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UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF NEW YORK

This Document Applies to:

City of Fresno (Plaintiff) Case No. 04 CV-04973 (SAS)

v.

Chevron U.S.A. Inc., et al (Defendants)

AMENDED EXPERT REPORT OF JOHN B. O'BRIEN

Date: November 21, 2011

AMENDED EXPERT REPORT OF JOHN B. O'BRIEN

Pursuant to the Federal Rules of Civil Procedure, Mr. John B. O'Brien submits the following expert report (the "Report") in the above-referenced matter on behalf of Defendants Atlantic Richfield Company, Chevron Corporation (f/k/a ChevronTexaco Corporation), Chevron Environmental Services Company (n/k/a Chevron Environmental Management Company), Chevron U.S.A. Inc., CITGO Petroleum Corporation, ConocoPhillips Company, Equilon Enterprises LLC, Exxon Mobil Corporation, Kern Oil & Refining Co., Lyondell Chemical Company, Shell Oil Company, Texaco, Inc., Ultramar Inc., Union Oil Company of California, Unocal Corporation, Valero Marketing and Supply Company, and Valero Refining Company-California.

I. QUALIFICATIONS FOR SUBMISSION OF EXPERT TESTIMONY, SCOPE OF WORK, AND COMPENSATION

1. My name is John B. O'Brien. I am Executive Chairman and co-owner of Baker & O'Brien, Inc. (Baker & O'Brien), an independent energy consulting firm specializing in the hydrocarbon processing industry. I hold both a Bachelor's and a Master's Degree in Chemical Engineering from the Massachusetts Institute of Technology. I have 46 years of experience working in and consulting for the oil refining and marketing industry. I have been qualified and have testified as an expert in this field on numerous occasions. A listing of my expert witness testimony (at trial, arbitration, or by deposition) since 2006 is included as Appendix 1. A description of my qualifications and experience is set forth in Appendix 2. A discussion of Baker & O'Brien and its areas of expertise are presented in Appendix 3.

2. I am submitting this Report in connection with the lawsuit (the "First Amended Complaint") filed by the City of Fresno (Fresno) against the Defendants listed above in connection with the Defendants' alleged manufacture and/or use of methyl tertiary butyl ether (MTBE) and/or tertiary butyl alcohol (TBA) in gasolines supplied, distributed, and sold at gasoline retail outlets located in Fresno.[1]

3. The purpose of this Report is to provide background information about petroleum refining; the manufacture and supply of gasoline; the evolution of gasoline quality and composition as influenced by economic, political, and regulatory developments; and how various gasoline "supply chain" participants responded to those developments.[2]

4. Within the context of this discussion, this Report describes the development of the use of oxygenates (including MTBE, TBA, ethanol, or others) in producing motor gasoline. It also discusses factors that influenced gasoline manufacturers in deciding which oxygenate to use in different geographic areas to meet the requirements of the California Air Resources Board (CARB) and/or the 1990 Clean Air Act Amendments (1990 CAAA). Oxygenates are gasoline blending components that contain oxygen in their chemical formulas. MTBE, TBA, and ethanol are blending components that have been used from time to time in the production of motor gasoline by supply chain participants in California, as well as in the United States (U.S.) as a whole, since the late 1970s.[3] As explained in more detail below, the manufacture (refining) of gasoline is a highly technical and complex process. The refining industry, which manufactures and distributes gasoline, as well as other petroleum products, is complicated in its structure.

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[1] First Amended Complaint, City of Fresno vs. Chevron U.S.A. Inc., et al, Case No. 04CV-04973 (SAS), United States District Court, Southern District of New York, October 28, 2004.

[2] The gasoline supply chain is the entire set of interdependent activities carried out to bring gasoline from the petroleum refinery to the end user.

[3] To the best of my knowledge, TBA was never used to any significant extent as a gasoline additive to meet the 1990 CAAA requirements. However, in the early 1980s, it was used by certain gasoline suppliers during a brief period to replace some of the octane lost due to the phase out of octane-boosting lead additives.

Finally, the distribution and marketing of gasoline—from the refinery to the retail outlet—is also complex, highly regulated, intensely competitive, and involves a large number of participants.

5. In evaluating the issues involved in this case, it is helpful to understand certain basic facts regarding the structure of the petroleum refining industry, the complex infrastructure that is used to bring gasoline to market, the history of gasoline quality and regulations, and how oxygenates came to be used to satisfy market and regulatory demands in California and the U.S.

6. In more specific terms, in this Report I have been asked to address:

- The major processes and process streams within a petroleum refinery and their role in the manufacture of gasoline;
- The different manufacturing processes for both MTBE and ethanol, and the competing roles these and other oxygenates (such as TBA) have historically played in the motor gasoline manufacturing process;
- The major economic, political, and regulatory developments that have affected gasoline quality and composition over the past 50 years in both California and the U.S. as a whole;
- How gasoline is delivered from the refinery to the consumer—i.e., how the gasoline supply chain works and how it is regulated;
- A comparison of MTBE versus ethanol as gasoline blending components and a discussion of the factors that would have influenced refiners in deciding which oxygenate to use in meeting the requirements of both the CARB regulations and the requirements of the 1990 CAAA;
- Issues and opinions provided in the reports, depositions, and trial testimony of Plaintiff's experts, Mr. Robert Reynolds and Dr. W. Ed Whitelaw, including evidence they submitted in various MDL 1358 and other State of California MTBE cases that may be relevant to the subject case. I reserve the right to provide rebuttal testimony on any future reports of Mr. Reynolds and Dr. Whitelaw.
- The assertion of Plaintiff that, in supplying gasoline to Fresno, Defendants chose to use MTBE and/or TBA, despite the "*availability of reasonable alternatives*."[4] This assumption regarding the reasonable availability of alternative oxygenates leads to the incorrect conclusion that *all* Fresno gasoline suppliers could have reasonably and

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[4] First Amended Complaint, Paragraph 62, p. 11.

independently decided to use ethanol (or some other competing oxygenate) to meet the requirements of CARB and the 1990 CAAA.

7. I am being compensated for my work on this matter at my normal hourly rate of $450 per hour. I have been assisted by other members of my firm who are also being compensated at their normal hourly rates.

8. In preparing this Report, I applied my background in the fields of both chemical engineering and chemistry. I also utilized the knowledge, skills, and experience that I have acquired through working 46 years within the refining and marketing industry. During this period, I was involved in studies concerning the manufacture and distribution of gasoline, as well as the manufacture and use of both MTBE and ethanol in gasoline. Part of my work in preparing this Report involved a review of historical data and information relating to these issues. Appendix 4 is a list of the source materials that I reviewed or relied upon in the preparation of this Report.

II. DEFINITION OF IMPORTANT TERMS

9. In this section, I define various technical or frequently used terms relating to petroleum products, product specifications, gasoline blending, and the use of MTBE, TBA, and ethanol. The definitions provided are either my own, or those of various authorities cited. Also, they refer specifically to the terms and the context in which they are used in this Report. Thus, they may be different from the definitions used by others, even the Defendants in this case. Brief descriptions are given for each of the following:

(1) gasoline or motor gasoline;

(2) gasoline specifications;

(3) octane rating;

(4) vapor pressure;

(5) oxygen content;

(6) oxygenates;

(7) solubility;

(8) gasoline additives; and

(9) gasoline components or blendstocks.

Included as Appendix 5 are definitions of other petroleum industry terms that are also used in this Report. Appendix 6 lists the meanings of many of the abbreviations and acronyms used throughout this Report.

10. **Gasoline or Motor Gasoline** – The Energy Information Administration (EIA) of the Department of Energy (DOE) defines "motor gasoline" (or, more simply, "gasoline" or "mogas") as "*A complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines*" (principally automobile engines).[5] Gasoline is produced in a variety of different grades and to multiple specifications to meet the requirements of different engines, geographic regions, and climatic zones.

11. **Gasoline Specifications** – These are the physical and chemical characteristics that define a particular gasoline quality or grade. Specifications are established by regulatory requirements, industry standards (e.g., American Society for Testing and Materials [ASTM] Standard D-4814), and individual refiner requirements. Refiners manufacture gasoline to meet the specifications applicable to the particular grade and quality demanded in the marketplace.

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[5] *Petroleum Supply Monthly*, EIA, March 2011, p. 142.

Although there are approximately a dozen specifications that are commonly used to define gasoline quality, only a few are of critical importance in defining the gasoline's performance and in limiting how much gasoline can be produced from a given volume of crude oil. Since March 1996, California has had the most stringent gasoline specifications in the U.S.

12. **Octane Rating** – This is the most important gasoline specification. In the simplest terms, the octane rating of a gasoline is a measure of its resistance to "knock" when used in a spark-ignition automobile engine.[6] It is measured in a laboratory test engine and is expressed as a number, with a higher number indicating a smaller likelihood of knocking. There are two types of octane ratings—the Research Octane Number (RON) and the Motor Octane Number (MON). The RON is measured under mild engine conditions, and the MON under more severe engine conditions. A gasoline's octane rating is reported as the arithmetic average of the RON and MON and is often simply referred to as "(R+M)/2." The latter number, under federal law, must be displayed on all retail service station pumps dispensing gasoline. Regular gasoline normally has an octane rating of 87, with premium gasoline ranging from 92 to 94. Automotive engines are designed to run on gasolines of a certain minimum octane rating (usually 87), with high performance engines requiring the higher octane grades. As automobiles age, they may sometimes see an increase in gasoline octane requirement due to the buildup of engine deposits.

13. **Vapor Pressure** – This is the second most important gasoline specification. Vapor pressure is a measure of the tendency of a gasoline to evaporate—to turn from a liquid into a vapor at a given temperature. Vapor pressure is one element of what is referred to as the

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[6] Engine knock is a phenomenon that is characterized by inefficient fuel combustion that can lead to physical damage to the engine. Different engine designs vary in their susceptibility to engine knock and, therefore, may exhibit different octane requirements.

"volatility" of the gasoline.[7] Vapor pressure is important because the gasoline must be vaporized and mixed with air for it to burn in the engine. If the vapor pressure is too low, the fuel may not vaporize sufficiently and the engine may not start. If it is too high, vapor may completely fill the fuel delivery system, causing the engine to stall in what is called "vapor lock." Gasoline with too high of a vapor pressure can also be a significant source of air pollution when vapors, often referred to as volatile organic compounds (VOCs), are inadvertently released into the atmosphere (e.g., during refueling). Vapor pressure is measured in the laboratory using the Reid Vapor Pressure (RVP) method and is reported numerically in pounds per square inch (psi).[8] A higher number indicates a greater tendency to evaporate. Refiners carefully control the RVP of gasoline to meet engine requirements, regional and seasonal climatic conditions, and environmental controls. Gasoline RVP typically ranges from approximately 6 to 15 psi, depending on the market being served and the time of year.

14. **Oxygen Content** – This is the percentage (by weight) of oxygen present in a gasoline. In its natural state, gasoline contains no elemental oxygen, but oxygen-bearing chemicals are sometimes blended with gasoline to improve combustion characteristics. As explained in more detail below, gasolines marketed in certain parts of California and the U.S. have, in the past, been required by law to contain oxygen at certain specified concentrations. Since May 2006, the federal Renewable Fuel Standard (the "RFS") has required that certain minimum volumes of ethanol be used annually in the U.S. motor gasoline supply, but there are no longer any minimum oxygen content requirements.

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[7] The term volatility refers not only to vapor pressure, but also the gasoline's distillation characteristics and the vapor/liquid (V/L) ratio observed at a given temperature.

[8] The RVP is measured at 100 degrees Fahrenheit (°F).

15. **Oxygenates** – These are oxygen-containing hydrocarbons that have historically been blended with gasoline to improve the octane rating or to satisfy gasoline oxygen content specifications. Broadly speaking, oxygenates are classified as either "alcohols" or "ethers." Alcohols that have been used in gasoline include: (1) methanol (commonly referred to as "wood" alcohol); (2) ethanol (commonly referred to as "grain" alcohol); and (3) TBA. Ethers that have been used in gasoline include: (1) MTBE; (2) ethyl tertiary butyl ether (ETBE); and (3) tertiary amyl methyl ether (TAME). Diisopropyl ether (DIPE), although approved for use in gasoline, has never been used in significant quantities. Exhibit A compares the chemical structures of these various oxygenates.

16. **Solubility** – This refers to how much of one material will dissolve in another. Water solubility refers to how much of a given material will dissolve in water. Solubility is reported as the percentage (by weight) that the dissolved material represents of the total mixture. Materials completely soluble in each other, in all proportions, are said to be "miscible." The water solubility of oxygenates can be an important consideration when transporting gasoline, because water is always present in various parts of the distribution system. Alcohols are quite soluble in gasoline, but are usually miscible in water. Ethers, such as MTBE, that were once commonly used in gasoline in both California and the rest of the U.S., are also readily soluble in gasoline, but much less soluble in water than alcohols.

17. **Gasoline Additives** – These are specialty chemicals added to gasoline, usually in very small amounts, that serve to impart some new and desirable performance property or reinforce some desirable property already present. Additives commonly used in gasoline include: (1) antioxidants to reduce thermal degradation; (2) detergents to lessen the buildup of harmful engine deposits; (3) corrosion inhibitors to minimize rust and corrosion; and (4) anti-

wear agents to reduce the wear on an engine's moving parts. Most additives are usually used and effective in quantities of less than 0.1 volume percent (Vol.%).

18. **Gasoline Components (Blendstocks)** – These are any and all of the various hydrocarbon materials ("stocks") that are blended together by refiners or blenders to produce finished gasoline meeting the required specifications.

III. REFINERY GASOLINE MANUFACTURE AND THE ROLE OF OXYGENATES

19. Processing crude oil through various refining processes produces gasoline and other useful products, such as propane, jet fuel, diesel fuel, and home heating oil. Crude oil is recovered from beneath the earth's surface in thousands of locations around the world, both on land (onshore) and under the seabed (offshore). After reaching the surface, the crude oil is transported to refineries, predominantly by pipelines or oceangoing vessels, where it is off-loaded into large storage tanks. Today, there are over 660 refineries in the world, of which about 130 are located in the U.S., and 15 in California.[9] Of the domestic plants, only about 110 are "fuels" refineries designed primarily to manufacture finished gasolines, jet fuels, diesel fuels, and other fuel products. Thirteen of the California plants are fuels refineries. The other two are specialty facilities making primarily asphalt, lubricants, or unfinished intermediate products.

Gasoline Production at Refineries

20. Crude oil consists primarily of a mixture of chemical compounds called hydrocarbons, which contain varying combinations of carbon and hydrogen. Along with the hydrocarbons, crude oil also contains compounds that include, along with the carbon and hydrogen, various other elements such as sulfur, oxygen, nitrogen, and certain metals. In total,

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[9] "Worldwide Refining Survey," *Oil & Gas Journal,* PennWell Corporation, Tulsa, Oklahoma, December 6, 2010.

crude oil typically includes several thousand different compounds.[10] The basic function of a petroleum refinery is to separate these different compounds into various fractions that can either be incorporated directly into final products or further processed to chemically transform and/or purify the fractions to generate streams that can then be used in making finished products. Accordingly, the processing sequence at a refinery typically entails the separation of crude oil into specified fractions by distillation, followed by chemical conversion and/or purification of some of these fractions by various processes, such as catalytic cracking, isomerization, reforming, hydrotreating, etc., and, finally, the blending of various streams to make finished products.

21. Gasoline production at refineries is a complex process involving a wide variety of different chemical processing units. Each unit performs a specific function in producing components that are subsequently blended together, in varying proportions, to make finished gasolines that are suitable for use in internal combustion engines. The different components of gasoline are commonly referred to as blendstocks. Appendix 7 is an overview of the processing that commonly takes place at a domestic fuels-oriented refinery to make finished gasoline. It discusses the blendstocks typically available and how MTBE can be produced within the refinery. Complex refineries, such as those described in Appendix 7, often produce more than 65 Vol.% of their total product output as gasoline of different grades.[11]

Gasoline Grades and Refinery Blending

22. Refiners produce many different grades of gasoline to satisfy market demand. The three major gasoline octane grades are: (1) regular unleaded [87 octane]; (2) mid-grade unleaded

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[10] "Gasoline," *Chemical & Engineering News*, American Chemical Society, Washington, D.C., February 21, 2005, p. 37.

[11] R. E. Maples, *Petroleum Refinery Process Economics*, 2nd Edition, 2000, p. 409.

