maximum average standard'' will require that the annual average of actual benzene levels that each refinery produces be less than or equal to 1.3 vol% without the use of credits, beginning July 1, 2012.[177]

—*An averaging, banking, and trading (ABT) program.* The ABT program allows refiners and importers to choose the most economical compliance strategy (investment in technology, credits, or both) for meeting the 0.62 vol% annual average benzene standard. The program allows refiners to generate ''early credits'' for making qualifying benzene reductions earlier than required and allows refiners and importers to generate ''standard credits'' for overcomplying with the 0.62 vol% benzene standard in 2011 and beyond. Credits may be used interchangeably towards compliance with the 0.62 vol% standard, ''banked'' for future use, and/or transferred nationwide to other refiners/importers subject to the standard. While credits may not be used to demonstrate compliance with the 1.3 vol% maximum average standard, the ABT program in its entirety provides the refining industry with significant compliance flexibility. To achieve compliance with the 0.62 vol% average standard in 2011 and beyond, refiners and importers may use credits generated and/or obtained under the ABT program, reduce their gasoline benzene levels, or any combination of these.

—*Provisions for refiners facing economic hardship.* Refiners approved as ''small refiners'' will have access to special temporary relief provisions. In addition, any refiner facing extreme unforeseen circumstances or extreme hardship circumstances can apply for temporary relief.

1. Gasoline Benzene Content Standard

a. Description of the Average Benzene Content Standard

The program finalized in this rule requires significant reductions in the average levels of benzene in gasoline sold in the U.S. Beginning in 2011, the average benzene level of all batches of gasoline produced during a calendar year at each refinery will need to be at or below a standard of 0.62 vol% benzene. Approved small refiners must comply with this requirement by 2015. Each gasoline importer will need to meet the 0.62 vol% standard on average for its imported gasoline during each year. The 0.62 vol% average standard may be met through actual production/importation of fuel with a benzene content of 0.62 vol% or less, on average, and/or by using benzene credits. A deficit is created when compliance is not achieved in a given year. This deficit may be carried forward without regulatory approval but must be made up the next year. (See VI.B (Implementation), below.) While this subsection focuses on the 0.62 vol% average standard, refiners and importers will also be subject to a ''maximum average benzene standard'' of 1.3 vol%, which is discussed below in section VI.A.1.d.

The 0.62 vol% average benzene standard applies to all gasoline, both RFG and CG. Gasoline sold nationwide is covered by the standard, with the exception of gasoline sold in California. California gasoline is covered by existing State of California benzene requirements that result in benzene reductions similar to the federal program finalized here.

The 0.62 vol% average benzene standard and the 1.3 vol% maximum average standard result in air toxics emissions reductions that are greater than required under all existing gasoline-related MSAT programs. As a result, upon implementation in 2011, the regulatory provisions for this gasoline benzene control program will become the regulatory mechanism used to implement the RFG and CG (Anti-Dumping) annual average toxics performance requirements and the annual average benzene content requirement for RFG. The current RFG and Anti-Dumping annual average toxics provisions thus will be replaced by this benzene control program. This final benzene control program will also replace the requirements of the 2001 MSAT rule (''MSAT1''). In addition, the program will satisfy certain conditions of the Energy Policy Act of 2005 (EPAct) and thus remove the need to revise individual MSAT1 toxics baselines for RFG otherwise required by the EPAct. In all of these ways, this program will significantly consolidate and simplify the existing national fuel-related MSAT regulatory program while achieving greater overall emission reductions.[178] See Section VI.C below for additional discussion of this issue.

b. Why Are We Finalizing a Benzene Content Standard?

As discussed in the proposal, we believe a benzene content standard is the most cost-effective and most certain way to reduce gasoline benzene emissions from vehicles. Fuel benzene reductions directly and demonstrably result in benzene emissions reductions which also results in overall MSAT emission reductions. Focusing MSAT control on benzene alone means that the effectiveness of the control will not be affected by changes in fuel composition or vehicle technology. Because benzene is a small component of gasoline (around 1 vol%), gasoline octane is not significantly affected by a reduction in benzene content. Other fuel changes that could be undertaken to reduce MSATs would significantly impact octane, and replacing that octane would be costly and could increase emissions of MSATs other than benzene. Nonetheless, in addition to proposing to control fuel-related MSAT emissions by means of a gasoline benzene content standard, we sought comment on a

[177] The per-gallon benzene cap (1.3 vol%) in the RFG program will continue to apply separately.

[178] Although this program will supersede several compliance requirements from other programs, we are retaining certain recordkeeping and reporting requirements from these programs. For example, refiners will need to continue to provide gasoline fuel property data for more than just benzene. This is discussed in more detail in VI.B below.

number of alternative approaches, including control of toxics in addition to benzene and more stringent limits on gasoline sulfur and volatility. A number of commenters expressed support for some of these alternatives and others opposed them. In reaching our decision to finalize a benzene content standard, we evaluated the comments on each of the alternative approaches, and we discuss these next.

i. Standards That Would Include Toxics Other Than Benzene

We considered separate standards for each of the key fuel-related toxics (we discuss control of aromatic compounds separately) as well as a total toxics performance standard.

A Standard for Total Toxics Performance

Several commenters advocated a standard in the form of a toxics emissions performance standard, analogous to the current MSAT1 and RFG standards. Some commenters requested an air toxics standard in addition to the fuel benzene content standard we are finalizing. In general, these commenters expressed concern that if toxics other than benzene are not also controlled simultaneously, refiners may allow the emissions of these other compounds to increase, even while benzene is being reduced. Other commenters requested a toxics standard instead of fuel benzene control (or as an alternative compliance option). These commenters felt that a toxics performance standard offered more compliance flexibility. Other commenters supported our proposed benzene-only standard, stating that a total toxics standard would add complexity without additional benefit.

For several reasons, we continue to believe that a benzene-only standard is superior to a toxics emissions performance standard. First, because controlling benzene is much more cost-effective than controlling emissions of other MSATs, refiners historically have preferentially reduced benzene under the MSAT1 and other air toxics control programs. This is despite the theoretical flexibility that refiners have under a toxics performance standard to change other fuel parameters instead of benzene. Thus, even if we were to express the proposed standard as an air toxics performance standard, we would expect the outcome to be the same—refiners would reduce benzene content and leave unchanged the levels of other MSATs.

Even with, or as a result of, this fuel benzene control, we do not expect refiners to actively modify their refinery operations such that increases will occur in emissions of the other MSATs currently controlled under the toxics performance standards. These other MSATs are acetaldehyde, formaldehyde, POM, and 1,3-butadiene, and they are all affected to varying degrees by VOC emissions control. VOC emissions are generally decreasing due to the gasoline sulfur controls recently phased in along with tighter vehicle controls under the Tier 2 program, as well as the vehicle controls being finalized under this program (see section V above). In combination, these changes are expected to decrease VOC-based MSAT emissions substantially.

In addition to reductions because of declining VOC emissions, formaldehyde emissions are currently, and for the foreseeable future, declining as MTBE use ends. See 71 FR 15860.

According to the Complex Model, the Agency's current gasoline emissions compliance model, POM emissions correlate directly with VOC emissions (see 40 CFR 80.45(e)(8). Therefore, we expect significant POM emission reductions as VOC emissions decline.

For 1,3-butadiene, the fuel parameter of interest is olefins. Increasing olefins increases 1,3-butadiene emissions. However, olefins are expected to decrease as a result of the implementation of the gasoline sulfur program because they are reduced along with sulfur during the desulfurization process. Olefins are also often used for their octane value, but because of increased ethanol use, this need should be reduced. As a result, we do not expect refiners to take actions to increase olefins, and thus 1,3-butadiene emissions should not increase. Also, 1,3-butadiene, like other MSATs, is reduced when VOC is reduced due to fuel and vehicles standards being implemented (see 71 FR 15860).

The one MSAT likely to increase in the future is acetaldehyde. Current market forces, along with state and federal policies and requirements such as the proposed Renewable Fuels Standard (RFS) Program,[179] ensure that ethanol use will increase, and thus acetaldehyde as well, since that MSAT is directly and substantially affected by ethanol use. Acetaldehyde emissions are currently about one-seventh the magnitude of benzene emissions from motor vehicles, but are increasing (while formaldehyde emissions are decreasing) due to the substitution of ethanol for MTBE in RFG as a result of state MTBE bans. Any action that refiners could take to offset the total toxics increase as a result of acetaldehyde increasing would be through benzene control, which we are already requiring to be controlled to the maximum extent possible. The EPAct, which charged EPA with developing the RFS program, also requires an evaluation of that Act's impacts on air quality. Any future control of acetaldehyde emissions will be based primarily on the results of that study. EPA thus believes it premature to act until we determine a course of future action reflecting the EPAct study, a draft of which is due to Congress in 2009.

As described above, with the exception of acetaldehyde, the benzene control program will ensure the certainty of additional MSAT reductions. Other MSAT emissions are thus unlikely to increase under this program. Because an air toxics standard would not provide any additional emission reductions, we believe that the regulatory controls, and the associated paperwork and the other administrative costs that would result if standards explicitly including these other MSATs were adopted, are not necessary. The benzene control program will thus ensure the certainty of additional MSAT reductions. A toxics emissions performance standard that would effectively achieve the same level of MSAT reduction would be more costly and complex. For all of these reasons, we believe a standard in the form of a benzene content standard will produce more certain environmental results with less complexity than a toxics emissions performance standard, and we are therefore finalizing only a benzene content standard.

A Standard for Aromatic Compounds in Addition to Benzene

In the proposal, we considered MSAT control through the reduction of the content of aromatics in addition to benzene in gasoline. For a number of reasons, we did not propose such control (see 71 FR 15860 and 15864). During the comment period, we received comments urging EPA to impose controls on non-benzene gasoline aromatic compounds, in addition to controlling benzene. These commenters believe aromatics control would provide more toxics emissions reductions than a benzene-only control program, and they also believe it would improve air quality by significantly reducing fine particulate matter. Expanded use of E85 and flexible-fuel vehicles and ETBE were suggested as ways to replace the octane value which would be lost if aromatics were reduced. They also cited other benefits such as energy independence and reduction of trade deficits, and stated that costs to

[179] 71 FR 55552, September 22, 2006.

the refining industry would not be significant. A significant rebuttal to this request for aromatics control was presented by the refining industry.

We note first that regardless of specific regulatory action to control aromatics, the increased use of ethanol in response to current market forces and state and federal policies (including the RFS program) will contribute to lower aromatics levels. This will occur for two reasons. First, ethanol has historically been blended downstream of refineries, either as a ''splash blend'' or as a ''match blend.'' In a splash blend, the ethanol is mixed with finished gasoline. In a match blend, refiners prepare a special subgrade of gasoline that, when blended with ethanol, becomes finished gasoline. In recent years, match blending has increased as refiners have been producing RFG with ethanol, and it is expected to increase even more as ethanol use expands. A splash blend will reduce aromatics by about 3 vol% by simple dilution.[180] A match blend will reduce aromatics by about 5 vol%.[181] With ethanol use expected to more than double, we expect a significant reduction in aromatics levels. Second, with all of this ethanol there will be excess octane in the gasoline pool. Thus, not only will increased ethanol use decrease aromatics concentrations through dilution, but refiners will make the economic decision to use ethanol to reduce or avoid producing aromatics for the purpose of increasing octane.

Because of differences in how refiners will respond to the rapid increase in ethanol use, it would be difficult to determine an appropriate level for an aromatics standard at this time. The gasoline market is going through an historic transition now due to the removal of MTBE, conversion of some portion of the MTBE production volume to other high octane blendstock production, growth of ethanol use, and the rise in crude oil prices. Consequently, it is difficult to reliably project a baseline level of aromatics for the gasoline pool with any confidence. This is compounded by a great deal of uncertainty in knowing how much of the market ethanol will capture. Projections by EIA are significantly higher now than just a few months ago, and Presidential and Congressional proposals could easily result in 100% of gasoline being blended with ethanol. Second, aromatics levels vary dramatically across refineries based on a number of factors, including refinery configuration and complexity, access to other high octane feedstocks, access to the chemicals market, crude sources, and premium grade versus regular grade production volumes. Third, without knowing with some certainty the range of aromatics contents of refineries' gasoline, we cannot determine the greatest degree of emission reduction achievable, and also cannot make reasonable estimates regarding cost, lead time, safety, energy impacts, etc. As a result, at this time we would not be able to determine an appropriate or meaningful aromatics standard.

For the purpose of reducing total toxics emissions, fuel benzene control is far more cost-effective than control of total aromatics, for a number of reasons. As we explained in the proposal, reducing the content of other aromatics in gasoline is much less effective at reducing benzene emissions than reducing fuel benzene content. Based on the Complex Model,[182] roughly 20 times greater reduction in total aromatics content is needed to achieve the same benzene emission reduction as is achieved by fuel benzene reductions. At the same time, to broaden the program to control other aromatics would result in a significant octane loss. While we have not yet conducted a thorough refinery modeling evaluation, based on existing refinery and market information the alternative sources of octane (other than ethanol) appear to be of limited supply and would be of limited effectiveness in replacing the octane lost from any fuel aromatics reductions. Furthermore, as noted above, the uncertainty in the extent to which ethanol will penetrate the market makes it difficult to project the potential replacement of aromatics with ethanol. Any significant reduction in aromatics would also affect the gasoline and diesel sulfur reduction programs because hydrogen, which is used in the desulfurization process, is produced when aromatics are produced. If refiners were required to reduce their aromatics levels, costs would increase further because some would have to expand or build new hydrogen production facilities.

Reducing aromatics would also raise other environmental concerns that would need to be addressed in any regulation. Actions available to refineries for replacing octane, including adding ethanol, can increase other MSATs, as mentioned above. In addition, some commenters encouraged the use of the ether derived from ethanol, ETBE, to make up octane. Any regulatory action that required or was based on the use of ETBE would likely raise issues of potential groundwater contamination given the groundwater contamination caused by the use of the chemically similar MTBE.

There may be compelling reasons to consider aromatics control in the future, especially regarding reduction in secondary $PM_{2.5}$ emissions, to the extent that evidence supports a role for aromatics in secondary $PM_{2.5}$ formation.[183] Unfortunately, there are limitations in both primary and secondary PM science and modeling tools that limit our present ability to quantitatively predict what would happen for a given fuel control. Thus, at this point, we do not feel that the existing body of information and analytical tools provide a sufficient basis to determine if further fuel aromatics control is warranted. However, we do feel that additional research is very important. Test programs and analyses are planned to address primary PM issues, including those examining the role of aromatics. Also, more work is underway on how fuel aromatics, including toluene, affect secondary PM formation, and how aromatics control should be incorporated into air quality predictive models.[184]

In summary, we believe that aromatics levels will be falling even without an aromatics standard, and aromatics control will need to be evaluated in the context of what might be possible beyond what will occur through the expanded use of ethanol. Furthermore, any additional control would be costly and raise a number of other issues which need further investigation before EPA could responsibly initiate such a control effort. Thus, we have concluded that additional aromatics control for MSAT purposes is not warranted at this time.

[180] If the aromatics content of a gallon of gasoline is 30 vol%, adding 10% ethanol dilutes the aromatic content to about 27 vol%.

[181] Section 2.2 ''Effects of Ethanol and MTBE on Gasoline Fuel Properties'' in the Renewable Fuel Standard Program: Draft Regulatory Impact Analysis, September, 2006.

[182] Total toxics emissions are as calculated by the Complex Model. This model is the tool used to determine compliance with the toxics emissions controls in the RFG, Anti-dumping, and MSAT1 programs. Cost estimates for aromatics control and analysis of relative benzene emissions with control of aromatics and benzene are found in Regulation of Fuels and Fuel Additives; Standards for Reformulated and Conventional Gasoline; Final rule, Table VI–A6 of the Regulatory Impact Analysis, February 16, 1994.

[183] See Chapter 1 in the RIA for more on current studies on this subject.

[184] See Chapter 1 in the RIA for more on current studies on this subject.

ii. Control of Gasoline Sulfur and/or Volatility for MSAT Reduction

In the proposal, we outlined a number of issues related to further control of gasoline sulfur content and volatility (usually described as Reid vapor pressure, or RVP) as a means of MSAT emissions reduction.[185] (See 71 FR 15861–62.) In both cases, there was insufficient data on newest technology vehicles at that time to evaluate their effectiveness as MSAT controls. Therefore, we did not propose changes to existing standards.

We received several comments related to sulfur and RVP control, but there was general agreement in the comments from auto manufacturers and refiners that sufficient data does not yet exist for EPA to take action as a part of this rule. Consequently, we are not taking action to adopt additional control of gasoline sulfur or RVP. However, since the proposal, we have completed a small fuel effects test program in cooperation with several automakers to help evaluate the impact of fuel property changes on emissions from Tier 2 vehicles. These data suggest that reducing gasoline sulfur below 30 ppm could bring significant reductions in VOC and NO_X, but the data relating to air toxics reductions were not statistically significant. Unlike past programs on older technology vehicles, these data suggest that reducing gasoline volatility from 9 to 7 psi RVP under normal testing conditions (75° F) may actually increase exhaust toxics emissions. The program did not examine the impacts of fuel volatility on evaporative emissions. These data indicate that there may be benefits to future fuel control but that more testing is warranted. More details on the test program and its results are available in Chapter 6 of the RIA.

iii. Diesel Fuel Changes

In the proposal, EPA did not propose additional controls on diesel fuel for MSAT control. We continue to believe that the recent highway and nonroad diesel programs (see section IV. D. 1. c above) will achieve the greatest currently achievable reductions in diesel-related MSAT control (i.e., reductions in emissions of diesel particulate matter and exhaust organic gases). These emission reductions will result from the deep cuts in diesel fuel sulfur that will be implemented in the same time frame as this gasoline benzene rule, along with the associated diesel engine emission control requirements of the diesel programs. We said that we were unaware of other changes to diesel fuel that could have a significant effect on MSAT emissions, and requested comment about limiting this action to gasoline benzene.

One group of commenters stated in joint comments that they believe that EPA needs to do more to protect human health and the environment from the effects of diesel exhaust emissions. While they specifically mention actions to accelerate the introduction of cleaner diesel engines, they do not suggest any additional changes to diesel fuel. Another commenter, a refiner, believes that further diesel fuel controls are not warranted.

Some commenters support control of the polyaromatic hydrocarbon (PAH) content of diesel fuel. The actions refiners are taking to produce ultra-low sulfur diesel fuel (15 ppm sulfur) are expected to reduce the PAH content in diesel fuel.[186] In addition, available data indicate that the advent of exhaust emission controls on diesel engines under the recent diesel programs will reduce exhaust PAH, regardless of any changes to diesel fuel.

We continue to believe that existing regulations will achieve the greatest currently achievable reductions in MSAT emissions from diesel engines. EPA will continue to monitor MSAT issues related to diesel fuel. For example, there are active programs underway to measure PAH exhaust emissions from diesel engines meeting the 2007 PM engine standards.[187] However, at this time, we are not aware of diesel fuel controls that could significantly affect MSAT emissions and commenters did not offer specific information to the contrary. Consequently, we have focused our fuel-related MSAT action on gasoline benzene, as proposed.

c. Why Are We Finalizing a Level of 0.62 vol% for the Average Benzene Standard?

We considered a range of average benzene standards, taking into account technological feasibility as well as cost and the other enumerated statutory factors. We received comments from a variety of parties supporting standards more stringent than the proposed level of 0.62 vol%. In general, the refining industry did not express strong opposition to a standard of 0.62 vol%. However, several small refiners opposed a benzene standard and argued for relief for small refiners if EPA went forward with such a program. One commenter, an importer, proposed a standard of 1.0 vol%. None of the commenters opposing the 0.62 vol% standard provided analytical support for a less stringent standard, or addressed how a less stringent standard might reflect the greatest emission reductions achievable based on the statutory factors. We have considered all of these comments and reassessed the level of the standard in light of the key factors we are required to consider, and have concluded that, as proposed, 0.62 vol% is the appropriate level for the average standard, because it achieves the greatest achievable emission reductions through the application of technology that will be available, considering cost, energy, safety, and lead time.[188] As discussed in section VI.A.1.d below, we have drawn this conclusion in the context of the 1.3 vol% maximum average benzene standard. We summarize our assessment of technological and economic factors next.

i. General Technological Feasibility of Benzene Control

Benzene Control Technologies

We have identified several technologies that can cost-effectively reduce gasoline benzene levels and we assessed their feasibility. These benzene control technologies function primarily by controlling the benzene in the feedstock to and the product stream from the reformer. They primarily focus on the reformer because refiners rely on the reformer to produce aromatic compounds for their octane content, and benzene is one of the aromatic compounds produced. For refiners who are not actively reducing the benzene in their gasoline today, we estimate that the reformer is responsible for about one half to three quarters of the benzene in gasoline.

Since the proposal, we learned of a change in how a particular gasoline blending stream is being routed in the refinery which affects its treatability for reducing benzene. After speaking to several refiners, we learned that natural gasoline is being blended differently into gasoline today because of the need to address the sulfur in this stream for compliance with Tier 2. Specifically, natural gasoline is being blended with the crude oil before the crude oil is refined in the refinery. Therefore the benzene in natural gasoline would be treated along with the naturally occurring benzene in crude oil using the

[185] For further discussion of the impact of these fuel properties on emissions, see RIA Chapter 7.

[186] Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel—Final Rule, Section 5.9.4 of the Regulatory Impact Analysis, June 29, 2004.

[187] Health Effects Institute's Advanced Collaborative Emissions Study.

[188] EPA does not believe that there are any noise issues associated with these standards, and no comments suggested any such issues exist.

benzene control technologies described below. We reflected this change in our refinery modeling.

One approach to reducing gasoline benzene levels is to reroute around the reformer the intermediate refiner streams that have the greatest tendency to form benzene in the reformer. This technology is usually termed light naphtha splitting. Assuming that a refinery applying this technology is not applying any sort of benzene control today, we estimate that this method reduces the benzene levels of reformate (the stream leaving the reformer) by 60 percent. This approach requires little or no capital investments in refineries to realize the results, but its effectiveness is limited because it does not address any of the naturally-occurring benzene found in crude oil and from natural gasoline and the other benzene which is formed in the reformer. Although this benzene control technology normally will not achieve the most substantial benzene control, refiners choosing it will achieve some measure of benzene control and then would likely need to purchase credits to comply with the 0.62 benzene standard.

To achieve deeper benzene control, refiners with an isomerization unit can send the rerouted intermediate refinery stream to their isomerization unit. The isomerization unit would saturate the naturally-occurring benzene from crude oil and natural gasoline in the rerouted refinery intermediate stream mentioned above, thus achieving additional benzene reduction. Using these two technologies together, refiners will be able to reduce reformer benzene levels by an estimated 80 percent. However, the benzene formed in the reformer would still not be treated using these two technologies together.

For even deeper benzene reductions than benzene precursor rerouting by itself or in combination with isomerization, refiners could choose between benzene saturation and benzene extraction. Each of these technologies work by reducing the benzene levels in the reformate, achieving an estimated 96 percent reduction in benzene, assuming that the refinery is not already taking steps to control its benzene levels. Benzene saturation involves using hydrogen to saturate the benzene into cyclohexane, which is a compound usually found in gasoline. Benzene extraction units chemically extract the benzene from the rest of the hydrocarbon compounds in reformate and concentrate it to a high purity using distillation such that it is suitable for sale into the chemicals market. Either of these technologies is capable of achieving the deepest levels of gasoline benzene reductions, allowing virtually all refiners to meet or exceed the 0.62 vol% gasoline benzene standard.

The actual impact of these benzene control technologies on an individual refinery's finished gasoline benzene content, however, will be a function of many different refinery-specific factors. These factors include the types of refining units in each refinery and the benzene levels produced by them, and the extent to which they are already utilizing one or more of these benzene control technologies.

Each of the benzene control technologies associated with the reformer has been commercially demonstrated by at least half a dozen units in U.S. refineries today operating for at least two years. Also, we did not receive any comments questioning the viability of these technologies for achieving the benzene reduction attributed to these technologies in the proposed rule. We therefore conclude that these technologies can feasibly achieve the benzene reductions that we attribute to them. We discuss the economics for each of these approaches to benzene reduction in more detail in section VIII.A. of this preamble, and we discuss their feasibility and cost in detail in Chapters 6 and 9 of the RIA.

We evaluated the benzene control level achievable without the use of credits by each refinery using either benzene saturation or extraction, since this would represent the maximum technologically feasible level of benzene control by each refinery. Our refinery cost model shows that based on the application of one or the other of these two benzene technologies, eight refineries would still not be able to achieve the final 0.62 vol% benzene average standard. We believe that these refineries would, however, be able to achieve the 1.3 vol% maximum average standard (which, as explained in section VI.A.1.d below, must be achieved without the use of credits) through the use of one of these technologies.

These eight refineries would be able to further reduce their gasoline benzene levels by treating the benzene contained in other gasoline blendstocks, particularly light straight run, light coker naphtha and light hydrocrackate. We believe that refiners could merge these streams with their reformate gasoline stream, so that these other sources of benzene would be treated along with the benzene in the reformate using either benzene saturation or benzene extraction. The results of this additional analysis summarized in the RIA show that these eight refineries would be able to meet the 0.62 vol% average standard if they were to apply one or more of these additional benzene control steps, though in some cases it may be at a considerably higher cost than through the purchase of credits. The cost and ultimate feasibility for controlling the benzene in light straight run, light coker naphtha and light hydrocrackate is very difficult to determine without detailed and comprehensive knowledge about how refineries are configured and operated today. It might be possible for a refinery to adjust existing distillation units, either operationally or with minor capital investments, to change the cutpoints for these streams. They might then route the benzene in these streams to the reformer, where a benzene control technology would be applied. On the other hand, changing the cutpoints to reroute the benzene might require the addition of a whole new distillation column, similar in function to a reformate splitter. Adding such grassroots distillation columns to make these splits would be much more costly. Finally we have not found any commercially demonstrated benzene control technologies that can reduce the benzene of FCC naphtha, the second largest contributor of benzene to the gasoline pool.

Impacts on Octane and Strategies for Recovering Octane Loss

All these benzene reduction technologies tend to cause a small reduction in the octane value of the final gasoline, since benzene is high in octane (about 101 octane number ((R+M)/2). Understanding how lost octane will be recovered is critical to determining the feasibility and cost of benzene control. Regular grade gasoline must comply with a minimum 87 octane number (or a sub-octane rating of 86 for driving in altitude), while premium grade gasoline must comply with an octane rating which ranges from 91 to 93 octane numbers. Gasoline must meet these octane ratings to be sold at retail. Routing the benzene precursors around the reformer reduces the octane of the six-carbon compound stream (by foregoing the formation of benzene) which normally exits the reformer with the rest of the reformate. Without these compounds in the reformate, our refinery model shows that a loss of octane in the gasoline pool of about 0.14 octane numbers will typically occur. If this rerouted stream can be sent to an isomerization unit additional octane loss will occur due to the saturation of benzene[189]; however, as described below, the isomerization unit offsets a part of the octane loss caused by this combination of saturation and rerouting. Benzene saturation and benzene extraction both affect the octane of reformate and therefore of the gasoline pool. Our refinery model estimates that benzene saturation typically reduces the octane of gasoline by 0.24 octane numbers, and benzene extraction typically reduces the octane of gasoline by 0.14 octane numbers.

Refiners have several choices available to them for recovering the lost octane. One is to blend in ethanol. Ethanol has a very high octane number rating of 115. Thus, only a small amount of ethanol (one percent of the gasoline pool or less) would be necessary to offset the octane loss associated with benzene reductions. Moreover, ethanol blending will occur for reasons independent of the benzene control requirements (and attendant octane loss) of the present rule. As explained in the discussion of potential aromatics controls above, current market forces and state and federal policies (including the RFS program) will increase the volume of renewable fuels, including ethanol, which is to be blended into gasoline. The volume of renewable fuels must increase from around 4 billion gallons in 2004 to 7.5 billion gallons in 2012 when the renewable fuels provisions of the RFS are fully implemented. However, as part of the Annual Energy Outlook for 2006, the Energy Information Administration projects that the economics driven by higher crude oil prices will result in more like 9.6 billion gallons of ethanol use by 2012.

Octane may also be increased by increasing the severity of the reformer (which determines the final octane of the reformate). However, if the refiner is reducing benzene through precursor rerouting or saturation, this strategy can be somewhat counterproductive. This is because increased severity increases the amount of benzene in the reformate and thus increases the cost of saturation and offsets some of the benzene reduction of precursor rerouting. Increasing reformer severity also decreases the operating cycle life of the reformer, requiring more frequent regeneration. However, where benzene extraction is used, increased reformer severity can improve the economics of extraction because not only is lost octane replaced by other aromatic compounds, but more benzene is extracted and sold.

Refiners can also recover lost octane by increased use of isomerization and alkylate units. As discussed above, saturating benzene in the isomerization unit results in an octane loss, but the octane loss is partially offset by the simultaneous formation of branch-chain compounds in the isomerization unit. The isomerization unit would only offset a portion of the octane loss caused by saturating the benzene if the unit has sufficient capacity to treat both the five-carbon hydrocarbons normally sent to the unit as well as the newly rerouted six-carbon hydrocarbons. Also, many refineries produce a high-octane blendstock called alkylate. Refiners can alter their refineries to produce more alkylate or they may be able to purchase alkylate on the open market. Not only is alkylate moderately high in octane (93 or 94 octane numbers), but it converts four-carbon (i.e., butane) compounds that are too volatile to be blended in large amounts into the gasoline pool into heavier compounds that can be readily blended into gasoline, thus increasing gasoline volume.

All these means available to refiners for recovering the octane loss associated with gasoline benzene reductions are commercially demonstrated, and we did not receive any comments questioning our reliance on them at proposal for maintaining the octane of the gasoline pool in the proposal. Therefore, we conclude that it is feasible for refiners to recover the octane loss associated with benzene control.

ii. Appropriateness of the 0.62 vol% Average Benzene Content Standard

As discussed above, we received many comments about the proposed level of the benzene standard. Many commenters advocated a more stringent standard, generally pointing to refineries currently producing gasoline with benzene levels below the proposed 0.62 vol% standard and stating that the average standard should be sufficiently stringent that all refineries, especially those with higher benzene levels, would be required to use similar technologies and achieve similarly low levels. We also received broad support for the 0.62 vol% standard in the comments from the refining industry, although several small refiners opposed imposing a benzene standard and argued for relief for small refiners if EPA implemented the proposed standard. One importer was concerned that the standard of 0.62 vol% could make it more difficult for importers to find compliant gasoline shipments and proposed a standard of 1.0 vol%. None of the commenters opposing the 0.62 vol% standard provided analytical support for a less stringent standard or addressed how a less stringent standard might reflect the greatest emission reductions achievable based on the statutory factors.

