

TABLE VI.B-4.—SCHEDULE FOR IN-USE STANDARDS FOR HLDVs/MDPVs

Model year of introduction	2010	2011	2012	2013	2014	2015
Models years that the in-use standard is available for carry-over test groups.	2010	2011	2012	2013	2014	2015
	2011	2012	2013	2014	2015	2016
	2012	2013	2014	2015	2016	
	2013	2014	2015			

7. Monitoring and Enforcement

Under the proposed programs, manufacturers could either report that they met the relevant corporate average standard in their annual reports to the Agency, or they could show via the use of credits that they have offset any exceedance of the corporate average standard. Manufacturers would also report their credit balances or deficits. EPA would monitor the program.

As in Tier 2, the averaging, banking and trading program would be enforced through the certificate of conformity that manufacturers must obtain in order to introduce any regulated vehicles into commerce.¹⁹⁸ The certificate for each test group would require all vehicles to meet the emissions level to which the vehicles were certified, and would be conditioned upon the manufacturer meeting the corporate average standard within the required time frame. If a manufacturer failed to meet this condition, the vehicles causing the corporate average exceedance would be considered to be not covered by the certificate of conformity for that engine family. A manufacturer would be subject to penalties on an individual vehicle basis for sale of vehicles not covered by a certificate.

EPA would review the manufacturer's sales to designate the vehicles that caused the exceedance of the corporate average standard. We would designate as nonconforming those vehicles in those test groups with the highest certification emission values first, continuing until a number of vehicles equal to the calculated number of noncomplying vehicles as determined above is reached. In a test group where only a portion of vehicles would be deemed nonconforming, we would determine the actual nonconforming vehicles by counting backwards from the last vehicle produced in that test group. Manufacturers would be liable for penalties for each vehicle sold that is not covered by a certificate.

We are proposing to condition certificates to enforce the requirements that manufacturers not sell credits that

they have not generated. A manufacturer that transferred credits it did not have would create an equivalent number of debits that it would be required to offset by the reporting deadline for the same model year. Failure to cover these debits with credits by the reporting deadline would be a violation of the conditions under which EPA issued the certificate of conformity, and nonconforming vehicles would not be covered by the certificate. EPA would identify the nonconforming vehicles in the same manner described above.

In the case of a trade that resulted in a negative credit balance that a manufacturer could not cover by the reporting deadline for the model year in which the trade occurred, we propose to hold both the buyer and the seller liable. We believe that holding both parties liable will induce the buyer to exercise diligence in assuring that the seller has or will be able to generate appropriate credits and will help to ensure that inappropriate trades do not occur.

We are not proposing any new compliance monitoring activities or programs for vehicles. These vehicles would be subject to the certification testing provisions of the CAP2000 rule. We are not proposing to require manufacturer in-use testing to verify compliance. There is no cold CO manufacturer in-use testing requirement today (similarly, we do not require manufacturer in-use testing for SCO3 standards under the SFTP program). As noted earlier, manufacturers have limited cold temperature testing capabilities and we believe these facilities will be needed for product development and certification testing. However, we have the authority to conduct our own in-use testing program for exhaust emissions to ensure that vehicles meet standards over their full useful life. We will pursue remedial actions when substantial numbers of properly maintained and used vehicles fail any standard in-use. We also retain the right to conduct Selective Enforcement Auditing of new vehicles at manufacturers' facilities.

The use of credits would not be permitted to address Selective Enforcement Auditing or in-use testing failures. The enforcement of the

averaging standard would occur through the vehicle's certificate of conformity. A manufacturer's certificate of conformity would be conditioned upon compliance with the averaging provisions. The certificate would be void ab initio if a manufacturer failed to meet the corporate average standard and did not obtain appropriate credits to cover their shortfalls in that model year or in the subsequent model year (see proposed deficit carryforward provision in section VI.B.5.e.). Manufacturers would need to track their certification levels and sales unless they produced only vehicles certified to NMHC levels below the standard and did not plan to bank credits.

We request comments on the above approach for compliance monitoring and enforcement.

C. What Evaporative Emissions Standards Are We Proposing?

We are proposing to adopt a set of numerically more stringent evaporative emission standards for all light-duty vehicles, light-trucks, and medium-duty passenger vehicles. The proposed standards are equivalent to California's LEV II standards, and these proposed standards are shown in Table VI.C-1. The proposed standards would represent about a 20 to 50 percent reduction (depending on vehicle weight class and type of test) in diurnal plus hot soak standards from the Tier 2 standards that will be in effect in the years immediately preceding the implementation of today's proposed standards.¹⁹⁹ As with the current Tier 2 evaporative emission standards, the proposed standards vary by vehicle weight class. The increasingly higher standards for heavier weight class vehicles account for larger vehicle sizes

¹⁹⁹ Diurnal emissions (or diurnal breathing losses) means evaporative emissions as a result of daily temperature cycles or fluctuations for successive days of parking in hot weather. Hot soak emissions (or hot soak losses) are the evaporative emissions from a parked vehicle immediately after turning off the hot engine. For the evaporative emissions test procedure, diurnal and hot soak emissions are measured in an enclosure commonly called the SHED (Sealed Housing for Evaporative Determination).

¹⁹⁸ "Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements", Final Rule, 65 FR 6797, February 10, 2000.

and fuel tanks (non-fuel and fuel emissions).²⁰⁰

TABLE VI.C-1.—PROPOSED EVAPORATIVE EMISSION STANDARDS
[Grams of hydrocarbons per test]

Vehicle class	3-day diurnal plus hot soak	Supplemental 2-day diurnal plus hot soak
LDVs	0.50	0.65
LLDTs	0.65	0.85
HLDTs	0.90	1.15
MDPVs	1.00	1.25

1. Current Controls and Feasibility of the Proposed Standards

Evaporative emissions from light-duty vehicles and trucks will represent about 35 percent of the light-duty VOC inventory and about 4 percent of the benzene inventory in 2020. As described earlier, we are proposing to reduce the level of the evaporative emission standards applicable to diurnal and hot soak emissions from these vehicles by about 20 to 50 percent. These proposed standards are meant to be effectively the same as the evaporative emission standards in the California LEV II program. Although the California program contains evaporative emissions standards that appear more stringent than EPA Tier 2 standards if one looks only at the level of the standard, we believe they are essentially equivalent because of differences in testing requirements. For these same reasons, some manufacturers likewise view the programs as similar in stringency. (See section VI.C.5 below for further discussion of such test differences, e.g., test temperatures and fuel volatilities.) Thus, some manufacturers have indicated that they will produce 50-state evaporative systems that meet both sets of standards (manufacturers sent letters indicating this to EPA in 2000).^{201 202 203} In addition, a review of recent model year certification results indicates that essentially all manufacturers certify 50-state systems, except for a few limited cases where manufacturers have not yet needed to certify a LEVII vehicle in California due to the phase-in schedule.

Also, in recent discussions, manufacturers have restated that they plan to continue producing 50-state evaporative systems in the future. Based on this understanding, we do not project additional VOC or air toxics reductions from the evaporative standards we are proposing today.²⁰⁴ Also, we do not expect additional costs since we expect that manufacturers will continue to produce 50-state evaporative systems. Therefore, harmonizing with California's LEV-II evaporative emission standards would be an "anti-backsliding" measure—that is, it would prevent potential future backsliding as manufacturers pursue cost reductions.²⁰⁵ It would thus codify (*i.e.*, lock in) the approach manufacturers have already indicated they are taking for 50-state evaporative systems.

We believe this proposed action would be an important step to ensure that the federal standards reflect the lowest possible evaporative emissions, and it also would provide states with certainty that the emissions reductions we project to occur due to 50-state compliance strategies will in fact occur. In addition, the proposed standards will assure that manufacturers continue to capture the abilities of available fuel system materials to minimize evaporative emissions.

We also considered the possibility of whether it is feasible to achieve further evaporative emission reductions from motor vehicles. In this regard, it is important to note that California's LEV II program includes partial zero-emission vehicle (ZEV) credits for

vehicles that achieve near zero emissions (*e.g.*, LDV evaporative emission standards for both the 2-day and 3-day diurnal plus hot soak tests are 0.35 grams/test, which are more stringent than proposed standards).²⁰⁶ The credits would include full ZEV credit for a stored hydrogen fuel cell vehicle and 0.2 credits for (among other categories for partial credit) a partial zero emission vehicle (PZEV).²⁰⁷ Currently, only a fraction of California's certified vehicles (gasoline powered, hybrid, and compressed natural gas vehicles) meet California's optional PZEV standards, but this number is expected to increase in coming years.^{208 209} These limited PZEV vehicles require additional evaporative emissions technology or hardware (*e.g.*, modifications to fuel tank and secondary canister) than we expect to be needed for vehicles meeting the proposed standards. At this time, we need to better understand the evaporative system modifications (*i.e.*, technology, costs, lead time, etc.) potentially needed for other vehicles in the fleet to meet PZEV-level standards before we can rationally evaluate whether to adopt more stringent standards. For example, at this point we cannot even determine whether the PZEV technologies could be used fleetwide or on only a limited set of vehicles. Thus, in the near term, we lack any of the information necessary to determine if further reductions are feasible, and if they could be achievable considering cost, energy and safety issues. However, we intend to consider

²⁰⁰ Larger vehicles may have greater non-fuel evaporative emissions, probably due to an increased amount of interior trim, vehicle body surface area, and larger tires.

²⁰¹ DaimlerChrysler, Letter from Reginald R. Modlin to Margo Oge of U.S. EPA, May 30, 2000. A copy of this letter can be found in Docket No. EPA-HQ-OAR-2005-0036.

²⁰² Ford, Letter from Kelly M. Brown to Margo Oge of U.S. EPA, May 26, 2000. A copy of this letter can be found in Docket No. EPA-HQ-OAR-2005-0036.

²⁰³ General Motors, Letter from Samuel A. Leonard to Margo Oge of U.S. EPA, May 30, 2000. A copy of this letter can be found in Docket No. EPA-HQ-OAR-2005-0036.

²⁰⁴ U.S. EPA, Office of Air and Radiation, Update to the Accounting for the Tier 2 and Heavy-Duty 2005/2007 Requirements in MOBILE6, EPA420-R-03-012, September 2003.

²⁰⁵ Anti-backsliding provisions can satisfy the requirement in section 202 (l) (2) that emission reductions of hazardous air pollutants be the greatest achievable. *Sierra Club v. EPA*, 325 F. 3d at 477.

²⁰⁶ California Air Resources Board, Fact Sheet, LEV-II Amendments to California's Low-Emission Vehicle Regulations, February 1999

²⁰⁷ PZEV meets California super ultra low emission vehicle exhaust emission standards and have near zero evaporative emissions. California Air Resources Board, News Release, ARB Modifies Zero Emission Vehicle Regulation, April 24, 2003.

²⁰⁸ California Air Resources Board, Fact Sheet, California Vehicle Emissions, April 8, 2004.

²⁰⁹ California Air Resources Board, Consumer Information: 2006 California Certified Vehicles, November 7, 2005.

more stringent evaporative emission standards in the future, and revisiting this issue in a future rulemaking will allow us time to obtain the important necessary additional information for such standards.

2. Evaporative Standards Timing

We are proposing to implement today's evaporative emission standards in model year 2009 for LDVs/LLDTs and model year 2010 for HLDTs/MDPVs. Today's proposed rule is not expected to be finalized until February 2007, at which time many manufacturers already will have begun or completed model year 2008 certification. Thus, model year 2009 is the earliest practical start date of new standards for LDVs/LLDTs. For HLDTs/MDPVs, the phase-in of the existing Tier 2 evaporative emission standards ends in model year 2009. Thus, the model year 2010 is the earliest start date possible for HLDTs/MDPVs. Since the proposed standards are an anti-backsliding measure and we believe that manufacturers already meet these standards, there is no need for additional lead time beyond the implementation dates proposed. We request comment on this proposed schedule.

3. Timing for Multi-Fueled Vehicles

As discussed earlier in this section, manufacturers appear to view the Tier 2 and LEV II evaporative emission programs as similar in stringency, and thus, they have indicated that they will produce 50-state evaporative systems that meet both sets of standards. For multi-fueled vehicles capable of operating on alternative fuel (e.g., E85 vehicles—fuel is 85% ethanol and 15% gasoline) and conventional fuel (e.g., gasoline),²¹⁰ this commitment for 50-state systems would still apply. However, a few multi-fueled vehicles were certified only on the conventional fuel (gasoline) for the California LEV II program even though they had 50-state evaporative emission systems. For such cases, manufacturers did not intend to sell these vehicles for operation on the alternative fuel (e.g. E85) in California (only for operation on conventional fuel in California), but they did certify and plan to sell these vehicles in the federal Tier 2 program for operation on the alternative and conventional fuels.²¹¹ For these few types of multi-fueled vehicles, manufacturers are potentially at risk of not complying with the

²¹⁰ 40 CFR 86.1803–01 defines multi-fuel as capable of operating on two or more different fuel types, either separately or simultaneously.

²¹¹ For the Tier 2 program, multi-tier vehicles must meet the same standards on conventional and alternative fuel.

proposed new evaporative emission certification standards (which are equivalent to California LEV II certification standards) when operating on the alternative fuel.

For such multi-fueled vehicles or evaporative emission systems, manufacturers would need a few additional years of lead time to adjust their evaporative systems to comply with the proposed evaporative emission certification standards when operating on the alternative fuel. Thus, to reduce the compliance risk for these types of multi-fueled vehicles (or evaporative families) when they first certify to the more stringent evaporative standards, the proposed evaporative emission certification standards would apply to the non-gasoline portion of multi-fueled vehicles beginning in the fourth year of the program—2012 for LDVs/LLDTs and 2013 for HLDTs/MDPVs. The proposed evaporative emission certification standards would be implemented in 2009 for LDVs/LLDTs and 2010 for HLDTs/MDPVs for the gasoline portion of multi-fueled vehicles and vehicles that are not multi-fueled. We believe this additional three years of lead time would provide sufficient time for manufacturers to make adjustments to their new evaporative systems for multi-fueled vehicles, which are limited product lines.

The provisions for in-use evaporative emission standards described below in section VI.C.4 would not change for multi-fueled vehicles. We believe that three additional years to prepare vehicles (or evaporative families) to meet the certification standards, and to simultaneously make vehicle adjustments from the federal in-use experience of other vehicles (other vehicles that are not multi-fueled) is sufficient to resolve any issues for multi-fueled vehicles. Therefore, the proposed evaporative emission standards would apply both for certification and in-use beginning in 2012 for LDVs/LLDTs and 2013 for HLDTs/MDPVs.

4. In-Use Evaporative Emission Standards

As described earlier in this section, we are proposing to adopt evaporative emission standards that are equivalent to California's LEV II standards for all light duty vehicles, light trucks, and medium duty passenger vehicles. Currently, the Tier 2 evaporative emission standards are the same for certification and in-use vehicles. However, the California LEV II program permits manufacturers to meet less stringent standards in-use for a short time period in order to account for

potential variability in-use during the initial years of the program when technical issues are most likely to arise.²¹² The LEV II program specifies that in-use evaporative emission standards of 1.75 times the certification standards will apply for the first three model years after an evaporative family is first certified to the LEV II standards (only for vehicles introduced prior to model year 2007, the year after 100 percent phase-in).^{213 214} An interim three-year period was considered sufficient to accommodate any technical issues that may arise.

Federal in-use conditions may raise unique issues (e.g., salt/ice exposure) for evaporative systems certified to the new proposed standards (which are equivalent to the LEV II standards), and thus, we propose to adopt a similar, interim in-use compliance provision for federal vehicles. As with the LEV II program, this provision would enable manufacturers to make adjustments for unforeseen problems that may occur in-use during the first three years of a new evaporative family. Like California, we believe that a three-year period is enough time to resolve these problems, because it allows manufacturers to gain real world experience and make adjustments to a vehicle within a typical product cycle.

Depending on the vehicle weight class and type of test, the Tier 2 certification standards are 1.3 to 1.9 times the LEV II certification standards. On average the Tier 2 standards are 1.51 times the LEV II certification standards. Thus, to maintain the same level of stringency for the in-use evaporative emission standards provided by the Tier 2 program, we propose to apply the Tier 2 standards in-use for only the first three model years after an evaporative family is first certified under today's proposed standards instead of the 1.75 multiplier implemented in the California LEV II program. Since the proposed evaporative emission certification standards (equivalent to LEV II standards) would be implemented in model year 2009 for LDVs/LLDTs and model year 2010 for HLDTs/MDPVs, these same certification

²¹² California Air Resources Board, "LEV II" and "CAP 2000" Amendments to the California Exhaust and Evaporative Emission Standards and Test Procedures for Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles, and to the Evaporative Emission Requirements for Heavy-Duty Vehicles, Final Statement of Reasons, September 1999.

²¹³ 1.75 times the 3-day diurnal plus hot soak and 2-day diurnal plus hot soak standards.

²¹⁴ For example, evaporative families first certified to LEV II standards in the 2005 model year shall meet in-use standards of 1.75 times the evaporative certification standards for 2005, 2006, and 2007 model year vehicles.

standards would apply in-use beginning in model year 2012 for LDVs/LLDTs and model year 2013 for HLDTs/MDPVs.²¹⁵

5. Existing Differences Between California and Federal Evaporative Emission Test Procedures

As described above, the California LEV II evaporative emission standards are numerically more stringent than EPA's Tier 2 standards, but due to differences in California and EPA evaporative test requirements, EPA and most manufacturers view the programs as similar in stringency. The Tier 2 evaporative program requires manufacturers to certify the durability of their evaporative emission systems

using a fuel containing the maximum allowable concentration of alcohols (highest alcohol level allowed by EPA in the fuel on which the vehicle is intended to operate, i.e., a "worst case" test fuel). Under current requirements, this fuel would be about 10 percent ethanol by volume.²¹⁶ (We are retaining these Tier 2 durability requirements for the proposed evaporative emissions program.) California does not require this provision. To compensate for the increased vulnerability of system components to alcohol fuel, manufacturers have indicated that they will produce a more durable evaporative emission system than the Tier 2 numerical standards would imply, using

the same low permeability hoses and low loss connections and seals planned for California LEV II vehicles.

As shown in Table VI.C-2, combined with the maximum alcohol fuel content for durability testing, the other key differences between the federal and California test requirements are fuel volatilities, diurnal temperature cycles, and running loss test temperatures.²¹⁷ The EPA fuel volatility requirement is 2 psi greater than that of California. The high end of EPA's diurnal temperature range, is 9° F lower than that of California. Also, EPA's running loss temperature is 10° F lower than California's.

TABLE VI.C-2.—DIFFERENCES IN TIER 2 AND LEV II EVAPORATIVE EMISSION TEST REQUIREMENTS

Test requirement	EPA tier 2	California LEV II
Fuel volatility (Reid Vapor Pressure in psi)	9	7.
Diurnal temperature cycle (degrees F)	72 to 96	65 to 105.
Running loss test temperature (degrees F)	95	105.

Currently, California accepts evaporative emission results generated on the federal test procedure (using federal test fuel), because available data indicates the federal procedure to be a "worst case" procedure. In addition, manufacturers can obtain federal evaporative certification based upon California results (meeting LEV II standards under California fuels and test conditions), if they obtain advance approval from EPA.²¹⁸

D. Opportunities for Additional Exhaust Control Under Normal Conditions

In addition to the cold temperature NMHC and evaporative emission standards we are proposing, we evaluated an additional option for reducing hydrocarbons from light-duty vehicles. This option would further align the federal light-duty exhaust emissions control program with that of California. We are not proposing this option today for the reasons described below. It is possible that a future evaluation could result in EPA reconsidering the option of harmonizing the Tier 2 program with California's LEV-II program or otherwise seeking emission reductions beyond those of the

Tier 2 program and those being proposed today.²¹⁹

As explained earlier, section 202(l)(2) requires EPA to adopt regulations that contain standards which reflect the greatest degree of emissions reductions achievable through the application of technology that will be available, taking into consideration existing motor vehicle standards, the availability and costs of the technology, and noise, energy and safety factors. The cold temperature NMHC program proposed today is appropriate under section 202(l)(2) as a near-term control: That is, a control that can be implemented relatively soon and without disruption to other existing vehicle emissions control program. We are not proposing long-term (i.e., controls that require longer lead time to implement) at this time because we lack the information necessary to assess appropriate long-term controls. We believe it will be important to address the appropriateness of further MSAT controls in the context of compliance with other significant vehicle emissions regulations (discussed below).

In the late 1990's both the EPA and the California Air Resources Board

finalized new and technologically challenging light-duty vehicle/truck emission control programs. The EPA program, known as Tier 2, focused on reducing NOx emissions from the light-duty fleet. The California program, which is the second generation of their low emission vehicle (LEV) program and is known as LEV-II, focuses primarily on reducing hydrocarbons by tightening the light-duty NMOG standards. Both programs are expected to present the manufacturers with significant challenges, and will require the use of hardware and emission control strategies not used in the fleet under previously existing programs. Both programs will achieve significant reductions in emissions. Taken as a whole, the Tier 2 program presents the manufacturers with significant challenges in the coming years. Bringing essentially all passenger vehicles under the same emission control program regardless of their size, weight, and application is a major engineering challenge. The Tier 2 program represents a comprehensive, integrated package of exhaust, evaporative, and fuel quality standards which will achieve significant reductions in

²¹⁵ For example, evaporative families first certified to the proposed LDV/LLDT evaporative emission standards in the 2011 model year would be required to meet the Tier 2 LDV/LLDT evaporative emission standards in-use for 2011, 2012, and 2013 model year vehicles (applying Tier 2 standards in-use would be limited to the first three years after introduction of a vehicle), and 2014 and later model year vehicles of such evaporative families would be required to meet the

proposed LDV/LLDT evaporative emission standards in-use.

²¹⁶ Manufacturers are required to develop deterioration factors using a fuel that contains the highest legal quantity of ethanol available in the U.S.

²¹⁷ Running loss emissions means evaporative emissions as a result of sustained vehicle operation (average trip in an urban area) on a hot day. The

running loss test requirement is part of the 3-day diurnal plus hot soak test sequence.

²¹⁸ EPA may require comparative data from both federal and California tests.

²¹⁹ See *Sierra Club v. EPA*, 325 F.3d at 480 (EPA can reasonably determine that no further reductions in MSATs are presently achievable due to uncertainties created by other recently promulgated regulatory provisions applicable to the same vehicles).

NMHC, NO_x, and PM emissions from all light-duty vehicles in the program. These reductions will include significant reductions in MSATs. Emission control in the Tier 2 program will be based on the widespread implementation of advanced catalyst and related control system technology. The standards are very stringent and will require manufacturers to make full use of nearly all available emission control technologies.

Today the Tier 2 program remains early in its phase-in. Cars and lighter trucks will be fully phased into the program with the 2007 model year, and the heavier trucks won't be fully entered into the program until the 2009 model year. Even though the lighter vehicles will be fully phased in by 2007, we expect the characteristics of this segment of the fleet to remain in a state of transition at least through 2009, because manufacturers will be making adjustments to their fleets as the larger trucks phase in. The Tier 2 program is designed to enable vehicles certified to the LEV-II program to cross over to the federal Tier 2 program. At this point in time, however, it is difficult to predict the degree to which this will occur. The fleetwide NMOG levels of the Tier 2 program will ultimately be affected by the manner in which LEV-II vehicles are certified within the Tier 2 bin structure, and vice versa. We intend to carefully assess these two programs as they evolve and periodically evaluate the relative emission reductions and the integration of the two programs.

Today's proposal addresses toxics emissions from vehicles operating at cold temperatures. The technology to achieve this is already available and we project that compliance will not be costly. However, we do not believe that we could reasonably propose further controls at this time. There is enough uncertainty regarding the interaction of the Tier 2 and LEV-II programs to make it difficult to evaluate today what might be achievable in the future. Depending on the assumptions one makes, the LEV-II and Tier 2 programs may or may not achieve very similar NMOG emission levels. Therefore, the eventual Tier 2 baseline technologies and emissions upon which new standards would necessarily be based are not known today. Additionally, we believe it is important for manufacturers to focus in the near term on developing and implementing robust technological responses to the Tier 2 program without the distraction or disruption that could result from changing the program in the midst of its phase-in. We believe that it may be feasible in the longer term to seek additional emission reductions

from the base Tier 2 program, and the next several years will allow an evaluation based on facts rather than assumptions. For these reasons, we are deferring a decision on seeking additional NMOG reductions from the base Tier 2 program.

E. Vehicle Provisions for Small Volume Manufacturers

Prior to issuing a proposal for this proposed 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 propose to include lead time transition and hardship provisions that would be applicable to small volume manufacturers as described below in section VI.E.1 and VI.E.2. For further discussion of the Panel process, see section XII.C of this proposed rule and/or the Final Panel Report.

As discussed in more detail in section XII.C in addition to the major vehicle manufacturers, three distinct categories of businesses relating to highway light-duty vehicles would be covered by the new vehicle standards: Small volume manufacturers (SVMs), independent commercial importers (ICIs),²²⁰ and alternative fuel vehicle converters.²²¹ We define small volume manufacturers as those with total U.S. sales less than 15,000 vehicles per year, and this status allows vehicle models to be certified under a slightly simpler certification process. For certification purposes, SVMs include ICIs and alternative fuel vehicle converters since they sell less than 15,000 vehicles per year.

About 34 out of 50 entities that certify vehicles are SVMs, and the Panel identified 21 of these 34 SVMs that are small businesses as defined by the Small Business Administration criteria (5 manufacturers, 10 ICIs, and 6 converters). Since a majority of the SVMs are small businesses and all

²²⁰ ICIs are companies that hold a Certificate (or certificates) of Conformity permitting them to import nonconforming vehicles and to modify these vehicles to meet U.S. emission standards.

²²¹ Alternative fuel vehicle converters are businesses that convert gasoline or diesel vehicles to operate on alternative fuel (e.g., compressed natural gas), and converters must seek a certificate for all of their vehicle models.

SVMs have similar characteristics as described below in section VI.E.1, the Panel recommended that we apply the lead time transition and hardship provisions to all SVMs. These manufacturers represent just a fraction of one percent of the light-duty vehicle and light-duty truck sales. Our proposal today is consistent with the Panel's recommendation.

1. Lead Time Transition Provisions

In these types of vehicle businesses, predicting sales is difficult and it is often necessary to rely on other entities for technology (see earlier discussions in section VI on technology needed to meet the proposed standards).^{222 223} Moreover, percentage phase-in requirements pose a dilemma for an entity such as a SVM that has a limited product line. For example, it is challenging for a SVM to address percentage phase-in requirements if the manufacturer makes vehicles in only one or two test groups. Because of its very limited product lines, a SVM could be required to certify all their vehicles to the new standards in the first year of the phase-in period, whereas a full-line manufacturer (or major manufacturer) could utilize all four years of the phase-in. Thus, similar to the flexibility provisions implemented in the Tier 2 rule, the Panel recommended that we allow SVMs, manufacturers with sales less than 15,000 vehicles per year (includes all vehicle small entities that would be affected by this rule, which are the majority of SVMs) the following flexibility options for meeting cold temperature NMHC standards and evaporative emission standards as an element of determining appropriate lead time for these entities to comply with the standards.

For cold NMHC standards, the Panel recommended that SVMs simply comply with the standards with 100 percent of their vehicles during the last year of the 4 year phase-in period. Since these entities could need additional lead time flexibility and proposed standards for light-duty vehicles and light light-duty trucks would begin in model year 2010 and would end in model year 2013 (25%, 50%, 75%, 100% phase-in over 4

²²² For example, as described later in section VI.E.3, ICIs may not be able to predict their sales because they are dependent upon vehicles brought to them by individuals attempting to import uncertified vehicles.

²²³ SVMs (those with sales less than 15,000 vehicles per year) include ICIs, alternative fuel vehicle converters, companies that produce specialty vehicles by modifying vehicles produced by others, and companies that produce small quantities of their own vehicles, but rely on major manufacturers for engines and other vital emission related components.

years), we propose that the SVM provision would be 100 percent in model year 2013. Also, since the proposed standard for heavy light-duty trucks and medium-duty passenger vehicles would start in 2012 (25%, 50%, 75%, 100% phase-in over 4 years), we propose that the SVM provision would be 100 percent in model year 2015.

In regard to evaporative emission standards, the Panel recommended that since the proposed evaporative emissions standards would not have phase-in years, we allow SVMs to simply comply with standards during the third year of the program (we have implemented similar provisions in past rulemakings). Given the additional challenges that SVMs face, as noted above, we believe that this recommendation is reasonable. Therefore, for a 2009 model year start date for light-duty vehicles and light-duty trucks, we propose that SVMs meet the evaporative emission standards in model year 2011. For a model year 2010 implementation date for heavy light-duty trucks and medium-duty passenger vehicles, we propose that SVMs comply in model year 2012.

2. Hardship Provisions

In addition, the Panel recommended that hardship provisions be extended to SVMs for the cold temperature NMHC and evaporative emission standards as an aspect of determining the greatest emission reductions feasible. These entities could, on a case-by-case basis, face hardship more than major manufacturers (manufacturers with sales of 15,000 vehicles or more per year), and we are proposing this provision to provide what could prove to be a needed safety valve for these entities. SVMs would be allowed to apply for up to an additional 2 years to meet the 100 percent phase-in requirements for cold NMHC and the delayed requirement for evaporative emissions. As with hardship provisions for the Tier 2 rule, we propose that appeals for such hardship relief must be made in writing, must be submitted before the earliest date of noncompliance, must include evidence that the noncompliance will occur despite the manufacturer's best efforts to comply, and must include evidence that severe economic hardship will be faced by the company if the relief is not granted.

We would work with the applicant to ensure that all other remedies available under this rule are exhausted before granting additional relief. To avoid the very existence of the hardship provision prompting SVMs to delay development, acquisition and application of new

technology, we want to make clear that we would expect this provision to be rarely used. Our proposed rule contains numerous flexibilities for all manufacturers and it delays implementation dates for SVMs, which effectively provides them more time. We would expect small volume manufacturers to prepare for the applicable implementation dates in today's proposed rule.

3. Special Provisions for Independent Commercial Importers (ICIs)

Although the SBAR panel did not specifically recommend it, we are proposing to allow ICIs to participate in the averaging, banking, and trading program for cold temperature NMHC fleet average standards (as described in Table IV.B.-1), but with appropriate constraints to ensure that fleet averages will be met. The existing regulations for ICIs specifically bar ICIs from participating in emission related averaging, banking, and trading programs unless specific exceptions are provided (see 40 CFR 85.1515(d)). The concern is that they may not be able to predict their sales and control their fleet average emissions because they are dependent upon vehicles brought to them by individuals attempting to import uncertified vehicles. However, an exception for ICIs to participate in an averaging, banking, and trading program was made for the Tier 2 NO_x fleet average standards, and today we propose to apply a similar exception for the cold temperature NMHC fleet average standards.

If an ICI is able to purchase credits or to certify a test group to a family emission level (FEL) below the applicable cold temperature NMHC fleet average standard, we would permit the ICI to bank credits for future use. Where an ICI desires to certify a test group to a FEL above the applicable fleet average standard, we would permit them to do so if they have adequate and appropriate credits. Where an ICI desires to certify to an FEL above the fleet average standard and does not have adequate or appropriate credits to offset the vehicles, we would permit the manufacturer to obtain a certificate for vehicles using such a FEL, but would condition the certificate such that the manufacturer can only produce vehicles if it first obtains credits from other manufacturers or from other vehicles certified to a FEL lower than the fleet average standard during that model year.