[89 octane]; and (3) premium unleaded [92-94 octane]. Mid-grade is often simply a blend of regular and premium gasoline. Gasoline sold in the U.S. is also categorized as being reformulated, oxygenated, oxy-reformulated, or conventional, depending on when and where it is intended for use.[12] Within each gasoline grade are also various volatility specifications that must be satisfied, depending on both the geographic market and the season. Because of these multiple federal and local requirements, a single refiner may often need to manufacture a dozen or more separate grades of gasoline at one time to meet market demands.

23. Final production of gasoline at the refinery occurs through the controlled blending of available blendstocks. Blending is the process by which blendstocks are mixed together to maximize the production of gasoline and still satisfy all of the gasoline grade specifications. Only rarely does a single individual refinery stream meet all the requirements for commercial grade motor gasoline. The blending process entails trade-offs between the properties of different streams to produce an aggregate blend that adequately meets all requirements for the final product grade. The two most important properties that must be considered in blending gasoline are octane and RVP. Other important properties, especially those related to meeting environmental regulations, are sulfur, aromatics, and olefins content.

24. Refineries use one of two methods for gasoline blending. These two methods are: (1) "in-tank" or "batch" blending; and (2) "in-line" blending. In-tank blending is an older method that is still, however, employed by many refiners. An in-tank blend is made by combining calculated percentages of several blendstocks in a gasoline storage tank. After testing, adjustments are made to correct the blend if any specifications are not met. Each

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[12] As explained further in Section IV of this Report, gasoline blended to meet the statutory requirements for reformulated fuels is termed Reformulated Gasoline (RFG), while gasoline blended with oxygenates to meet the federal wintertime oxygenated fuels program is referred to as Oxygenated Fuels Program (OFP) gasoline.

blendstock is stored separately and tested for critical gasoline specifications. Detailed blending calculations determine the optimum blend for a particular gasoline grade. Exhibit B shows an example of an in-tank blend for premium unleaded gasoline. After the gasoline blend meets all of its specifications, it is released for shipping. The specific practices used by individual refiners employing the in-tank blending method can vary widely.

25. Almost all of the larger refineries in California and the U.S. now blend finished gasoline using the in-line method in which blendstocks are fed directly and proportionally into a pipeline, reducing or eliminating the need for intermediate storage tanks. While individual refiner practices vary, a typical in-line blending system is shown in Exhibit C. For in-line blending of RFG, there are additional Environmental Protection Agency (EPA) testing requirements to ensure gasoline quality.

MTBE Manufacturing and Sources

26. As described in Appendix 7, MTBE can be produced at petroleum refineries by reacting methanol with an isobutylene stream derived from the fluid catalytic cracking unit (FCCU). However, commercial production of MTBE in the U.S. often employed several other isobutylene sources from outside the refinery, including co-product and by-product isobutylene streams from petrochemical production, as well as isobutylene made from natural gas-derived butane streams. Appendix 8 describes these production routes in greater detail. Irrespective of the source(s) of isobutylene, all commercial MTBE plants have always used this chemical, combined with methanol, as basic raw materials.

27. During the past ten years, approximately one-half of the states in the U.S. have imposed either partial or total restrictions on the use of MTBE in gasoline.[13] Accordingly, most

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[13] In March 1999, California Governor Davis issued Executive Order D-5-99 directing the CARB to establish a

U.S. refineries have now discontinued production of MTBE. However, if a refinery does not produce MTBE, there are many other commercial uses for isobutylene. Within most fuels refineries, isobutylene (along with other olefins) is commonly used as feedstock (with isobutane) to alkylation plants to produce alkylate, a relatively high-octane gasoline component particularly effective in meeting cleaner burning gasoline requirements (see Appendix 7). Alkylation technology has been widely used in the refining industry since the 1940s. In the past, some refineries have employed isobutane dehydrogenation units to make additional isobutylene for either alkylation or MTBE production. Isobutylene can also be used to make ETBE, a fuel oxygenate alternative to MTBE, made from the chemical reaction of isobutylene and ethanol. Finally, isobutylene has been used since the 1930s as a petrochemical feedstock in the production of butyl rubber (a tough, temperature resistant synthetic rubber) and polyisobutylene, a polymer used in lubricating oils, as well as caulking and sealants.[14] Thus, the isobutylene that was previously used by refineries to make MTBE has many other valuable commercial outlets.

Ethanol Manufacturing and Sources

28. The ethanol used in fuel is not a hydrocarbon-derived material that can be manufactured at refineries. Ethanol is a fermentation product from biomass materials. Almost all of the fuel-grade ethanol in the U.S. is derived from corn.[15] Corn is the preferred feedstock because of its availability and its high starch content. Starch is the biomass material that is converted to ethanol through the process of fermentation. There are basically two types of corn-based ethanol production facilities: (1) the "dry mill" process; and (2) the "wet mill" process. In

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timetable for removing MTBE from California gasolines at the earliest possible date, but no later than December 31, 2002. Ultimately, the phaseout was not completed until December 31, 2003.

[14] P. Wiseman, *Petrochemicals*, Ellis Horwood Ltd., Chichester, 1986, pp. 85-86.

[15] Throughout this Report, the term "ethanol" refers to fuel-grade ethanol, an anhydrous (water-free) mixture of ethanol plus approximately 2 Vol.% gasoline or naphtha as a denaturant. The typical qualities of fuel-grade ethanol can be found in a 1998 Archer Daniels Midland Corporation (ADM) publication, *Fuel Ethanol - Technical Bulletin.*

a dry mill ethanol plant, the entire corn kernel is first ground ("milled") into a corn "mash" prior to conversion to sugar and subsequent fermentation of the sugar into ethanol. The ethanol is recovered from the fermentation products through simple distillation. Dry mills also produce a co-product called distillers dry grain with solubles (DDGS) which is sold as a feed for livestock. In the wet mill process, the corn is first "steeped" in water[16] before several stages of grinding and separation to isolate the starch prior to the fermentation and distillation steps. Wet mills recover a wider variety of by-products, including corn oils, high-fructose corn syrup, and several gluten livestock feeds. They also have the flexibility to switch from ethanol to high-fructose corn syrup production (used in canned soda drinks and other food items) if the market for the latter is more profitable. Wet mill plants are more complex than dry mills, cost as much as three times more to build, and use more energy per gallon (/Gal.) of ethanol produced. However, they produce more co-products, which lowers the net cost of corn feedstock. Wet mill plants are usually larger than dry mill plants to take advantage of economies of scale.[17]

Blending, Handling, and Storage of Oxygenates

29. When blending oxygenates into gasoline, refiners must consider how the oxygenate will perform in the finished blend. The physical properties of MTBE and ethanol, as well as some other oxygenates, are shown in Exhibit D. Some blendstocks behave differently when mixed with other materials, as compared to when they are in their pure state. The RVP that a blendstock actually exhibits when blended into gasoline is often referred to as its "blending RVP." As shown in Exhibit D, ethanol's blending RVP is much higher than its RVP in the pure ("neat") state. Thus, when ethanol is blended with gasoline it behaves as if it has an RVP of 18

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[16] Steeping is a process in which starch is separated from the protein, fiber, and other parts of the corn by soaking in hot water.

[17] U.S. DOE – Energy Efficiency and Renewable Energy, Alternative Fuels, and Advanced Vehicles Data Center, website article on ethanol production: http://www.afdc.energy.gov/afdc/ethanol/production_starch_sugar.html.

psi, compared to its measured RVP of only 3.5 psi. Consequently, a gasoline blended with ethanol exhibits a higher RVP than the same gasoline blended with MTBE. To compensate for ethanol's RVP penalty, federal regulations have historically permitted conventional ethanol-blended gasolines (often referred to as "gasohol") to have an RVP of about one psi higher than would otherwise be allowed (the so-called "ethanol waiver").[18] This waiver has never been granted to ethanol-blended RFG gasolines.

30. Because RFG gasoline was not covered under the ethanol waiver, refiners that intended to use ethanol to meet the RFG oxygen requirements of the 1990 CAAA were forced to prepare a summertime "base" gasoline (before ethanol blending) with an RVP approximately 1.3 psi lower than the final blend.[19] This special base gasoline, which is required for all of today's ethanol-blended RFG fuels, is called Reformulated Blendstock for Oxygenate Blending (RBOB) and has lighter components, such as butanes and pentanes, removed from the base blend.[20] This removal of light compounds often entails significant refinery capital and operating expense, increasing the cost of finished gasoline. Plaintiff's expert Mr. Reynolds recognized these facts in his report in the Suffolk Case[21] when he said, "*In the case of RFG, such adjustments* [to the base gasoline] *are more severe and, for* ***some*** [emphasis added] *refiners, necessitate the installation of new equipment such as debutanizers and depentanizers and the pressurized vessels to store butane and/or pentane....*"[22] Also, in one of his depositions in the Suffolk Case, Mr. Reynolds

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[18] *An Overview of the Use of Oxygenates in Gasoline*, CARB, September 1998, p. 19.

[19] *Supply Impacts of an MTBE Ban*, EIA, September 2002, p. 9.

[20] In California, this special base gasoline is referred to as California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) to distinguish it from the ordinary RBOB used in the rest of the U.S.

[21] In his expert report (the "Reynolds Fresno Report") submitted on May 2, 2011, in this matter (Case No. 04-CV-04973 [SAS]), Mr. Reynolds incorporates by reference as Appendix C, a report he submitted on March 22, 2007, in the prior MDL 1358 matter: County of Suffolk and Suffolk County Water Authority v. Amerada Hess Corp., et al (referred to herein as the "Suffolk Case"). Mr. Reynolds' Appendix C is referred to herein as the "Reynolds Suffolk Report."

[22] Reynolds Suffolk Report, p. 12, lines 3-5.

discussed the potential economic penalties of these adjustments.[23] Although I agree with Mr. Reynolds' description of the equipment required, I disagree that only "some" refiners would have needed it. In my experience, most, if not all, refiners would have needed to install the equipment described in order to make the low RVP RBOB for summertime ethanol blending. Such costs and supply reductions were able to be avoided when refiners chose MTBE instead of ethanol as the oxygenate for RFG or OFP gasoline production.

31. In addition to the increased capital and operating costs associated with removing light components from gasoline, the choice of ethanol over MTBE had another deleterious effect—it reduced the volume of gasoline that could be produced by a refiner from a barrel of crude oil. Because ethanol, on a weight basis, contains more oxygen than MTBE, it only needed to be blended at 5.7 Vol.% to meet oxygenate requirements, versus 11 Vol.% for MTBE. Consequently, the so-called "dilution" effect of oxygenate blending was reduced.[24] If refiners wanted to use ethanol to meet their oxygenate requirements, and still have the same emissions levels as could be achieved with an MTBE blend, they often had to remove some of the heavier, higher emission-producing gasoline components (usually aromatics and/or olefins) from the blend, or find a way to introduce more "clean" components, such as alkylate or isooctane. However, the latter are among the most expensive gasoline components to produce or purchase. Thus, the choice of ethanol had profound and costly effects on the way refiners blended gasoline, and how much gasoline they could produce from a barrel of crude oil.

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[23] Reynolds Deposition in the Suffolk Case, August 3, 2007, p. 415, line 4, to p. 417, line 24.

[24] The blending of clean burning oxygenates into gasoline helped refiners meet RFG specifications by "diluting" the emissions effects of other gasoline components. If less oxygenate was used, this beneficial effect was proportionately reduced.

32. Mr. Reynolds' Suffolk Report acknowledges both the dilution effect and the potential gasoline volume reductions associated with ethanol blending.[25] However, he attempts to minimize the impact on gasoline volume by quoting from a study by Mr. Reynolds' firm, Downstream Alternatives, Inc., which concluded that, "*...there should be no gasoline shortages as a result of switching to ethanol from MTBE, largely because of the ability to produce or import gasoline components such as alkylate.*"[26] He makes the same point in one of his depositions.[27] What Mr. Reynolds' theory fails to recognize is that most refineries, including those in California, had only limited alkylate capacity with no means to produce more. One of the major factors limiting additional alkylate production in California refineries was the shortage of isobutane, a key ingredient in the alkylation process.[28]

33. Imported alkylate was in limited supply and very costly. Whether or not refiners may have been willing or able to acquire such incremental volumes, the necessity to produce or import alkylate (or isooctane, a potential alternative) proves the point—ethanol blending has the net effect of reducing available gasoline volumes for the same volume of crude oil processed. This situation is more pronounced in summer months when lower RVP specifications are in effect and more light components must be removed from the base gasoline. These ethanol-blending effects on gasoline volume are real and not insignificant. Of course, as Mr. Reynolds suggests, refiners can often produce (by processing more crude oil) or import more product to make up the difference—but these options raise the cost of gasoline to the consumer.

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[25] Reynolds Suffolk Report, Section 9.1.1, p. 26.

[26] Ibid.

[27] Reynolds Deposition, Suffolk Case, August 2, 2007, p. 252, lines 13-19.

[28] Isobutane is obtained largely through the processing of natural gas, and there was little natural gas production in California. Accordingly, in the early 1990s, California refineries had only about 80% of the alkylate capacity of refineries in the rest of the U.S. as a percentage of crude oil processing capacity.

34. In addition to blending issues, the way oxygenates impact the handling and storage of finished gasoline is also important to refiners. Since ethanol is a biomass-derived product, and not petroleum-based, it is not produced at oil refineries. Therefore, as described in more detail below, refiners seeking to use ethanol to meet the requirements of the 1990 CAAA had to purchase the product from third parties outside of the oil industry.[29] Such parties were often small and potentially unreliable long-term producers. If a refiner chose to sell ethanol-blended gasoline at the refinery loading rack, it had to have segregated facilities to receive, store, and blend the ethanol. Alternatively, these facilities had to be available at the distribution terminal where the gasoline was sold to the wholesale distributor or retailer.

35. From a refiner's perspective, the most important difference between MTBE and ethanol (apart from ethanol's potentially unreliable supply) has always been MTBE's ability to be blended directly into finished gasoline blends at the refinery, while ethanol must be blended just prior to delivery to the point of consumption. Ethanol's water miscibility and corrosiveness precludes either ethanol or ethanol-blended gasolines from being shipped on pipelines.[30] There have been a few proposals to construct large ethanol-dedicated pipelines to move ethanol from the Midwest to the major areas of consumption in the Northeast. However, none of these has ever come to fruition. Recently, Magellan Midstream Partners, L.P. (MMP) withdrew from a plan to build an ethanol pipeline from the Midwest to the East Coast. In an October 2011 interview, MMP chief executive officer Donald Wellendorf stated that, "*We're not willing to spend the kind of money it would take on a project that's viable only as long as the government*

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[29] Today, some refiners (e.g., Valero Refining) have acquired existing ethanol production facilities to provide the ethanol needed to meet their RFS requirements. However, this was not the case during the early 1990s.

[30] A pipeline in Florida that runs from Tampa to Orlando has been modified to occasionally ship "neat" ethanol for blending into gasoline at Orlando, and there have been studies done on other such systems. However, to the best of my knowledge, there have never been any proposals to transport pre-blended ethanol gasoline on pipelines.

continues its interest in ethanol."[31] Ethanol is corrosive and can degrade ordinary pipelines, necessitating the use of special materials not normally required for typical hydrocarbon service.

36. Exhibit D shows that both ethanol and TBA are completely miscible with water. Even trace amounts of water that may come in contact with ethanol-blended gasoline can result in ethanol absorption into the water and phase separation of the ethanol-water mixture, leaving a gasoline product with lower ethanol content. As shown in Exhibit D, the various ethers, including MTBE, ETBE, TAME, and DIPE, are soluble in water only to the extent of between 1.2 weight percent (Wt.%) to 4.3 Wt.% —much less than ethanol or TBA, which are 100% soluble (i.e., miscible). However, all the alcohols and ethers are substantially more soluble in water than gasoline hydrocarbon components, such as benzene, toluene, or xylenes (collectively, "BTX"), which have solubilities ranging from only 0.01 Wt.% to 0.07 Wt.%.[32]

37. Because of its water miscibility issue, ethanol must be blended directly into tank trucks just prior to final delivery to the retail gasoline stations.[33] However, because water can never be completely eliminated from gasoline distribution systems, special attention is required when handling ethanol-blended gasolines to avoid water intrusion into the system and to immediately remove any such contamination. Examples of often unavoidable water intrusion into gasoline distribution systems include atmospheric water vapor condensation in storage tanks, rainwater leakage through tank roofs, or ingress during tank filling.

38. To minimize phase separation problems when using ethanol, the low RVP RBOB is kept segregated until immediately prior to delivery to service stations. The specified volume of

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[31] "Magellan Midstream Backs Off 1,800-Mile Midwest-to-Northeast Ethanol Pipeline," Industrial Info Resources, October 11, 2011.