In the proposal, EPA described in detail what we believe would be the consequences of average standards of different stringencies to the overall goals of the program (see 71 FR 15866–67). These anticipated consequences relate in large part to how we believe refiners would respond to the benzene averaging and benzene credit trading provisions that were integral to the proposed program. For the final rule, we have reassessed how we believe refiners would respond to different average standards. We continue to believe that increasing the stringency of the average benzene standard would have the effect of reducing the number of benzene credits generated, since fewer refineries are likely or able to take actions to significantly reduce benzene further than required by the standard. This would reduce the liquidity of the credit trading market. As discussed in section VI.A.2, a well functioning averaging, banking, and trading program is integral to the achievability of the benzene standard. With fewer credits available that are affordable as an alternative to immediate capital investment, investment in relatively expensive benzene saturation equipment would be necessary for a greater number of refiners. We specifically considered a level of 0.50 vol% for the average standard, which we expected would require all refineries to install the most expensive benzene control technologies. We concluded that this level would clearly not be achievable, considering cost. In a related analysis, we also showed that if, contrary to our expectations, credits were not easily available as a compliance option, there are several refineries for which it may be technologically feasible to reach benzene levels below 0.62 vol%, but only at costs far greater than for most other refiners.

Decreasing the stringency of the standard would fail to meet our obligation under 202(l)(2) to set the most stringent standard achievable considering costs and other statutory factors. First, over the last several years RFG benzene levels have already been averaging around 0.62 vol%, and we have no information to suggest that this level is not technologically feasible for the rest of the gasoline pool as well. In fact, our analysis shows that this level is feasible for the pool of gasoline as a whole. Commenters did not provide any analysis that a standard of 0.62 vol%

[189] The chemical process of benzene saturation in the isomerization unit is the same as the process that occurs in a benzene saturation unit, as described above.

was not the greatest achievable after considering cost and the other statutory factors. Second, a standard less stringent than 0.62 vol% would not achieve a number of important programmatic objectives. As shown in Table VI.C–1 below, a 0.62 vol% standard is necessary to satisfy the conditions on overall RFG toxics performance established by EPAct and thus to avoid the requirement for updated individual refinery baselines. We believe that any level for the standard above 0.62 vol% would require EPA to promulgate regulations requiring RFG refiners to continue to maintain individual refinery-specific baselines, adjusted to 2001–2 as required by EPAct. The refining industry believes that this would continue to penalize the cleanest refineries, constrain their flexibility, and cause market inefficiencies that increase costs. They have been strongly supportive of a program that eliminates the need for individual refinery baselines. EPA agrees with these concerns, and believes that the nationwide ABT program allowed under this program will remove these impacts. Another of EPA's policy objectives that has been strongly supported by the refining industry was establishing the same standard nationwide for the combined pool of RFG and CG. The level of 0.62 vol% allows us to establish a single combined program for RFG and CG. In addition, the level of 0.62 vol% for the standard allows us to streamline with confidence our toxics regulations for RFG and CG, so that this benzene program (along with the gasoline sulfur program) will become the regulatory mechanism used to implement the RFG and CG annual average toxics performance requirements and the annual average benzene content requirement for RFG. Further, we believe that with such a stringent benzene standard, refiners should have the certainty they need for their investment and planning decisions.

Many comments that supported a more stringent standard pointed to average costs projected in the proposal that are higher than for the proposed standard, but are not large on a per-gallon basis compared to other EPA fuel programs. However, these commenters did not address the wide range of compliance costs for individual refineries that we discuss in the proposal (see Chapter 9 of the proposed and final RIA documents). It is critical to recognize that as more stringent average standards are considered, the costs for many refineries begin to rise significantly, especially for some individual technologically-challenged refineries. This potential for high costs at more stringent average standards exists if, as we expect, the ABT program functions as it is designed to. If the ABT program operates less efficiently than projected, the costs for some individual refineries could be higher still. (We discuss issues related to the 1.3 vol% maximum average standard, which cannot be met through the use of credits, in section VI.A.1.d, ''Upper Limit Benzene Standard,'' below.)

Based on our analysis of the projected response of the refining industry to an average benzene standard, we are finalizing the 0.62 vol% standard as proposed. We believe that this average benzene standard of 0.62, in the context of the associated ABT program and the 1.3 vol% maximum average standard, results in the greatest reductions achievable, taking into account cost and the other statutory factors in CAA 202(l)(2).

iii. Timing of the Average Standard

Section 202(l)(2) requires that we consider lead time in adopting any fuel control for MSATs. We proposed that refiners and importers meet the 0.62 vol% average benzene standard beginning January 1, 2011 (January 1, 2015 for small refiners). This date was based on the industry experience that most of the technological approaches that we believe refiners will apply—rerouting of benzene precursors around the reformer and use of an existing isomerization unit—will take less than two years. The more capital intensive approaches—saturation and extraction—generally take two to three years to complete. The January 1, 2011 date provides nearly four years of lead time. We believe this is an appropriate amount of lead time, even taking into account that other fuel control programs (notably the Nonroad Diesel program) will be implemented in the same time frame.

Some commenters supported earlier start dates, referring in some cases to the experience of Canada in regulating gasoline benzene. However, these comments failed to acknowledge the less stringent Canadian standard (0.95 vol%) which naturally takes less lead time to implement. No commenter provided information that challenged our assessments of the technical lead time for the range of benzene control approaches that will be implemented. Other commenters, mostly from the refining industry, supported a start date that would be at least four years after the date of the final rule. For the reasons described above, we do not believe this additional time is necessary for this program. We are finalizing a start date of January 1, 2011, as proposed.

We discuss the lead time for the 1.3 vol% maximum average standard, which takes effect July 1, 2012 for non-small refiners and importers, and July 1, 2016 for small refiners, in the next section.

d. Upper Limit Benzene Standard

In the proposal, we discussed the potential concern that without an upper limit, some refiners may choose to allow their benzene levels to increase, or to remain unchanged indefinitely. However, we also said that once an average standard is in place, any increase in benzene levels will necessarily come at the cost of purchasing additional credits. We tentatively concluded that this downward pressure on benzene levels meant there would likely be no increases in benzene from any refinery, whether or not there was an upper limit. In fact, we concluded that this pressure would result in actual reductions at almost all refineries, especially into the future as refiners try to limit their reliance on credits as much as and whenever it is economical to do so (see 71 FR 15867–68).

We nonetheless considered the implications of an upper limit on the actual level of benzene in the gasoline that refiners produce (as opposed to the level achieved using credits). (See 71 FR 15678–79.) We considered an upper limit both in the form of a per-gallon benzene cap and a limit on the average of actual benzene in gasoline produced by a refinery (''maximum average standard''). Of these two approaches, we recognized that a per-gallon cap would be the more rigid. If every batch needed to meet the cap, there would be no opportunity to offset benzene spikes with lower-benzene production at other times. Even during times of normal operation, our review of refinery batch data indicated that unavoidable wide swings commonly occur in the benzene content of gasoline batches, even for refineries that have relatively low benzene levels on average. A per-gallon cap could result in refiners halting gasoline production during short-term shut-downs of benzene control equipment or in other temporary excursions in benzene levels. Unless a per-gallon limit were generous enough or included case-by-case exceptions (eroding the possible benefit of the cap), many refiners would likely need to implement much deeper and more costly reductions in benzene than would otherwise be necessary, simply to protect against such fluctuations. For some refiners, we concluded, a cap could make complying with the program prohibitively expensive.

The other option on which we solicited comment, a maximum average standard, would be more flexible. A maximum average standard would limit the average benzene content of the actual production at each refinery over the course of the year, regardless of the extent to which credits may have been used to comply with the 0.62 vol% average standard. Thus, a maximum average standard would allow for short-term benzene fluctuations as long as the annual average benzene level of actual production was less than that upper limit.

Several commenters stated that an upper limit would add costs without resulting in additional benefits, and supported a program without upper limits. Other commenters, however, expressed serious concerns about the potential consequences of a program without upper limits. Several commenters were concerned that under the program as proposed, it would be possible for refiners to maintain benzene levels well above the standard indefinitely while complying through the use of credits, thus potentially reducing the benefits of the program where this gasoline is used. Some commenters noted that under the proposed program, gasoline in some areas could still have significantly higher benzene levels than in other parts of the country. These commenters believe that these projected disparities raise issues of fairness. While our modeling of the proposed average standard suggested that all refineries were likely to reduce their benzene levels to some extent and that there would be significant reductions in gasoline benzene levels in each PADD, the commenters noted that an upper limit would provide a guarantee of reduction to at least the level of the upper limit.

After evaluating the results of our updated refinery analysis and considering all of the comments, we have reconsidered the appropriateness of an upper limit standard. For the reasons discussed above, we continue to believe that a per-gallon cap for CG would be inappropriate for a benzene control program due to actions refineries would need to take to protect against common fluctuations in benzene content, and the related adverse cost and energy implications if refineries invest in deeper benzene reductions or need to temporarily shut down. In contrast, the per-gallon cap for RFG of 1.3 vol%, which is currently in place, functions differently than would a per-gallon cap that applied to both the RFG and CG pools. The per-gallon cap for RFG alone is appropriate because the CG pool provides an outlet for batches of higher benzene RFG. However, if such a cap were applied to CG as well, refiners would be left without an outlet. As we said in the proposal, any meaningful level for a per-gallon cap applying to CG would thus overly restrict the normal fluctuations in gasoline benzene (see 71 FR 15869).

On the other hand, we now believe that the program should include a maximum average benzene standard, set at an appropriate level. The maximum average standard has the strong advantage of ensuring that the benzene content of gasoline produced by each refinery (or imported by each importer) will average no higher than this standard, regardless of the use of credits, providing greater assurance that actual in-use benzene reductions more clearly reflect our modeled projections which form the basis for this rule. At the same time, the maximum average standard avoids the serious drawbacks of a per-gallon cap.

Our refinery modeling is state of the art, but it cannot predict with high confidence each refinery's actions and how benzene trading will occur in each instance. We have done a refinery-by-refinery assessment of the most economical decisions we believe the industry will make to comply with the standard. However, in developing the model, we did not have access to specific information on many refineries, much of which is confidential business information. To fill these gaps, we used broader industry average information for a number of key model input parameters (including benzene levels in crude oil and in gasoline blendstocks, individual refinery unit throughput and operating conditions, distillation ''cut points,'' and future refinery expansions). Since there is wide variation in these important parameters among different refineries that impacts their baseline benzene levels and their opportunities for control, our model's assumptions inherently vary from actual refinery circumstances. Furthermore, by necessity, our model assumes that all refineries will, in effect, work collectively to make the most economical investment decisions on a nationwide basis, as though each knew in advance the investment decisions of the others. In reality, each individual refinery will be making its decisions independently of each other, based on very limited information about other refineries' actions. In addition, our model assumes that refiners will limit their actions to only treat the principal benzene-containing stream (reformate). There are individual circumstances where it may be economical to also treat other refinery streams. If the benzene in these other streams is indeed treated by some refineries, it is possible that sufficient credits might be generated to allow more refineries to avoid benzene reductions altogether by simply purchasing credits. Consequently, although our refinery-by-refinery modeling predicts significant benzene reductions in all areas nationwide, individual refineries might continue to have gasoline with higher benzene levels than the model predicts. This may also result in higher regional variation in gasoline benzene levels than the model predicts. Thus, we cannot dismiss this possibility with a high degree of confidence.

For these reasons, we believe that the addition of a maximum average standard to the 0.62 average standard provides far greater assurance that refineries will control benzene in the future as projected—and certainly will not increase benzene levels to be greater than the level of the maximum average standard. Furthermore, through selection of an appropriate level for the maximum average standard, we believe that we are achieving this goal with a minimal impact on the overall costs of the program.

We did not originally propose a maximum average standard, largely because of our interpretation of our modeling done for the proposal. That modeling indicated that adding a maximum average standard would result in significantly more benzene reduction in some areas, but that these increases would cause other areas to experience slightly smaller benzene reductions (see 71 FR 15903). Our updated modeling results are similar. In the proposal, we considered this potential for smaller benzene reductions in some areas to be a reason not to propose a maximum average standard. However, upon further evaluation of these modeling results, given the level of uncertainty in the model to predict individual refinery and regional benzene levels (as discussed above), we do not have confidence in the size of any offsetting increases in benzene levels in other areas, or even whether they would occur. In addition, we recognize that some of the refiners that the model predicts would reduce benzene slightly less (creating the apparent offsetting regional effects) may in fact decide to overcomply with the standard in order to maintain a compliance ''safety margin,'' regardless of the presence of a maximum average standard, and regardless of the strength of the market for the generated credits.

In light of this, we do not think it warrants giving up the benefits resulting from the inclusion of the maximum average standard.

Absent concern about any measurable offsetting effects from a maximum average standard, we believe that the major benefit of such a standard can and should be pursued. That is, the program can achieve increased certainty that the significant gasoline benzene reductions across all parts of the nation that our modeling projects will indeed occur, and thus that regional variations in gasoline benzene levels will indeed be minimized as we project.

We believe that setting the maximum average standard at a level of 1.3 vol% accomplishes the goal of reasonably assuring lower benzene levels for all refineries while balancing the negative aspects of more- and less-stringent benzene standards. Virtually all the commenters who supported a maximum average standard agreed that 1.3 vol% would be a reasonable level for such a standard. EPA agrees. Implementing a maximum average standard lower than 1.3 vol% would begin to significantly increase the number of refineries that would need to install the more expensive benzene reduction equipment. This would quickly diminish the value of the flexibility provided by the ABT program and thus force an increasing number of refineries to make expenditures in benzene control that could otherwise be smaller or avoided entirely, significantly increasing the overall cost 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. As shown in detail in Chapter 9 of the RIA, the addition of the 1.3 vol% standard has minimal impact on the overall costs of the program. It is for this reason that we find that the 0.62 vol% annual average standard, in tandem with the 1.3 vol% maximum average standard, represents the greatest benzene reductions achievable considering cost, energy supply, and other enumerated statutory factors.

We believe that it is very important to monitor levels of benzene as refiners and importers begin to respond to the average and maximum average standards. EPA currently collects information on benzene and several other gasoline parameters for every batch of gasoline produced in or imported into the U.S., and publishes it in aggregate form on the EPA Web site. By January 1, 2011, we plan to begin publishing a more detailed annual report on gasoline quality. We will present this data on a PADD-by-PADD basis (to the extent that protection of confidential business information allows). We expect that these reports will be a valuable tool to stakeholders and members of the public who are interested in following the real-world progress of this rule's gasoline benzene reductions.

Among other changes discussed in section VIII below, our updated refinery-by-refinery model uses year-round 2004 gasoline production data as a starting point (replacing 2003 summer production data used in the proposal) and incorporates updated crude oil and benzene prices. The model thus generates updated predictions of the responses of refineries to the benzene standards. Our updated analysis shows that with the 0.62 vol% average standard and the maximum average benzene standard of 1.3 vol%, benzene levels will be reduced very significantly in all parts of the country. However, a degree of variation will continue to exist, due to the wide variety of refinery configurations, crude oil supplies, and approaches to benzene control, among other factors. This remaining variation is clearly legally permissible, notwithstanding the reasonable objective of assuring that reductions occur both regionally and nationally, because we do not read CAA section 202(l)(2) as requiring uniform gasoline benzene levels in each area of the country, since the standard is to be technology-based considering costs and other factors which vary considerably by region and by refinery. On the other hand, the maximum average standard will have the appropriate effect of directionally providing a greater degree of geographic uniformity of gasoline benzene levels and these levels remain achievable considering cost and the other enumerated factors. Reducing gasoline benzene levels on both a national and regional basis is within the discretion of the Administrator, since section 202(l)(2) does not specify whether the maximum degree of emission reductions are to be achieved nationally, regionally, or both.

The 1.3 vol% maximum average standard will become effective 18 months after the 0.62 vol% average standard, on July 1, 2012, and on July 1, 2016 for small refiners. While there is ample lead time for non-small refiners to meet the 0.62 vol% standard by January 1, 2011, we believe that staggering the implementation dates will ensure that the implementation of the programs by the refining industry is as smooth and efficient as possible. An important aspect of the design of this program as proposed is the recognition that not all of the benzene reduction would occur at once. As discussed in detail in section VI.A.2.b below, we expect that individual refiners will use the ABT program to schedule their benzene control expenditures in the most efficient way, using the early credit and standard credit provisions. This will essentially create a gradual phasing-in of the reductions in gasoline benzene content, beginning well before the initial compliance date of January 1, 2011 and spreading out industry-wide compliance activities over several years. Since the 1.3 vol% standard may not be met using credits, we have set the implementation dates for this standard such that the credit program can continue to be fully utilized for an additional 18 months after the effective date of the 0.62 vol% average standard to allow the intended phasing-in of the program to occur (i.e., there will be 18 additional months during which the 0.62 vol% average standard may be achieved exclusively by using credits).

We acknowledge that by incorporating the 1.3 vol% maximum average standard into the program, we are creating additional compliance challenges for a small number of refineries that might have relied on credits but will now need to install capital equipment to meet the 1.3 vol% maximum average standard. Most refiners will need to take these steps by July 1, 2012. Small refiners will need to take these steps four years later, by July 1, 2016. Although we believe that most (possibly all) refiners will be able to install appropriate benzene control equipment by these future dates, there may be a small number of refiners that continue to face significant financial hurdles as these dates approach. We have considered this concern, and we believe that the leadtime provided, including the longer leadtime for small refiners, and the hardship relief provisions discussed below, are sufficient to address any circumstances of severe economic impacts on individual refineries. We are making clear that serious economic difficulties in meeting the 1.3 vol% maximum average standard may be a basis for granting relief under the ''extreme hardship'' provision discussed in sectionVI.A.3. below.

2. Description of the Averaging, Banking, and Trading (ABT) Program

a. Overview

We are finalizing a nationwide averaging, banking, and trading (ABT) program that allows us to set a more stringent annual average gasoline benzene standard than would otherwise be justifiable. The ABT program allows refiners and importers to choose the most economical compliance strategy (investment in technology, credits, or both) for meeting the 0.62 vol% annual average benzene standard. The flexibility afforded by the program is especially significant and needed given the considerable variation in existing gasoline benzene levels, which reflects important differences in crude oil composition and individual refinery design.

From 2007–2010, refiners can generate ''early credits'' by making qualifying benzene reductions earlier than required. In 2011 and beyond, refiners and importers can generate ''standard credits'' by producing/importing gasoline with benzene levels below 0.62 volume percent (vol%) on an annual average basis. Credits may be used interchangeably towards compliance with the 0.62 vol% standard, ''banked'' for future use, and/or transferred nationwide to other refiners/importers subject to the standard. In addition to the 0.62 vol% standard, refiners and importers must also meet a 1.3 vol% maximum average benzene standard beginning July 1, 2012. To comply with the maximum average standard, gasoline produced by a refinery or imported by an importer may not exceed 1.3 vol% on an annual average basis. While the 1.3 vol% maximum average standard places a limitation on credit use, we believe that the ABT program still provides the refining industry with significant compliance flexibility as described below.

b. Credit Generation

i. Eligibility

Under the ABT program, U.S. refiners (including ''small refiners''[190]) who produce gasoline by processing crude oil and/or intermediate feedstocks through refinery processing units (see § 80.1270) are eligible to generate both early and standard benzene credits. Foreign refiners with individual refinery baselines established under § 80.910(d) who imported gasoline into the U.S. in 2004–2005 are also eligible to generate early credits. Importers, on the other hand, are only eligible to generate standard credits under the ABT program. As explained in the proposal, importers are precluded from generating early credits because, unlike refineries, they do not need additional lead time to comply with the standard since they are not investing in benzene control technology. Additionally, due to their variable operations, importers could potentially redistribute the importation of foreign gasoline to generate ''windfall'' early credits with no associated benzene emission reduction value (see 71 FR 15874).

Benzene credits may only be generated on gasoline which is subject to the benzene requirements as described at § 80.1235. This excludes California gasoline (gasoline produced or imported for use in California) but includes gasoline produced by California refineries for use outside of California. Despite the fact that California gasoline is not covered by this program, EPA sought comment on whether and how credits could be generated based on California gasoline benzene reductions and applied towards non-California gasoline compliance (see 71 FR 15873). We did not receive any substantive comments on this matter but nonetheless considered the feasibility of such a program (described in more detail in the Summary and Analysis of Comments). We concluded that such a program could be very problematic to implement and, based on the apparent lack of interest by California gasoline refineries, it is likely that there would be very few participants. As a result, we have decided to maintain the proposed ABT provision which excludes California gasoline from generating credits.

ii. Early Credit Generation

To encourage early innovation in gasoline benzene control technology, refiners are eligible to generate early credits for making qualifying benzene reductions prior to the start of the program. Refiners must first establish individual benzene baselines for each refinery planning on generating early credits (discussed further in section VI.B.1). Benzene baselines are defined as the annualized volume-weighted benzene content of gasoline produced at a refinery from January 1, 2004 through December 31, 2005. To qualify to generate early credits, refineries must make operational changes and/or improvements in benzene control technology to reduce gasoline benzene levels in accordance with § 80.1275. Additionally, a refinery must produce gasoline with at least ten percent less benzene (on a volume-weighted annual average basis) than its 2004–2005 baseline. The first early credit generation period is from June 1, 2007 through December 31, 2007, and subsequent early credit generation periods are the 2008, 2009, and 2010 calendar years (2008 through 2014 calendar years for small refiners).

We are setting a ten percent reduction trigger point for early credits to ensure that changes in gasoline benzene levels result from real refinery process improvements. Without a substantial trigger point, refiners could earn credits for the normal year-to-year fluctuations in benzene level at a given refinery allowed under MSAT1. These windfall credits could negatively impact the ABT program because—as reflections of normal variability—they would have no associated benzene emission reduction value. As described in the proposal, we believe that a percent reduction trigger point, as opposed to an absolute level or fixed reduction trigger point, is the most appropriate early credit validation tool considering the wide range in starting benzene levels. In addition, we believe that ten percent is an appropriate value for the trigger point because it prevents most windfall credit generation, yet is not so restrictive as to discourage refineries from making early benzene reductions (see 71 FR 15875).

Once the ten percent reduction trigger point is met, refineries can generate credits based on the entire gasoline benzene reduction. For example, if in 2008 a refinery reduced its annual average benzene level from a baseline of 2.00 vol% to 1.50 vol% (below the trigger point of $0.90 \times 2.00 = 1.80$ vol%), its early benzene credits would be determined based on the difference in annual benzene content ($2.00 - 1.50 = 0.50$ vol%) divided by 100 and multiplied by the gallons of gasoline produced in 2008 (expressed in gallons of benzene).

We proposed that refiners be prohibited from moving gasoline or gasoline blendstock streams from one refinery to another in order to generate early credits (see 71 FR 15875). We received comments indicating that many refiners trade blending components between refineries to maximize gasoline production while minimizing cost, and that such companies should not be prohibited from generating early credits. In fact, we are not prohibiting these types of normal refinery activities, nor are we prohibiting such refineries from participating in the early credit program. We are simply requiring that all refineries make real operational changes and/or improvements in benzene control technology to reduce gasoline benzene levels in order to be eligible to generate early credits. In most cases, moving gasoline blendstocks from one refinery to another does not result in a net benzene reduction (one refinery gets cleaner at the expense of another

[190] Refiners approved as small refiners under § 80.1340.

getting dirtier). Accordingly, refineries that lower their benzene levels exclusively through blendstock trading (no additional qualifying reductions) are not eligible to generate early credits under the ABT program. An exception exists for refineries that transfer benzene-rich reformate streams for processing at other refineries with qualifying post-treatment capabilities, e.g., extraction or benzene saturation units. Under this scenario, the transferring refinery would be eligible to generate early credits because a real operational change to reduce gasoline benzene levels has been made. The regulations at § 80.1275 have been modified to more clearly reflect our intended early credit eligibility provisions, and specifically address blendstock trading.

iii. Standard Credit Generation

Refiners and importers may generate standard credits for overcomplying with the 0.62 vol% gasoline benzene standard on a volume-weighted annual average basis in 2011 and beyond (2015 and beyond for small refiners).[191] For example, if in 2011 a refinery's annual average benzene level is 0.52, its standard benzene credits would be determined based on the margin of overcompliance with the standard (0.62 − 0.52 = 0.10 vol%) divided by 100 and multiplied by the gallons of gasoline produced during the 2011 calendar year (expressed in gallons of benzene). Likewise, if in 2012 the same refinery were to produce the same amount of gasoline with the same average benzene content, they would earn the same number of credits. The standard credit generation opportunities for overcomplying with the standard continue indefinitely (see 71 FR 15872).

c. Credit Use

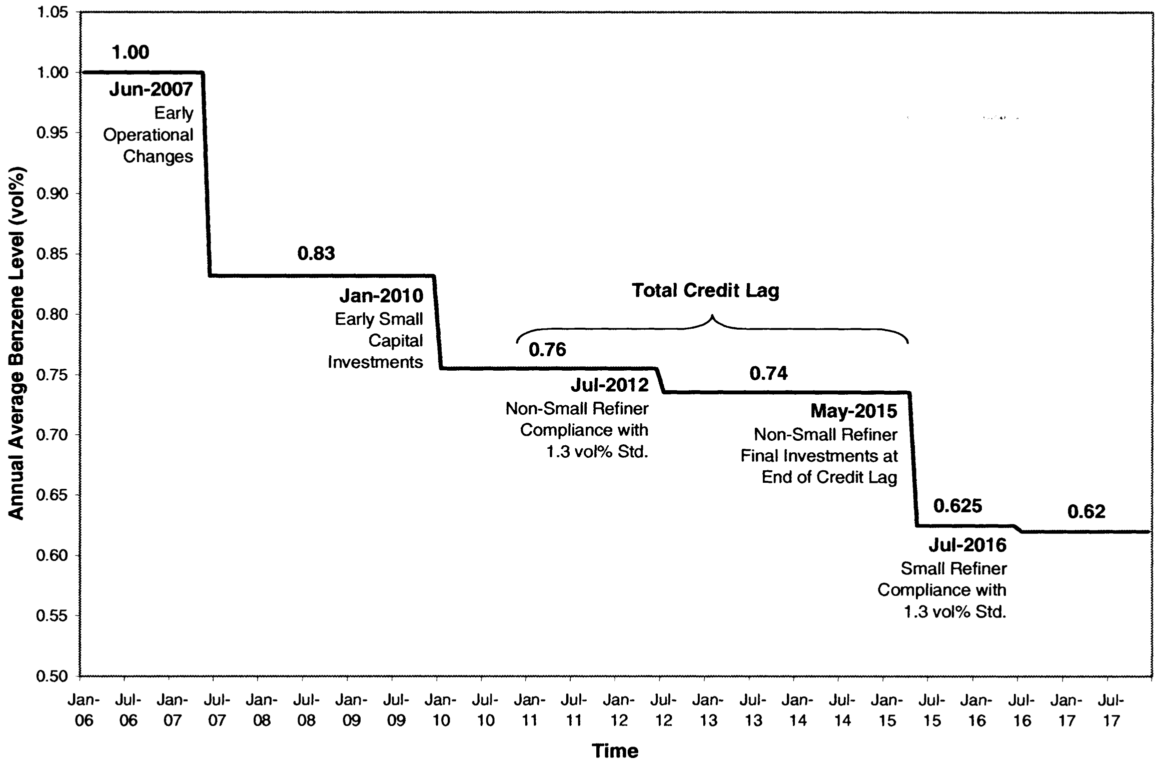
As proposed, we are finalizing a program where refiners and importers can use benzene credits generated or obtained under the ABT program to meet the 0.62 vol% annual average standard in 2011 and beyond (2015 and beyond for small refiners). We are also finalizing a 1.3 vol% maximum average standard which takes effect in July 2012 (July 2016 for small refiners). The maximum average standard must be met based on actual refinery benzene levels, essentially placing a cap on total credit use. As discussed above in section VI.A.1.d, we believe this is an appropriate strategy for addressing the current disparity in gasoline benzene levels throughout the country.

Overall, the ABT program will allow for a more gradual phase-in of the 0.62 vol% benzene standard and a more cost-effective program. The early credit program gives refiners an incentive to make initial gasoline benzene reductions sooner than required. The early credits generated can be used to provide refiners with additional lead time to make their final (more expensive) investments in benzene control technology. As a result, some benzene reductions will occur prior to the start of the program while others will lag (within the realms of the credit life provisions described below). We anticipate that there will be enough early credits generated to allow refiners to postpone their final investments by up to three years, which coincides with the maximum time afforded by the early credit life provisions. In addition, we predict that standard credits generated during the early credit lag period will allow for an additional 16 months of lead time. The result is a gradual phase-in of the 0.62 vol% benzene standard beginning in June 2007 and ending in July 2016, as shown below in Figure VI.A–1. Without early credits, refineries would be immediately constrained by the 0.62 vol% standard and likely forced to make their final investments sooner (including those necessary to meet the 1.3 vol% maximum average standard).

[191] Standard credit generation begins in 2011, or 2015 for small refiners, regardless of whether a refinery pursues early compliance with the 0.62 vol% standard under § 80.1334.

Figure VI.A-1

Benzene Level vs. Time



In addition to earlier benzene reductions and a more gradual phase-in of the 0.62/1.3 vol% standards (as shown above), the ABT program results in a more cost-effective program for the refining industry. Our modeling shows that allowing refiners to average benzene levels nationwide to meet the 0.62 vol% standard reduces ongoing compliance costs by about 50% from 0.51 to 0.27 cents per gallon (refer to RIA Section 9.6.2). Our modeling further shows that the early credit program we are finalizing results in the lowest possible compliance costs during the phase-in period. Without an early credit program, the total amortized capital and operating costs incurred by the refining industry during the phase-in period is estimated to be $905 million (2003 dollars).[192] With an early credit program, the total cost incurred during the same phase-in period is reduced to $608 million, providing about $300 million in savings. In the absence of an ABT program altogether, the total cost incurred during the phase-in period would be $1.7 billion. As a result, the ABT program in its entirety could save the refining industry up to $1.1 billion in compliance costs from 2007–2015. For a more detailed discussion on compliance costs, refer to section VIII.A. For more information on how the cost savings associated with the ABT program were derived, refer to RIA Section 6.5.5.12.

Under the ABT program, early and standard benzene credits can be used interchangeably towards compliance with the 0.62 vol% standard (within the realms of the credit life provisions described below). Each credit (expressed in gallons of benzene) can be used on a one-for-one basis to offset the same volume of benzene produced/imported in gasoline above the standard. For example, if in 2011 a refinery's annual average benzene level was 0.72, the number of benzene credits needed to comply would be determined based on the margin of undercompliance with the standard ($0.72 - 0.62 = 0.10$ vol%) divided by 100 and multiplied by the gallons of gasoline produced during the 2011 calendar year. The credits needed would be expressed in gallons of benzene.