Our experience over the years through certification indicates that the nature of the ICI business is such that these companies cannot predict or estimate

their sales of various vehicles well. Therefore, we do not have confidence in their ability to certify compliance under a program that would allow them leeway to produce some vehicles to a higher FEL now but sell vehicles with lower FELs later, such that they were able to comply with the fleet average standard. We also cannot reasonably assume that an ICI that certifies and produces vehicles one year, would certify or even be in business the next. Consequently, we propose that ICIs not be allowed to utilize the deficit carryforward provisions of the proposed ABT program.

VII. Proposed Gasoline Benzene Control Program

A. Overview of Today's Proposed Fuel Control Program

As discussed in sections I, IV, and V above, people experience elevated risk of cancer and other health effects as a result of inhalation of air toxics. Mobile sources are responsible for a significant portion of this risk. As required by section 202(l) of the Clean Air Act, EPA has evaluated options to reduce MSAT emissions by setting standards for motor vehicle fuel. We have determined that there are fuel-related technologies available to feasibly reduce MSAT emissions and that these reductions are achievable, considering cost, energy, and other factors. These feasible reductions would be in addition to those resulting from actions taken by the industry in response to the earlier fuel-related MSAT programs described in section V above. Accordingly, we believe a fuel control program is necessary and appropriate to reduce air toxics emissions from motor vehicles to the greatest extent achievable (in addition to the programs proposed elsewhere in this notice to reduce MSAT emissions by changes to gasoline-powered motor vehicles and gas cans). This section of the preamble describes our proposed fuel control program.

The section begins with a detailed description of today's proposed program. In summary, we propose that beginning January 1, 2011, refiners would meet an average gasoline benzene content standard of 0.62% by volume on all their gasoline (reformulated and conventional) nationwide.²²⁴ We also propose that refiners could generate benzene credits and use or sell them as a part of a nationwide averaging, banking, and trading (ABT) program.

²²⁴ The State of California has a similar benzene standard and gasoline sold there is not covered by this proposal. For more information, see California Code of Regulations, Title 13 Section 2262.

We believe that the proposed benzene standard, combined with the proposed ABT program, would result in the largest feasible overall reductions in benzene emissions of any potential fuel-based MSAT control program. Finally, as an aspect of achieving the greatest emission reductions, we also propose special compliance flexibility for approved small refiners.

This section then describes in detail how we arrived at the proposed program. We discuss a range of potential approaches to reducing MSATs through changes in fuel, concluding that benzene emissions would be significantly more responsive to fuel changes than emissions of any other fuel-related MSAT. This is followed by discussion of alternate methods of reducing benzene emissions, resulting in the proposed approach of directly controlling benzene content. We also discuss how we arrived at the proposed level of 0.62 volume percent (vol%) for the benzene standard. We discuss why we believe that incorporating the proposed ABT program would be crucial for the effectiveness of the overall benzene control program and describe how the system would work. Finally, we review the recommendations of the special panel that was convened to assess the potential for disproportionate impacts of the proposed program on small refiners, and present our reasoning for the special small refiner provisions we are proposing today.

Today's proposed action would fulfill several statutory and regulatory goals for gasoline-related MSAT emissions, which are discussed in more detail in this section. The program would meet our commitment in the MSAT1 program to consider further MSAT control. The program would also allow EPA to streamline the regulatory provisions for the air toxics performance requirements of the reformulated gasoline (RFG) and Anti-dumping programs. The expected levels of benzene control by individual refiners under this proposal, combined with other gasoline controls such as sulfur, RVP, and VOC controls, mean that compliance with these provisions is expected to lead to compliance with the annual average requirements for benzene and toxics performance for RFG and the annual average Anti-dumping toxics performance for conventional gasoline. EPA is therefore proposing that upon full implementation in 2011, the regulatory provisions for the benzene control program would become the single regulatory mechanism used to implement these RFG and Anti-dumping annual average toxics requirements, replacing the current RFG

and Anti-dumping annual average provisions (although the 1.3 vol% benzene cap would still apply for RFG). The proposed benzene control program would also replace the MSAT1 requirements. In addition, the program would satisfy certain fuel MSAT conditions of the Energy Policy Act of 2005. By consciously designing this proposed program to address these separate but related goals, we would significantly consolidate and simplify the existing national fuel-related MSAT regulatory program.

Finally, this section concludes with a detailed summary of our assessment of the technological feasibility for different types of refineries, and the refining industry as a whole, to meet the program as proposed. We request general and specific comment on all aspects of the proposed program, and we request that comments include supporting data whenever possible.

B. Description of the Proposed Fuel Control Program

Today's proposed program has three main components, the development of each of which is further described later in this section:

—A gasoline benzene content standard.

We propose that an annual average gasoline benzene standard of 0.62 vol% be implemented beginning January 1, 2011. This single standard would apply to all gasoline, both reformulated (RFG) and conventional (CG) nationwide (except for gasoline sold in California, which is already covered by a similar state program).

—An averaging, banking, and trading (ABT) program.

From 2007–2010 refiners could generate benzene credits by taking early steps to reduce gasoline benzene levels. Beginning in 2011 and continuing indefinitely, refiners could generate credits by producing gasoline with benzene levels below the 0.62% average standard. Refiners could apply the credits towards company compliance, “bank” the credits for later use, or transfer (“trade”) them to other refiners nationwide (outside of California) under the proposed program. Under this program, refiners could use credits to achieve compliance with the benzene content standard, regardless of their actual gasoline benzene levels.²²⁵

—Hardship provisions.

Refiners approved as “small refiners” would have access to special temporary relief provisions. In addition, any refiner

²²⁵ However, the per-gallon benzene cap (1.3 vol%) in the RFG program would continue to apply separately.

facing extreme unforeseen circumstances or extreme hardship circumstances could apply for similar temporary relief.

C. Development of the Proposed Gasoline Benzene Standard

EPA believes that benzene control is by far the most effective fuel-based means of achieving MSAT emissions control, as described in this section. There are other options that can target individual MSATs or reduce overall VOCs and thereby reduce MSATs as well. We have evaluated these other options, as discussed below, and our analysis indicates that the potential MSAT reductions would be considerably smaller and more expensive.

1. Why Are We Focusing on Controlling Benzene Emissions?

We considered controlling emissions of several MSATs through changes to fuel parameters. There are only a limited number of MSATs that are affected through fuel changes, each of which we discuss below. For several reasons, we have concluded that the most effective and appropriate means of reducing fuel-related MSATs is to reduce the benzene emissions attributable to gasoline.

Benzene emissions can be reduced much more significantly through fuel changes than can emissions of other MSATs. Relatively small changes in gasoline can result in very significant reductions in benzene emissions. This relative responsiveness of benzene emissions to fuel controls (specifically to control of gasoline benzene content, as discussed in the next section) is coupled with little negative impact on other important characteristics of gasoline or refining processes. A related and critical advantage of fuel control of benzene emissions, as compared to fuel control of emissions of other MSATs as discussed below, is that controlling benzene emissions does not significantly increase emissions of other MSATs.²²⁶

In determining an appropriate approach to fuel-related MSAT control, a key consideration was octane value.

²²⁶ A key tool in evaluating the potential for fuel changes to affect MSAT emissions is EPA's Complex Model. This model relates changes in gasoline parameters with emissions of specific MSATs and was developed for refiners and EPA to assess compliance with the RFG, Anti-dumping, and MSAT1 programs. (See section V.D.1 above.) Given a set of gasoline parameters, it estimates the emissions of an average vehicle based on a large set of fuel effects data. We further discuss the Complex Model, as well as other sources of information the relationships between fuel changes and MSAT emissions, in chapter 6 of the RIA.

Among potential approaches to fuel-related MSAT emission reduction, only benzene emission reduction can avoid major losses in octane value and the negative cost and environmental consequences discussed below of replacing that lost octane value. Finished gasoline must meet minimum specifications for octane value; these specifications are tied to the operational needs of motor vehicles. Thus, refiners must be keenly aware of how any changes in gasoline production might reduce the octane value of their fuel, what approaches to restore the octane value might be available, and the costs in material and operational changes of any selected approach.

There are a limited number of approaches refiners have at their disposal to restore gasoline octane value lost through control of MSAT emissions. These approaches vary in their economics and effectiveness, and their availability may be limited by the specific configuration of a given refinery. However, all methods of replacing octane value have cost implications, and as shown in the next paragraph, air toxics implications as well.

In the case of changes in gasoline production that are intended to reduce MSAT emissions, it is also important to consider whether restoring any lost octane might itself significantly increase other MSAT emissions. Some methods of replacing octane value can increase other MSATs. For example, increasing aromatics would increase benzene emissions; adding MTBE would increase formaldehyde emissions; and adding ethanol would increase acetaldehyde emissions. Given the very large MSAT emission reduction associated with benzene control, these impacts on other MSATs are relatively insignificant. However, in the case of changes in other fuel qualities (e.g., aromatics control), the relative impacts on other MSATs would be greater.

We encourage comment on our decision to propose a program that directly controls gasoline benzene content, including comments on each of the alternate approaches to MSAT control discussed in the following paragraphs.

a. Other MSAT Emissions

As alternatives to the proposed program focusing on benzene emission reductions, we considered other MSATs that are responsive to fuel-based emission control. Each of these is discussed next.

Polycyclic Organic Matter, or POM, is composed of a number of combustion products of gasoline. According to the

Complex Model, POM emissions are a function of exhaust VOC. Several fuel parameters including volatility and sulfur content affect VOC emissions. As discussed below, little data exists about the potential impacts of changes in gasoline volatility and sulfur content on VOC, and thus POM, emissions from new Tier 2-compliant vehicles. In any event, because POM is only a tiny fraction of vehicle VOC emissions, we expect that further changes in these fuel parameters would have only small effects on POM. As a result, we are not proposing fuel controls to address POM emissions in today's action.

Emissions of the compound 1,3-butadiene can be reduced by reducing the olefin content of gasoline. However, olefin reduction yields relatively small reductions in 1,3-butadiene and can increase VOC emissions. In addition, olefin reduction significantly affects octane, with the negative cost and MSAT emissions consequences of octane replacement. We are thus not proposing to address 1,3-butadiene emissions through fuel changes.

Emissions of the compound formaldehyde can only be effectively reduced by reducing use of the octane enhancer methyl tertiary butyl ether (MTBE). This is because formaldehyde increases significantly as a combustion product when MTBE is added to gasoline. Formaldehyde also increases to a lesser extent when ethanol is added to gasoline, as described below. For a number of years, MTBE has been used as a cost-effective way to meet mandated fuel oxygenate requirements and to boost octane. In recent years, many states have banned the use of MTBE because it has leaked from storage tanks and caused significant groundwater contamination. More recently, in the wake of the removal of the oxygenate requirement in the Energy Policy Act of 2005, many refiners are taking action to remove MTBE from their gasoline as soon as possible. As a result, MTBE use and the resulting formaldehyde emissions are expected to continue to decline, and no additional federal action appears warranted at this time.

The compound acetaldehyde is a combustion product of gasoline when ethanol is added. Controlling acetaldehyde would require reductions in the use of ethanol as a gasoline additive. However, the Energy Policy Act of 2005 (section 1501) includes a renewable fuels program that will increase use of ethanol in gasoline nationwide. That Act requires a study of the Act's impacts on public health, air quality, and water resources. We accordingly intend to defer further

evaluation of acetaldehyde emissions to the analyses associated with the Energy Policy Act.

b. MSAT Emission Reductions Through Lowering Gasoline Volatility or Sulfur Content

We also considered two approaches to fuel-related MSAT control that would involve increasing the stringency of two existing emission control programs. Both were originally promulgated primarily to address ozone but also have the effect of reducing some MSAT emissions by virtue of their control of VOC emissions. As explained in section V, the Tier 2 program included the pairing of lower vehicle emissions standards with large reductions in gasoline sulfur levels. The low sulfur fuel helped enable development of more advanced catalytic aftertreatment systems needed to meet the stringent tailpipe standards. These actions will result in large reductions of VOC, NO_x, and air toxics emissions. In development of today's proposal, we considered whether further reductions in fuel sulfur would bring significant additional reductions in MSAT emissions.

The second program considered for additional stringency was the gasoline volatility program, which was implemented in 1989 to address evaporative VOC emissions from gasoline vehicles. Reducing the volatility of gasoline can reduce evaporative VOC emissions as well as exhaust emissions. Evaporative VOC emissions include benzene. As a result, in developing this proposal we have considered whether further reductions in gasoline volatility may be effective in further reducing MSAT emissions.

In the cases of both further reductions in RVP and sulfur reductions below the current 30 ppm standard, the available data is not sufficient to conclude that additional control of either would be a valuable MSAT emission reduction strategy. Historic data suggest that reducing both RVP and sulfur content would reduce overall VOC emissions from vehicles, in turn reducing both MSATs and ozone formation. However, vehicles complying with the stringent new Tier 2 emission standards have dramatically lower VOC emissions than earlier vehicles. Furthermore, it is likely that VOC emissions for these vehicles would react differently to RVP and sulfur control than older vehicles, as new catalysts and control systems may have more or less sensitivity to these variables. Since the dominant effect on MSAT emissions of changing these fuel parameters is through their impact on total VOC mass, it is not possible to

properly assess the impact of changes in these fuel parameters on MSAT emissions without additional data. We have begun collecting data on some of these new vehicles, but more work will be required before we can draw conclusions about the effectiveness of these fuel controls in reducing MSAT emissions. Therefore, we are not proposing additional control of gasoline volatility or sulfur at this time, but will continue to evaluate them for possible future action. We request comments on these potential fuel controls as emission reduction strategies, in particular for MSAT emissions, including any data that does or does not support the effectiveness of such controls.

i. Gasoline Sulfur Content

In general, reducing gasoline sulfur levels increases the effectiveness of the catalytic converter at destroying unburned fuel and other VOCs in vehicle exhaust. Catalytic converters contain a variety of physical and chemical structures that act as reaction sites for conversion of raw exhaust gases into less harmful ones before they are emitted into the atmosphere. Over time, sulfur compounds in the exhaust gases interfere with these processes, making the catalyst less effective under normal driving conditions.²²⁷ Since many air toxics are part of the exhaust VOCs, reduction of fuel sulfur would be expected to reduce air toxics emissions. As with the Tier 2 program, however, desulfurizing gasoline further would reduce gasoline octane. Most options for recovering this lost octane (e.g., increasing aromatics) would result in some offsetting MSAT emissions increases.

EPA primarily uses two computer models for examining emissions impacts when considering changes in fuel properties: the Complex Model and the MOBILE model. The Complex Model (CM) was developed as a compliance tool that refiners use to ensure their gasoline meets its baseline requirements under the RFG, Anti-dumping, and MSAT1 programs. Given a set of fuel parameters, it estimates the emissions of an average vehicle using regression relationships drawn from a large set of fuel effects data. The CM contains data on test fuels with sulfur levels as low as 5 ppm, but is based on the Auto/Oil research programs of the early 1990s, and reflects performance of vehicles on the road during that time period. With a sulfur reduction from 30 ppm to 10 ppm applied to average 2003

conventional gasoline, the CM projects a decrease of approximately 1% for exhaust benzene, NO_x and CO.

MOBILE was developed to estimate aggregate emissions on a county, state, or national scale. It uses a fuel effects dataset that includes the CM dataset with some updates, along with driving data, to predict emissions inventories of pollutants for a specified time period and area of the country. MOBILE6.2 contains updates from a small number of LEV and ULEV vehicles in addition to the CM dataset, but applies a lower limit of 30 ppm to fuel sulfur content being modeled to avoid extrapolation beyond the range of available emissions data.

Based primarily on the above models, the analyses done for the Tier 2 rulemaking suggested benzene emission reductions on the order of 9% could be expected in 2020 as a result of the fuel sulfur reduction expected from that program alone (the final Tier 2 program included low sulfur gasoline as well as tightened vehicle standards).²²⁸ A recent study done on vehicles meeting LEV, TLEV, and ULEV standards indicates that sulfur reductions from 30 to 5 ppm may reduce NMHC by more than 10%, bringing similar reductions in air toxics.²²⁹ Additional analyses done by EPA on sulfur reductions in this range suggest VOC emission reductions on the order of 5% may be expected, with refining costs estimated at about a half cent per gallon. Given these analyses using available data, using sulfur reductions as air toxics control alone would not be as cost-effective as other options in this proposal. Further discussion of the feasibility and costs are available in Chapters 6 and 9, respectively, of the RIA.

Since our models do not reflect the significant improvements in emissions control technology over the past decade, more fuel effects studies are necessary on newest-technology vehicles before going forward with sulfur control. A small cooperative test program is currently underway between EPA and the Alliance of Automobile Manufacturers to evaluate the effects of reducing sulfur below 10 ppm on Tier 2 Bin 5 compliant vehicles.

In addition to potential air toxics reductions from adjustment of gasoline sulfur to 10 ppm, reducing sulfur may also provide significant VOC and NO_x emission reductions. These emission reductions may be important for states in complying with the National

Ambient Air Quality Standards (NAAQS) for ozone. Since the implementation of the RFG program, several states and localities have made their own unique fuel property requirements in an effort to further improve air quality.²³⁰ As a result, by summer 2004 the gasoline distribution and marketing system in the U.S. had to differentiate between more than 12 different fuel specifications, when storing and shipping fuels between refineries, pipelines, terminals, and retail locations. These unique fuels decrease nationwide fungibility of gasoline, which can lead to local supply problems and amplify price fluctuations.^{231, 232} In addition to the existing state fuel programs, we are aware of a number of other states considering new programs (although in the context of the recently enacted Energy Policy Act it is unclear what will occur). While the timeline for state action on new fuel formulations could be prior to any nationwide ultra-low sulfur standard, implementation of such a standard could help diminish issues related to small-market fuel programs in the long term.

From the perspective of gasoline production, reducing sulfur to ultra-low levels does not happen completely independently of other fuel parameters. The emissions benefits of further sulfur reduction gained in vehicle aftertreatment may be offset by unintended changes in other gasoline properties. The refining process modifications required to bring sulfur to ultra-low levels begin to have a stronger effect on other components of gasoline, such as olefins (the effect of which is discussed in the previous section). These impacts must be further evaluated before moving forward with a proposal of additional sulfur reductions for the purpose of air toxics reduction. These issues are also discussed in more detail in Chapter 6 of the RIA.

Refiners with whom we have met have generally expressed disapproval of further sulfur control. The Tier 2 gasoline sulfur program requires refiners to meet an average standard of 30 ppm. In response many have invested in and brought online desulfurization units, which would not have the capacity to

²³⁰ These changes have focused almost exclusively on additional RVP control, with just one program also controlling sulfur to 30 ppm earlier than required by EPA.

²³¹ EPA, Study of Unique Gasoline Fuel Blends ("Boutique Fuels"), Effects on Fuel Supply and Distribution and Potential Improvements, EPA420-P-01-004

²³² GAO, Special Gasoline Blends Reduce Emissions and Improve Air Quality, but Complicate Supply and Contribute to Higher Prices, GAO-05-421

²²⁷ For further discussion on sulfur effects on emissions, see the Tier 2 Regulatory Impact Analysis, EPA 420-R-99-023.

²²⁸ Tier 2 Regulatory Impact Analysis, EPA 420-R-99-023

²²⁹ AAM-Honda fuel effects study, 2000

reach a new, lower standard of 10 ppm in many cases. Modifications would have to be made to units that have recently been installed to comply with the current gasoline sulfur requirements. In some cases these units might have to be replaced with new units. EPA requests comments on the magnitude of the impact of a new, lower sulfur standard, including the potential effect on refiners that have recently installed desulfurization units.

On the automotive side, sulfur reduction may encourage further development of lean-burn or direct-injection gasoline technology. Leaner combustion of gasoline results in greater fuel economy and less VOC and carbon dioxide emissions, but generally produces more engine-out nitrogen oxides. Reducing fuel sulfur to 10 ppm would improve feasibility and reduce cost of next-generation aftertreatment designed to control these higher levels of nitrogen oxides. EPA will continue to evaluate further gasoline sulfur reductions, and seeks comment on it, especially with data supporting or opposing such action.

ii. Gasoline Vapor Pressure

According to the Complex Model and the MOBILE model, reducing fuel vapor pressure reduces evaporative as well as exhaust VOC emissions. Reducing VOC emissions in turn reduces MSAT emissions. A portion of this MSAT emission decrease through VOC control would likely be offset through an increase in the relative concentration of MSAT emissions. As volatility is decreased, non-aromatic compounds are removed from the gasoline, increasing the concentration of aromatics. Furthermore, these non-aromatic compounds are higher in octane, which would have to be offset—perhaps with still further increases in aromatics. Such increases in aromatics would lead to an increase in the relative concentration of benzene in VOC emissions. However, since changing vapor pressure has an effect on evaporative emissions, reducing vapor pressure can also reduce evaporative benzene from stationary sources related to gasoline distribution and marketing. Moreover, reducing overall VOC emissions reduces ground level ozone in urban areas, which itself has a significant impact on health and welfare.

Currently, in reformulated gasoline (RFG) areas, fuel is limited to roughly 7.0 psi Reid vapor pressure (RVP) in the summer season in order to meet the VOC performance standard. Additional vapor pressure controls considered for this proposal would regulate RVP levels to 7.0 or 7.8 in some conventional

gasoline (CG) ozone nonattainment areas, resulting in an impacted volume of gasoline equal to about 50% of that of current federal RFG. Further details of these analyses are covered in Chapter 6 of the RIA.

As with the sulfur analyses above, EPA also uses the Complex Model and MOBILE to estimate emissions impacts of changes in gasoline vapor pressure. In terms of the fuel parameter itself, this process is somewhat simpler than modeling sulfur effects since the range of vapor pressures useful in conventional vehicles has been well-defined for a number of years and is not expected to change. However, parallel to the arguments made above for sulfur, data on the effects of RVP changes on air toxics in these models is dated and does not represent newest technology. Since our models do not reflect improvements in emissions control technology for the Tier 2 program, more fuel effects studies must be carried out before making decisions on further gasoline vapor pressure controls. The cooperative test program between EPA and the Alliance of Automobile Manufacturers described above is also examining some of the effects of changes in RVP.

Looking beyond emissions benefits, more stringent national vapor pressure standards could also help avoid additional small market (“boutique”) fuels. Several states and localities have adopted their own seasonal requirements for vapor pressure in an effort to improve air quality, contributing to constraints on gasoline supply and potential for price volatility.^{233 234}

Feedback from refiners on further volatility control has highlighted concerns with the summer-winter butane balance and resulting potentially adverse supply implications. Currently, refiners who produce large quantities of RFG must remove a significant amount of the light-end components from their fuel in the summer to meet the vapor pressure specifications. These light components, primarily butanes, are often stored and then blended back into gasoline in the winter when higher fuel vapor pressures are needed for drivability reasons. Several refiners have indicated that a new rule adding a number of reduced RVP areas would cause the amount of butanes removed in

summer to exceed what is useable in winter, resulting in a net loss of volume from the annual pool and a need to make up supply at additional expense. EPA will continue to evaluate further gasoline volatility reductions, and seeks comment on it, especially with data supporting or opposing such action.

c. Toxics Performance Standard

While we are not proposing it, we considered and are seeking comment on the merits of expressing the standard as an air toxics performance standard rather than as a benzene content standard. Such a standard would be analogous to the current MSAT1 standard, but more stringent and with an ABT component. In theory, a toxics performance standard could provide broader environmental benefits by addressing other toxics in addition to benzene. However, because controlling benzene is more cost-effective than controlling emissions of other MSATs, refiners are unlikely to reduce emissions of other MSATs whether or not the standard is in the form of a toxics performance standard or a benzene content standard. Setting a toxics performance standard at an appropriate level also requires us to predict future changes in fuel properties in addition to benzene, and to be able to establish as precisely as possible the effects of those fuel properties on emissions of several MSATs. In addition, a toxics emission performance standard is more complex to implement and enforce than a benzene content standard. For all of these reasons, as discussed more fully below, we believe a benzene content standard offers more certain environmental results and less complexity. However, we seek comment on the overall merits of an air toxics performance standard, including comments specifically on the tradeoff between the complexity of complying with a performance standard and the additional environmental benefits it could provide.

Based on our analysis for this proposal, fuel benzene control is by far the most effective and cost-effective means of achieving MSAT emission reductions. This is consistent with our experience with the MSAT1 and other air toxics control programs, which have shown that even when refiners have the flexibility to choose among different fuel changes to achieve MSAT control, reduction in benzene content is the predominant choice. Only when other fuel changes that impact MSAT emission performance are mandated (e.g., sulfur control, oxygenate use) have refiners made fuel changes other than benzene content to control MSAT

²³³ EPA, Study of Unique Gasoline Fuel Blends (“Boutique Fuels”), Effects on Fuel Supply and Distribution and Potential Improvement, EPA420-P-01-004.

²³⁴ GAO, Special Gasoline Blends Reduce Emissions and Improve Air Quality, but Complicate Supply and Contribute to Higher Prices, GAO-05-421.

emissions. As a result, even if we were to express the proposed standard as an air toxics performance standard rather than a benzene content standard, we would expect the outcome to be the same—benzene content control with corresponding benzene emission reductions and no changes in other MSAT emissions. Our analysis of the feasibility and cost of the program would be identical as well. If future fuel parameters are significantly different than we have projected in this analysis such that emissions of other MSATs decrease, then a toxic performance standard would result in less benzene control than would be achieved by the benzene content standard we propose today, with a corresponding overall reduction in cost. If future fuel parameters are significantly different such that emissions of other MSATs increase, then refiners would need to reduce benzene content to levels that are not feasible considering cost, but overall toxics performance would be maintained.

If we were to set an air toxics performance standard, the accuracy of the model used in estimating the real world effects of the many different fuel parameters on MSAT emissions also becomes of critical importance. To the extent fuel changes are projected to result in air toxics emission reductions that are not in fact borne out in-use, then the standard will have less benefit. There was a great deal of work done in the early 1990's to develop the Complex Model for the reformulated gasoline program. It estimates VOC, NO_x, and certain MSAT emissions (benzene, 1,3-butadiene, formaldehyde, acetaldehyde, and POM) as a function of eight fuel properties (RVP, oxygen, aromatics, benzene, olefins, sulfur, E200, and E300) for 1990 technology vehicles. However, a similar set of comprehensive data does not yet exist for new Tier 2 vehicles. Some of the fuel effects that were found to be statistically significant in the Complex Model may not be significant for Tier 2 vehicles (e.g., distillation properties). Others that impacted MSAT emissions primarily through their impact on VOC emissions may be of much less importance, due to the much lower VOC emissions of Tier 2 vehicles.²³⁵ To the extent that the Complex Model gives air toxics credit for fuel changes that are later found to be much smaller or not valid at all, a toxics performance standard could result in less fuel benzene control and less in-use MSAT control. Of all the fuel

changes from past modeling, we would have the greatest confidence that the benzene relationships are unlikely to change significantly. This is due to the direct relationship between benzene fuel content and benzene evaporative and exhaust emissions, and due to the magnitude of these impacts. Thus, we would have the greatest confidence that the MSAT emission reductions projected from a fuel benzene content standard will be realized in-use.

In addition, if we were to set an air toxics performance standard, it would be important to have a clear understanding of the changes in fuel properties anticipated in the future independent of today's proposal. Significant changes in the composition of gasoline are anticipated over the next several years as a result of the Energy Policy Act of 2005 (EPAAct). MTBE is being removed from gasoline, ethanol use is increasing dramatically, and the oxygenate mandate for RFG is being eliminated. To the extent that these changes would result in reductions in modeled MSAT emission performance automatically, then refiners could comply with an air toxics performance standard with less benzene control than would be achieved under today's proposed benzene standard, and with lower overall costs. Conversely, to the extent that these changes would result in increases in modeled MSAT emission performance, an air toxics performance standard would require refiners to take additional measures to maintain overall MSAT performance, but these measures may not be cost-effective.

Although a toxics performance standard could theoretically give refiners more flexibility than a program focusing only on benzene emissions, we do not believe that such flexibility would be meaningful in actual practice. As discussed above, in order to comply with a new total MSAT standard, we expect that refiners would rely almost exclusively on benzene control. However, if their emission performance for other MSATs changed in the future (due to such factors as changes in oxygenate use, octane needs, or crude oil quality), refiners could find themselves unable to maintain overall MSAT performance using cost-effective controls.

For all these reasons, we are not proposing to address fuel-related MSAT emissions with a toxics performance standard, but we seek comment on this option.²³⁶ We also seek comment on the

merits of applying an air toxics performance standard in addition to a fuel benzene content standard, and how such a dual standard could be implemented. From a theoretical standpoint, this dual standard might serve as a backstop to ensure overall toxics performance is maintained. However, it is not clear how such an approach could be realistically implemented, especially in the context of ABT programs that apply to both.

d. Diesel Fuel Changes

We are also not proposing today to reduce MSATs by changing diesel fuel. The existing major diesel fuel sulfur programs being implemented in the next few years for highway and nonroad diesel fuel will have a very large impact on reducing MSAT emissions “ specifically diesel particulate matter and exhaust organic gases. We have found in the on-highway diesel engine rulemaking that these are the greatest reductions achievable and reiterate that finding here. (See also section V.D.1.f above.) We are not aware of other changes to diesel fuel that could have a significant effect on emissions of any other MSATs. We welcome comment on our decision to focus this proposed program exclusively on changes to gasoline.

2. Why Are We Proposing To Control Benzene Emissions By Controlling Gasoline Benzene Content?

In the previous section, we describe how we decided to focus today's proposed fuel program on gasoline benzene emissions. This section describes our decision to propose to reduce benzene emissions through a gasoline benzene content standard. We also describe our consideration of two other potential approaches to reducing benzene emissions, both of which would indirectly reduce gasoline benzene content: a standard to control the gasoline content of all aromatic compounds; and a standard to control benzene emissions.

a. Benzene Content Standard

For several reasons we have decided that a benzene content standard would be the most cost-effective and most certain way to reduce gasoline benzene emissions (and thereby MSAT emissions in general). First, a small change in gasoline benzene content results in large reductions in benzene emissions “ benzene typically

current MSAT 1 program, and (consistent with section 1504(b)(2) of the EPAAct) greater overall reductions of air toxics from reformulated gasoline than would be obtained under amended section 211(k)(1)(B) as well.

²³⁵ This is one reason why the Energy Policy Act of 2005 requires EPA to create an updated gasoline emissions model by 2009.