[32] Robert H. Perry and Cecil H. Chilton, *Chemical Engineers' Handbook*, Fifth Edition, McGraw-Hill, New York, 1973, pp. 3-25, 3-27, 3-43, and 3-44.

[33] An Overview of the Use of Oxygenates in Gasoline, p. 19.

ethanol is then usually metered "in-line" directly into gasoline tank trucks, either at the refinery or terminal truck racks. Although less common today, ethanol is occasionally still "splash" blended (i.e., added separately after the gasoline has been loaded) into tank trucks at terminal truck racks or at separate ethanol blending facilities. In splash blending, the motion of the tank truck on the way to the gasoline retail site is relied on to mix the ethanol-gasoline blend. Splash blending tends to be more common in rural areas where conventional gasolines are blended with ethanol, or where there are well-established independent blenders who make a business out of ethanol blending.[34] Splash blending is less accurate than in-line blending and increases the potential for off-specification blends.

39. Another disadvantage of ethanol-blended RFG is that the final specification tests are performed only on the RBOB, not the final retail product delivered. This means that the refiner loses some measure of quality control over the product delivered to the consumer. Mr. Reynolds understood the importance of this when, in one of his depositions in this MDL 1358 litigation, he said that, in relation to using ethanol in gasoline, "*...you're taking the product and you're moving the quality control point one point farther downstream...*" and later, "*...you're allowing something to be put in the gasoline once it's left your quality control circle.*"[35] In subsequent deposition testimony, Mr. Reynolds affirmed that such quality control issues contributed to the decision by CITGO Petroleum Corporation (CITGO) to exit certain portions of the ethanol market in the late 1980s.[36]

40. The costs and risks associated with a refiner choosing to use ethanol over MTBE as its gasoline oxygenate to satisfy the requirements of the 1900 CAAA were very substantial.

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[34] Brian Jennings, American Coalition for Ethanol, Executive Vice President, Letter to the EPA, November 10, 2006.

[35] Reynolds Deposition, Suffolk Case, August 2, 2007, p. 79, line 21 to p. 80, line 4.

[36] Reynolds Deposition, Suffolk Case, November 9, 2007, p. 125, lines 5-20.

Some of these costs and risks had to be borne directly by California gasoline consumers. Later in this Report, I explain how Plaintiff's expert, Dr. Whitelaw, conducted an analysis which demonstrates that the net costs, benefits, and risks associated with ethanol blending in California in the mid-1990s outweighed those associated with the use of MTBE.

IV. HISTORY OF GASOLINE REGULATION AND OXYGENATE USAGE

41. The quality and composition of gasoline has changed significantly over the years. Some of these changes have resulted from economic forces (including competition), political events, and regulatory initiatives. Often there have been conflicting issues to be addressed that have forced refiners, automobile manufacturers, policy makers, and regulators to make choices between various competing solutions. Thus, today's motor gasoline is the result of a broad collection of ideas, research, analysis, competitive forces, negotiations, compromises, and regulations. Exhibit E is a time line showing the major events that have impacted gasoline quality in both California and the U.S. as a whole.

Pre-1970 Motor Gasoline Regulation

42. The introduction and large-scale production of gasoline commenced in the 1920s. For almost the next 40 years, there was little direct regulation of gasoline quality.[37] Local regulation often existed, but usually was related to fair trade practices rather than specific issues of quality. The automotive industry worked to develop engines to meet the consumer demands for larger, more powerful cars, and the oil industry generally responded by providing gasolines that satisfied the octane ratings and other characteristics demanded by the higher performance

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[37] L. M. Gibbs, "The Impact of State Air Quality and Product Regulations on Current and Future Fuel Properties," *The Impact of U.S. Environmental Regulations on Fuel Quality*, K. H. Strauss and W. G. Dukek, Eds., ASTM, 1992, p. 30.

engines. Competition among refiners and retailers was strong, and consumers enjoyed relatively low and stable gasoline prices.

43. Beginning in 1923, research indicated that "lead" additives (primarily in the form of tetra ethyl lead–TEL), when introduced into gasoline in small quantities, could significantly "boost" the octane rating of the product. TEL was used as a gasoline additive until the lead phase-down of the 1970s, as discussed below.

44. In the 1940s, air quality started to become a serious issue in many urban areas. For example, Los Angeles, California, was noted as having the worst "smog" (thought at the time to be a combination of smoke and fog) in the country. It was not until the mid-1950s, however, that research established links between automobile exhaust and the formation of atmospheric ozone, a precursor of smog. Accordingly, automobile manufacturers began to investigate how automobiles could be modified to reduce air emissions. Based on this work, and a growing environmental movement, regulators in California initiated legislation in the late 1950s and early 1960s that was focused on reducing automobile emissions. These programs were specifically aimed at the reduction of airborne hydrocarbons and carbon monoxide (CO). At the federal level, the 1963 Clean Air Act (CAA) and the 1965 Motor Vehicle Pollution Control Act set the stage for greater regulation of automobile emissions and gasoline composition throughout the nation.[38]

1970 CAA and Establishment of the EPA

45. In 1970, Congress reauthorized the CAA and established the EPA. These events had far reaching effects on both the automobile industry and the refining industry. Under the 1970 CAA, the EPA was authorized to establish National Ambient Air Quality Standards

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[38] Alex Farrell, *Historical Patterns in the Science, Engineering, and Policy of Vehicle Emissions*, Carnegie Mellon University, Department of Engineering and Public Policy, p. 9.

(NAAQS) to limit sulfur dioxide, oxides of nitrogen, CO, ozone, non-methane hydrocarbons, opacity, and total suspended solids in ambient air. The 1970 CAA also called for the first tailpipe emissions standards for the control of CO, VOCs, and oxides of nitrogen. It also established a schedule for the reduction of lead in gasoline to no more than 0.5 grams/Gal.[39] Airborne lead from vehicle exhausts was considered to be a potential health hazard.

46. Between 1973 and 1974, the Arab Oil Embargo resulted in a five-fold increase in the price of crude oil, with corresponding increases in gasoline and other refined product prices. This "price shock" highlighted the vulnerability of the nation's oil supply to control by foreign interests and spurred initiatives to reduce dependence on imported oil. One initiative was encompassed in the 1975 Energy Policy and Conservation Act, which established fuel economy standards for new cars beginning in 1978. Under these standards, automobile manufacturers would be subject to severe financial penalties if the average fuel economy of their new car fleets fell below certain limits. These limits became known as the Corporate Average Fuel Economy (CAFE) standards.[40]

47. One of the automobile manufacturers' important strategies to comply with the tailpipe emissions requirements imposed by the 1970 CAA was the use of catalytic converters. These devices, which comprised metal canisters installed on the exhaust system, were designed to chemically reduce exhaust pollutants. Catalytic converters were first installed on new cars in 1975 and continue in use today. Since the platinum-based catalyst in these converters is "poisoned" by lead, the mandatory and widespread use of unleaded gasolines was timed to correspond with the introduction of the 1975 vehicles. This required the addition of separate

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[39] *Profile of the Petroleum Refining Industry*, Office of Compliance Sector Notebook Project, U.S. EPA, September 1995, p. 88.

[40] *Review of Procedures for Determining Corporate Average Fuel Economy*, EIC Corp., Newton, Massachusetts, prepared for the National Highway Traffic Safety Administration, July 1979, pp. 1-13.

handling and storage facilities to prevent the mixing of unleaded gasoline with leaded gasoline. Initially, the overall demand for unleaded gasoline was relatively small, but as newer cars replaced older ones, the demand increased nationwide. The increased use of unleaded gasoline forced refiners to significantly adjust their operations to produce the required high-octane gasolines without the "boost" provided by TEL.[41]

1977 CAA Amendments and Elimination of Lead Additives

48. The 1977 Clean Air Act Amendments (1977 CAAA) required, among other things, that any additive or chemical blendstock used in gasoline must be "substantially similar" to those used in the emissions certification of 1975 model year or later vehicles. This requirement was intended to ensure that the emission performance of automobiles would not be adversely affected by fuel composition. If an otherwise prohibited additive was shown to cause no harm to emissions performance, the EPA could grant a waiver (the so-called "sub-sim" waiver) for use of the specific additive or chemical blendstock in gasoline.[42] Some waivers that were applied for were granted, and some were denied.[43]

49. By 1978, as a result of the CAFE standards, automobile manufacturers had greatly improved fleet fuel economy through significant vehicle design changes. In general, cars were smaller and lighter, with smaller displacement engines that operated more efficiently at higher loads.[44] However, engine design changes that improved fuel economy, including advancing the spark timing and raising compression ratios, also raised octane requirements. From the refiners'

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[41] *Gasoline Octane Enhancement: Technology, Economics, and Environmental, Health and Safety Considerations*, prepared for the Office of Environmental Analysis, Assistant Secretary for Environment, Safety, and Health, U.S. DOE, July 1985, p. II-1.

[42] Ibid., p. II-7.

[43] Ibid., pp. II-4-6.

[44] David L. Greene, *Why CAFE Worked*, Center for Transportation Analysis, Oak Ridge National Laboratory, prepared for the U.S. DOE, November, 1997, p. 1.

perspective, such changes exacerbated the octane shortage caused by the removal of lead additives.

50. In California, MTBE was first used in conventional gasolines as an octane-enhancing component in 1986. MTBE gained industry acceptance because it could be blended directly at the refinery like any other gasoline blendstock and did not disrupt the existing distribution and marketing operations. At this same time, other oxygenated blendstocks, including ethanol and other alcohols, were also experiencing some commercial success in certain parts of the country.

51. Many states in the Midwest, because of the ready availability of corn feedstock, encouraged the manufacture and blending of ethanol into gasoline to expand regional gasoline supplies and support the local farm-based industry. By the end of 1981, either through waiver or interpretive ruling, several oxygenated materials, including TBA, MTBE, ethanol, blends of methanol with co-solvents, and certain other alcohols, had been sanctioned by the EPA for use in unleaded gasoline.[45] Thus, by the early 1980s, refiners had a choice of EPA-approved high-octane oxygenate blendstocks that could be used as effective replacements for the previously used lead additives. However, not all these materials were readily available to all refiners or at all locations, and they were not all equally effective or cost-efficient. The choice often came down to the specific refiner's process configuration, the gasoline market being served, the cost and availability of competing materials, and the competitive environment.

52. Over the 1978 and 1979 time period, the Iranian Revolution roughly tripled the price of crude oil. This second "price shock" set the stage for even more significant changes in

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[45] *Gasoline Octane Enhancement: Technology, Economics, and Environmental, Health and Safety Considerations*, prepared for the Office of Environmental Analysis, Assistant Secretary for Environment, Safety, and Health, U.S. DOE, July 1985, p. II-7.

the character of the oil industry. By 1982, as a result of higher energy costs, consumers began to make fundamental changes in their demand patterns. High fuel prices and the recession of the early 1980s caused demand for refined products to fall dramatically and the refining industry found itself in a period of significant oversupply. Refining economics changed and many refineries were forced to close. The refining industry continued in a period of oversupply throughout the remainder of the decade of the 1980s. The decline in gasoline demand, and the concurrent reduction in prices, made the production of fuel ethanol uneconomic in many places and forced many ethanol plants to close. The economics of ethanol production are covered in more detail later in this Report.

53. During the 1980s, the EPA began to take steps to completely eliminate lead from motor gasoline. The process was long and complex. In 1985, the EPA promulgated its final lead regulations which effectively removed all but a small amount of lead from gasolines by January 1, 1986. Although lead was not totally eliminated from gasoline until 1995, the volume of leaded gasoline sold in the U.S. was very small after the mid-1980s.[46]

TBA Usage in Gasoline

54. In 1979, TBA was granted a sub-sim waiver by the EPA permitting its use in gasoline. However, TBA's use as a gasoline blending component was severely restricted when its water miscibility became a significant problem in gasoline blends destined for pipeline transportation. Some attempts were made to introduce TBA in "co-solvent" blends with methanol (e.g., "Oxinol") to improve the overall performance of methanol-gasoline blends.[47] However, many customers discontinued their acceptance of Oxinol when consumers reported instances of phase separation and/or damage to elastomeric engine seals. Subsequently, Oxinol

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[46] *MTBE, Oxygenates, and Motor Gasoline*, EIA, March 6, 2000, p. 1.
[47] George H. Unzelman, "Problems Hinder Full Use of Oxygenates," *Oil & Gas Journal*, July 2, 1984, pp. 63-64.

marketing was discontinued in 1986, and it was rejected as a practical refinery blending component.[48] By the mid-1980s, TBA's role had become limited to its use as a feedstock for MTBE production, rather than as a direct gasoline blending component.[49]

55. The production process for MTBE results in several "side" reactions which produce small quantities of other compounds.[50] For example, some isobutylene can be converted to TBA through a process called hydration. Although less than 0.5 Wt.% of the isobutylene usually reacts in this way, it can result in the presence of small quantities of TBA in the MTBE product. In addition, because MTBE can degrade to TBA, either naturally or biologically, some TBA is almost always found in contaminated sites where MTBE is present.[51] Thus, the Plaintiff's claims in this case regarding TBA are likely to be more related to the foregoing factors than to any intentional usage of TBA by Defendants.

1989 Reductions in Gasoline Volatility

56. To reduce emissions of VOCs and other ground-level ozone precursors, the EPA implemented gasoline RVP limitations in 1989. The regulations set maximum standards for the volatility of summertime gasoline in urban areas. The program was implemented in two phases, with the first beginning in the spring of 1989 and the second in 1992. From the refiner's perspective, the first phase necessitated the removal of most of the butane from gasoline with resultant additional loss in gasoline octane and volume.[52]

57. The requirement for additional sources of octane, which resulted from the EPA's regulation of gasoline quality, stimulated the demand for oxygenates. During the late 1980s,

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[48] George H. Unzelman, "U.S. Gasoline Pool Octane Increase May Be Limited," *Oil & Gas Journal*, April 4, 1988, p. 40.

[49] TBA can be easily dehydrated to produce isobutylene, a component in MTBE production.

[50] In chemistry, a "side" reaction is an unwanted reaction that diminishes the quantity of the desired product.

[51] "Challenging a Paradigm: MTBE Shown to Degrade to TBA Without Microorganisms," U.S. Geological Survey Toxic Substances Hydrology Program website.

[52] *Profile of the Petroleum Refining Industry*, p. 91.

MTBE's position as most domestic refiners' prime source of additional octane was solidified. Among the drivers behind the use of MTBE by some refiners were its ease of blending at the refinery level, its high octane, and its relatively low RVP. Furthermore, because the blending RVP of MTBE is significantly lower than ethanol, the reduction in RVP mandated by the EPA was more easily accomplished with MTBE than with ethanol. By the end of the 1980s, MTBE was the primary oxygenate used by refineries.[53] However, during this period, ethanol was also used by many refiners, especially in the Midwest where it was plentiful, as a gasoline blendstock to make what was called "gasohol"—a blend of conventional gasoline plus 10 Vol.% ethanol.[54] Rising gasoline prices, combined with federal and state subsidies, served to make ethanol usage economically attractive in corn-producing states. Prior to 1995, when MTBE was used as an octane enhancer in conventional gasolines, a concentration in the range of 1-7 Vol.% was typical.[55] The price and availability of MTBE, as well as blending options available to gasoline producers, determined the actual quantity used. Premium gasoline usually contained more MTBE than regular gasoline because of MTBE's high octane.

<u>1990 CAAA and the RFG Era</u>

58. The 1990 CAAA, enacted on November 15, 1990, provided an update to the 1970 CAA and the 1977 CAAA. The 1990 CAAA provided the framework for addressing areas of the country that were not in compliance with the NAAQS. Although the 1990 CAAA covered nearly every aspect of air quality, there were only two programs that had a large impact on gasoline composition. These were: (1) the OFP; and (2) the RFG program. The OFP was

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[53] *Status and Impact of State MTBE Bans*, EIA, March 27, 2003, p. 1.

[54] The term "gasohol" is no longer in common usage today. Gasoline containing 10 Vol.% ethanol is now normally referred to as "E10" gasoline.