To enable enforcement of the program, the ABT program we are finalizing includes a limit on credit life (for both early and standard credits), a limit on the number of times credits may be traded, and a prohibition on outside parties taking ownership of credits. We believe that these provisions are necessary to ensure that the full benzene reduction potential of the program is realized and that the credit trading program is equitably administered among all participants. In the proposal, we acknowledged concerns that credit use limitations might in some circumstances unnecessarily hamper the credit market. Specifically, we requested comment on ways that some of the provisions might be reduced or eliminated while still maintaining an enforceable program (see 71 FR 15872). Although we received many comments on the proposed ABT program, we did not receive any substantive comments indicating that the proposed credit provisions would be a significant burden on refiners or importers. Likewise, we did not receive

[192] ABT program cost calculations consider future gasoline growth and the time value of money. The gasoline growth rate from 2004–2012 was estimated by the refinery cost model and future growth rates were obtained from EIA's AEO 2006. The costs and resulting cost savings estimated for the phase-in period were calculated based on compliance costs presented in RIA Section 9.6.2 and adjusted back to 2007 to account for the time-value of money based on a 7% average rate of return.

any substantive comments suggesting that the removal of such restrictions would greatly improve the efficiency of the ABT program. For these reasons, we are finalizing such provisions for credit use (described in more detail below).

i. Early Credit Life

Early credits must be used towards compliance within three years of the start of the program; otherwise they will expire and become invalid. In other words, early credits generated or obtained under the ABT program must be applied to the 2011, 2012, or 2013 compliance years. Similarly, early credits generated/obtained and ultimately used by small refiners must be applied to the 2015, 2016, or 2017 compliance years. The result is that no early credits may be used toward compliance with the 2014 year. This break in the early credit application period may help funnel surplus early credits facing expiration to small refiners in need.

ii. Standard Credit Life

Standard credits must be used within five years from the year they were generated (regardless of when/if they are traded). For example, standard credits generated in 2011 would have to be applied towards the 2012 through 2016 compliance year(s); otherwise they would expire and become invalid. To encourage trading to small refiners, there is a credit life extension for standard credits traded to and ultimately used by small refiners. These credits may be used towards compliance for an additional two years, giving standard credits a maximum seven-year life. For example, the same above-mentioned standard credits generated in 2011, if traded and used by a small refiner, would have until 2018 to be applied towards compliance before they would expire.

iii. Consideration of Unlimited Credit Life

Since compliance with the gasoline benzene standards is determined at the refinery or importer level, there are no enforceable downstream standards associated with this rulemaking. Thus, it is critical that EPA be able to conduct enforcement at the refinery or importer level. Additionally, since EPA enforcement activities are limited by the five-year statute of limitations in the Clean Air Act, allowing credit life beyond five years poses serious enforcement issues. As a result, we are finalizing three-year early credit life and five-year standard credit life provisions (as just described above). We believe that these credit life provisions are limited enough to satisfy enforcement and trading concerns yet sufficiently long to provide necessary program flexibility. However, we recognize that extending credit life might result in increased program flexibility. Accordingly, in the proposal, EPA sought comment on different ways to structure the program that would allow for unlimited credit life. Specifically, we asked for comment on how unlimited credit life could be beneficial to the program and/or how the associated increase in recordkeeping and enforcement issues could be mitigated (see 71 FR 15872). Comments received provided no support for why unlimited credit life would improve program flexibility or how enforcement issues could be addressed. Furthermore, we did not receive any comments suggesting that the proposed credit life provisions would significantly hamper trading. As such, we are finalizing the credit life provisions as proposed.

iv. Credit Trading Provisions

It is possible that benzene credits could be generated by one party, subsequently transferred or used in good faith by another, and later found to have been calculated or created improperly or otherwise determined to be invalid. If this occurs, as in past programs, both the seller and purchaser will have to adjust their benzene calculations to reflect the proper credits and either party (or both) could be determined to be in violation of the standards and other requirements if the adjusted calculations demonstrate noncompliance with the 0.62 vol% standard.

Credits must be transferred directly from the refiner or importer generating them to the party using them for compliance purposes. This ensures that the parties purchasing them are better able to assess the likelihood that the credits are valid. An exception exists where a credit generator transfers credits to a refiner or importer who inadvertently cannot use all the credits. In this case, the credits can be transferred a second time to another refiner or importer. After the second trade, the credits must be used or terminated. In the proposal, we requested comment on whether more than two trades should be allowed—specifically, whether three or four trades were more appropriate and/or more beneficial to the program (see 71 FR 15876). We did not receive any comments providing analytical support for an additional number of trades. We are finalizing a maximum of two trades, consistent with other recent rulemakings, in order to provide flexibility while still maintaining enforceability as discussed in the proposal.

There are no prohibitions against brokers facilitating the transfer of credits from one party to another. Any person can act as a credit broker, regardless of whether such person is a refiner or importer, as long as the title to the credits is transferred directly from the generator to the user. This prohibition on outside parties taking ownership of credits was promulgated in response to problems encountered during the unleaded gasoline program and has since appeared in subsequent fuels rulemakings. To reevaluate potential stakeholder interest in removing this prohibition, EPA sought comment on this provision in the proposal—specifically, whether there were potential benefits to allowing other parties to take ownership of credits and how such a program would be enforced (see 71 FR 15876). We did not receive any comments on this issue and continue to believe that our proposal is appropriate. Therefore, to maintain maximum program enforceability and consistency with all of our other ABT programs for mobile sources and their fuels, we are maintaining our existing prohibition on outside parties taking ownership of credits.

We are not imposing any geographic restrictions on credit trading. Credits may be traded nationwide between refiners or importers as well as within companies to meet the 0.62 vol% national average benzene standard. We believe that restricting credit trading could reduce refiners' incentive to generate credits and hinder trading essential to this program. In addition, since there are no fuel-availability issues associated with this rule (as opposed to the case of the ultra-low sulfur diesel program), there is no need to impose a geographic restriction.

3. Provisions for Small Refiners and Refiners Facing Hardship Situations

In developing the MSAT2 program, we evaluated the need for and the ability of refiners to meet the proposed benzene standards as expeditiously as possible. We continue to believe that it is feasible and necessary for the vast majority of the program to be implemented in the time frame stated above to achieve the air quality benefits as soon as possible. Further, we believe that refineries owned by small businesses generally face unique hardship circumstances as compared to larger refiners. We are also finalizing provisions for other refiners to allow them to seek limited relief from hardship situations on a case-by-case basis. These provisions are discussed in detail below.

a. Provisions for Small Refiners

We proposed several special provisions for refiners that are approved as small refiners (see VI.A.3.a.ii below). This is due to the fact that small refiners generally have greater difficulty than larger companies (including those large companies that own small-capacity refineries) in raising capital for investing in benzene control equipment. Small refiners are also likely to have more difficulty in competing for engineering resources and in completing construction of the needed benzene control (and any necessary octane recovery) equipment in time to meet the required standards (see also the more detailed discussion at 71 FR 15877).

As explained in the discussion of our compliance with the Regulatory Flexibility Act below in section XII.C and in the Final Regulatory Flexibility Analysis in Chapter 14 of the RIA, we carefully considered the impacts of the regulations on small businesses. Most of our analysis of small business impacts was performed as a part of the work of the Small Business Advocacy Review Panel (''SBAR Panel'', or ''the Panel'') convened prior to the proposed rule, pursuant to the Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). (The final report of the Panel is available in the docket.)

For the SBREFA process, EPA conducted outreach, fact-finding, and analysis of the potential impacts of our regulations on small businesses. Based on these factors and analyses by all Panel members, the Panel concluded that small refiners in general would likely experience a significant and disproportionate financial hardship in reaching the objectives of the MSAT2 program. We proposed many of the provisions recommended by the Panel and we are finalizing these provisions in this action.

i. Definition of Small Refiner for Purposes of the MSAT2 Small Refiner Provisions

The criteria to qualify for small refiner status for this program are in most ways the same as those required in the Gasoline Sulfur and the Highway and Nonroad Diesel rules. However, there are some differences; as stated in our more recent fuels programs, we believe that it is necessary to limit relief to those small entities most likely to experience adverse economic impacts from fuel regulations. We are finalizing the following provisions for determining small refiner status.

To qualify as a small refiner, a refiner must demonstrate that it meets all of the following criteria: (1) Produced gasoline from crude during calendar year 2005; (2) had no more than 1,500 employees, based on the average number of employees for all pay periods from January 1, 2005 to January 1, 2006; and, (3) had an average crude oil capacity less than or equal to 155,000 barrels per calendar day (bpcd) for 2005. We are likewise finalizing the provision requiring refiners to apply for, and for EPA to approve, a refiner's status as a ''small refiner''.

Small refiner provisions are limited to refiners of gasoline from crude because they are the entities that bear the investment burden and the consequent economic hardship. Therefore, blenders, importers, and additive component producers are not eligible. For these same reasons, small refiner status is limited to those refiners that owned and operated the refinery during the period from January 1, 2005 through December 31, 2005. This is consistent with the approach taken in the Nonroad Diesel rule, but we are revising the text to be more clear on this issue.

In determining its crude oil capacity and total number of employees, a refiner must include the crude oil capacity and number of employees of any subsidiary companies, any parent companies, any subsidiaries of the parent companies, and any joint venture partners. As stated in the proposal, there was confusion in past rules regarding ownership. Thus, we proposed defining a parent company as any company (or companies) with controlling ownership interest, and a subsidiary of a company as any company in which the refiner or its parent(s) has a controlling ownership interest (see 71 FR 15878). We requested comment on these clarifications in the proposal, but did not receive any comments on these aspects of the small refiner definition. Therefore, we are finalizing the definition of parent company and related clarifying provisions such that the employees and crude capacity of all parent companies, and all subsidiaries of all parent companies, must be taken into consideration when evaluating compliance with these criteria.

We received comments regarding the small refiner employee count and crude capacity criteria. These commenters stated that they believed that EPA's criteria fail to provide relief to a small number of refiners whom they believe are similar in many respects to those refiners that will qualify as small under our criteria. The commenters pointed to recent Congressionally enacted programs, specifically the Energy Policy Act of 2005 (EPAct) and the American Jobs Creation Act of 2004 (Jobs Act), which use definitions that are different from the SBA definition, and from the criteria EPA is adopting in this rule. The EPAct focuses on refinery size rather than company size, and the Jobs Act focuses on refinery-only employees rather than employees company-wide. EPA has established the criteria for qualifying for small refiner relief based on the Small Business Administration's (SBA) small business definition (per 13 CFR 121.201).

We do not believe that it would be appropriate to change the proposed small refiner employee count or crude capacity limit criteria to fit the definitions used in either of the two recent statutes. While Congress is able to establish special provisions for subsets of the industry in programs like those mentioned above, EPA appropriately focuses, under SBREFA and in this rulemaking, on consideration of relief on those refining companies that we believe are likely to face serious economic hardship as a result of compliance with the rule. Under programs subject to the EPAct and Jobs Act definitions, relief would be granted to refineries that are owned by larger companies, or companies that have additional sources of revenue (indicated by more employees and/or refining capacity), and also refineries owned by foreign governments. These definitions do not focus as directly on refiners which, due to their size, could incur serious adverse economic impact from fuel regulations; and EPA consequently is not adopting either of them in this rule. Further, SBA established its small business definition to set apart those companies which are most likely to be at an inherent economic disadvantage relative to larger businesses. We agree with the assessment that refiners of this size may be afforded special consideration under regulatory programs that have a significant economic impact on them (insofar as is consistent with Clean Air Act requirements). We continue to believe that it is most appropriate to remain consistent with our previous fuels programs and retain the criteria to qualify for small refiner status that have been used in the past (with some minor clarifications to avoid confusion), since these criteria best identify the class of small refiner which may incur disproportionate regulatory impact under the rule. We are therefore finalizing the small refiner qualification criteria that were proposed.

As previously stated, our intent has been, and continues to be, limiting the small refiner relief provisions to the small subset of refiners that are likely to be seriously economically challenged as a result of the new regulations. We assume that new owners that purchase a refinery after December 31, 2005 do so with full knowledge of the proposed regulation. Given that they have the resources available to purchase the refinery assets, they are not in an economic hardship situation. Therefore, they should include compliance planning as part of their purchase decision. Similar to earlier fuel rules, we are finalizing a provision that a refiner that restarts a refinery in the future is eligible for small refiner status. In such cases, we will judge eligibility under the employment and crude oil capacity criteria based on the most recent 12 consecutive months before the application, unless we conclude from data provided by the refiner that another period of time is more appropriate. However, unlike past fuel rules, this will be limited to a company that owned the refinery at the time that it was shut down. New purchasers will not be eligible for small refiner status for the reasons described above. Companies with refineries built after January 1, 2005 will also not be eligible for the small refiner hardship provisions, again for the reasons given above.

Similar to previous fuel sulfur programs, we also proposed that refiners owned and controlled by an Alaska Regional or Village Corporation organized under the Alaska Native Claims Settlement Act are also eligible for small refiner status, based only on the refiner's employee count and crude oil capacity (see 71 FR 15878). We did not receive any comments on this provision, and we are finalizing it in this action.

ii. Small Refiner Status Application Requirements

A refiner applying for status as a small refiner under this program is required to apply and provide EPA with several types of information by December 31, 2007. (The application requirements are summarized in section VI.B.2, below.) A refiner seeking small refiner status under this program must apply for small refiner status, regardless of whether the refiner had been approved or rejected for small refiner status under another fuel program. As with applications for relief under other rules, applications for small refiner status under this rule that are later found to contain false or inaccurate information will be void ab initio.

iii. Small Refiner Provisions

Delay in the Effective Date of the Standards

We proposed that small refiners be allowed to postpone compliance with the 0.62 vol% benzene standard until January 1, 2015, four years after the general program would begin (see 71 FR 15878). At such time, approved small refiners would be required to meet the 0.62 vol% benzene standard. As stated in the proposal, this additional lead time is justified because small refiners face disproportionate challenges, which the additional lead time will help to mitigate. We requested comment on this proposed provision, and we received many comments supporting it and none opposing it.

Normally a period of two to three years of lead time is required for a refiner to secure necessary financing and to carry out capital improvements for benzene control (see VI.A.1.c.i. above). Commenters specifically noted that additional lead time would allow small refiners to more efficiently obtain financing and contracts to carry out necessary capital projects (or to obtain credits) with less direct competition with non-small refiners for financing and for contractors to carry out capital improvements. Some commenters noted that they generally supported the proposed program of a 0.62 vol% benzene standard with no upper limit and the proposed small refiner relief. While we did not propose an upper limit, as discussed above in section VI.A.1, we have chosen to finalize a 1.3 vol% refinery maximum average.

The additional lead time also allows EPA to make programmatic adjustments, if necessary, before small refiners are required to comply with the benzene standards. As discussed below, we are finalizing a requirement that EPA review the program in 2012, leaving a number of years to adjust the program before small refiners are required to meet the benzene standards. The additional lead time for small refiners will also provide these refiners with three years of lead time following the review to take the review results into account in completing capital projects if necessary or desirable to meet the benzene standards. Based on these assessments, we are therefore finalizing a four-year period of additional lead time for small refiners for compliance with the 0.62 vol% benzene standard, until January 1, 2015 (and small refiners would continue to meet the requirements of MSAT1 until January 1, 2015). Further, we are finalizing an additional 4 years of lead time for small refiners to comply with the 1.3 vol% maximum average benzene standard, until July 1, 2016.

Early ABT Credit Generation Opportunities

During the development of the proposal, we anticipated that many small refiners would likely find it more economical to purchase credits for compliance than to comply by making capital investments to reduce gasoline benzene. However, some small refiners indicated that they would make reductions to their gasoline benzene levels to fully or partially meet the proposed 0.62 vol% benzene standard. Therefore, we proposed that small refiners that take steps to meet the benzene requirement before January 1, 2015 would be eligible to generate early credits (see 71 FR 15879). Current and previous fuels programs allow for credit generation opportunities to encourage early compliance, and extending this opportunity to small refiners, based on the small refiner effective date, is consistent with this objective. Small refiners generally supported this provision and we did not receive any adverse comments on it.

Early credit generation opportunities will provide more credits for the MSAT2 ABT program and will help to achieve the air quality goals of the MSAT2 program earlier than otherwise required. We are therefore finalizing an early credit generation provision for small refiners. This is similar to the general early credit generation provision that is provided to all refiners, except that small refiners may generate early credits until January 1, 2015. As discussed in section VI.A.2.b.ii above, refineries must reduce their 2004–2005 benzene levels by at least ten percent to generate early credits. This ten percent threshold is being set to ensure that changes in gasoline benzene levels result from real refinery process improvements, not just normal fluctuations in benzene levels at a given refinery (allowed under MSAT1). The small refiner early credit generation period will be from June 1, 2007 to December 31, 2014, after which standard credits may be generated indefinitely for those that overcomply with the 0.62 vol% annual average standard.

Extended Credit Life

During the SBREFA process, many small refiners expressed interest in relying upon credits as an ongoing compliance strategy for meeting the 0.62 vol% gasoline benzene standard. However, several small refiners voiced concerns surrounding the idea of relying on the credit market to avoid large capital costs for benzene control. One of their primary concerns was that credits might not be available and/or traded to small refiners in need. To increase the certainty that credits would be available, we proposed a two-year credit life extension for credits generated by or traded to small refiners (see 71 FR 15879). Not only does this provision encourage trading to small refiners, it creates a viable outlet for credits facing expiration. Most small refiners supported the proposed credit life provision. However, one refiner suggested that we finalize unlimited credit life for credits traded to small refiners. Although unlimited credit life could have some perceived benefits, overall it poses serious enforcement problems. Therefore, for the reasons described above in VI.A.2.c.iii, we are not finalizing unlimited credit life for credits traded to small refiners. Further, we are finalizing a slightly modified version of the proposed small refiner extended credit life provision to better reflect its intended purpose. First, the two-year credit life extension pertains only to standard credits. The extension does not apply to early credits because refiners already have an incentive to trade early credits to small refiners. Based on the nature of the early credit life program (three-year life based on the start of the program) and small refiners' delayed program start date (2015 as opposed to 2011), early credits traded to small refiners are already valid for an additional four years. Second, the two-year credit life extension applies only to standard credits traded to small refiners. There is no need to extend credit life for credits generated by small refiners, because in this event, the small refiner would already have the utmost certainty that the credits would be available for use.

ABT Program Review

We proposed that we would perform a review of the ABT program (and thus, the small refiner flexibility options) by 2012, one year after the general program begins (see 71 FR 15879). Coupled with the small refiner four-year additional lead time provision, the ABT program review after the first year of the overall program will provide small refiners with roughly three years, after learning the results of the review, to obtain financing and perform engineering and construction. We are committing to this provision today. The review will take into account the number of early credits generated industry-wide each year prior to the start of the MSAT2 program, as well as the number of credits generated and transferred during the first year of the overall benzene control program. In part to support this review, we are requiring that refiners submit pre-compliance reports, similar to those required under the highway and nonroad diesel programs. In addition, the first compliance report that refiners submit (for the 2011 compliance period) will provide important information on how many credits are actually being generated or utilized during the first year of the program.

The ABT pre-compliance reports will be due annually on June 1 from 2008 through 2011. The reports must include projections of how many credits will be generated and how many credits will need to be used at each refinery. The reports must also contain information on a refiner's plans (for each refinery) for compliance with the benzene standard, including whether or not the refiner will utilize credits alone to comply with the standard. Refiners must also report any early credits that may have been transferred to another entity prior to January 1, 2011 and the sale price of those credits.

In addition, ABT compliance reports will be due annually beginning February 28, 2012. For any refiner expecting to participate in the credit trading program (under § 80.1275 and/or § 80.1290, the report must include information on actual credit generation and usage. Refiners must also provide any updated information regarding plans for compliance. EPA will publish the results of these refinery compliance reports and the results of our review as soon as possible to provide small refiners with information on the ABT program roughly three years prior to the small refiner compliance date. EPA will maintain the confidentiality of information from individual refiners submitted in the reports. We will present generalized summaries of the reports annually.

If, following the review, EPA finds that the credit market is not adequate to support the small refiner provisions, we will revisit the provisions to determine whether or not they should be altered or whether EPA can assist the credit market (and small refiners' access to credits). For example, the Panel suggested that EPA could consider actions such as: (1) The ''creation'' of credits by EPA that would be introduced into the credit market to ensure that there are additional credits available for small refiners; (2) a requirement that a percentage of all credits to be sold be set aside and only made available for small refiners; and (3) a requirement that credits sold, or a certain percentage of credits sold, be made available to small refiners before they are allowed to be sold to any other refiners.

Further, we are finalizing an additional hardship provision to assist small refiners. This hardship provision would be for the case of a small refiner for which compliance with the 0.62 vol% benzene standard would be feasible only through the purchase of credits, but for whom purchase of credits is not economically feasible. This hardship provision will only be available following the ABT program review, since EPA wishes to use the most accurate information to assess credit availability and the working of the credit market. The provision will only be afforded to a small refiner on a case-by-case basis, and must be based on a showing by the refiner of the practical or economic difficulty in acquiring credits for compliance with the 0.62 vol% benzene standard (or some other type of similar situation that would render its compliance with the standard not economically feasible). The relief offered under this hardship provision is a further delay, on an individual refinery basis, for up to two years. Applications for relief under this provision must meet the requirements set out in § 80.1343. Following the two years, a small refiner will be allowed to request one or more extensions of the hardship until the refinery's material situation has changed. Finally, if a small refiner is unable to comply with the 1.3 vol% refinery maximum average, it may apply for relief from this standard under the general hardship provisions discussed below in section VI.A.3.b. Applications for relief from the 1.3 vol% refinery maximum average must be received by January 1, 2013 and must meet the requirements set out in § 80.1335.

iv. The Effect of Financial and Other Transactions on Small Refiner Status and Small Refiner Relief Provisions

We believe that the effects of financial (and other) transactions are also relevant to this action. We proposed these provisions (see 71 FR 15880) and did not receive any comments on them. We continue to believe that these provisions are appropriate and are finalizing the provisions discussed below.

Large Refiner Purchasing a Small Refiner's Refinery

One situation involves a ''non-small'' refiner that wishes to purchase a refinery owned by an approved small refiner. The small refiner may not have completed or even begun any necessary planning to meet the MSAT2 standards, since it would likely have planned to make use of the special small refiner relief provisions. We assume that the refiner would have incorporated financial planning for compliance into its purchase decision. However, we recognize that a limited amount of time would be required for the physical completion of the refinery upgrades for compliance. (This situation would be similar to that addressed in the Nonroad Diesel program (96 FR 39051).)

We therefore believe that an appropriate period of lead time for compliance with the MSAT2 requirements is warranted where a refiner purchases any refinery owned by a small refiner, whether by purchase of a refinery or purchase of the small refiner entity. A refiner that acquires a refinery from an approved small refiner will be provided with 30 additional months from the date of the completion of the purchase transaction (or until the end of the applicable small refiner relief interim period if it is within 30 months). During this 30-month period, production at the newly-acquired refinery may remain at the benzene levels that applied to that refinery for the previous small refiner owner, and all existing small refiner provisions and restrictions will also remain in place for that refinery. At the end of this period, the refiner must comply with the ''non-small refiner'' standards. There will not be an adverse environmental impact of this provision, since the small refiner would already have been provided relief prior to the purchase and this provision would be no more generous.

We expect that in most (if not all) cases, the 30 months of additional lead time will be sufficient for the new refiner-owner to accomplish the necessary planning and any needed refinery upgrades. If a refiner nonetheless believes that the technical characteristics of its plans would require additional lead time, the refiner may apply for additional time and EPA will consider such requests on a case-by-case basis. Based on information provided in such an application and other relevant information, EPA will decide whether additional time is technically necessary and, if so, how much additional time would be appropriate. As discussed above, in no case will compliance dates be extended beyond the time frame of the applicable small refiner relief.

Small Refiner Losing Its Small Refiner Status Due To Merger or Acquisition

Another type of potential transaction involves a refiner with approved small refiner status that later loses its small refiner status because it no longer meets the small refiner criteria. An approved small refiner that exceeds the small refiner employee or crude capacity limit due to merger or acquisition will lose its small refiner status. This includes exceedances of the employee or crude capacity criteria caused by acquisitions of assets such as plants and equipment, as well as acquisitions of business entities.

Our intent has been, and continues to be, to limit the small refiner relief provisions to a small subset of refiners that are most likely to be significantly economically challenged, as discussed above. At the same time, it is also our intent to avoid stifling normal business growth. Therefore, under this program, a refiner will be disqualified from small refiner status if it exceeds the small refiner criteria through its involvement in transactions such as being acquired by or merging with another entity, through the small refiner itself purchasing another entity or assets from another entity, or when it ceases to process crude oil. However, if a small refiner grows through normal business practices, and exceeds the employee or crude capacity criteria without merger or acquisition, it will retain its small refiner status for this program.

In the sole case of a merger between two approved MSAT2 small refiners, both small refiners will be allowed to retain their small refiner status under this program. As in past fuel rulemakings, we believe the justification for continued small refiner relief for each of the merged entities remains valid. Small refiner status for the two entities of the merger will not be affected, and hence the original compliance plans of the two refiners should not be impacted. Moreover, no environmental detriment will result from the two small refiners maintaining their small refiner status within the merged entity as they would have likely maintained their small refiner status had the merger not occurred. We did not receive any comments on this provision.

We recognize that a small refiner that loses its small refiner status because of a merger with, or acquisition of, a non-small refiner would face the same type of technical lead time concerns discussed above for a non-small refiner acquiring a small refiner's refinery. Therefore, we are also providing the 30 months of additional lead time described above for non-small refiners purchasing a small refiner's refinery.

b. Provisions for Refiners Facing Hardship Situations

The MSAT2 program includes a nationwide credit trading program of indefinite duration for the 0.62 vol% annual average benzene standard, and we expect that credits will be available at a reasonable cost industry-wide. However, as explained in the proposal (71 FR 15880–15881), there could be circumstances when refiners would need hardship relief. We reiterate this conclusion here, especially given the 1.3 vol% refinery maximum average benzene standard in the final rule. These hardship provisions are available to all refiners, small and non-small, with relief being available on a case-by-case basis following a showing of certain requirements (as described in the regulations at sections 80.1335 and 80.1336). We believe that the inclusion of hardship provisions for refiners is a necessary part of adopting the benzene requirements as the maximum reduction achievable considering costs. Without a mechanism to consider economic hardship to particular refineries, the overall level of the standards would need to be higher to reflect the potential increased costs. Note, however, that we do not intend for these hardship waiver provisions to encourage refiners to delay planning and investments they would otherwise make.

We are finalizing two forms of hardship relief: the first applies to situations of extreme and unusual hardship, and the second applies to situations where unforeseen circumstances prevent the refiner from meeting the benzene standards. These provisions are similar to the hardship provisions that were proposed, but with some modification because this final rule includes a 1.3 vol% refinery maximum average benzene standard, which cannot be satisfied through the use of credits. While we sought comment in the proposal on such a standard, we did not propose it, and therefore also did not propose any hardship relief specific to it.

As discussed further below, the application requirements and potential relief available differ somewhat depending upon whether a refiner applies for hardship relief for the 0.62 vol% benzene standard, the 1.3 vol% refinery maximum average, or both (a refiner may apply for relief from both standards, but EPA will address them independently). This is partly due to the fact that a refiner may use credits to meet the 0.62 vol% benzene standard, but credits cannot be used for compliance with the 1.3 vol% refinery maximum average standard. EPA can impose appropriate conditions on any hardship relief. Note also that any hardship relief granted under this rule will be separate and apart from EPA's authority under the Energy Policy Act to issue temporary waivers for extreme and unusual supply circumstances, under amended section 211(c)(4). In general, commenters stated that they supported the inclusion of hardship provisions, but they did not provide any specific comments regarding these provisions.

i. Temporary Waivers Based on Extreme Hardship Circumstances

We are finalizing the proposed hardship relief provisions based on a showing of extreme hardship circumstances, with some slight modifications from the proposed extreme hardship relief provision (see 71 FR 15881). We did not receive comment on the proposed hardship provision.

Extreme hardship circumstances could exist based on severe economic or physical lead time limitations of the refinery to comply with the benzene standards required by the program. Such extreme hardship may be due to an inability to physically comply in the time available, an inability to secure sufficient financing to comply in the time available, or an inability to comply in the time available in a manner that would not place the refiner at an extreme competitive disadvantage sufficient to cause extreme economic hardship. A refiner seeking such hardship relief under this provision will have to demonstrate that these criteria were met. In addition to showing that unusual circumstances exist that impose extreme hardship in meeting the benzene standards, the refiner must show: (1) Circumstances exist that impose extreme hardship and significantly affect the ability to comply with the gasoline benzene standards by the applicable date(s); and (2) that it has made best efforts to comply with the requirements. Refiners seeking additional time must apply for hardship relief, and the hardship applications must contain the information required under § 80.1335.

For relief from the 0.62 vol% benzene standard in extreme hardship circumstances, an aspect of the demonstration of best efforts to comply is that severe economic or physical lead time limitations exist and that the refinery has attempted, but was unable, to procure sufficient credits. EPA will determine an appropriate extended deficit carry-forward time period based on the nature and degree of the hardship, as presented by the refiner in its hardship application, and on our assessment of the credit market at that time. Moreover, because we expect the credit program to be operating and robust, we believe that circumstances under which we would grant relief from the 0.62 vol% benzene standard will be rare, and should we grant relief, it would likely be for less than three years. Further, we may impose additional conditions to ensure that the refiner was making best efforts to comply with the benzene standards while offsetting any loss of emission control from the program (due to extended deficit carry-forward).

For relief from the 1.3 vol% refinery maximum average benzene standard in extreme hardship circumstances, a refiner must show that it could not meet the 1.3 vol% standard, despite its best efforts, in the timeframe required due to extreme economic or technical problems. Extreme hardship relief from the 1.3 vol% refinery maximum average standard is available for both non-small and small refiners. This provision is intended to address unusual circumstances that should be apparent now, or well before the standard takes effect. Thus, refiners must apply for such relief by January 1, 2008, or January 1, 2013 for small refiners. If granted, such hardship relief would consist of additional time to comply with the 1.3 vol% refinery maximum average. The length of such relief and any conditions on that relief will be granted on a case-by-case basis, following an assessment of the refiner's hardship application, but could be for a longer period than for relief from the 0.62 vol% standard since credits cannot be used for compliance with the 1.3 vol% refinery maximum average.

ii. Temporary Waivers Based on Unforeseen Circumstances

We are also finalizing the proposed temporary hardship provision based on unforeseen circumstances, which, at our discretion, will permit any refiner or importer to seek temporary relief from the benzene standards under certain rare circumstances (see 71 FR 15880). This waiver provision is similar to provisions in prior fuel regulations. It is intended to provide refiners and importers relief in unanticipated circumstances—such as a refinery fire or a natural disaster—that cannot be reasonably foreseen now or in the near future. We did not receive comments on this proposed hardship provision.

To receive hardship relief based on unforeseen circumstances, a refiner or importer will be required to show that: (1) The waiver is in the public interest; (2) the refiner/importer was not able to avoid the noncompliance; (3) the refiner/importer will meet the benzene standard as expeditiously as possible; (4) the refiner/importer will make up the air quality detriment associated with the nonconforming gasoline, where practicable; and (5) the refiner/importer will pay to the U.S. Treasury an amount equal to the economic benefit of the noncompliance less the amount expended to make up the air quality detriment. These conditions are similar to those in the RFG, Tier 2 gasoline sulfur, and the highway and nonroad diesel regulations, and are necessary and appropriate to ensure that any waivers that are granted will be limited in scope. Such a request must be based on the refiner or importer's inability to produce compliant gasoline at the affected facility due to extreme and unusual circumstances outside the refiner or importer's control that could not have been avoided through the exercise of due diligence.

For relief from the 0.62 vol% benzene standard based on unforeseen circumstances, the hardship request must also show that other avenues for mitigating the problem, such as the purchase of credits toward compliance under the credit provisions, had been pursued and yet were insufficient or unavailable. Hardship relief from that standard will allow a deficit to be carried forward for an extended, but limited, time period (more than the one year allowed by the rule). The refiner or importer must demonstrate that the magnitude of the impact was so severe as to require such an extension. EPA will determine an appropriate extended deficit carry-forward time period based on the nature and degree of the hardship, as presented by the refiner or importer in its hardship application, and on our assessment of the credit market at that time.

