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Draft Technical Support Document:

Analysis of Regulation to Establish New Date for Receipt of Summer Grade RFG at Terminals

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Analysis of Regulation to Establish New Date for Receipt of Summer Grade RFG at Terminals

Transportation and Regional Programs Division
Office of Transportation and Air Quality
U.S. Environmental Protection Agency

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I. INTRODUCTION

A. Background

In response to concerns about tight RFG supplies in the Midwest during spring 2000 and spring 2001, EPA met with midwestern producers and distributors of RFG in March, 2001 and asked that anyone experiencing difficulty with tank turnover contact EPA for help in addressing their problem. No refiners, importers or terminal operators contacted EPA during the transition months regarding difficulties with tank turnover. Nonetheless, we believe that the practice of drawing down terminal tanks in connection with the transition from winter to summer grade RFG can have an adverse impact on spring RFG inventories and potentially on gasoline supply. Therefore, we are proceeding with a rulemaking that will help to ensure a smoother seasonal transition from winter to summer RFG.

B. Description of proposal

We are proposing to establish a new April 15 date on or after which no persons except retailers and wholesale purchaser consumers would be able to accept receipt of any RFG other than summer grade RFG. While this restriction would apply to terminals, pipelines, barges and other companies transporting fuel to terminals, effectively the restriction applies most directly to terminals, so for ease of discussion the proposed April 15 compliance date will be referred to as a terminal receipt date. In order to comply with this new terminal receipt date, refiners would, on average, need to begin shipping summer grade RFG on April 8 to ensure its receipt before April 15. Batch report information submitted to EPA for 2000 indicates that 315.6 million gallons of winter grade RFG was produced by refiners or imported from April 8, 2000 through April 30, 2000. All 315.6 million gallons of RFG were produced or imported in PADDs 1, 2, and 3, and the average RVP of this volume was 8.34 psi. Thus, establishing an April 15 summer RFG receipt date would require the RVP of 315.6 million gallons of RFG to be reduced from an average of 8.34 psi to a nominal 6.8 psi to meet the summer RFG specifications.

C. How the proposed rule will help the transition period

EPA believes that the proposed rule will help provide a smoother transition from winter to summer RFG by requiring some terminals to begin turning over their tanks from winter grade RFG to summer grade RFG earlier than current practice. Because some terminals draw down their gasoline storage tanks to very low levels in late April to drain as much winter grade RFG as possible from their tanks before refilling the tanks with summer grade RFG, in order to minimize cost, there is the potential for very low inventories of RFG during this transitional period which increases the likelihood of supply problems. Requiring all terminals to begin receiving summer grade RFG by a fixed date will remove much of the incentive for terminals to draw down their tanks to very low levels all at the same time. We expect instead that it will encourage a blend down of terminal tanks to meet summer RFG requirements and increase volumes of RFG at terminals during the transition. This will allow terminals to more gradually turn over their tanks from winter to summer grade RFG, and help spread the transition period out over the last two weeks in April. This will help to avoid situations where many terminals draw down their inventories and turn over their tanks simultaneously at the end of April.

Establishing an April 15 terminal receipt date for summer grade RFG will not reduce the market pressure for refiners to delay production of summer gasoline until it is required. However, the April 15 date will reduce the market pressure that causes terminals to delay accepting summer grade RFG for as long as possible. Terminals would be required to begin receiving summer grade RFG by April 15 and would, at the latest, turn their tanks over between April 15 and May 1. Turnover times will vary with terminal storage capacity and throughput of RFG at individual terminals. Terminals would not be economically encouraged to draw down the winter gasoline in their tanks prior to April 15. The April 15 date applies to gasoline supplies received on or after that date, but does not require that the gasoline in the tanks be in compliance with summer specifications on April 15. This should lead to greater use of gradual tank blend down to meet the May 1 date by which all RFG in terminal storage tanks must meet the summertime RFG standards[1].

D. Cost of the proposed rule

The total estimated cost of establishing an April 15 receipt date is estimated to be between $1.5 million per year and $2.3 million per year. Dividing these costs by the 315.6 million gallons per year of gasoline which would need to be produced as summer grade RFG instead of winter grade RFG produces an equivalent cost range of 0.49 cent per gallon RFG to 0.73 cent per gallon

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1 Note that while we are not proposing eliminating this May 1 terminal compliance requirement, we are interested in the continuing need for a May 1 terminal compliance requirement to ensure adequate and timely supplies of summer RFG to meet the existing requirement of June 1 for retail station compliance.

RFG. Both of these estimates include the operational cost of removing sufficient butane to reduce the RVP of 315.6 million gallons per year of winter grade RFG from an average RVP of 8.34 psi to a nominal summer grade RFG RVP of 6.8 psi. Assuming an RVP decrease of 1 psi for every 1.5 volume percent decrease in butane[2], 7.3 million gallons per year of butane must be removed from 315.6 million gallons per year of RFG.

The lower cost estimate ($1.5 million per year or 0.49 cent per gallon RFG) includes the cost of new tankage to store all the butane until the butane can be used the following winter. The higher cost estimate ($2.3 million per year or 0.73 cent per gallon RFG) assumes that all the additional butane removed is directly sold to the spot butane market. Thus, the higher cost estimate includes the effect of directly selling 7.3 million gallons per year of product as relatively less valuable butane instead of more valuable RFG.

This document provides the supporting analysis for the cost, as well as a thorough discussion of the blendstock accounting system.

2 This correlation between volume percent butane and RVP is taken from the study, "The Refining Economics and Modeling Ban of MTBE" by PACE Consultants under contract to EPA , contract # 68-C-98-169, April, 2001.