²³⁶ As explained further in section VII.C.5 below, based on the use of the currently available models, the proposed rule would result in greater overall reduction of air toxics from all gasoline than the

represents around 1 percent of gasoline, but this contributes about 25 percent of benzene exhaust and evaporative emissions.²³⁷ Second, we have high confidence in the benzene emission reductions that would result from fuel benzene control. Historical data across a range of vehicles and engine types continues to support the relationship between fuel benzene content and benzene emissions. Even if Tier 2 vehicles react differently, the relationship is unlikely to change significantly. Third, because a relatively small change in gasoline properties is needed to achieve the desired result, reducing benzene content does not have a large impact on octane value. Benzene itself does contribute to the octane value of gasoline, but the small loss of octane from reducing benzene content is much less than the octane loss from reducing other aromatics for the same benzene emission effect, as discussed below, and the consequences of refiners having to replace that octane value are also much less. (This is why, as noted earlier, we anticipate that refiners would seek to comply with any toxics standard by reducing benzene levels in any case.) Fourth, we believe that a direct benzene content standard would best ensure real benzene emission reductions, including both exhaust and evaporative benzene emissions. We discuss this conclusion below, in the context of the potential alternative of a benzene emission standard.

b. Gasoline Aromatics Content Standard

Because benzene emissions are formed from benzene and other aromatics that are present in gasoline, we considered a standard that would limit the aromatics content of gasoline. However, we believe that reducing benzene emissions through a more general reduction in gasoline aromatics content would be much less cost-effective than direct benzene reduction. Non-benzene aromatics account for on average about 30 percent of gasoline (typically ranging between about 20 percent and 40 percent), and this fraction contributes about 30 percent of benzene emissions. In contrast, benzene only makes up about 1 percent of gasoline but is responsible for about 25 percent of benzene emissions. The remaining benzene emissions are formed from other compounds. Based on the Complex Model, it would require about a 20 percent reduction in non-benzene aromatics to achieve the same benzene emission reductions as the proposed benzene content standard. As we discussed earlier, a major

consequence of removing a significant amount of the aromatics in gasoline is the need to replace the large loss in octane value. As a result, it is much more costly for refiners to reduce benzene emissions through aromatics control than through benzene control. We have not evaluated the cost of aromatics control recently, but when we did so for the RFG rule in the early 1990s, the cost was about 5 times more to achieve the same benzene reduction through aromatics control than through benzene control.²³⁸ In recent years a variety of factors have reduced the use of MTBE as an octane booster; we expect that this trend will raise the relative cost of aromatics control even further.

In addition, aromatics reductions would have to be offset with other high-octane compounds, such as ethanol and ethers (e.g., ETBE and MTBE). Increasing other high-octane compounds tends to significantly increase other air toxics emissions (like acetaldehyde or formaldehyde). Consequently, the benzene emission reductions would be substantially offset by increases in other toxics. For these reasons, aromatics control has historically only been cost-effective for refiners when other requirements are placed on them, such as state or federal oxygenate mandates that also serve to boost octane value. For this same reason, we anticipate that further aromatics reductions will occur as a result of the near doubling of the use of ethanol in gasoline due to the renewable fuels standard contained in the EPA Act. Given a mandate for ethanol use and the cost associated with it, refiners can reduce their refining costs by further reducing aromatics.

Aromatics control would also affect other recent fuel control programs. For example, many refineries depend on the reforming process that produces aromatics to also supply much or all of the hydrogen needed for gasoline and diesel desulfurization processes. Reducing aromatics thus would indirectly reduce hydrogen supply, which would then likely require refiners to either purchase hydrogen or build hydrogen production facilities.

At the same time, although it would not be constrained, we do not believe that in the absence of aromatics control, refiners would be likely to increase gasoline aromatics content in the future. Aromatics are a relatively valuable gasoline component, and refiners are generally careful not to make changes

that would increase aromatics content more than is needed for octane purposes. In addition, as mentioned previously, the Renewable Fuel Standard that will be promulgated under the new Energy Policy Act will, by boosting ethanol use, increase the octane of the gasoline pool. We expect that this, in turn, will prompt refiners to reduce their use of aromatics for octane enhancement. Also, higher gasoline prices recently have reduced the demand for premium grade gasoline, which generally has higher aromatics levels. To the extent that this trend continues, we expect that it will tend to further reduce the levels of aromatics in the overall gasoline pool.

For all of these reasons, we believe that reducing benzene emissions through a benzene content standard would be much superior to doing so through an aromatics content standard. However, there may be other benefits associated with aromatics control in addition to benzene emissions. EPA is working to improve its understanding of the effect of mobile source emissions on ambient PM, especially secondary PM. For example, there is limited data that suggest that aromatic compounds (toluene, xylene, and benzene) react photochemically in the atmosphere to form secondary particulate matter (in the form of secondary organic aerosol (SOA)), although our current modeling tools do not fully reflect this. One caveat regarding this work is that a large number of gaseous hydrocarbons emitted into the atmosphere having the potential to form SOA have not yet been studied in this way. It is possible that hydrocarbons which have not yet been studied produce some of the SOA species which are being used as tracers for other gaseous hydrocarbons. This means that the current interpretation of the available studies may over-estimate the amount of SOA formation in the atmosphere. We seek comment on the potential benefits, costs, and other implications of aromatics control for consideration in the future.

c. Benzene Emission Standard

In addition to the benzene or aromatics fuel content standards discussed above, we have considered reducing benzene emissions through a benzene emission standard. The primary argument for such an approach is that it would focus on the environmental outcome we are interested in “reduced benzene emissions” while providing refiners some flexibility in how that goal was met.

In order to fully discuss this option, it is useful to clarify how such a

²³⁸ Final Regulatory Impact Analysis for Reformulated Gasoline, AEP4420-R-93-017, December 1993.

²³⁷ Based on the Complex Model.

benzene emission standard would be implemented. Instead of directly measuring gasoline content to determine compliance, as would be the case with a benzene (or aromatics) content standard, compliance would be determined using EPA's Complex Model or an updated version of it. Several parameters of a refiner's gasoline (including benzene and aromatics content) would be used as inputs into the model. Based on these and other assumed properties of the gasoline, the model would estimate the expected level of benzene emissions from that gasoline formulation.

As compared to a program based on the direct measurement of benzene content in gasoline, we believe that one relying on modeled estimates of benzene emissions would be difficult to set today. As with the toxics performance standard we considered above, gasoline parameters and their effects on MSAT emissions will be changing in the future due to the Energy Policy Act, changes in crude oil supplies, and perhaps other unknown factors. In addition, the effects of fuel changes on MSAT emissions from the new Tier 2 vehicles now entering the light-duty fleet are poorly represented in our modeling. Thus, it would be difficult to accurately predict future gasoline parameters and set an appropriate benzene emission standard that ensured the greatest emission reduction achievable, especially a standard that could remain stable for a number of years. As benzene content has been and is sure to remain by far the most important fuel parameter in estimating benzene emissions, a benzene content standard provides greater assurance of actual benzene emission reduction in-use.

Even if it were practical to set a long-term benzene emission standard, such an approach would be problematic for other reasons. As we have stated, the only significant option for reducing benzene emissions other than reducing benzene content is reducing aromatics content. Since we do not believe that requiring control of gasoline aromatics is appropriate at this time, a benzene emission standard would not result in appreciably different emission reductions than would result from a benzene content standard. However, given that aromatics control is a less effective means of reducing benzene emissions and has a more disruptive effect on octane values (as just discussed), requiring more aromatics control could dramatically increase the cost of compliance. Finally, although a benzene emission standard might be assumed to offer additional flexibility to

refiners, we do not believe that such flexibility would actually exist. Faced with a dependence on aromatics to meet octane requirements, and in some cases to provide hydrogen supply for desulfurization of gasoline and diesel fuel, we believe that refiners would choose benzene content reduction over aromatics reductions even when they theoretically had the choice to do otherwise. Experience with the MSAT1 emissions performance standard has confirmed this. However, as mentioned previously, gasoline parameters do change, octane requirements can decrease, ethanol will supply additional octane, and therefore aromatic reductions may occur in the future regardless. Were this to occur, a benzene emission standard set today could allow benzene content to increase in the future. Given the additional complexity and uncertainty associated with a benzene emission standard, we have therefore elected to propose a benzene content standard exclusively. We request comment on this approach and on a benzene emission standard.

3. How Did We Select the Level of the Proposed Gasoline Benzene Content Standard?

a. Current Gasoline Benzene Levels

In selecting an appropriate level for the proposed benzene content standard, we began by evaluating the current status of the industry regarding gasoline benzene. Benzene content varies widely among refineries, depending on such factors as refinery configuration and proximity to benzene markets. The national average benzene level was 1.6 vol% in 1990. Due to the 0.95 vol% requirement of the 1995 RFG program, the introduction of gasoline oxygenate requirements, and other factors, benzene levels have since declined. By 2003, RFG averaged 0.62 vol% benzene. (See section V.D.1 above.)

Benzene levels have also declined for CG over the same period, to an average of 1.14 vol%. This is in part because when faced with investing in new processes to comply with the RFG benzene standard, some refiners found it economical to install more benzene extraction capacity than was needed to meet the standard. As a result, in many cases, these refiners have also controlled benzene from CG.

b. The Need for an Average Benzene Standard

Even before considering the level of the benzene content standard, we first needed to consider the standard's potential form. A standard for this purpose could be expressed as a per-

gallon benzene limit, which would ensure that no gasoline exceeded a specified benzene level. In contrast, a benzene content standard could be expressed as a flexible average level, allowing some of the existing variability in current benzene levels to remain while reducing overall benzene levels. For several reasons, it became clear that an average standard was the most appropriate for this program.

As mentioned above, there is a great diversity in the benzene content of gasoline currently produced at refineries across the country. In 2003, the annual average benzene content of refineries ranged nationally from under 0.5 vol% to above 3.5 vol%. This variation among refineries is also reflected in large regional differences in average gasoline benzene content, as illustrated below (Tables VII.C-2 and VII.F-1).

In addition to average benzene levels varying widely across refineries and regions, per-gallon benzene levels for individual batches produced by a refinery also vary dramatically depending on the crude oil supply and the refinery streams used to produce a particular batch. This variation occurs as a result of a wide range of day-to-day decisions necessary in producing marketable gasoline within a refinery on a continuous basis. We reviewed actual batch data for a typical refinery producing both RFG and CG with an average benzene content of 1.6 vol% for all its gasoline, and batch benzene levels ranged from under 0.1 to 3.0 vol% for CG. The range for RFG is typically narrower due to the existing 1.3 vol% per gallon cap, but still shows significant batch to batch fluctuations. Batches that refiners produce with benzene higher than 1.3 vol% are marketed as CG.

We considered controlling benzene emissions with a fixed, per-gallon benzene content standard to be met at all refineries. By capping gasoline benzene content in this way, the program would ensure that all gasoline nationwide would have benzene levels below the selected upper limit. However, as we developed the rule, it became clear that with the large variation in benzene levels among refineries and regions (reflecting the variation in the economics of reducing benzene), a per-gallon standard would have to be so high (to account for maximum, legitimate potential variability) as to leave most refineries with little or no need to reduce benzene. Moreover, the burden of the national control program would fall almost entirely on the refineries where the challenges of control would be greatest, and where the most lead time would be

required for compliance. With many refineries able to comply without making any changes, we do not believe such a program would represent the greatest reduction feasible, as the Clean Air Act requires.

The typical fluctuations in benzene content among batches at individual refineries, as discussed above, also indicate the need for refiners to have a degree of flexibility in producing gasoline, as would be provided by an average benzene standard. Restrictions on day-to-day fluctuations would not significantly affect average benzene levels, but would certainly increase costs as refiners invested in avoiding occasionally higher benzene batches. We believe that allowing refiners to average batches with fluctuating benzene over a year's time, as we propose, would result in a more cost-effective program.

Most importantly, it is clear that with the incorporation of a carefully-designed benzene credit averaging, banking, and trading (ABT) program, a more stringent benzene standard would be feasible, and implementation could occur earlier. Thus, we are proposing a 0.62 vol% annual average standard to begin in 2011. Under the proposed ABT program, refiners could generate early credits by making early reduction efforts prior to 2011. Refiners would have an incentive to do so, because the credits generated could be used to postpone more expensive final investments in benzene control technology. In this way, the ABT program would allow the economic burden of the benzene standard to be more efficiently distributed among refiners and over time. The proposed ABT program would result in lower benzene levels in all areas of the country compared to today's levels, as described in more detail below in section VII.D.

c. Potential Levels for the Average Benzene Standard

We evaluated a range of potential standards on a national refinery annual average basis from 0.52 to 0.95 vol% benzene.²³⁹ Our refinery-by-refinery model incorporates data on individual refineries whenever possible and estimates the likely technological approaches that refiners would choose for each refinery to comply with each potential standard at the least cost. The model chooses among several technological options that are the most common and effective methods available to refiners to reduce gasoline

benzene content. (Section VII.F below and Chapter 6 of the RIA have more detailed discussions of benzene reduction technologies).

All of the methods that we considered focus on reducing benzene content in the reformat stream, which is the product of the reformer unit. The role of the reformer unit is to increase gasoline octane, which it does by generating aromatic compounds from simpler hydrocarbons. Benzene is one of the aromatic compounds produced by the reformer. Reformate accounts for 30–40% of gasoline volume and can contain as much as 12% benzene. As a result, reformate contributes the majority of the total benzene content of gasoline. For these reasons, treatment of reformate is usually the most effective and economical means of reducing benzene content. Several proven and commercially available technologies exist for reducing benzene creation in the reformer and removing it from the reformat product.

The least stringent standard we evaluated, a national average of 0.95 vol% benzene, would not require any changes at most refineries. For the refineries where action would be needed, we project that most could be brought into compliance by reducing creation of benzene in the reformer using the simplest and least costly of the technology options evaluated. We do not believe that a standard at this level would meet the statutory requirements of section 202(l) of the Clean Air Act to achieve the greatest reductions achievable considering cost and other factors since, as discussed below, greater reductions are feasible at reasonable cost, and without adverse energy or safety implications.

As the most stringent case, we evaluated a national average benzene content standard of 0.52 vol%. Our analysis indicates that a standard at this level would require all refiners to invest in the most effective technologies used today that remove the benzene from their reformat product streams (benzene saturation and benzene extraction, as discussed below). If the ABT program were fully utilized (all credits generated were used), we believe all refiners might comply with this average standard. Because of the almost universal need for refineries to use the most expensive reformat-based benzene control technologies, we believe a standard of 0.52 vol% would be very challenging economically for many refineries, and we believe that such a standard would not be achievable taking costs into consideration, as we are required to do under section 202(l). In addition, if, as

appears likely, “perfect” credit trading did not occur, some refiners would have to use additional, more extreme approaches that would be even more costly and would require more difficult compromises in the operation of the refineries. (We discuss these technological and operational approaches to benzene reduction in more detail in section VII.F below and in Chapter 6 of the RIA.)

In 2003, the average benzene level in RFG was 0.62 vol%.²⁴⁰ We believe an annual average benzene standard of 0.62 vol% applied to all gasoline (both CG and RFG) would be feasible considering cost and other factors. Furthermore, implementing an average benzene standard of 0.62 vol% would achieve several other important program goals. At this level, the same benzene standard could be applied to both RFG and CG nationwide, and our analysis shows that the RFG benzene reductions already achieved by the industry to date would not be lost. We expect that refiners currently producing RFG with benzene levels below 0.62 vol% would continue to be committed to producing low-benzene gasoline based on prior investment in benzene extraction equipment or ABT credit incentives. Additionally, as discussed below in VII.C.5, a gasoline benzene standard of 0.62 vol% would achieve sufficient mobile source air toxic reductions allowing this program to supersede the additional MSAT requirements under EPCRA. Finally, an average benzene standard applied to both CG and RFG, would allow for a uniform nationwide ABT program providing additional flexibility and reduced compliance costs to refiners, resulting in the greatest achievable reductions within the meaning of section 202(l).

At a national average standard of 0.62 vol%, we estimate that a number of refiners would produce gasoline with significantly lower fuel benzene levels, creating enough benzene credits to allow refiners in less economically favorable positions to purchase these credits on an on-going basis and use them for compliance purposes. We project that further reductions would occur not only in CG, but also in RFG, despite the fact that RFG is already averaging 0.62 vol%. As discussed in section IX below and in Chapter 9 of the RIA, as the stringency is pushed below 0.62 vol%, the overall program costs would begin to rise more steeply. This is because in meeting a lower average standard, there would be fewer

²³⁹ For this evaluation we used both refinery linear programming (LP) models and a refinery-by-refinery model developed specifically for this rule.

²⁴⁰ Volume-weighted average benzene level based on January 1, 2003 to December 31, 2004 RFG batch reports.

refineries able to comply at low cost, resulting in fewer credits being generated. This in turn would require more investment among refiners with higher costs of compliance.

We also considered a program that would apply separate benzene content standards to RFG and CG. In the context of any nationwide ABT program that allowed trading across both RFG and CG, separate standards for these two gasoline pools would not be fundamentally different from the proposed unified standard. The only impact would be to somewhat change which refiners generated credits and which used credits, and to what degree. For separate RFG and CG standards to have a meaningful impact in comparison to today's proposed program, separate trading programs for each of the two gasoline pools would be required. Our modeling shows that without the credits generated by RFG producers in a nationwide trading program, it would not be possible to set as stringent a standard for CG. The higher-benzene refineries that would most need credits to meet a stringent average standard are a subset of refineries that produce CG. As a result, in a program with separate RFG and CG pools, we would expect to set a slightly more stringent standard for RFG alone, but we would need to set a substantially relaxed standard for CG. The net result would be, at best, the same nationwide average benzene reductions in the RFG and CG pools that would be expected under a unified standard. However, there would be a clear risk that the reduced generation of credits by lower-cost refineries would lead to either a significant increase in the cost of the program (because higher-cost refineries would need to make refinery changes earlier) or the potential for fewer reductions through the process of setting the levels for the separate CG and RFG standards. Conversely, with a

unified standard and nationwide ABT, we believe that the program would achieve the maximum economical reduction in all areas and greater overall benzene reduction over the CG and RFG pools.

In addition, we considered a somewhat less stringent national average standard than the proposed 0.62 vol% (e.g., 0.65 or 0.70 vol%). Such standards would still achieve significant benzene emission reductions. However, we are concerned that a less stringent standard would not satisfy our statutory obligation for the most stringent standard feasible considering cost and other factors. Furthermore, such standards would not allow us to accomplish several important programmatic objectives. Given that the average benzene content of RFG in 2003 was already 0.62 vol%, such higher standards would not provide the certainty that the air toxics performance of RFG would decline in the future. This would then trigger the provisions in the 2005 EPAct to adjust the MSAT1 baseline for RFG. The only way of avoiding this situation would be to maintain separate standards for RFG and CG where the RFG standard was still more stringent than 0.62 vol% and credits could not be used from CG to comply. As discussed above, having separate standards with separate ABT programs raises additional cost and feasibility issues.

For all of the above reasons, we believe that a refinery annual average benzene content standard of 0.62 vol% applying to all gasoline nationwide (excluding California), in conjunction with an appropriately-designed ABT system, would maximize benzene emission reductions considering cost and other factors.

Section 202(l)(2) also requires that we consider lead time in determining the greatest reductions achievable. We are proposing that the standard of 0.62

vol% become effective on January 1, 2011. Because the final rule will be completed in early 2007, this would allow about 4 years for refiners to plan and execute the necessary capital projects and operational changes needed to meet the program requirements. We discuss our assessment of necessary lead time in section VII.F below. We believe that this proposed level for the standard, the proposed ABT program, and the proposed implementation date together meet the statutory requirement that the program results in the greatest emission reduction achievable considering costs and other factors.

We encourage comment on our selection of this level for the standard, especially with data and analysis that support the comments.

d. Comparison of Other Benzene Regulatory Programs

In addition to the benzene content standard of the RFG program, California and several countries have regulatory limits on the benzene content of gasoline. Table VII.C-1 shows the basic provisions of each of these programs.

Canada has limits similar to those covering U.S. RFG. In Canada, producers may either comply with a 1.0 vol% flat limit or an averaging standard of 0.95 vol%, with a per-gallon cap of 1.5 vol%. The European Union regulates fuel to the same level in all its member countries, currently a per-gallon cap of 1.0 vol%. Japan has the same limit as the E.U., while South Korea will be moving from a cap of 1.5 to 1.0 vol% in 2006.

California is the only state that has implemented a benzene standard, and it is similar to the standard we are proposing today. California's average standard is 0.7 vol%, with a per-gallon cap of 1.1 vol%. Together, these standards result in an average 0.62 vol% in-use gasoline benzene level.

TABLE VII.C-1.—OTHER GASOLINE BENZENE CONTROL PROGRAMS

	Federal RFG	California phase 3 RFG	Canada	South Korea	Japan	European Union
Average Std (vol%)	0.95 ^a	0.7	0.95
Per-gallon Cap (vol%)	1.3	1.1	1.5	1.5 ^b	1.0	1.0

^a Producers may also comply with a per-gallon cap of 1.0.
^b Limit to be lowered to 1.0 in 2006.

4. How Do We Address Variations in Refinery Benzene Levels?

a. Overall Reduction in Benzene Level and Variation

As explained above, there is currently a wide variation in gasoline benzene

levels across the country. According to summer 2003 batch data (proposed baseline²⁴¹), average benzene content

²⁴¹ For the purpose of our analyses, we selected 2003 to represent current (baseline) conditions because it reflected the most recent batch data available. The refinery-by-refinery model used to

ranged from 0.41 to 3.81 vol%, including both RFG and CG. The current

predict refinery behavior (discussed later in section IX) is based on inputs from the linear programming (LP) model, which is set up to only model the summer season. As a result, we have used summer 2003 as our baseline period.

variation in benzene levels is primarily attributable to differences in crude oil quality, different refinery configurations, and differences in refinery operations. Our analysis of the proposed program, summarized below, concludes that average benzene levels would be reduced in all areas of the country (PADDs²⁴²) and variation among refineries would also be reduced. We believe that under the proposed rule, virtually all refineries would reduce their benzene levels and that no

refineries would increase their benzene levels. Upon implementation of the proposed 0.62 vol% benzene standard in 2011, we believe that some refiners would reduce benzene levels to below the standard while others would reduce benzene levels but would need to rely partially or largely on credits generated and traded under the proposed ABT program, as described below. Refiners' compliance strategies would ultimately be driven by economics. For many it would be economical to reduce gasoline benzene levels to 0.62 vol% or below.

For others it would be economical to make some reduction in gasoline benzene levels and rely partially upon credits. For some refineries already below the standard, no benzene reduction efforts would be necessary. For the limited number of remaining technologically-challenged refineries it would be most economical to rely wholly upon credits. Regardless of the compliance strategies selected, under the proposed program, benzene levels and variation would be reduced nationwide.

TABLE VII.C-2.—BENZENE LEVELS IN GASOLINE PRODUCED CURRENTLY AND UNDER THE PROPOSED PROGRAM

	Number of refineries by gasoline benzene level (vol%)						Benzene level (vol%) *			
	<0.5	0.5-<1.0	1.0-<1.5	1.5-<2.0	2.0-<2.5	>=2.5	Min	Max	Range **	Avg ***
Starting Gasoline Benzene Levels***										
PADD 1	4	3	3	0	2	0	0.41	2.19	1.77	0.62
PADD 2	0	5	8	11	1	1	0.60	2.85	2.25	1.32
PADD 3	4	18	10	7	0	2	0.41	3.10	2.69	0.86
PADD 4	0	1	4	6	3	2	0.60	3.56	2.96	1.60
PADD 5****	0	0	1	3	2	2	1.36	3.81	2.44	2.06
Total	8	27	26	27	8	7	0.41	3.81	3.39	0.97
Benzene Levels After Program Implementation										
PADD 1	4	5	1	2	0	0	0.41	1.96	1.54	0.51
PADD 2	1	22	1	2	0	0	0.49	1.95	1.46	0.73
PADD 3	10	27	3	0	1	0	0.36	2.07	1.71	0.55
PADD 4	0	8	7	1	0	0	0.53	1.94	1.40	0.95
PADD 5****	0	4	2	2	0	0	0.54	1.84	1.30	1.04
Total	15	66	14	7	1	0	0.36	2.07	1.71	0.62

* Starting benzene levels based on summer 2003 batch data.
 ** Range in benzene level (MIN-MAX).
 *** Average volume-weighted benzene level.
 **** PADD 5 excluding California.

As shown in Table VII.C-2, average benzene levels would be reduced by 36%, from 0.97 vol% (baseline) to 0.62 vol% once the program is fully implemented. Variation in benzene level, measured in terms of range, would be reduced by 50% (from 3.39 vol% to 1.71 vol%). In addition the areas with the highest starting benzene levels and variation (PADDs 2, 3, 4 and 5) would experience the greatest reductions.

In conclusion, we project that under the proposed program all areas of the country would see reductions in average benzene level and variation among refineries would also be reduced. Refiners would have several motivations for making the benzene reductions projected by our analysis. First, reducing actual benzene levels could be the most economically-favorable compliance strategy. Secondly, reducing benzene levels would help reduce or

eliminate the uncertainty associated with relying on credits. Finally, reducing benzene levels could generate credits that would be valuable to the refining industry.

b. Consideration of an Upper Limit Standard

We believe that the proposed program would provide significant benefits in all areas of the nation. Nevertheless, we recognize that some commenters are likely to be concerned that under a flexible ABT program it is possible that some refiners could maintain their current benzene levels or even increase them and comply through the use of credits. If such a refinery dominated a particular market, then even though nationally there would be significant benzene reductions, they might not occur in that market. While our analysis does not lead us to believe that such an outcome would happen, we have

nevertheless considered whether an upper limit on benzene (in addition to the average standard) would be valuable to prevent that outcome from happening.²⁴³ We considered two different forms of an upper benzene limit to complement the average standard: a per-gallon cap standard and a maximum average standard.

i. Per-Gallon Cap Standard

A cap would require that each gallon (or batch) of gasoline produced or imported not contain more than a specified concentration of benzene. Such a standard would force those refineries with the highest benzene levels to make physical changes to their gasoline instead of having the option of relying exclusively on credits. In addition to formally limiting the maximum benzene content sold anywhere in the country, such a cap would also be straightforward to enforce

²⁴² The Department of Energy divides the United States into five Petroleum Administration for

Defense Districts, or PADDs. The states included in each PADD are defined at 40 CFR 80.41.

²⁴³ Upper limits on benzene are a part of comparable programs in California and in other countries.

at any point in the distribution system. Note that we are proposing that the existing per-gallon cap of 1.3 vol% benzene would remain in effect for RFG under this rule. EPA invites comment on whether the RFG benzene cap should be retained.

The primary disadvantage of adding a rigid cap is that it would not allow for occasional, short-term fluctuations in benzene content. Refiners are faced with a range of unexpected or planned circumstances that could cause temporary spikes in benzene content, including equipment malfunctions and periodic maintenance. Although the 1.3 vol% cap would remain for RFG, to apply a cap in this range to CG would eliminate a necessary market for higher benzene batches.²⁴⁴ With no ability to market the gasoline, the refiner would be forced to suspend gasoline production. This could in turn force the shutdown of the entire refinery, sacrificing supply of all products. To attempt to avoid this situation, refiners would need to invest more heavily in benzene control than needed to meet the average standard, simply to provide back-up control to protect against short-term fluctuations. For some higher-benzene refineries, a cap could make complying with the program prohibitively expensive.

Consequently, we concluded that if we were to impose a per-gallon cap, it would have to be high enough to allow most refineries to continue to operate even in such upset situations (in order to account for legitimate maximum potential daily variability), thereby providing little overall benefit.²⁴⁵ Alternatively, we would have to allow exceptions to the per-gallon cap for such upset situations, which would be burdensome to implement and also result in little overall benefit.

If refineries with higher-benzene refineries need to invest in greater benzene control in order to protect against unpredictable upsets, their costs would be even higher relative to those of lower-benzene refineries. As in the case of a program with no ABT at all, the statutory requirement to balance the degree of feasible emission reduction with cost (and other factors) would have the counterproductive effect of requiring a less stringent overall program.

²⁴⁴ As explained in section VII.C.5 below, CG provides a limited safety valve for occasional batches of high-benzene RFG due to the Anti-dumping provisions.

²⁴⁵ In California and other countries with benzene control programs, the refining industry tends to be more homogeneous than in the U.S. as a whole and face different market situations, resulting in different considerations regarding upper limits.

At the same time, the per-gallon cap would appear to provide no overall additional reduction in benzene levels. Despite the increased costs, particularly for higher-benzene refineries, our analysis indicates that little additional emission reduction would result (primarily because the higher-benzene refineries represent a relatively small fraction of nationwide gasoline production). Instead, as discussed below, emission reductions are expected to simply shift from one region of the country to another, with no change in the overall emission reductions. Because of this, and due to the potential deleterious cost impacts, we are not proposing a per-gallon cap benzene standard.

ii. Maximum Average Standard

Another means of ensuring some reduction by those refineries with the highest benzene concentrations would be to impose a maximum average standard. An annual maximum average standard for each refinery would limit the average benzene content of its actual production over the course of the year, regardless of the extent to which credits may have been used for compliance. While slightly less restrictive than a per-gallon cap standard in that some shorter-term fluctuations in benzene levels could occur, a maximum average standard would still limit the flexibility otherwise available through the ABT program. Our modeling shows that a number of refineries would need to invest substantially more to ensure compliance with both the average and maximum average standards. With the addition of a maximum average standard, we expect emission reductions to simply shift from one region of the country to another with no net change in overall emission reductions. For example, when analyzing a 1.3 vol% maximum average standard, benzene levels were lowered in two PADDs and raised in three PADDs compared to our proposed program yet the overall emission reductions remained the same.²⁴⁶ Since we believe that a maximum average standard would increase costs but not achieve any greater emission reduction, we are not proposing such a standard.

We believe that the proposed ABT program, in combination with the proposed 0.62 vol% benzene standard without a cap or maximum average limit, would result in the maximum feasible reduction in benzene emissions, considering costs, energy, and safety issues. The proposed ABT program would provide refineries with compliance flexibility while ensuring that the

²⁴⁶ This program comparison is discussed further in Chapter 9 of the RIA (Table 9.6–7).

national program achieves significant overall benzene emission reductions.

We invite comment on our conclusions about having an upper limit in addition to an average standard.

5. How Would the Proposed Program Meet or Exceed Related Statutory and Regulatory Requirements?

Three fuels programs (RFG, Anti-dumping and MSAT1) currently contain direct controls on the toxics performance of gasoline.²⁴⁷ Based on our analyses of the proposed program, including the proposed ABT program, we expect that meeting the proposed fuel benzene content standard combined with other fuel controls would also lead to compliance with the toxics requirements of all these programs.

The RFG program, implemented in 1995, contains a fuel benzene standard that requires a refinery's or importer's RFG to average no greater than 0.95 vol% benzene annually.²⁴⁸ In addition, RFG has a per-gallon benzene cap of 1.3 vol%. Each refinery's or importer's RFG must also achieve at least a 21.5% annual average reduction in total toxics emissions compared to 1990 baseline gasoline.²⁴⁹ The Anti-dumping regulations require that a refinery's or importer's CG produce no more exhaust toxics emissions on an annual average basis than its 1990 gasoline.²⁵⁰ This program keeps refineries from shifting fuel components responsible for elevated toxic emissions into CG as a way to comply with the RFG standards. Section V.D.1 above describes these programs in more detail.

The MSAT1 program, implemented in 2002, was overlaid on the RFG and Anti-dumping programs.²⁵¹ As explained in section V.D above, it was not designed to further reduce MSAT emissions, but to lock in overcompliance on toxics performance that was being achieved in RFG and CG under the RFG and Anti-dumping programs. The MSAT1 rule requires the annual average toxics performance of a refinery's or importer's gasoline to be at least as clean as the average performance of its gasoline during the three-year baseline period 1998–

²⁴⁷ Other gasoline fuel controls, such as sulfur, RVP or VOC performance standards, indirectly control toxics performance by reducing overall emissions of VOCs.

²⁴⁸ 40 CFR 80 Subpart D. Refiners also have the option of meeting a per gallon limit of 1.0 vol%.

²⁴⁹ Emissions determined using the Complex Model, as defined in 40 CFR 80.45.