For relief from the 1.3 vol% refinery maximum average benzene standard based on unforeseen circumstances, the hardship request must show that, despite its best efforts, the refiner or importer cannot meet the standard in the timeframe required. Relief will be granted on a case-by-case basis, following an assessment of the refiner's hardship application.

c. Option for Early Compliance in Certain Circumstances

We are finalizing an option that would allow a refinery to begin compliance with the MSAT2 benzene standards earlier than 2011 instead of maintaining compliance with its MSAT1 baseline. See 71 FR 15881 for the proposal's discussion of this option.[193] We are providing this option because refineries that meet the criteria discussed below are already providing the market with very clean gasoline from a mobile source air toxics

[193] The 1.3 vol% maximum average standard was not discussed in the proposal vis-a-vis this early compliance option. However, any refinery approved for this option should easily meet the 1.3 vol% standard.

perspective. In the proposal, we took comment on such an option, stating that eligibility for this option would be limited to those that have historically better than average toxics performance, lower than average benzene and sulfur levels, and a significant volume of gasoline impacted by the phase-out of MTBE use. However, in order to qualify for this option, a refinery must produce gasoline by processing crude and other intermediate feedstocks and not merely be a blender or importer of gasoline, as discussed later.

A refinery that is approved for this option would comply with the 0.62 vol% annual average and 1.3 vol% maximum average benzene standards and would not be required to continue to comply with its applicable toxics performance requirements, i.e., its MSAT1 baseline and its anti-dumping or RFG toxics performance standards. We believe this option is appropriate because if qualifying refineries had to continue to comply with MSAT1 [194] until 2011, they would likely be forced to reduce gasoline output in order to comply, while other refineries or importers, most likely with less clean MSAT1 baselines, would provide the replacement gasoline. The result would be less supply of these refineries' cleaner gasoline and more supply of fuel with higher toxics emissions, leading to a net detrimental effect on overall MSAT emissions in the surrounding region.

We chose 2003 as the period for determining eligibility for this option because State MTBE bans began taking effect in 2004. Refiners who had used MTBE generally now use ethanol as the replacement source for oxygen. Although RFG no longer has an oxygen requirement [195], MSAT1 baselines were established when that requirement was still in place. Even some CG producers used significant amounts of MTBE as reflected in their MSAT1 baselines. Ethanol provides less toxics reduction benefits than MTBE, and so the refinery must take other actions in order to continue to meet its MSAT1 standard. Consequently, while MSAT1 baseline adjustments in the past were limited to RFG, it may be possible for a refinery to also qualify to adopt MSAT2 early for its CG pool. Both qualification and the ability to adopt MSAT2 are allowed separately for RFG and CG. For example, a refinery that qualifies to adopt MSAT2 early for RFG will be permitted to do so for RFG alone while maintaining its MSAT1 baseline for its CG, or vice versa.

As mentioned in the proposal, the criteria for eligibility for early compliance are similar in concept to those EPA has used in granting refinery-specific adjustments to MSAT1 baselines, that is, significantly cleaner than the national average for toxics, benzene, and sulfur, and relatively high MTBE use. We re-evaluated those criteria to determine the numerical criteria that a refinery would have to meet in order to qualify for this option. Specifically, a refinery must at minimum meet the following criteria:

—2003 annual average benzene level less than or equal to 0.62 vol%
—2003 annual average MTBE use greater than 6.0 vol%
—2003 annual average sulfur level less than 140 ppm
—MSAT1 RFG baseline greater than 30.0% reduction or CG less than 80 mg/mile

Many refineries can reduce benzene and sulfur levels to reduce toxics emissions. However, those that used a significant amount of MTBE and already have low benzene and sulfur levels also have fairly stringent toxics emissions performance standards. As a result, they may have little ability to further reduce sulfur or benzene or make other refinery changes to offset the impact of switching from MTBE to ethanol. Refineries that are not in this situation are not so constrained. We believe that the criteria above are an appropriate screening to delineate between these two groups.

To qualify for this provision we believe it is appropriate for a refinery to have used at least 6.0 vol% MTBE in their gasoline in their 2003 baseline; when the oxygen provided by this amount of MTBE is provided instead by ethanol, a substantial loss in toxics performance results. A benzene average of less than or equal to the 0.62 vol% standard is appropriate because if a refinery's average benzene is higher, they would have to further reduce benzene to comply with the MSAT2 standard early. However, to qualify for this provision to switch to MSAT2 early, a refinery should have no viable options for reducing benzene further to continue to meet their MSAT1 baseline. We chose the 140 ppm sulfur level because we found that even for refineries with significant MTBE use (in the 6–13 vol% range), the sulfur reductions brought about by the Tier 2 gasoline sulfur standard provided sufficient benefit to offset much of the increase in toxics emissions that results from eliminating MTBE and replacing it with ethanol. Finally, refineries should have had MSAT1 baseline toxics performance significantly cleaner than the average in order to qualify. The MSAT1 baseline toxics performance thresholds listed above were set based on past experience with baseline adjustments where we found that only those with significantly clean baselines (in addition to low benzene, low sulfur, and high MTBE use) would have to reduce production in order to comply with their MSAT1 standard in the face of MTBE bans. Thus, we are limiting this provision to those with relatively clean baselines as our goal is preventing the perverse outcome that refineries with cleaner gasoline may be forced to reduce their production volume only to have it be made up by refineries with dirtier baselines. The threshold helps ensure that only those refineries in situations where such an outcome could realistically have otherwise occurred are permitted to exercise this option. Refineries that do not fulfill all of the threshold requirements may have to take further refinery processing-related actions to meet their MSAT1 baseline, but are unlikely to have to reduce production and/or have that production replaced by someone with a less clean standard.

In addition to meeting the screening criteria mentioned, a refinery would still have to apply to EPA to use this compliance option and would need to demonstrate that it cannot further reduce its benzene or sulfur levels, nor make other refinery processing changes in order to maintain compliance with its MSAT1 baseline due to the impact of switching from MTBE to ethanol. Details of the application requirements and approval process are provided in section 80.1334 of the regulations. We estimate that less than 10 refineries may meet the screening criteria and thus potentially qualify for this option based on our analysis of their 2003 data and MSAT1 baselines. Note that this early compliance option will apply only to the type of gasoline that qualifies—RFG or CG—not to the refinery's total pool. In 2011, the MSAT2 benzene standards will apply to the refinery's total applicable gasoline pool.

We are limiting this compliance option to refineries that produce gasoline by processing crude and intermediate feedstocks through refinery processing equipment. Thus, this option is not available to gasoline blenders and importers. While gasoline blenders and importers may have gasoline with significantly cleaner than average toxics

[194] While refineries are subject to MSAT1 and anti-dumping or RFG toxics performance requirements depending on the gasoline type (CG and/or RFG) they produce, in almost all cases, the MSAT1 standard is more stringent than the corresponding anti-dumping or RFG toxics standard.

[195] 71 FR 26691, May 8, 2006.

performance, benzene and sulfur levels, and may have used large amounts of MTBE, they have more options in the marketplace for obtaining qualifying gasoline and gasoline blending components. Refineries have comparatively less ability to adjust their refining operations, without significantly reducing volume, in order to accommodate the change from MTBE to ethanol.

Few comments were received regarding this provision. All commenters supported the provision. Many of those suggested that it be available to any refinery. We continue to believe that this provision should apply only to those entities that meet the criteria above. Those that do not meet the criteria have the ability to further adjust their benzene and sulfur content values to be able to comply with their MSAT1 baselines. If this provision was available to all refineries, it could result in an overall nationwide backsliding on MSAT1. The intent of this provision is to provide appropriate relief to a limited number of entities that have unique challenges, while at the same time ensuring that the net result is cleaner gasoline in the marketplace than would otherwise be there.

EPA also took comment on when entities that are approved for this option should be allowed to begin compliance with the MSAT2 benzene standards. We received comment supporting allowing such compliance for the entire calendar year 2007, even though the rule will not be final until partway into that year. Other suggested options include the next calendar year, and partial year compliance for 2007. This latter option would likely be unworkable under MSAT1 due to differences between summer and winter MSAT performance. Thus, we decided that refineries that are approved for this option will be allowed to comply with the MSAT2 benzene standard for the entire 2007 period. We have also decided against requiring approved refineries to wait until the 2008 compliance period because we want to ensure that gasoline production from these refineries is maximized, and waiting until 2008 would not achieve that goal. Because this is an optional program for those that qualify, approved refiners may choose to comply with MSAT2 beginning in 2007, or beginning in 2008.

As a final note on this subject, we also proposed that refineries that meet the criteria and are approved for early compliance with the MSAT2 benzene standards would not be allowed to generate early benzene credits (see 71 FR 15881). A few commenters thought that such refineries should be allowed to generate early credits. However, the criteria for generating early credits require that the refinery reduce benzene by 10% below its 2004–2005 baseline benzene level. The early compliance provision is predicated on the fact that an approved refinery has almost no ability to reduce benzene in order to maintain compliance with its MSAT1 baseline. If such a refinery were able to further reduce benzene, it would negate its need for early compliance with the MSAT2 benzene standard. Therefore, we are finalizing this early compliance option with this limitation as proposed.

B. How Will the Gasoline Benzene Standard Be Implemented?

This section summarizes the main implementation provisions in the regulations and provides additional clarification in a few cases.

1. General Provisions

Compliance with the 0.62 vol% annual average and 1.3 vol% maximum average benzene standards is determined over a refiner's or importer's total gasoline pool, RFG and conventional gasoline (CG) combined. For the 0.62 vol% standard, the first annual compliance period for non-small refiners and for importers is 2011. For the 1.3 vol% standard, the first compliance period for these entities is July 1, 2012 through December 31, 2013. Thereafter, compliance is determined annually. Small refiners will comply with the 0.62 vol% on an annual basis beginning in 2015. Compliance with the 1.3 vol% maximum average standard commences for small refiners on July 1, 2016. For small refiners, the first compliance period for the 1.3 vol% standard is July 1, 2016 through December 31, 2017. Thereafter, compliance is determined annually.

Compliance with the benzene standards is achieved separately for each refinery of a refiner.[196] For an importer, compliance is achieved over its total volume of imports, regardless of point of entry. As discussed in the proposal, gasoline produced by a foreign refiner is included in the compliance calculation of the importer of that gasoline, with certain exceptions for early credit generation and small foreign refiners.

Finished gasoline and gasoline blendstock that becomes finished gasoline solely upon the addition of oxygenate are included in the compliance determination. Gasoline produced for use in California is not included. Gasoline produced for use in the American territories—Guam, Northern Mariana Islands, American Samoa—is not subject to the benzene standard. Gasoline produced for use in these areas is currently exempt from the MSAT1 standards, and for the same reasons we discussed in the MSAT1 final rule[197], including distance from gasoline producers, low gasoline use, and distinct environmental conditions, we are exempting gasoline produced for these areas from this rule.

Oxygenate and butane blenders are not subject to the benzene standard unless they add other gasoline blending components beyond oxygenates and butane. Similarly, transmix processors are not subject to the benzene standard. We proposed that transmix processors would be subject to the benzene standard if they add gasoline blending components to the gasoline produced from transmix (see 71 FR 15891). One commenter suggested that only the blending component added to the gasoline produced from transmix should be subject to the standard because the transmix processor has no control over the benzene level in the gasoline produced from transmix, and the benzene in the gasoline produced from transmix would have already been accounted for by another entity. We agree with this comment, and have modified the final rule accordingly.

As discussed earlier, this benzene program has both an early credit generation period and a standard credit generation period that begins when the program takes effect. Early credits may be generated from January 1, 2007 through December 31, 2010 by refineries with approved benzene baselines. For small refiners, early credit generation extends through December 31, 2014 for their refineries with approved benzene baselines. Benzene baselines are based on a refinery's 2004–2005 average benzene content, and refiners can begin applying for benzene baselines as early as March 1, 2007. Although there is no single cut-off date for applying for a baseline, refiners planning to generate early credits must submit individual refinery baseline applications at least 60 days prior to beginning credit generation at that refinery.

As explained earlier, in order to generate early credits, a refinery's annual average benzene level must be at least 10 percent lower than its baseline benzene level, and the refinery must show that its low benzene levels result, in part, from operational changes and/

[196] Aggregation of facilities for compliance is not allowed under this benzene control program. However, as pointed out in the proposal, the ABT program's credit generation and transfer provisions provide compliance flexibility similar to that provided by aggregation.

[197] 66 FR 17253, March 29, 2001.

or improvements in benzene control technology since the baseline period. Foreign refiners who sent gasoline to the U.S. during 2004–2005 under their foreign refiner baseline may generate early credits if they are able to establish a benzene baseline and agree to comply with other requirements that help to ensure enforcement of the regulation at the foreign refinery. Early credits generated or obtained under the ABT program must be used towards compliance within three years of the start of the program; otherwise they will expire and become invalid. In other words, early credits must be applied to the 2011, 2012, or 2013 compliance years. In the case of small refiners, early credits must be applied to the 2015, 2016, or 2017 compliance years.

Standard credits may be generated by refiners and importers beginning with the 2011 compliance period. Standard credits may be generated by small refiners beginning with the 2015 compliance period. For refiners, credits are generated on a refinery-by-refinery basis for each facility. For importers, credits are generated over the total volume imported, regardless of point of entry. Foreign refiners are not allowed to generate standard credits because compliance for their gasoline is the responsibility of the importer. In order to generate standard credits, a refinery's or importer's annual average benzene level must be less than 0.62 vol%. Standard credits are valid for five years from the year they were generated. A credit life extension exists for standard credits traded to and ultimately used by small refiners. These credits may be used towards compliance for an additional two years, giving standard credits a maximum seven-year life.

Compliance with the 0.62 vol% standard is based on the annual average benzene content of the refinery's or importer's gasoline production or importation, any credits used, and any compliance deficit carried forward from the previous year. Credits may be used in any quantity and combination (i.e., early or standard credits) to achieve compliance with the 0.62 vol% benzene standard beginning with the first compliance period in 2011, or 2015 for approved small refiners. For the 2011 and 2012 compliance periods, credits may be used in any amount, and from any starting average benzene level. For example, if the refinery's annual average benzene level at the end of 2011 is 1.89 vol%, it may use credits to meet the 0.62 vol% standard for that compliance period. If its average benzene level at the end of 2012 is 1.45 vol%, it may likewise use credits to meet the 0.62 vol% standard for that period.

The first averaging period for the 1.3 vol% standard for non-small refiners and importers begins July 1, 2012 and ends December 31, 2013, an 18-month period. Similarly, the first averaging period for the 1.3 vol% standard for small refiners begins July 1, 2016 and ends December 31, 2017. Credits may not be used to achieve compliance with the 1.3 vol% standard at any time. A refinery must make capital improvements and/or operational or blending practice changes such that it achieves an actual average benzene level of no greater than 1.3 vol% for the initial (18-month) compliance period, and each annual compliance period thereafter. (An importer must bring in gasoline with benzene levels that will average to 1.3 vol% or less during these same compliance periods.) Continuing from our previous example, if at the end of 2012, the refinery's average benzene level is 1.45 vol%, no further action is yet needed to meet the 1.3 vol% standard. However, the refinery must make capital improvements and/or operational or blending practice changes such that it achieves an actual average benzene level of no greater than 1.3 vol% for the 18-month period July 1, 2012-December 31, 2013. We will assume for this example that the refinery has a 1.0 vol% average benzene level at the end of 2013. The refinery can then use credits to meet the 0.62 vol% standard.

Lack of compliance with the 0.62 vol% standard creates a deficit that may be carried over to the next year's compliance determination. Lack of compliance with the 0.62 vol% standard could occur for a number of reasons, for example, a refinery or importer may choose not to use (buy) sufficient offsetting credits. However, in the next year, the refinery or importer must make up the deficit (through credit use and/or refining or import improvements) and be in compliance with the 0.62 vol% standard.[198] There is no deficit carry-forward provision associated with the 1.3 vol% standard. If a refinery or importer is out of compliance with the 1.3 vol% standard, it is subject to enforcement action immediately.

2. Small Refiner Status Application Requirements

A refiner applying for status as a small refiner under this program is required to apply to and to provide EPA with several types of information by December 31, 2007. The application requirements are summarized below. A refiner seeking small refiner status under this program would need to apply to EPA for that status, regardless of whether or not the refiner had been approved for small refiner status under another fuel program. As with applications for relief under other rules, applications for small refiner status under this rule that are later found to contain false or inaccurate information would be void ab initio. Requirements for small refiner status applications include:

—The total crude oil capacity as reported to the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE) for the most recent 12 months of operation. This would include the capacity of all refineries controlled by a refiner and by all subsidiaries and parent companies and their subsidiaries. We will presume that the information submitted to EIA is correct. In cases where a company disagreed with this information, the company could petition EPA with appropriate data to correct the record when the company submitted its application for small refiner status. EPA could accept such alternate data at its discretion.
—The name and address of each location where employees worked from January 1, 2005 through December 31, 2005; and the average number of employees at each location during this time period. This must include the employees of the refiner and all subsidiaries and parent companies and their subsidiaries.
—In the case of a refiner who reactivated a refinery that was shutdown or non-operational between January 1, 2005, and January 1, 2006, the name and address of each location where employees worked since the refiner reactivated the refinery and the average number of employees at each location for each calendar year since the refiner reactivated the refinery.
—The type of business activities carried out at each location.
—The small refiner option(s) the refiner intends to use for each refinery.
—Contact information for a corporate contact person, including: name, mailing address, phone and fax numbers, e-mail address.
—A letter signed by the president, chief operating officer, or chief executive officer of the company (or a designee) stating that the information contained in the application was true to the best of his/her knowledge and that the company owned the refinery as of January 1, 2007.

[198] An extension of the period of deficit carryover may be allowed in certain hardship situations, as discussed in section A.3.

3. Administrative and Enforcement Provisions

Most of the administrative and enforcement provisions are similar to those in effect for other gasoline programs, as discussed in the proposal. The discussion below highlights those areas that we wish to clarify and those that received significant comment.

a. Sampling/Testing

Because compliance with this program and with the gasoline sulfur program will become the compliance mechanism for certain RFG and anti-dumping requirements, some reporting simplifications will occur, as described below. However, sampling, testing, and reporting of all of the current fuel parameters will continue to be required. It is important to continue to monitor how refiners continue to achieve the toxics control required of RFG and CG through fuel composition changes, and how other toxics emissions may be affected by this MSAT2 benzene rule. Continued collection of all of the fuel parameters will facilitate future toxics evaluation activities.

We proposed to require every-batch sampling for CG under this program, but indicated that results would not have to be available before the batch leaves the refinery (see 71 FR 15893). RFG already is every-batch tested, and the results must be available before the batch leaves the refinery because of RFG's 1.3 vol% per gallon cap. Several commenters stated that every-batch testing for CG was unnecessary because the benzene standard is an average standard, and that it would be costly, especially for small refiners. These commenters requested that continued composite sampling be allowed for conventional gasoline.[199] Nevertheless, we are concerned about potential downstream benzene addition. Requiring every-batch testing for CG will allow for closer monitoring of the movement of high benzene streams. In this program, we are relying on there being no significant incentive to dump benzene-rich streams into gasoline downstream of the refinery where the benzene levels are originally measured. With every-batch benzene testing of all gasoline, we will be able to better discern if high benzene batches originated at the refinery, or downstream. With composite testing, it would be significantly more difficult to determine the source of the high benzene streams. Thus, we are finalizing every-batch benzene testing for all gasoline.

b. Recordkeeping/Reporting

This program will require some new records to be kept, such as the benzene baseline, credits generated, and credit transactions, and new reports to be filed (e.g., benzene pre-compliance reports). However, because the current regulations for RFG and anti-dumping toxics controls and MSAT1 controls are being removed, certain recordkeeping and reporting requirements will be reduced or eliminated, as detailed in the regulations. Because the program will not be fully implemented until small refiners are also subject to both the 0.62 vol% and the 1.3 vol% benzene standards, the process of streamlining the reporting forms will not be complete until that time.

As mentioned above, in order to provide an early indication of the credit market for refiners and importers planning on relying upon benzene credits as a compliance strategy in 2011 and beyond, we are requiring refiners to submit pre-compliance reports to us in the years leading up to start of the program. Pre-compliance reporting has proven to be an indispensable mechanism in implementing the gasoline and diesel sulfur programs, and we expect this to be the case in this program as well. Refiners are required to submit annual pre-compliance reports on June 1st of every year beginning in 2008 and continuing through 2011 (2015 for small refiners). The pre-compliance reports must contain engineering and construction plans as well as actual/projected gasoline production levels, actual/projected gasoline benzene levels, and actual/projected credit generation and use.

Several commenters suggested that the RFG NO_X retail survey be discontinued after 2006, and that the RFG toxics retail survey be discontinued after 2010. The surveys use fuel parameters of RFG sampled from retail stations to estimate VOC, NO_X, and toxics emissions. There are also fuel benzene and oxygen content surveys. If a survey is ''failed'', gasoline sent to the area must meet a more stringent standard. Because we are finalizing, as proposed, provisions that make the gasoline sulfur program the sole regulatory mechanism used to implement gasoline NO_X requirements, and the benzene control program the sole regulatory mechanism used to implement the toxics requirements of RFG[200] and anti-dumping, we agree that the NO_X and toxics surveys are no longer needed. A discussion of the origin of the survey program, and how the toxics and NO_X requirements for CG and RFG will be met under the MSAT2 program is provided in Chapter 6.13 of the RIA for this rulemaking.

C. How Will the Program Relate to Other Fuel-Related Toxics Programs?

In the proposal we presented an analysis that examined quantitatively how the fuel performance under the new gasoline content standard and vehicle emissions standard as proposed would compare to current toxics performance requirements and to performance as modified by the Energy Policy Act of 2005. This analysis suggested that the fuel standard alone would exceed previous performance for RFG, and significantly exceed it for CG.

We have updated the results of this analysis, using better estimates of future ethanol use developed for the RFS final rulemaking, as well as the updated benzene projections from the refinery-by-refinery analysis done for this final rulemaking. As shown in Table VI.C–1, these updated analyses continue to support the conclusion that the MSAT2 fuel program will provide greater toxics reductions for both CG and RFG.

TABLE VI.C–1.—ESTIMATED ANNUAL AVERAGE TOTAL TOXICS PERFORMANCE OF LIGHT DUTY VEHICLES IN MG/MI UNDER CURRENT AND PROJECTED SCENARIOS.[a]

Regulatory scenario	Fleet year	RFG by PADD			CG by PADD				
		I	II	III	I	II	III	IV	V
MSAT1 Baseline[b] (1998–2000)	2002	112	129	97	114	145	107	145	156
EPAct Baseline[b] (RFG: 2001–2002)	2002	104	121	87	114	145	107	145	156
EPAct Baseline, 2011[c]	2011	67	78	52	62	83	54	82	88
MSAT2 program, 2011[c] (Fuel standard only)	2011	66	76	52	60	77	52	74	81

[199] Section 80.101(i).

[200] The 1.3 vol% per gallon cap on RFG benzene remains.

TABLE VI.C–1.—ESTIMATED ANNUAL AVERAGE TOTAL TOXICS PERFORMANCE OF LIGHT DUTY VEHICLES IN MG/MI UNDER CURRENT AND PROJECTED SCENARIOS.[a]—Continued

Regulatory scenario	Fleet year	RFG by PADD			CG by PADD				
		I	II	III	I	II	III	IV	V
MSAT2 program, 2011[c] (Fuel + vehicle standards)	2011	64	72	48	56	74	47	70	78
MSAT2 program, 2025[c] (Fuel + vehicle standards)	2025	39	45	31	36	45	31	44	48

[a] Total toxics performance for this analysis includes overall emissions of 1,3-butadiene, acetaldehyde, acrolein, benzene and formaldehyde as calculated by MOBILE6.2. Although POM appears in the Complex Model, it is not included here. However, it contributes a small and relatively constant mass to the total toxics figure (~4%), and therefore doesn't make a significant difference in the comparisons. Toxics performance figures here are for representative cities in each PADD, and therefore some geographical variation is not captured here.

[b] Baseline figures generated in this analysis were calculated differently from the regulatory baselines determined as part of the MSAT1 program, and are only intended to be a point of comparison for future year cases.

[c] Future year scenarios include (in addition to the MSAT2 standards, where stated) effects of the Tier 2 vehicle and gasoline sulfur standards, and vehicle fleet turnover with time, as well as estimated effects of the renewable fuels standard and the phase-out of ether blending as developed in the RFS rulemaking.

D. How Does This Program Satisfy the Statutory Requirements of Clean Air Act Section 202(l)(2)?

As discussed earlier in this section, we have concluded that the most effective and appropriate program for MSAT emission reduction from gasoline is a benzene control program. We are finalizing, as proposed, an average benzene content standard of 0.62 vol% along with a specially-designed ABT program, as well as a maximum average annual standard of 1.3 vol%. In sections VI.A.1.c and d above, we summarize our evaluation of the feasibility of the program, and in section VIII.A we summarize our evaluation of the costs of the program. The analyses supporting our conclusions in these sections are discussed in detail in Chapters 6 and 9 of the RIA.

Taking all of this information into account, we believe that a more stringent program would not be achievable, taking costs into consideration. As we have discussed, making the 0.62 vol% standard more stringent would require more refiners to install the more expensive benzene control equipment, with very little incremental decrease in benzene emissions. Also, we have shown that refinery costs increase very rapidly as the level of the average standard is made more stringent, especially for certain individual technologically-challenged refineries. We discuss the costs of this program in detail in section VIII.A of this preamble and in Chapter 9 of the RIA. Moreover, the 0.62 vol% standard achieves significant reductions in benzene levels nationwide, and achieves significant reductions in each PADD. The 1.3 vol% annual average standard makes it more certain that the predicted emission reductions will in fact occur.

Conversely, we believe that a less stringent national average standard than 0.62 vol% would not satisfy our statutory obligation to promulgate the most stringent standard achievable considering cost and other factors along with technological feasibility. Furthermore, as discussed in section VI.A, less stringent standards would not accomplish several important programmatic objectives, such as avoiding the triggering of the provisions in the 2005 EPAct to adjust the MSAT1 baseline for RFG. We have also considered energy implications of the proposed program, as well as noise and safety, and we believe that the MSAT2 program will have very little impact on any of these factors (although, as explained in section VI.A above, some of the alternative toxic control strategies urged by commenters could have adverse energy supply implications). Analyses supporting these conclusions are also found in Chapter 9 of the RIA. We carefully considered lead time in establishing the stringency and timing of the proposed program (see section VI.A above).

We have carefully reviewed the technological feasibility (see section VI.A.1.c.i above and chapter 6 of the RIA) and costs of this program. Based on the considerations outlined in this section VI, we conclude that this program meets the requirements of section 202(l)(2) of the Clean Air Act, reflecting ''the greatest degree of emission reduction achievable through the application of technology which is available, taking into consideration * * * the availability and costs of the technology, and noise, energy, and safety factors, and lead time.''

VII. Portable Fuel Containers

As described in this section, we are adopting new HC emissions standards for portable gasoline containers (gas cans) essentially as proposed. We are also finalizing the same requirements for portable diesel and kerosene containers, containers which could easily be used for gasoline. Manufacturers must begin meeting the new requirements on January 1, 2009. These new emissions control requirements will reduce HC emissions from uncontrolled gasoline containers by about 75%, including reducing spillage losses. The final rule also includes new certification and compliance requirements that will help ensure that the containers achieve emissions control in use over the life of the container. The standards and program requirements we are finalizing are very similar to those adopted by California in 2005, so that manufacturers will be able to sell 50-state products. Overall, commenters were very supportive of the proposed new emissions control program for portable fuel containers.

We are establishing the portable fuel container (PFC) standards and emissions control requirements under section 183(e) of the Clean Air Act, which directs EPA to study, list, and regulate consumer and commercial products that are significant sources of VOC emissions. In 1995, after conducting a study and submitting a Report to Congress on VOC emissions from consumer and commercial products, EPA published an initial list of product categories to be regulated under section 183(e). Based on criteria that we established pursuant to section 183(e)(2)(B), we listed for regulation those consumer and commercial products that we considered at the time to be significant contributors to the ozone nonattainment problem, but we did not include PFC emissions.[201] After analyzing the emissions inventory impacts of these containers, we published a **Federal Register** notice that added PFCs to the list of consumer

[201] 60 FR 15264 ''Consumer and Commercial Products: Schedule for Regulation,'' March 23, 1995.

products to be regulated.[202] We requested comment on the data underlying the listing but did not receive any comments.[203] We continue to believe that the standards we proposed and are finalizing for fuel containers represent ''best available controls'' as required by section 183(e)(3)(A). Determination of the ''best available controls'' requires EPA to determine the degree of reduction achievable through use of the most effective control measures (which includes chemical reformulation, and other measures) after considering technological and economic feasibility, as well as health, energy, and environmental impacts.[204]

A. What Are the New HC Emissions Standards for PFCs?

1. Description of Emissions Standard

We are finalizing as proposed a performance-based standard of 0.3 grams per gallon per day (g/gal/day) of HC to control evaporative and permeation losses. The standard will be measured based on the emissions from the container over a diurnal test cycle. The cans will be tested as a system with their spouts attached. Manufacturers will test the containers by placing them in an environmental chamber which simulates summertime ambient temperature conditions and cycling the containers through the 24-hour temperature profile (72–96 °F), as discussed below. The test procedures, which are described in more detail below, ensure that containers meet the emissions standard over a range of in-use conditions such as different temperatures, different fuels, and taking into consideration factors affecting durability. EPA received only supportive comments on the proposed emissions standards.

2. Determination of Best Available Control

We continue to believe that the 0.3 g/gal/day emissions standard and associated test procedures reflect the performance of the best available control technologies including durable permeation barriers, auto-closing spouts, and a can that is well-sealed to reduce evaporative losses. The standard is both economically and technologically feasible. To comply with California's program, gas can manufacturers have developed gas cans with low VOC emissions at a reasonable cost (see section XIII. for costs). Testing of cans designed to meet CARB standards has shown the new standards to be technologically feasible. When tested over cycles very similar to those we are adopting, emissions from these cans have been in the range of 0.2–0.3 g/gal/day.[205] These cans have been produced with permeation barriers representing a high level of control (over 90 percent reductions) and with auto-closing spouts, which are technologies that represent best available controls for gas cans. Establishing the standard at 0.3 g/gal/day will require the use of best available technologies. As discussed in the proposal, we are finalizing a level at the upper end of the tested performance range to account for product performance variability (see 71 FR 15896). In addition, we believe that current best designs can achieve these levels, so we do not believe that the standard forecloses use of any of the existing performing product designs. Our detailed feasibility analysis is provided in the Regulatory Impact Analysis. We did not receive any comments on our feasibility analysis.

In addition to considering technological and economic feasibility, section 183(e)(1)(A) requires us to consider ''health, environmental, and energy impacts'' in assessing best available controls. Environmental and health impacts are discussed in section III. Moreover, control of spillage from containers may reduce fire hazards as well because cans would stay tightly closed if tipped over. We expect the energy impacts of gas can control to be positive, because the standards will reduce evaporative fuel losses.

3. Diesel, Kerosene and Utility Containers

Diesel and kerosene containers are manufactured by the same manufacturers as are gasoline containers and are identical to gasoline containers except for color (diesel containers are yellow and kerosene containers are blue). In the proposal, we requested comment on applying the emissions control requirements being proposed for gasoline containers to diesel and kerosene containers (see 71 FR 15897). California included diesel and kerosene cans in their regulations largely due to the concern that they would be purchased as substitutes for gasoline containers. We received only supportive comments for including these containers in the program. Several states and state organizations urged EPA to include these containers in the EPA program, viewing their omission as a significant difference between the California program and EPA's proposed program.