II. COST SUMMARY

Establishing a new date for receipt of summer grade RFG will require some refineries to begin producing summer grade RFG earlier than they currently do. Summer grade RFG is more expensive to produce than winter grade RFG due to the cost of removing additional butanes and pentanes for RVP control and either selling or storing the removed butanes. Typically, during the winter gasoline production season, refiners directly add purchased and refinery generated butanes to their gasoline pool to increase RVP to a maximum allowable limit. Refiners also allow more butanes and pentanes to remain in winter gasoline by decreasing the debutanization and depentanization of gasoline blendstocks. Butanes removed from gasoline in order to reduce RVP can either be sold to the spot butane market or stored and later added to the winter gasoline pool. Pentanes removed for RVP control are assumed to be moved from RFG to the conventional summer gasoline market. Because we are uncertain how much of the removed butane will be sold directly to the spot market vs. stored, we have developed two cost estimates for an April 15 terminal receipt date and two cost estimates for an April 1 terminal receipt date. The first, highest cost estimate for each date assumes that all of the removed butanes generated by a new terminal receipt date are sold directly to the spot butane market. The second, lowest cost estimate for each date assumes that new tankage is built to store all of the removed butanes generated by a new terminal receipt date, and the butanes are later blended into the wintertime gasoline pool.

The tables below summarize the volumes and average RVP of winter grade RFG from 2000 batch reports, by PADD, that would need to be produced or imported as summer grade RFG for each terminal receipt date. Table 1 summarizes the volumes and RVP for an April 15 terminal receipt date and Table 2 summarizes the volumes and RVP for an April 1 terminal receipt date. Both tables include winter grade RFG produced 7 days before the terminal receipt date to account for average transportation time of RFG from refinery to terminal.

Table 1: RFG Batch Information from April 8, 2000 through April 30, 2000 in Support of an April 15 Receipt Date

PADD	Winter grade RFG produced from April 8, 2000 through April 30, 2000 (million gallons)	Average RVP of RFG produced from April 8, 2000 through April 30, 2000 (psi)
1	132.8	9.06
2	160.7	7.52
3	22.1	9.97
total	315.6	8.34

Table 2: RFG Batch Information from March 24, 2000 through April 30, 2000 in Support of an April 1 Receipt Date

PADD	Winter grade RFG produced from March 24, 2000 through April 30, 2000 (million gallons)	Average RVP of RFG produced from March 24, 2000 through April 30, 2000 (psi)
1	378.5	9.65
2	283.0	8.52
3	77.1	10.27
total	738.6	9.28

Based on the information in Table 1, we estimate the maximum total costs for an April 15 receipt date to be \$2.3 million per year for direct sale of all additional butane production to spot market or 0.73 cent per gallon RFG for 315.6 million gallons RFG. We estimate the minimum total costs to be \$1.5 Million per year for storing all butanes and blending into the winter gasoline pool or 0.49 cent per gallon RFG for 315.6 million gallons RFG. Capital costs are 24 million dollars. For both costs, butane volume is that necessary to reduce RVP of 315.6 million gallons RFG from an RVP of 8.34 psi to 6.8 psi.

Based on the information in Table 2, we estimate the maximum total costs for an April 1 receipt date to be \$7.6 million per year for direct sale of all additional butane production to spot market or 1.04 cents per gallon for 738.6 million gallons RFG. We estimate minimum total costs to be \$4.8 million per year for storing all butanes and blending into the winter gasoline pool or 0.65 cent per gallon RFG for 738.6 million gallons RFG. Capital costs are 92 million dollars.

For both costs, butane volume is that necessary to reduce RVP of 738.6 million gallons RFG from an RVP of 9.28 psi to 6.8 psi.

The cost, in cents per gallon affected RFG, of producing more summer grade RFG and less winter grade RFG from April 8 through April 30 is less than the cost differential between typical winter grade RFG and summer grade RFG. Based on data obtained from DOE, winter grade RFG prices were approximately 6 cents per gallon less than summer grade RFG during Phase I, and 9 cents per gallon less than summer grade RFG during Phase II[3]. These price differences are due to two factors, the additional cost to produce summer grade RFG, and demand. The cost difference is due to blending more butane, a relatively inexpensive gasoline blendstock, into winter grade RFG in place of more expensive blendstocks required for summer grade RFG, especially alkylate blendstock needed to produce very low RVP RBOB for ethanol blended RFG. DOE has estimated the cost differential between winter and summer RFG at approximately 3 cents per gallon, which doesn't include demand induced price effects[4].

Typical winter grade RFG may have an RVP as high as 15 psi, compared to an average RVP of 8.34 psi for all winter grade RFG produced between April 8, 2000 and April 30, 2000. EPA's cost estimate includes only the cost of reducing the RVP of winter grade RFG produced from April 8 through April 30 to summer grade RVP levels. However, we are aware there may be other costs associated with the production of more summer grade RFG and less winter grade RFG

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3 EIA Memo: Potential Gasoline Price Impacts Due to Winter-Summer Transition, November, 8, 2001.

4 EIA Memo: Potential Gasoline Price Impacts Due to Winter-Summer Transition, November, 8, 2001.

from April 8 through April 30, in addition to the cost of reducing RVP.

III. ESTIMATE OF OPERATING COSTS

All of EPA's cost estimates include operational distillation costs for removal of butanes and pentanes from gasoline blendstocks. Refiners would use two strategies to reduce the RVP of the affected volumes of RFG. First, they would reduce the amount of purchased and generated butanes that they add to these volumes of winter RFG. Second, they would perform additional distillation of this gasoline in debutanizers and depentanizers. For this cost analysis, we assume that refiners achieve all removal of butanes through additional debutanization of gasoline blendstocks. Distillation vendors confirmed that refiners primarily achieve RVP reduction through the additional debutanization and depentanization of FCC gasoline, and to a lesser extent by debutanization of other gasoline blendstocks.

According to distillation vendors, 20 percent additional energy is typically required in an FCC debutanizer to reduce gasoline RVP from 9 to10 psi to 6.8 psi. FCC debutanizer operating costs were determined using 20 percent of Oak Ridge National Laboratory (ORNL) naphtha splitter energy factors shown in Table 3, and the energy costs shown in Table 4. FCC depentanizer operating costs to reduce RVP from 6.8 to 5.5 psi for RBOB production were calculated using the energy factors from the ORNL FCC fractionator model for pentane removal from gasoline shown in Table 3, and the energy costs shown in Table 4. FCC depentanizer operating costs were multiplied by the PADD 2 fractional production of RFG relative to the aggregate RFG gasoline production of PADDs 1 through 3. FCC debutanizer operating costs and FCC depentanizer operating costs were added together to produce a total operating cost of 0.46 cent per gallon FCC gasoline.