[55] M. J. Volandt, ARCO Products, L.C., Letter to B. R. Jackson, EPA, December 6, 1978, regarding waiver requests on the use of up to 7% "Arconol" in unleaded gasoline and the use of up to 7% MTBE in unleaded gasoline.

developed because vehicle emissions testing during the 1980s had indicated that oxygen-bearing compounds, such as MTBE and ethanol, when blended into gasoline, significantly reduced tailpipe emissions of CO. This was particularly true in older vehicles equipped with carburetors that were running at very high ("rich") fuel/air mixture ratios. The OFP provided a "quick fix" for many CO non-attainment areas to come into compliance with the NAAQS. The OFP required that by November 1992, all gasoline sold in certain CO non-attainment areas must contain a minimum of 2.7 Wt.% oxygen for at least four winter months.[56] If an area mandated for wintertime OFP could demonstrate that it was in compliance with the NAAQS, it was allowed to petition the EPA to "opt out" of the program. Exhibit F shows geographic areas that were participants in the OFP, including state requirements, at any time during the program's existence through the end of 2003 (including those that may have eventually "opted out").

59. The 1990 CAAA only broadly defined the RFG and OFP programs and left specific details to be worked out by the EPA. For example, although the 1990 CAAA mandated certain minimum oxygen contents in RFG and OFP gasolines, and established air quality standards, the development of regulations to implement the Act's requirements was left to the EPA, in consultation with the various "stakeholders." During the late 1980s, petroleum refiners generally opposed the mandatory inclusion of oxygenates in RFG, and would have preferred to use them only on a case-by-case basis where they provided the most technical and economic benefits.[57,58] The refining industry's opposition to the oxygenate mandate was also chronicled in Mr. Reynolds' deposition testimony.[59] However, as Mr. Reynolds noted, the mandatory use of

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[56] See Federal Register, Volume 57, p. 47853 (57 FR 47853).

[57] Deposition of Paul Cuneo, South Tahoe Public Utility District v. Atlantic Richfield Company, et al, September 8, 2000, p. 129, line 9 to p. 130, line 7.

[58] *Oxygenated Fuels Mandating – Against the National Interest*, American Petroleum Institute, January 4, 1988.

[59] Reynolds Deposition in the MDL 1358 case involving the City of New York (the "City of New York Case"), March 16, 2009, p. 34, line 7, to p. 36, line 15.

oxygenates (whether ethanol or MTBE) was imposed by the federal government over such industry objections.[60]

60. Congress established the RFG program to address the areas of the country that were not in compliance with the ozone standard of the NAAQS. The RFG program was a more specific and wide-ranging regulation that required refiners to manufacture gasolines with substantially cleaner burning characteristics at all times of the year. This improvement was achieved through a combination of lower gasoline RVP limits, reducing the allowable levels of the more toxic components in gasoline (e.g., benzene, olefins, aromatics, etc.), and requiring that RFG contain a minimum of 2 Wt.% oxygen in the form of oxygen-bearing components.[61] In its final form, the RFG program required the year-round use of RFG by January 1, 1995, in nine metropolitan areas that had the worst ground-level ozone problems. "Opt in" and "opt out" provisions, similar to those in the OFP, were included in the program. Other non-attainment areas could, and did, "opt in" to the program as a way of reducing ozone levels.[62]

61. The RFG program required that gasoline marketed in these areas have a minimum oxygen content of 2 Wt.%, a maximum benzene content of 1 Vol.%, and contain no lead or manganese. Although the limit on benzene, a high-octane aromatic chemical contained in some gasoline blendstocks, exacerbated the octane shortage, the mandate to blend high-octane oxygenate compounds helped fill the octane gap. RFG gasoline was also required to provide quantitative reductions in certain emissions. In 1998, and again in 2000, further emissions reductions were required. In 2000, summertime RFG was required to provide a reduction of nitrogen oxides of at least 5 Wt.%, a reduction in VOCs of at least 25 Wt.%, and a reduction in

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[60] Ibid., p. 64, lines 13-17.

[61] *Profile of the Petroleum Refining Industry*, p. 90.

[62] The nine metropolitan areas where RFG was mandated, plus the "opt in" areas, were estimated to comprise approximately one-third of total domestic U.S. gasoline demand when the RFG program started in 1995.

air toxics of at least 20 Wt.% compared to the 1990 "baseline" emissions.[63] In order to meet the stringent 2000 VOC regulations, RFG needed to exhibit an average RVP of no higher than approximately 6.9 psi. Exhibit G shows geographic areas that were participants in the federal RFG program during the program's existence through the end of 2003, including those that may have "opted out." The requirements of the 1990 CAAA for fuels and fuel additives were embodied in the Code of Federal Regulations (CFR), Title 40, Part 80 (40 CFR 80).

62. To implement the new 1990 CAAA standards, the EPA used a process termed "regulatory negotiation," or "Reg Neg." In this process, an agreement was reached among the stakeholders, primarily the EPA, the automakers, the oil industry, and environmental groups (such as the Sierra Club and the Natural Resources Defense Council), on the most practical and cost-effective way to meet the program requirements. Consumer groups, oxygenate producers, ethanol producers and supporters, and federal and state regulatory bodies also had a role in the process. An agreement was reached among the stakeholders in August 1991, and the EPA issued its proposed regulations in April 1992. However, the final EPA RFG regulations were not issued until February 16, 1994—less than a year before they were due to take effect.[64]

63. The final EPA RFG regulations dictated a gasoline "recipe" rather than allowing individual refiners to manufacture their gasolines to meet specific performance standards. Although most refiners, during the Reg Neg process, were generally opposed to this approach, especially the mandatory inclusion of oxygenates, they were overruled by federal regulators who saw oxygenates as the only "quick fix" to the air pollution problems in many metropolitan areas. The signatories to the Reg Neg agreement were bound not to litigate or lobby against regulations

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[63] *Profile of the Petroleum Refining Industry*, pp. 88-91.
[64] See 59 FR 7813.

that implemented compromises reached as a result of the negotiations.[65]

64. To clarify the terminology associated with the 1990 CAAA gasoline regulations, and as used in this Report, gasoline made to meet the requirements of the OFP is referred to as "oxygenated" gasoline, while gasoline made to meet the requirements of the RFG program is referred to as "reformulated" gasoline, or simply RFG. Both of these grades of gasoline were required to contain minimum levels of oxygen through the addition of oxygenates, as described above.[66] Gasoline sold in areas not covered by either the OFP or RFG programs was not required to contain oxygenates and is referred to as "conventional" gasoline. However, conventional gasoline may, and often does, contain oxygenates depending on logistics, octane requirements, and processing economics. Also, so-called "anti-dumping" regulations preclude refiners from simply blending ("dumping") all of their most highly polluting components into conventional gasoline. Following the January 1995 introduction of RFG, there was a period of regulatory overlap between the OFP and RFG programs when RFG was required to contain 2.7 Wt.% oxygen (instead of 2 Wt.%) during the winter months in OFP areas. This was done to avoid having two conflicting fuel regulations in areas covered by both OFP and RFG.

CARB Reformulated Gasoline Regulations

65. CARB was formed by the California legislature in 1968 to find solutions to California's air pollution problems. Since its establishment, CARB has often been in the forefront of the development of automobile emission controls. In 1971, CARB adopted the nation's first automobile emissions standards for oxides of nitrogen. In 1975, exhaust catalytic

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[65] Michael Weisskopf, "Rare Pact Reached to Fight Smog; Environmentalists, Oil Firms Agree on Gasoline Standards," *The Washington Post*, August 16, 1991, p. 1.

[66] The requirement that RFG contain a minimum oxygen content was lifted in May 2006, after Congress passed the RFS mandating that the domestic gasoline supply contain certain minimum volumes of blendstocks made from renewable sources.

converters were required on all new cars sold in California under CARB's Motor Vehicle Emission Control program. In 1988, CARB adopted regulations requiring all new cars sold in the state to have onboard computer-controlled emission monitoring systems.

66. However, CARB's most significant statewide gasoline regulations occurred when Phase I of the California Reformulated Gasoline (CaRFG1) program became effective on January 1, 1992. CaRFG1 totally eliminated the use of lead additives, mandated the use of deposit control additives, and in some areas of the state, extended the new federal RVP limits for longer time periods.

67. For federal OFP-designated areas, California obtained an EPA waiver to use gasoline containing between 1.8 and 2.2 Wt.% oxygen, instead of the standard federal level of 2.7 Wt.% for wintertime OFP gasolines.[67] Also, when the federal OFP program commenced in November 1992, CARB required the entire state to comply with the wintertime oxygenate program because approximately 80% of the state's gasolines were marketed in areas that were non-attainment for CO according to federal regulations.[68] This statewide wintertime oxygenate requirement started in November 1992 and terminated in February 1998. However, CARB required certain selected counties and areas of the state to continue their wintertime oxygenate use even though they were CO-compliant. For example, the counties of Fresno, Madera, and the Lake Tahoe Air Basin were required to continue wintertime oxygenate use through January 2000, even though they had achieved CO-compliance in June 1998.[69] The CARB wintertime oxygenate target of 2.0 Wt.% oxygen was equivalent to 11.0 Vol.% MTBE or 5.7 Vol.% ethanol.

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[67] The waiver was requested as part of California's State Implementation Plan (SIP). Data showed that oxygen levels above 2.2 Wt.% increased nitrogen oxide emissions and added to ozone and particulate matter pollution.

[68] James D. Boyd, CARB, Letter to Daniel W. McGovern, EPA, October 30,1992, regarding revisions to California's SIP for compliance with the federal OFP program.

[69] See 63 FR 15305 and year 2000 version of Title 13, California Code of Regulations, Section 2262.5 (13 CCR 2262.5).

In his report in this matter, Plaintiff's expert Mr. Reynolds incorrectly states that CARB's wintertime oxygenate requirements only applied to Greater Los Angeles and Imperial County.[70] In fact, they applied throughout the state for several years.

68. CARB Phase II (CaRFG2) gasoline regulations were promulgated in October 1991 and became effective on March 1, 1996, 15 months after the federal RFG regulations were implemented. The CaRFG2 regulations were more stringent than those for federal Phase I RFG and substantially lowered the sulfur dioxide, nitrogen oxides, and VOC emissions compared to Phase I RFG. The emissions behavior of CaRFG2 gasoline was estimated based on CARB's own "predictive model" and measured the emissions compliance of each gasoline blend based on its RVP, aromatics, olefins, sulfur, benzene, oxygen, and distillation. CaRFG2 gasoline sulfur content was limited to 30 parts per million (ppm) using the averaging method of compliance versus an average level of 130 ppm for federal RFG. In order to meet the tougher emission requirements, the average level of aromatics and olefins in CaRFG2 gasoline also had to be lower than typical federal RFG.

69. Because CaRFG2 was more restrictive than federal RFG, it was allowed to supersede federal requirements. Most CaRFG2 gasoline was targeted to contain 2.0 Wt.% oxygen year-round, with an allowable compliance range of between 1.8 and 2.2 Wt.%.[71] Although CaRFG2 was required statewide, some areas of the state were subject to the requirements of the federal OFP and RFG programs as well. Exhibit H shows the counties in California that were subject to the federal OFP or RFG programs, or both, at any time during the

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[70] Reynolds Fresno Report, May 2, 2011, Section 4.2, p. 7.

[71] If gasoline suppliers complied with the CARB emissions requirements under the predictive model, they were permitted to produce gasoline without oxygenates if they so chose (except in RFG-designated areas.) The oxygenate requirement only applied to suppliers complying under the so-called "flat limits" of 1.8 to 2.2 Wt.%. See 13 CCR 2262. Although small amounts of non-oxygenated CaRFG2 were produced between 1996 to 2003, high refining costs precluded any significant volumes. CaRFG2 also allowed 10 Vol.% ethanol blends with a maximum of 3.7 Wt.% oxygen.

period from 1995 to 2003. In December 2001, the counties in the San Joaquin Valley Air Basin[72] were designated by the federal government as ozone non-attainment areas and, effective December 2002, these counties were required to meet federal RFG requirements.[73]

70. CaRFG2 specifications proved very difficult for refiners to meet and required numerous modifications to refinery facilities. Difficulties in obtaining the necessary construction permits in the highly regulated California environment added time and cost to the necessary refinery modification projects. CARB-compliant gasoline became the most expensive in the nation and its availability from sources outside the state was very limited.

71. CARB Phase III (CaRFG3) gasoline regulations became effective December 31, 2003, the same time that the state's MTBE phaseout was complete. Because CaRFG3 gasoline used in federal RFG areas was still required to contain 2.0 Wt.% oxygen, completion of the MTBE phaseout was effectively a mandate for the use of 5.7 Vol.% ethanol (the only CARB-approved source of oxygen) in those gasolines.[74] CaRFG3 also lowered the levels of sulfur and benzene permitted in gasoline and slightly adjusted distillation temperature limits.

72. Despite recent federal mandates to increase the blending of ethanol into all domestic gasoline supplies, the 5.7 Vol.% ethanol level was retained in all California gasolines until January 1, 2010, when the state's Low Carbon Fuel Standard (LCFS) was passed into law.[75] Although the LCFS did not specifically mandate an increase in ethanol blending, increasing the ethanol content from 5.7 to 10 Vol.% became, along with other adjustments in fuel quality, an

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[72] The San Joaquin Valley Air Basin comprises the counties of San Joaquin, Stanislaus, Merced, Madera, Fresno, Kings, Tulane, and western Kern County.

[73] See 66 FR 56476-484.

[74] See 13 CCR 2262.6.

[75] California's LCFS is aimed at reducing greenhouse gases from all of the state's energy sources.

integral part of California refiners' strategy to comply with the new law.

The Federal Renewable Fuel Standard ("RFS")

73. In August 2005, the federal government passed the Energy Policy Act of 2005, which included the first RFS. Commencing in May 2006, the first RFS required certain minimum volumes of ethanol to be used annually in the nation's fuel supply, at the same time eliminating any requirement for oxygenates in RFG. The intended purpose of the first RFS was to reduce dependence on foreign oil through increased use of domestic renewable fuels, reduce greenhouse gas emissions, and support new domestic economic activity in renewable fuels production. In December 2007, the federal government passed the Energy Independence and Security Act of 2007 (EISA), which substantially expanded the RFS requirements for the nationwide blending of fuels from renewable sources.[76] As of the time of this Report, minimum oxygen requirements remain only in certain OFP regulated areas.[77] However, all such oxygen is currently provided through ethanol blending.

V. GASOLINE SUPPLY CHAIN OVERVIEW

74. The gasoline "supply chain" is the entire set of interdependent activities that are carried out to bring gasoline to the end user. The supply chain is very complex, highly regulated, intensely competitive, and involves a large number of business relationships. The business relationships exist throughout the entire supply chain—from the refiner, blender, or importer to the retail service station operator. Exhibit I is a diagram showing the complexity of the

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[76] EISA increased the annual volume of renewable fuels (including ethanol) required in the U.S. motor fuel supply to 36 billion gallons by the year 2022, or approximately 2,350,000 barrels per day (B/D). Of that total, only a maximum of 15 billion gallons per year (BGY), or approximately 978,500 B/D of corn-based ethanol can be used to meet RFS requirements.

[77] See 13 CCR 2262.5(a). The remaining OFP areas are the South Coast Area (Los Angeles and Orange Counties, as well as parts of Riverside and San Bernardino Counties) and Imperial County.

interrelationships that can exist along the supply chain among different industry participants. Given both the number of refiners and other participants that compete in California, the number of supply chain relationships created is large and diverse. Furthermore, these relationships are not static—they change, for example, when participants enter or leave markets.

Gasoline Supply Chain Competition

75. A wide range of commercial interests own and/or operate the assets that comprise the supply chain in California. Owners include not only refining and marketing companies, but also a large number of independently owned and managed entities, such as transport companies, traders, marketers, and blenders that specialize in particular supply chain functions.

76. This large number of participants makes the production, supply, and marketing of gasoline to the retail consumer an intensely competitive business. This was acknowledged by Plaintiff's expert Mr. Reynolds in one of his depositions.[78] Each industry participant seeks to find and capitalize on some competitive advantage not enjoyed by others. Suppliers may compete on the basis of price, quality, and service to win over customers. In such an environment, suppliers often enter or exit individual marketing regions based on local conditions and/or their ability to remain competitive. Thus, the participants supplying a given region and the relationships between participants are not static, but change over time based on economics and corporate strategy. As companies seek to achieve a competitive advantage, it is not uncommon to find that a specific geographic area has changed significantly over a period of years in terms of its primary gasoline manufacturers, wholesale distributors, and retailers. This often leads to major changes in the competitive environment within which the various supply chain participants supply, distribute, and market gasoline. This continually changing

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[78] Reynolds Deposition, Suffolk Case, November 9, 2007, p. 70, lines 12-19.

environment makes it extremely difficult to accurately identify which business entities may have been supplying gasoline to specific locations during specific time periods.