We recognize that using uncontrolled diesel and kerosene containers as a substitute for gasoline containers would result in a loss of emissions reductions. California collected limited survey data which indicated that about 60 percent of kerosene containers were being used for gasoline. In addition, keeping gasoline in containers marked for other fuels could lead to misfueling of equipment and possible safety issues. Finally, not including these containers would likely be viewed as a gap in EPA's program, resulting in states adopting or retaining their own emissions control program for PFCs. This would hamper the ability of manufacturers to have a 50-state product line. For these reasons, we are including diesel and kerosene containers in the program.

We are also clarifying that utility jugs are considered portable gasoline containers and therefore are subject to the program. They are designed and marketed for use with gasoline, often to fuel recreational equipment such as all-terrain vehicles and personal watercraft. This interpretation is consistent with the scope of the California program. California recently issued a clarification that these containers are covered by their program, after some utility jug manufacturers failed to meet the existing California requirements.

4. Automatic Shut-Off

We received a few comments encouraging EPA to consider or evaluate spillage control requirements. California's original program which began in 2001 required automatic shut-off as a way to reduce spillage. However, for reasons discussed in the proposal, we did not propose and are not finalizing automatic shut-off requirements (see 71 FR 15896). Automatic shut-off is supposed to stop the flow of fuel when the fuel reaches the top of the receiving tank in order to prevent over-filling. However, due to a wide variety of receiving fuel tank designs, the auto shut-off spouts do not work well with a variety of equipment types. In California, this problem led to spillage and consumer dissatisfaction, and California has removed automatic shut-off requirements from their program.

[202] 71 FR 28320 ''Consumer and Commercial Products: Schedule for Regulation,'' May 16, 2006.

[203] See not only the notice cited in the previous note, but also 71 FR 15894 (''EPA will afford interested persons the opportunity to comment on the data underlying the listing before taking final action on today's proposal'').

[204] See section 183(e)(1); see also section 183(e)(4) providing broad authority to include ''systems of regulation'' in controlling VOC emissions from consumer products.

[205] ''Quantification of Permeation and Evaporative Emissions From Portable Fuel Container'', California Air Resources Board, June 2004.

We continue to believe that including an automatic shut-off requirement would be counterproductive at this time. We believe that the automatic closing cans, even without automatic shut-off requirements, will lead to reduced spillage. Consumers will be able to watch the fuel rise in the receiving tank and stop fuel flow using the automatic close features prior to overfill. As discussed in the proposal, automatic closure keeps the cans closed when they are not in use and provides more control to the consumer during use. We believe consumers will appreciate this feature and see it as an improvement over existing cans, whereas an automatic shut-off that worked with only some equipment types would not be acceptable.

B. Timing of Standard

We are finalizing as proposed a start date for the new PFC standards of January 1, 2009. We received comments from state organizations recommending that the program start on January 1, 2008. In the proposal we recognized that adequate lead time is a key aspect of the standard's technological feasibility. Manufacturers have developed the primary technologies to reduce emissions from gas cans but will need a few years of lead time to certify products and ramp up production to a national scale. The certification process will take at least six months due to the required durability demonstrations described below, and manufacturers will need time to procure and install the tooling needed to produce gas cans with permeation barriers for nationwide sales. Commenters did not provide any new information to counter these points and we continue to believe for these reasons that the January 1, 2009 start date is appropriate.

The standards apply to containers manufactured on or after the start date of the program and do not affect cans produced before the start date. As proposed, as of July 1, 2009, manufacturers and importers must not enter into U.S. commerce any products not meeting the emissions standards. This provides manufacturers with a 6-month period to clear any stocks of containers manufactured prior to the January 1, 2009 start of the program, allowing the normal sell-through of these cans to the retail level. Retailers may sell their stocks of containers through the course of normal business without restriction. Containers are required by this rule to be stamped with their production date (consistent with current industry practices), which will allow EPA to determine which cans are required to meet the new standards. We did not receive any comments on these aspects of the proposal or comments suggesting that the proposed lead times would not be adequate.

C. What Test Procedures Would Be Used?

As proposed, we are finalizing a system of regulations for containers that includes test conditions designed to assure that the intended emission reductions occur over a range of in-use conditions such as operating at different temperatures, with different fuels, and considering factors affecting durability. These test procedures are authorized under section 183(e)(4) as part of a system of regulations to achieve the appropriate level of emissions reductions. Emission testing on all containers that manufacturers produce is not feasible due to the high annual production volumes and the cost and time involved with emissions testing. Instead, before the containers are introduced into commerce, the manufacturer will need to receive a certificate of conformity from EPA that the containers conform to the emissions standards, based on manufacturers' applications for certification. Manufacturers must submit test data on a sample of containers that are prototypes of the products the manufacturer intends to produce. The certificate issued by EPA will cover the range of production containers represented by the prototype container. As part of the application for certification, manufacturers also need to declare that their production cans will not deviate in materials or design from the prototype cans that are tested. If the production containers do deviate, then they will not be coved by the certificate and it will be a violation of the regulations to introduce such uncertified containers into commerce. Manufacturers must obtain their certification from EPA prior to introducing their products into commerce. The test procedures and certification requirements are described in detail below. Unless otherwise noted below, we did not receive comments on these test procedures.

We are requiring that manufacturers test cans in their most likely storage configuration. The key to reducing evaporative losses from gasoline containers is to ensure that there are no openings on the cans that could be left open by the consumer. Traditional cans have vent caps and spout caps that are easily lost or left off cans, which leads to very high evaporative emissions. We expect manufacturers to meet the evaporative standards by using automatic closing spouts and by removing other openings that consumers could leave open. However, if manufacturers choose to design cans with an opening that does not close automatically, we are requiring that containers be tested in their open condition. If the containers have any openings that consumers could leave open (for example, vents with caps), these openings thus would need to be left open during testing. This applies to any opening other than where the spout attaches to the can. We believe it is important to take this approach because these openings could be a significant source of in-use emissions and there is a realistic possibility that these openings would be inadvertently left open in use.

Except for pressure cycling, discussed below, spouts would be in place during testing because this would be the most likely storage configuration for the emissions compliant cans. Spouts would still be removable so that consumers would be able to refill the cans, but we would expect the containers to be resealed by consumers after being refilled in order to prevent spillage during transport. We do not believe that consumers would routinely leave spouts off cans because spouts are integral to the cans' use and it is obvious that they need to be sealed.

1. Diurnal Test

We are finalizing as proposed a test procedure for diurnal emissions testing where the containers are placed in an environmental chamber or a Sealed Housing for Evaporative Determination (SHED), the temperature is varied over a prescribed temperature and time profile, and the hydrocarbons escaping from the can are measured. Containers are to be tested over the same 72–96 °F (22.2–35.6 °C) temperature profile used for automotive applications. This temperature profile represents a hot summer day when ground level ozone emissions would be highest. Three containers must be tested, each over a three-day test. Testing three cans for certification will help address variability in products or test measurements. All three cans must individually meet the standard. As noted above, cans must be tested in their most likely storage configuration.

The final results are to be reported in grams per gallon, where the grams are the mass of hydrocarbons escaping from the container over 24 hours and the gallons are the nominal can capacity. The daily emissions will then be averaged for each can to demonstrate compliance with the standard. This test captures hydrocarbons lost through permeation and any other evaporative losses from the container as a whole. The grams of hydrocarbons lost may be determined by either weighing the gas can before and after the diurnal test cycle or measuring emissions directly using the SHED instrumentation.

Consistent with the automotive test procedures, we are requiring that the testing take place using 9 pounds per square inch (psi) Reid Vapor Pressure (RVP) certification gasoline, which is the same fuel required by EPA to be used in its other evaporative test programs. We are requiring testing be done using E10 fuel (10% ethanol blended with the gasoline described above) to help ensure in-use emission reductions on ethanol-gasoline blends, which tend to have increased evaporative emissions with certain permeation barrier materials. We continue to believe that including ethanol in the test fuel will lead to the selection of materials by manufacturers that are consistent with ''best available control'' requirements for all likely contained gasolines, and is clearly appropriate given the expected increase over time of the use of ethanol blends of gasoline under the renewable fuel provisions of the Energy Policy Act of 2005.

Diurnal emissions are not only a function of temperature and fuel volatility, but of the size of the vapor space in the container as well. We are finalizing as proposed that the fill level at the start of the test be 50% of the nominal capacity of the can. This would likely be the average fuel level of the gas can in-use. Nominal capacity of the cans is defined as the volume of fuel, specified by the manufacturer, to which the can could be filled when sitting on level ground. The vapor space that normally occurs in a container, even when ''full,'' would not be considered in the nominal capacity of the can. All of these test requirements are meant to represent typical in-use storage conditions for containers, on which EPA can base its emissions standards. The above provisions for diurnal testing are included as a way to implement the standards effectively, which, in conjunction with the new emissions standard, will lead to the use of best available technology at a reasonable cost. We did not receive comment on these test procedures.

Before testing for certification, the container must be run through the durability tests described below. Within 8 hours of the end of the soak period contained in the durability cycle, the cans are to be drained and refilled to 50 percent nominal capacity with fresh fuel, and then the spouts re-attached. When the can is drained, it must be immediately refilled to prevent it from drying out. The timing of these steps is needed to ensure that the stabilized permeation emissions levels are retained. The can will then be weighed and placed in the environmental chamber for the diurnal test. After each diurnal, the can must be re-weighed. In lieu of weighing the container, manufacturers may opt to measure emissions from the SHED directly. For any in-use testing of containers, the durability procedures will not be run prior to testing.

California's test procedures are very similar to those described above. However, the California procedure contains a more severe temperature profile of 65–105 °F. As proposed, we will allow manufacturers to use this temperature profile to test cans as long as other parts of the EPA test procedures are followed, including the durability provisions below.

2. Preconditioning to Ensure Durable In-Use Control

a. Durability Cycles

As proposed, we are specifying three durability aging cycles to help ensure durable permeation barriers: slosh, pressure-vacuum cycling, and ultraviolet (UV) exposure. They represent conditions that are likely to occur in-use for gas cans, especially for those cans used for commercial purposes and carried on truck beds or trailers. The purpose of these deterioration cycles is to help ensure that the technology chosen by manufacturers is durable in-use, representing best available control, and the measured emissions are representative of in-use permeation rates. Fuel slosh, pressure cycling, and ultraviolet (UV) exposure each impact the durability of certain permeation barriers, and we believe these cycles are needed to ensure long-term emissions control. Without these durability cycles, manufacturers could choose to use materials that meet the standard when they are new but have degraded performance in-use, leading to higher emissions. We do not expect these procedures to adversely impact the feasibility of the standards, because there are permeation barriers available at a reasonable cost that do not deteriorate significantly under these conditions (these permeation barriers are examples of best available controls).

For slosh and pressure cycling, we are finalizing durability tests that are based on draft recommended SAE practice for evaluating permeation barriers.[206] For slosh testing, the container is to be filled to 40 percent capacity with E10 fuel and rocked for 1 million cycles. The pressure-vacuum testing contains 10,000 cycles from −0.5 to 2.0 psi. This pressure may be applied through the opening where the spout attaches, in order to avoid the need to drill a hole in the container. The third durability test is intended to assess potential impacts of ultraviolet (UV) sunlight (0.2 µm–0.4 µm) on the durability of a surface treatment. In this test, the container must be exposed to a UV light of at least 0.40 Watt-hour/meter^2 /minute on the container surface for 15 hours per day for 30 days. Alternatively, containers may be exposed to direct natural sunlight for an equivalent period of time. We have also established these same durability requirements as part of our program to control permeation emissions from recreational vehicle fuel tanks.[207] While there are obvious differences in the use of gas cans compared to the use of recreational vehicle fuel tanks, we believe the test procedures offer assurance that permeation controls used by manufacturers will be robust and will continue to perform as intended when in use.

Manufacturers may also do an engineering evaluation, based on data from testing on their permeation barrier, to demonstrate that one or more of these factors (slosh, UV exposure, and pressure cycle) do not impact the permeation rates of their fuel containers and therefore that the durability cycles are not needed. Manufacturers may use data collected previously on gas cans or other similar containers made with the same materials and processes to demonstrate that the emissions performance of the materials does not degrade when exposed to slosh, UV, and/or pressure cycling. The test data must be collected under equivalent or more severe conditions as those noted above. EPA must approve an alternative demonstration method prior to its use for certification.

b. Preconditioning Fuel Soak

It takes time for fuel to permeate through the walls of containers. Permeation emissions will increase over time as fuel slowly permeates through the container wall, until the permeation finally stabilizes when the saturation point is reached. We want to evaluate emissions performance once permeation

[206] Draft SAE Information Report J1769, ''Test Protocol for Evaluation of Long Term Permeation Barrier Durability on Non-Metallic Fuel Tanks,'' (Docket A–2000–01, document IV–A–24).

[207] Final Rule, ''Control of Emissions from Nonroad Large Spark-ignition engines, and Recreational Engines (Marine and Land-based)'', 67 FR 68287, November 8, 2002.

emissions have stabilized, to ensure that the emissions standard is met in-use. Therefore, as proposed, prior to testing the containers, the cans need to be preconditioned by allowing the cans to sit with fuel in them until the hydrocarbon permeation rate has stabilized. Under this step, the container is filled with a 10-percent ethanol blend in gasoline (E10), sealed, and soaked for 20 weeks at a temperature of 28 ± 5 °C. As an alternative, the fuel soak may be performed, for example, for 10 weeks at 43 ± 5 °C to shorten the test time, if the certifier can demonstrate that the hydrocarbon permeation rate has stabilized. During this fuel soak, the container must be sealed with the spout attached. This is representative of how the gas cans would be stored in-use. We have established these soak temperatures and durations based on protocols EPA has established to measure permeation from fuel tanks made of HDPE.[208] These soak times should be sufficient to achieve stabilized permeation emission rates. However, if a longer time period is necessary to achieve a stabilized rate for a given container, the manufacturer must use a longer soak period (and/or higher temperature) consistent with good engineering judgment.

Durability testing that is performed with fuel in the container may be considered part of the fuel soak provided that the container continuously has fuel in it. This approach would shorten the total test time. For example, the length of the UV and slosh tests may be considered as part of the fuel soak provided that the container is not drained between these tests and the beginning of the fuel soak. In such cases, manufacturers must use the 40 percent fill level for the soak period. The reduced fill level will not affect the permeation rate of the container because the vapor space in the container will be saturated with fuel vapor.

c. Spout Actuation

In its recently revised program for PFCs, California included a durability demonstration for spouts. We are finalizing as proposed a durability demonstration consistent with California's procedures. Automatically closing spouts are a key part of the emissions controls expected to be used to meet the new standards. If these spouts stick or deteriorate, in-use emissions could remain very high, at essentially uncontrolled levels. California requires manufacturers to actuate the spouts 200 times prior to the soak period and 200 times near the conclusion of the soak period to simulate spout use. The spouts' internal components would be required to be exposed to fuel by tipping the can between each cycle. Spouts that stick open or leak during these cycles would be considered failed. The total of 400 spout actuations represents about 1.5 actuations per week on average over the average container life of 5 years. In the absence of data, we believe this number of actuations appears to reasonably replicate the number that can occur in-use for high-end usage and will help ensure quality spout designs that do not fail in-use. We also believe that finalizing requirements consistent with California will help manufacturers to avoid duplicate testing.

One commenter stated that 400 actuations over a short period of time is not representative of real life and that many containers will last 15–25 years. In response, we understand that 5 years is an estimate of the average life and that some containers will be used longer than 5 years. However, we continue to believe that the approach we are finalizing is reasonable. This provision is meant to help ensure that spouts are made of quality materials so that the emissions performance will not deteriorate readily during normal use. The provision also helps to ensure that spouts will not break easily or stick open during normal use, and helps to identify issues during the certification process prior to sale. In addition, this approach balances the need to ensure quality designs with the manufacturers' need to be able to conduct certification testing in a reasonable amount of time. This type of ''accelerated aging'' of components is a necessary part of many of EPA's mobile source emissions control programs.

D. What Certification and In-Use Compliance Provisions Is EPA Adopting?

1. Certification

Section 183(e)(4) authorizes EPA to adopt appropriate systems of regulations to implement the program, including requirements ranging from registration and self-monitoring of products, to prohibitions, limitations, economic incentives and restrictions on product use. We are finalizing as proposed a certification mechanism pursuant to these authorities. Manufacturers are required to apply for and receive an EPA certificate of conformity, using the certification process specified in the regulations, before entering their containers into U.S. commerce. To have their products certified, manufacturers must first define their emission families. This is generally based on selecting groups of products that have similar emissions. For example, co-extruded containers of various geometries could be grouped together. The manufacturer must select a worst-case configuration for testing, such as the thinnest-walled container. Manufacturers may group gasoline, diesel, and kerosene containers together as long as the containers do not differ materially in a way that could be anticipated to cause differences in emissions performance. These determinations must be made using good engineering judgment and are subject to EPA review. Testing with those products, as specified above, must show compliance with emission standards. The manufacturers must then send us an application for certification. As proposed, we define the manufacturer as the entity that is in day-to-day control of the manufacturing process (either directly or through contracts with component suppliers) and responsible for ensuring that components meet emissions-related specifications. Importers are not considered a manufacturer under this program, and thus would not receive certificates. The manufacturers of the PFCs they import would have to certify the cans. Importers will only be able to import PFCs that are certified.

After reviewing the information in the application, if all the required information is provided and it demonstrates compliance with the standards, then we will issue a certificate of conformity allowing manufacturers to introduce into commerce the containers from the certified emission family. We expect EPA review to typically take about 90 days or less, but could be longer if we have questions regarding the application. The certificate of conformity will be for a production period of up to 5 years. Manufacturers are allowed to carry over certification test data if no changes are made to their products that would affect emissions performance. We may revoke or void a certificate if we find that data and information on which it is based is false or inaccurate. We will notify the manufacturer in writing and the manufacturer may request a hearing. Changes to the certified products that affect emissions require reapplication for certification. Manufacturers wanting to make changes without doing testing are required to present an engineering

[208] Final Rule, ''Control of Emissions from Nonroad Large Spark-ignition engines, and Recreational Engines (Marine and Land-based)'', 67 FR 68287, November 8, 2002.

evaluation demonstrating that emissions are not affected by the change.

The manufacturer is responsible for meeting applicable emission standards. Importers are also responsible for the product meeting the standards. While we are not including requirements for manufacturers to conduct production-line testing, we may pursue EPA in-use testing of certified products to evaluate compliance with emission standards. If we find that containers do not meet emissions standards in use, we would consider the new information during future product certification. Also, we may require certification prior to the end of the 5-year production period otherwise allowed between certifications. The details of the certification process are provided in the regulatory text. We did not receive any comments on the certification procedures described above.

EPA is authorized under the Independent Offices Appropriation Act of 1952 to establish fees for Government services and things of value that it provides. This provision encourages Federal regulatory agencies to recover, to the fullest extent possible, costs provided to identifiable recipients. The agency currently collects fees for compliance programs administered by EPA including those for certification of motor vehicles and motor vehicle engines. At this time, we are not finalizing a fee program for PFC certification. However, we may establish a certification fee for PFCs in a future rulemaking.

2. Emissions Warranty and In-Use Compliance

We are finalizing as proposed an emissions warranty period of one year to be provided by the manufacturer of the PFC to the consumer. The warranty covers emissions-related materials defects and breakage under normal use. For example, the warranty covers failures related to the proper operation of the auto-closing spout or defects with the permeation barriers. We are also requiring that manufacturers submit a warranty and defect report documenting successful warranty claims and the reason for the claim to EPA annually so that EPA may monitor the program. Unsuccessful claims will not need to be submitted. We believe that this warranty will encourage designs that work well for consumers and are durable. Although it does not fully cover the average life of the product, it is not typical for very long consumer warranties to be offered with such products and therefore we believe a one-year warranty is reasonable. Also, the warranty period is more similar to the expected life of gas cans when used in commercial operations, which would need to be considered by the manufacturers in their designs. We did not receive any comments on these warranty provisions.

EPA views this aspect of the final rule as another part of the ''system of regulation'' it is finalizing to control VOC emissions from PFCs. A warranty will promote the objective of the rule by providing consumers with an opportunity to replace containers that have failed in use. The warranty provides an obvious remedy to consumers if issues arise. The provision also helps to ensure that manufacturers will ''stand behind'' their product if they fail in use, thus improving product design and performance. Similarly, the defect reporting requirement will promote product integrity by allowing EPA to readily monitor in-use performance by tracking successful warranty claims.

Gas cans have a typical life of about 5 years on average before they are scrapped. We are including durability provisions as part of certification testing to help ensure containers perform well in use. Under this final rule, we could test containers within their five-year useful life period to monitor in-use performance and take steps to correct in-use failures, including denying certification, for container designs that are consistently failing to meet emissions standards. (This provision thus would work in tandem with the warranty claim reporting provision contained in the preceding paragraph.)

3. Labeling

Since the requirements will be effective based on the date of manufacture of the container, we are requiring as proposed that the date of manufacture must be indelibly marked on the can. This is consistent with current industry practices. This is needed so that we and others can recognize whether a unit is regulated or not. In addition, we are requiring a label providing the manufacturer name and contact information, a statement that the can is EPA certified, citation of EPA regulations, and a statement that it is warranted for one year from the date of purchase. The manufacturer name and contact information is necessary to verify certification. Indicating that a one-year warranty applies will ensure that consumers have knowledge of the warranty and a way to contact the manufacturer. Enforcement of the warranty is critical to the defect reporting system. In finalizing this labeling requirement, we further believe, pursuant to CAA section 183(e)(8), that these labeling requirements will be useful in meeting the NAAQS for ozone. They provide necessary means of implementing the various measures described above which help ensure that VOC emission reductions from the proposed standard will in fact occur in use. We did not receive any comments on these labeling requirements.

E. How Would State Programs Be Affected By EPA Standards?

Several states have adopted emissions control programs for PFCs. California implemented an emissions control program for PFCs in 2001. Fifteen other states, mostly in the northeast, have adopted or are considering adopting the California program.[209] In 2005, California adopted a revised program, which will go into effect on July 1, 2007. The revised California program is very similar to the program we are finalizing. We believe that although a few aspects of the program we are finalizing are different, manufacturers will be able to meet both EPA and CARB requirements with the same container designs and therefore sell a single product in all 50 states. In most cases, we believe manufacturers will take this approach. By closely aligning with California where possible, we will allow manufacturers to minimize research and development (R&D) and emissions testing, while potentially achieving better economies of scale. It may also reduce administrative burdens and market logistics from having to track the sale of multiple can designs. We consider these to be important factors under CAA section 183(e) which requires us to consider economic feasibility of controls.

States that have adopted the original California program will likely choose to either adopt the new California program or eliminate their state program in favor of the federal program. Because the programs are similar, we expect that most states will eventually choose to rely on implementation of the EPA program rather than continue their own program. Including diesel and kerosene containers in our final program further aligns the two programs and several states commented in support of this approach. We expect very little difference in the emissions reductions provided by the EPA and California programs in the long term.

[209] Delaware, Maine, Maryland, Pennsylvania, New York, Connecticut, Massachusetts, New Jersey, Rhode Island, Vermont, Virginia, Washington DC, Texas, Ohio, and New Hampshire.

F. Provisions for Small PFC Manufacturers

As discussed in previous sections, prior to issuing our proposal for this rulemaking, we analyzed the potential impacts of these regulations on small entities. As a part of this analysis, we convened a Small Business Advocacy Review Panel (SBAR Panel, or ''the Panel''). During the Panel process, we gathered information and recommendations from Small Entity Representatives (SERs) on how to reduce the impact of the rule on small entities, and those comments are detailed in the Final Panel Report which is located in the public record for this rulemaking (Docket EPA–HQ–OAR–2005–0036). Based upon these comments, we proposed to include flexibility and hardship provisions for container manufacturers. Since nearly all manufacturers are small entities and they account for about 60 percent of sales, the Panel recommended that we extend the flexibility options and hardship provisions to all manufacturers. Our proposal was consistent with that recommendation. We did not receive any comments on our proposed flexibilities and are finalizing them as proposed. The flexibility provisions are incorporated into the program requirements described earlier in sections VII.B through VII.D. The hardship provisions are described below. For further discussion of the Panel process, see section X.C of this rule and/or the Final Panel Report.

The Panel recommended and we are finalizing two types of hardship provisions for container manufacturers. These entities could, on a case-by-case basis, face hardship, and we are finalizing these provisions to provide what could prove to be needed safety valves for these entities. Thus, the hardship provisions are as follows:

1. First Type of Hardship Provision

Container manufacturers may petition EPA for limited additional lead-time to comply with the standards. A manufacturer would have to demonstrate that it has taken all possible business, technical, and economic steps to comply but the burden of compliance costs prevents it from meeting the requirements of this subpart by the required compliance date and not having an extension would jeopardize the company's solvency. Hardship relief may include requirements for interim emission reductions.

2. Second Type of Hardship Provision

Container manufacturers are permitted to apply for hardship relief if circumstances outside their control cause the failure to comply (i.e., an ''Act of God,'' a fire at the manufacturing plant, or the unforeseen shut down of a supplier with no alternative available), and if failure to sell the subject containers would jeopardize the company's solvency. The terms and timeframe of the relief will depend on the specific circumstances of the company and the situation involved.

For both types of hardship provisions, the length of the hardship relief will be established, during the initial review, for not more than one year and will be reviewed annually thereafter as needed. As part of its application, a company is required to provide a compliance plan detailing when and how it will achieve compliance with the standards.

VIII. What Are the Estimated Impacts of the Rule?

A. Refinery Costs of Gasoline Benzene Reduction

The benzene control program we are finalizing today is expected to result in many refiners investing in benzene control hardware and changing the operations in their refineries to reduce their gasoline benzene levels. The finalized benzene control program requires refiners and importers to reduce their gasoline benzene levels on average down to 0.62 vol% benzene. The averaging, banking and trading (ABT) provisions being finalized along with the 0.62 vol% average benzene control standard allows refineries that reduce their gasoline benzene levels below 0.62 vol% to earn credits and transfer those credits to other refineries which would find it more expensive to reduce their benzene levels down to the average standard. The ABT program will allow refiners to optimize their investments, which we believe will result in achieving the average benzene control standard nationwide at much lower costs. The final benzene control program also puts into place a 1.3 vol% benzene maximum average standard which requires each refinery to reduce its gasoline benzene levels to or below this standard and will increase the benzene control costs only slightly compared to a benzene control program which does not contain a maximum average standard. We estimate that the national average refinery costs incurred to comply with the fully phased-in benzene control program will be 0.27 cents per gallon, averaged over all gasoline. This estimate includes the capital costs, which are amortized over the volume of gasoline produced.

In this section we summarize the methodology used to estimate the costs of benzene control (including changes we have made since the proposal) and our estimated costs for the program. In addition we evaluate the cost estimate provided by the American Petroleum Institute. A detailed discussion of all of these analyses is found in Chapter 9 of the RIA.

1. Methodology

a. Overview of the Benzene Program Cost Methodology

The basic methodology we used to estimate the cost of benzene control for the final rule is the same as that used for the proposed rule. Using a refinery-by-refinery cost model that we developed for this rulemaking, we projected which refineries implement what benzene control technology, and the cost of each refinery's benzene control step, to estimate compliance with the final benzene control program. We aggregated the individual refinery costs to develop a national average cost estimate for the final benzene control program. Based on the flexibilities offered by the ABT program, refiners are expected to come very close to achieving the 0.62 vol% average benzene standard on average with little overcompliance. For this reason, we modeled refiners achieving the average standard without any overcompliance. To the extent that any overcompliance does occur the costs and benefits of the benzene program will increase.

b. Changes to the Cost Estimation Methodology Used in the Proposed Rule

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, which increased the crude oil price used in the analysis from $27 per barrel to $47 per barrel. Other changes included: (1) Updating the refinery modeling base year to 2004 (used for calibrating each refinery's gasoline benzene levels); (2) modeling the baseline benzene levels and reductions on an annual basis instead of on a summer-only basis; (3) increasing the tax-hurdle rate of return to 15 percent from the 10 percent hurdle used in the proposed rule, and (4) including the treatment of the benzene in natural gasoline, which was assumed to be left untreated in the proposed rule analysis.

In addition, we also made some adjustments that were based on comments we received on the cost analysis that we conducted for the proposal, as well as the peer review process that we undertook for the proposal's refinery cost model. One of the peer reviewers for the refinery-by-refinery cost model, and API in its comments on the proposed rule, provided capital cost estimates for the benzene control technologies.[210] We reviewed these capital cost estimates and made some adjustments to somewhat increase the capital cost figures used in the final rule analysis. These changes were partially responsible for the higher costs reported here compared to those reported in the proposed rule. More complete descriptions of these and other changes made to the refinery cost model are contained in Chapter 9 the RIA.

c. Linear Programming Cost Model

We considered performing our cost assessments using a linear programming (LP) cost model. LP cost models are based on a set of complex mathematical representations of refineries which, for national analyses, are usually conducted on a regional basis. This type of refining cost model has been used by the government and the refining industry for many years for estimating the cost and other implications of changes to fuel quality.

The design of LP models lends itself to modeling situations where every refinery in a region is expected to use the same control strategy and/or has the same process capabilities. As we began to develop a gasoline benzene control program with an ABT program, it became clear that LP modeling was not well suited for evaluating such a program. Because refiners will be choosing a variety of technologies for controlling benzene, and because the program will be national and will include an ABT program, we initiated development of a more appropriate cost model, as described below. However, the LP model remained important for providing many of the inputs into the cost model developed for this rulemaking.

d. Refinery-by-Refinery Cost Model

In contrast to LP models, refinery-by-refinery cost models are useful when individual refineries are expected to respond to program requirements in different ways and/or have significantly different process capabilities. Thus, in the case of modeling gasoline benzene control programs, we needed a model that could accurately simulate the variety of decisions refiners will make at different refineries, especially in the context of a nationwide ABT program. For this and other related reasons, we developed a refinery-by-refinery cost model specifically to evaluate the benzene control program.

Our refinery-by-refinery benzene cost model incorporates the capacities of all the major units in each refinery in the country, as reported by the Energy Information Administration and in the Oil and Gas Journal. Regarding operational information, we know less about how specific refineries use the various units to produce gasoline and about such factors as octane and hydrogen costs for individual refineries. We used the LP model to estimate these factors on a regional basis, and we applied the average regional result to each refinery in that region (PADD). We calibrated the model for each individual refinery based on 2004 gasoline volumes and benzene levels (from the RFG data base), which was the most recent year for which data was available. After calibration, each refinery's gasoline volume and benzene level closely matched their actual gasoline volumes and benzene levels. We also compared cost estimates of similar benzene control cases from both the refinery-by-refinery model and the LP model, and the results were in close agreement.[211]

Refinery-by-refinery cost models have been used in the past by both EPA and the oil industry for such programs as the highway and nonroad diesel fuel sulfur standards, and they are a proven means for estimating the cost of compliance for fuel control programs. For this refinery-by-refinery benzene cost model, we conducted a peer review process, and have received some comments on the design of our model. We summarize some of these comments here, and they are summarized and addressed in detail in the RIA. (See Chapter 9 of the RIA for our responses to these peer-review comments.) The oil industry has also conducted similar analyses using a refinery-by-refinery modeling technique, including the oil industry's cost analysis carried out for this rulemaking.