Table 3: Process Operations Information for Debutanizer and Depentanizer

	Debutanizer	*Depentanizer*
Electricity (Kw-hr/bbl)*	0.02	0.17
Steam (lb/bbl)*	11.6	98
Other Variable Operating Costs ($/bbl)	0.012	0.045

* Kw-hr/bbl is kilowatt hour per barrel. lb/bbl is pound per barrel. $/bbl is dollar per barrel. Steam and electricity usage for the debutanizer are 20 percent of ORNL naphtha splitter model values and represent required incremental usage. Steam rate of 98 lbs/bbl used for the new depentanizer taken from ORNL FCC fractionator model value for separation of pentanes from gasoline.

Table 4: **Summary of Energy Costs Taken from EIA and NPC Data Tables 1999**

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

* ¢/KwH is cents per kilowatt-hour, $/FOE is dollars per fuel oil equivalent. PADDs 1 through 3

average obtained by volume weighting each PADD's total refinery gasoline to PADDs 1 through 3 aggregate total refinery gasoline production multiplied by the cost of electricity or fuel gas in each PADD.

FCC gasoline is 39 percent of the average refiner's total gasoline production based on 1996 API/NPRA data[5]. From the API/NPRA data in Table 5, the fraction of FCC gasoline in each PADD was calculated by dividing the average FCC gasoline production for each PADD by the average refinery total gasoline production for each PADD. The FCC gasoline fraction of each PADD was then volume weighted by each PADD's percent contribution to the aggregate gasoline production of PADDs 1 through 3 to produce an overall average of 39 percent.

Table 5: **Fraction FCC Gasoline to Total Refinery Gasoline**[6]

Factor	PADD 1	PADD 2	PADD 3	PADDs 1-3
Aggregate Gasoline Production (bbl/day)	998,082	1,763,419	3,579,334	6,340,836
Fraction of Aggregate Gasoline Production	0.16	0.28	0.56	1.00
Avg. Refinery Total Gasoline (bbl/day)	46,345	66,348	75,907	62,866

5 Final Report, 1996 American Petroleum Institute/National Petroleum Refiners Association, Survey of Refining Operations and Product Quality, July 1997.

6 Final Report, 1996 American Petroleum Institute/National Petroleum Refiners Association, Survey of Refining Operations and Product Quality, July 1997.

Factor	PADD 1	PADD 2	PADD 3	PADDs 1-3
Avg. FCC Gasoline (bbl/day)	21,452	17,622	33,335	24,136
Fraction of FCC Gasoline to Total Refinery Gasoline	0.46	0.27	0.44	0.39

Multiplying the 0.46 cent per gallon operating cost to debutanize and depentanize FCC gasoline by the 0.39 volume fraction of FCC gasoline produces a cost of 0.18 cent per gallon RFG. This is the cost for lowering the RVP of FCC gasoline blendstock per RFG gallon.

We also assumed that additional debutanization is required for all other gasoline blendstocks except alkylate and reformate. The RVP of alkylate and reformate is typically less than 6.5 psi so we assumed that these two blendstocks do not require additional debutanization. According to a study by PACE consultants for EPA, alkylate and reformate are approximately 36 percent of the total gasoline pool for PADDs 1 through 3 [7]. Subtracting the sum of 39 percent FCC gasoline and 36 percent alkylate and reformate from 100 percent (representing the total gasoline pool) leaves 25 percent of the blendstocks in the total gasoline pool, such as light straight run gasoline or light coker gasoline, which must also be debutanized. The debutanizer cost factors from Table 3 were used to produce a cost of 0.15 cent per gallon for removing butanes from this 25 percent volume of the pool. Multiplying the 0.15 cent per gallon operating cost by the 0.25

[7] "The Refining Economics and Modeling Ban of MTBE" by PACE Consultants under contract to EPA , contract # 68-C-98-169, April, 2001.

volume fraction of the pool produces a cost of 0.03 cent per gallon RFG to debutanize the total volumes in Tables 1 and 2. Total operating cost to debutanize and depentanize the total RFG volumes in Tables 1 and 2 is 0.18 + 0.03 = 0.21 cent per gallon RFG.

IV. ESTIMATE OF COST TO SELL BUTANE DIRECTLY TO SPOT MARKET

In addition to operating cost, the costs of selling all additional butane production directly to the spot market include the price differential between summertime gasoline and summertime butane. To estimate the cost of reducing the RVP of the total volumes of RFG in Tables 1 and 2 to 6.8 psi, we calculated the equivalent volume of butane that such reduction would generate, assuming a 1.5 volume percent reduction in butane for every 1.0 psi reduction in RVP. For an April 15 terminal receipt date (see Table 1) reducing the RVP for 315.6 million gallons of RFG from 8.34 to 6.8 psi would generate an equivalent butane volume of 7.3 million gallons. For an April 1 terminal receipt date (see Table 2) reducing the RVP of 738.6 million gallons of RFG from 9.28 to 6.8 psi would generate an equivalent butane volume of 27.5 million gallons.

Total cost for sales of butanes directly to the market is the difference in average prices between summertime RFG (US Gulf Coast unleaded; octane equal to 87) and summertime butane (Mt Belvieu spot price) multiplied by the additional butane volume. Table 6 summarizes the averages of years 2000 and 2001 for the winter and summer prices of butane and gasoline. Multiplying the price differential between summer RFG and summer butane, 34.5 cents per gallon, by the equivalent butane volume generated for each receipt date and dividing by the total volumes of RFG in Tables 1 and 2 results in a cost of 0.80 cent per gallon RFG for an April 15 receipt date and 1.29 cents per gallon RFG for an April 1 receipt date.

Table 6: Summer and Winter Prices for Butane and Gasoline

	Summer	Winter
Butane price, cents/gallon (Mt. Belvieu spot price)*	56	74
Gasoline price, cents/gallon (US Gulf Coast RFG - regular unleaded)*	90.5	83

* Prices are averages of year 2000 and 2001 data.