²⁵⁰ CFR 80 Subpart E, emissions determined using the Complex Model.

²⁵¹ 40 CFR 80 Subpart J.

2000.²⁵² Compliance with MSAT1 is determined separately for each refinery's or importer's RFG and CG.

Today's proposed 0.62 vol% benzene content standard would apply to all of a refinery's or importer's gasoline "that is, the total of its RFG and CG production or imports. This level of benzene control would far surpass the RFG standard of 0.95 vol%, and would put in place a benzene content standard for CG for the first time.²⁵³ As described further in Chapter 6 of the RIA, we analyzed the expected overall toxics performance under today's proposed program of benzene and vehicle standards using currently-available models and compared it to toxics performance under the pre-existing standards.²⁵⁴ When RFG and CG toxics emissions are evaluated at this new level of benzene control, it is clear that the benzene standard proposed today would result in the MSAT1 toxics emissions performance requirements being surpassed (i.e., bettered) not only on average nationwide, but for every PADD.²⁵⁵

To address compliance with statutory requirements currently in effect through the RFG and Anti-dumping programs, we carried out a refinery-by-refinery analysis of toxics emissions performance using the Complex Model (the same model used for determining compliance with these programs). We used 2003 exhaust toxics performance for CG and 2003 total toxics performance for RFG as benchmarks, which are at least as stringent as the relevant toxics performance baselines. We applied changes to each refiner's fuel parameters for today's proposed standards and the gasoline sulfur standard phased in this year (30 ppm average, 80 ppm max). The results indicate that all refineries maintained or reduced their emissions of toxics over 2003. We expect large reductions in sulfur for almost all refineries under the gasoline sulfur program, and large reductions in CG benzene levels along with modest reductions in RFG benzene levels. We do not expect backsliding in sulfur levels by the few refiners previously below 30 ppm because they had been producing ultra-low sulfur gasoline for reasons related to refinery configuration. Furthermore, because of

its petrochemical value and the credit market, we do not expect any refiners to increase benzene content in their gasoline.

In addition, we expect significant changes in oxygenate blending over the next several years, but these are very difficult to predict on a refinery-by-refinery basis. Regardless of how individual refineries choose to blend oxygenates in the future, we believe their gasoline will continue to comply with baseline requirements. This is because all RFG is currently overcomplying with the statutory requirement of 21.5% annual average toxics reductions by a significant margin. Similarly, most CG is overcomplying with its 1990 baselines by a significant margin. Furthermore, we believe most refiners currently blending oxygenates will continue to do so at the same or greater level into the future.

EPA is thus proposing that upon full implementation in 2011 the regulatory provisions for the benzene control program would become the single regulatory mechanism used to implement these RFG and Anti-dumping annual average toxics requirements, replacing the current RFG and Anti-dumping annual average provisions. However, the 1.3 vol% maximum benzene cap would remain in place for RFG under 40 CFR 80.41; we are requesting comment on the need to retain this requirement for RFG. The proposed benzene control program would also replace the MSAT1 requirements.

Section 1504(b) of the Energy Policy Act of 2005 (EPAct) requires that the MSAT1 toxics emissions baselines for RFG be adjusted to reflect 2001–2002 fuel qualities, which would make them slightly more stringent than the 1998–2000 baselines originally used in the MSAT1 program. However, as provided for in the Act, this action becomes unnecessary and can be avoided if today's proposed program achieves greater overall reductions of toxics emissions from RFG (i.e., PADDs 1 and 3) than would be achieved by this baseline year adjustment. Therefore, in addition to comparing the proposed standard to the current MSAT1 program, we also compared it to the

program as the standards would be modified by the EPAct.

We performed an analysis of aggregate toxics emissions for the relevant baseline periods as well as for future years with and without the proposed program. This analysis was carried out using MOBILE6.2 because that model accounts for changes in the vehicle fleet, which is important when modeling future years. Results are shown in Table VII.C–3. Since this modeling approach was intended to compare emissions from different fuels and fleet year mixes, the emissions figures generated here are different from those used for gasoline compliance determination.

The first row shows mg/mi air toxics emissions in 2002 under the MSAT1 refinery-specific baseline requirements. The second row shows how these would change by updating the RFG baselines to 2001–02 as specified in EPAct. Since significant changes are expected in the gasoline pool between 2002 and the proposed implementation time of the fuel standard, such as gasoline sulfur reductions and oxygenate changes, we decided to model a "future baseline" to allow comparison with the proposed standard at the time it would become effective in 2011. As a result, the third row shows the projected mg/mi emissions in 2011 under the EPAct baseline adjustments, but without today's proposed program. The large reductions in air toxics emissions between the EPAct baseline and this 2011 baseline are primarily due to nationwide reduction in gasoline sulfur content to 30 ppm average and significant phase-in of Tier 2 vehicles into the national fleet.

An important comparison is made between rows three and four, where the estimated toxics emissions under the proposed fuel standard only are compared to the projected emissions without the proposed standard. The fourth row shows small reductions for RFG and more significant reductions for CG with the introduction of the proposed benzene standard in 2011. We also evaluated the effects of the vehicle standard also proposed today on toxics emissions at two points in time, shown in the last two rows of the table.

²⁵² Emissions determined using the Complex Model, as defined in 40 CFR 80.45.

²⁵³ Proposed program retains the 1.3 vol% maximum benzene cap for RFG required by 40 CFR 80.41.

²⁵⁴ As discussed previously, the existing models contain limited data on the impacts of fuel changes on 2004 and later technology vehicles, making such

projections difficult. However, we do not believe the conclusions would change for these reasons: (1) The fuel effect changes modeled here related to benzene, for which we expect data for new technology vehicles to show similar trends as those for older vehicles; (2) much of the projected change in future emissions are due to changes in vehicle technology, not fuel changes; and (3) for this analysis we need only look at the relative changes,

and given the magnitude of the projected effects we do not expect that the direction of the result would change even if significantly different values for absolute emissions were submitted.

²⁵⁵ The analysis shows an even greater benefit in overall toxics reductions when the combined effect of the benzene standard and the vehicle standards are considered.

TABLE VII.C-3.—ESTIMATED ANNUAL AVERAGE TOTAL TOXICS PERFORMANCE OF LIGHT DUTY VEHICLES IN MG/MI UNDER CURRENT AND PROPOSED PROGRAMS ^a

Regulatory scenario	Fleet	RFG by PADD			CG by PADD				
	Year	I	II	III	I	II	III	IV	V
MSAT1 Baseline ^b (1998–2000) ...	2002	108	124	89	104	135	96	137	152
EPA Act Baseline ^b (RFG: 2001–2002)	2002	103	121	85	104	135	96	137	152
EPA Act Baseline, 2011 ^c	2011	67	79	51	62	79	54	77	96
Proposed program, 2011 ^c (Fuel standard only)	2011	66	78	50	59	74	51	71	85
Proposed program, 2011 ^c (Fuel + vehicle standards)	2011	63	76	47	55	72	47	67	81
Proposed program, 2025 ^c (Fuel + vehicle standards)	2025	39	46	30	35	44	31	42	50

^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.

^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 controls proposed today, where stated) effects of the Tier 2 vehicle and gasoline sulfur standards and vehicle fleet turnover with time, as well as rough estimates of the renewable fuels standard and the phase-out of ether blending.

Based on these analyses, we believe the fuel program proposed in this notice, as well as the combined fuel and vehicle program, would also achieve greater overall toxics reductions than would be achieved under the EPA Act were the RFG baseline period updated to 2001–2002.

In summary, today's proposed action for fuels would fulfill several statutory and regulatory goals related to control of gasoline mobile source air toxics emissions. The proposed program (in conjunction with the proposed vehicle standards) would meet our commitment in the MSAT1 rulemaking to consider further MSAT control. It would also result in air toxics emission reductions greater than required under all pre-existing gasoline toxics programs, as well as under the baseline adjustments specified by the Energy Policy Act. By designing this program to address these separate but related goals, we would be able to achieve a benefit in addition to the emissions reductions: A significant consolidation and simplification of regulation of gasoline MSATs.

As part of today's action, in addition to the streamlining of toxics requirements, we propose that the gasoline sulfur program become the sole regulatory mechanism used to implement gasoline NO_x requirements. Gasoline producers are required to show reductions from their RFG relative to the 1990 Clean Air Act baseline gasoline NO_x emissions, as determined using the Complex Model. Conventional gasoline must comply with Anti-dumping individual NO_x baselines for each refinery, similar to the Anti-dumping toxics standards. A refinery-by-refinery NO_x analysis parallel to that described above indicated that with the final

implementation of the gasoline sulfur program (January 1, 2006), all gasoline will continue to meet or exceed the NO_x requirements of the RFG and Anti-dumping programs.

As discussed elsewhere in this preamble, we believe that today's proposed nationwide program would achieve significant reductions in gasoline-related benzene emissions. The program would also have the effect of preempting states from regulating gasoline benzene content. The program is proposed under Clean Air Act section 211(c), which includes preemption of state fuel programs in section 211(c)(4).²⁵⁶ The existing RFG benzene program, also authorized under section 211(c)(1), preempts states in RFG areas from regulating benzene. Today's nationwide program expands this preemption to all states except California, which is exempt from this preemption.

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

1. Overview

As mentioned earlier, we are proposing a specially-designed ABT program to allow EPA to set a more stringent nationwide gasoline benzene standard than otherwise possible. The proposed ABT program would allow refiners and importers to use benzene credits generated or obtained under the provisions of the ABT program to comply with the 0.62 vol% refinery average standard in 2011 and indefinitely thereafter. Benzene credits could be generated by refineries that

²⁵⁶ See discussion of statutory authority in section I.C. of this preamble.

make qualifying early baseline reductions prior to 2011 and by refineries and importers that overcomply with the 0.62 vol% standard in 2011 and beyond. All credits generated could be used internally towards company compliance ("averaged"), "banked" for future use, and/or transferred ("traded") to another refiner or importer.

The majority of the ABT credit provisions we are proposing are similar to those offered in the gasoline sulfur program, with a few exceptions. The major difference is that in the proposed program, credit use would not be restricted by an upper limit (discussed in VII.C.4.b above) and in fact would be encouraged by extended credit life and nationwide credit trading provisions. We are able to propose a flexible ABT program and a gradual phase-in of the 0.62 vol% benzene because there is no corresponding vehicle standard being proposed that is dependent on gasoline benzene content. A program with fewer restrictions would help ensure that the overall proposed benzene control program would result in the greatest achievable benzene reductions, considering cost and other factors.

Because of the wide variation in current benzene levels among refineries, we recognize that some refiners would be better situated than others, technologically and financially, to respond to the proposed benzene standard. As we discuss below, we believe that the credit trading provisions of the ABT program would be well suited to moderate the financial impacts that could otherwise occur with the proposed benzene control program.

However, in other air quality programs, we have used other trading

mechanisms to address the varying impacts of such programs on different regulated entities. For example, in EPA's Acid Rain program a limited number of "emissions allowances" are allocated among entities, which can then be banked and traded. We invite comment on this and other alternative credit approaches that might be appropriate to gasoline benzene control.

The following paragraphs provide more details on our proposed benzene ABT program. We encourage comments on the design elements we have proposed for the program. If you believe that alternative approaches would make the program more effective, please share your specific comments and recommendations with us.

2. Standard Credit Generation (2011 and Beyond)

We are proposing that standard benzene credits could be generated by any refinery or importer that overcomplies with the 0.62 vol% gasoline benzene standard on an annual volume-weighted basis in 2011 and beyond. For example, if in 2011 a refinery's annual average benzene level was 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. The credits would be expressed as gallons of benzene. Likewise, if in 2012 the same refinery produced the same amount of gasoline with the same benzene content they would earn the same amount of credits. The standard credit generation opportunities for overcomplying with the standard would continue indefinitely.

The refinery cost model discussed further in section IX.A, predicts which refineries would reduce benzene levels in an order of precedence based on cost until the 0.62 vol% refinery average standard is achieved. The model also predicts which refineries would overcomply with the standard in 2011 and beyond and in turn generate standard credits.²⁵⁷ Credits would be generated by two main sources.

First, standard credits would be generated by refineries whose current gasoline benzene levels are already below the 0.62 vol% standard. According to the model, 19 refineries are predicted to maintain current gasoline benzene levels and overcomply

with the standard without making any additional process improvements. These refineries would generate approximately 42 million gallons of benzene credits per year without making any investment in technology. Additionally, the model predicts that 5 other refineries would reduce gasoline benzene levels even further below 0.62 vol% resulting in deeper overcompliance and an additional 6 million gallons of benzene credits per year.

Second, standard credits would be generated by refineries whose current gasoline benzene levels are above 0.62 vol% but are predicted by the model to overcomply with the standard based on existing refinery technology, access to capital markets, and/or proximity to the benzene chemical market. The model predicts that 34 refineries with gasoline benzene levels above 0.62 vol% would make process improvements to reduce benzene levels below the standard and in turn generate approximately 40 million gallons of benzene credits per year.

For the refineries which the model predicts to make process changes to overcomply with the standard, the incremental cost to overcomply is relatively small or even profitable in some cases of benzene extraction.²⁵⁸ As expected, refineries with the lowest compliance costs would have the greatest incentive to overcomply based on the value of the credits to the refining industry.

3. Credit Use

We are proposing that refiners and importers could use benzene credits generated or obtained under the provisions of the ABT program to comply with the 0.62 vol% gasoline benzene standard in 2011 and indefinitely thereafter. Refineries and importers could use credits to comply on a one-for-one basis, applying each benzene gallon credit to offset the same volume of benzene produced 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 under-compliance 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.

We believe that individual refineries would rely differently upon credits, depending on their unique refinery situations. As mentioned earlier, the current range in gasoline refinery technologies and starting benzene levels would make it significantly more expensive for some refineries to comply with the standard based on actual reduced benzene levels than others. As such, some technologically-challenged refiners may choose to rely largely or entirely upon credits because it would be much more economical than making process improvements to reduce benzene levels. Other refiners may choose to make incremental process improvements to reduce refinery benzene levels and then rely partially on credits to fully comply. Still others may choose to reduce benzene levels to at or around 0.62 vol% and maintain an "emergency supply" of credits to address short-term spikes in benzene levels due to refinery malfunctions. Overall, the proposed credit trading program would encourage low-cost refineries to comply or overcomply with the standard while allowing high-cost refineries to rely upon credits to comply. This would reduce the total economic burden to the refining industry.

a. Credit Trading Area

We are proposing a nationwide credit trading program with no geographic restrictions on trading. In other words, a refiner or importer could obtain benzene credits and use them towards compliance regardless of where the credits were generated. We believe that restricting credit trading could reduce refiners' incentive to generate credits and hinder trading essential to this program. As explained in Chapter 6 of the RIA, if PADD restrictions were placed on credit trading, there would be an imbalance between the supply and demand of credits.

In other fuel standard ABT programs (e.g., the highway diesel sulfur program), credit trading restrictions were necessary to ensure there was adequate low-sulfur fuel available in each geographic area to meet the corresponding vehicle standard. Since there is no vehicle emission standard being proposed that is dependent on gasoline benzene content, we do not believe there is a need for geographic trading restrictions. As mentioned above, we project that under the proposed ABT program, all areas of the country (i.e., all PADDs) would

²⁵⁷ The refinery cost model assumes that all credits generated are used each year. To the extent that this does not occur, more refiners would have to invest in technology to comply, increasing the cost of the program.

²⁵⁸ Despite the low costs of benzene extraction, without a benzene control standard refiners are reluctant to invest in capital-intensive processes such as extraction. This is because many other projects involving capital investments that they may be considering typically have a better or more certain payout (past price volatility in the benzene chemical market can discourage future investment). Thus, refiners tend to postpone capital projects such as extraction even if they may appear to be profitable today.

experience a large reduction in gasoline benzene levels as a result of the standard.

As discussed earlier, California gasoline would not be subject to the proposed benzene standards. However, California refiners that produce gasoline that is used outside of California would be able to generate credits on that gasoline (and use credits to achieve compliance on their non-California gasoline if necessary). Likewise, as proposed, refiners outside of California that produce gasoline that is used in California would not be allowed to use that gasoline as the basis for any credit generation, or compliance with the proposed benzene standard. However, we request comment on whether and how credits could be allowed to be generated on California gasoline benzene reductions and applied to the benzene compliance for non-California gasoline.

EPA seeks comment on the proposed nationwide trading provision, its effect on incentives for refiners to generate credits, and environmental impacts.

b. Credit Life

We are proposing limited credit life to enable proper enforcement of the program and to encourage trading of credits. Since the proposed standard is a refinery gate standard (i.e., enforced as the fuel leaves the refinery) with no enforceable downstream standard, it is critical that EPA be able to conduct enforcement at the refinery. A reasonable limitation on credit life would allow EPA to verify the validity of credits through record retention. Credit information must be independently verifiable such that, in the event of violations involving credits, the liable party is identifiable and accountable. EPA enforcement activities are limited by the five-year statute of limitations in the Clean Air Act. As a consequence, credit life greater than five years creates potentially serious enforcement difficulties. This is particularly important given the ongoing changes in business relationships, ownership, and merger practices that are characteristic of the refining industry. In addition, since credit trading plays an essential role in moderating program costs, it is important that refiners have an incentive to trade credits rather than hoard them. Instituting a credit expiration date would promote trading because refiners would be forced to "use it or lose it." In summary, we believe the proposed credit life provisions, described in more detail below, are limited enough to satisfy enforcement

and trading concerns yet sufficiently long to provide program flexibility.

We are proposing that standard credits generated in 2011 and beyond would have to be used within five years of the year in which they were generated. For example, credits generated based on 2011 gasoline production would have to be used towards compliance with the 2016 calendar year or earlier, otherwise they would expire. Standard credits traded to another party would still have to be used during the same five-year period because credit life is tied to the date of generation, not the date of transfer.

We are proposing that early credits generated prior to 2011 (discussed in the paragraphs to follow) would have a three-year credit life from the start of the program. In other words, early credits would have to be applied to the 2011, 2012, and/or 2013 compliance years or they would expire.

These proposed credit life provisions are similar to those finalized in the gasoline sulfur program, except the early credit life is three years instead of two. We are proposing a three-year early credit life because it corresponds with the number of early credits projected to be generated according to our refinery cost model.²⁵⁹ Additionally, we predict that three years would be more than sufficient time for all early credits generated to be utilized. We believe that this certainty that all credits could be utilized would strengthen refiners' incentive to generate early credits and subsequently establish a more reliable credit market for trading.

In addition to the above-mentioned provisions, we are proposing that credit life may be extended by two years for early credits and/or standard credits generated by or traded to approved small refiners. We are offering this provision as a mechanism to encourage more credit trading to small refiners. Small refiners often face special technological challenges, so they would tend to have more of a need to rely on credits. At the same time, they often have fewer business affiliations than other refiners, so they could have difficulty obtaining credits. We believe this provision would be equally beneficial to refiners generating credits. This additional credit life for credits traded to small refiners would give refiners generating credits a greater opportunity to fully utilize the credits before they expire. For example, a refiner who was holding on to credits for emergency purposes or other reasons later found to be unnecessary, could

trade these credits at the end of their life to small refiners who could utilize them for two more years. However, EPA is concerned that extending credit life beyond the five-year statute of limitations in the Clean Air Act (net 7-year credit life for standard credits generated by or traded to small refiners) could create significant enforceability problems. Consequently, EPA seeks comment on provisions that could be included in the regulations that would address this enforceability concern regarding the extended credit life for small refiner standard credits.

As discussed in Section X.A, we are also seeking comment on different ways of structuring the program that may be able to allow for unlimited credit life since, unlike in the gasoline sulfur program, there is no vehicle standard being proposed that is dependent on fuel quality. We considered that unlimited credit life could further promote credit generation and allow refiners to maintain an ongoing supply of credits in the event of an emergency. However, for several reasons we have elected to propose a limited credit life based on the context of the rest of the proposed program. If unlimited credit life were to discourage trading of credits, this could force refineries with more expensive benzene control technologies to comply and thus increase the total cost of the program. In addition, unlimited credit life would make it more difficult to verify compliance with the standard. One way of addressing this concern would be to require refiners to retain credit records indefinitely. Even then, given the fluid nature of refiner and importer ownership in recent years, in many cases it would still be difficult to verify the validity of historical credit generation and use. Since the proposed benzene standard would be enforced solely at the refinery, it is critical that such enforcement be as simple and straightforward as possible. Nonetheless, as discussed in Section X.A, it may be possible to design the overall program in such a way to address these concerns and still allow for infinite credit life.

In conclusion, we are proposing a reasonably limited credit life for both early and standard benzene credits. We seek comment on unlimited credit life. Please share with us any additional ideas you may have on how unlimited credit life could be beneficial to this program and/or how associated recordkeeping and enforcement issues could be mitigated.

²⁵⁹ Derivation of three-year early credit lag is found in Chapter 6 of the RIA (section 6.5.3.1).

4. Early Credit Generation (2007–2010)

To encourage early application of and innovation in benzene control technology, we are proposing that refiners could generate early benzene credits from June 1, 2007 to December 31, 2010 by making qualifying reductions from their pre-determined refinery baselines. A discussion of how refinery baselines are established and

what constitutes a qualifying benzene reduction is found in the subsections to follow. The early credits generated under this program would be interchangeable with the standard credits generated in 2011 and beyond and would follow the above-mentioned credit use provisions.

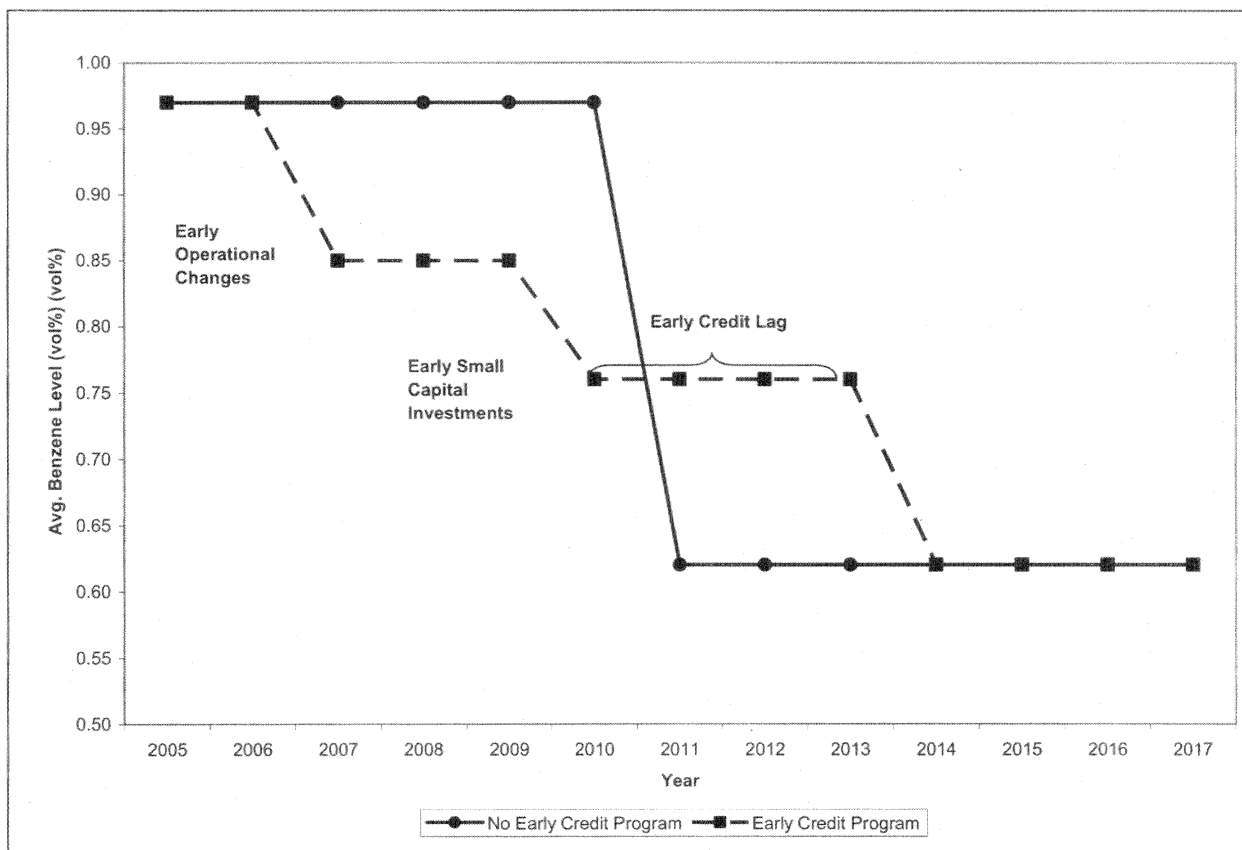
The early reductions we are projecting to occur would be the initial steps of each refinery’s ultimate benzene control

strategy, but completed earlier than required. We project that from mid-2007 to 2010, refiners could implement operational changes and/or make small capital investments to reduce gasoline benzene. These actions would create a two-step phase down in gasoline benzene prior to 2011 as shown in Figure VII.D-1.

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Figure VII.D-1

Average Gasoline Benzene Level vs. Year



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The credits generated under the early credit program could be used to provide refiners with additional lead time to make their investments. If properly implemented, we project that the delay could be as much as three years as described in Chapter 6 of the RIA. Accordingly, we are proposing a three-year early credit life, as discussed earlier. The additional lead time would allow the refining industry to spread out demand for design, engineering,

construction and other related services, reducing overall compliance costs.

Importers would not be permitted to generate early credits, for several reasons.²⁶⁰ First, unlike refineries, importers would not need additional lead time to comply with the standard, since they would not be investing in benzene control technology. Additionally, because importer

²⁶⁰ As discussed in section VIII.I.1 below, foreign refiners may generate early credits under the proposed 40 CFR 80.1420 provisions.

operations are more variable than refinery operations, importers could potentially redistribute the importation of foreign gasoline based on benzene level to generate early credits without making a net reduction in gasoline benzene. This type of scheme could result in a large number of early credits being generated with no net benzene emission reduction value. This is not expected to occur for refineries because they are already operating at high capacity and do not have the flexibility

to quickly increase, decrease, or shift production volumes. Additionally, under the proposed program, refineries are prohibited from moving benzene-rich blendstocks around to generate early credits as described below.

We believe that refiners would have several motivations for making early benzene reductions. For refiners who have a series of technology improvements to make, early innovative improvements would help the refiner get one step closer to compliance. Early reductions would also generate credits which could be used to postpone subsequent investments. For refiners capable of making early advancements to reduce their benzene levels below 0.62 vol%, the early credits generated would not be needed for their own future use. For these refiners, trading early credits to other refiners may be a way to offset the cost of their early capital investment(s).

a. Establishing Early Credit Baselines

We are proposing that any refiner planning on generating early credits would have to obtain an individual refinery benzene baseline in order to provide a starting point for calculating early credits.

Refinery benzene baselines would be defined as the annualized volume-weighted benzene content of gasoline produced at a refinery from January 1, 2004 to December 31, 2005. We are proposing a two-year baseline period to account for normal operational fluctuations in benzene level. We propose using the 2004 and 2005 calendar years because we believe this would represent the most current batch gasoline data available prior to today's proposal.

We would require refiners to submit individual baselines for each refinery that is planning to generate early benzene credits. Refinery benzene baselines would be calculated using the 2004–2005 batch data submitted to us under the RFG and Anti-dumping requirements.²⁶¹ We propose that joint ventures, in which two or more refiners collectively own and operate one or more refineries, be treated as separate refining entities for early credit generation purposes.

Refiners would be required to submit their refinery baselines in writing to EPA. We propose that refiners could begin applying for 2004–05 benzene baselines as early as March 1, 2007. There would be no single cut-off date for applying for a baseline; however, a refiner planning on generating early

credits would need to submit a baseline application at least 60 days prior to beginning credit generation. We are proposing a shorter notification period for this rule (past rules were 120 days) to accommodate our proposed early credit generation start date of June 1, 2007. EPA would review all baseline applications and notify the refiner of any discrepancies found with the data submitted. If we did not respond within 60 days, the baseline would be considered to be approved, subject to later review by EPA.

Under the proposed program, refiners would be prohibited from moving gasoline and gasoline blendstock streams from one refinery to another in order to generate early credits. This type of transaction would result in artificial credits with no associated emission reduction value. If traded and used towards compliance, these artificial credits could negatively impact the benefits of the program. We considered basing credit generation for multi-refinery refiners on corporate benzene baselines instead of individual refinery baselines, but determined that this could hinder credit generation. If a valid reduction was made at one refinery and an unrelated expansion occurred at another facility during this time, the credits earned based on a corporate baseline could be reduced to zero. Instead, we propose to validate early credits based on existing reporting requirements (e.g., batch reports and pre-compliance reporting data). We seek comment on this approach.

b. Early Credit Reduction Criteria (Trigger Points)

We are proposing that to generate early credits, refiners would first need to reduce gasoline benzene levels to 0.90 times their refinery benzene baseline during a given averaging period. The purpose of setting an early credit generation trigger point is to ensure that changes in benzene level are representative of real process improvements. Without a trigger point, refineries could generate “windfall” early credits based on normal year to year fluctuations in benzene level associated with MSAT1. These artificial credits would compromise the environmental benefits of an ABT program because they would have no real associated benzene emission reduction value.

In designing the early credit generation program, we considered a variety of different types of trigger points. We performed sensitivity analyses around absolute level trigger points (refineries must reduce gasoline benzene levels to a certain

concentration), fixed reduction trigger points (refineries must reduce gasoline benzene levels by a certain concentration), and percent reduction trigger points (refineries must reduce gasoline benzene by a percentage). Based on our analysis found in Chapter 6 of the RIA, we found absolute level trigger points to be too restrictive for high benzene level refineries that could benefit from reductions the most. We also found fixed reduction trigger points to be too restrictive to low benzene level refineries which would be penalized for already being “cleaner.” Percent reduction trigger points were found to be consistently limiting towards all refineries, regardless of starting benzene level. As such, we propose to conclude that a percent reduction trigger point would be the most appropriate early credit validation tool to address the wide range in starting benzene levels.

To determine an appropriate value for the percent reduction trigger point, we considered a range of reductions from 5–40% and examined the resulting early credit generation outcomes. We found that as the value of the percent reduction trigger point increased, the potential for windfall credit generation decreased, but unfortunately so did the number of early credits generated from legitimate refinery modifications. To address this competing relationship between windfall and early credit generation, we are proposing a 10% reduction trigger point. We believe that this trigger point is restrictive enough to prevent most windfall credit generation, but not too restrictive to discourage refineries from making early benzene reductions. The proposed 10% reduction trigger point roughly coincides with the average fluctuation in benzene level in 2004 as discussed in Chapter 6 of the RIA. A 10% reduction trigger point for early credits was also finalized in the gasoline sulfur rulemaking, which also affected the entire gasoline pool and had to encompass a variety of unique refinery situations.²⁶² EPA requests comments on the proposed trigger point and seeks alternate recommendations for validating early credits.

c. Calculating Early Credits

We are proposing that once the 10% reduction trigger point was met, refineries could generate early credits based on the entire reduction. In terms of benzene levels, a refinery would first have to reduce its average benzene level to 0.90 times its original baseline benzene level during a given averaging period in order to generate credits. For

²⁶¹ RFG, 40 CFR 80.75; Anti-dumping, 40 CFR 80.105.