Based on our understanding of the primary benzene control technologies (see section VI.A.1.c.i. above), the cost model assumes that four technologies will be used, as appropriate, for reducing benzene levels. All of these technologies focus on addressing benzene in the reformate stream. They are (1) routing the benzene precursors around the reformer (also called light naphtha splitting and reformer feed fractionation); (2) routing benzene precursors to an existing isomerization unit, if available; (3) benzene extraction (extractive distillation); and (4) benzene saturation. For the proposed rulemaking we assumed that only the usual feed or the product stream of the reformer will be processed by these benzene control technologies. However, since the proposal, we learned that another refinery stream—natural gasoline—contains some benzene and will likely be treated by the saturation and extraction processes in refineries if they have or install these units. For the proposal, we assumed that natural gasoline would be blended directly into gasoline and not be treated by refiners if faced with a benzene control standard. However, most refiners have been combining natural gasoline with their crude oil to enable treating the sulfur in natural gasoline to help comply with the Tier 2 gasoline sulfur standard. Because the natural gasoline will be refined along with crude oil, the benzene in natural gasoline can and will be treated along with the benzene in crude oil.

The nationwide ABT program is intended to optimize benzene reduction by allowing each refinery to individually choose the most cost-effective means of complying with the program. To model this phenomenon, we first established an estimated cost for the array of technologies that could be employed by each refinery to reduce its gasoline benzene levels. We then deployed these technologies to refineries with baseline benzene levels above the 1.3 vol% benzene maximum average standard to bring them into compliance with this standard. Next we ranked the refineries in order from lowest to highest benzene control cost per gallon of gasoline and estimated the impact of their projected benzene

[210] An important reason for the discrepancy between our capital cost estimate and that by API (which was about three times higher) was that we only estimated the capital costs related to the benzene control technologies, not those related to octane recovery and increased hydrogen production needed for saturation or to replace the octane lost due to reduced benzene production by the reformer. For the final rule, we estimated these additional capital costs and included them in our capital cost estimates.

[211] Despite our commitment to accurately model the baseline operations of each refinery, we recognize that without detailed refinery-specific operations information at our disposal, that our modeling may not be accurate in some specific cases. Particular refineries may choose a different benzene control path than that estimated by our analysis for a number of reasons, including differences in the baseline and our lack of knowledge for investment and ABT program use preferences for each refiner. We believe, though, that overall our refinery cost model captures the strategies and costs for complying with the benzene control program.

control strategies on refinery benzene levels. The model then follows this ranking, starting with the lowest-cost refineries, and adds refineries and their associated control technologies one-by-one until the projected national average benzene level reaches 0.62 vol% benzene. This modeling strategy projects the benzene control technology that will be used by each refinery, as well as identifies those refineries that are expected to generate credits and those that are expected to use credits in lieu of investing in benzene control. The sum of the costs of the refineries expected to invest in benzene control provides the projected overall cost of the program.

Finally, we projected how the ABT program will affect the program cost and benzene levels starting in 2007, when early credits can be generated. We assumed that refiners will use operational changes (benzene precursor rerouting, with isomerization if available) to the maximum extent possible in mid-2007, when they are able to start to generate credits. We also assumed that refiners will choose to accumulate additional early credits by making their initial lowest-cost capital investments for reducing their gasoline benzene levels, and that these changes will take effect in 2010. We modeled compliance by nonsmall and small refiners with the maximum average standard taking effect in mid-2012 and the beginning of 2015, respectively, as well as the final benzene control step to meet the 0.62 vol% standard—the phase-in of which depends on the aggregate amount of credits generated.[212]

e. Price of Chemical Grade Benzene

The price of chemical grade benzene is critical to the benzene control program because it defines the opportunity cost for benzene removed using benzene extraction and sold into the chemicals market. According to 2004 World Benzene Analysis authored by Chemical Market Associates Incorporated (CMAI), during the consecutive five-year period ending with 2004, the price of benzene averaged 24 dollars per barrel higher than regular grade gasoline. During the three consecutive year period ending with 2004, the price of benzene averaged 28 dollars per barrel higher than regular grade gasoline. However, during the first part of 2004, the price of benzene relative to gasoline rose steeply, primarily because of high energy prices adding to the cost of extracting benzene. The 2004 benzene price averaged 78 dollars per barrel higher than regular grade gasoline. Since early 2006, CMAI has been projecting that the future price of benzene relative to gasoline will return to more historic levels, in the range of 30 dollars per barrel higher than regular grade gasoline (in 2005, CMAI was projecting that the benzene price would be 20 dollars per barrel higher than gasoline). We have based our modeling for the final rule on the 30 dollar per barrel value.

2. Summary of Costs

a. Nationwide Costs of the Final Benzene Control Program

We have used the refinery-by-refinery cost model to estimate the costs of the benzene control program being finalized today. In general, the cost model indicates that among the four primary reformate-based technologies, benzene precursor rerouting will be the most cost-effective. The next most cost-effective technologies are isomerization of the rerouted light straight run material, revamped extraction units and new installations of large extraction units. The model indicates that benzene saturation and small installations of new extraction units will be the least cost-effective.

Based on the results of our analysis using the refinery-by-refinery model, we estimate that when the benzene control program is fully phased in, 78 refineries of the total 104 gasoline-producing refineries in the U.S. (outside of California) will have to put in new capital equipment or change their refining operations to reduce the benzene levels in their gasoline. Of these refineries, we estimate that 17 will use benzene precursor removal, 28 refineries will use benzene precursor removal coupled with isomerization, 16 will use extraction, and 17 will use benzene saturation. We project that 52 refineries will continue to produce gasoline with benzene levels greater than the average standard and will need to purchase credits to comply. 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, the model projects that 26 refineries will take no steps to reduce their gasoline benzene levels, which includes those which remain above the average benzene standard as well as those already below the average standard.

Based on the results of our cost analysis, we estimate that the final benzene control program will cost 0.27 cents per gallon when it is fully phased in, assuming that capital investments are amortized at a 7 percent return on investment before taxes and expressed in 2003 dollars. Our cost analysis projects that the ABT program will result in a phase-in of the benzene control standard from mid-2007 to early in 2015. Starting in mid-2007 we believe that refiners will take the opportunity to achieve modest benzene reductions to generate early credits using simple operational changes. We project that these actions taken in mid-2007 will result in a reduction of the average U.S. gasoline benzene level from 0.99 to 0.81 vol% at an average cost of 0.04 cents per gallon.

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 project that these additional early benzene reductions will not occur until the beginning of 2010, although in reality these investments and associated benzene reductions would likely occur before and after the beginning of 2010. These benzene reductions are expected to further reduce the average benzene level of U.S. gasoline to 0.74 vol% 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% benzene control 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 vol% 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. Although the early credit use period terminates at the end of 2013, refiners will again have flexibility in scheduling their most expensive capital

[212] The ABT analysis assumed that small refiners would comply with the 1.3 vol% maximum average standard in January 2015 at the same time as the 0.62 vol% annual average standard. We are finalizing a later maximum average standard implementation date (July 2016), which will have very little effect on the overall program and therefore has not been incorporated into this analysis.

investments by using standard credits (which will have been accruing since the start of 2011). 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 with the 0.62 vol% 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 which was assumed to occur at the beginning of 2015 so they also will be reducing their gasoline benzene levels to that standard or below.[213] Taken together, these reductions in 2015 will bring the U.S. gasoline pool down to the 0.62 vol% benzene standard at an average cost of 0.14 cents per gallon averaged over all U.S. gasoline, based on the addition of $634 million in capital investments.

To comply with the fully phased-in final benzene control program, refiners are expected to have made a total of $1110 million in capital investments. This will amount to an average of $14 million in capital investment in each refinery that adds such equipment.

We also estimated annual aggregate costs, including the amortized capital costs, associated with the new fuel standard. As shown in Table VIII.A–1, these costs are projected to begin at $28 million in 2007 and increase to $363 million in 2015 when the benzene program is fully phased in. These aggregated costs continue to increase over time as fuel demand increases.

TABLE VIII.A–1.—PER-GALLON AND ANNUAL AGGREGATE FUEL COSTS FOR THE FINAL BENZENE CONTROL PROGRAM

(7% ROI before taxes and 2003 dollars)

Year	Per-gallon cost (c/gal)	Aggregate cost ($million)
2007	0.02	28
2008	0.04	49
2009	0.04	50
2010	0.09	101
2011	0.09	104
2012	0.11	133
2013	0.13	164
2014	0.13	166
2015	0.27	363
2020	0.27	388
2025	0.27	412
2030	0.27	437
2035	0.27	464

Several observations can be made from these results of our nationwide cost analysis. First, significantly reducing gasoline benzene levels to low levels, coupled with the flexibility of an ABT program, will incur fairly modest aggregate program costs. This is primarily because we expect that refiners will optimize their benzene control strategies, resulting in large benzene reductions at a relatively low overall program cost. With higher benzene prices relative to those of gasoline projected to continue (even if they drop from the recent very high levels), extraction is expected to be a very low-cost technology—the primary reason why the cost of the overall program is very low. Also, precursor rerouting, either with or without isomerization in an existing unit, is a low-cost technology requiring little or no capital to realize. The model concludes that even the higher-cost benzene saturation technology will be fairly cost-effective overall because larger refineries that install this technology will take advantage of their economies of scale.

b. Regional Costs

The benzene reductions estimated by the cost model and associated costs vary significantly by region. Table VIII.A–2 summarizes the estimated per-gallon costs for complying with the benzene control standard by PADD region.

TABLE VIII.A–2.—PROJECTED BENZENE CONTROL COSTS BY PADD FOR THE FINAL BENZENE CONTROL PROGRAM

(2003 dollars, 7% ROI before taxes)

	PADD					U.S.
	1	2	3	4	5 (w/o CA)	
Cost (c/gal)	0.14	0.35	0.15	0.55	1.21	0.268

Table VIII.A–2 shows that the PADD-average costs are highest in PADD 5 followed next by PADD 4. In PADDs 1, 2 and 3, where reformulated gasoline programs have already forced gasoline benzene levels lower, the benzene control costs are lower. Extraction is the technology most used in PADDs 1 and 3, resulting in lower benzene control cost in these regions. Individual refineries show a wider range of control costs than the PADD-average costs. There are 20 refineries for which we estimate benzene control costs lower than 0.20 cents per gallon. Also, there are 11 refineries, all of which are very small refineries, with costs in the range of 3 to 7 cents per gallon range.

c. Refining Industry Cost Study

The American Petroleum Institute (API) conducted its own refinery modeling study to evaluate the cost of benzene control. The API study analyzed the cost of three different benzene control programs. Two of the benzene control programs analyzed by API were very different than our final benzene control program and we will not discuss them here (see Chapter 9 of the RIA). The third program analyzed by API was nearly identical to the final benzene control standard, and we have carefully compared API's cost analysis to ours.

API analyzed a benzene control program with a nationwide 0.60 vol% benzene standard and with an ABT program and with no upper benzene limit. API also assumed that credits will 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. Including the compliance margin and the 10 percent credit margin, the API study estimated that under its modeled benzene control program and associated assumptions that U.S. gasoline would average 0.56 vol% benzene. The API study estimates the cost of complying with its modeled benzene control program to be 1.00 cent

[213] The ABT analysis assumed that small refiners would comply with the 1.3 vol% maximum average standard in January 2015 at the same time as the 0.62 vol% annual average standard. We are finalizing a later maximum average standard implementation date (July 2016), which will have very little effect on the overall program and therefore has not been incorporated into this analysis.

per gallon.[214] This estimated benzene control cost is substantially higher than our estimated 0.27 cents per gallon cost for our nearly identical program. After comparing their methodology to ours we identified three primary differences which explain the large difference in costs.

The first difference is that API modeled a somewhat lower benzene control standard and assumed a credit generation margin which resulted in refiners achieving a much lower benzene level than the 0.62 vol% benzene control standard. A primary reason why the refining industry study modeled overcompliance with the benzene standard is due to an assumption that refiners will want to hold onto a substantial quantity of credits, yet the API cost study did not provide a justification for the accumulation of credits. EPA does not believe that refiners will significantly overcomply with the average benzene standard. This is because the 0.62 vol% benzene standard is an averaging standard which is met across the entire industry, 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 produced 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. 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 following year. With this degree of flexibility, any significant overcompliance with the 0.62 vol% average benzene standard is unnecessary.

The second reason why the API costs are much higher than ours is because API used a more restrictive assumption with respect to benzene extraction—a more cost-effective benzene control technology than benzene saturation, as discussed above. API assumed that no new grassroots benzene extraction capacity will 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 several refineries will install new grassroots extraction units. Our premise is supported by CMAI projections of a robust benzene market in the future with benzene priced higher than its historical margin above gasoline. Higher benzene price margins will provide an incentive to refiners to add grassroots benzene extraction units, even in areas where benzene markets are 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 small with less room for increased supply (although this benzene could be shipped down to the Gulf Coast). 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 much larger with much more room to absorb increased supply.

The third reason why the API benzene control costs are much higher than ours is their very high octane control costs. For both studies, the octane loss that occurs due to the modeled application 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 higher than the future octane recovery costs that we are projecting. The octane costs used by API are higher because API used the rack price differential between premium and regular grade gasolines as summarized by the Energy Information Administration. However, the rack price differential between premium and regular grade gasolines reflects 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 more per gallon for premium gasoline at retail. Some of this inflated price appears at the rack price differential between regular and premium grades of gasoline. In addition, future octane control costs, when the benzene control standard takes effect, are expected to be much lower due to the very large volume of ethanol that is expected to enter the gasoline market by then.

Overall, we have carefully evaluated the differences between our cost analysis and that provided by API. Except for the differences described above, the assumptions used and the conclusions reached were very similar. We believe our revised analysis provides a more accurate assessment of the costs of the benzene control program.

B. What Are the Vehicle Cost Impacts?

In assessing the economic impact of setting cold temperature emission standards, we have made a best estimate of the necessary vehicle modifications and their associated costs. In making our estimates we have relied on our own technology assessment, which includes information supplied by individual manufacturers and our own in-house testing. Estimated costs typically include variable costs (for hardware and assembly time) and fixed costs (for research and development, retooling, and certification). All costs are presented in 2003 dollars. Full details of our cost analysis can be found in Chapter 8 of the RIA.

As described in section V, we are not expecting hardware changes to Tier 2 vehicles in response to new cold temperature standards. Tier 2 vehicles are already being equipped with very sophisticated emissions control systems. We expect manufacturers to use these systems to minimize emissions at cold temperatures. We were able to demonstrate significant emissions reductions from a Tier 2 vehicle through recalibration alone. In addition, the standard we are finalizing is based on averaging which allows some vehicles to be above the numeric standard as long as those excess emissions are offset by vehicles below the standard. Averaging will help manufacturers in cases where they are not able to achieve the numeric standard for a particular vehicle group, thus helping manufacturers avoid costly hardware changes. The phase-in of standards and emissions credits provisions also help manufacturers avoid situations where expensive vehicle modifications will be needed to meet the new cold temperature NMHC standard. Therefore, we are not projecting hardware costs or additional assembly costs associated with meeting new cold temperature NMHC emissions standards.

Manufacturers will incur research and development (R&D) costs associated with a new cold temperature standard, and some likely will need to upgrade testing facilities to handle an increased number of cold tests during vehicle development. We have estimated the fixed costs associated with R&D and test facilities. We project that manufacturers will recover R&D costs over a five-year

[214] This cost estimate includes an adjustment we made to convert the API capital cost amortization from the after-tax 10 percent rate of return that was the basis for the estimated costs in their report to a before-tax 7 percent rate of return, which is how our rules are estimated.

period and their facilities costs over a ten-year period. Long-term impacts on engine costs are expected to decrease as manufacturers fully amortize their fixed costs. Because manufacturers recoup fixed costs over a large volume of vehicles, average per vehicle costs due to the new cold temperature NMHC standards are expected to be low. We project that the average incremental costs associated with the new cold temperature standards will be less than $1 per vehicle.

We did not receive comments on the methodology we used to derive average cost estimates. However, we did receive comments from one manufacturer with a limited product line who believes new hardware will be needed on its vehicles to meet the new cold temperature standards. Other manufacturers did not comment that hardware changes would be needed, and they generally supported our lead-time, phase-in, and other transitional provisions as providing the flexibility needed to meet the standards. We continue to believe that manufacturers will be able to meet the standards through vehicle development without additional hardware. However, we conducted a sensitivity analysis in response to this comment, assuming the commenter would use new hardware to meet the cold temperature standard. If one percent of new vehicles required additional hardware costing $100–$200 per vehicle, the average cost would increase from less than $1 to the range of $1.60–$2.60 per vehicle. The commenter did not provide cost information in their comments and we believe that the costs used in our sensitivity analysis are conservatively high, given the lead time provided for vehicle development and market pressures to keep costs in line with those of competitors. In any event, we believe the costs associated with the program are reasonable. Additional discussion of the comments received on the vehicle cold temperature standard is provided in Chapter 3 of the Summary and Analysis of Comments for this rule.

We are not anticipating additional costs for the new evaporative emissions standard. As discussed in section V, we expect that manufacturers will continue to produce 50-state evaporative systems that meet LEV II standards. Therefore, harmonizing with California's LEV–II evaporative emission standards will streamline certification and be an ''anti-backsliding'' measure. It also codifies the approach manufacturers have already indicated they are taking for 50-state evaporative systems.

We also estimated annual aggregate costs associated with the new cold temperature emissions standards. These costs are projected to increase with the phase-in of standards and peak in 2014 at about $13.4 million per year, then decrease as the fixed costs are fully amortized. The projected aggregate costs are summarized below, with annual estimates provided in Chapter 8 of the RIA.

TABLE VIII.B–1.—ANNUAL AGGREGATE COSTS

2010	2012	2014	2016	2018	2020
$11,119,000	$12,535,000	$13,406,000	$12,207,000	$10,682,000	$0

C. What Are the PFC Cost Impacts?

For PFCs, we have made a best estimate of the necessary technologies and their associated costs. Estimated costs include variable costs (for hardware and assembly time) and fixed costs (for research and development, retooling, and certification). The analysis also considers fuels savings associated with low emission PFCs. Cost estimates based on the projected technologies represent an expected change in the cost of PFCs as they begin to comply with new emission standards. All costs are presented in 2003 dollars. We did not receive comments on estimated costs for PFCs controls. Full details of our cost analysis, including fuel savings, can be found in Chapter 10 of the RIA.

Table VIII.C–1 summarizes the projected near-term and long-term per unit average costs to meet the new emission standards. Long-term impacts on PFCs are expected to decrease as manufacturers fully amortize their fixed costs. We project that manufacturers will generally recover their fixed costs over a five-year period, so these costs disappear from the analysis after the fifth year of production. These estimates are based on the manufacturing cost rather than predicted price increases.[215] The table also shows our projections of average fuel savings over the life of the PFC when used with gasoline. Fuel savings can be estimated based on the VOC emissions reductions due to controls.

TABLE VIII.C–1.—ESTIMATED AVERAGE PER UNIT PFC COSTS AND LIFETIME FUEL SAVINGS

	Cost
Near-Term Costs	$2.69
Long-Term Costs	1.52
Fuel Savings (NPV)	4.24

With current and projected estimates of PFC sales, we translate these costs into projected direct costs to the nation for the new emission standards in any year. A summary of the annual aggregate costs to manufacturers is presented in Table VIII.C–2. The annual cost savings due to fuel savings start slowly, then increase as greater numbers of compliant PFCs enter the market. Table VIII.C–2 also presents a summary of the estimated annual fuel savings. Aggregate costs are projected to peak in 2013 at about $61 million and then drop to about $34 million once fixed costs are recovered. The change in numbers beyond 2015 occurs due to projected growth in sales and population.

TABLE VIII.C–2.—TOTAL ANNUALIZED COSTS AND FUEL SAVINGS

	2009	2013	2015	2020
Costs	$58,070,000	$60,559,000	$34,004,000	$37,543,000

[215] These costs numbers may not necessarily reflect actual price increases as manufacturer production costs, perceived product enhancements, and other market impacts will affect actual prices to consumers.

TABLE VIII.C–2.—TOTAL ANNUALIZED COSTS AND FUEL SAVINGS—Continued

	2009	2013	2015	2020
Fuel Savings	15,347,000	83,506,000	102,523,000	109,589,000

D. Cost per Ton of Emissions Reduced

We have calculated the cost per ton of HC, benzene, total MSATs, and PM emissions reductions associated with the fuel, vehicle, and PFC programs using the costs described above and the emissions reductions described in section IV. More detail on the costs, emissions reductions, and cost per ton estimates can be found in the RIA. We have calculated the costs per ton using the net present value of the annualized costs of the program, including PFC gasoline fuel savings, from 2009 through 2030 and the net present value of the annual emission reductions through 2030. We have also calculated the cost per ton of emissions reduced in the year 2030 using the annual costs and emissions reductions in that year alone. This number represents the long-term cost per ton of emissions reduced. For fuels, the cost per ton estimates include costs and emission reductions that will occur from all motor vehicles and nonroad engines fueled with gasoline.[216]

For vehicles and PFCs, we are establishing NMHC and HC standards, respectively, which will also reduce benzene and other VOC-based toxics. For vehicles, we are also expecting direct PM reductions due to the NMHC standard.[217] Section IV above provides an overview of how we are estimating benzene and PM reductions resulting from the NMHC standards for vehicles and benzene reductions resulting from the HC standard for PFCs. We have not attempted to apportion costs across these various pollutants for purposes of the cost per ton calculations since there is no distinction in the technologies, or associated costs, used to control the pollutants. Instead, we have calculated costs per ton by assigning all costs to each individual pollutant. If we apportioned costs among the pollutants, the costs per ton presented here would be proportionally lowered depending on what portion of costs were assigned to the various pollutants.

The results for HC for vehicles and PFCs are provided in Table VIII.D–1 using both a three percent and a seven percent social discount rate. Again, this analysis assumes that all costs are assigned to HC control. The discounted cost per ton of HC reduced for the final rule as a whole would be $0 because the gasoline fuel savings from PFCs offsets the costs of PFC and vehicle controls. The table presents these as $0 per ton, rather than calculating a negative value that has no clear meaning. For vehicles in 2030, the cost per ton is $0 because by 2030 all fixed costs have been recovered and there are no variable costs estimated for the new vehicle program.[218]

The cost per ton estimates for each individual program are presented separately in the tables below, and are part of the justification for each of the programs. For informational purposes, we also present the cost per ton for the three programs combined.

TABLE VIII.D–1.—HC AGGREGATE COST PER TON AND LONG-TERM ANNUAL COST PER TON
[$2003]

	Discounted lifetime cost per ton at 3%	Discounted lifetime cost per ton at 7%	Long-Term cost per ton in 2030
Vehicles	$14	$18	$0
PFCs (without fuel savings)	240	270	190
PFCs (with fuel savings)	0	0	0
Combined (with fuel savings)	0	0	0

The cost per ton of benzene reductions for fuels, vehicles, and PFCs are shown in Table VIII.D–2 using the same methodology as noted above for HC. The results are calculated by assigning all costs to benzene control.

TABLE VIII.D–2.—BENZENE AGGREGATE COST PER TON AND LONG-TERM ANNUAL COST PER TON
[$2003]

	Discounted lifetime cost per ton at 3%	Discounted lifetime cost per ton at 7%	Long-term cost per ton in 2030
Fuels	$22,400	$23,100	$22,500
Vehicles	270	360	0
PFCs (without fuels savings)	74,500	82,900	56,200
PFCs (with fuel savings)	0	0	0

[216] The proposed standards do not apply to nonroad engines, since section 202(l) authorizes controls only for ''motor vehicles,'' which term does not include nonroad vehicles (CAA section 216(2)). However, we are reducing benzene in all gasoline, including that used in nonroad equipment. Therefore, we are including both the costs and the benzene emissions reductions associated with the fuel used in nonroad equipment.

[217] Again, although gasoline PM is not a mobile source air toxic, the rule will result in emission reductions of gasoline PM, which reductions are accounted for in our analysis.

[218] We note that in determining whether the new vehicle controls represent the greatest emissions reductions achievable considering costs, we have considered the new cold-start standards separately from any other new control program. Similarly, in considering whether the new controls for PFCs represent the best available control considering economic feasibility, we considered the PFC standards separately from any other new control program.

TABLE VIII.D–2.—BENZENE AGGREGATE COST PER TON AND LONG-TERM ANNUAL COST PER TON—Continued

[$2003]

	Discounted lifetime cost per ton at 3%	Discounted lifetime cost per ton at 7%	Long-term cost per ton in 2030
Combined (with fuel savings)	8,200	8,600	5,900

The cost per ton of reductions of all MSAT reductions for fuels, vehicles, and PFCs are shown in Table VIII.D–3 using the same methodology as noted above for HC and benzene. The results are calculated by assigning all costs to MSAT control.

TABLE VIII.D–3.—MSAT AGGREGATE COST PER TON AND LONG-TERM ANNUAL COST PER TON

[$2003]

	Discounted lifetime cost per ton at 3%	Discounted lifetime cost per ton at 7%	Long-term cost per ton in 2030
Fuels	$22,400	$23,100	$22,500
Vehicles	42	54	0
PFCs (without fuel savings)	2,800	3,100	2,200
PFCs (with fuel savings)	0	0	0
Combined (with fuel savings)	1,700	1,800	1,100

We have also calculated a cost per ton for direct PM reductions for vehicles. Again, this analysis assigns all related costs to direct PM reductions.

TABLE VIII.D–4.—DIRECT PM AGGREGATE COST PER TON AND LONG-TERM ANNUAL COST PER TON

[$2003]

	Discounted lifetime cost per ton at 3%	Discounted lifetime cost per ton at 7%	Long-term cost per ton in 2030
Vehicles	$650	$870	$0

E. Benefits

This section presents our analysis of the health and environmental benefits that will occur as a result of the final standards throughout the period from initial implementation through 2030. In terms of emission benefits, we expect to see significant reductions in mobile source air toxics (MSATs) from the vehicle, fuel and PFC standards; reductions in VOCs (an ozone and $PM_{2.5}$ precursor) from the cold temperature vehicle and PFC standards; and reductions in direct $PM_{2.5}$ from the cold temperature vehicle standards. When translating emission benefits to health effects and monetized values, however, we quantify only the PM-related benefits associated with the cold temperature vehicle standards.

The reductions in $PM_{2.5}$ from the cold temperature vehicle standards will result in significant reductions in premature deaths and other serious human health effects, as well as other important public health and welfare effects. We estimate that in 2030, the benefits we are able to monetize will be approximately $6.3 billion using a 3 percent discount rate and $5.7 billion using a 7 percent discount rate. Total social costs of the entire rule for the same year (2030) are $400 million. Details on the costs of the final standards are in section VIII.F. These estimates, and all monetized benefits presented in this section, are in year 2003 dollars.

The $PM_{2.5}$ benefits are scaled based on relative changes in direct $PM_{2.5}$ emissions between this rule and the proposed Clean Air Nonroad Diesel (CAND) rule.[219] As explained in Section 12.2.1 of the RIA for this rule, the $PM_{2.5}$ benefits scaling approach is limited to those studies, health impacts, and assumptions that were used in the proposed CAND analysis. As a result, PM-related premature mortality is based on the updated analysis of the American Cancer Society cohort (ACS; Pope *et al.*, 2002). However, it is important to note that since the CAND rule, EPA's Office of Air and Radiation (OAR) has adopted a different format for its benefits analyses in which characterization of the uncertainty in the concentration-response function is integrated into the main benefits analysis. This new approach follows the recommendation of NRC's 2002 report ''Estimating the Public Health Benefits of Proposed Air Pollution Regulations'' to begin moving the assessment of uncertainties from its ancillary analyses into its main benefits presentation through the conduct of probabilistic analyses. Within this context, additional data sources are available, including a recent expert elicitation and updated analysis of the Six-Cities Study cohort (Laden *et al.*, 2006). Please see the PM NAAQS RIA for an indication of the sensitivity of our results to use of alternative concentration-response functions.

We also demonstrate that the final standards will reduce cancer and noncancer risk from reduced exposure to MSATs (as described in Section IV of this preamble). However, we do not

[219] Due to time and resource constraints, EPA scaled the final CAND benefits estimates from the benefits estimated for the CAND proposal. The scaling approach used in that analysis, and applied here, is described in the RIA for the final CAND rule.

translate this risk reduction into benefits. We also do not quantify the benefits related to ambient reductions in ozone and $PM_{2.5}$ due to the VOC emission reductions associated with the final standards. The following section describes in more detail why these benefits are not quantified.

1. Unquantified Health and Environmental Benefits

This benefit analysis estimates improvements in health and human welfare that are expected as a result of the final standards, and monetizes those benefits. The benefits will come from reductions in emissions of air toxics (including benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein, naphthalene, and other air toxic pollutants discussed in section III), ambient ozone (as a result of VOC controls), and direct $PM_{2.5}$ emissions.

While there will be benefits associated with air toxic pollutant reductions, notably with regard to reductions in exposure and risk (see section IV), we do not attempt to monetize those benefits. This is primarily because available tools and methods to assess air toxics risk from mobile sources at the national scale are not adequate for extrapolation to incidence estimations or benefits assessment. The best suite of tools and methods currently available for assessment at the national scale are those used in the National-Scale Air Toxics Assessment (NATA; these tools are discussed in Chapter 3 of the RIA). The EPA Science Advisory Board specifically commented in their review of the 1996 NATA that these tools were not yet ready for use in a national-scale benefits analysis, because they did not consider the full distribution of exposure and risk, or address sub-chronic health effects.[220] While EPA has since improved the tools, there remain critical limitations for estimating incidence and assessing benefits of reducing mobile source air toxics. We continue to work to address these limitations, and we are exploring the feasibility of a quantitative benefits assessment for air toxics through a benzene case study as part of the revised study of ''The Benefits and Costs of the Clean Air Act'' (also known as the ''Section 812'' report).[221] In this case study, we are attempting to monetize the benefits of reduced cancer incidence, specifically leukemia, and are not addressing other cancer or noncancer endpoints.

We also do not estimate the monetized benefits of VOC controls in this benefits analysis. Though VOCs will be demonstrably reduced as a result of the cold temperature vehicle standards, we assume that these emissions will not have a measurable impact on ozone formation since the standards will reduce VOC emissions at cold ambient temperatures and ozone formation is primarily a warm ambient temperature issue. The PFC controls will likely result in ozone benefits, though we do not attempt to monetize those benefits. This is primarily due to the magnitude of, and uncertainty associated with, the estimated changes in ambient ozone associated with the final standards. In Section IV.C., we discuss that the ozone modeling conducted for the final PFC standards results in a net reduction in ambient ozone concentrations within the modeled domain (37 Eastern states and the District of Columbia). The net improvement is very small, however, and will likely lead to negligible monetized benefits. Instead, we acknowledge that this analysis may underestimate the benefits associated with reductions in ozone precursor emissions achieved by the various standards. We discuss these benefits qualitatively within the RIA.