Costs for selling the butanes directly to the spot market in the transition period are partially offset by the societal benefit of increasing the energy density in the remaining gasoline volume. Since butane has a lower energy density than gasoline, the average energy density of the gasoline pool will increase as relatively less energy-dense butane is removed from the pool. Dividing the total societal benefit by the total volumes in Tables 1 and 2 results in a benefit of 0.28 cents per gallon RFG for an April 15 terminal receipt date and 0.46 cents per gallon RFG for an April 1 terminal receipt date.

Table 7 summarizes the costs of selling all additional butane production directly to the spot market, in cents per gallon RFG for the total volumes in Tables 1 and 2.

Table 7: Cost Summary for Selling All Butane to Spot Market, cents per gallon RFG

	April 15 receipt date	April 1 receipt date
Operating Cost	0.21	0.21
Downgrade Cost	0.80	1.29
Societal Benefit	-0.28	-0.46
Total	0.73	1.04

V. ESTIMATE OF COSTS TO STORE AND SELL BUTANE

The costs of storing additional butane until winter include the capital cost to build new tanks for butane storage, the interest paid to store butane at a rate of interest of 7.5 percent for 168 days, and price adjustments to the stored butane to account for summer and winter seasonal price changes in butane and RFG in addition to operating cost. Total capital costs for butane storage are $90/bbl (based on year 1992)[8] and include all pumps, piping and associated equipment. Capital costs were calculated for an average refinery to build new butane storage capacity for 15 days of incremental butane production from additional RVP reduction. The average refinery's daily additional butane production for Table 1 was estimated to be 68,678 gallons/day or 1,635 BPSD and 110,598 gallons/day or 2,633 BPSD for Table 2. Thus, the average refinery would need new butane tank storage for 1.03 million gallons, or 24,528 bbls, of additional butane for Table 1 and 1.66 million gallons, or 39,499 bbls for Table 2.

The average refinery's additional butane production was calculated using an average refinery gasoline production of 70,724 BPSD and assuming a 1.5 volume percent butane reduction for every 1.0 psi RVP reduction. The average refinery's gasoline production was calculated by

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[8] Gary, James and Handwerk, Glenn. Petroleum Refining Technology and Economics, 1992.

multiplying the average refinery gasoline production of 62,866 BPSD for PADDs 1 through 3 in 2000 by a factor of 1.125 to account for growth in gasoline production through 2006. Thus, for Table 1, approximately 7 average refineries would need to build additional butane storage capacity and for Table 2, approximately 17 average refineries would need to build additional butane storage capacity.

Butane capital costs were scaled by a factor of approximately 1.1 to adjust capital prices to year 2000 using a Marshall and Swift index of 993 for year 1992 and 1089 for year 2000. Butane capital cost were also multiplied by an average refinery offsite factor of 1.11 and location factor of 1.16 representative of PADDs 1 through 3. These factors, shown in Table 8, were used to adjust capital costs to reflect the regional differences of costs for labor, location, etc. Average factors were calculated based on the sum of each PADD's gasoline production fraction times each PADD's respective factor. The offsite factor was cut in half to account for utilization of existing offsite facilities at the refinery. Capital costs were then multiplied by a factor of 1.1 to account for unknown contingencies in building the storage facilities to calculate final capital costs.

Table 8: **Offsite and Location Factors Used for Estimating Capital Costs**

Factor	PADD 1	PADD 2	PADD 3	PADDs 1-3 Average
Offsite	1.25	1.25	1.2	1.22
Location	1.5	1.3	1.0	1.16

Capital costs were amortized by multiplying the average refinery's capital cost by an amortization factor of 0.11, then divided by the average refinery's gasoline production rate and divided by the time the storage facilities would be in service. Economic cost factors used to calculate the amortization factor are shown in Table 9, and the storage facilities are assumed to be in service only 168 days a year (168 days is the summer gasoline season). The amortized capital cost for an April 15 terminal receipt date is 0.08 cent per gallon RFG for 315.6 million gallons RFG and the amortized capital cost for an April 1 terminal receipt date is 0.12 cent per gallon RFG for 738.6 million gallons RFG.

Table 9: **Economic Cost Factors Used in Calculating the Capital Amortization Factor**

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

Interest cost for storing butane is 0.02 cent per gallon RFG for an April 15 terminal receipt date and 0.04 cent per gallon RFG for an April 1 terminal receipt date. The stored butanes gasoline blending value is reduced by 7.5 cents per gallon based on average price data from years 2000 and 2001 to account for summer/winter price changes in butane and RFG. This corrects for the decreased economic benefit of blending butanes in gasoline in the winter. Multiplying the stored butanes blending price adjustment by the total additional volume of butane removed and dividing by the total volumes of RFG in Tables 1 and 2 produces a cost of 0.17 cent per gallon RFG for an April 15 terminal receipt date and 0.28 cent per gallon RFG for an April 1 terminal receipt date.

Table 10 summarizes the costs of storing all additional butane production and blending it in winter, in cents per gallon RFG for the total volumes in Tables 1 and 2.

Table 10: Cost summary for Storing and Blending Butane in Winter Gasoline, cents per gallon RFG

	April 15 receipt date	April 1 receipt date
Operating Cost	0.21	0.21
Capital Cost	0.08	0.12
Interest Cost	0.02	0.04
Downgrade Cost	0.17	0.28
Total	0.49	0.65

VI. SIMPLIFY BLENDSTOCK ACCOUNTING REGULATION 40 CFR § 80.102

A. Background

1. Anti-Dumping Standards

Section 211(k) of the Clean Air Act (CAA or Act) directed EPA to establish standards for RFG to be used in specified ozone nonattainment areas. The CAA also directed EPA to establish regulations which require conventional gasoline (CG) used in the rest of the country to be as clean as the gasoline produced or imported in 1990. CAA § 211(k)(8). The requirements for CG are called the anti-dumping requirements. The regulations implementing the anti-dumping requirements are contained in 40 CFR Subpart E.

RFG is formulated to produce relatively low levels of emissions compared to CG. The anti-dumping regulations prevent a refinery from transferring, or “dumping,” from RFG to CG significant amounts of gasoline blendstocks, such as benzene, which produce relatively high levels of emissions. That is, the anti-dumping regulations prevent CG from becoming higher in emissions due to the extensive use of clean blendstocks in RFG.