²⁶² 40 CFR 80.305.

example, if in 2008 a refinery reduced its annual benzene level from a baseline of 2.00 vol% to 1.50 vol% (below the trigger of $0.90 \times 2.00 = 1.80$ vol%), its 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. The credits would be expressed in gallons of benzene.

5. Additional Credit Provisions

a. Credit Trading

The potential exists for credits to 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. As in past programs, we propose that should this occur both the seller and purchaser would 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. This would allow the credit market to properly allocate any such risk.

As with ABT programs in other rules, we are proposing that credits should be transferred directly from the refiner or importer that generated them to the party that would use them for compliance purposes. This would ensure that the parties purchasing them would be better able to assess the likelihood that the credits were valid, and would aid in compliance monitoring. An exception would exist where a credit generator transferred credits to a refiner or importer who could not use all the credits, in which event that transferee could transfer the credits to another refiner or importer. However, based on the increased difficulty in assuring the validity of credits as the credits change hands more than once, we are proposing that credits could only be transferred a limited number of times. We are requesting comment on the maximum number of allowable trades, in the range of 2 to 4 trades. After the maximum number of trades, such credits would have been used or terminated.

We propose no prohibitions against brokers facilitating the transfer of credits from one party to another. Any person could act as a credit broker, whether or not such person was a refiner or importer, so long as the title to the credits was transferred directly from the generator to the user. Further discussion of these credit trading provisions and

alternative options is found in section X.A below.

b. Pre-Compliance Reporting Requirements

In order to provide an early indication of the credit market for refiners planning on relying upon benzene credits as a compliance strategy in 2011 and beyond, we are requesting that refiners submit pre-compliance reports to us in 2008, 2009, and 2010. EPA would then summarize this information (in such a way as to protect confidential business information) in a report available to the industry. This is similar to the way pre-compliance reports are used for the ultra-low sulfur diesel program. In addition, we are proposing that refiners provide us with a final summary pre-compliance report in 2011, to allow for a complete account of early credit generation.²⁶³ The reports would be due annually by June 1st and would contain refiners' most up-to-date implementation plans for complying with the 0.62 vol% benzene standard. More specifically, we would require refiners to annually submit to us engineering and construction plans and the following data:

- Actual/projected gasoline production volume and average benzene level for the June 1, 2007 through December 31, 2007 annual averaging period, and for the 2008–2015 annual averaging periods.
- Actual/projected early credits generated during the June 1, 2007 through December 31, 2007 annual averaging period, and for the 2008–2010 annual averaging periods (June 1 through December 31, 2007 and 2008–2014 for small refiners).
- Standard credits projected to be generated during the 2011–2015 annual averaging periods (2015 for small refiners).
- Credits projected to be needed for compliance during 2011–2015 annual averaging periods (2015 for small refiners).

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 today's proposed program. A detailed understanding of how individual refiners and the industry at large are progressing toward final implementation of the proposed standards would help identify early concerns and allow timely action if

²⁶³ Based on their proposed January 1, 2015 compliance date, small refiners would be required to submit annual pre-compliance reports to us in 2008 through 2014 with a final summary pre-compliance report in 2015.

necessary to prevent the development of major problems.

6. Special ABT Provisions for Small Refiners

Approved small refiners would follow all the above-mentioned ABT provisions with the exception of special credit generation provisions which accommodate their 2015 compliance start date. Early credits could be generated by small refiners from June 1, 2007 to December 31, 2014 for refineries that reduce their average gasoline benzene level to 0.90 times their original 2004–2005 baseline level. Standard credits could also be generated by small refiners beginning January 1, 2015 and continuing indefinitely for refineries that overcomply with the standard by producing gasoline with an annual average benzene content below 0.62 vol%. Additionally, all credits generated by or traded to approved small refiners would have an additional two-year credit life as described above in VII.D.3.b.

E. Regulatory Flexibility Provisions for Qualifying Refiners

1. Hardship Provisions for Qualifying Small Refiners

In developing our proposed MSAT program, we evaluated the need and the ability of refiners to meet the proposed benzene standards as expeditiously as possible. We believe it is feasible and necessary for the vast majority of the program to be implemented in the proposed time frame to achieve the air quality benefits as soon as possible. However, based on information available from small refiners, we believe that refineries owned by small businesses generally face unique hardship circumstances, compared to larger refiners. Thus, we are proposing several special provisions for refiners that qualify as "small refiners" to reduce the disproportionate burden that the proposed standards would have on these refiners. These provisions are discussed in detail below.

a. Qualifying Small Refiners

EPA is proposing several special provisions that would be available to companies that are approved as small refiners. Small refiners generally lack the resources available to larger companies that help large companies, including those large companies that own small-capacity refineries, to raise capital for investing in benzene control equipment. These resources include shifting internal funds, securing financing, or selling assets. Small refiners are also likely to have more

difficulty in competing for engineering resources and completing construction of the needed benzene control equipment (and any necessary octane recovery) equipment in time to meet the standards proposed today. Therefore, we are proposing small refiner relief provisions in today's action as an aspect of realizing the greatest emission reductions achievable.

Since small refiners are more likely to face hardship circumstances than larger refiners, we are proposing temporary provisions that would provide additional time to meet the benzene standards for refineries owned by small businesses. This approach would allow the overall program to begin as early as possible, while still addressing the ability of small refiners to comply.

i. Regulatory Flexibility for Small Refiners

As explained in the discussion of our compliance with the Regulatory Flexibility Act below in section XII.C and in the Initial Regulatory Flexibility Analysis in Chapter 14 of the RIA, we considered the impacts of today's proposed 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 (SBAR) Panel convened by EPA, 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 this proposed rule.

For the SBREFA process, EPA conducted outreach, fact-finding, and analysis of the potential impacts of our regulations on small businesses. Based on these discussions 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 today's proposed program.

One indication of this disproportionate hardship for small refiners is the higher per-gallon capital costs projected for the removal of benzene from gasoline under the proposed program. Refinery modeling of refineries owned by refiners likely to qualify as small refiners, and of non-small refineries, indicates that small refiners could have significantly higher costs to apply some technologies. For two of the technologies that we believe that refiners would use to reduce their benzene levels, routing the six carbon hydrocarbon compounds around the reformer and isomerizing these compounds, we anticipate that small

refiners' costs would likely be similar to non-small refiners, as very little capital investment would need to be made for these technologies. However, for technologies such as benzene saturation and benzene extraction, we anticipate that the costs to small refiners would be higher. Due to the poorer economies of scale, benzene saturation is expected to cost small refiners about 2.2 cents per gallon (while it is projected that benzene saturation would cost a non-small refinery about 1.3 cents per gallon).²⁶⁴ Likewise, benzene extraction is estimated to cost those refineries able to use this technology about 0.1 cents per gallon; however, for small refiners benzene extraction is expected to cost about 0.5 cents per gallon.

The Panel also noted that the burden imposed on the small refiners by the proposed benzene standard could vary from refiner to refiner. Thus, the Panel recommended that more than one type of burden reduction be offered so that most, if not all, small refiners could benefit. We have continued to consider the issues that were raised during the SBREFA process and have decided to propose the provisions recommended by the Panel.

ii. Rationale for Small Refiner Provisions

Generally, we structured these proposed provisions to reduce the burden on small refiners while still achieving the air quality benefits that this program would provide. We believe that the proposed regulatory flexibility provisions for small refiners are a necessary aspect of standards reflecting the greatest achievable emission reductions considering costs and lead time, because they would appropriately adjust potential costs and lead time for the dissimilarly situated small refiner industry segment, and at the same time allow EPA to propose a uniform benzene standard for all refineries.

First, the proposed compliance schedule for this program, combined with flexibility for small refiners, would achieve the air quality benefits of the program as soon as possible, while still ensuring that small refiners that choose to comply by raising capital for benzene reduction technologies would have adequate time to do so. As noted above, most small refiners have limited

additional sources of income or capital beyond refinery earnings for financing and typically do not have the financial backing that larger and generally more integrated companies have. Therefore, they could benefit from additional time to accumulate capital internally or to secure capital financing from lenders.

Second, providing small refiners more time to comply would increase the availability of engineering and construction resources to them. Some refiners would need to install additional processing equipment to meet the proposed benzene standard. We anticipate that there could be increased competition for technology services, engineering resources, and construction management and labor. In addition, vendors would be more likely to contract with the larger refiners first, as their projects would offer larger profits for the vendors. Temporarily delaying compliance for small refiners would spread out the demand for these resources and probably reduce any cost premiums caused by limited supply.

Third, we are anticipating that many small refiners may choose to comply with the proposed benzene standard by purchasing credits. Having additional lead time (which could also result in additional time to generate credits for some small refiners) could help to ensure that there would be sufficient credits available and that there would be a robust credit trading market. Furthermore, offering two years of additional credit life for credits traded to small refiners, as discussed in section VII.D.3.b, would improve credit availability.

Lastly, we recognize that while the proposed benzene standard may be achieved using the four technologies suggested above, new technologies may also be developed that may reduce the capital and/or operational costs. Thus, we believe that allowing small refiners some additional time for newer technologies to be proven out by other refiners would have the added benefit of reducing the risks faced by small refiners. The added time would likely allow for small refiners to benefit from the lower costs of these technologies. This would help to offset the potentially disproportionate financial burden facing small refiners.

We discuss below the provisions that we are proposing to help mitigate the effects on small refiners. Small refiners that chose to make use of the small refiner delayed provision would also delay, to some extent, the benzene emission reductions that would otherwise have been achieved. However, the overall impact of these postponed reductions would be

²⁶⁴ Smaller refineries are less likely to be able to take advantage of economies of scale. For example, a portion of the capital costs invested for a benzene control unit is fixed (i.e., engineering design costs) resulting in similar costs for each investment project. However, when amortized over the volume of fuel processed by a small versus large unit, the per-gallon capital costs are higher for the smaller unit, resulting in poorer economies of scale.

reasonable, for several reasons. Small refiners represent a relatively small fraction of national gasoline production. Our current estimates (of refiners that we expect would qualify as small refiners) indicate that these refiners produce about 2.5 percent of the total gasoline pool. In addition, these small refiners are generally dispersed geographically across the country and the gasoline that they produce is sometimes transported to other areas, so the limited loss in benzene emissions reduction would also be dispersed. Finally, absent small refiner flexibility, EPA would likely have to consider setting a less stringent benzene standard or delaying the overall program (until the burden of the program on many small refiners was diminished), which would serve to reduce and delay the air quality benefits of the overall program. By providing temporary relief to small refiners, we are able to adopt a program that would reduce benzene emissions in a timely and feasible manner for the industry as a whole.

The proposed small refiner provisions should be viewed as a subset of the hardship provisions described in section VII.E.2.b. Rather than dealing with many refineries on a case-by-case basis through the general hardship provisions (described later), we limit the number by proposing to provide predetermined types of relief to a subset of refineries based on criteria designed to identify refineries most likely to be in need of such automatic relief.

b. How Do We Propose To Define Small Refiners for the Purpose of the Hardship Provisions?

The definition of small refiner for this proposed program is in most ways the same as our small refiner definitions in the Gasoline Sulfur and Highway and Nonroad Diesel rules. These definitions, in turn, were based on the criteria use by the Small Business Administration. However, we are proposing to clarify some ambiguities about the definition that have existed in the past.

A small refiner would need to demonstrate that it met all of the following criteria:

Produced gasoline from crude during calendar year 2005.

Small refiner provisions would be limited to refiners of gasoline from crude because they would be the ones that bore the investment burden and therefore the inherent economic hardship. Therefore, blenders and importers would not be eligible, nor would be additive component producers.

Small refiner status would be limited to refiners that owned and operated the

refinery during the period from January 1, 2005 through December 31, 2005. New owners that purchased a refinery after that date would do so with full knowledge of the proposed regulations, and should have planned to comply along with their purchase decisions. As with the earlier fuel rules, we are proposing that a refiner that restarts a refinery in the future may be eligible for small refiner status. Thus, a refiner restarting a refinery that was shut down or non-operational between January 1, 2005 and January 1, 2006 could apply for small refiner status. In such cases, we would judge eligibility under the employment and crude oil capacity criteria based on the most recent 12 consecutive months prior to the application, unless we conclude from data provided by the refiner that another period of time is more appropriate. However, unlike past fuel rules, we propose to limit this to a company that owned the refinery at the time that it was shut down. New purchasers would not be eligible for small refiner status for the same reasons described above. Companies with refineries built after January 1, 2005 would also not be eligible for the small refiner hardship provisions.

—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,

—Had a crude oil capacity less than or equal to 155,000 barrels per calendar day (bpcd) for 2005.

In determining its total number of employees and crude oil capacity, a refiner would need to include the number of employees and crude oil capacity of any subsidiary companies, any parent companies, any subsidiaries of the parent companies, and any joint venture partners. There has been some confusion in past rules regarding how these provisions were interpreted, and as a result, we are proposing to clarify (and, in some cases, modify) them here. For example, in previous rules we defined a subsidiary to be a company in which the refiner or its parent(s) has a 50 percent or greater interest. We realize that it is possible for a parent to have controlling ownership interest in a subsidiary despite having less than 50 percent ownership. Similarly, we realize that it is also possible for multiple parents to each have less than 50 percent ownership interest but still maintain a controlling ownership interest. Therefore, in order to clarify our rules, we are proposing to define a parent company as any company (or companies) with controlling interest,

and to define a subsidiary of a company to mean any company in which the refiner or its parent(s) has a controlling ownership interest. In many cases, there are likely to be multiple layers of parent companies, with the ultimate parent being the one for which no one else has controlling interest. The employees and crude capacity of all parent companies, and all subsidiaries of all parent companies, would thus be taken into consideration when evaluating compliance with these criteria.

As with our earlier fuel sulfur regulations, we are also proposing today that refiners owned and controlled by an Alaska Regional or Village Corporation organized under the Alaska Native Claims Settlement Act, would also be eligible for small refiner status, based only on the refiner's employees and crude oil capacity.²⁶⁵

c. What Options Would Be Available For Small Refiners?

We are proposing several provisions today to help reduce the burdens on small refiners, as discussed above. In addition, these provisions would also allow for incentives for small refiners that make reductions to their benzene levels.

i. Delay in Standards

We propose that small refiners be allowed to postpone compliance with the proposed benzene standard until January 1, 2015, which is four years after the general program would begin. While all refiners would be allowed some lead time before the general proposed program began, we believe that in general small refiners would still face disproportionate challenges. The proposed four-year delay for small refiners would help mitigate these challenges. Further, previous EPA fuel programs have included two to four year delays in the start date of the effective standards for small refiners, consistent with the lead time we believe appropriate here.

Small refiners have indicated to us that an extension of available lead time would allow them to more efficiently carry out necessary capital projects with less direct competition with non-small refiners for financing and for contractor to carry out capital improvements. There appears to be merit in this position, and we propose that approved small refiners have four years of additional lead time. This would provide three years after the 2012 review of the program, which we believe would be enough time for such

²⁶⁵ 43 U.S.C. 1626.

refiners to complete necessary capital projects if they chose to pursue them.

ii. ABT Credit Generation Opportunities

While we have anticipated that many small refiners would likely find it more economical to purchase credits for compliance, some have indicated they would make reductions to their gasoline benzene levels to meet the proposed benzene standard. Further, a few small refiners indicated that they would likely do so earlier than would be required by the January 1, 2015 proposed small refiner start date. Therefore, we are proposing that early credit generation be allowed for small refiners that take steps to meet the benzene requirement prior to their effective date. Small refiner credit generation would be governed by the same rules as the general program, described above in section VII.D, the only difference being that small refiners would have an extended early credit generation period of up to seven years. Early credits could be generated by small refiners making qualifying reductions from June 1, 2007 to December 31, 2014, after which credits could be generated indefinitely for those that overcomplied with the standard.

iii. Extended Credit Life

As discussed previously, in order to encourage the trading of credits to small refiners, we are proposing that the useful life of credits be extended by 2 years if they are generated by or traded to small refiners. This is meant to directly address concerns expressed by small refiners that they would be unable to rely on the credit market to avoid large capital costs for benzene control.

iv. ABT Program Review

As previously stated, we are anticipating that it may be more economically sound for some refiners to purchase and use credits. During discussions with small refiners, all of the small refiners voiced their concerns about reliance on a credit market for compliance with the benzene standard. Specifically, small refiners feared that: (1) there could be a shortage of credits, (2) that larger refiners would not trade credits with smaller refiners, and (3) that the cost of credits could be so high that the option to purchase credits for compliance would not be a viable option. Due to these concerns it was suggested that EPA perform a review of the ABT program (and thus, the small refiner flexibility options) by 2012, one year after the general program begins.

Such a review would take into account the number of early credits generated, as well as the number of credits generated and transferred during

the first year of the overall benzene control program. Further, requiring the submission of pre-compliance reports from all refiners, similar to the highway and nonroad diesel programs, would aid in assessing the ABT program prior to performing the review. A small refiner delay option of four years after the compliance date for other refiners, coupled with a review after the first year of the overall program, would still provide small refiners with roughly three years that we believe would be needed to obtain financing and perform engineering and construction. We are proposing to perform a review within the first year of the overall program (i.e., by 2012). To aid the review, we are also proposing the requirement that all refiners submit refinery pre-compliance reports annually beginning June 1, 2008. Refiners' 2011 annual compliance reports will be similar to the pre-compliance reports, but the annual compliance reports will also contain information such as credits generated, credits used, credits banked, credit balance, cost of credits purchased. EPA would aggregate the data (to protect individual refiners' confidentiality) and make the results available to the industry. When combined with the four-year delay option, this would provide small refiners (and others) with the knowledge of the credit trading market's status before they would need to make a decision to either purchase credits or to obtain financing to invest in capital equipment.

Further, we are requesting comment on elements to be included in the ABT program review, and suggested actions that could be taken following such a review. Such elements could include:

- Revisiting the small refiner provisions if it is found that the credit trading market did not exist to a sufficient degree to allow them to purchase credits, or that credits were only available at a cost-prohibitive price.
- Options to either help the credit market, or help small refiners gain access to credits.

With respect to the first element, the SBAR Panel recommended that EPA consider establishing an additional hardship provision to assist any small refiners that were unable to comply with the benzene standard even with a viable credit market. Such a hardship provision would address the case of a small refiner for which compliance would be feasible only through the purchase of credits, but it was not economically feasible for the refiner to do so. This hardship would be provided to a small refiner on a case-by-case basis following the review and based on a

summary, by the refiner, of technical or financial infeasibility (or some other type of similar situation that would render its compliance with the standard difficult). This hardship provision might include further delays and/or a slightly relaxed standard on an individual refinery basis for up to two years. Following the two-year relief, a small refiner would be allowed to request multiple extensions of the hardship until the refinery's material situation changed. We are proposing the inclusion of such a hardship provision which could be applied for following, and based on the results of, the ABT program review.

With respect to the second element, the Panel recommended that EPA develop options to help the credit market if it is found (following the review) that there is not an ample supply of credits or that small refiners are having difficulty obtaining credits. These options could include 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. Another option the Panel discussed to assist the credit market was to impose additional requirements to encourage trading with small refiners. These could include a requirement that a percentage of all credits sold be set aside and only made available for small refiners. Similarly, we could require 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. Options such as these would help to ensure that small refiners were able to purchase credits. One such recommendation by the Panel, to extend credit life for small refiners, is included in today's proposal and described above.

We welcome comment on additional measures that could be taken following the review if it was found that there was a shortage of credits or that credits were not available to small refiners.

d. How Would Refiners Apply for Small Refiner Status?

A refiner applying for status as a small refiner would be required to apply and provide EPA with several types of information by December 31, 2007. (The detailed application requirements are summarized below.) All refiners seeking small refiner status under this program would need to apply for small refiner 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 proposed rule

that were later found to contain false or inaccurate information would be void ab initio.

Requirements for small refiner status applications:

- 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 would 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 during the 12 months preceding January 1, 2006; and the average number of employees at each location during this time period. This would 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.
- An indication of 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.

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

In situations where a small refiner loses its small refiner status due to merger with a non-small refiner, acquisition of another refiner, or

acquisition by another refiner, we are proposing provisions which are similar to those finalized in the nonroad diesel final rule to allow for an additional 30 months of lead time. A complete discussion of this provision is located in the preamble to the final nonroad diesel rule.

2. General Hardship Provisions

Unlike previous fuel programs, today's program includes inherent flexibility because there is a nationwide credit trading program. Refiners would have the ability to avoid or minimize capital investments indefinitely by purchasing credits, and we expect that many refiners would utilize this option. We also expect that refiners and importers who normally would produce or import gasoline that met the proposed standard would periodically rely on credits in order to achieve compliance. As discussed in section VII.D, we expect that sufficient credits would be available on an annual basis to accommodate the needs of the regulated industry, and we expect that these credits would be available at prices that are comparable to the alternative cost of making the capital investment necessary to produce compliant gasoline. We are proposing to require that refiners submit pre-compliance reports beginning in 2008. These reports would indicate how the refinery plans to achieve compliance with the 0.62 vol% standard as well as the amount of credits expected to be generated or expected to be needed. The information provided in these reports would enable an assessment of the robustness of the credit market and the ability of refiners to rely on credits as the program began.

Although we expect credits to be available at competitive prices to those who need them, we are proposing hardship provisions to accommodate an inability to comply with the proposed standard at the start of the program, and to deal with unforeseen circumstances. These provisions would be available to all refiners, small and non-small, though relief would be granted on a case-by-case basis following a showing of certain requirements, primarily that compliance through the use of credits was not feasible. We are proposing that any hardship waiver would not be a total waiver of compliance. Rather, such a waiver would allow the refiner to have an extended period of deficit carryover. Under regular circumstances, our proposed deficit carryover provision would allow an entity to be in deficit with the proposed benzene standard for one year, provided that they made up the deficit and were in compliance the

next year. The proposed hardship provisions would allow a deficit to be carried over for an extended, but limited, time period. EPA would determine an appropriate extended deficit carryover time period based on the nature and degree of the hardship, as presented by the refiner in their hardship application, and on our assessment of the credit market. Note that any waivers granted under this proposed rule would be separate and apart from EPA's authority under the Energy Policy Act to issue temporary waivers for extreme and unusual supply circumstances, under section 211(c)(4).

a. Temporary Waivers Based on Unforeseen Circumstances

We are proposing a provision which, at our discretion, would permit any refiner to seek a temporary waiver from the MSAT benzene standard under certain rare circumstances. This waiver provision is similar to provisions in prior fuel regulations. It is intended to provide refiners relief in unanticipated circumstances—such as a refinery fire or a natural disaster—that cannot be reasonably foreseen now or in the near future.

Under this provision, a refiner could seek permission to extend the deficit carryover provisions of the proposal for more than the one year already allowed if it could demonstrate that the magnitude of the impact was so severe as to require such an extension. We are proposing that the refiner would be required to show that: (1) The waiver would be in the public interest; (2) the refiner was not able to avoid the nonconformity; (3) it would meet the proposed benzene standard as expeditiously as possible; (4) it would make up the air quality detriment associated with the nonconforming gasoline, where practicable; and (5) it would pay to the U.S. Treasury an amount equal to the economic benefit of the nonconformity 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 were granted would be limited in scope.

As discussed, such a request would be based on the refiner's inability to produce compliant gasoline at the affected facility due to extreme and unusual circumstances outside the refiner's control that could not have been avoided through the exercise of due diligence. The hardship request would also need to show that other avenues for mitigating the problem,

such as the purchase of credits toward compliance under the proposed credit provisions, had been pursued and yet were insufficient or unavailable. Especially in light of the credit flexibilities built into the proposed overall program, we expect that the need for additional relief would be rare.

b. Temporary Waivers Based on Extreme Hardship Circumstances

In addition to the provision for short-term relief in extreme unforeseen circumstances, we are also proposing a hardship provision where a refiner could receive an extension of the deficit carryover provisions based on extreme hardship circumstances. Such hardship could exist based on severe economic or physical lead time limitations of the refinery to comply with the benzene standard at the start of the program, and if they were unable to procure sufficient credits. A refiner seeking such hardship relief under this proposed rule would have to demonstrate that these criteria were met. In addition to showing that unusual circumstances exist that impose extreme hardship in meeting the proposed standard, the refiner would have to show (1) best efforts to comply, including through the purchase of credits, (2) the relief granted under this provision would be in the public interest, (3) that the environmental impact would be acceptable, and (4) that it has active plans to meet the requirements as expeditiously as possible. Because such a demonstration could not be made prior to the development of the credit market, EPA would not begin to consider such hardship requests until August 1, 2010, that is, until after the final pre-compliance reports are submitted. Consequently, requests for such hardship relief would have to be received prior to January 1, 2011.

If hardship relief under these circumstances was approved, we would expect to impose appropriate conditions to ensure that the refiner was making best efforts to achieve compliance

offsetting any loss of emission control from the program through the deficit carryforward provisions. We believe that providing short-term relief to those refiners that need additional time due to hardship circumstances would help to facilitate the adoption of the overall MSAT program for the majority of the industry. However, we do not intend for hardship waiver provisions to encourage refiners to delay planning and investments they would otherwise make. Again, because of the flexibilities of the proposed overall program, we expect that the need for additional relief would be rare.

c. Early Compliance With the Proposed Benzene Standard

We are also requesting comment on a means for allowing refineries, under certain conditions, to meet the proposed benzene standard early in lieu of MSAT1. In order to meet the proposed benzene standard early, refiners would need to meet several criteria similar to those used in the past when EPA has adjusted refinery baselines under the MSAT1 program. Specifically, the eligibility for such provisions would be limited to refiners that have historically had 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 as an oxygenate. The result of not allowing such early compliance could be less supply of their cleaner fuel and more supply of fuel with higher toxics emissions, with a worsening of overall environmental performance under MSAT1. A refiner opting into such provisions would not be allowed to generate benzene credits on the affected fuel prior to 2011, since an ability to reduce benzene further would presumably negate the need for an early compliance option.

F. Technological Feasibility of Gasoline Benzene Reduction

This section summarizes our assessment of the feasibility for the

refining industry to reduce benzene levels in gasoline to an average of 0.62 vol% starting January 1, 2011. Based on this assessment, we believe that it is technologically feasible for refiners to meet the benzene standard by the start date using technologies that are currently available.

We begin this section by describing where benzene comes from and the current levels found in gasoline. Next we discuss the benzene reduction technologies available to refiners today and how they are expected to be used to meet the proposed benzene standard. Then we provide our analysis of the lead time necessary for complying with the benzene standard. All of these issues are discussed in more detail in Chapters 6 and 9 of the Regulatory Impact Analysis.

1. Benzene Levels in Gasoline

EPA receives information on gasoline quality, including benzene levels, from each refinery and importer in the U.S. under the reporting requirements of the RFG and CG programs. As discussed earlier in this section, benzene levels averaged 0.94 vol% for gasoline produced in and imported into the U.S. in 2003, which is the most recent year for which complete data is available. However, for individual refineries, daily batch gasoline benzene levels and annual average levels can vary significantly from the national average. As indicated earlier in describing our decision-making process for the type and level of gasoline benzene standard, it is very important to understand how current benzene levels vary by individual refinery, by region, as well as day-to-day by batch.

The variability in 2003 average annual gasoline benzene levels by individual refinery is shown in Figure VII.F-1. This figure contains a summary of annual average gasoline benzene levels by individual refinery for CG and RFG versus the cumulative volume of gasoline produced.

Figure VII.F-1.

Benzene Levels in U.S. Gasoline Produced and Imported in 2003 (Excluding California).

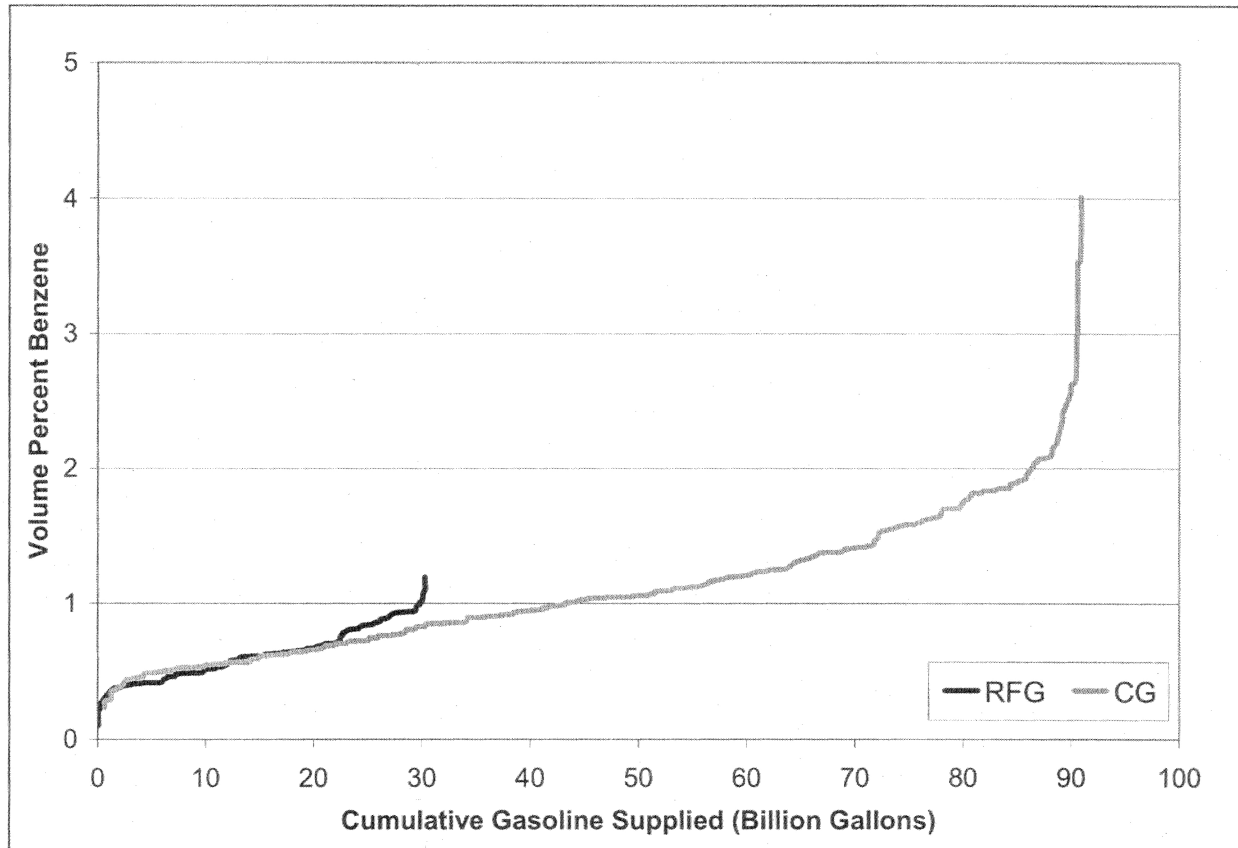


Figure VII.F-1 shows that the annual average benzene levels of CG as produced by individual refineries varies from 0.29 to 4.01 vol%. Based on the data in the figure, the volume-weighted average benzene content for U.S. CG is 1.10 vol%. As expected, the annual average benzene levels of RFG as produced by individual refineries are lower, ranging from 0.10 to 1.09 vol%. The volume-weighted average benzene content for U.S. RFG (not including California) is 0.62 vol%.