Refiners and Other Gasoline Producers/Suppliers

77. The gasoline supply chain begins with gasoline production at either a domestic or foreign refinery, from a gasoline blender that produces gasoline from blendstocks, or from traders that either import gasoline into the U.S., or trade domestically. Gasoline blenders purchase gasoline blendstocks from domestic or foreign sources and blend finished products. These blenders have many potential sources of blending components, including refining companies (usually foreign), oil trading companies, and other blenders or marketers. Some independent terminal companies also blend gasoline.

78. Oil trading companies buy, sell, trade, or import gasoline and gasoline blendstocks domestically or internationally, based on product price differences between various geographical regions. Profiting from such differences is known as "arbitrage." Generally, trading companies carry out their transactions in the so-called "spot" market, buying and selling cargoes of gasoline, gasoline blendstocks, and other products on an opportunistic basis. The spot price is a single cargo price for any day at a particular location. Spot prices are reported by independent price reporting services and reflect the averages of individual transactions on a particular day. Examples of international trading companies that buy, sell, and trade gasoline and gasoline blendstocks include Vitol Group, Glencore, Ltd., and Trafigura AG.

Gasoline Transportation

79. Most large refineries have only limited storage capacity for refined products because of their ability to move products quickly into pipelines, to terminals, or onto marine tankers. Gasoline storage capacity at U.S. refineries is estimated to be only 53 million barrels

(Bbls.), or about 6 days of supply.[79] For markets located in relative proximity to refineries, gasoline is sometimes delivered directly by tanker trucks from the refinery loading racks to the retail service stations. More often, however, products must first be transported to regional terminal facilities by pipelines, marine vessels, or railcars prior to final distribution to the consumer by truck.

Product Pipelines and Gasoline Fungibility

80. Both refiners and independent operators own product pipelines.[80] Some pipelines are jointly owned by several suppliers, but others have single owners and operate on a proprietary basis. Most of the larger pipelines are "common carrier" lines, meaning that they establish and publish tariffs from one location to another, and any qualifying shipper can move product between those locations simply by paying the published tariff. This is not unlike the "toll road" concept.[81] One of the largest companies providing product pipeline transportation services to the U.S. West Coast and the Southwest is Kinder Morgan Energy Partners (KMEP). Through its Pacific Operations unit, KMEP owns and operates the Santa Fe Pacific Pipeline (SFPP), as well as the CALNEV Pipeline system, both of which are shown in Exhibit J. These pipelines deliver finished products, including gasoline, from imported sources or from refineries located in the Bay Area; Bakersfield, California; or southern California, to markets in California, Arizona, and Nevada.

81. The efficient movement of petroleum products, including gasoline, through pipeline distribution systems relies on the fact that products of the same grade and specification, whatever their source, can often be treated as "fungible." Fungibility, as used in the context of petroleum

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[79] "2010 Market Facts," *National Petroleum News*, October 2010, p. 65.

[80] *Oil & Gas Journal,* November 1, 2010, pp. 117-120.

[81] Shippers on common carrier pipelines must pay the "toll" for the distance the product is transported, as well as meet all other tariff requirements, including minimum volume and quality specifications.

pipeline transportation, means that two petroleum products of the same grade and specification may be mixed or substituted, one for the other, to satisfy an obligation. For example, gasolines having the same octane rating and vapor pressure can often be mixed or substituted, even if they are produced from different sources. In such mixtures or substitutions, the "shipper" (i.e., the owner of record) does not receive the chemically identical gasoline molecules that were delivered into the pipeline. Gasoline fungibility permits the use of common storage at pipeline terminals, thus reducing storage tank requirements.

82. Fungibility does not mean that all gasolines are necessarily mixed together or "commingled" throughout the entire gasoline supply chain. Fungible gasolines are only those that meet the same specification and grade. For example, RFG gasoline cannot be mixed with non-RFG conventional gasoline and still be sold as RFG gasoline. Also, gasolines of different octanes and RVP specifications cannot be commingled. Because there are so many different gasoline grades and specifications, commingling of gasolines tends to occur less than is often believed. Higher grade gasolines (e.g., RFG) can be substituted for lower grades (e.g., non-RFG conventional), all else being equal, but such mixtures can only be supplied against the specifications for the lower grade and sold as the lower grade. Thus, the terms fungibility and ability to commingle should not be considered synonymous.

83. The potential substitutability of two gasolines for pipeline transportation purposes does not mean the gasolines are identical, either in their molecular make-up or in their "bulk" properties. It simply means that the two products both meet the pipeline's specifications for products of that particular grade and commercial functionality. For example, the relative quantities of different blendstocks included in two fungible conventional gasolines might differ substantially. Fungibility ceases to exist after a gasoline has been injected with an individual oil

company's gasoline additive "package" (see discussion under Retail Operations regarding additive packages).

84. Ethanol-blended and MTBE-blended gasolines are non-fungible products. This is because: (a) federal RFG regulations prohibit the blending of ethanol-based RFG with MTBE-based RFG during most times of the year;[82] and (b) since 1986, the EPA has only allowed the blending of ethanol with conventional gasoline if the latter contains no more than 2 Vol.% MTBE and the MTBE was not intentionally added.[83] The conventional gasoline ruling was initiated following reported difficulties that many ethanol blenders had encountered in securing MTBE-free gasoline for ethanol blending.[84] Many refiners had increased their MTBE usage to replace the octane lost from the lead phase down, and MTBE was often found in small concentrations in gasolines to which it had not been intentionally added. This non-fungibility of ethanol and MTBE blends was an important factor in many suppliers deciding against offering ethanol-blended gasolines.

85. Despite the fungibility of gasoline meeting the same specification, the title holder of each and every parcel of gasoline bought or sold along the distribution system is always known at any point in time. Common carrier pipelines provide solely a transportation service and do not take title to gasoline. The "owner of record" for each product parcel in the pipeline can be traced through contractual agreements between the various supply chain participants.

86. As noted earlier, California and federal gasoline regulations have led to a proliferation of distinctly different gasoline grades that must be kept segregated along the supply

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[82] See 40 CFR §80.78(a)(8). The combination of ethanol-based RFG and MTBE-based RFG is prohibited from January 1 through September 15.

[83] Richard D. Wilson, Director, Office of Mobile Sources, U.S. EPA, Letter to Marilyn Herman, President, Herman and Associates, December 18, 1986.

[84] Reynolds Deposition, Suffolk Case, November 9, 2007, p. 51, lines 13-19.

chain. As the number of grades increases, the capacity of a pipeline is reduced and more storage is required.[85] An EIA study into the impact of RFG on the domestic transportation system made this clear when it noted that, "*A number of pipelines will move product more slowly through their systems, thereby diminishing their capacities as a result of the increased segregation requirements coupled with the increased number of products that must be segregated.*"[86] Because of the limitations it places on system capacity, the SFPP and CALNEV pipelines do not permit shippers to transport batches on a fully segregated basis and the pipelines retain the right to commingle products of the same grade and specification.

87. A refiner/shipper on a common carrier pipeline must nominate a minimum shipping volume at some selected time. As an example, the minimum shipping volume on the SFPP system is 5,000 Bbls. for most destinations and 10,000 Bbls. for Phoenix-bound shipments. After all volumes have been nominated for a given period, the pipeline then schedules the nominations to operate most efficiently. Each product transported must meet the pipeline's specifications for the grade being shipped.

88. Shipments on common carrier pipelines like the SFPP system are referred to as "batches." A batch is a distinct volumetric parcel of a particular product—or grade of product—that is pumped through the pipeline from an origin point to a predetermined destination point. Individual batches are moved through the pipeline in sequence and discharged into a storage tank at the delivery location. Exhibit K provides an illustration of how individual product batches move through a pipeline system. Some limited mixing occurs between adjacent batches on such

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[85] As noted earlier, one advantage MTBE enjoyed over ethanol was that MTBE-based CaRFG could be transported by pipeline, but ethanol-based CaRFG could not. Introduction of ethanol into the gasoline distribution system increases the number of gasoline grades that need to be handled because ethanol blending requires a special low RVP base gasoline (CARBOB).

[86] *The Energy Information Administration's Assessment of Reformulated Gasoline*, EIA, October 1994, p. 43.

pipelines. The extent of this mixing is dependent on a number of factors, including the physical characteristics of the two products, the total time that the two products are in contact, and the throughput rate of the pipeline. Depending on its composition, the mixed material (called "interface" or "transmix") is either downgraded to a product of lesser value, or reprocessed to separate the mixed products. In either case, the creation of interface or transmix represents an additional cost of operating the pipeline system, either through a quality downgrade or additional operating expenses. These costs are shared by the pipeline shippers (the owners of the batches) and, like other transportation costs, are ultimately passed on to the consumer as part of the product price. The more grades a pipeline transports, the more interface will be created, and the more such costs will be incurred. Proper handling and disposition of interface and transmix by pipelines is essential in maintaining the specification integrity of products, especially the state-mandated CaRFG gasolines. The same handling principles apply to products placed in storage tanks or transported by railcars, marine vessels, barges, or tank trucks.

Marine Vessels, Barges, and Railcars

89. Although product pipelines represent the lowest cost method of product movement, they are also the least flexible in reaching specific customers at specific times. Tanker trucks are the most expensive, but they also provide the most flexibility in when and where they can deliver products. In areas of the country like California, which are accessible by water, purpose-built ships or barges frequently offer another low-cost option for the efficient delivery of petroleum products. Railcars are occasionally used for remote inland locations, but only when economically warranted based on the volumes required.

90. Marine cargoes of product destined for California typically involve three separate trade routes: (1) Pacific Northwest to southern California; (2) imports from Asian or other

foreign refineries; and (3) USGC to California. From 1995 to 2003, such marine movements into California, which comprised primarily gasoline blending components, are estimated to have averaged approximately 38,000 barrels per day (B/D) from the Pacific Northwest, 16,800 B/D from foreign imports (excluding MTBE), and 7,750 B/D from the USGC.[87, 88, 89] Together, however, they comprised less than 6% of total California gasoline demand during that period.

91. Petroleum barges, with capacities of as much as 20,000 Bbls., deliver products on relatively short port-to-port trips and to terminals that are too small to accept larger oceangoing vessels. Smaller barges transport products along inland waterways such as San Francisco Bay to both terminals and refineries that have barge access.

92. Railcars typically have a capacity of about 500 to 700 Bbls. of product. Most are used for specialty products that cannot be shipped in pipelines, such as asphalt and lubricants. I am not aware of any routine intrastate rail shipments of gasoline in California. However, as will be explained in more detail later in this Report, most of the ethanol currently used in gasoline in California is delivered by rail from sources outside the state.

Tanker Trucks and Retail Deliveries

93. Tanker trucks are used to deliver petroleum products from terminals to retail and commercial customer sites. Trucks can be owned by refiners, distributors, retail customers, or independent transportation companies. Trucks, which typically hold approximately 7,500 Gals. (about 180 Bbls.) of product, are usually only economic for gasoline deliveries within no more than a 100-mile radius from the refinery or terminal pickup point. Truck drivers typically pump gasoline from their trucks into underground storage tanks at retail service station sites.

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[87] *Petroleum Supply Annuals,* EIA, 1995-2003, Table 34.

[88] *Company Level Imports*, EIA, 1995-2003. Imports of MTBE comprised approximately 46,600 B/D.

[89] *California Strategic Fuel Reserve,* California Energy Commission, March 2002, p. 11, and Baker & O'Brien estimates.

94. Each refiner/supplier faces a unique set of circumstances with respect to its location, the supply infrastructure available, and the region being served, among other factors. Each attempts to optimize the modes of transportation employed to meet individual requirements. Different refiners serving the same region may often use different modes of transportation to deliver products to the end user, and will, therefore, incur different costs.

Terminal, Blending, and Wholesale Operations

95. Terminals that store gasoline can be connected to a pipeline or a waterway system, or both. Multiple tanks are used to segregate gasolines and other petroleum products in order to maintain the specification integrity of products. Many terminals also have special tanks for additives, such as detergents, and blending components, such as ethanol or butanes. Proprietary additive packages and other additional brand characteristics are added at the terminal.

96. Terminals can be owned by refiners, pipeline owners, independent operators, blenders, importers, or joint ventures between such supply chain participants. Transactions at terminals are in larger volumes than at retail sites and are termed "wholesale" sales. Gasoline retains its fungible character in the terminal storage tanks until an additive package, specific to the retailing entity, has been blended into a given volume, at which point the gasoline is considered to be "branded."[90]

97. Large volume gasoline consumers (e.g., government agencies, overnight courier firms, bus companies, rental car companies, taxi fleets, etc.) often own their own storage and dispensing facilities. These firms may purchase gasoline from distributors or other marketers under long-term contracts or on a one-time basis. Agreements between such companies and their upstream suppliers permit establishment of gasoline ownership at different distribution points.

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[90] A more detailed discussion of the distinction between branded vs. unbranded gasoline occurs later in this Report.

98. A "jobber" is an independent wholesale gasoline distributor who can also own, operate, or lease retail stations. Some jobbers purchase and market gasoline exclusively under one company's brand, while others purchase gasoline from multiple suppliers. Jobbers provide transportation services and also take title to gasoline before it is distributed to retail stations.

99. A "rack" marketer is an entity that sells truckload quantities of gasoline (about 180 Bbls.) or other petroleum products at terminal loading racks, either to jobbers or directly to retail stations. The terminal rack is the point where gasoline is blended with additives and ethanol before being loaded into a tank truck. Rack marketers can include oil companies, traders, blenders, and other independent gasoline resellers that own or purchase their gasoline supplies in "bulk" (i.e., typically >1,000 Bbls.) and sell it in smaller truckload quantities. Over a period of years, it is not uncommon for rack marketers to enter or exit the market at different terminals.

100. Gasoline traders buy, sell, and/or arrange for transport of gasoline and gasoline blendstocks, both domestically and internationally. It is also quite common for trading companies to act as gasoline blenders (see below) on an opportunistic basis. Traders usually deal in so-called "cargo-sized" volumes (i.e., typically >50,000 Bbls.) and operate mostly at the large terminal distribution level of the supply chain. They can, however, also serve as rack marketers selling to jobbers and other resellers.

101. Gasoline blenders purchase gasoline blending components and combine them together to make gasoline, including RFG. Blending components are often purchased from foreign refiners, oxygenate manufacturers, and/or gasoline traders. Blenders may act as rack marketers, or they may sell into pipelines or marine vessels for delivery to terminals.

102. Refineries in California move cargo-sized quantities of gasoline into proprietary or common-carrier pipelines or marine vessels for delivery to large distribution terminals. These

terminals are owned by both oil refining companies and independent terminal operators who can provide product handling and storage on a fee-for-service basis. Gasoline is typically accumulated at these larger terminals before being transferred to smaller terminals that service local markets. However, some rack marketers also sell gasoline directly to jobbers for tank truck transport to retail outlets in reasonable proximity to the larger terminals. Most refineries also sell tank truck quantities of gasoline at refinery truck rack facilities.

103. A wide range of commercial entities own the products that are stored at terminals. These include, for example, oil refiners and marketers, jobbers, traders, blenders, rack marketers, or product importers. Independent terminal operators do not take title to products unless they serve as rack marketers. Individual tanks are sometimes leased to companies that regularly store large volumes. Even though the base gasoline for a particular grade is often stored in "community" storage[91] with other gasolines of the same grade, the ownership interest in such gasoline is always well defined.

Retail Operations

104. The retail outlet is the final point of gasoline purchase for a consumer. From a marketing standpoint, the finished gasoline[92] that is sold to consumers can be broadly categorized as either "branded" or "unbranded." Branded gasoline is finished gasoline that is either: (a) sold directly by the branding company to commercial customers or through retail outlets; or (b) sold first to a jobber who then resells the product to a branded customer or branded retail outlet. When gasoline is sold under a branded name, it typically means that there is a contract between

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[91] Community storage is storage in which multiple suppliers' product may be commingled as long as it is of the same grade and specification.

[92] For purposes of this Report, finished gasoline refers only to gasoline that meets all the quality specifications for the location where it is intended to be marketed, and which has also been injected with at least the minimum quantity of government-mandated deposit control additive.

the refiner, supplier, or jobber and the retail outlet owner, obligating the owner to: (a) purchase product from that refiner, supplier, or jobber; and (b) sell product using the refiner or supplier's logo (brand) identification. If gasoline is sold under a brand name, such as ABC Oil, it does not mean that ABC Oil necessarily owns or operates the retail outlet displaying the brand. In fact, in today's retail marketplace, only a relatively small number of retail outlets are actually owned and operated by the branding company.