To be in compliance with the anti-dumping regulations, the exhaust toxics and NOx emissions performance of a refinery's or importer’s CG production must be no “dirtier” than the refinery's or importer's 1990 exhaust toxics and NOx emissions performance, on an annual average basis. Accordingly, the regulations require each refiner and importer of CG to establish an individual baseline for exhaust toxics and NOx based on their 1990 gasoline production. 40 CFR § 80.91. This individual 1990 baseline is the refinery's or importer's anti-dumping "standard."[9] Exhaust toxics and NOx emissions of gasoline produced or imported during a given annual averaging period, up to the refinery's or importer's 1990 production volume (baseline volume), must be no dirtier than the refinery's or importer's 1990 baseline emissions.

The anti-dumping regulations provide that gasoline produced or imported during the annual averaging period in excess of the refinery's or importer's baseline volumes, must be no dirtier than the anti-dumping statutory baseline emissions for exhaust toxics and NOx. The anti-dumping statutory baseline is an estimate of the average quality of gasoline sold in 1990 nationwide. Requiring compliance with the anti-dumping statutory baseline for gasoline production or imports exceeding the refinery's or importer's 1990 baseline volume is intended to prevent the overall emissions performance of the CG pool from deteriorating compared to the average quality of 1990 gasoline. Refineries and importers who do not have the data necessary to establish an individual 1990 baseline are required to comply with the anti-dumping statutory baseline for exhaust toxics and NOx for all of their gasoline production or imports during each annual averaging period.

[9] Refiners producing CG at several facilities have the option of meeting the antidumping standards on an aggregate basis with an aggregated multi-refinery baseline. 40 CFR 80.101(h).

When a refinery's or importer’s annual gasoline volume (including RFG, CG and reformulated gasoline blendstock for oxygenate blending, or RBOB) exceeds its 1990 baseline volume, the regulations require the use of a specified “compliance baseline”equation. 40 CFR 80.101(f). This equation was intended to adjust the refinery’s or importer’s individual baseline such that the volume of the refinery’s or importer’s total annual gasoline production or imports which is in excess of the refinery’s or importer’s 1990 baseline volume would be subject to the anti-dumping statutory baseline rather than the refinery’s or importer’s individual baseline. This adjusted compliance baseline then is the refinery's or importer’s anti-dumping “standard” for that annual averaging period, and the total volume of conventional gasoline produced or imported by that refinery or importer during the annual averaging period must meet that average standard.

2. Blendstock Accounting Requirements

In certain situations, refiners and importers are required to account for blendstocks that they produce (or import) *and* transfer. 40 CFR § 80.102. Because some refineries have baselines with much lower emissions than the 1990 average (“cleaner” baselines), and some have baselines much higher than the 1990 average (“dirtier” baselines), there were concerns that refineries with cleaner baselines would have an incentive to transfer dirty blendstocks to refineries with dirtier baselines, since these refineries would be better able to absorb dirty blendstocks for purposes of anti-dumping compliance. A refinery with a cleaner baseline could, in effect, transfer the “production” of gasoline to a refining facility with a dirtier baseline through the transfer of blendstocks, and thereby comply with a less stringent baseline for the gasoline produced at the refinery. For example, a refinery with a baseline cleaner than the statutory baseline could establish a blending facility as a new business, which would be subject to the anti-dumping statutory baseline, and transfer its blendstocks to the new facility to be blended into finished gasoline. The new business would be acting as a new refinery and the finished gasoline at this terminal refining facility would then be subject to the less stringent anti-dumping statutory baseline.

To ensure that each refinery meets the anti-dumping standards using the baseline that properly applies to the refinery, EPA included in the anti-dumping regulations provisions for tracking and accounting for certain blendstocks, called "applicable blendstocks."[10] Under these blendstock accounting provisions, refineries and importers are required to establish a baseline of the volume of applicable blendstocks produced or imported and transferred to other facilities relative to the volume of gasoline produced or imported. This is called the "blendstock-to-gasoline ratio." A refinery or importer establishes its baseline blendstock-to-gasoline ratio by determining the volume of gasoline produced or imported and the volume of applicable blendstocks produced or imported and transferred during each calendar year 1990 through 1993,

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[10] Applicable blendstocks are blendstocks that have properties that are "dirtier" than the 1990 CAA anti-dumping average fuel parameters. These blendstocks include reformate, light coker naphtha, FCC naphtha, benzene/toluene/xylene, pyrolysis gas, aromatics, polygasoline, and dimate.

Certain applicable blendstocks are exempted from the blendstock tracking and accounting requirements. Exempted blendstocks include those that are: exported; used for other than gasoline blending purposes; transferred to a refinery that uses the blendstock as "feedstock" in a refining process during which the blendstock undergoes a substantial chemical or physical transformation; transferred between refineries that are aggregated under § 80.101(h) for purposes of anti-dumping compliance; and used to produce California gasoline as defined in § 80.81(a)(2). These blendstocks are exempted from the blendstock requirements because transfers of such blendstocks would not be indicative of an attempt by a refiner to circumvent the anti-dumping requirements.

and calculating the annual and four-year average blendstock-to-gasoline ratios. Refineries and importers also determine a blendstock-to-gasoline ratio for each annual compliance period, and a running cumulative four-year average of the annual ratios, which is then compared to the baseline ratio. If the running cumulative compliance period ratio exceeds the baseline ratio by ten percent or more, the refinery or importer must include the volume and properties of all blendstocks it produces (or imports) *and* transfers in its anti-dumping compliance calculations for the subsequent two annual averaging periods. The refinery or importer also must notify any recipients of the blendstocks that the blendstocks have been accounted for, and the recipient must exclude those blendstocks from its compliance calculations. If the ten percent threshold is again exceeded in a subsequent year, blendstock accounting is required for four years following the subsequent exceedance.