The information presented for annual average gasoline benzene levels does not illustrate the very large day-to-day variability in gasoline batches produced by each refinery. We evaluated the batch-by-batch gasoline benzene levels for several refineries that produce both RFG and CG, using information submitted to EPA as part of the reporting requirements for the RFG and CG Anti-dumping Programs. One refinery had no particular trend for its CG benzene levels, with benzene levels that varied from 0.1 to 3 vol%. That same refinery's RFG averaged around 0.95 vol% benzene, ranging from 0.05 to

1.1 vol%. The second refinery had RFG benzene levels that averaged around 0.4 vol% ranging from 0.1 to 1.0 vol%. Its CG benzene levels averaged about 0.6 vol% with batches that ranged from 0.1 to 1.2 vol%. The batches for both RFG and CG varied on a day-to-day basis and, overall, by over an order of magnitude. It is clear from our review of batch-by-batch data submitted to EPA that benzene variability is typical of refineries nationwide.

There are several contributing factors to the variability in refinery gasoline benzene levels across all the refineries. We will review these factors and describe how each impacts batch-by-batch and annual average gasoline benzene levels.

The first factor contributing to the variability in gasoline benzene levels is crude oil quality. Each refinery processes a particular crude oil slate, which tends to be fairly constant except for seasonal changes that reflect changes in product demand. Crude oil varies greatly in aromatics content. Since benzene is an aromatic compound, its level tends to vary with the aromatics

content of crude oil. For example, Alaskan North Slope crude oil contains a high percentage of aromatics. Refiners processing this crude oil in their refineries shared with us that their straight run naphtha contains on the order of 3 vol% benzene (the production of naphtha is discussed further below). This is one reason why the gasoline in PADD 5 outside of California is high in benzene. Conversely, refiners that process very paraffinic crude oils (low in aromatics) usually have a low amount of benzene in their straight run naphtha. Because crude oil supplies tend to be constant over periods of months, crude oil quality is not a major contributor to day-to-day variations in benzene among gasoline batches. However, because crude oil supplies often vary from refinery to refinery, differences in crude quality are an important factor in the variability among refineries.

The second factor contributing to the variability in benzene levels is differences in the types of processing units and gasoline blendstocks among refineries. If a refinery is operated to rely on its reformer for virtually all of

its octane needs—especially the type that operates at higher pressures and temperatures and thus tends to produce more benzene—it will likely have a high benzene level in its gasoline. Refineries with a reformer and without a fluidized catalytic cracking (FCC) unit are particularly prone to higher benzene levels, since they rely heavily on the product of the reformer (reformate) to meet octane needs. However, refineries that can rely on other means for boosting their gasoline octane can usually rely less on the reformer and can run this unit at a lower severity, resulting in less benzene in their gasoline pool. Examples of such other octane-boosting refinery units include the alkylation unit, the isomerization unit and units that produce oxygenates. Refiners may have these units in their refineries, or in many cases, they can purchase the gasoline blendstocks produced by these units from other refineries or third-party producers. The blending of the products of these processes—alkylate, isomerate, and oxygenates—into the gasoline pool provides a significant octane contribution, which can allow refiners to rely less on the octane from reformate. Since refiners make individual decisions about producing or purchasing different blendstocks for each refinery, this variation is another important contributor to differences in gasoline benzene content among refineries. In addition, the variation in gasoline blendstocks used to produce different batches of gasoline is by far the

most important factor in the drastically differing benzene levels among batches of gasoline at any given refinery.

This practice by refiners of producing or purchasing different blendstocks and blending them in different ways to produce gasoline is an integral and essential aspect of the refining business. Thus, in designing an effective benzene control program, it is critical that benzene levels be reduced while refiners retain the ability to change blendstocks (and crude supplies) as needed from batch to batch and refinery to refinery. We believe that the proposed program accomplishes these goals.

A third important source of variability in existing benzene levels in gasoline is the fact that many refiners are already operating their refineries today to intentionally reduce benzene levels in their gasoline, while others are not. For example, refiners that are currently producing RFG must ensure their RFG averages 0.95 vol% or less and is always under the 1.3 vol% cap (see discussion of the current toxics program in section VII.C.5 above). Similarly, refiners producing gasoline to comply the California RFG program need to produce gasoline with reduced benzene. These refiners are generally using benzene control technologies to actively produce gasoline with lower benzene levels. If they are producing CG along with the RFG, their CG is usually lower in benzene as well compared with the CG produced by other refiners, since the benzene control technology often affects

some of the streams used to blend CG. In addition, some refiners add specific refinery units such as benzene extraction to intentionally produce chemical-grade benzene. Benzene commands a much higher price on the chemical market compared to the price of gasoline. For these refiners, the profit from the sale of benzene pays for the equipment upgrades needed to greatly reduce the levels of benzene in their gasoline. In most cases, refineries with extraction units are marketing their low-benzene gasoline in the RFG areas.

The use of these benzene control technologies by some refiners contributes to the variability in gasoline benzene levels among refineries. The use of these technologies can also contribute to the batch-to-batch variability in benzene levels. This is because, as with different blendstocks, refiners need to be able to change the operating characteristics of these technologies to meet varying needs in gasoline quality. In addition, planned or unexpected shut-downs of benzene control equipment may result in temporarily high batch benzene levels relative to the normally low gasoline levels when the unit is operating.

The variations in gasoline benzene levels among refineries also lead to variations in benzene levels among regions of the country. Table VII.F-1 shows the average gasoline benzene levels for all gasoline produced in (and imported into) the U.S. by PADD for 2003. The information is presented for both CG and RFG.

TABLE VII.F-1.—BENZENE LEVELS BY GASOLINE TYPE PRODUCED IN OR IMPORTED INTO EACH PADD IN 2003

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	U.S.
Conventional Gasoline	0.84	1.39	0.94	1.54	1.79	0.63	1.11
Reformulated Gasoline	0.60	0.82	0.56	n/a	n/a	0.62	0.62
Gasoline Average	0.70	1.28	0.87	1.54	1.79	0.62	0.94

Table VII.F-1 shows that benzene levels vary fairly widely across different regions of the country. PADD 1 and 3 benzene levels are lower because the refineries in these regions produce a high percentage of RFG for both the Northeast and Gulf Coast. Also, a number of refineries in these two regions are extracting benzene for sale into the chemicals market, contributing to the much lower benzene level in these PADDs. It is interesting to note that, in addition to RFG, CG benzene levels are low in PADDs 1 and 3. There are two reasons for this. First, some RFG produced by refineries ends up being sold as CG. Second, as mentioned above, refiners that are reducing the

benzene levels in their RFG generally also impact the benzene levels in their CG. In contrast, other parts of the U.S. with little to no RFG production and little extraction have much higher benzene levels.

2. Technologies for Reducing Gasoline Benzene Levels

a. Why Is Benzene Found in Gasoline?

To discuss benzene reduction technologies, it is helpful to first review some of the basics of refinery operations. Refineries process crude oil into usable products such as gasoline, diesel fuel and jet fuel. For a typical crude oil, about 50 percent of the crude

oil falls within the boiling range of gasoline, jet fuel and diesel fuel. The rest of crude oil boils at too high a temperature to be blended directly into these products and therefore must be cracked into lighter compounds. Material that boils within the gasoline boiling range is called naphtha. There are two principal sources of naphtha. The first is “straight run” naphtha, which comes directly off of the crude oil atmospheric distillation column. Another principle source of naphtha is that generated from the cracking reactions. Each type of naphtha contributes to benzene in gasoline.

Typically, little of the benzene in gasoline comes from benzene naturally

occurring in crude oil. Straight run naphtha, which comes directly from the distillation of crude oil, thus tends to have a low benzene content, although it can contain anywhere from 0.3 to 3 vol% benzene. While straight run naphtha is in the correct distillation range to be usable as gasoline, its octane value is too low for blending directly into gasoline. Thus, the octane value of this material must be increased to enable it to be used as a gasoline blendstock.

The primary means for increasing the octane value of naphtha (whether straight run or from cracking processes) is reforming. Reforming reacts the heavier portion of straight run naphtha (six-carbon material and heavier) over a precious metal catalyst at a high temperature. The reforming process converts many of the naphtha compounds to aromatic compounds, which raises the octane of this reformat stream to over 90 octane numbers. ("Octane number" is the unit of octane value.) Since benzene is an aromatic compound, it is produced along with toluene and xylene, the other primary aromatic compounds found in gasoline. The reforming process increases the benzene content of the straight run naphtha stream from 0.3 to 3 vol% to 3 to 11 vol%.

There are two ways that benzene levels increase in the reformer above the benzene levels occurring naturally in crude oil—the conversion of non-aromatic six-carbon hydrocarbons into benzene, and the cracking of heavier aromatic hydrocarbon compounds into

benzene.²⁶⁶ In the discussion below about how benzene in the reformat stream can be reduced, we elaborate further about the opportunities that refiners have to manage both of these benzene-producing processes.

Three factors contribute to the wide range in benzene levels in the reformat stream, and these factors are important in the decisions refiners would make in response to the proposed benzene control program. First, different feedstocks contain different amounts of benzene and different levels of benzene precursors that are more or less capable of being converted to benzene by the reformer. Second, the type of reformer being used affects how much benzene is produced during the reforming process. For example, refineries with the older, higher pressure reformers tend to form more benzene by cracking heavier aromatics than refineries with newer, lower pressure units. Third, the severity with which the reformer is being operated also affects benzene levels in reformat. The greater the severity at which the reformer is operated, the greater the conversion of feedstocks to aromatics (and the more hydrogen is produced). However, more severe operation shortens the time between the catalyst regeneration events that the reformer must periodically undergo. Greater severity also lowers the gasoline yield from this unit. Because refiners balance these operation and production factors individually at each refinery in deciding on how severely to operate the reformer, these decisions contribute to

the range of benzene levels found in reformat from refinery to refinery.

In addition to benzene occurring in the reformat stream, another source of benzene in gasoline is naphtha produced from cracking processes. There are three primary cracking processes in the refinery—the FCC unit, the hydrocracker, and the coker. The naphthas produced by these cracking processes contain anywhere from 0.5 to 5 vol% benzene. The benzene in these streams is typically formed from the cracking of heavier aromatic compounds into lighter compounds that can then be blended into gasoline. The benzene content of cracked streams is therefore largely a function of the aromatics content of the crude oil feedstocks and the need of a particular refinery to produce gasoline from heavier feedstocks. As we discuss later, we do not expect that benzene reductions from these cracked naphthas would be a major avenue for compliance with the proposed benzene control program for most refiners.

Finally, there are other intermediate streams that contribute to benzene in gasoline but that have such low benzene content or are found in such low volumes in gasoline that they are of very limited importance in reducing benzene levels. Examples of these are light straight run naphtha and the oxygenates MTBE and ethanol.

Table VII.F-2 summarizes the typical ranges in benzene content and average percentages of gasoline of the various intermediate streams that are blended to produce gasoline.

TABLE VII.F-2.—BENZENE CONTENT AND TYPICAL GASOLINE FRACTION OF VARIOUS GASOLINE BLENDSTOCKS

Process or blendstock name	Typical benzene level (vol%)	Average volume in gasoline (percent)
Reformat	3–11	30
FCC Naphtha	0.5–2	36
Alkylate	0	12
Isomerate	0	4
Hydrocrackate	1–5	3
Butane	0	4
Light Straight Run	0.3–3	4
MTBE/Ethanol	0.05	3
Natural Gasoline	0.3–3	3
Coker Naphtha	3	1

Table VII.F-2 shows that the principal contributor of benzene to gasoline is reformat. This is due both to its high benzene content and the relatively large gasoline fraction that reformat comprises of the gasoline pool. The

product stream from the reformer, reformat, accounts for between 15 and 50 percent of the content of gasoline, depending on the refinery (typically about 35 percent.) For this reason and as discussed below, reducing the

benzene in reformat is the primary focus of the various benzene reduction technologies available to refiners. Control of benzene from the other streams quickly becomes cost prohibitive due to either the low

²⁶⁶ In the process of converting the straight run naphtha into aromatics, a significant amount of

hydrogen is produced that is critical for the various hydrotreating operations in refineries. As discussed

later, the impact on hydrogen production is an important consideration in reducing benzene levels.

depending on the refinery (typically about 35 percent.) For this reason and as discussed below, reducing the benzene in reformate is the primary focus of the various benzene reduction technologies available to refiners. Control of benzene from the other streams quickly becomes cost prohibitive due to either the low concentration of benzene in the stream, the low volume of the stream, or both.

b. Benzene Control Technologies Related to the Reformer

There are several technologies that reduce gasoline benzene by controlling the benzene in the feedstock to and the product stream from the reformer.²⁶⁷ One approach is to route the intermediate reformer streams that have the greatest tendency to form benzene in a way that bypasses the reformer. This approach is very important in benzene control, but it is limited in its effectiveness because it does not address any of the naturally-occurring benzene and some of the benzene formed in the reformer. For this reason, refiners often use a second category of technologies that remove or destroy benzene, including both the naturally occurring benzene as well as that formed in the reformer. These technologies are isomerization, benzene saturation, and benzene extraction. We discuss each of these approaches to benzene reduction below. The effectiveness of these technologies in reducing the benzene content of reformate varies from approximately 60% to 96%. The actual impact on an individual refinery's finished gasoline benzene content, however, will be a function of many different refinery-specific factors, including the extent to which they are already utilizing one of these technologies.

i. Routing Around the Reformer

The primary compounds that are converted to benzene by the reforming unit are the six-carbon hydrocarbon compounds contained in the straight run naphtha fed to the reformer. These compounds, along with the naturally-occurring benzene in this straight run naphtha stream, can be removed from the feedstock to the reforming unit using the upstream distillation unit, bypassed around the reforming unit, and then blended directly into gasoline. Routing

these compounds around the reformer prevents the formation of much of the benzene in the reformer, though it does not reduce the naturally-occurring benzene.

For a typical refinery, the technology to route the six-carbon material around the reformer would likely require only a small capital investment. Compared with a scenario where all of this material goes to the reformer, the combined rerouted and reformate streams would overall have about 60 percent less benzene, and finished gasoline would have about 31 percent less benzene. However, in most cases this would not be sufficient to achieve a 0.62 vol% benzene standard, and some combination of the technologies discussed next would also be needed.

ii. Routing to the Isomerization Unit

A variation of routing around the reformer involves the isomerization of the re-routed benzene precursors. Rather than directly blending the rerouted stream into gasoline, this stream can first be processed in the isomerization unit. This has two main advantages. First, it increases the effectiveness of benzene control, since the isomerization process converts the naturally-occurring benzene in this rerouted stream to another compound. Second, it recovers some of the octane otherwise lost by the conversion of benzene.

The typical role of the isomerization unit is to convert five-carbon hydrocarbons from straight-chain to branched-chain compounds, thus increasing the octane value of this stream. If the isomerization unit at a refinery has sufficient additional capacity to handle the rerouted six-carbon hydrocarbons, that stream can also be sent to this unit, where the benzene present in that stream would be saturated and converted into another compound (cyclohexane). (This benzene saturation process is similar to what occurs in a dedicated benzene saturation unit, as described below.) Compared to a scenario where all this material goes to the reformer, routing the six-carbon compounds to the isomerization unit in this manner can reduce the benzene levels in the combined rerouted and reformate streams by about 80 percent. The option of isomerization is currently available to those refineries with sufficient capacity in an existing isomerization unit to treat all of the six-carbon material.

iii. Benzene Saturation

The function of a benzene saturation unit is to react hydrogen with the benzene in the reformate (that is, to saturate the benzene) in a dedicated

reactor, converting the benzene to cyclohexane. Because hydrogen is used in this process, refiners that choose this technology need to ensure that they have a sufficient source of hydrogen. Refiners cannot afford to saturate other aromatic compounds present in their reformate as it would cause too great an octane loss. Thus, it is necessary to separate a six-carbon stream, which contains the benzene, from the rest of reformate, and only feed the six-carbon stream to the benzene saturation unit. This separation is done with a distillation unit called a reformate splitter placed just after the reformer.

There are two vendors that produce benzene saturation units. UOP produces a technology named Bensat. There are at least six Bensat units operating in the U.S. today and many more around the world. CDTEch licenses another, somewhat newer technology for this purpose called CDHydro. There are six CDHydro units operating today, mostly outside of the U.S. Benzene saturation can reduce benzene in the reformate by about 96 percent.

iv. Benzene Extraction

Extraction is a technology that chemically removes benzene from reformate. The removed benzene can be sold as a high-value product in the chemicals market. To extract only benzene from the reformate, a reformate splitter is installed just after the reformer to separate a benzene-rich stream from the rest of the reformate. The benzene-rich stream is sent to an extraction unit which separates the benzene from the rest of the hydrocarbons. Since the benzene must be sufficiently concentrated before it can be sold on the chemicals market, a very thorough distillation step is incorporated with the extraction step to concentrate the benzene to the necessary purity. Where it is economical to use, benzene extraction can reduce benzene levels in the reformate by 96 percent.

There are two important considerations refiners have with respect to using benzene extraction. The first is the price of chemical grade benzene. If the price of chemical grade benzene is sufficiently higher than the price of gasoline, benzene extraction can realize an attractive return on capital invested and is often chosen as a technology for achieving benzene reduction. The difference in price between benzene and gasoline has been significantly higher than its historic levels during the last few years. While we expect that this difference will return closer to the lower historic levels by the time the proposed program

²⁶⁷ The benzene reduction technologies are discussed here in the context of the feasibility for reducing the benzene levels of gasoline to meet a gasoline benzene content standard. However, this discussion applies equally to the feasibility of a total air toxics standard, since we believe that benzene control would be the only means that refiners would choose in order to comply with such a standard.

would be implemented, the difference in prices should still be sufficient to make extraction a very cost-effective technology for reducing gasoline benzene levels. A more detailed discussion about benzene prices is contained later in this preamble (section IX) and in Chapter 9 of the RIA.

The other consideration in using benzene extraction is the distance that a refinery is from the markets where benzene is used as a chemical feedstock. Transportation of chemical grade benzene requires special hazardous-materials precautions, including protection against leaks. Certain precautions are also necessary to preserve the purity of the benzene during shipment. These special precautions are costly for shipping benzene over long distances. Thus if a refinery were located far from the chemical benzene markets, the economics for using extraction would be much less attractive compared to that of refineries located near benzene markets.

The result has been that chemical grade benzene production has been limited to those refineries located near the benzene markets. This includes refineries on the Gulf and on the East Coast and to a limited extent, several refineries in the Midwest. This could change if the very high benzene prices in 2004 and the beginning of 2005 were to continue, instead of returning to lower historical levels. However, even if benzene prices remain high by the time that a benzene control standard would take effect, refineries located away from the benzene markets may be concerned that the higher benzene prices may not be certain enough for the long term to warrant investment in extraction. Our analysis for today's proposal conservatively assumes that only refineries on the Gulf and East coasts would choose to use benzene extraction to lower their gasoline benzene levels. Despite some existing extraction units in the Midwest, the benzene market there is small and no additional benzene extraction is assumed to occur there.

c. Other Benzene Reduction Technologies

We are aware of other, less attractive technologies capable of achieving benzene reductions in gasoline. These technologies tend to have more serious impacts on other important refinery processes or on fuel quality and are generally capable of only modest benzene reductions. We do not currently have sufficient information about how widely these approaches are or could be utilized or their potential costs, and in our modeling we have not assumed that refineries would use them.

However, because they may be feasible in some unique situations, we mention these potential gasoline benzene reduction approaches here.

One of these less attractive opportunities for additional benzene reduction would be for refineries to capture more of the reformate benzene in the reformate splitter and send this additional benzene to the saturation unit. Refiners attempt to minimize both the capital and operating costs when splitting a benzene-rich stream out of the reformate stream for treating in a benzene saturation unit. To do this, they optimize the distillation cut between benzene and toluene, thus achieving a benzene reduction of about 96 percent in the reformate while preserving all but about 1 percent of the high-octane toluene. However, if a refiner were to be faced with a dire need for additional benzene reductions, it could change its distillation cut to send the last 4 percent of the benzene to the saturation unit. Since this cut would also bring with it more toluene than the normal optimized scenario, this toluene would also be saturated, resulting in a larger loss in octane and greater hydrogen consumption.

Some refineries with hydrocracking units may have another means of further reducing the gasoline benzene levels. They may be able to reduce the benzene content of one of the products of the hydrocracker, the light hydrocrackate stream. Today, light hydrocrackate is normally blended directly into gasoline. Light hydrocrackate contains a moderate level of benzene, although its contribution to the gasoline benzene levels is significant only in those refineries with hydrocrackers. Light hydrocrackate could be treated by routing this stream to an isomerization unit, similar to how refineries isomerize the six-carbon straight run naphtha as discussed above. Alternatively, refineries could use additional distillation equipment to cut the light hydrocrackate more finely. In this way, more of the benzene could be shifted to the "medium" hydrocrackate stream, which in most refineries is sent to the reformer and thus would be treated along with the reformate.

Another way that we believe some refineries could further reduce their benzene levels would be to treat the benzene in natural gasoline. Many refineries, especially in PADDs 3 and 4, blend some light gasoline-like material, which is a by-product of natural gas wells, into their gasoline. In most cases, we believe that this material is blended directly into gasoline. Because the benzene concentration in this stream is not high, it would be costly to treat the

stream to reduce benzene. However, there could be other reasons that refineries might find compelling for treating this stream. First, since its octane is fairly low to begin with, it could be fed to the reformer and its benzene would be treated in the reformate, along with the benefit of improving the octane quality of this stream. Second, refineries producing low-sulfur gasoline under the gasoline sulfur program may not be able to easily tolerate the sulfur from this stream if it were blended directly into gasoline. Thus, if they treat this stream in the reformer, it would undergo the hydrotreating (desulfurization) that is necessary for all streams fed to the reformer. Overall, we do not have sufficient information to conclude whether treating natural gasoline might become more attractive in the future.

Another approach to benzene reduction that we believe could be attractive in certain unique circumstances relates to the benzene content in naphtha from the fluidized catalytic cracker, or FCC unit. As shown in Table VII.F-2, FCC naphtha contains less than 1 percent benzene on average. Despite the very low concentration of benzene in FCC naphtha, the large volumetric contribution of this stream to gasoline results in this stream contributing a significant amount of benzene to gasoline as well. There are no proven processes which treat benzene in FCC naphtha. This is because its concentration is so low as well as because FCC naphtha contains a high concentration of olefins. Segregating a benzene-rich stream from FCC naphtha and sending it to a benzene saturation unit would saturate the olefins in the same boiling range, resulting in an unacceptable loss in octane value. Also, some refineries operate their FCC units today more severely to improve octane, an action that also increases benzene content. Conceivably, refineries could redesign their FCC process (change the catalyst and operating characteristics) to reduce the severity and produce slightly less benzene. We do not have sufficient information to know whether many refineries are already operating at high FCC severity and thus have the potential to reduce benzene by reducing that severity.

We request comment on our assessment of benzene reduction approaches, including data related to the current or potential usage and potential effectiveness of each approach.

d. Impacts on Octane and Strategies for Recovering Octane Loss

All these benzene reduction technologies affect the octane of the final gasoline. Regular grade gasoline must comply with a minimum 87 octane (R+M)/2 rating (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 (R+M)/2. Gasoline must meet these octane ratings to be sold as gasoline at retail. Routing the benzene precursors around the reformer reduces the octane of the six-carbon compound stream, which normally exits the reformer with the rest of the reformate. Without these compounds in the reformate, a loss of octane in the gasoline pool of about 0.14 octane numbers typically occurs. If this rerouted stream can be sent to an isomerization unit, a portion of this lost octane can be recovered, provided that sufficient capacity remains in that unit to continue treating the five-carbon naphtha compounds. Benzene saturation and benzene extraction both affect the octane of reformate and therefore the gasoline pool. Benzene saturation typically reduces the octane of gasoline by 0.24 octane numbers, and benzene extraction typically reduces the octane by 0.14 octane numbers.

Refiners can recover the lost octane in a number of ways. First, the reformer severity can be increased. 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 would also decrease 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 but the amount of benzene extracted is increased. Again, operating the reformer more severely would have the negative impact of shortening the reformer's operating cycle between regeneration events.

Lost octane can also be recovered by increasing the activity of other octane-producing units at the refinery. As discussed above, saturating benzene in the isomerization unit loses the octane value of that benzene, but octane is increased by the simultaneous formation of branch-chain compounds. Also, many refineries produce a high-

octane blendstock called alkylate. Alkylate is produced by reacting normal butane and isobutane with isobutylene over an acid catalyst. Not only is this stream high in octane, but it converts 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. If the refinery is short of feedstocks for alkylate, then the operations of the FCC unit, which is the principal producer of these feedstocks, can be adjusted to produce more of the feedstocks for the alkylate unit, increasing the availability of this high octane blendstock.

Octane can also be increased by purchasing high-octane blendstocks and blending them into the gasoline pool. For example, some refiners with excess octane production capacity market high octane blendstocks such as alkylate or aromatics such as toluene. Oxygenates, such as ethanol, can also be blended into the gasoline pool. Other oxygenates such as methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), tertiary amyl methyl ether (TAME), and other ethers are sometimes used. The availability and cost of oxygenates for octane replacement vary according to material prices as well as state and federal policies that either encourage or discourage their use. (For example, the Energy Policy Act of 2005 requires an increase in the volume of renewable fuels, including ethanol, which are blended into gasoline).

e. Experience Using Benzene Control Technologies

All of the benzene reduction technologies and octane generating technologies described above have been demonstrated in refineries in the U.S. and abroad. All four of these technologies have been used for compliance purposes for the federal RFG program, which has required that benzene levels be reduced to an average of 0.95 vol% or lower since 1995.

According to the Oil and Gas Journal's worldwide refining capacity report for 2003, there were 27 refineries in the U.S. with extraction units. Those refineries that chose extraction often reduced their benzene to levels well below 0.95 vol% because of the value of benzene as a chemical feedstock, as discussed above. Once a refiner invests in extraction, they have a strong incentive to maximize benzene production and thus the availability of benzene to sell to the chemical market, often reducing gasoline benzene more than is required by regulation. The RFG program also led to the installation of a small number of benzene saturation

units in the Midwest to produce RFG for the markets there. California has its own RFG program which also put into place a stringent benzene standard for the gasoline sold there. The Oil and Gas Journal's Worldwide Refining Report shows that four California refineries have benzene saturation units. If we assume that those RFG and California refineries that do not have extraction or saturation units are routing their precursors around their reformer, then there are 28 refineries using benzene precursor rerouting as their means to reduce benzene levels. Thus, these technologies have been demonstrated in many refineries since the mid-1990s in the U.S. and are considered by the refining community as commercially proven technologies.

Worldwide experience provides further evidence of the commercial viability of these benzene control technologies. A vendor of benzene control technology has shared with us how the refining companies in other countries have controlled the benzene levels of their gasoline in response to the benzene standards put in place there. In Europe, benzene control is typically achieved by routing the benzene precursors around the reformer and feeding that rerouted stream to an isomerization unit. In Japan, much of the benzene is extracted from gasoline and sold to the chemicals market. Finally, in Australia and New Zealand, refiners tend to use benzene saturation to reduce the benzene levels in their gasoline.

f. What Are the Potential Impacts of Benzene Control on Other Fuel Properties?

With the complex nature of modern refinery operations, most changes to fuel properties affect other fuel properties to some degree. In the case of benzene control, the "ripple effects" on other fuel properties tends to be limited. However, as discussed above, the reduction in benzene content that we are proposing in this rule, depending on how it is accomplished, would in most cases slightly reduce the overall octane of the resulting gasoline. Refiners would likely compensate by increasing the volume of reformate (other aromatics) blended into the gasoline, requiring a small increase in reformer severity and energy inputs. Some analysis of gasoline property survey data suggests that as benzene is reduced in gasoline, other aromatics may increase somewhat to help compensate.

Another option refiners might consider in response to the proposed rule is match-blending ethanol to make up octane and increase supply volume.

This has been done for several years with MTBE as an economical way to meet toxics performance requirements and octane targets for RFG. Like MTBE, ethanol has a relatively high blending octane, and is already added in many markets to take advantage of tax benefits or to support local suppliers. Since the use of ethanol is being encouraged in the recently-enacted energy legislation, refiners will likely seek to capture the octane benefits as part of their process, which could help offset the octane loss some refiners will see as a result of benzene reduction processes. Furthermore, to the extent that current MTBE production is shifted to production of isooctene, isooctane, and alkylate, these compounds would be available as high-octane, low-benzene gasoline blendstocks.

Finally, refiners may blend in isomerate or alkylate, which are very "clean" gasoline blendstocks, thereby reducing the levels of "dirtier" gasoline blendstocks, and reducing overall sulfur, olefins, and aromatics. We do not anticipate major changes in other fuel properties due to reductions in benzene. Our modeling of the emissions impacts of the proposed benzene standard does account for the modest changes in other fuel properties. As discussed in section V of this preamble and Chapter 2 of the RIA, this emissions modeling indicates that the proposed benzene standard has negligible impacts on the emissions of other mobile source air toxics.

3. Feasible Level of Benzene Control

A key aspect of our selection of the level of the proposed average benzene standard of 0.62 vol% was our evaluation of the benzene levels achievable by individual refineries. Our modeling analyses, which combine our understanding of technological and economic factors, is summarized in section IX below and discussed in detail in Chapter 9 of the RIA. Later in this section we summarize our conclusions about the overall feasibility of the program in terms of the requirements of the Clean Air Act.

We assessed the benzene levels achievable for each refinery, assuming that each refinery pursued the most stringent form of reformate benzene control available to it—installing either benzene saturation or extraction units. Based on this assessment, we project that the most stringent benzene level achievable on average for all U.S. gasoline would be 0.52 vol% benzene.²⁶⁸ As discussed above,

however, a standard at this level would require significant investment at essentially all refineries—that is, near-universal installation of either benzene saturation or benzene extraction capability. As discussed in section IX below, this would be a very expensive result—costing about three times more than the proposed program—that we do not believe would be reasonable when costs are taken into account.

Furthermore, the model projects that all refineries would use optimal combinations of actual benzene reductions and/or credit purchases and would meet the average standard without going beyond the primary technologies of reformate benzene reduction discussed earlier in this section. To reach this conclusion, our model assumes a fully utilized credit trading program (that is, each refiner is assumed to minimize its average costs and to freely trade credits among companies so that all credits generated are used). Although the assumption of a fully utilized credit trading program is appropriate for our modeling purposes, it is very possible that this would not occur in practice. For example, some refiners might choose to hold onto credits that they generate, saving them for potential "emergencies" when unexpected events would otherwise cause noncompliance with the benzene standard.

Given the high cost of control for some refineries and the potential that credit trading would be less-than-fully utilized, we have looked at standards less stringent than 0.52 vol% that might be feasible, considering cost. Based on our modeling, we believe that with the proposed ABT program all gasoline could be produced at the proposed average level of 0.62 vol% without extreme economic consequences. We believe that sufficient credits would be generated such that refineries facing the highest costs of benzene control would have sufficient access to credits and would not need to turn to cost prohibitive technologies.

From a strict feasibility standpoint, we have also assessed whether all refineries could meet the proposed benzene level in cases where sufficient credits were not available to every refinery that might want them. We found that, despite the application of maximum reformate benzene control in the refinery model to all refineries, the analysis concluded that 13 refineries would still have benzene levels that exceeded a 0.62 benzene level, with one refinery as high as 0.77 vol% benzene. We have evaluated how these 13 refineries might use the other, less attractive benzene control technologies

discussed above (assuming that an ABT option is not available to them).