105. In comparison to the branded product, unbranded gasoline is a generic form of finished gasoline that is not typically marketed under any widely-recognized brand name. Unbranded retail outlets may often display their own unique signage, such as "John's Gas." Most unbranded marketers can, and do, purchase product from a number of different sources. Like the branded jobber, the unbranded jobber is simply an independent wholesale gasoline distributor. The unbranded jobber may: (1) own and operate service stations outright; (2) lease stations to dealers who operate them on the jobber's behalf; (3) deliver gasoline to retailers under some supply arrangement; and (4) purchase and resell gasoline from any unbranded supply source. Some unbranded jobbers supply only a few retail outlets, while larger ones can often supply hundreds of different locations.

106. A number of large, independent, non-refining retail marketing companies purchase gasoline and market it under their own identifiable brand (e.g., 7-Eleven, Circle K, or Costco). Some of these companies buy products on the domestic wholesale market from refiners or gasoline blenders, while others import product. While some of these companies may market exclusively under their own brand, it is not unusual to find them also marketing under another company's brand in some locations.

107. Refiners that manufacture, distribute, and market gasoline under their own brand (or allow others to do so) add proprietary additives that distinguish their product from the competition and impart qualities such as detergency and oxidation stability. Branded gasoline is usually contractually required to contain the branded company's unique additive "package." Additive packages are blended at terminals immediately prior to retail delivery.

108. As noted previously, starting in January 1992, as part of the CaRFG1 regulations, CARB began requiring that all gasoline, branded or unbranded, contain chemical additives to provide detergency and oxidation stability. If a branded additive package is not designated, the distribution terminals will add a "generic" additive package. Thus, beginning in California in 1992, gasoline has not been considered a "finished" product until it includes an additive package as required by law.

Regulation of Gasoline Supply and Distribution

109. The supply and distribution of gasoline is a highly regulated activity. In addition to many industry standard practices that have developed over the years based on operating experience, there are numerous regulations and laws controlling the handling of gasoline throughout the supply chain. Many are embodied in either the CFR or the California Health & Safety Code covering the handling of hydrocarbon materials. These laws and regulations are intended to safeguard the public during normal operations, prevent mishandling during use, and minimize the impact on the environment. Some of the federal regulations that cover gasoline handling are:

- Hazardous Material (Hazmat) Regulations (49 CFR 100-185) - covers shipment and handling of gasolines; Hazmat communications and training; oil spill prevention and response plans; and labeling and packaging requirements.
- Transportation of Hazardous Materials (49 CFR 386, 397).

- Fire Protection (29 CFR 1910.155-165) - fire detection, alarm, and extinguishment systems.
- Process Safety Management (29 CFR 1910.119).
- National Emission Standards for Hazardous Air Pollutants (40 CFR, Sub C, Part 61) - fugitive emission monitoring requirements for gasoline equipment.
- Chemical Accident Prevention (40 CFR, Sub C, Part 68).
- Oil Pollution Prevention (40 CFR, Sub D, Part 110, 112).
- Underground Storage Tanks (40 CFR, Sub I, Part 280-282) - establishes standards and corrective action required for leaking underground storage tanks, mandatory overspill prevention, and corrosion protection requirements.
- Gasoline Loading Rack systems (40 CFR 60.502 and 40 CFR 63.422).
- Solid Waste Regulations (40 CFR, Sub I, Part 260-266) - covers cleanup, handling, and monitoring of contaminated soil cleanup.
- Emergency Planning and Notification (40 CFR, Sub J, Part 355).
- Hazardous Chemical Reporting: Community Right-to-Know (40 CFR, Sub J, Part 370 and 372).
- Toxic Substances Control Act (40 CFR, Sub R, Part 370) - health and safety reporting and record keeping requirements and inventory reporting.

110. The state of California has promulgated a number of regulations that impose additional requirements beyond those covered under the federal rules listed above. Some of these California regulations include, but are not limited to:

- Underground Storage of Hazardous Substances Act (the "Tank Act"); California Health and Safety Code §25280 to 25299.8.
- Above-Ground Petroleum Storage Act; California Health and Safety Code §25270 to 25270.13.
- California Hazardous Waste Control Act, California Health & Safety Code § 25100 to 25250.
- California Solid Waste Management and Resource Recovery Act, California Government Code § 66700, *et seq.*

California administers the above regulations through a system of 83 separate Certified Unified Program Agencies (CUPAs) that cover the entire state. The California Environmental Protection Agency (Cal EPA) is responsible for CUPA oversight.

VI. FACTORS IMPACTING THE MTBE VS. ETHANOL DECISION

Overview of Major Issues

111. Although ethanol was first used as a fuel for internal combustion engines as early as 1908, significant usage in the U.S. did not begin until the late 1970s, following the gasoline supply disruption caused by the 1973 Arab Oil Embargo.[93] During the 1980s, after the oil price "shock" that followed the Iranian Revolution, and in response to the phase down of lead in gasoline, ethanol was used more extensively as both a gasoline "extender" and as an octane enhancer. Beginning in the 1990s, ethanol started to be used in some states to satisfy the gasoline compositional requirements of the OFP and RFG programs. For example, in several states of the Midwest, some refiners used ethanol extensively to meet federal oxygenate requirements.

112. The OFP and RFG programs significantly increased the demand for oxygenates because of the requirement that these gasolines contain specified concentrations of oxygen. Although refiners differed in their response to these government mandates, most of the oxygenate demand on the East and West Coasts was satisfied by MTBE for numerous reasons, including supply, logistics, economic, and competitive factors. Unlike ethanol, MTBE was relatively easy to produce on a nationwide basis, was readily available from a number of sources,

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[93] *Fuel Ethanol and Agriculture: An Economic Assessment,* U.S. Department of Agriculture, Report No. AER-562, August 1986, pp. 1- 4.

including refiners themselves, and could be blended directly at the refinery and (once blended into gasoline) transported over pipelines. By comparison, ethanol production was limited to the farm states in the Midwest. Ethanol was produced almost entirely from corn, could not be blended directly into finished gasoline at the refinery and transported by pipelines, and made the refiners that used it dependent on third-party suppliers from an entirely different industry.[94] Because the ethanol industry dealt in much smaller volumes than the petroleum industry, refiners that chose to use ethanol often had to contract with multiple producers to obtain their requisite volumes. Finally, the segregated transportation, storage, and blending infrastructure was not in place to support the increased production that would have been needed to meet any significant new ethanol demand. These factors, as well as others discussed later in this Report, tended to limit ethanol usage to those geographic areas where it was readily available, i.e., mostly the U.S. Midwest.

113. There were some efforts by gasoline suppliers to manufacture and/or market ethanol-blended gasolines to retail customers in areas outside of the Midwest, but many problems arose for such suppliers. After the federal RFG regulations became effective in January 1995, followed by CaRFG2 regulations in March 1996, there was very limited availability of the special RBOB, and later CARBOB, base gasoline required to meet the CaRFG specifications. During the early years of the RFG program, RBOB for ethanol blending could be produced by some refineries in limited volumes, but it generally proved uneconomic to do so outside of the Midwest, where ethanol was widely used. "Summertime" RBOB, which demanded very low vapor pressure, was particularly hard and expensive to make, especially in

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[94] Although refiners routinely buy and sell feedstocks and/or by-products to/from other industries (e.g., the petrochemical industry), most refiners, in the early 1990s, had few business dealings with the ethanol industry and they were unfamiliar with agribusiness in general.

small volumes. Thus, California refiners generally did not produce any of this CARBOB during the summer months until the 2003 mandated transition from MTBE to ethanol in CaRFG3.

114. In the Reynolds Fresno Report, Mr. Reynolds states that, "*Ethanol and MTBE have similar, but not identical, blending properties.*"[95] I disagree with Mr. Reynolds. There are very significant differences in the blending properties between ethanol and MTBE, as well as important other differences in their physical properties. These differences resulted in the types of problems discussed above, and caused most refiners to select MTBE over ethanol in many markets. The remainder of this section of this Report discusses the many physical, economic, and market differentiators between MTBE and ethanol, and how they resulted in significant barriers and risks that precluded the widespread adoption of ethanol by many refiners as a source of oxygenate to meet the requirements of the OFP and RFG programs in the 1990s.

Barriers and Risks Associated with Ethanol Blending for RFG

115. In the early 1990s, there were a number of significant barriers and risks associated with the choice of ethanol as an oxygenate for blending RFG. They included, but were not limited to: (1) ethanol supply and availability; (2) ethanol distribution and blending problems; (3) poor manufacturing economics; (4) supply reliability and quality issues; (5) consumer acceptance issues; and (6) limited availability of alternative oxygenates. Each of these six factors is discussed in the subsections that follow.

116. In addition to all of the above, it was well understood by most analysts at the time that the widespread adoption of ethanol blending, compared with the alternative of MTBE, would have a significant negative impact on the nation's overall gasoline supply—at a time when rising gasoline prices were of increasing concern. The ultimate costs of the RFG and OFP

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[95] Reynolds Fresno Report, Section 6.0, Paragraph 6, p. 19.

programs themselves were uncertain at best, and anything that reduced supply and overlaid additional costs raised politically charged issues. The use of ethanol negatively impacted on gasoline supply because: (i) for the same oxygen content, almost twice the volume of MTBE compared to ethanol was needed (the choice of MTBE also helped refiners meet environmental standards through the dilution effect); (ii) ethanol caused a significant "back out" of other light gasoline components (discussed in more detail below); and (iii) ethanol provides approximately 30% less energy content (and gasoline mileage) than an equivalent volume of hydrocarbon gasoline and approximately 20% less than an equivalent volume of MTBE. This issue of reduced gasoline supply is addressed at the end of this section.

(1) Limited Domestic Ethanol Supply and Import Limitations

117. In order to minimize grain transportation costs, and to take advantage of attractive state excise taxes and other subsidies, ethanol production plants have always tended to be located primarily in corn producing states—far removed from the East and West Coasts where the primary RFG and oxygenated fuel demand existed under the 1990 CAAA. It made no economic sense to transport grain from the Midwest to California for the purpose of converting it into ethanol within California. Each bushel of grain typically produces only approximately 2.8 gallons of ethanol. Therefore, from a sheer volume perspective, it was much more expensive to transport grain than ethanol.[96] Thus, if ethanol was to be used in California, it had to first be manufactured in the Midwest, and then transported, usually in railcars, to the locations of primary demand. This long distance rail transportation raises the finished gasoline cost. Exhibit L shows where U.S. ethanol plants were located in 2000.

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[96] Also, solids (i.e., grains) are more expensive to handle than liquids, which can easily be pumped into and out of storage vessels.

118. Exhibit M shows the relative size and locations of ethanol plants in operation in 1990 and compares them to the relative size and locations of gasoline oxygenate demand which was projected, at the time, for 1995. Ethanol plant capacity is expressed in terms of MTBE volume equivalents based on oxygen content. One barrel of ethanol has the oxygenate equivalency of 1.92 Bbls. of MTBE. Thus, ethanol production and oxygenate demand are compared on an MTBE "oxygen equivalent" basis. Exhibit M shows that in 1990, as noted earlier, ethanol capacity was concentrated in the Midwest (red circles on the map), but the bulk of the oxygenate demand (green squares sized in proportion to annualized demand) was concentrated in the Northeast, California, and some smaller widely scattered regions.

119. Exhibit N lists the estimated capacities of the 39 domestic ethanol plants operating in 1990. The total 1990 ethanol production capacity (in MTBE equivalents) was approximately 165,000 B/D. Although projections varied at the time, the 1995 demand for oxygenate, in MTBE equivalents, was generally expected to be in the range of 360-400,000 B/D.[97] This was well over twice the installed ethanol capacity in 1990, even assuming that every plant operated at 100% of its rated capacity every day of the year. Thus, in the early 1990s, if every U.S. refiner had chosen ethanol to satisfy its projected oxygenate demand (as the Reynolds Fresno Report alleges was feasible[98]), not only would ethanol capacity have had to more than double, but a massive redistribution of ethanol supplies from the Midwest to the East and West Coasts would have been required.

120. Mr. Reynolds acknowledges in one of his depositions that throughout the entire time period 1995-2003, available ethanol capacity was insufficient to meet the requirements of

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[97] This includes estimated demand for both the RFG and OFP programs.
[98] Reynolds Fresno Report, Section 6.0, Paragraph 5, pp. 18-19.

the U.S. RFG and OFP programs.[99] However, he asserts that the shortfall could have been made up by additional imports and/or additional capacity increases. I disagree on both counts. I address the matter of ethanol imports later in this section and explain how Mr. Reynolds' assumptions cannot be supported. With respect to ethanol capacity increases, in one of his depositions, Mr. Reynolds states that, in a 24-month period, the ethanol industry could have added, "*...probably somewhere around 600 million* [gallons per year] *in grass roots production.*"[100] This is equal to an MTBE equivalent capacity of approximately 75,000 B/D, which, even if it could have been achieved, would have still left total ethanol capacity more than 120,000 B/D short of the RFG and OFP estimated 1995 requirements. Mr. Reynolds' capacity increase assumption is based on the construction of ten new plants, each having a capacity in the range of 50-75 million gallons per year (MMGal./Yr.). To put Mr. Reynolds' assumption in perspective, in 1990, only 7 of the existing 39 ethanol plants were larger than 50 MMGal./Yr. Of those seven, four were large "wet mill" (refer to earlier discussion) processing facilities owned by ADM. The capacity of the four ADM plants constituted almost 80% of the total capacity of the seven largest. In my opinion, it would have been impossible in the early 1990s to radically alter the whole structure of the ethanol industry in the time frame Mr. Reynolds assumes. In particular, it is highly unlikely that ten new ethanol plants, of the size suggested by Mr. Reynolds, could have been permitted, designed, financed, engineered, and constructed in such a relatively short 24-month period. In an earlier deposition when asked about this timing, Mr. Reynolds contradicted his later testimony above, when he stated, "*If you are a grass roots operation,...for those people if they don't have their financing yet, they have to deal with their equity, their financial plan, and their permitting, in those cases you are looking at up to three*

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[99] Reynolds Deposition, Suffolk Case, August 2, 2007, p. 217, lines 13-20.
[100] Ibid., p. 260, lines 17-24.

years, probably."[101]

121. Even if it was somehow possible to install sufficient ethanol production capacity in time to fully meet the new RFG regulations (which I do not accept), the infrastructure needed to manufacture the special base gasoline, as well as to distribute and blend the required ethanol volumes, was not in place. Unless the ethanol transportation, blending, and distribution infrastructure could have been concurrently developed during the same short time frame (which I also do not accept), the additional ethanol production would not have been able to be fully utilized.

122. Mr. Reynolds believes that if refiners had simply entered into contracts with ethanol producers to purchase their product, "*..similar to those that it gave the MTBE industry...*" that the ethanol industry would have expanded to meet the new demand.[102] In one of his depositions, he explains that such contracts could have taken the form of a processing arrangement that "*guarantees you a profit*"[103] or an alternative approach that indexed the ethanol price to the prevailing price of gasoline. In my view, few, if any, refiners would have been interested in entering into contracts that guaranteed the ethanol producers a profit, while the refiner bore all the economic risks associated with variations in corn costs, energy prices, by-product prices, etc. With respect to indexing of ethanol prices to gasoline, Mr. Reynolds explained in his deposition that typically one would have a contract in which 15 cents/Gal. (¢/Gal.) was subtracted from the prevailing gasoline price, plus subsidy, to establish the ethanol contract price.[104] Later in this Report I show that such a formula would have led to significant economic losses for ethanol

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[101] Reynolds Deposition, *Fruitridge Vista Water Company v. Atlantic Richfield Company, et al*, March 15, 2006, p. 88, lines 15 to 21.

[102] Reynolds Fresno Report, Section 6.0, Paragraph 5, pp. 18-19.

[103] Reynolds Deposition, Suffolk Case, August 2, 2007, p. 300, lines 13-16.

[104] Reynolds Deposition, Suffolk Case, August 3, 2007, p. 328, line 8, to p. 329, line 9.

producers throughout most of the 1990s, and would likely have led to plant shutdowns.