In addition to the criterion discussed in the previous paragraph, there are certain situations in which the blendstock accounting requirements do not apply. The requirements do not apply in the case of a refinery or importer whose averaging period blendstock-to-gasoline ratio is equal to or less than 0.0300. This exemption was included because of the limited environmental effects and economic advantage that would result where small amounts of blendstock are transferred.[11]

The blendstock accounting requirements also do not apply in the case of a refinery or importer whose 1990 baseline values for exhaust toxics and NOx are less stringent than the anti-

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[11] The regulations also provide that EPA may grant a waiver of the blendstock accounting requirements if the level of blendstock production was the result of extreme or unusual circumstances (e.g., a natural disaster or act of God). § 80.102(f)(2)((i).

dumping statutory baseline values for these emissions.[12] (However, if the refinery's or importer's 1990 baseline value for either exhaust toxics or NOx is more stringent than the anti-dumping statutory baseline value for that emissions performance, the refinery or importer is not exempt from the blendstock tracking and accounting requirements.) This exemption was included in the regulations because a refiner would have little or no incentive to transfer blendstocks where the refinery's 1990 baseline is less stringent than the anti-dumping statutory baseline. A refinery with a baseline less stringent than the anti-dumping statutory baseline could not circumvent the anti-dumping requirements by shifting blendstocks to a refinery with the more stringent anti-dumping statutory baseline. A refinery with a baseline less stringent than the anti-dumping statutory baseline also would likely be unable to circumvent the anti-dumping requirements by shifting blendstock to a refinery with an even less stringent baseline, because the volume of gasoline that may be produced against a refinery's individual baseline is limited to that refinery's 1990 baseline volume. Gasoline produced in excess of the refinery's 1990 volume is measured against the anti-dumping statutory baseline. As a result, if blendstocks are shifted by one refinery to another refinery with a more lenient baseline, the shifted blendstock would likely have to meet the more stringent anti-dumping statutory baseline emissions standards.

B. Discussion

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[12] In a Question and Answer Guidance document dated May 9, 1995, EPA extended this exemption to refineries and importers whose 1990 baseline values for exhaust toxics and NOx are equal to, as well as less stringent than, the anti-dumping statutory baseline values for exhaust toxics and NOx. This approach is reflected in today's proposed changes to the regulations in determining which parties may be affected by the much more limited applicability of the petition procedures described below.

In order to more fully understand how blendstock transfers could result in degradation of conventional gasoline quality it is necessary to consider the concept of compliance baselines. The complex model standards applicable to conventional gasoline require that annual average levels of exhaust toxics emissions and NOx emissions, weighted by volume for each batch shall not exceed the refiner's or importer's compliance baseline for exhaust toxics and NOx emissions, respectively. The compliance baseline for each emissions performance standard (CB_i) is currently defined by the following equation:[13]

Equation 1

$$CB_i = B_i * \left(\frac{V_{1990}}{V_a}\right) + DB_i * \left(1 - \frac{V_{1990}}{V_a}\right) \qquad \textbf{(1)}$$

B_i is the refiner's or importer's individual baseline value, representing the emissions of that refiner or importer's gasoline in 1990. DB_i is the 1990 statutory baseline, the emissions of a fuel formulation specified in the Clean Air Act. V_{1990} is the refiner's or importer's 1990 baseline volume and V_a is the refiner's or importer's total volume produced or imported during the averaging period (i.e., the total CG and RFG volume).[14]

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13 See 40 CFR 80.101(f)

14 See 40 CFR 80.102(f) for the precise regulatory definition of these terms.

This equation applies only when a refiner or importer's total volume is greater than its 1990 baseline volume. If the total volume is less than or equal to the 1990 baseline volume the compliance baseline is equal to the refiner's individual baseline.

To illustrate this, consider a hypothetical case in which a refiner has a 1990 baseline volume of 10 gallons, and currently produces only CG. If this refiner produces 10 or fewer gallons of gasoline, the compliance baseline is equal to the refiner's individual baseline. Thus, if the refiner produces each of these gallons with an emissions performance exactly equal to this individual baseline, the refiner's average would be exactly equal to the compliance baseline. If the refiner produced any more than 10 gallons, the compliance baseline is determined by the above equation. If the refiner produced 10 gallons with an emissions performance equal to its individual baseline and each additional gallon with an emissions performance equal to the statutory baseline, the refiner's volume weighted average performance would be always exactly equal to the compliance baseline determined by the above equation. For example, if this refiner produced 15 gallons of gasoline with 10 gallons at the individual baseline and 5 gallons at the statutory baseline, the volume weighted average would be equal to $(B_i*10+DB_i*5)/15$. This is exactly equal to the compliance baseline described in equation (1). Substituting 10 gallons for V_{1990} and 15 gallons for V_a in the compliance baseline equation demonstrates that the compliance equation reduces to the volume weighted average for this case:

$$CB_i = B_i \times \frac{10}{15} + DB_i \times \left(1 - \frac{10}{15}\right) = \frac{(B_i \times 10) + (DB_i \times 5)}{15}$$

As described above, refiners comply with anti-dumping standards by meeting an individual baseline for volumes up to 1990 production levels but, for production levels over 1990 levels, meet a different compliance baseline based upon a combination of an individual baseline and the statutory baseline. As shown in the previous example, a “CG only” refiner’s current production volume relative to its 1990 baseline volume determines whether it can produce incremental volume of gasoline at its individual baseline or at the statutory baseline. If both the refinery that transfers the blendstock and the refinery that receives the blendstock are meeting the statutory baseline for incremental volumes of additional CG, then it would appear that no economic or compliance benefit may be accrued from shifting blendstocks from a clean refinery to a dirty refinery. Additionally, since all refineries are today producing substantially more gasoline than produced in 1990, it appears that most refineries would gain little compliance advantage by blendstock transfers. However, as is explained below, the situation is somewhat more complicated, at least for refiners producing both CG and RFG, because of the equivalent CG volume concept found in the compliance baseline equation (1).

In addition to total production volume relative to 1990 baseline production, we have found that whether a refinery produces only CG or a combination of CG and RFG also plays a key role in determining if a compliance advantage may occur with the transfer of blendstocks from a clean refinery to a dirty refinery. To illustrate both of these factors, we look at several different scenarios described below.