The approach of capturing more of the reformate benzene in the reformate splitter and sending this additional benzene to the saturation unit would allow 7 of the 13 challenged refineries to reach the 0.62 vol% level. Then, those refineries with a hydrocracker or a coker could reduce the benzene content of the light hydrocrackate or coker stream. This step would allow 5 more refineries to reach the target level. Finally, the treatment of benzene in natural gasoline would bring the remaining 1 refinery to the 0.62 vol% level or below. (Because of our lack of information about the potential for reducing the severity of the FCC unit, and because we do not believe that reducing the benzene level of FCC naphtha is feasible, we did not consider FCC options in this analysis.) Again, we expect that at the proposed standard level of 0.62 vol% in the context of the proposed ABT program, all refineries would be able to comply. This analysis demonstrates that there are options, although extreme and costly, for challenged refineries even if the ABT program does not fully function as projected.

4. Lead Time

Our proposal for the gasoline benzene standard to begin on January 1, 2011 would allow about four years after we expect the rulemaking to be finalized for refiners to comply with the program's requirements. As discussed below, we believe that four years of lead time would allow refiners sufficient time to install the capital equipment they would need to lower their benzene levels, and would also allow this program to avoid significant conflict with other fuel programs being implemented around the same time. In addition, the ABT program would allow the industry to phase in the program, through the early credit provisions, so that significant benzene reductions would occur earlier than the program start date. The credits earned could allow the investment in higher capital cost and less cost-effective technologies to be delayed relative to the program start date.

In recent years, the implementation of the gasoline sulfur and highway diesel sulfur programs has provided an opportunity to observe the response of the refining industry to major fuel control requirements. Many refiners have demonstrated their ability to make very large, expensive sulfur control modifications to their refineries in less than four years, and in some cases significantly less. It is helpful to

²⁶⁸ This analysis is within the constraints of our modeling and the refinery-specific information available to us at the time of this proposal.

compare this sulfur control experience with the types of technologies refiners would use to reduce benzene.

Refiners could implement approaches to benzene control that require very little or no capital equipment, including routing of benzene precursors around the reformer and the use of an existing isomerization unit, with very little lead time requirements. We believe that approaches using moderately complex capital equipment, including improving the effectiveness of precursor rerouting and expanding existing extraction capacity, would generally require one to two years of lead time. Projects that involve the installation of new equipment, including benzene saturation and extraction units, require more time, generally two to three years. This includes time for the equipment installation as well as related offsite equipment and any necessary capital equipment for production of hydrogen or high-octane blendstocks. Of all the benzene control approaches, benzene extraction is closest in scope and complexity to the technologies the industry is using for fuel sulfur control. In addition to the time needed for planning and installing the extraction unit and related equipment, extraction also requires time to install additional facilities for storing extracted benzene and for loading it for transport. Thus, as with the earlier programs, we believe the refiners choosing to add a benzene extraction unit could in some cases need as much as four years to complete the project. Overall, we believe that four years of lead time would ensure that all refiners would have sufficient time to comply, regardless of the benzene control technology they select.

Another factor in selecting an appropriate date to begin the program is the timing of the implementation of other large fuel control programs, especially the Nonroad Diesel rule.²⁶⁹ The 15 ppm sulfur standard mandated by the Nonroad Diesel Fuel program applies to nonroad diesel fuel in 2010 and to locomotive and marine diesel fuel in 2012. Refiners modifying their refineries to produce either ultra low sulfur nonroad or locomotive and marine diesel fuel will do so during the several years prior to 2010 and 2012. For each of those start dates, there is a progression of actions which includes

planning, design, construction and start-up all during the four year run-up toward the start date of the program. For example, the engineering and construction (E&C) industry will be busy designing and constructing each of the units that will be installed. Different portions of the E&C industry will be engaged at specific periods of time leading up to the time that the unit is started up. For this reason, staggering the start year of this benzene fuel standard with the start years for the Nonroad Diesel program would help to avoid excessive demand on specific parts of the E&C industry. The staggering of today's proposed program's start date with those of the Nonroad Diesel program may also help refiners that might be seeking to acquire capital through banks or other lending institutions by spreading out the requests.

We believe that the proposed implementation date of January 1, 2011 would minimize overlap and possible interference with the implementation of the Nonroad Diesel rule. Implementation of the proposed benzene standard one year earlier or one year later would overlap directly with one of the two Nonroad Diesel implementation dates. We also believe that the additional year of lead time, compared to a 2010 start date, would make the program more effective. Because we expect that the proposed ABT program would encourage many refiners to reduce benzene levels early whenever possible, we believe that significant benzene reductions would occur prior to 2011. We discuss this expected early benzene reduction further as a part of the description of the proposed ABT program in section VII.D above.

For these reasons, we are proposing that the gasoline benzene standard be implemented beginning January 1, 2011. We request comment on the issue of lead time, including data supporting four years or a different length of time.

5. Issues

a. Small Refiners

Small refiners are technically capable of realizing a similar benzene reduction from their gasoline as large refiners. Because of economies of scale, however, some of the benzene control technologies which would be more affordable for larger refineries would be much more challenging and more expensive for small refiners. This is due to the poorer economies of scale that the small refiners are faced with installing capital into their refineries. Two of the benzene control technologies discussed

above would be particularly attractive to small refiners for implementing into their refineries. These are benzene precursor rerouting, and, if the refinery has an isomerization unit, routing the benzene precursors to the isomerization unit. These technologies would be attractive to small refiners because they would require little or no capital investments to implement for reducing their gasoline benzene levels. Therefore, the per-gallon cost of these two technologies is about the same as that for large refineries.

Smaller refineries tend to have fewer process units and blending streams, which generally also means that they will have fewer options for recovering lost octane. For example, these refineries are less likely to have an alkylation unit. An alkylation unit gives refiners short on octane the option to change the operations of their FCC unit to make more olefins and then send the appropriate olefins to their alkylation unit to produce more of that high octane blendstock. This is not an option for several of the small refiners that do not have an alkylation unit. Also, small refineries are more likely to have a higher pressure reforming unit. The higher pressure reformer units tend to produce more benzene from the cracking of heavier aromatic compounds and will tend to do this more as their severity is increased. A higher pressure reformer also has a more difficult regeneration cycle and shorter cycle lengths as it is operated more severely. Thus, while other refiners with lower pressure units may be able to increase the severity of their reformers to make more octane without producing much more benzene and greatly reducing the cycle lengths of their reformers, many of the small refiners may not have as much flexibility in this area. In any event, these greater technological challenges can be offset somewhat where it is economical to purchase high octane blendstocks or oxygenates from other refiners or from the petrochemical industry.

b. Imported Gasoline

Although the majority of petroleum products in the U.S. are made from imported crude oil, only about five percent of the gasoline consumed in this country was imported as finished gasoline in 2003. This imported fuel is approximately half RFG and half CG, and had an average benzene content of 0.8% volume in 2003. No batches of imported gasoline had a benzene level above 2.4%. Over 90% of the imported gasoline was delivered into the East Coast and Florida, with about 5% arriving on the West Coast, and the

²⁶⁹ The months leading up to January 2010 will also be when several small refiners and refiners that were granted hardship relief will be implementing their gasoline sulfur programs. We believe that any serious interference among implementation projects that individual refiners might demonstrate during this time period could be addressed under the small refiner or general hardship provisions of the proposed rule.

remainder being brought into other regions of the country. The origin of the majority of this gasoline was Canada (40%), Western Europe (31%), and South America (17%).

Since imported finished gasoline is not processed in a domestic refinery, where refiners would be taking steps to meet the proposed benzene standard, importers would be affected in other ways. Importers would most likely either begin to purchase gasoline that is low enough in benzene to meet the standard, or they would continue to import gasoline with benzene at current levels but purchase credits to cover the fuel being above the standard. As shown above, over 70 percent of imported gasoline comes from countries that have already set benzene limits on their gasoline. As a result, we believe that gasoline with some degree of benzene control will be easily available for importers to market. In some cases, we also expect that some foreign refiners may produce for export some fraction of their gasoline to meet our proposed 0.62 vol% average standard benzene. This would provide importers further options in the U.S. gasoline market.

G. How Does the Proposed Fuel Control Program Satisfy the Statutory Requirements?

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. Today's action proposes such a program, with an average benzene content standard of 0.62 vol% and a specially-designed averaging, banking, and trading program. In section VII.F above, we summarize our evaluation of the feasibility of the proposed program, and in section IX.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 program more stringent than the proposed program would not be feasible, taking into consideration cost. As we have discussed, making the standard more stringent would require more refiners to install the more expensive benzene control equipment, with very little improvement in benzene emissions. Also, we have shown that related costs increase very rapidly as the level of the standard is made more stringent. Conversely, while it would provide significant benzene emission reductions, we are concerned that a somewhat less stringent national

average standard than the proposed 0.62 vol% (e.g., 0.65 or 0.70 vol%) would not satisfy our statutory obligation for the most stringent standard feasible considering cost and other factors. Furthermore, such standards would not accomplish several important programmatic objectives as discussed in section VII.C.

We have also considered energy implications of the proposed program, as well as noise and safety, and we believe the proposed program would have very little impact on any of these factors. 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 VII.F above).

Consequently, we believe that the proposed program would meet the requirements of section 202(l) 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."

H. Effect on Energy Supply, Distribution, or Use

This rule is not a "significant energy action" as defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. If promulgated, the gasoline benzene provisions of the proposed rule would shift about 22,000 barrels per day of benzene from the gasoline market to the petrochemical market. This volume represents about 0.2 percent of nationwide gasoline production. The actual impact of the rule on the gasoline market, however, is likely to be less due to offsetting changes in the production of petrochemicals, as well as expected growth in the petrochemical market absent this rule. The major sources of benzene for the petrochemical market other than reformat from gasoline production are also derived from gasoline components or gasoline feedstocks. Consequently, the expected shift toward more benzene production from reformat due to this proposed rule would be offset by less benzene produced from other gasoline feedstocks.

The rule would require refiners to use a small additional amount of energy in processing gasoline to reduce benzene levels, primarily due to the increased

energy used for benzene extraction. Our modeling of increased energy use indicates that the process energy used by refiners to produce gasoline would increase by about one percent. Overall, we believe that the proposed rule would result in no significant adverse energy impacts.

The proposed gasoline benzene provisions would not affect the current gasoline distribution practices.

We discuss our analysis of the energy and supply effects of the proposed gasoline benzene standard further in section IX of this preamble and in Chapter 9 of the Regulatory Impact Analysis.

The fuel supply and energy effects described above would be offset substantially by the positive effects on gasoline supply and energy use of the proposed gas can standards also proposed in today's action. These proposed provisions would greatly reduce the gasoline lost to evaporation from gas cans. This would in turn reduce the demand for gasoline, increasing the gasoline supply and reducing the energy used in producing gasoline.

I. How Would the Proposed Gasoline Benzene Standard Be Implemented?

This section discusses the details associated with meeting the proposed 0.62 vol% benzene standard.

1. General Provisions

a. What Are the Implementation Dates for the Proposed Program?

We are proposing that refiners and importers would achieve compliance with the requirements of the proposed benzene program beginning with the annual averaging period beginning January 1, 2011. Refineries with approved benzene baselines could generate early credits from June 1, 2007, through December 31, 2010. Refineries and importers could generate standard credits beginning with the annual averaging period beginning January 1, 2011, provided that the average benzene content of the gasoline they produce or import during the year was less than 0.62 vol% benzene.

Approved small refiners would be allowed to delay compliance with the 0.62 vol% standard until the annual averaging period beginning January 1, 2015. They could, however, generate early credits beginning June 1, 2007 through December 31, 2014, provided that they had an approved benzene baseline. They would be able to generate standard credits beginning January 1, 2015.

b. Which Regulated Parties Would Be Subject to the Proposed Benzene Standards?

Domestic refiners and importers would be subject to the proposed standards. We are proposing that each refinery of a refiner must meet the standard, and all associated requirements, individually. Refinery grouping, or aggregation, as allowed in the Anti-dumping and MSAT1 program for CG, would not be permitted for purposes of complying with the proposed benzene standard (although the ABT provisions provide similar flexibility, and the credit generation and transfer provisions would perform basically the same functions). For an importer, we are proposing that the requirements apply to the entire volume imported during the averaging period regardless of import locations or sources. In addition, where a company has both refinery and import operations, each operation would have to achieve its own compliance with the 0.62 vol% benzene standard. We are proposing that those who only added oxygenate or butane to gasoline or gasoline blending stock would not be subject to the proposed standards for that gasoline unless they also added other blending components to the blend. This would be similar to the current treatment of these entities and their gasoline under the RFG, Anti-dumping and MSAT1 programs, where specialized accounting and calculation procedures are specified. In these cases, the refinery (or importer) that produces gasoline or gasoline blendstock includes the oxygenate in its own compliance determination. We are proposing that this practice would continue under today's program. Transmix processors would not be subject to the proposed requirements for gasoline produced from transmix, but gasoline produced from transmix to which other blendstocks were added would be subject to the proposed benzene standard.

We are proposing that all gasoline produced by foreign refineries for use in the United States would be included in the compliance and credit calculation of the importer of record. Under the Anti-dumping and MSAT1 rules, as well as the gasoline sulfur requirements, additional requirements applicable to foreign refiners who chose to comply with those regulations separately from any importer were included to ensure that enforcement of the regulation at the foreign refinery would not be compromised. We are proposing similar provisions here. Specifically, we are proposing to allow foreign refiners to

generate early credits and to apply for temporary hardship relief and small refiner status. See proposed 40 CFR 80.1420. However, under the earlier rules, few foreign refiners have chosen to undertake these additional requirements, and almost all gasoline produced at foreign refineries is included in an importer's compliance determination for the current EPA gasoline programs.²⁷⁰ We invite comment on the value of extending these provisions to this proposed benzene program.

As mentioned, we are proposing to extend the small refiner provisions to foreign refiners. Our experience in past rules is that they are not taken advantage of for various reasons. Most foreign refineries are state-owned or owned by large multinational companies, and would exceed the employee-count criterion. Others have typically not been interested in fulfilling the enforcement-related requirements that apply to foreign refineries. We request comment on extending the small refiner provisions to foreign refiners.

c. What Gasoline Would Be Subject to the Proposed Benzene Standards?

All finished gasoline produced by a refinery or imported by an importer would be subject to the proposed benzene content standard. In addition, gasoline blending stock which becomes finished gasoline solely upon the addition of oxygenate would also be subject to the proposed standard.²⁷¹ Other gasoline blendstocks which are shifted among refiners prior to turning them into finished gasoline would not be subject to the benzene standard. They would be included at the point they are converted or blended to produce finished gasoline.

We are proposing to exclude gasoline produced or imported for use in California from this benzene requirement. Although California's benzene averaging standard is greater than 0.62 vol%, California in-use benzene levels are currently below the level of the proposed standard.²⁷² We

²⁷⁰ Often, the importer of record is the foreign reiner. In these instances, the importer/foreign refiner has simply opted to achieve compliance via the applicable importer provisions.

²⁷¹ As stated earlier, both blending stock and oxygenate would be included in the refinery's or importer's compliance determination. Conventional gasoline refiners are required to have agreements with downstream oxygenate blenders to ensure that the appropriate type and amount of oxygenate is added to the gasoline blending stock, per 40 CFR 80.10(d). Absent such agreements, the refinery may only include the gasoline blending stock in its compliance determination and the oxygenate is not included in any compliance determination.

²⁷² California Code of Regulations, Title 13 Section 2262.

expect this situation will continue. There would be no additional benefit to consumers of California gasoline or to the implementation and benefits of the proposed program by the inclusion of gasoline used in California.

This proposal also would exclude those specialized gasoline applications that have been exempted from other EPA gasoline rules, such as gasoline used to fuel aircraft, or for sanctioned racing events, gasoline that is exported for sale and use outside of the U.S., and gasoline used for research, development or testing purposes, under certain circumstances.

d. How Would Compliance With the Benzene Standard Be Determined?

Compliance with the proposed benzene standard would be on an annual, calendar year basis, similar to almost all other current gasoline controls. A refiner's or importer's compliance (or Compliance Benzene Value, as used in the proposed regulation) would be determined from the annual average benzene content of its gasoline (produced or imported), any credits used for compliance purposes, and any deficit carried over from the previous year, and would have to be 0.62 vol% or lower, on a benzene volume basis. The Compliance Benzene Value would differ from the refiner's or importer's actual annual average benzene concentration because the latter would be solely a volume weighted average of the benzene concentrations of the refinery's or importer's actual gasoline batches.

Credits, in any amount, could be used to achieve compliance. As mentioned, we are also proposing to allow a deficit to be carried forward for one year. Under these circumstances, in the next compliance period, the refinery or importer would have to be in compliance, that is, the refinery or importer would have to, through production or import practices, and/or the use of credits, make up the deficit from the previous year and be in compliance with the proposed benzene standard. This provision could be especially helpful to refiners in the first year of the program, until the availability and need for credits was established.

In the RFG and Anti-dumping programs, and MSAT1, by extension, refiners and importers generally include oxygenate added downstream from the refinery or the import facility in their compliance calculations.²⁷³ Refiners

²⁷³ As a result, oxygenate blenders would not be subject to the RFG, Anti-dumping or MSAT1

and importers of RBOB are required to account for the oxygenate in their own compliance. As mentioned earlier, refiners and importers of conventional gasoline can include the oxygenate if they have met the Anti-dumping requirements for ensuring that the amount and type of oxygenate was indeed added. We are not proposing any changes to these provisions for the purposes of compliance with the proposed benzene program. However, average pool benzene levels are expected to decrease as a result of increased ethanol use due to requirements of the Energy Policy Act of 2005, and this would affect both early and standard credit generation, as will be discussed below. However, we request comment on how, if at all, additional oxygenate use should be considered, and perhaps limited, in compliance determinations for the proposed program.

2. Averaging, Banking and Trading Program

a. Early Credit Generation

As discussed, early credit generation could occur as early as the averaging period beginning June 1, 2007, through the averaging period ending December 31, 2010, or ending December 31, 2014, for small refiners. In order to generate early benzene credits, a refinery would first establish a benzene baseline which is its average benzene concentration over the period January 1, 2004, through December 31, 2005. A refinery would be eligible to generate early credits when it reduced its annual average benzene concentration by at least 10% compared to its benzene baseline. Credits would then be calculated based on the entire reduction in benzene below the baseline. Generation of early credits for the first averaging period, June 1, 2007 through December 31, 2007, which is less than a calendar year, would be based on the average benzene level of the gasoline produced only during this period. Gasoline produced before June 1, 2007, would not be included in the credit generation determination.

We are proposing to allow only refiners (and not importers) to generate early benzene credits because it is at the refinery, or production level, where real changes in the production of gasoline can be made. Importers would simply seek out blending streams or gasoline with lower benzene, but would not have to invest or take other action involving the production of the lower benzene gasoline. Furthermore, many importer operations grow in volume, shrink in

regulations except for gasoline to which they add other blendstocks in addition to the oxygenate.

volume, come into existence and go out of existence on a continual basis, making it difficult to assess the appropriateness of both the baseline and any early credits. Thus, even though an importer may have had regular, consistent import activity during the 2004–2005 baseline period, we are proposing that only refiners would be allowed to apply for a benzene baseline, and if approved, to generate early benzene credits based on reductions in future averaging period gasoline benzene levels.

As discussed above, one of the purposes of allowing the early generation of benzene credits would be to promote reductions in benzene through refinery processing changes. We are concerned that benzene reductions due to increased oxygenate use would result in reduced benzene concentrations. Oxygenate use (in the form of ethanol) in CG is expected to increase as a result of the Energy Policy Act requirements.²⁷⁴ This additional oxygenate will dilute gasoline benzene levels as well as extend the gasoline pool. As a result, refinery average benzene levels would be likely to be lower during the early credit generation period than during the benzene baseline period (2004–2005) if there is an increase in the amount of CG refiners send for downstream blending with ethanol (CBOB). We are concerned that reductions in fuel benzene levels due to oxygenate addition significantly beyond the average levels of recent years could result in windfall early credit generation for some refineries. We request comment on the likelihood of windfall early credit generation, and if such a situation were to occur, whether it would warrant limiting early benzene credits by consideration of the average oxygenate use during the baseline period compared to the early credit generation period or by adjusting the early credit trigger point. We believe this would be less of an issue during the standard credit generation period beginning in 2011 (2015 for small refiners) because of the more stringent requirements for generating standard credits (getting below the 0.62 vol% standard) compared to the early credit generation requirements (achieving a minimum 10% reduction in baseline benzene levels).

²⁷⁴ Even though the Energy Policy Act of 2005 eliminated the oxygen mandate for RFG, oxygenate use (in the form of ethanol) in RFG is expected to continue.

b. How Would Refinery Benzene Baselines Be Determined?

As mentioned above, a refiner would submit a benzene baseline application to EPA for any of its refineries which planned to generate early credits. The benzene baseline would be the volume-weighted average of the benzene levels of the gasoline produced by the refinery during 2004–2005. Note that the gasoline would be the combination of the refinery's RFG and CG, if applicable, and would exclude California gasoline and other fuels exempted from the proposed standard. The benzene values used in the benzene baseline calculation should be the same as used in the RFG, Anti-dumping and MSAT1 compliance determinations. We are not proposing provisions for adjusting these benzene baselines based on circumstances during the baseline years or otherwise.

Though we expect that most refineries that apply for a benzene baseline would have data for both 2004 and 2005, if a refinery was shut down for part of the 2004–2005 period, it could still be able to establish a benzene baseline. Under these circumstances, the refiner would have to provide and justify, using refinery and engineering analyses, an appropriate adjusted value that reflects the likely average benzene concentration for the refinery, had it been fully operational. A refinery that was non-operational for the entire period January 1, 2004 through December 31, 2005 would not be able to establish a benzene baseline and therefore not allowed to generate early credits.

c. Credit Generation Beginning in 2011

Credits could be generated in any annual averaging period beginning January 1, 2011, or for small refiners, beginning January 1, 2015. These credits, also called standard benzene credits, could be generated by a refinery or importer when the refinery's or importer's annual average benzene concentration was less than the proposed standard of 0.62 vol%.

While the proposed benzene standard is a 49-state standard due to the fact that California would maintain its existing benzene standard, we request comment on the appropriateness of allowing California refineries to generate credits that could be used to demonstrate compliance outside of California.

d. How Would Credits Be Used?

We are proposing that all gasoline benzene credits that are properly created may be used equally and interchangeably. That is, once generated, there would be no difference

between early credits and standard credits, except for their credit life, as discussed below. Under this proposal, credits could be transferred to another refiner or importer, or they could be banked by the refinery or importer that created them for use or transfer in a later compliance period.

As in past credit programs, we are proposing some limits on credit use. First, we are proposing to limit the number of times a credit could be transferred. At the end of the allowable number of transfers, the credit would have to be used by the last transferee before its expiration date. Second, we are proposing that credits would have a finite life whether or not transferred. We are proposing that early credits, those generated prior to 2011, would have a three-year credit life from the start of the program in 2011. These credits would have to be used to achieve compliance with the proposed benzene standard in 2011, 2012, and/or 2013, or they would expire. In addition, we are proposing that credits generated in 2011 and beyond (or early credits generated by small refiners during this period) would have to be used within five years of the year in which they were generated. We had considered requiring credits be used in order of their generation date, that is, credits generated earlier would have to be used before credits generated later. However, the finite credit life is likely to ensure this usage, and thus we are not proposing to regulate credit use in this manner. We are also proposing that credit life could be extended by two years for any credits that are generated by or traded to approved small refiners.

Under the proposed regulations, a refiner or importer would have to use all benzene credits in its possession before being allowed to have deficit carryover, and would have to meet its own compliance requirement before transferring any gasoline benzene credits. In the case of invalid credits, or credits improperly created, all parties would have to adjust their credit records, reports, and compliance calculations to reflect proper credit use. The transferor would first correct its own records and ensure its own compliance, and then apply any remaining properly created credits to the transferee before trading or banking those credits. See section X.A below for more discussion of these issues.

3. Hardship and Small Refiner Provisions

a. Hardship

The hardship provisions and requirements are extensively discussed in section VII.E.2, and thus are only

briefly addressed here. We are proposing that a refiner for any of its refineries could seek temporary relief from meeting the proposed benzene standard due to unusual circumstances, including those situations, such as a natural disaster, which would clearly be outside the control of the refiner. A refiner would have to apply to EPA for this temporary relief, and EPA could deny the application or approve it for an appropriate period of time. However, given the existence of a flexible ABT program, EPA expects that, prior to requesting hardship relief, the refiner would have made best efforts to obtain credits in order to comply with the proposed benzene standard. In past rulemakings, for example the gasoline sulfur rule, the hurdle for receiving a hardship was very high, with very few granted. While we are proposing these provisions again here, the expectation is that the hurdle would be even higher. Given the existence and flexibility afforded by the ABT program and the more limited cost of the benzene standard, it is our expectation that as long as a viable credit market existed, it would be difficult to justify granting a hardship. Furthermore, the form of any relief we are proposing is in the form of additional time to demonstrate compliance via credits as opposed to any waiver of the standards.

b. Small Refiners

As discussed earlier, we are proposing to allow small refiners to meet the proposed benzene standard beginning with the 2015 averaging period, which is four years later than non-small refiners and importers. Small refiners could also generate both early and standard credits if they can meet the requirements of those programs. A refiner would have to apply to EPA by December 31, 2007 in order to be considered a small refiner under this proposed rule even if the entity was or had been considered a small refiner under other EPA rules. The requirements for small refiners under this rule are detailed in section VII.E.

4. Administrative and Enforcement Related Provisions

a. Sampling/Testing

As under the Tier 2 program where a sulfur concentration must be determined for every batch of gasoline, we are proposing that a benzene concentration value also be determined for every batch of gasoline produced or imported. Thus, as gasoline samples are taken for sulfur measurement, they would also be taken for benzene measurement. The RFG program, which

has both a toxics emissions requirement and a per-gallon benzene cap, already requires a benzene value to be determined for every batch of gasoline. The Anti-dumping program, which has only a toxics emissions requirement, allows benzene values to be determined from composite samples. See 40 CFR 80.101(i). Thus, the proposed sampling requirement would be a change from the current sampling methodology allowed under the Anti-dumping provisions but makes it consistent with the ongoing Tier 2 sulfur program. However, unlike the gasoline sulfur requirements, this every batch testing requirement for conventional gasoline benzene would not have to occur prior to the batch leaving the refinery. Additionally, the batch numbering system would be the same as that used for conventional gasoline sulfur.

We are not proposing any changes to the benzene test methodology. See 40 CFR 80.46(e). We are proposing sample retention requirements similar to those in the gasoline sulfur provisions. See 40 CFR 80.335.

b. Recordkeeping/Reporting

We are proposing to require that records be kept for each averaging period in order to accommodate the proposed benzene standard and the accompanying credit trading program. These records would include: the benzene baseline calculation, if applicable; the number of early credits generated, if applicable; the actual average benzene concentration of gasoline produced or imported; the compliance benzene value; any deficit; the number of credits generated; and records of any credit transfers to or from the refinery or importer, including price of the credits and dates of transactions. All of this information, and any other information that EPA may require, such as information similar to that proposed below for inclusion in the pre-compliance reports, would be submitted in a refiner's or importer's annual report to the Agency. Since we are proposing that the regulatory provisions for the benzene control program would become the single regulatory mechanism covering RFG and Anti-dumping annual average toxics requirements once the benzene standard is in effect, and would replace the MSAT1 requirements, we expect to be able to streamline several of the current reporting forms once the proposed program is fully implemented in 2015.

As mentioned, we are also proposing to require that refiners and importers submit pre-compliance reports in order to provide information as to the likely number of benzene credits needed and

available, and how the refiner or importer plans to achieve compliance with the proposed benzene requirements. These reports would be required annually each June 1 from 2001 through 2011 (or through 2015 for small refiners). In addition to information regarding gasoline production and the number of credits expected to be used or produced, the pre-compliance reports would include information regarding the benzene reduction technology expected to be used, any capital commitments, and information on the progress of the installation of the technology. We are also proposing that these reports include price and quantity information for any credits bought or sold. The reports would include updates from the previous year's estimates, and comparison of previous year actual production to the projected values.

c. Attest Engagements, Violations, Penalties

We are proposing to require attest engagements for generation of both early and other credits, credit use, and compliance with the proposed program, using the usual procedures for attest engagements. The violation and penalty provisions applicable to this proposed benzene program would be very similar to the provisions currently in effect in other gasoline programs. We request comment on the need for additional attest engagement, violation or penalty provisions specific to the proposed benzene program.

5. How Would Compliance With the Provisions of the Proposed Benzene Program Affect Compliance With Other Gasoline Toxics Programs?

As discussed above, we expect that virtually all refineries will reduce benzene from their current levels, and no refineries will increase it. This impact on benzene levels, combined with the pre-existing gasoline controls in sulfur, RVP, and VOC performance, means that compliance with the benzene content provisions is also expected to lead to compliance with the annual average requirements on benzene and toxics performance for reformulated gasoline and the annual average Anti-dumping toxics performance for conventional gasoline. EPA is therefore proposing that upon full implementation in 2011 the regulatory provisions for the benzene control program would become the single regulatory mechanism used to implement these RFG and Anti-dumping annual average toxics requirements, replacing the current RFG and Anti-dumping annual average

toxics standards as unnecessary. The proposed benzene control program would also replace the MSAT1 requirements. However, we propose the RFG per gallon benzene cap of 1.3 vol% remain in effect; we are requesting comment on the need to retain this requirement for RFG. Note that compliance with the proposed benzene standard would ensure compliance with the aforementioned RFG, Anti-dumping and MSAT1 requirements beginning with the 2011 averaging period, or the 2015 averaging period for small refiners. Thus, during the early credit generation period, 2007 through 2010, all entities would still be required to comply with their applicable RFG, Anti-dumping and MSAT1 requirements. In addition, from 2011 through 2014, small refiners would have to continue to meet their applicable RFG, Anti-dumping and MSAT1 requirements. As discussed earlier in section VII.E.2, we are also requesting comment on the option of allowing some refineries to meet the proposed benzene standard early, thus replacing the current RFG and Anti-dumping annual average toxics provisions and replacing MSAT1 requirements for these refineries.

VIII. Gas Cans

Gas cans are consumer products people use to refuel a wide variety of gasoline-powered equipment. Their most frequent use is for refueling lawn and garden equipment such as lawn mowers, trimmers, and chainsaws. They are also routinely used for recreational equipment such as all-terrain vehicles and snowmobiles, and for passenger vehicles which have run out of gas. The gas cans are red, per ASTM specifications, and about 95 percent of them are made of plastic (high density polyethylene (HDPE)). There are approximately 20 million gas cans sold annually and about 80 million cans are in use nationwide. The average lifetime of a gas can is about 5 years.

California has established an emissions control program for gas cans which began in 2001. Since then, some other states have adopted the California requirements. Last year, California adopted a revised program which is very similar to the one we are proposing in this rulemaking. Manufacturers are required to meet the new requirements in California by July 1, 2007 at the latest. State programs are discussed further in section VIII.A.3., below.