123. As Exhibit O shows, the four ADM facilities, located in Illinois and Iowa, along with other wet mill facilities, accounted for approximately 70% of all 1990 ethanol production.[105] As shown in Exhibit N, more than one-half of the 39 ethanol plants were relatively small, having a capacity of less than 1,000 B/D of MTBE equivalent (only about 8 MMGal./Yr. of ethanol). Also, most were also located in rural areas, and only two small plants (each having less than 400 B/D MTBE equivalent capacity, or about 3 MMGal./Yr. of ethanol) were located in California. There were several reasons for this. First, such facilities were often built to stimulate economic activity in these rural, relatively underdeveloped regions. Second, because many ethanol plant owners were a so-called "mom and pop" operation, capital was limited and they relied on government guaranteed loans for the construction of small, low investment facilities with limited capital exposure. Third, government loans and state tax subsidies often had a "cap" on the qualifying plant size, thus encouraging the construction of smaller, inefficient plants. Finally, many ethanol producers could not economically gather the quantities of corn needed to support a large production plant. An ethanol plant designed to produce a relatively modest 30 MMGal./Yr. of ethanol must gather and process approximately 12 million bushels of corn per year, which requires approximately 80,000 acres (125 square miles) of cropland—an area encompassing more than the entire City of Fresno.[106] More than 20 plants of this capacity (requiring more than 2,500 square miles of cropland—over twice the size of the state of Rhode Island) would have been necessary to provide the ethanol needed to oxygenate only the gasoline sold in southern California to comply with the 1995 federal RFG regulations.

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[105] *Analysis of the Economic and Environmental Effects of Ethanol as an Alternative Fuel*, EPA, April 1990, Executive Summary, Paragraph 3, p. i.

[106] *The Structure and Outlook for the U.S. Biofuels Industry*, Report by Informa Economics for the Indiana State Department of Agriculture, October 2005, pp. 15-16.

124. There were also political concerns in the early 1990s as to what the effect might be on the price of corn due to the large scale conversion of corn into ethanol unless the production of corn was increased substantially.[107] Such factors raised unacceptable risks for many refiners considering the use of ethanol as an oxygenate to satisfy future gasoline regulations. If a refiner contracted on a long-term basis to purchase ethanol from a supplier who went out of business, or could not economically acquire sufficient corn feedstock, or who suffered from a crop reduction due to severe weather, or could not operate reliably—then the refiner was essentially "out of business" with respect to RFG or OFP gasoline production. The possibility of an unreliable ethanol supply was a risk that most gasoline producers were not prepared to accept.

125. During the late 1980s and early 1990s, the period when refiners were making decisions regarding oxygenate usage, the perceived risks associated with investment in ethanol production facilities were very high—much higher, for example, than in the mid-2000s, after the implementation of the ethanol mandate and the restrictions on the use of MTBE in many states. During this critical time period, it was still not known what role ethanol would ultimately play in gasoline blending, and it is unreasonable to expect that refiners would have accepted such risks. In a free market economy, investment capital flows to the most attractive investments, not to the most risky. Refiners would have been understandably reluctant to enter into supply contracts with unknown participants in a potentially volatile industry whose economics depended largely on the availability and price of corn feedstock and the continuation of government subsidies.

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[107] To the best of my knowledge, the Plaintiff has not presented any evidence that in the early 1990s it would have been possible for corn production to increase sufficiently fast to meet the 1990 CAAA oxygenate demands. Also, since the introduction of the federal RFS programs that mandate the use of minimum volumes of renewable fuels in gasoline, the price of corn has increased from an average of $2.00 per bushel to $6.50 per bushel at the time of this writing.

126. As a business matter, the question is not whether it may have been theoretically possible to overcome all of the above-mentioned barriers to ethanol blending. Instead, the question is whether a reasonable refiner, in selecting between two federally approved oxygenates to comply with federal law, would have chosen, in a competitive market environment, to accept the higher risks. Where those risks were more limited or could be mitigated, such as in the Midwest, many refiners did select ethanol. However, in California, where the risks posed were more substantial, it was reasonable for a refiner in a competitive market environment to select MTBE as its oxygenate. A refiner would also reasonably expect its competitors to do likewise. This is important because refiners often obtain "exchange" gasoline with other refiners to meet market demands under certain situations, and, as noted earlier, MTBE-blended gasoline is not fungible with ethanol-blended gasoline. Thus, a refiner would want to sell the same type of gasoline that most of the rest of the market was selling in order to be able to obtain supplies from others if needed. Additionally, it would not want to accept greater costs or risks than its market competitors. In one of his depositions, Mr. Reynolds acknowledged these facts when he explained, "*…if there's ten companies in the area and six of them go with MTBE instead of ethanol, the other four are probably going to do the same thing.*"[108] And later, "*It's really kind of an almost all-or-none.*"[109]

127. Exhibit P shows the location and relative size of MTBE plants in operation (red circles) and under construction (blue circles) in 1990, immediately following passage of the CAAA that required oxygenates to be included in RFG by 1995. As of 1990, over 20 plants had already been built and were in operation, and many were located at and integrated with

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[108] Reynolds Deposition, Suffolk Case, August 2, 2007, p. 181, lines 7-9.
[109] Ibid., p. 181, lines 13-14.

refineries. Exhibit P also shows where oxygenated fuel demand was expected to be concentrated in 1995 (green squares).

128. Although there are product pipelines that run from the USGC to the Midwest, the proximity of ethanol production to the Chicago RFG market, as well as the Minneapolis and Cleveland OFP markets, made ethanol—assuming that federal and state tax subsidies remained in place—a more competitive option for these areas. Under these conditions, many refiners, including some of the Defendants in this case, chose to use ethanol.

129. The planned expansion of MTBE capacity in the early 1990s stood in stark contrast to the ethanol situation. During this period, because of the highly uncertain investment environment discussed above, only a few ethanol plants were being constructed or expanded.[110] However, substantial new MTBE capacity was planned or under development from two sources: (1) refinery-based MTBE plants utilizing feedstock from FCCUs; and (2) "stand-alone" merchant MTBE facilities using purchased butane feedstocks. These two primary sources of MTBE, along with two other production routes, are discussed in Appendix 8.

130. Many of the MTBE plants under construction in the 1990s time frame were being added at refineries. There were a number of important reasons why MTBE production at refineries represented an attractive choice for gasoline oxygenate supply. First, as noted previously, by 1990 MTBE had established itself as an effective gasoline component, had received EPA approval as a gasoline component, and had received good consumer acceptance. Not only was it easy to use and store at the refinery, but it could be blended like any other gasoline component and shipped via normal pipeline delivery systems.

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[110] Domestic ethanol capacity added in 1992, 1993 and 1994, either through construction or expansion, can be determined by reference to the EIA's *Petroleum Supply Annuals* (Tables 49, 51, and 51, respectively).

131. Second, not only was the equipment required to manufacture MTBE at refineries relatively simple to install and operate, but the unit offered synergies with the refinery's "alkylation" unit. Figure A7-1 (in Appendix 7) illustrates how a typical MTBE unit was incorporated into a refinery. MTBE is produced through the chemical reaction of methanol with isobutylene derived from the refinery's FCCU light olefin stream. Alkylation is a process that typically combines a portion of that stream with isobutane to produce another high-octane gasoline component, called "alkylate." Since isobutylene normally comprises 15% of the FCCU light olefin stream, installing an MTBE plant enabled refiners to process 15% more light olefins through the refinery's alkylation unit, which increased gasoline production. An added benefit to refineries with alkylation plants using sulfuric acid as the catalyst, was the removal of isobutylene from the alkylation unit feedstock (and making MTBE instead), which raised the octane rating of the alkylate by two to three numbers. This was of great assistance to refiners that were octane deficient.

132. Third, because of the simplicity of the process, MTBE production at refineries was not very capital intensive. One of the major reasons for this was that isobutylene was already available in the alkylation unit's feedstock stream. It merely had to be separated out and rerouted to the MTBE reactor vessel, chemically reacted with purchased methanol, and the MTBE separated from any unreacted material. This type of processing was very familiar to refiners and something easily integrated into their operations.

133. Finally, if a refinery decided to add an MTBE plant, it could monitor its production cost versus the prevailing market price for MTBE and make a "make or buy" decision with respect to its required RFG production. This gave the refinery additional flexibility in its gasoline blending program. Even prior to 1990, some refiners had recognized the advantages of

producing MTBE within the refinery and had started plans for construction of these "captive" units (i.e., for use solely by the refinery in its own gasoline production). These captive plants also gave refiners more control over the end product that they were selling, as they were less dependent on third-party suppliers for an essential gasoline component.

134. MTBE units, in comparison with many of the process units operated by refiners and chemical manufacturers, are relatively simple and straightforward. The chemical reactions involved are well known and easily catalyzed, the separation process is simple, and there are essentially no by-products to deal with. Also, the capital investment in a captive MTBE process is not large by refining standards. Although new, stand-alone, merchant MTBE facilities required significant capital investment (primarily because they were built with large capacities to capture economies-of-scale), all the process technologies involved were commercially proven and could operate with a high degree of reliability.

135. Mr. Reynolds asserts that if all U.S. refiners had chosen ethanol to meet the 1990 CAAA fuel requirements, much of the potential domestic production shortfall could have been made up through additional foreign imports.[111] According to Mr. Reynolds' theory, global ethanol supplies might simply have been "bid away" from other uses and markets. What Mr. Reynolds seems not to consider is that such "bidding away," even if it was possible, would have raised the price of all ethanol volumes and put ethanol in an even worse economically competitive position than it already was.

136. Mr. Reynolds' theory also appears to ignore the fact that ethanol imports into the U.S. were (and still are) subject to a tariff approximately equal to the federal ethanol tax subsidy, making imports economically prohibitive under most circumstances. During the 1990s, the

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[111] Reynolds Suffolk Report, Section 8.1, pp. 16-18.

ethanol import duty was equal to the tax subsidy of 54¢/Gal. This is compared to the five-year average (1991-1995) retail price for regular gasoline of $1.09/Gal. While the ethanol import duty remains at 54¢/Gal. today, the tax subsidy was gradually reduced from 54¢/Gal. in 2000 to its current rate of 45¢/Gal. in January 2009.

137. Since 1983, limited volumes of ethanol have been able to be imported into the U.S. under the so-called Caribbean Basin Initiative (CBI) program. The CBI allows duty-free imports of certain commodities from various underdeveloped Caribbean nations. Ethanol from CBI countries can be imported duty-free into the U.S. in volumes not to exceed 7% of the prior year's domestic ethanol consumption. However, notwithstanding this incentive, CBI-sourced imports proved not to be a significant source of oxygenate supply in the 1990s. Imports only averaged 3 to 16 MMGal./Yr. (195-1,040 B/D) during the 1990s, or 0.2% to 1.1% of total domestic ethanol consumption.[112] This was primarily because ethanol prices in the U.S., during most of this period, were insufficient to cover the CBI costs of production plus ocean transportation to U.S. shores.

138. Brazil, which is not a CBI member, is the world's largest fuel ethanol producer and also the largest potential source of U.S. imports. However, during the 1990s, Brazil was a net importer of ethanol.[113] This fact provides further evidence that ethanol imports were not a significant potential source of oxygenate supply to meet the CAAA fuel oxygenate requirements in the 1990s. This conclusion is directly at odds with alleged facts presented by Mr. Reynolds.

139. Mr. Reynolds presents a table on page 17 of the Reynolds Suffolk Report that purports to show U.S. "non-beverage" (i.e., fuel-grade) ethanol trade with Brazil for the period 1992-2003. He concludes that, "*...in most years the United States actually exported more*

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[112] *Annual Energy Review*, EIA, 2006, Table 10.3.
[113] Christopher Berg, *World Fuel Ethanol Analysis and Outlook*, April 2004, p. 11.

ethanol to Brazil than it imported."[114] Mr. Reynolds uses these data to support his theory that these volumes could have been "bid back" from the export market. Mr. Reynolds' data do not conform to the facts as I understand them. The United States International Trade Commission (USITC), the source Mr. Reynolds reportedly relied on for his data, stated in its June 2004 report that, "*The U.S. is a net importer of ethanol and does not typically export ethanol.*" Further, it states that, "*U.S. ethanol exports of $3 million were recorded in 2000, the only year showing exports during the period under review.*"[115] Mr. Reynolds also completely ignores the facts that: (a) ethanol imports from non-CBI countries (including Brazil), were subject to a 54¢/Gal. duty, as well as a 2.5% import tariff; (b) ethanol exports from the U.S. would receive no federal subsidy; and (c) ethanol was significantly *cheaper* to produce in Brazil than in the U.S., virtually foreclosing U.S. producers from exporting ethanol to Brazil as Mr. Reynolds alleges they did. Finally, Mr. Reynolds argues that, "*…non-fuel use ethanol could have been imported and converted to fuel use ethanol.*"[116] Since non-fuel ethanol has a higher valued use than fuel-grade ethanol, this defies basic economic principles.

(2) Ethanol Distribution and Blending Issues

140. As noted earlier, most domestic ethanol production facilities have historically been located in the upper Midwest states where corn, the primary ethanol feedstock, is abundant. This isolation of ethanol production from major fuel markets substantially increases ethanol transportation costs because ethanol must be moved by railcar or tank truck, rather than by pipeline. For example, a June 2007 study indicated that the cost of transporting ethanol by railcar from the Midwest averages 13-18¢/Gal.—versus only 3-5¢/Gal. to transport gasoline

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[114] Reynolds Suffolk Report, Section 8.1, p. 17.

[115] *The Economic Effects of Significant U.S. Import Restraints*, United States International Trade Commission, June 2004, p. 47.

[116] Reynolds Suffolk Report, Section 8.1, p. 18, lines 5-6.

from the refinery to the service station.[117] California, because it is more distant from the Midwest than the East Coast, is likely to incur costs at the higher end of the expected range. In addition to the actual transportation costs, movement by railcar also increases working capital and storage costs due to slower and less reliable delivery schedules. Trucks are also used to deliver ethanol, but they are usually economic only within a radius of about 250 miles from the production facility. Trucking costs are highly dependent on regional competition, but can range up to 5¢/Gal. per 100 miles. This is approximately three times more expensive than using railcars for long-haul transportation. Railcar costs to transport ethanol from the Midwest to California can add as much as 1.8¢/Gal. to the "pump" price of gasoline, costing California consumers over $275 million annually. The intrastate distribution by trucks can add even more to this cost.

141. Although barge transportation can be cheaper than rail, movements of ethanol from the Midwest (via the Mississippi River) to the West Coast involve a circuitous route through the Gulf of Mexico and a transit of the Panama Canal. Upon reaching the USGC, the ethanol product must be placed in storage before being reloaded onto oceangoing vessels for the USGC-Panama-West Coast voyage. For these reasons, since 2004, almost all of the domestically produced ethanol destined for to California has been delivered by rail, with only small foreign imports of ethanol received by water.[118]

142. The bulk of the MTBE supplies required in California also had to be provided from sources outside the state. However, the USGC was a nexus of MTBE production, and the product could be loaded directly into oceangoing vessels for transit directly to the West Coast. The cost of such transportation was typically about one-half the cost of moving ethanol from the

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[117] *Ethanol Production Impacts Transportation System,* NADO Research Foundation, June 2007, p. 5.

[118] *Ethanol Market Outlook for California,* California Energy Commission (CEC), November 2005, pp. 1 and 6.

Midwest to the West Coast by rail.[119] These higher ethanol transportation costs, which had to be recovered in the ethanol price, simply served to make ethanol less competitive when suppliers were deciding on what oxygenate to utilize to satisfy the 1990 CAAA regulations.

143. Mr. Reynolds appears to downplay the importance of the higher transportation costs associated with ethanol (versus MTBE, for example) when, in one of his depositions, he says, "*...the transportation is the cost borne—cost borne by the ethanol producer, not the refiner.*"[120] Although it is true that the ethanol producer may actually pay for the transportation costs, these costs are an inherent element in the price that is ultimately paid by the refiner or blender who purchases the ethanol. Thus, the higher transportation costs are not "borne by the ethanol producer." Such costs, which are included in the ethanol price, simply served to make ethanol less competitive when suppliers were deciding on what oxygenate to utilize to satisfy the 1990 CAAA regulations.

144. As mentioned previously, ethanol's water miscibility can cause severe problems when an ethanol-gasoline mixture is contacted with water. Water and hydrocarbons are relatively insoluble in each other. Thus, water entering a hydrocarbon-based gasoline system will, because of its higher density, separate as a distinct liquid phase at the bottom of the storage vessel or tank. Ethanol, even though it is completely miscible with both water and gasoline, has a greater affinity for water. Because of this, when ethanol is introduced into a system containing both gasoline and water, the ethanol will migrate from the gasoline to the water phase, leaving an ethanol-lean gasoline phase. Ethanol's affinity for water is sufficiently large that it can cause serious handling problems in gasoline pipeline systems, which often have unavoidable sources of

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[119] *Supply and Cost Alternatives to MTBE in Gasoline,* CEC, December 1998, Technical Appendices - Adequacy of Marine Infrastructure, Section 3, Paragraph 2.