1. Case 1: Both Refiners Produce Less Gasoline than in 1990

Take the case where both the transferring refiner and the receiving refiner are producing yearly gasoline volumes less than 1990 baseline volumes. If blendstocks are transferred from the "clean" refinery to the "dirty" refinery, this could result in increases in the overall average emission level of their combined CG production. For example, a one gallon transfer from the "clean" to the "dirty" refinery could allow the "clean" refinery to produce one less gallon at its individual cleaner baseline and the "dirty" refinery to produce one more gallon at its individual dirtier baseline. This is the classic blendstock accounting situation which the regulations were meant to prevent and which results in the most significant compliance or "gaming" advantage. However, EPA's data indicated that all refineries are currently producing more gasoline than in 1990, with the vast majority producing considerably more.[15] Thus, the situation described in Case 1 does not now exist in the normal course of refinery operations.

2. Case 2: Both Refiners Produce Only CG and One Refiner Produces Less CG than in 1990

Another case is where the clean refiner is producing a yearly gasoline volume less than its 1990 baseline volume and the dirty refiner is producing a gasoline volume greater than its 1990 baseline volume and both refiners produce only CG. If blendstocks are transferred from the "clean" refinery to the "dirty" refinery, this could result in increases in the overall average

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[15] Detailed refinery production data are collected as a requirement of 40 CFR 80.75 and 40 CFR 80.105 and are confidential business information.

emission level of their combined CG production. For example, a one gallon transfer from the "clean" to the "dirty" refinery could allow the "clean" refinery to produce one less gallon at its individual baseline and the "dirty" refinery to produce one more gallon at the statutory baseline. In the case where the clean refinery is producing a yearly gasoline volume more than its 1990 baseline volume and the dirty refiner is producing a gasoline volume less than its 1990 baseline volume, the transfer would allow the "clean" refiner to produce one less gallon at the statutory baseline and the "dirty" refiner to produce one more gallon at its individual baseline. Thus, when either of the two refineries is producing less CG than it produced in 1990, an overall degradation of gasoline quality can result. Because the vast majority of refineries are producing considerably more gasoline than they were in 1990, however, we would expect that the scenario described here in Case 2 is unlikely to occur in the real world.

3. Case 3: Both Refiners Produce only CG and Both Produce More CG than in 1990

Any pair of "CG only" refineries that could conceivably exchange blendstocks would both be operating well into the range where each produces more CG than in 1990 and additional increments of CG produced in the case of either refiner would be produced at the statutory baseline. This would result in a decrease in one refiner's CG volume produced at the statutory baseline offset by an equal increase in the other refiner's volume produced at the statutory baseline; i.e. there would be no net effect on the overall average CG quality for the two refiners together and no net compliance advantage in transferring the blendstocks.

4. Case 4: One or Both Refiners Produce CG and RFG and Produce More Gasoline (CG+RFG) than in 1990

The situation becomes more complex when one or both refiners also produce RFG. This results from the calculation of the compliance baseline. It can best be understood by considering the origin of, and rationale for the compliance baseline equation and the concept of equivalent CG volume.

It was EPA's intent that the refiner's individual baseline would apply to all CG production except for the growth in production which was *allocated* to CG.[16] This calculated growth in CG production would have to meet the statutory baseline. Consequently, EPA initially developed the following equation to define the compliance baseline: [17]

Equation 2

$$CB_i = \left(\frac{\left(B_i \times V_{eq}\right) + DB_i \times \left(V_c - V_{eq}\right)}{V_c} \right) \qquad \textbf{(2)}$$

In this equation CB_i, B_i and DB_i are as defined as in equation 1. V_c is the refiner's CG production for the averaging period. V_{eq} is the 1990 equivalent CG volume. For a refiner currently producing both CG and RFG, this equivalent volume represents, in effect, the amount of CG that the refiner would have made in 1990 had the refiner been producing both CG and RFG. Such a

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[16] 57 FR 13481 (April 16, 1992)

[17] 59 FR 7871 (February 16, 1994)

value is only hypothetical and thus must be calculated. Once calculated, the amount of CG produced up to the equivalent volume would be subject to the refiner's individual baseline, while that produced over the equivalent volume (i.e., the growth in production allocated to CG) would be subject to the statutory baseline. Thus, equation 2 represents a volume weighted baseline made up of the individual baseline weighted by the equivalent volume and the statutory baseline weighted by the *allocated* growth in CG production.

EPA's regulation provided a method for calculating the equivalent CG volume or CG that *would have been produced in 1990 if RFG was also being produced*. This hypothetical 1990 CG production is back-calculated by first calculating a hypothetical growth in CG production. The hypothetical growth in production attributed to CG is taken as a portion of total growth in gasoline production $((V_r+V_c)-V_{1990})$ using the ratio of current CG production to current total production $(V_c/(V_r+V_c))$. This hypothetical growth in CG production is then subtracted from the current *actual* CG production to determine the hypothetical 1990 CG production or equivalent volume. The formula is as follows:

Equation 3

$$V_{eq} = V_c - ((V_r + V_c) - V_{1990}) x \frac{V_c}{(V_r + V_c)} \qquad \textbf{(3)}$$

where V_r is the volume of RFG made during the averaging period. Thus V_{eq}, the estimate of how much CG that a "CG and RFG" refiner would have made in 1990 depends on the amount of CG *and RFG* made during the *current* averaging period (V_c and V_r). In other words, to exactly maintain compliance for any volume of CG produced, such a refiner could not make a fixed volume of CG at the individual baseline and every additional gallon at the statutory baseline because the equivalent volume of CG (V_{eq}) changes with each additional gallon of gasoline made. EPA's current regulations do not require the direct calculation of V_{eq} in order to calculate the compliance baseline because the separate formulas for CB_i and V_{eq} (equations 2 and 3) were combined into a single simpler formula (equation 1).[18] However, since this formula is mathematically identical, the idea of equivalent volume is built into the current regulation.