A. Why Are We Proposing an Emissions Control Program for Gas Cans?

1. VOC Emissions

We are proposing standards to control VOCs as an ozone precursor and also to minimize exposure to VOC-based toxics such as benzene and toluene. Gasoline is highly volatile and evaporates easily from containers that are not sealed or closed properly. Although an individual gas can is a relatively modest emission source, the cumulative VOC emissions from gas cans are quite significant. We estimate that containers currently emit about 315,000 tons of VOC annually nationwide, which is equal to about 5 percent of the nationwide mobile source inventory (see section V.A.). Left uncontrolled, a gas can's evaporative emissions are up to 60 times the VOC of a new Tier 2 vehicle evaporative control system. Gas can emissions are primarily of three types: evaporative emissions from unsealed or open containers; permeation emissions from gasoline passing through the walls of the plastic containers; and evaporative emissions from gasoline spillage during use.

As discussed in section IV. above, ozone continues to be a significant air quality concern, and gas cans are currently an uncontrolled source of VOC emissions in many areas of the country. Section 183(e) of the Clean Air Act 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 gas can emissions.²⁷⁵ After analyzing the emissions inventory impacts of gas cans, EPA plans to publish a **Federal Register** notice that would add portable gasoline containers to the list of consumer products to be regulated and explain the rationale for this action in detail. EPA will afford interested persons the opportunity to comment on the data underlying the listing before taking final action on today's proposal. In today's notice, EPA is proposing that the standards for

²⁷⁵ 60 FR 15264 "Consumer and Commercial Products: Schedule for Regulation," March 23, 1995.

portable gasoline 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.²⁷⁶

2. Technological Opportunities to Reduce Emissions From Gas Cans

Gas can manufacturers have already developed and applied emissions controls in response to California requirements. Traditional gas cans typically have a spout for pouring fuel and a vent at the rear of the can to allow air to flow into the cans when in use. About 70 percent of emissions from gas cans are due to evaporative losses from caps being left off one or both of these openings. The primary way to reduce these emissions is to design cans that are not easily left open. To accomplish this, gas can manufacturers have developed spouts that incorporate a spring mechanism to close cans automatically when not in use. Many spout designs are opened by consumers pushing the spout against the equipment fuel tank. Some designs incorporate a button or trigger mechanism that the consumer pushes to start fuel flow and then releases when done refueling. Also, some cans are made without rear vents, incorporating venting into the spouts and thus eliminating one potential emission point. The consumer still must remove the spout to refill the cans but would replace the spout once the can is full in order to prevent spillage during transport.

The auto-closing spouts reduce spillage by giving consumers greater control over the fuel flow. The spouts allow consumers to place the can in position before activating or opening the cans. Once the receiving fuel tank is full, consumers can easily release the mechanism to stop the fuel flow. This reduces spillage during the positioning and removal of the can and reduces overall spillage by about half. Consumers generally appreciate the greater control over the refueling event.

Blow-molding is used to manufacture gas cans. Typically, blow-molding is performed by creating a hollow tube, known as a parison, by pushing high-

density polyethylene (HDPE) through an extruder with a screw. The parison is then pinched in a mold and inflated with an inert gas. The HDPE plastics used for gas cans allow gasoline molecules to permeate (i.e., pass through) the walls of the container. This contributes to overall emission losses from the containers. There are several effective permeation barriers that can be incorporated into the can walls. Gas can manufacturers have used several of these methods to meet California program requirements. The technologies were initially developed to meet automotive evaporative emissions standards and are now also being used for other types of fuel tanks. The barriers are either incorporated as part of the manufacturing process of the can (either as a layer or by mixing the barrier materials with the plastics) or are applied to the cans after they are manufactured. These barriers typically achieve reductions of 85 percent or better compared to untreated cans.

Some gas can manufacturers have produced non-permeable plastic gas cans by blow molding a layer of ethylene vinyl alcohol (EVOH) or nylon between two layers of polyethylene. This process is called coextrusion and requires at least five layers: The barrier layer, adhesive layers on either side of the barrier layer, and HDPE as the outside layers which make up most of the thickness of the gas can walls. However, this blow-molding process requires two additional extruder screws, which significantly increases its cost.

An alternative to coextrusion is to blend a low-permeability resin with the HDPE and extrude it with a single screw to create barrier platelets. The trade name typically used for this permeation control strategy is Selar. The low-permeability resin, typically EVOH or nylon, creates non-continuous platelets in the HDPE gas can which reduce permeation by creating long, tortuous pathways that the hydrocarbon molecules must navigate to pass through the gas can walls. Although the barrier is not continuous, this strategy can still achieve greater than a 90-percent reduction in permeation of gasoline. EVOH has much higher permeation resistance to alcohol than nylon; therefore, it would be the preferred material to use for meeting our proposed standard (described at Section B., below), which is based on testing with a 10-percent ethanol fuel.

Another type of low permeation technology for HDPE gas cans is treating the surfaces of plastic gas cans with a barrier layer. Two ways of achieving this are known as fluorination and sulfonation. The fluorination process

causes a chemical reaction where exposed hydrogen atoms are replaced by larger fluorine atoms, creating a barrier on the surface of the gas can. In this process, a batch of gas cans is generally processed post production by stacking them in a steel container. The container is then voided of air and flooded with fluorine gas. By pulling a vacuum in the container, the fluorine gas is forced into every crevice in the gas can. As a result of this process, both the inside and outside surfaces of the gas can would be treated. As an alternative, gas cans can be fluorinated on the manufacturing line by exposing the inside surface of the gas can to fluorine during the blow molding process. However, this method may not prove as effective as off-line fluorination, which treats the inside and outside surfaces.

Sulfonation is another surface treatment technology. In this process, sulfur trioxide reacts with the exposed polyethylene to form sulfonic acid groups on the surface. Current practices for sulfonation are to place a gas can on a small assembly line and expose the inner surfaces to sulfur trioxide, then rinse with a neutralizing agent. However, sulfonation can also be performed using a batch method. Either of these processes can be used to reduce gasoline permeation by more than 95 percent.

3. State Experiences Regulating Gas Cans

California established an emissions control program for gas cans that began in 2001.²⁷⁷ Twelve other states and the District of Columbia have adopted the California program in recent years. These states include Delaware, Maine, Maryland, Pennsylvania, New York, Connecticut, Massachusetts, New Jersey, Rhode Island, Vermont, Virginia, Washington, DC, and Texas.

Last year, California adopted a revised program that is very similar to the one we are proposing in this rulemaking.²⁷⁸ California's new program goes into effect on July 1, 2007. California addressed several deficiencies they observed in their first program by adding new enhanced diurnal standards, new testing requirements, and new certification requirements, and by removing automatic shut-off requirements that lead to designs that do not work well in the field.

²⁷⁷ Portable Fuel Container Spillage Control Regulations, Final Statement of Reasons, State of California Environmental Protection Agency Air Resources Board, June 2000.

²⁷⁸ Public Hearing to Consider Amendments to the Regulations for Portable Fuel Containers, Final Statement of Reasons, California Air Resources Board, October 2005.

²⁷⁶ 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.

California's original program contained several design specifications which limited manufacturer flexibility and resulted, in many cases, in products that were difficult for consumers to use. California has removed most of these design specifications from their revised program.

California's original program included an automatic shut-off requirement intended to reduce spillage caused by overfilling the receiving fuel tank. The spouts were required to be designed to stop fuel flow when the fuel reached the tip of the spout, similar to how gas pumps shut off when refueling a vehicle. California specified a test fixture, the height of the fuel in the receiving tank at which point the fuel flow must stop, and the minimum fuel flow rate. The gas cans were designed by manufacturers to work well with the test fixture, but the automatic shut-off failed in use a significant amount of the time. California found that the design of the equipment fuel tank had a big impact on the performance of the automatic shut-off. Due to the wide variety of fuel tank designs, the automatic shut-off worked on a relatively small percentage of equipment. In addition, many of the spout designs were not compatible with passenger vehicles. This is especially critical because the cans are customarily used by consumers when their vehicles run out of gas.

These problems led to many consumer complaints to both the manufacturers and to the California Air Resources Board. It also led to increased spillage in many cases. It was also found that many consumers did not understand how the spouts were supposed to operate. Even in cases where the spouts would have stopped the flow of fuel in time, consumers did not use the cans properly. Consumers are used to actively controlling the flow of fuel. For these reasons, California removed the automatic shut-off requirements from their program for all cans.

B. What Emissions Standard Is EPA Proposing, and Why?

1. Description of Emissions Standard

We are proposing 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 would be measured based on the emissions from the can over a diurnal test cycle. The cans would be tested as a system with their spouts attached. Manufacturers would test the cans by placing them in an environmental chamber which

simulates summertime ambient temperature conditions and cycling the cans through the 24-hour temperature profile (72–96° F), as discussed below. The test procedures, which are described in more detail below, would ensure that gas cans meet the emission standard over a range of in-use conditions such as different temperatures, different fuels, and taking into consideration factors affecting durability.

2. Determination of Best Available Control

The 0.3 g/gal/day emissions standard and associated test procedures reflect the performance of the best available control technologies discussed above, 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. As discussed above, to comply with California's program, gas can manufacturers have developed gas cans with low VOC emissions at a reasonable cost (see section IX. for costs). Testing of cans designed to meet CARB standards has shown the proposed standards to be technologically feasible. When tested over cycles very similar to those we are proposing, emissions from these cans have been in the range of 0.2–0.3 g/gal/day.²⁷⁹ 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 would require the use of best available technologies. We are proposing a level at the upper end of the tested performance range to account for product performance variability. In addition, we believe that any of the current best designs can achieve these levels, so we do not believe that the proposed standard forecloses use of any of the existing performing product designs. Our detailed feasibility analysis is provided in the Regulatory Impact Analysis. We request comment on the level of the standard and on its feasibility. We request that commenters provide detail and data where possible.

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 IV. Moreover, control of spillage from gas cans 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. Emissions Performance vs. Design Standard

We are proposing an emissions performance standard rather than mandating that gas cans be of any specified design. Rather than proposing to require that gas cans only have one opening, or other design-based requirements, we believe that it is sufficient to require gas cans to meet an emissions performance standard. A performance standard allows flexibility in can design while ensuring the overall emissions performance of the cans. We are reluctant to specify design standards for consumer products in order not to limit manufacturer (and ultimately consumer) choice. The market will encourage manufacturers to offer products that work well for consumers, and design-based requirements could unnecessarily limit manufacturer design flexibility.

4. Automatic Shut-Off

We are not requiring automatic shut-off as a design-based standard, or considering it to be a "best available control." As described in section VIII.A.3. above, the automatic shut-off has been shown to be problematic for consumers for several reasons, and we believe that including requirements for automatic shut-off would be counterproductive. 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 overfilling. 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. We want to avoid cases where spills occur even when consumers are using the products properly due to a mismatch between the spout design and the design of the receiving fuel tank being filled. Excessive consumer difficulties in using new cans would likely lead to some consumers defeating the low emissions features of the cans by removing the spouts and using other means such as funnels to refuel equipment. Any additional emissions reductions provided by automatic shut-off in cases where it worked properly would likely be largely or completely offset by increased spillage due to cases where

²⁷⁹ "Quantification of Permeation and Evaporative Emissions From Portable Fuel Container", California Air Resources Board, June 2004.

consumers defeated the designs or the designs failed to work properly. We believe that the automatic closing cans, even without automatic shut-off requirements, will lead to reduced spillage. As discussed above, automatic closure keeps the cans closed when they are not in use and provides more control to the consumer during use.

Some additional reduction in spillage is likely possible in some cases with automatic shut-off, but may not be feasible across the wide array of gas can usage. It is possible to design a spout that works well on some equipment but not for all equipment. It might also be possible to cover more uses by having multiple spouts, but we believe that having multiple spouts would lead to confusion and would also require consumers to have multiple cans depending on the types of equipment that they refuel. We request comment on automatic shut-off requirements and on ways to establish an automatic shut-off requirement that would reduce spillage, be feasible for manufacturers, and be practical for consumers.

5. Consideration of Retrofits of Existing Gas Cans

Clean Air Act section 183(e) provides authority to consider retrofitting gasoline containers as an approach for controlling emissions. We do not believe, however, that requiring the retrofit of existing gas cans would be a feasible approach for controlling gas can emissions, either technically or economically. This would likely entail manufacturers first developing retrofit systems (including spouts for various previous gas can designs), testing them for emissions performance, and certifying them with EPA. Manufacturers would need time to develop and certify systems and also to develop an implementation strategy, considering that there are millions of cans in use. Manufacturers would then likely need to collect gas cans from consumers, recondition the cans, permanently close vents, incorporate permeation barriers, and incorporate new spouts. We believe that this process would lead to costs that far exceed the cost of newly manufactured gas cans. In addition, emissions reductions would depend on consumer participation, which would be highly uncertain given that gas cans are relatively low-cost consumer products. In fact, we believe that consumers who are concerned about emissions would be more likely to discard old gas cans and purchase new cans meeting emissions standards. For all these reasons, we do not believe that a retrofitting approach makes sense for gas cans.

6. Consideration of Diesel, Kerosene and Utility Containers

We are requesting comment on but not proposing applying emissions control requirements to diesel, kerosene, and utility containers. Due to the low volatility of diesel and kerosene, the evaporative losses from diesel and kerosene cans would be minimal when used with the designated fuels. California has included diesel and kerosene cans in their regulations largely due to the concern that they would be purchased as substitutes for gasoline containers. California also included utility containers in their portable fuel container program due to concerns that these containers would be used for gasoline. We believe that manufacturers can minimize this incentive by designing gasoline cans and spouts that are easy to use and beneficial to the consumer. However, storing gasoline in diesel, kerosene, and utility containers would result in a loss of emissions reductions and therefore we are requesting comment on including them in the program. The costs for these containers would be similar to the costs estimated for gasoline containers. We request comment on the potential for diesel, kerosene, and utility containers to be used as a substitute for regulated gas cans, and the cost and other implications of including them in the program.

C. Timing of Standard

As an aspect of considering the proposed standard's technological feasibility, we are proposing to require manufacturers to meet the standard beginning January 1, 2009. 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 would take at least six months due to the required durability demonstrations described below, and manufacturers would need time to procure and install the tooling needed to produce gas cans with permeation barriers for nationwide sales.

The standards would apply to gas cans manufactured on or after the start date of the program and would not affect cans produced before the start date. We propose that 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 gas cans manufactured prior to the January

1, 2009 start of the program, allowing the normal sell through of these cans to the retail level. Retailers would be able to sell their stocks of gas cans through the course of normal business without restriction. Gas cans are currently stamped with their production date, which would allow EPA to determine which cans are required to meet the new standards.

We believe that the 2009 time frame is feasible, but recognize that it could be a challenge for manufacturers with high volume sales to ramp up production. We request comment on the economic feasibility of the proposed timing and also on whether or not a phase-in of the standards would ease the transition to a national program. We encourage commenters to provide detailed rationale and data where possible to support their comments.

D. What Test Procedures Would Be Used?

As part of the proposed system of regulations for gas cans, we are proposing 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 proposed test procedures implement section 183(e)(4), which authorizes EPA to develop appropriate standards relating to product use. Emission testing on all gas cans that manufacturers produce is not feasible due to the high volumes of gas cans produced every year and the cost and time involved with emissions testing. Instead, we are proposing that before the gas cans are introduced into commerce, EPA would need to certify gas cans to the emissions standards based on manufacturers' applications for certification. Manufacturers would submit test data on a sample of gas cans that are prototypes of the products manufacturers intend to produce. Manufacturers would also need to certify that their production cans would not deviate in materials or design from the prototype gas cans that are tested. Manufacturers would need to obtain approval of their certification from EPA prior to introducing their products into commerce. The proposed test procedures and certification requirements are described in detail below.

We are proposing that manufacturers would test cans in their most likely storage configuration. The key to reducing evaporative losses from gas cans 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 proposing to require that containers be tested in their open condition. If the gas cans 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 would apply 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.

We propose that 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 proposing a test procedure for diurnal emissions testing where manufacturers (or others conducting the testing) place gas cans in an environmental chamber or a Sealed Housing for Evaporative Determination (SHED), vary the temperature over a prescribed temperature and time profile, and measure the hydrocarbons escaping from the gas can. We are proposing that gas cans would 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 (formed from hydrocarbons and oxides of nitrogen) would be highest. We propose that three containers would be tested, each over a three-day test. We are proposing that three cans would be tested for certification in order to address variability in products or test measurements. All three cans would have to individually meet the proposed standard. As noted above, gas cans would be tested in their most likely storage configuration.

The final result would be reported in grams per gallon, where the grams are the mass of hydrocarbons escaping from the gas can over 24 hours and the gallons are the nominal gas can capacity. The daily emissions would then be averaged for each can to demonstrate compliance with the standard. This test would capture hydrocarbons lost through permeation and any other evaporative losses from the gas can as a whole. We are proposing that the grams of hydrocarbons lost would 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 proposing 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 proposing for this testing to use E10 fuel (10% ethanol blended with the gasoline described above) in this testing to help ensure in-use emission reductions on ethanol-gasoline blends, which tend to have increased evaporative emissions with certain permeation barrier materials. We believe 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 proposing that the fill level at the start of the test be 50% of the nominal capacity of the gas can. This would likely be the average fuel level of the gas can in-use. Nominal capacity of the gas cans would be defined as the volume of fuel, specified by the manufacturer, to which the gas can could be filled when sitting on level ground. The vapor space that normally occurs in a gas can, even when "full," would not be considered in the nominal capacity of the gas can. All of these test requirements are proposed to represent typical in-use storage conditions for gas cans, on which EPA can base its emissions standards. These provisions are proposed as a way to implement the standards effectively, which will lead to the use of best available technology at a reasonable cost.

Before testing for certification, the gas cans would be run through the

durability tests described below. Within 8 hours of the end of the soak period contained in the durability cycle, the gas cans would be drained and refilled to 50 percent nominal capacity with fresh fuel, and then the spouts re-attached. When the gas can is drained, it would have to 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 would be re-weighed. In lieu of weighing the gas cans, we propose that manufacturers could opt to measure emissions from the SHED directly. For any in-use testing of gas cans, the durability procedures would 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. We propose to allow manufacturers to use this temperature profile to test gas cans as long as other parts of the EPA test procedures are followed, including the durability provisions below. We request comment on these test procedures, including ways the procedures may be further streamlined without impacting the overall emissions measurements and performance of the gas cans.

2. Preconditioning To Ensure Durable In-Use Control

a. Durability Cycles

To determine permeation emission deterioration rates, we are specifying three durability aging cycles: Slosh, pressure-vacuum cycling, and ultraviolet 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 certification standard 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 (which permeation barriers are examples of best available controls). As described above, we believe including these cycles as part of the certification test is preferable to a design-based requirement.

For slosh and pressure cycling, we are proposing to use durability tests that are based on draft recommended SAE practice for evaluating permeation barriers.²⁸⁰ For slosh testing, the gas can would 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. The third durability test is intended to assess potential impacts of ultraviolet (UV) sunlight ($0.2 \mu\text{m}$ – $0.4 \mu\text{m}$) on the durability of a surface treatment. In this test, the gas cans must be exposed to a UV light of at least 0.40 Watt-hour/meter²/minute on the gas can surface for 15 hours per day for 30 days. Alternatively, gas cans could 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.²⁸¹ 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. We request comments on the use of these procedures for gas cans to help ensure permeation control in-use.

We also propose to allow manufacturers to 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 gas cans and therefore that the durability cycles are not needed. Manufacturers would 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

would have to be collected under equivalent or more severe conditions as those noted above.

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 emissions have stabilized, to ensure that the emissions standard is met in-use. Therefore, we are proposing that prior to testing the gas cans, the cans would 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 gas can would be filled with a 10-percent ethanol blend in gasoline (E10), sealed, and soaked for 20 weeks at a temperature of $28 \pm 5^\circ\text{C}$. As an alternative, we are proposing that the fuel soak could be performed for 10 weeks at $43 \pm 5^\circ\text{C}$ to shorten the test time. During this fuel soak, the gas cans would 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.²⁸² 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 gas can, we would expect the manufacturer to use a longer soak period (and/or higher temperature) consistent with good engineering judgment.

Durability testing that is performed with fuel in the gas can may be considered part of the fuel soak provided that the gas can continuously has fuel in it. This approach would shorten the total test time. For example, the length of the UV and slosh tests could be considered as part of the fuel soak provided that the gas can is not drained between these tests and the beginning of the fuel soak.

c. Spout Actuation

In its recently revised program for gas cans, California included a durability demonstration for spouts. We are proposing 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 proposed standards. If these spouts stick or deteriorate, in-use emissions could remain very high (essentially uncontrolled). We are interested in ways to ensure during the certification procedures that the spouts also remain effective in use. 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 proposing requirements consistent with California will help manufacturers to avoid duplicate testing. We request comment on the above approach for demonstrating spout durability.

E. What Certification and In-Use Compliance Provisions Is EPA Proposing?

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 proposing a certification mechanism pursuant to these authorities. Manufacturers would be required to go through the certification process specified in the proposed regulations before entering their containers into commerce. To certify products, manufacturers would first define their emission families. This is generally based on selecting groups of products that have similar emissions. For example, co-extruded gas cans of various geometries could be grouped together. The manufacturer would select a worst-case configuration for testing, such as the thinnest-walled gas can. These determinations may be made using good engineering judgment and would be subject to EPA review. Testing with those products, as specified above, would need to show compliance with emission standards. The manufacturers would then send us an application for certification. We propose to define the

²⁸⁰ 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).

²⁸¹ Final Rule, "Control of Emissions from Nonroad Large Spark-ignition engines, and Recreational Engines (Marine and Land-based)", 67 FR 68287, November 8, 2002.

²⁸² Final Rule, "Control of Emissions from Nonroad Large Spark-ignition engines, and Recreational Engines (Marine and Land-based)", 67 FR 68287, November 8, 2002.

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 would not be considered a manufacturer and thus would not be certifying entities; the manufacturers of the cans they import would have to certify the cans. Importers would only be able to import gas cans that are certified.

After reviewing the information in the application, we would issue a certificate of conformity allowing manufacturers to introduce into commerce the gas cans from the certified emission family. EPA review would typically take about 90 days or less, but could be longer if we have questions regarding the application. The certificate of conformity would be for a production period of up to five years. Manufacturers could carry over certification test data if no changes are made to their products that would affect emissions performance. Changes to the certified products that would affect emissions would require reapplication for certification. Manufacturers wanting to make changes without doing testing would be required to present an engineering evaluation demonstrating that emissions are not affected by the change.

The certifying manufacturer accepts the responsibility for meeting applicable emission standards. While we are proposing no requirement 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 gas cans 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 five-year production period otherwise allowed between certifications. The details of the proposed certification process are provided in the proposed regulatory text. We request comments on the certification process we are proposing.

2. Emissions Warranty and In-Use Compliance

We are proposing a warranty period of one year to be provided by the manufacturer of the gas can to the consumer. The warranty would cover emissions-related materials defects and breakage under normal use. For example, the warranty would cover failures related to the proper operation of the auto-closing spout or defects with the permeation barriers. We are also

proposing to require 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 would not need to be submitted. We believe that this warranty will encourage designs that work well for consumer and are durable. Although it does not fully cover the average life of the product, it is not typical for very long warranties to be offered with 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 request comment on the warranty period.

EPA views this aspect of the proposal as another part of the "system of regulation" it is proposing to control VOC emissions from gas cans, which system may include "requirements for registration and labeling * * * use, or consumption * * * of the product" pursuant to section 183(e)(4) the Act. A warranty will promote the objective of the proposed rule by assuring that manufacturers will "stand behind" their product, thus improving product design and performance. Similarly, the proposed 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 five years on average before they are scrapped. We are proposing durability provisions as part of certification testing to help ensure containers perform well in use (a system of regulation for "use" of the product, pursuant to section 183(e)(4)). Under the proposal, we could test gas cans 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 proposed provision thus would work in tandem with the warranty claim reporting provision proposed in the preceding paragraph.)

We are not proposing any recall provisions for gas cans. Manufacturers do not have registration programs for gas cans and implementing such a program for a low-cost consumer product may be overly burdensome, and have a very low participation rate. Also, we would not expect a high participation rate from consumers in a recall, in any event, due to the nature of

gas cans as a consumer product. We believe, however, that by having the authority to test products in use, along with the possible repercussions, will encourage manufacturers to develop robust designs.

3. Labeling

Since the requirements will be effective based on the date of manufacture of the gas can, we propose 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 propose to require 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 1 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 proposing this labeling requirement, we further believe, pursuant to section 183(e)(8), that these labeling requirements would 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.

F. How Would State Programs Be Affected by EPA Standards?

As described in section VIII.A.3. above, several states have adopted emissions control programs for gas cans. California implemented an emissions control program for gas cans in 2001. Thirteen other states, mostly in the northeast, have adopted the California program in recent years.²⁸³ Last year, 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 proposing. We believe that although a few aspects of the program we are proposing are different, manufacturers will be able to meet both EPA and CARB requirements with the same gas can designs and therefore sell a single product in all 50

²⁸³ Delaware, Maine, Maryland, Pennsylvania, New York, Connecticut, Massachusetts, New Jersey, Rhode Island, Vermont, Virginia, Washington DC, and Texas.

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 factor 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 the EPA program rather than continue their own program. We expect very little difference in the emissions reductions provided by the EPA and California programs in the long term. In addition, if EPA's program starts in 2009, as discussed above, this would be the same timing states would likely target in their program revisions.

G. Provisions for Small Gas Can Manufacturers

As discussed in previous sections, prior to issuing a proposal for this proposed 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 propose to include flexibility and hardship provisions for gas can manufacturers. Since nearly all gas can manufacturers (3 of 5 manufacturers as defined by SBA) are small entities and they account for about 60 percent of sales, the Panel recommended to extend the flexibility options and hardship provisions to all gas can manufacturers. (Our proposal today is consistent with that recommendation.) Moreover, implementation of the program would be much simpler by doing so. The flexibility provisions are incorporated into the program requirements described earlier in sections VIII.C through VIII.E. The hardship provisions

are described below. For further discussion of the Panel process, see section XII.C of this proposed rule and/or the Final Panel Report.

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

1. First Type of Hardship Provision

Gas can manufacturers would be able to 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 or would have a significant adverse effect on the company's solvency. Hardship relief could include requirements for interim emission reductions.

2. Second Type of Hardship Provision

Gas can manufacturers would be permitted to apply for hardship relief if circumstances outside their control cause the failure to comply (*i.e.* supply contract broken by parts supplier), and if failure to sell the subject containers would have a major impact on the company's solvency. The terms and timeframe of the relief would depend on the specific circumstances of the company and the situation involved.

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

IX. What Are the Estimated Impacts of the Proposal?

A. Refinery Costs of Gasoline Benzene Reduction

The proposed 0.62 volume percent benzene standard would generally result in many refiners investing in benzene control hardware and changing the operations in their refineries to reduce their gasoline benzene levels. The proposed ABT program would allow refiners to optimize their investments, which we believe would maximize the benzene reductions at the lowest possible cost. We have estimated that the capital and operating costs that we

believe would result from the proposed program would average 0.13 cents per gallon of gasoline.

In this section we summarize the methodology used to estimate the costs of benzene control, the scenarios we evaluated, and our estimated costs for the program. We also summarize the results of our analyses of other potential MSAT control programs. A detailed discussion of all of these analyses is found in Chapter 9 of the RIA.

1. Tools and Methodology

a. Linear Programming Cost Model

We considered performing our cost assessments for this proposed program 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 would be choosing a variety of technologies for controlling benzene, and because the program would be national and would 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 new model, and for performing analyses of other potential programs.

b. Refiner-by-Refinery Cost Model

In contrast to LP models, refinery-by-refinery cost models are useful when individual refineries would respond to program requirements in different ways and/or have significantly different process capabilities. Thus, in the case of today's proposed gasoline benzene control program, we needed a model that would accurately simulate the variety of decisions refiners would 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 proposed benzene control program.

Our 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 the various units are used to produce gasoline and 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 2003 gasoline volumes and benzene levels, which was the most recent year for which data was available, and found that the model simulated the actual situation well. 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.

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 the specific benzene cost model, we have initiated a peer review process, and have received some comments on the design of our model. Although we did not receive these comments in time to respond to them in this proposal, we plan to address all peer review comments in the development of the final rule. (Based on our initial assessment of these comments, we do not believe that the changes suggested would significantly affect the projected costs of the program. See Chapter 9 of the RIA for our initial responses to these peer-review comments.)

Based on our understanding of the primary benzene control technologies (see section VII.F above), the cost model assumes that four technologies would be used, as appropriate, for reducing benzene levels. All of these technologies focus on addressing benzene in the reformat stream. They are (1) routing the benzene precursors around the reformer; (2) routing benzene precursors to an existing isomerization unit, if available; (3) benzene extraction (extractive distillation); and (4) benzene saturation. There are several restrictions on the use of these various technologies (such as the assumption that benzene extraction would only be expanded in areas with strong benzene chemical markets) and these are incorporated into the model.

For the proposed benzene control program, the associated 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 establish an estimated cost for the set of technologies required for each refinery to meet the standard. We then rank the refineries in order from lowest to highest control cost per gallon of gasoline. 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 volume percent. This establishes which refineries we expect to apply control technologies to comply, as well as those that would generate credits and those that would use credits in lieu of investing in control. The sum of the costs of the refineries expected to invest in control provides the projected overall cost of the program.

c. Price of Chemical Grade Benzene

The price of chemical grade benzene is critical to the proposed 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 produced 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 projected benzene price for 2004 indicated that the benzene price averaged 38 dollars per barrel higher than regular grade gasoline.

For the future, CMAI projects that the price of benzene relative to gasoline will return to more historic levels or lower, in the range of \$20 per barrel higher than regular grade gasoline. We have based our modeling on this value. However, we have also examined the sensitivity of the projected overall program costs for a case where the cost of benzene control remains at \$38 higher than gasoline into the future.

d. Applying the Cost Model to Special Cases

For the comparative cases we modeled that involve a maximum-average (max-avg) standard in addition to an average benzene standard,

modeling the costs requires a different modeling methodology. Refineries that the model estimates would have benzene levels above the max-avg standard are assumed to apply the most cost-effective benzene reduction technologies that the model shows would reduce benzene levels to below the max-avg standard. The benzene reductions associated with meeting the max-avg standard may or may not be sufficient for also meeting the average standard, depending on how stringent the max-avg standard is relative to the average standard. If the model indicates that additional benzene reduction would be necessary, these additional benzene reductions are modeled in the same way as the case of an average standard only, as described above.

We also evaluated a limited number of cases that did not include an ABT program. In such cases, the model assumes that all the refineries with benzene levels below the standard would maintain the same benzene level, while each refinery with benzene levels above the standard would take all the necessary steps to reduce their benzene levels down to the standard. If the model shows that capital investments are needed to achieve the necessary benzene reduction, we assume that the refiner installs a full sized unit to treat the entire stream and then operates the unit only to the extent necessary to meet the standard.

2. Summary of Costs

a. Nationwide Costs of the Proposed Program

We have used the refinery-by-refinery cost model to estimate the costs of the proposed program, with an average gasoline benzene content standard of 0.62 volume percent and the proposed ABT program. In general, the cost model indicates that among the four primary reformat-based technologies, benzene extraction would be the most cost effective. The next most cost effective technologies are benzene precursor rerouting, and rerouting coupled with isomerization. The model indicates that benzene saturation would be the least cost-effective, but only marginally so in the larger refineries.

Our refinery-by-refinery model estimates that 92 refineries of the total 115 gasoline-producing refineries in the U.S. would have to put in new capital equipment or change their refining operations to reduce the benzene levels in their gasoline. Of these refineries 25 would use benzene precursor removal, 32 refineries would use benzene precursor removal coupled with isomerization, 24 would use extraction,