The VOC reductions resulting from the cold temperature vehicle standards and PFC standards will also likely reduce secondary $PM_{2.5}$ formation. However, we did not quantify the impacts of these reductions on ambient $PM_{2.5}$ or estimate any resulting benefits. As described further below, we estimated PM benefits by scaling from a previous analysis, and this analysis did not examine the relationship between VOC reductions and ambient PM. As a result, we did not quantify PM benefits associated with this rule's VOC reductions, and we acknowledge that this analysis may therefore underestimate benefits.

Table VIII.E–1 lists each of the MSAT and ozone health and welfare effects that remain unquantified because of current limitations in the methods or available data. This table also includes the PM-related health and welfare effects that also remain unquantified due to current method and data limitations. Chapter 12 of the RIA for the final standards provides a qualitative description of the health and welfare effects not quantified in this analysis.

[220] Science Advisory Board. 2001. NATA—Evaluating the National-Scale Air Toxics Assessment for 1996—an SAB Advisory. *http://www.epa.gov/ttn/atw/sab/sabrev.html.*

[221] The analytic blueprint for the Section 812 benzene case study can be found at *http://www.epa.gov/air/sect812/appendixi51203.pdf.*

TABLE VIII.E–1.—UNQUANTIFIED AND NON-MONETIZED EFFECTS

Pollutant/effects	Effects not included in primary estimates—changes in:
Ozone Health [a]	Premature mortality: short-term exposures [b].
	Hospital admissions: respiratory.
	Emergency room visits for asthma.
	Minor restricted-activity days.
	School loss days.
	Asthma attacks.
	Cardiovascular emergency room visits.
	Acute respiratory symptoms.
	Chronic respiratory damage.
	Premature aging of the lungs.
	Non-asthma respiratory emergency room visits.
	Exposure to UVb (+/-) [e].
Ozone Welfare	Decreased outdoor worker productivity.
	Agricultural yields for
	—commercial forests.
	—some fruits and vegetables.
	—non-commercial crops.
	Damage to urban ornamental plants.
	Impacts on recreational demand from damaged forest aesthetics.
	Ecosystem functions.
	Exposure to UVb (+/-) [e].
PM Health [c]	Premature mortality—short-term exposures [d].
	Low birth weight.
	Pulmonary function.
	Chronic respiratory diseases other than chronic bronchitis.
	Non-asthma respiratory emergency room visits.
	Exposure to UVb (+/-) [e].
PM Welfare	Visibility in many Class I areas.
	Residential and recreational visibility in non-Class I areas.
	Soiling and materials damage.
	Damage to ecosystem functions.
	Exposure to UVb (+/-) [e].
MSAT Health [f]	Cancer (benzene, 1,3-butadiene, formaldehyde, acetaldehyde, naphthalene).
	Anemia (benzene).
	Disruption of production of blood components (benzene).
	Reduction in the number of blood platelets (benzene).
	Excessive bone marrow formation (benzene).
	Depression of lymphocyte counts (benzene).
	Reproductive and developmental effects (1,3-butadiene).

TABLE VIII.E–1.—UNQUANTIFIED AND NON-MONETIZED EFFECTS—Continued

Pollutant/effects	Effects not included in primary estimates—changes in:
	Irritation of eyes and mucus membranes (formaldehyde).
	Respiratory irritation (formaldehyde).
	Asthma attacks in asthmatics (formaldehyde).
	Asthma-like symptoms in non-asthmatics (formaldehyde).
	Irritation of the eyes, skin, and respiratory tract (acetaldehyde).
	Upper respiratory tract irritation and congestion (acrolein).
	Neurotoxicity (n-hexane, toluene, xylenes).
MSAT Welfare [f].	Direct toxic effects to animals.
	Bioaccumulation in the food chain.
	Damage to ecosystem function.
	Odor.

[a] In addition to primary economic endpoints, there are a number of biological responses that have been associated with ozone health effects including increased airway responsiveness to stimuli, inflammation in the lung, acute inflammation and respiratory cell damage, and increased susceptibility to respiratory infection.

[b] Recent analyses provide evidence that short-term ozone exposure is associated with increased premature mortality. As a result, EPA is considering how to incorporate ozone mortality benefits into its benefits analyses as a separate estimate of the number of premature deaths that would be avoided due to reductions in ozone levels.

[c] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[d] While some of the effects of short-term exposures are likely to be captured in the estimates, there may be premature mortality due to short-term exposure to PM not captured in the cohort study upon which the primary analysis is based. However, the PM mortality results derived from the expert elicitation do take into account premature mortality effects of short-term exposures.

[e] May result in benefits or disbenefits.

[f] The categorization of unquantified toxic health and welfare effects is not exhaustive.

2. Quantified Human Health and Environmental Effects of the Final Cold Temperature Vehicle Standard

In this section we discuss the benefits of the final cold temperature vehicle standard related to reductions in directly emitted $PM_{2.5}$. To estimate $PM_{2.5}$ benefits, we rely on a benefits transfer technique. The benefits transfer approach uses as its foundation the relationship between emission reductions and ambient $PM_{2.5}$ concentrations modeled across the contiguous 48 states (and DC) for the Clean Air Nonroad Diesel (CAND) proposal.[222] For a given future year, we first calculate the ratio between CAND direct $PM_{2.5}$ emission reductions and direct $PM_{2.5}$ emission reductions associated with the final cold temperature vehicle control standard (cold temperature vehicle emission reductions/CAND emission reductions). We multiply this ratio by the percent that direct $PM_{2.5}$ contributes towards population-weighted reductions in total $PM_{2.5}$ due to the CAND standards. This calculation results in a ''benefits apportionment factor'' for the relationship between direct PM emissions and primary $PM_{2.5}$, which is then applied to the BenMAP-based incidence and monetized benefits from the CAND proposal. In this way, we apportion the results of the proposed CAND analysis to its underlying direct PM emission reductions and scale the apportioned benefits to reflect differences in emission reductions between the two rules.[223] This benefits transfer method is consistent with the approach used in other recent mobile and stationary source rules.[224]

Table VIII.E–2 presents the estimates of reduced incidence of $PM_{2.5}$-related health effects for the years 2020 and 2030 for the final cold temperature vehicle control strategies. In 2030, we estimate that $PM_{2.5}$-related annual benefits will result in approximately 880 fewer premature fatalities, 600 fewer cases of chronic bronchitis, 1,600 fewer non-fatal heart attacks, and 900 fewer hospitalizations (for respiratory and cardiovascular disease combined). In addition, we estimate that the emission controls will reduce days of restricted activity due to respiratory illness by about 600,000 days and reduce work-loss days by about 100,000 days. We also estimate substantial health improvements for children from reduced upper and lower respiratory illness, acute bronchitis, and asthma attacks.

It is important to note that since the CAND rule, EPA's Office of Air and Radiation (OAR) has adopted a different format for its benefits analysis in which characterization of the uncertainty in the concentration-response function is integrated into the main benefits analysis. Within this context, additional data sources are available, including a recent PM-related premature mortality expert elicitation and updated analysis of the Six-Cities Study cohort (Laden et al., 2006). Please see the PM NAAQS RIA for an indication of the sensitivity of our results to use of alternative concentration-response functions.

TABLE VIII.E–2.—ESTIMATED ANNUAL REDUCTIONS IN INCIDENCE OF HEALTH EFFECTS RELATED TO THE FINAL COLD TEMPERATURE VEHICLE STANDARD [A]

Health effect	2020 Annual incidence reduction	2030 Annual incidence reduction
PM-Related Endpoints:		
Premature Mortality [b] Adult, age 30+ and Infant, age <1 year	480	880

[222] See 68 FR 28327, May 23, 2003.

[223] Note that while the final regulations also control VOCs, which contribute to PM formation, the benefits transfer scaling approach only scales benefits based on NO_X, SO_2, and direct PM emission reductions. PM benefits will likely be underestimated as a result, though we are unable to estimate the magnitude of the underestimation.

[224] See: Clean Air Nonroad Diesel final rule (69 FR 38958, June 29, 2004); Nonroad Large Spark-Ignition Engines and Recreational Engines standards (67 FR 68241, November 8, 2002); Final Industrial Boilers and Process Heaters NESHAP (69 FR 55217, September 13, 2004); Final Reciprocating Internal Combustion Engines NESHAP (69 FR 33473, June 15, 2004); Final Clean Air Visibility Rule (EPA–452/R–05–004, June 15, 2005); Ozone Implementation Rule (documentation forthcoming).

[225] Pope, C.A., III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston. 2002. ''Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution.'' Journal of American Medical Association 287:1132–1141.

[226] Woodruff, T.J., J. Grillo, and K.C. Schoendorf. 1997. ''The Relationship Between Selected Causes of Postneonatal Infant Mortality and Particulate Infant Mortality and Particulate Air Pollution in the United States.'' Environmental Health Perspectives 105(6):608–612.

TABLE VIII.E–2.—ESTIMATED ANNUAL REDUCTIONS IN INCIDENCE OF HEALTH EFFECTS RELATED TO THE FINAL COLD TEMPERATURE VEHICLE STANDARD [A]—Continued

Health effect	2020 Annual incidence reduction	2030 Annual incidence reduction
Chronic bronchitis (adult, age 26 and over)	330	570
Non-fatal myocardial infarction (adult, age 18 and over)	810	1,600
Hospital admissions—respiratory (all ages) [c]	260	530
Hospital admissions—cardiovascular (adults, age >18) [d]	210	390
Emergency room visits for asthma (age 18 years and younger)	350	610
Acute bronchitis, (children, age 8–12)	780	1,400
Lower respiratory symptoms (children, age 7–14)	9,300	16,000
Upper respiratory symptoms (asthmatic children, age 9–18)	7,000	12,000
Asthma exacerbation (asthmatic children, age 6–18)	12,000	20,000
Work loss days	62,000	100,000
Minor restricted activity days (adults age 18–65)	370,000	600,000

[a] Incidence is rounded to two significant digits. Estimates represent benefits from the final rule nationwide, excluding Alaska and Hawaii.
[b] PM-related adult mortality based upon the ACS cohort study (Pope et al., 2002).[225] PM-related infant mortality based upon studies by Woodruff, Grillo, and Schoendorf, 1997.[226] Due to analytical constraints associated with the PM benefits scaling approach, we are unable to present the premature mortality impacts associated with the recent Six-Cities study (Laden et al., 2006) or the impacts associated with the recent PM-related premature mortality expert elicitation (IEc, 2006). Chapter 12.6 of the RIA discusses the implications these new studies have on the benefits estimated for the final rule.
[c] Respiratory hospital admissions for PM include admissions for chronic obstructive pulmonary disease (COPD), pneumonia and asthma.
[d] Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

$PM_{2.5}$ also has numerous documented effects on environmental quality that affect human welfare. These welfare effects include direct damages to property, either through impacts on material structures or by soiling of surfaces, and indirect economic damages through the loss in value of recreational visibility or the existence value of important resources. Additional information about these welfare effects can be found in Chapter 12 of the Regulatory Impact Analysis.

3. Monetized Benefits

Table VIII.E–3 presents the estimated monetary value of reductions in the incidence of those health effects we are able to monetize for the final cold temperature vehicle standard. Total annual PM-related health benefits are estimated to be approximately $6.3 or $5.7 billion in 2030 (3 percent and 7 percent discount rate, respectively). These estimates account for growth in real gross domestic product (GDP) per capita between the present and 2030.

Table VIII.E–3 indicates with a ''B'' those additional health and environmental benefits of the rule that we are unable to quantify or monetize. These effects are additive to the estimate of total benefits, and are related to the following sources:

- There are many human health and welfare effects associated with PM, ozone, and toxic air pollutant reductions that remain unquantified because of current limitations in the methods or available data. A listing of the benefit categories that could not be quantified or monetized in our benefit estimates are provided in Table VIII.E–1.
- The $PM_{2.5}$ benefits scaled transfer approach, derived from the Clean Air Nonroad Diesel rule, does not account for VOCs as precursors to ambient $PM_{2.5}$ formation. To the extent that VOC emission reductions associated with the final regulations contribute to reductions in ambient $PM_{2.5}$, this analysis does not capture the related health and environmental benefits of those changes.
- The PM air quality model only captures the benefits of air quality improvements in the 48 states and DC; PM benefits for Alaska and Hawaii are not reflected in the estimate of benefits.

TABLE VIII.E–3.—ESTIMATED ANNUAL MONETARY VALUE OF REDUCTIONS IN INCIDENCE OF HEALTH AND WELFARE EFFECTS RELATED TO THE FINAL COLD TEMPERATURE VEHICLE STANDARD

(Millions of 2003$) [a,b]

Health effect	Pollutant	2020 estimated value of reductions	2030 estimated value of reductions
PM-Related Premature mortality [c,d] Adult, 30+ years and Infant, <1 year:			
3 percent discount rate	$PM_{2.5}$	$3,100	$5,800
7 percent discount rate		2,800	5,200
Chronic bronchitis (adults, 26 and over)	$PM_{2.5}$	150	260
Non-fatal acute myocardial infarctions:			
3 percent discount rate		79	150
7 percent discount rate	$PM_{2.5}$	76	140
Hospital admissions for respiratory causes	$PM_{2.5}$	4.7	10
Hospital admissions for cardiovascular causes	$PM_{2.5}$	5.0	9.1
Emergency room visits for asthma	$PM_{2.5}$	0.11	0.20
Acute bronchitis (children, age 8–12)	$PM_{2.5}$	0.32	0.56
Lower respiratory symptoms (children, age 7–14)	$PM_{2.5}$	0.16	0.29
Upper respiratory symptoms (asthma, age 9–11)	$PM_{2.5}$	0.20	0.35
Asthma exacerbations	$PM_{2.5}$	0.56	1.0

TABLE VIII.E–3.—ESTIMATED ANNUAL MONETARY VALUE OF REDUCTIONS IN INCIDENCE OF HEALTH AND WELFARE EFFECTS RELATED TO THE FINAL COLD TEMPERATURE VEHICLE STANDARD—Continued

(Millions of 2003$) [a,b]

Health effect	Pollutant	2020 estimated value of reductions	2030 estimated value of reductions
Work loss days	$PM_{2.5}$	9.1	14
Minor restricted activity days (MRADs)	$PM_{2.5}$	21	35
Monetized Total[e]			
Base estimate:			
3 percent discount rate	$PM_{2.5}$	3,300+ B	6,300+ B
7 percent discount rate		3,000+ B	5,700+ B

[a] Dollars are rounded to two significant digits. The PM estimates represent benefits from the final rule across the contiguous United States.

[b] Monetary benefits adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2020 or 2030).

[c] Valuation of premature mortality based on long-term PM exposure assumes discounting over the SAB recommended 20-year segmented lag structure described in the Regulatory Impact Analysis for the Final Clean Air Interstate Rule (March 2005). Results show 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (US EPA, 2000 and OMB, 2003).[227,228]

[d] Adult mortality based upon the ACS cohort study (Pope et al., 2002). Infant mortality based upon studies by Woodruff, Grillo, and Schoendorf, 1997. Due to analytical constraints associated with the PM benefits scaling approach, we are unable to present the premature mortality impacts associated with the recent Six-Cities study (Laden et al., 2006) study or the impacts associated with the recent PM-related premature mortality expert elicitation (IEc, 2006). Chapter 12.6 of the RIA discusses the implications these new studies have on the benefits estimated for the final rule.

[e] B represents the monetary value of health and welfare benefits not monetized. A detailed listing is provided in Table VIII.E–1.

4. What Are the Significant Limitations of the Benefit Analysis?

The most significant limitation of this analysis is our inability to quantify a number of potentially significant benefit categories associated with improvements in air quality that would result from the final standards. Most notably, we are unable to estimate the benefits from reduced air toxics exposures because the available tools and methods to assess mobile source air toxics risk at the national scale are not adequate for extrapolation to incidence estimations or benefits assessment. We also do not quantify ozone benefits associated with the final PFC standards, despite the fact that there are net benefits, when population-weighted, in the ozone design value metric across the modeled domain (see section IV.C). We do not quantify these benefits because of their magnitude and the uncertainty associated with them.

More generally, every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Deficiencies in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects. Deficiencies in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes which can be quantified. These general uncertainties in the underlying scientific and economics literature, which can cause the valuations to be higher or lower, are discussed in detail in the RIA and its supporting references. Key uncertainties that have a bearing on the results of the benefit-cost analysis of the final standards include the following:

- The exclusion of potentially significant and unquantified benefit categories (such as health, odor, and ecological benefits of reduction in air toxics, ozone, and PM);
- Errors in measurement and projection for variables such as population growth;
- Uncertainties in the estimation of future year emissions inventories and air quality;
- Uncertainties associated with the scaling of the PM results of the modeled benefits analysis to the final standards, especially regarding the assumption of similarity in geographic distribution between emissions and human populations and years of analysis;
- Uncertainty in the estimated relationships of health and welfare effects to changes in pollutant concentrations including the shape of the C–R function, the size of the effect estimates, and the relative toxicity of the many components of the PM mixture;
- Uncertainties in exposure estimation; and
- Uncertainties associated with the effect of potential future actions to limit emissions.

As Table VIII.E–3 indicates, total benefits are driven primarily by the reduction in premature fatalities each year. Elaborating on the list of uncertainties above, some key assumptions underlying the primary estimate for the premature mortality category include the following:

1. Inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Although biological mechanisms for this effect have not yet been completely established, the weight of the available epidemiological, toxicological, and experimental evidence supports an assumption of causality. The impacts of including a probabilistic representation of causality were explored in the expert elicitation-based results of the recently published PM NAAQS RIA. Because the analysis of the final cold temperature vehicle standard is constrained to the studies included in the CAND PM benefits scaling approach, we are unable to conduct the same analysis of expert elicitation-based mortality incidence for the final standards.[229] However, we qualitatively describe the expert elicitation-based mortality results associated with the final PM NAAQS to provide an indication of the sensitivity of our PM-related premature mortality results to use of alternative

[227] U.S. Environmental Protection Agency, 2000, Guidelines for Preparing Economic Analyses. *http://yosemite.epa.gov/ee/epa/eed.nsf/webpages/Guidelines.html.*

[228] Office of Management and Budget, The Executive Office of the President, 2003. Circular A–4. *http://www.whitehouse.gov/omb/circlars.*

[229] The scaling approach relies on the incidence and valuation estimates derived from the studies available at the time of the CAND analysis. Incidence estimates and monetized benefits derived from new information, including mortality derived from the full expert elicitation, are not available for scaling. Please refer to section 2 of this preamble and Chapter 12 of the RIA for more information about the benefits scaling approach.

concentration-response functions. We present this discussion in the RIA.

2. Since the publication of CAIR and CAND, a follow up to the Harvard Six-Cities study on premature mortality was published (Laden et al., 2006 based on Dockery et al., 1993),[230, 231] which both confirmed the effect size from the first study and provided additional evidence that reductions in $PM_{2.5}$ directly result in reductions in the risk of premature death. The impacts of including this study in the primary analysis were explored in the results of the recently published PM NAAQS RIA. Because the analysis of the final cold temperature vehicle standard is constrained to the studies included in the CAND PM benefits scaling approach, we are unable to characterize PM-related mortality based on Laden *et al.* However, we discuss the implications of these results in the RIA for the final standards.

3. All fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM produced via transported precursors emitted from vehicles at cold temperatures may differ significantly from PM precursors released from electric generating units and other industrial sources. However, no clear scientific grounds exist for supporting differential effects estimates by particle type.

4. The concentration-response function for fine particles is approximately linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM, including both regions that may be in attainment with $PM_{2.5}$ standards and those that are at risk of not meeting the standards.

Taking into account these uncertainties, we believe this benefit-cost analysis provides a conservative estimate of the expected economic benefits of the final standards for cold temperature vehicle control in future years because of the exclusion of potentially significant benefit categories. Acknowledging benefits omissions and uncertainties, we present a best estimate of the total benefits based on our interpretation of the best available scientific literature and methods. Furthermore, our analysis reflects many methodological improvements that were incorporated into the analysis of the final Clean Air Interstate Rule (CAIR), including a revised value of a statistical life, a revised baseline rate of future mortality, and a revised mortality lag assumption. Details of these improvements can be found in the RIA for this rule and in the final CAIR rule RIA.[232] Once again, however, it should be noted that since the CAIR rule, EPA's Office of Air and Radiation (OAR) has adopted a different format for its benefits analysis in which characterization of uncertainty is integrated into the main benefits analysis. Please see the PM NAAQS RIA for an indication of the uncertainty present in the base estimate of benefits and the sensitivity of our results to the use of alternative concentration-response functions.

In contrast to the additional benefits of the final standards discussed above, it is also possible that this rule will result in disbenefits in some areas of the United States. The effects of ozone and PM on radiative transfer in the atmosphere can lead to effects of uncertain magnitude and direction on the penetration of ultraviolet light and climate. Ground level ozone makes up a small percentage of total atmospheric ozone (including the stratospheric layer) that attenuates penetration of ultraviolet—b (UVb) radiation to the ground. EPA's past evaluation of the information indicates that potential disbenefits would be small, variable, and with too many uncertainties to attempt quantification of relatively small changes in average ozone levels over the course of a year.[233] EPA's most recent provisional assessment of the currently available information indicates that potential but unquantifiable benefits may also arise from ozone-related attenuation of UVb radiation.[234] In addition, EPA believes that we are unable to quantify any net climate-related disbenefit or benefit associated with the combined ozone and PM reductions in this rule.

5. How Do the Benefits Compare to the Costs of The Final Standards?

The final rule provides three separate provisions that reduce air toxics emissions from mobile sources: cold temperature vehicle controls, a PFC emissions control program, and a control program limiting benzene in gasoline. A full appreciation of the overall economic consequences of these provisions requires consideration of the benefits and costs expected to result from each standard, not just those that could be expressed here in dollar terms. As noted above, due to limitations in data availability and analytical methods, our benefits analysis only monetizes the $PM_{2.5}$ benefits from direct PM emission reductions associated with the cold temperature standards. There are a number of health and environmental effects associated with the final standards that we were unable to quantify or monetize (see Table VIII.E–1).

Table VIII.E–4 contains the estimates of monetized benefits of the final cold temperature vehicle standards only and estimated social welfare costs for all of the final control programs.[235] The annual social welfare costs of all provisions of the final rule are described more fully in Section VIII.F. It should be noted that the estimated social welfare costs for the vehicle program contained in this table are for 2019. The 2019 vehicle program costs are included for comparison purposes only and are therefore not included in the total 2020 social costs. There are no compliance costs associated with the vehicle program after 2019; as explained elsewhere in this preamble, the vehicle compliance costs are primarily R&D and facilities costs that are expected to be recovered by manufacturers over the first ten years of the program.

The results in Table VIII.E–4 suggest that the 2020 monetized benefits of the cold temperature vehicle standards are greater than the expected social welfare costs of that program in 2019. Specifically, the annual benefits of the program will be approximately $3,300 + B million or $3,000 + B million annually in 2020 (using a 3 percent and 7 percent discount rate in the benefits analysis, respectively), compared to estimated social welfare costs of approximately $10.6 million in the last year of the program (2019). These benefits are expected to increase to $6,300 + B million or $5,700 + B million annually in 2030 (using a 3 percent and

[230] Laden, F., J. Schwartz, F.E. Speizer, and D.W. Dockery. 2006. Reduction in Fine Particulate Air Pollution and Mortality. American Journal of Respiratory and Critical Care Medicine. 173: 667–672.

[231] Dockery, D.W., C.A. Pope, X.P. Xu, J.D. Spengler, J.H. Ware, M.E. Fay, B.G. Ferris, and F.E. Speizer. 1993. ''An Association between Air Pollution and Mortality in Six U.S. Cities.'' New England Journal of Medicine 329(24):1753–1759.

[232] See Chapter 4 of the Final Clean Air Interstate Rule RIA (*http://www.epa.gov/cair*) for a discussion of EPA's ongoing efforts to address the NAS recommendations in its regulatory analyses.

[233] EPA, 2005. Air Quality Criteria for Ozone and Related Photochemical Oxidants (First External Review Draft). January. *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=114523.*

[234] EPA, 2005. Air Quality Criteria for Ozone and Related Photochemical Oxidants (Second External Review Draft). August. *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=137307.*

[235] Social costs represent the welfare costs of the rule to society. These social costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth.

7 percent discount rate in the benefits analysis, respectively), even as the social welfare costs of that program fall to zero. Table VIII.E–4 also presents the costs of the other rule provisions: a PFC emissions control program and a control program limiting benzene in gasoline. Though we are unable to present the benefits associated with these two programs, the benefits associated with the final cold temperature vehicle standards alone outweigh the costs of all three rule provisions combined.

TABLE VIII.E–4.—SUMMARY OF ANNUAL BENEFITS OF THE FINAL COLD TEMPERATURE VEHICLE STANDARDS AND COSTS OF ALL PROVISIONS OF THE FINAL STANDARDS [a]

[Millions of 2003 dollars]

Description	2020 (Millions of 2003 dollars)	2030 (Millions of 2003 dollars)
Estimated Social Welfare Costs [b]		
Cold Temperature Vehicle Standards	$10.6 [c]	$0
PFC Standards	$37.5	$45.7
Fuel Standards [d]	$402.6	$445.8
Total	$440.1	$491.5
Fuel Savings	−$80.7	−$91.5
Net Social Welfare Costs	$359.4	$400.0
Total $PM_{2.5}$-Related Health Benefits of the Cold Temperature Vehicle Standards [e]		
3 percent discount rate	$3,300 + B [f]	$6,300 + B [f]
7 percent discount rate	$3,000 + B [f]	$5,700 + B [f]

[a] All estimates are rounded to two significant digits and represent annualized benefits and costs anticipated for the years 2020 and 2030, except where noted. Totals may not sum due to rounding.

[b] Note that costs are the annual costs of reducing all pollutants associated with each provision of the final MSAT control package in 2020 and 2030 (unless otherwise noted). To estimate fixed costs associated with the vehicle standards, we use a 7 percent average before-tax rate of return over 5 years to amortize the capital fixed costs. For the fuel standards, we use a 7 percent before-tax rate of return over 15 years to amortize the capital costs. Note that by 2020, PFC container standard costs are only variable and do not use a rate of return assumption. See Chapters 8 and 9 for discussion of the vehicle and fuel standard costs, respectively. In Chapter 13, however, we do use both a 3 percent and 7 percent social discount rate to calculate the net present value of total social costs consistent with EPA and OMB guidelines for preparing economic analyses (US EPA, 2000 and OMB, 2003).[236, 237]

[c] These costs are for 2019; the vehicle program compliance costs terminate after 2019 and are included for illustrative purposes. They are not included in the total social welfare cost sum for 2020.

[d] Our modeling for the total costs of the proposed gasoline benzene program included participation by California refineries (achieving benzene reductions below the 0.62 proposed benzene standard—thus generating credits), since it was completed before we decided that California gasoline would not be covered by the program. For the final rule, we exclude California refineries from the analysis. By excluding California refineries, other higher cost refineries will have to comply in their place, slightly increasing the costs for the program.

[e] Annual benefits reflect only direct PM reductions associated with the cold temperature vehicle standards. Annual benefits analysis results reflect the use of a 3 percent and 7 percent discount rate in the valuation of premature mortality and nonfatal myocardial infarctions, consistent with EPA and OMB guidelines for preparing economic analyses (US EPA, 2000 and OMB, 2003). Valuation of premature mortality based on long-term PM exposure assumes discounting over the SAB recommended 20-year segmented lag structure described in the Regulatory Impact Analysis for the Final Clean Air Interstate Rule (March 2005). Valuation of nonfatal myocardial infarctions (MI) assumes discounting over a 5-year period, reflecting lost earnings and direct medical costs following a nonfatal MI. Note that we do not calculate a net present value of benefits associated with the cold temperature vehicle standards.

[f] Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential benefit categories that have not been quantified and monetized are listed in Table VIII.E–1.

F. Economic Impact Analysis

We prepared an Economic Impact Analysis (EIA) to estimate the economic impacts of this rule on the portable fuel container (PFC), gasoline fuel, and light-duty vehicle markets. In this section we briefly describe the Economic Impact Model (EIM) we developed to estimate both the market-level changes in price and outputs for affected markets and the social costs of the program and their distribution across affected stakeholders. We also present the results of our analysis.

We estimate the net social costs of the program to be about $359.4 million in 2020. This estimate reflects the estimated costs associated with compliance with the gasoline, PFC, and vehicle controls and the expected gasoline fuel savings from better evaporative controls on PFCs. The results of the economic impact modeling performed for the gasoline fuel and PFC control programs suggest that the social costs of those two programs are expected to be about $440.1 million in 2020, with consumers of these products expected to bear about 58.4 percent of these costs. We estimate gasoline fuel savings of about $80.7 million in 2020, which will accrue to consumers. There are no social costs associated with the vehicle program in 2020 (these accrue only in the 10-year period from 2010 through 2019). These estimates, and all costs presented in this section, are in year 2003 dollars.

With regard to market-level impacts in 2020, the maximum price increase for gasoline fuel is expected to be about 0.3 percent (0.5 cents per gallon), for PADD 5. The price of PFCs is expected to increase by about 1.9 percent ($0.20 per can) in areas that already have PFC requirements and 32.5 percent ($1.52 per can) in areas that do not.

Detailed descriptions of the EIM, the model inputs, modeling results, and several sensitivity analyses can be found in Chapter 13 of the Regulatory Impact Analysis prepared for this rule.

1. What Is an Economic Impact Analysis?

An Economic Impact Analysis (EIA) is prepared to inform decision makers about the potential economic consequences of a regulatory action. The analysis consists of estimating the social costs of a regulatory program and the distribution of these costs across stakeholders. These estimated social costs can then be compared with estimated social benefits (as presented

[236] U.S. Environmental Protection Agency, 2000. Guidelines for Preparing Economic Analyses. *http://yosemite.epa.gov/ee/epa/eed.nsf/webpages/Guidelines.html*.

[237] Office of Management and Budget, The Executive Office of the President, 2003. Circular A–4. *http://www.whitehouse.gov/omb/circulars*.

in Section VIII.E). As defined in EPA's Guidelines for Preparing Economic Analyses, social costs are the value of the goods and services lost by society resulting from a) the use of resources to comply with and implement a regulation and b) reductions in output.[238] In this analysis, social costs are explored in two steps. In the market analysis, we estimate how prices and quantities of goods affected by the emission control program can be expected to change once the program goes into effect. In the economic welfare analysis, we look at the total social costs associated with the program and their distribution across stakeholders.

2. What Is the Economic Impact Model?

The Economic Impact Model (EIM) is a behavioral model developed to estimate price and quantity changes and total social costs associated with the emission controls set out in this rule. The EIM simulates how producers and consumers of affected products can be expected to respond to an increase in production costs associated with compliance with the emission control program. In this EIM, compliance costs are directly borne by producers of affected goods. Depending on the producers' and consumers' sensitivity to price changes, producers may be able to pass some or all of these compliance costs on to the consumers of these goods in the form of higher prices. Consumers adjust their consumption of affected goods in response to these price changes. This information is passed back to the producers in the form of purchasing decisions. The EIM takes these behavioral responses into account to estimate new market equilibrium quantities and prices for all modeled sectors and the resulting distribution of social costs across these stakeholders (producers and consumers).