To illustrate the above concept, consider a refiner with a 1990 baseline volume of 10 gallons, who makes 6 gallons of RFG during the current averaging period. (Table 11, which follows, summarizes this example.) For simplicity, assume that this "clean" refiner has an individual baseline value of 0.8 emission units for an emissions performance standard, where 1.0 is the statutory baseline. The refiner could make 4 gallons of CG at its individual baseline and maintain compliance. If the refiner makes a 5th gallon of CG (plus 6 gallons of RFG so that total production volume is 11 gallons), the compliance baseline calculated from equation 1 would be 0.8*10/11+1.0*(1/11)=0.818 emission units. For the refiner to maintain an average performance of 0.818 for the 5 gallons of CG, the performance of the fifth gallon would have to be at 0.891 emission units (i.e, 0.818=(0.8*4+0.891)/5). If the refiner makes a sixth gallon of CG (i.e. 12 gallons total), the compliance baseline from equation 1 would be 0.833 emission units. To

[18] 59 FR 36954 (July 20, 1994)

maintain an average performance of 0.833 for the 6 gallons of CG (with 4 gallons at 0.8 and 1 gallon at 0.891), the performance of the sixth gallon would have to be at 0.909 emission units. As the refiner makes more and more CG, the emissions performance of the last CG gallon approaches the statutory baseline but will always, in theory, be cleaner than the statutory baseline. In reality, the required performance of the last CG gallon would be indistinguishably close to the statutory baseline as the production gets much larger than the 1990 baseline volume.

A similar situation occurs if a refiner has an individual baseline above the statutory baseline. If a “dirty” refiner with an individual baseline of 1.2 emission units had a 1990 baseline volume of 10 gallons and made 6 gallons of RFG , it could make 4 gallons of CG at its individual baseline and maintain compliance. Again, the required performance of each succeeding CG gallon more closely approaches the statutory baseline. Each succeeding gallon could, in theory, still be dirtier than the statutory baseline, but would become indistinguishably close to the statutory baseline as production volume gets large.

The relationships described in the preceding paragraphs can be seen more clearly in the following table which shows the compliance baseline and quality of the last (incremental) CG gallon for these two hypothetical refiners over a total production volume ranging from 10 gallons to 20 gallons (100 to 200 percent of 1990 volume):

Table 11: Effect of Additional Gallons of CG Production on Compliance Baseline

				Clean Refiner		Dirty Refiner	
Total Gallons	Total RFG Gallons	Total CG Gallons	Gallons Over 1990 Baseline	Compliance Baseline	Quality Needed for Last Gallon	Compliance Baseline	Quality Needed for Last Gallon
10	6	4	0	0.800	0.800	1.200	1.200
11	6	5	1	0.818	0.891	1.182	1.109
12	6	6	2	0.833	0.909	1.167	1.091
13	6	7	3	0.846	0.923	1.154	1.077
14	6	8	4	0.857	0.934	1.143	1.066
15	6	9	5	0.867	0.943	1.133	1.057
16	6	10	6	0.875	0.950	1.125	1.050
17	6	11	7	0.882	0.956	1.118	1.044
18	6	12	8	0.889	0.961	1.111	1.039
19	6	13	9	0.895	0.965	1.105	1.035
20	6	14	10	0.900	0.968	1.100	1.032

Thus, each gallon of additional CG produced by an “RFG and CG” refiner with a clean baseline must be slightly cleaner than the statutory baseline. And for a refiner in this same situation but with a dirty baseline, incremental gallons of CG can be slightly dirtier than baseline.

Thus, for refiners making RFG but also making more total gasoline than 1990, a blendstock transfer from a clean refiner to a "dirty" refiner does not necessarily result in "no net change" in emissions as is the case when the refiners are making only CG. Instead, blendstock transfers from a "clean" refiner to a "dirty" refiner may have slightly greater potential to degrade their combined average CG quality if one or both of these refiners makes RFG as well as CG. If production volumes for the vast majority of refiners are significantly larger than 1990 baseline volumes, such transfers result in little potential for gaming and any economic benefit resulting from a transfer of blendstock in order to meet a less stringent baseline would be very small when compared to the risks associated with the illegality of the activity[19] and the logistical and transactional costs associated with such activity.

Currently, transfers from a "clean" to a "dirty" refiner would be subject to blendstock accounting requirements if the criteria specified in 40 CFR 80.102 are met. These blendstock accounting requirements are intended to mitigate the effects of blendstock transfers that might result in degradation of CG quality and to deter refiners from agreeing to transfer blendstocks in order to produce a combined pool of CG of poorer quality at lower cost (i.e. "gaming the system").

In conclusion, EPA now believes that the current blendstock accounting requirements are unnecessary. When refineries produce more total gasoline than that produced in 1990, the

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[19] It is important to note that today's proposal would still prohibit blendstock transfers conducted in order to meet less stringent standards ("gaming") even though the specific blendstock accounting requirements currently found in 40 CFR 80.102 would be eliminated. This prohibition would be applicable to all refiners/importers without regard to any other criteria.

additional gasoline over and above the 1990 baseline volume must meet the statutory baseline for all refineries regardless of the refinery's individual baseline. Since nearly all refineries currently produce significantly more gasoline than they produced in 1990, EPA believes that the blendstock transfers that are likely to occur today will be between donor and recipient refineries whose total production is well above 1990 baseline volume levels with or without a transfer. If transfers under these conditions occur between refiners producing only CG, there will be no net change in the quality of their combined CG pool because the donor refiner's gallons at the statutory baseline would be replaced by the recipient refiner's gallons at this same baseline. Thus, there would likely be no motivation or opportunity for "gaming the system" under these circumstances. Where either or both refiners make RFG and CG, there is some potential for meeting a slightly lower baseline by transferring blendstocks.[20] However, it is unlikely that there would ever be any impact more significant than a small decrease in the stringency of compliance requirements, meaning that the gaming possibilities of such a transfer are very small, and thus any such transfers would produce only very small economic benefits which may be more than offset by the transactional costs associated with the transfer. As a result, the shifting of blendstocks from one refinery to another where both refineries produce more gasoline than they did in 1990 has very little potential to cause any adverse environmental impact.

[20] This is due to the concept of "equivalent CG volume" contained in the compliance baseline equation under the anti-dumping regulations in § 80.101(f). For a full discussion of this concept and the effects of RFG production on anti-dumping compliance, see "Technical Support Document for RFG Terminal Receipt Date Rule" in the docket for this rulemaking.