3. What Economic Sectors Are Included in this Economic Impact Analysis?

There are three economic sectors affected by the control programs described in this rule: PFCs, gasoline fuel, and light-duty vehicles. In this Economic Impact Analysis we model only the impacts on the PFC and gasoline fuel markets. We did not model the impacts on the light-duty vehicle market. This is because the compliance costs for the vehicle program are expected to be very small, less than $1 per vehicle and, even if passed on entirely, are unlikely to affect producer or consumer behavior. Therefore, we do not expect these controls to affect the quantity of vehicles produced or their prices. At the same time, however, the light-duty vehicle compliance costs are a cost to society and should be included in the economic welfare analysis. We do this by adding the vehicle program engineering compliance cost estimates to the estimated social costs of the gasoline and PFC programs.

With regard to the gasoline fuel and PFC markets, we model the impacts on residential users of these products. This means that we focus the analysis on the use of these products for personal transportation (gasoline fuel) or residential lawns and garden care or recreational uses (PFCs) and do not separately model how the costs of complying with the standards may affect the production of goods and services that use gasoline fuel or PFCs as production inputs. We believe this approach is reasonable because the commercial share of the end-user markets for both gasoline fuel and PFCs is relatively small.[239, 240] In addition, for most commercial users the share of the cost of these products to total production costs is also small (e.g., the cost of a PFC is only a very small part of the total production costs for an agricultural or construction firm). Therefore, a price increase of the magnitude anticipated for this control program is not expected to have a noticeable impact on prices or quantities of goods produced using these inputs (e.g., agricultural product or buildings).

With regard to the gasoline fuel analysis, it should be noted that this EIA does not include California fuels in the market analysis. California currently has state-level controls that address air toxics from gasoline. Also, consistent with the cost analysis, the economic impact analysis does not distinguish between reformulated and conventional gasoline fuels.

The EIM models the economic impacts on two PFC markets (states that currently have requirements for PFCs and those that do not), and four gasoline fuel markets (PADDs 1+3, PADD 2, PADD 4, PADD 5). The markets included in this EIA are described in more detail in Chapter 13 of the RIA for this rule.

In the EIM, the gasoline fuel and PFC markets are not linked (there is no feedback mechanism between the PFC and gasoline fuel model segments). This is because these two sectors represent different aspects of fuel consumption (fuel storage and fuel production) and production and consumption of PFCs is not expected to have an impact on the production and supply of gasoline, and vice versa. Production and consumption of each of these products are the result of other factors that have little cross-over impacts (the need for fuel storage; the need for personal transportation).

4. What Are the Key Features of the Economic Impact Model?

A detailed description of the features of the EIM and the data used in the analysis is provided in Chapter 13 of the RIA prepared for this rule. The model methodology is firmly rooted in applied microeconomic theory and was developed following the methodology set out in the OAQPS's Economic Analysis Resource Document.[241]

The EIM is a computer model comprised of a series of spreadsheet modules that simulate the supply and demand characteristics of the affected markets. The initial market equilibrium conditions are shocked by applying the compliance costs for the control program to the supply side of the markets (this is done by shifting the relevant supply curves by the amount of the compliance costs). The model equations can be analytically solved for equilibrium prices and quantities for the markets with the regulatory program and these new prices and quantities are used to estimate the social costs of the model and how those costs are shared among affected markets.

The EIM is a partial equilibrium, intermediate-run model that assumes perfect competition in the relevant markets. As explained in EPA's Guidelines for Preparing Economic Analyses, ''partial equilibrium'' means that the model considers markets in

[238] EPA Guidelines for Preparing Economic Analyses, EPA 240–R–00–003, September 2000, p 113. A copy of this document can be found at *http://yosemite.epa.gov/ee/epa/eed.nsf/webpages/Guidelines.html#download.*

[239] The U.S Department of Energy estimates that about 92 percent of gasoline used in the United States for transportation is used in light-duty vehicles. About 6 percent is used for commercial or industrial transportation, and the remaining 2 percent is used in recreational marine vessels. See U.S Department of Energy, Energy Information Administration, 2004. ''Annual Energy Outlook 2004 with projections to 2025.'' Last updated June 2, 2004. Table A–2 and Supplemental Table 34. *http://www.eia.doe.gov/oiaf/aeoref_tab.html.*

[240] A recent study by CARB (1999) found that 94 percent of portable fuel containers in California were used by residential households California Environmental Protection Agency, Air Resources Board (CARB) 1999. See ''Hearing Notice and Staff Report, Initial Statement of Reasons for Proposed Rule Making Public Hearing to Consider the Adoption of Portable Fuel Container Spillage Control Regulation.'' Sacrament, CA: California Environmental Protection Agency, Air Resources Board (CARB). A copy of this document is available at *http://www.arb.ca.gov/regact/spillcon/isor.pdf.*

[241] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Innovative Strategies and Economics Group, OAQPS Economic Analysis Resource Document, April 1999. A copy of this document can be found at *http://www.epa.gov/ttn/ecas/econdata/Rmanual2/.*

isolation and that conditions in other markets are assumed either to be unaffected by a policy or unimportant for social cost estimation.[242] The use of the intermediate run means that some factors of production are fixed and some are variable. In very short analyses, all factors of production would be assumed to be fixed, leaving the producers with no means to respond to the increased production costs associated with the regulation (e.g., they cannot adjust labor or capital inputs). Under this time horizon, the costs of the regulation fall entirely on the producer. In the long run, all factors of production are variable and producers can adjust production in response to cost changes imposed by the regulation (e.g., using a different labor/capital mix). In the intermediate run there is some resource immobility which may cause producers to suffer producer surplus losses, but they can also pass some of the compliance costs to consumers.

The perfect competition assumption is widely accepted economic practice for this type of analysis, and only in rare cases are other approaches used.[243] It should be noted that the perfect competition assumption is not primarily about the number of firms in a market. It is about how the market operates: the nature of the competition among firms. Indicators that allow us to assume perfect competition include absence of barriers to entry, absence of strategic behavior among firms in the market, and product differentiation.

With regard to the fuel market, the Federal Trade Commission (FTC) has developed an approach to ensure competitiveness in gasoline fuel markets. It reviews oil company mergers and frequently requires divestiture of refineries, terminals, and gas stations to maintain a minimum level of competition. This is discussed in more detail in the industry profile prepared for this rule.[244]

With regard to the PFC market, the small number of firms in the market is offset by several features of this market. Because PFCs are compact and lightweight, they are easy to transport far from their place of manufacture. This means that production is not limited to local producers. Although they vary by size and material, consumers are likely to view all PFCs designed for storing a particular fuel (gasoline, diesel fuel, kerosene) as good substitutes for the storage of that particular fuel. Because the products are similar enough to be considered homogeneous (*e.g.*, perfectly substitutable), consumers can shift their purchases from one manufacturer to another. There are only minimal technical barriers to entry that would prevent new firms from freely entering the market, since manufacturing is based on well-known plastic processing methods. In addition, there is significant excess capacity, enabling competitors to respond quickly to changes in price. Excess production capacity in the general container manufacturing market also means that manufacturers could potentially switch their product lines to compete in this segment of the market, often without a significant investment. In addition, there is no evidence of high levels of strategic behavior in the price and quantity decisions of the firms. Finally, it should be noted that contestable market theory asserts that oligopolies and even monopolies will behave very much like firms in a competitive market if manufacturers have extra production capacity and this capacity could allow them to enter the market costlessly (*i.e.*, there are no sunk costs associated with this kind of market entry or exit).[245] As a result of all of these conditions, producers and consumers in the PFC market are expected to take the market price as given when making their production and consumption choices and the market can be modeled as a competitive market even though the number of producers is small.

5. What Are the Key Model Inputs?

Key model inputs for the EIM are the behavioral parameters, compliance costs estimates, and market equilibrium quantities and prices.

The EIM is a behavioral model. The estimated social costs of this emission control program are a function of the ways in which producers and consumers of the PFC and gasoline fuel affected by the standards change their behavior in response to the costs incurred in complying with the standards. These behavioral responses are incorporated in the EIM through the price elasticity of supply and demand (reflected in the slope of the supply and demand curves), which measure the price sensitivity of consumers and producers. The price elasticities used in this analysis are described in Chapter 13 of the RIA. The gasoline elasticities were obtained from the literature and are -0.2 for demand and 0.2 for supply. This means that both the quantity supplied and demanded are expected to be fairly insensitive to price changes and that increases in prices are not expected to cause sales to fall or production to increase by very much. Because we were unable to find published supply and demand elasticities for the PFC market, we estimated these parameters using the procedures described in Chapter 13 of the RIA. This approach yielded a demand elasticity of -0.01 and a supply elasticity of 1.5. The estimated demand elasticity is nearly perfectly inelastic (equal to zero), which means that changes in price are expected to have very little effect on the quantity of PFCs demanded. However, supply is fairly elastic, meaning producers are expected to respond to a change in price. Therefore, consumers are expected to bear more of the burden of PFC regulatory control costs than producers.

Initial market equilibrium conditions are simulated using the same current year sales quantities and growth rates used in the engineering cost analysis. The initial equilibrium prices for PFCs and gasoline fuel were obtained from industry sources and published government data. The initial equilibrium market conditions are shocked by applying the engineering compliance cost estimates described earlier in this section. Although both the PFC and gasoline fuel markets are competitive markets, the model is shocked by applying the sum of variable and fixed costs. Two sets of compliance costs are used in the PFC market analysis, reflecting states with existing controls and states without existing controls. The compliance costs used to shock the gasoline fuel market are based on an average total cost (variable + fixed) analysis. An explanation for this approach can be found in Section 13.2.4.1 of the RIA prepared for this rule. These gasoline fuel compliance costs differ across PADDs but are the same across years. Because California already has existing gasoline fuel controls, fuel volumes for that state are not included in the market analysis.

Additional costs that need to be considered in the EIM are the gasoline fuel savings associated with the PFC controls and the costs of the light-duty vehicle controls. The PFC controls are

[242] EPA Guidelines for Preparing Economic Analyses, EPA 240–R–00–003, September 2000, p. 125–6.

[243] See, for example, EPA Guidelines for Preparing Economic Analyses, EPA 240–R–00–003, September 2000, p 126.

[244] Section 3 Industry Organization, ''Characterizing Gasoline Markets: a Profile,'' Final Report, prepared for EPA by RTI, August 2005.

[245] A monopoly or firms in oligopoly may not behave as neoclassical economic theories of the firm predict because they may be concerned about new entrants to the market. If super-normal profits are earned, potential competitors may enter the market. To respond to this threat, existing firm(s) in the market will keep prices and output at a level where only normal profits are made, setting price and output levels at or close to the competitive price and output. See Chapter 13 of the RIA for more information, Section 13.2.3.

expected to reduce gasoline evaporative emissions from fuel storage, leading to gasoline fuel savings for users of these containers. These gasoline fuel savings are not included in the market analysis for this economic impact analysis because these savings are not expected to affect consumer decisions with respect to the purchase of new containers. Gasoline fuel savings are included in the social cost analysis, however, because they are a savings that accrues to society. The estimated gasoline fuel savings are added to the estimated social costs as a separate line item. As noted above, the economic impacts of the light-duty vehicle controls are not modeled in the EIM. Instead, the estimated engineering compliance costs are used as a proxy, and are also added into the estimated social costs as a separate line item.

The EIM relies on the estimated compliance costs for the PFC and gasoline fuel programs described elsewhere in this preamble. Thus, the EIM reflects cost savings associated with ABT or other flexibility programs to the extent they are included in the estimated compliance costs.

6. What Are the Results of the Economic Impact Modeling?

Using the model and data described above, we estimated the economic impacts of the rule. The results of our modeling for selected years are summarized in this section. The year 2009 is presented because that is the first year in which both the PFC and the gasoline programs are in effect (the PFC program begins in 2009; the gasoline fuel program goes into effect January 1, 2011 but the compliance cost analysis includes a phase-in starting in 2007 that ends May 2015). The year 2012 is presented because it is a high cost year due to the way the fuel program compliance costs were estimated.[246] The year 2015 is presented because beginning with that year compliance costs are stabilized for future years for both the gasoline and PFC programs (the vehicle program compliance costs continue for five more years). Detailed results for all years are included in the appendices to Chapter 13 of the RIA. Also included as an appendix to that chapter are sensitivity analyses for several key inputs.

Market Impact Analysis. In the market analysis, we estimate how prices and quantities of goods affected by the emission control program can be expected to change once the program goes into effect. As explained above, we estimated market impacts for only the gasoline fuel and PFC markets. The analysis relies on the baseline equilibrium prices and quantities for each market and the price elasticity of supply and demand. It predicts market reactions to the increase in production costs due to the new compliance costs. It should be noted that this analysis does not allow any other factors to vary. In other words, it does not consider that manufacturers may adjust their production processes or marketing strategies in response to the control program.

The market analysis results for 2009, 2012, 2015, and 2020 are presented in Table VIII.F–1. With regard to the gasoline fuel program, the market impacts are expected to be small, on average. The price of gasoline fuel is expected to increase by less than 0.5 percent, depending on PADD, with smaller increases during the program phase-in. The expected reduction in quantity of fuel produced is expected to be less than 0.1 percent.

The market impacts for the PFC program are expected to be more significant. In 2009, the first year of the PFC program, the model predicts a price increase of about seven percent for PFCs in states that currently have regulations for PFCs and about 57 percent for those that do not. Even with these large price increases, however, the quantity produced is not expected to decrease by very much: less than 0.6 percent. These percent price increases and quantity decreases are much smaller after the first five years. In 2015, the estimated PFC price increase is expected to be less than two percent for states that currently regulate PFCs and about 32.5 percent for states without such regulations. The quantity produced is expected to decrease by less than 0.4 percent. The results for 2020 are substantially the same as 2015, with a larger decrease in the number of PFCs produced.

TABLE VIII.F–1.—SUMMARY OF MARKET IMPACTS (2009, 2012, 2015, AND 2020; 2003$)

Market	Engineering cost per unit	Change in price		Change in quantity	
		Absolute	Percent	Absolute	Percent
2009					
	¢/gallon	¢/gallon		Million gallons	
Gasoline Fuel:					
PADD 1 & 3	0.016	0.009	0.006	−0.9	−0.001
PADD 2	0.091	0.050	0.033	−2.7	−0.007
PADD 4	0.033	0.018	0.011	−0.1	−0.002
PADD 5 (w/out CA)	0.007	0.004	0.002	−0.0	0.000
	$/can			Thousand cans	
Portable Fuel Containers:					
States with existing programs	0.77	0.76	6.9	−8.0	−0.07
States without existing programs	2.70	2.68	57.5	−104.7	−0.57
2012					
	¢/gallon			Million gallons	
Gasoline Fuel:					
PADD 1 & 3	0.058	0.032	0.021	−3.3	−0.004
PADD 2	0.308	0.168	0.111	−9.7	−0.022

[246] Actual fuel program compliance costs are expected to be spread more evenly across years.

TABLE VIII.F–1.—SUMMARY OF MARKET IMPACTS (2009, 2012, 2015, AND 2020; 2003$)—Continued

Market	Engineering cost per unit	Change in price		Change in quantity	
		Absolute	Percent	Absolute	Percent
PADD 4	0.213	0.116	0.074	−0.8	−0.015
PADD 5 (w/out CA)	0.140	0.768	0.046	−0.8	−0.009
	$/can			Thousand cans	
Portable Fuel Containers:					
States with existing programs	0.77	0.76	6.9	−8.5	−0.07
States without existing programs	2.70	2.68	57.5	−111.1	−0.57
2015					
	¢/gallon			Million gallons	
Gasoline Fuel:					
PADD 1 & 3	0.149	0.081	0.055	−8.9	−0.011
PADD 2	0.307	0.167	0.111	−10.4	−0.022
PADD 4	0.501	0.273	0.174	−1.8	−0.035
PADD 5 (w/out CA)	0.997	0.544	0.327	−6.1	−0.065
	$/can			Thousand cans	
Portable Fuel Containers:					
States with existing programs	0.21	0.20	1.9	−2.4	−0.02
States without existing programs	1.53	1.52	32.5	−66.7	−0.32
2020					
	¢/gallon			Million gallons	
Gasoline Fuel:					
PADD 1 & 3	0.149	0.081	0.055	−9.5	−0.011
PADD 2	0.307	0.167	0.111	−10.7	−0.022
PADD 4	0.501	0.273	0.174	−2.0	−0.035
PADD 5 (w/out CA)	0.997	0.544	0.327	−6.4	−0.065
	$/can			Thousand cans	
Portable Fuel Containers:					
States with existing programs	0.21	0.20	1.9	−2.7	−0.02
States without existing programs	1.53	1.52	32.5	−73.6	−0.32

Economic Welfare Analysis. In the economic welfare analysis, we look at the costs to society of the emission control program in terms of losses to key stakeholder groups that are the producers and consumers in the gasoline and PFC markets. These surplus losses are combined with estimated vehicle compliance costs, gasoline fuel savings, and government revenue losses to estimate the net economic welfare impacts of the program. Detailed economic welfare results for the rule are presented in Appendix C and are summarized below.

The estimated annual net social costs (total social costs less gasoline fuel savings) for all years are presented in Table VIII.F–2. These social costs follow the trend of the fuel program compliance costs. Initially, the estimated social costs of the program are relatively small as the gasoline program begins to phase in. The net social costs increase to 2012, fall somewhat for 2013 and 2014 due to changes in the fuel program compliance costs, and then increase again in 2015, after which time the per-gallon costs are expected to be stable. Some of the decrease in social costs in 2014 is also due to a decrease in costs associated with the PFC program, since fixed costs are fully amortized by 2014. The slight decrease in 2020 is due to the end of the vehicle compliance costs, which are incurred in the 10-year period from 2010 through 2019.

TABLE VIII.F–2.—ESTIMATED ENGINEERING COMPLIANCE AND SOCIAL COSTS THROUGH 2035

[Including fuel savings; $million; 2003$]

Year	Engineering compliance costs	Social costs
2007	$29.5	$29.5
2008	51.3	51.3
2009	99.0	98.9
2010	161.9	161.7
2011	152.6	152.4
2012	228.7	228.5
2013	190.9	190.8
2014	150.8	150.7
2015	350.8	350.7
2016	354.5	354.4
2017	358.0	357.9
2018	361.9	361.8
2019	366.1	366.0
2020	359.5	359.4
2021	363.5	363.4
2022	367.1	367.0
2023	370.7	370.6
2024	374.7	374.6
2025	378.7	378.6
2026	383.1	383.0

TABLE VIII.F–2.—ESTIMATED ENGINEERING COMPLIANCE AND SOCIAL COSTS THROUGH 2035—Continued

[Including fuel savings; $million; 2003$]

Year	Engineering compliance costs	Social costs
2027	387.5	387.4
2028	391.6	391.4
2029	396.0	395.9
2030	400.1	400.0
2031	404.6	404.5
2032	409.2	409.1
2033	413.9	413.7
2034	418.6	418.4
2035	423.4	423.2
3% NPV (2006–2035)	5,356.8	5,354.6
7% NPV (2006–2035)	2,901.0	2,899.7

Table VIII.F–3 shows how the social costs are expected to be shared across stakeholders, for selected years. Information for all years can be found in Appendix C. According to these results, consumers are expected to bear approximately 99 percent of the cost of the PFC program. This reflects the inelastic price elasticity on the demand side of the market and the elastic price elasticity on the supply side. The burden of the gasoline fuel program is expected to be shared more evenly, with about 54.5 percent expected to be borne by consumers and about 45.5 percent expected to be borne by producers. In all years, the estimated loss to consumer welfare will be offset somewhat by the gasoline fuel savings associated with PFCs. Beginning at about $11 million per year, these savings increase to about $76 million by 2015 as compliant PFCs are phased in. These savings continue for the life of the PFCs; total annual savings increase as the number of cans increases.

TABLE VIII.F–3.—SUMMARY OF ESTIMATED SOCIAL COSTS, 2009, 2012, 2015, AND 2020

[$million; 2003$]

Market	Change in consumer surplus	Change in producer surplus	Total
2009			
Gasoline U.S.	−$28.5 (54.6%)	−$23.8 (45.4%)	−$52.3
PADD 1 & 3	−$6.7	−$5.6	−$12.2
PADD 2	−$20.6	−$17.2	−$37.8
PADD 4	−$0.9	−$0.7	−$1.6
PADD 5 (w/out CA)	−$0.3	−$0.3	−$0.6
Portable Fuel Containers U.S.	−$57.5 (99.3%)	−$0.4 (0.7%)	−$57.9
States with existing programs	−$8.9	−$0.1	−$8.9
States without existing programs	−$48.7	−$0.3	−$49.0
Subtotal	−$86.1 (78.1%)	−$24.1 (22%)	−$110.2
Fuel Savings			$11.3
Vehicle Program			$0
Total			−$98.9
2012			
Gasoline U.S.	−$110.7 (54.5%)	−$92.3 (45.5%)	−$203.0
PADD 1 & 3	−$24.8	−$20.7	−$45.5
PADD 2	−$73.2	−$61.0	−$134.2
PADD 4	−$5.9	−$4.9	−$10.9
PADD 5 (w/out CA)	−$6.8	−$4.7	−$12.4
Portable Fuel Containers U.S.	−$61.1 (99.3%)	−$0.4 (0.7%)	−$61.5
States with existing programs	−$9.4	−$0.1	−$9.5
States without existing programs	−$51.7	−$0.4	−$52.1
Subtotal	−$171.8 (65.0%)	−$92.7 (35.0%)	−$264.5
Fuel Savings			$48.5
Vehicle Program			−$12.5
Total			−$228.5
2015			
Gasoline U.S.	−$207.0 (54.5%)	−$172.5 (45.5%)	−$379.4
PADD 1 & 3	−$66.3	−$55.3	−$121.6
PADD 2	−$75.9	−$63.2	−$139.1

TABLE VIII.F–3.—SUMMARY OF ESTIMATED SOCIAL COSTS, 2009, 2012, 2015, AND 2020—Continued

[$million; 2003$]

Market	Change in consumer surplus	Change in producer surplus	Total
PADD 4	−$14.5	−$12.1	−$26.6
PADD 5 (w/out CA)	−$50.3	−$41.9	−$92.2
Portable Fuel Containers U.S.	−$33.7	−$0.2	−$34.0
	(99.3%)	(0.7%)	
States with existing programs	−$2.7	$0.0	−$2.7
States without existing programs	−$31.0	−$0.2	−$31.3
Subtotal	−$240.7	−$172.7	−$413.4
	(58.2%)	(41.8%)	
Fuel Savings			$75.5
Vehicle Program			−$12.9
Total			−$350.7
2020			
Gasoline U.S.	−$219.6	−$183.0	−$402.6
	(54.5%)	(45.5%)	
PADD 1 & 3	−$70.4	−$58.6	−$129.0
PADD 2	−$80.5	−$67.1	−$147.6
PADD 4	−$15.4	−$12.8	−$28.2
PADD 5 (w/out CA)	−$53.4	−$44.5	−$97.8
Portable Fuel Containers U.S.	−$37.2	−$0.2	−$37.5
	(99.3%)	(0.7%)	
States with existing programs	−$3.0	$0.0	−$3.0
States without existing programs	−$34.3	−$0.2	−$34.5
Subtotal	−$256.8	−$183.3	−$440.1
	(58.4%)	(41.6%)	
Fuel Savings			$80.7
Vehicle Program			−$0
Total			−$359.4

The present value of net social costs (discounted back to 2006) of the standards through 2035, contained in Table VIII.F–2, is estimated to be about $5.4 billion (2003$). This present value is calculated using a social discount rate of three percent and the stream of economic welfare costs through 2035. We also performed an analysis using a seven percent social discount rate.[247] Using that discount rate, the present value of the net social costs through 2035 is estimated to be about $2.9 billion (2003$).

TABLE VIII.F–4.—NET PRESENT OF ESTIMATED SOCIAL COSTS 2007 THROUGH 2035, DISCOUNTED TO 2006

[$million; 2003$]

Market	Change in consumer surplus	Change in producer surplus	Total
Gasoline, U.S.	−$3,115.4	−$2,596.2	−$5,711.6
	(54.5%)	(45.5%)	
PADD 1 & 3	−$959.7	−$799.8	−$1,759.5
PADD 2	−$1,260.4	−$1,050.4	−$2,310.8
PADD 4	−$210.8	−$175.6	−$386.4
PADD 5 (w/out CA)	−$229.5	−$570.4	−$1,254.8
	−$684.5		
Portable Fuel Containers US	−$754.9	−$5.0	−$759.9
	(99.3%)	(0.7%)	
States with existing programs	−$78.7	−$0.5	−$79.3
States without existing programs	−$676.2	−$4.5	−$680.7

[247] EPA presents the present value of cost and benefits estimates using both a three percent and a seven percent social discount rate. According to OMB Circular A–4, ''the 3 percent discount rate represents the 'social rate of time preference' * * * [which] means the rate at which 'society' discounts future consumption flows to their present value''; ''the seven percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy * * * [that] approximates the opportunity cost of capital.''

TABLE VIII.F–4.—NET PRESENT OF ESTIMATED SOCIAL COSTS 2007 THROUGH 2035, DISCOUNTED TO 2006—Continued

[$million; 2003$]

Market	Change in consumer surplus	Change in producer surplus	Total
Subtotal	−$3870.3 59.8%	−$2,601.2 40.2%	−$6,471.6
Fuel Savings	$1,208.0		$1,208.0
Vehicle Program		−$91.1	−$91.1
Total	−$2,662.3	−$2,692.3	−$5,354.6

Table VIII.F–4 shows the distribution of total surplus losses for the cumulative net social costs of the rule. This analysis includes the estimated social costs from 2007 through 2035, discounted to 2006 at a 3 percent discount rate. These results suggest that consumers will bear about 60 percent of the total social costs associated with the PFC and gasoline fuel programs for that period. The consumer share of the NPV social costs is about $3,870 million, or about 60 percent of the total. Of that loss of consumer surplus, about $3,115 million (about 80 percent) is from the gasoline fuel program. When the total costs of the program are taken into account, including the fuel savings and the vehicle program costs, the loss of consumer surplus decreases to about $2,662.3 million (about 50 percent of the social costs of the program).

IX. Public Participation

Many interested parties participated in the rulemaking process that culminates with this final rule. This process provided opportunity for submitting written public comments following the proposal that we published on March 29, 2006 (71 FR 15804). We considered these comments in developing the final rule. In addition, we held a public hearing on the proposed rulemaking on April 12, 2006, and we have considered comments presented at the hearing.

Throughout the rulemaking process, EPA met with stakeholders including representatives from the fuel refining and distribution industry, automobile industry, emission control manufacturing industry, gas can industry, environmental organizations, states, interests, and others.

We have prepared a detailed Summary and Analysis of Comments document, which describes comments we received on the proposal and our response to each of these comments. The Summary and Analysis of Comments is available in the docket for this rule at the internet address listed under **ADDRESSES**, as well as on the Office of Transportation and Air Quality Web site (*http://www.epa.gov/otaq/toxics.htm#mobile*). In addition, comments and responses for key issues are included throughout this preamble.

X. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under section 3(f)(1) of Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to ''have an annual effect on the economy of $100 million or more'' and ''raise novel legal and policy issues.'' Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866, and any changes made in response to OMB recommendations have been documented in the docket for this action.

A final Regulatory Impact Analysis has been prepared and is available in the docket for this rulemaking and at the docket internet address listed under **ADDRESSES**.

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* The information collection requirements are not enforceable until OMB approves them.

The Agency will collect information to ensure compliance with the provisions in this rule. This includes a variety of requirements, both for vehicle manufacturers, fuel producers, and portable fuel container manufacturers. Information-collection requirements related to vehicle manufacturers are in EPA ICR #0783.52 (OMB Control Number 2060–0104); requirements related to fuel producers are in EPA ICR #1591.22 (OMB Control Number 2060–0277); requirements related to portable fuel container manufacturers are in EPA ICR #2213.02. For vehicle and fuel standards, section 208(a) of the Clean Air Act requires that manufacturers provide information the Administrator may reasonably require to determine compliance with the regulations; submission of the information is therefore mandatory. We will consider confidential all information meeting the requirements of section 208(c) of the Clean Air Act. For portable fuel container standards, recordkeeping and reporting requirements for manufacturers would be pursuant to the authority of sections 183(e) and 111 of the Clean Air Act.

As shown in Table X.B–1, the total annual burden associated with this rule is about 28,000 hours and $1,993,723, based on a projection of 521 respondents. The estimated burden for vehicle manufacturers and fuel producers is a total estimate for both new and existing reporting requirements. The portable fuel container requirements represent our first regulation of these containers, so those burden estimates reflect only new reporting requirements. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

TABLE X.B–1.—ESTIMATED BURDEN FOR REPORTING AND RECORDKEEPING REQUIREMENTS

Industry sector	Number of respondents	Annual burden hours	Annual costs
Vehicles	35	770	$80,900
Fuels	476	26,592	*1,888,032
Portable fuel containers	10	638	24,791
Total	521	28,000	1,993,723

*Does not include non-postage purchased services of approximately $1,988,000.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 and 48 CFR chapter 15 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule. EPA received various comments on the rulemaking provisions covered by the ICRs, but no comments on the paperwork burden or other information in the ICRs. All comments that were submitted to EPA are considered in the relevant Summary and Analysis of Comments, which can be found in the docket.

C. Regulatory Flexibility Act (RFA), as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), 5 U.S.C. 601 et seq.

1. Overview

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201 (see table below); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. The following table provides an overview of the primary SBA small business categories potentially affected by this regulation:

Industry	Defined as small entity by SBA if less than or equal to:	NAICS Codes[a]
Light-duty vehicles:		
—vehicle manufacturers (including small volume manufacturers)	1,000 employees	336111
—independent commercial importers	$6 million annual sales	811111
		811112
		811198
—alternative fuel vehicle converters	100 employees	424720
	1,000 employees	335312
	$6 million annual sales	811198
Gasoline fuel refiners	1500 employees[b]	324110
Portable fuel container manufacturers:		
—plastic container manufacturers	500 employees	326199
—metal gas can manufacturers	1,000 employees	332431

Notes:
[a] North American Industrial Classification System
[b] EPA has included in past fuels rulemakings a provision that, in order to qualify for EPA's small refiner flexibilities, a refiner must also produce no greater than 155,000 bpcd crude capacity.

Pursuant to section 603 of the RFA, EPA prepared an initial regulatory flexibility analysis (IRFA) for the proposed rule and convened a Small Business Advocacy Review Panel (SBAR Panel, or the 'Panel') to obtain advice and recommendations of representatives of the regulated small entities. A detailed discussion of the Panel's advice and recommendations is found in the Panel Report (see Docket EPA–HQ–OAR–2005–0036). A summary of the Panel's recommendations is presented at 71 FR 15922 (March 29, 2006).

As required by section 604 of the RFA, we also prepared a final regulatory flexibility analysis (FRFA) for today's final rule. The FRFA addresses the issues raised by public comments on the IRFA, which was part of the proposal of this rule. The FRFA is available for review in Chapter 14 of the RIA and is summarized below.

Key elements of our FRFA include:

- A description of the reasons the Agency is considering this action, and the need for, and objectives of, the rule;
- A summary of the significant issues raised by the public comments on the IRFA, a summary of the Agency's assessment of those issues, and any changes made to the proposed rule as a result of those comments;
- A description of the types and number of small entities to which the rule will apply;
- A description of the reporting, recordkeeping, and other compliance requirements of the rule;
- An identification, to the extent practicable, of all relevant Federal rules that may duplicate, overlap, or conflict with the rule; and
- A description of the steps taken to minimize the significant economic impact on small entities consistent with