[120] Reynolds Deposition, Suffolk Case, August 3, 2007, p. 420, lines 7-9.

water intrusion. For this reason, virtually all petroleum product pipelines prohibit the introduction of ethanol or ethanol-blended fuels into their systems. This excludes ethanol from the largest and most economical method of fuel transportation. Ethanol's water affinity also requires that special handling procedures be implemented with ethanol or ethanol-blended gasoline.

145. The gasoline distribution system operates as a "wet" system, which means that water can always be present throughout the system. Potential sources of water intrusion are many, including, for example, rainwater leakage through floating roof tanks, atmospheric water vapor condensation in storage tanks, or water entrained in other petroleum products shipped on pipelines. When transporting non-alcohol gasoline blends, the presence of a separate water phase (often called "free water") is not normally a problem other than having to drain or remove the free water and send it to a treatment plant. As noted earlier, however, such free water will "leach" out the ethanol from ethanol-gasoline blends. Because petroleum product pipelines prohibit the transportation of ethanol blends, refiners cannot blend ethanol into gasoline at the refinery. Instead, ethanol must be blended at the terminal's tank truck loading rack just prior to delivery to the retail outlet. This requirement places additional investment and operating expense burdens on gasoline distributors and suppliers.

146. Although Mr. Reynolds, in the Reynolds Suffolk Report, agrees that the water tolerance of ethanol and gasoline-ethanol blends requires special handling procedures, he concludes that these procedures "*...present no major obstacles to ethanol's commercial viability.*"[121] I disagree with this conclusion. The additional investment and operating expense for handling ethanol added significantly to the cost of using ethanol as an oxygenate, and would

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[121] Reynolds Suffolk Report, Section 6.0, p. 10, lines 4-5.

certainly have impacted its commercial viability relative to its easier-to-handle alternative, MTBE. In fact, Mr. Reynolds was well aware, as early as the mid-1980s, of the many obstacles to ethanol's commercial viability. In a speech he made at a 1984 fuel ethanol conference in Washington, D.C., he outlined many of the "logistical problems," concluding that ethanol's problems, "*...represent an effort which may not be worthwhile to undertake by many companies.*"[122] And later, "*This* [the handling and other issues] *makes refinery level planning difficult and diminishes ethanol's acceptance as an octane enhancer. Because of this, ethanol will not compete at parity with other more predictable octane options.*"[123] Finally, at a speech Mr. Reynolds gave at a 1985 alcohol conference, he concluded, "*When one considers all the negatives and complex details* [associated with alcohol blending], *one might ask if there would be anyone left with a strong enough incentive to use alcohol who has the capability to do so.*"[124] Thus, even well before the commencement of the federal RFG regulations mandating oxygenate blending, Mr. Reynolds knew that ethanol had many technical and economic obstacles to overcome before it could achieve commercial viability.

147. The additional investment and operating expense incurred to allow the blending of ethanol at terminal locations centers around ethanol segregation and special handling in the form of additional tankage, receiving, loading, and delivery systems. Additional terminal facilities needed to allow ethanol blending typically include:

- Tanks to receive and store fuel-grade ethanol;
- Segregated facilities for the unloading of ethanol by truck;

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[122] Robert E. Reynolds, *The Logistics of Sub-Octane Blending on a Large Scale*, presented to The 1984 Washington Conference on Fuel Ethanol, September 13, 1984, p. 6, Paragraph 1.

[123] Ibid., p.6, Paragraph 5.

[124] Robert E. Reynolds, *The Marketplace After EPA's Lead and DuPont Decisions*, presented to The Fourth Annual Conference for Alcohol as an Octane Enhancer, March 27, 1985, p. 10, Paragraph 4.

- Railcar unloading facilities, if ethanol sources are distant from the terminal; and
- Pumps, piping, valves, meters, and blending instrumentation.

148. As noted earlier, ethanol is added to gasoline at terminals either through splash or in-line blending. In splash blending, the proper quantity of ethanol is simply added to the tank truck after the gasoline has been loaded.[125] Splash blending relies on the ethanol thoroughly mixing with the gasoline while the truck is being driven to the retail delivery point. However, if only short delivery distances are involved, splash blending may result in insufficient mixing. When ethanol first started to be used as a gasoline blending agent, splash blending was the predominant method of blending and there were occasional issues of gasoline quality. Today, a more sophisticated (and expensive) in-line blending system is commonly used, and it solves the mixing problem by adding the ethanol ratably with the hydrocarbon gasoline as the tank truck is being filled.

149. As discussed earlier in this Report, in contrast to ethanol, which is miscible in water, MTBE is only soluble to the extent of 4.3 Wt.%. Although MTBE's solubility is considerably more than that of non-oxygen bearing hydrocarbons, it is not enough to cause hydrocarbon-water phase separation problems in the typical gasoline pipeline, terminal, and retail service station distribution systems. Thus, when it was used, MTBE could be added to gasoline at the refinery and the resulting blend shipped and distributed via the extensive domestic product pipeline system without being leached from the gasoline product. The fact that MTBE-blended gasolines could be efficiently and economically transported by pipelines was an especially important element in meeting the 1990 CAAA oxygenate requirements, because it

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[125] Ethanol can also be added to the tank truck *before* the gasoline is loaded. This process, often referred to as "sequential" blending, is thought to provide better ethanol-gasoline mixing during the loading process. Obviously, sequential blending is not possible if the ethanol is added at a location other than where the gasoline is lifted.

meant that no new large-scale investments were required to distribute, store, and market gasoline after it left the refinery.

150. In addition to the added investment and expense at terminals, the need to blend ethanol just prior to retail delivery places an incremental manufacturing cost on refineries and pipelines as well. As explained earlier, in order to ensure that a gasoline blend meets all required specifications, refiners must produce a special "base" gasoline to which the ethanol is added. For gasolines required to meet RFG specifications, the special base gasoline, as previously noted, is referred to as RBOB (CARBOB in California). For product certification, the refiner must certify that the RBOB, when blended with the designated volume of ethanol, will meet all RFG specifications. However, because the final terminal blend is not quality tested before it is delivered to the retail outlet, any "mis-blending" will usually not be identified before the fuel reaches the consumer.[126] With respect to pipelines, because RBOB is such a special blend (often referred to as a "boutique" fuel), it adds to pipeline transportation costs due to its need to be segregated during transport and storage. RBOB (or in the case of California, CARBOB) is also more costly to produce by refiners, for reasons outlined later in this Report.

151. Perhaps one of the most troublesome physical characteristics of ethanol from an environmental standpoint is that when blended into gasoline it acts as if its RVP is 18 psi—even though the RVP of fuel-grade ethanol itself is only about 3.5 psi. Thus, it raises the base gasoline RVP by approximately 1.3 psi, leading to higher evaporative emissions. Exhibit Q shows how the RVP of a 7.0 RVP base gasoline blend changes when ethanol or MTBE is added. The graph shows how ethanol has an immediate and dramatic effect on RVP, even at relatively low oxygen (ethanol) levels. By contrast, the addition of MTBE to the same base blend only

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[126] Sampling and testing of the final terminal blend is not practical due to the access to laboratory facilities and extensive time lost waiting for test results before release of the shipment.

slightly increases the RVP. Because of this RVP blending effect, refiners had to produce an RBOB (or a CARBOB in California after 1996) that compensated for the higher RVP of ethanol-blended fuels supplied in accordance with the RFG and later CaRFG2 regulations. Beginning in 1995, RFG summertime specifications called for a maximum RVP of 7.2 in California. Starting in March 1996, CaRFG2 needed to be approximately 6.9 RVP maximum to meet summertime VOC regulations.[127] These low summertime RVP requirements required refiners to remove light gasoline blending components, such as butanes and pentanes, which have relatively high RVPs. The potential impact of this effect on gasoline production at refineries is quantified in the following paragraphs.

152. Exhibit R shows how the year 1996 CaRFG2 summer RVP restrictions limited a typical refiner's production of ethanol-based CaRFG2 versus MTBE-based CaRFG2. The example is based on a maximum RVP of 6.9, which was the approximate average level required to meet the CaRFG2 VOC emission reductions. Referring to Exhibit R, CARBOB-M represents the refinery base gasoline used to blend CaRFG2 using MTBE, and CARBOB-E refers to the special low RVP base gasoline needed to make CaRFG2 using ethanol. As shown in the left-hand bar of Exhibit R, CARBOB-M, which comprises 89 Vol.% of the final blend, needs an RVP of 6.7 before being blended with 11 Vol.% of MTBE (at 8.0 RVP) to meet the 6.9 RVP of the final blend. In this example, CARBOB-M can contain no butanes and about 15% pentanes. The rest of the blend is comprised of gasoline molecules heavier than pentanes.

153. The right-hand bar in Exhibit R shows the significant volume loss that typically occurred when producing a CARBOB for ethanol blending. In the ethanol blend case, CARBOB-E, which comprises 94.3 Vol.% of the final blend, can have an RVP of only 5.6

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[127] The CaRFG2 Predictive Model terminology uses the fuel emission term "Total Hydrocarbons," which is in essence equivalent to the term VOCs.

before being blended with 5.7 Vol.% of ethanol (at a blending RVP of 18) to meet the 6.9 RVP of the final blend. Like the CARBOB-M, the CARBOB-E can contain no butanes, but the pentanes must also be substantially reduced (to 8.2% versus 15%). This pentane loss (6.8%), combined with the reduced oxygenate volume (5.7% for ethanol versus 11% for MTBE), results in an estimated total loss in the refiner's gasoline volume of 12.1%, as Exhibit R shows. This volume loss was often further exacerbated by the need to selectively remove some heavy, higher boiling hydrocarbons from the CARBOB-E to maintain the distillation range of the gasoline within specification limits and to account for lesser dilution effect of ethanol. The components removed from the blend had to be manufactured (by processing additional crude oil) or purchased from other sources.

154. In comparison, and unlike ethanol, MTBE's blending RVP is very close to its pure component value. Thus, when using MTBE to manufacture the 6.9 psi RVP gasoline referred to in Exhibit R, the base gasoline blend only needs to be 0.1 to 0.2 psi lower, as compared to the 1.3 psi reduction needed with ethanol. Choosing to use MTBE, instead of ethanol, significantly enhanced a refinery's ability to comply with summertime gasoline RVP specifications without a large reduction in gasoline volume. As quantified in Exhibit R, by selecting MTBE, refiners could make more gasoline from each barrel of crude oil. This was especially important during the summertime period when the market demand for gasoline is the highest. Refinery limitations in producing sufficient CARBOB in the summertime period were key factors in the decision by many suppliers to manufacture CaRFG2 and OFP gasoline using MTBE instead of ethanol.

155. The potential loss in gasoline supply, as well as the availability of sufficient ethanol, were major factors in California Governor Gray Davis' decision on March 15, 2002, to delay the final phaseout of MTBE in California gasolines from January 1, 2003, to January 1,

2004. In a March 2002 study, the California Energy Commission (CEC) estimated that the replacement of MTBE with ethanol would reduce California gasoline supply by 55-100,000 B/D and drive up gasoline prices due to the supply shortfall.[128] Governor Davis' Order announcing the delay in the MTBE phaseout referred to several factors that contributed to his decision, including: (1) EPA's June 12, 2001, denial of California's oxygenate waiver, which would require California to import up to 900 MMGal./Yr. of ethanol to comply with federal RFG oxygenate requirements; and (2) the current ethanol production, transportation, and distribution facilities were insufficient. The Order went on to say, "*I find that it is not possible to eliminate the use of MTBE on January 1, 2003, without significantly risking disruption of the availability of gasoline in California. This would substantially increase prices, harm California's economy and impose an unjustified burden upon our motorists.*"[129] In a press release accompanying his decision, Governor Davis said, "*If I could snap my fingers and make MTBE go away tomorrow, I would. But we've seen this movie before and I am not going to allow Californians to be held hostage to another out-of-state energy cartel.*"[130] The press release went on to say, "*The California Energy Commission and independent consultants have questioned whether the necessary quantity of ethanol could be efficiently transported to and distributed within California by 2003.*" Governor Davis' delay in the California MTBE phaseout meant that it took almost five years from the time of the original March 26, 1999, Executive Order for the state of California to fully transition to ethanol. I believe these events raise serious questions regarding Mr. Reynolds' claim that all of the U.S., including California, could have transitioned to ethanol in only two years during the early 1990s, when conditions were even less favorable for such a

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[128] *MTBE Phase Out in California*, CEC, March 2002, Executive Summary, Item (vii), p. 1.
[129] Executive Order D-52-02 by California Governor Gray Davis, March 15, 2002.
[130] Governor Davis Press Release, March 15, 2002.

transition than in 1999.

156. Plaintiff's expert Dr. W. Ed Whitelaw was engaged to "*...compare and contrast the benefits and costs, including risks, stemming from the use in California of MTBE-oxygenated gasoline (MTBE-RFG) with those stemming from the use of ethanol-oxygenated gasoline (ethanol-RFG) during the early to mid-1990s...*"[131] For his "Expected" case, Dr. Whitelaw has calculated that the incremental fuel-related costs and benefits associated with using ethanol-RFG versus MTBE-RFG were approximately $508 million, or about 3.8¢/Gal. based on an average mid-1990s California gasoline consumption of 870,000 B/D.[132] Thus, Dr. Whitelaw admits that ethanol blending would have been substantially more costly than MTBE blending. Dr. Whitelaw then goes on to calculate both the air-related and water-related costs and benefits of using ethanol-RFG versus MTBE-RFG in California and concludes that these combined mid-1990s annual costs would have been approximately $419 million in favor of ethanol-RFG. Finally, in his Section V. Conclusions, Dr. Whitelaw provides a summation of all the costs, benefits, and risks in each category. This summation shows that, in the Expected case, the net costs, benefits, and risks associated with ethanol-RFG were approximately $89 million higher than those associated with MTBE-RFG.[133] I do not understand, or necessarily agree with, each and every element of Dr. Whitelaw's analysis or conclusions, and understand that another expert is addressing his report in more detail. However, based on my knowledge of the very substantial additional costs associated with ethanol versus MTBE blending, many of which I have outlined above, I am not surprised by his conclusion.

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[131] Expert Report of Dr. W. Ed Whitelaw, May 2, 2011, Section II. Assignment, p. 1.
[132] Ibid., Table 1. Fuel Summary, p. 6.
[133] Ibid., Table 4, Summary, p. 16.

(3) Poor Manufacturing Economics

157. In the 1990s, it was axiomatic that ethanol required both federal and state tax subsidies to enable it to be price competitive with MTBE as a source of oxygen in gasoline. The Reynolds Suffolk Report clearly shows that there have been virtually no extended periods since 1994 when ethanol would have been price competitive with MTBE, absent the federal subsidy.[134] Mr. Reynolds concurred with this conclusion when, in one of his depositions, he was asked, "*Would you agree that* [in the 1990s] *without government subsidies, ethanol is not competitive with crude-based fuels?*", and he answered, "*I would say that that's correct in that time frame, yes.*"[135] Thus, Mr. Reynolds includes the federal subsidy in his calculations when he concludes in his expert report that, in these cases, "*...ethanol was competitively priced with MTBE.*" [during the period 1994-2003] because it was as much as 20¢/Gal. cheaper than MTBE much of the time.[136] However, in one of his depositions, Mr. Reynolds estimated that, "*...you need about a 20 cent price advantage for ethanol* [over MTBE] *to begin to recapture these other expenses.*" [i.e., the logistical expenses associated with ethanol].[137] Also, Mr. Reynolds' conclusion as to the competitiveness of ethanol did not, by his own admission, take into account any of the additional costs for adjustments to refineries to accommodate ethanol blending. When asked about these added costs at one of his depositions, Mr. Reynolds answered, "*...on the refinery side, I assume there would be a—a refinery expert that would handle that.*"[138]

158. Mr. Reynolds has testified that in the late 1980s a satisfactory price for ethanol from a producer standpoint, and one that would have encouraged expansion of the ethanol industry,

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[134] Reynolds Suffolk Report, Section 9.2, pp. 27-29.

[135] Reynolds Deposition, Suffolk Case, August 3, 2007, p. 559, lines 7-13.

[136] Reynolds Suffolk Report, Section 9.2, p. 29.

[137] Reynolds Deposition, Suffolk Case, August 3, 2007, p. 440, lines 1-7.

[138] Ibid., p. 412, lines 10-20.

would have been the market price for regular gasoline, plus the federal tax subsidy, minus approximately 15¢/Gal.[139] Exhibit S shows that for the period 1992-1997, such a formula would not even have covered the production and transportation costs for an efficient wet mill operation, much less for the historically less profitable dry mill operation. In Exhibit S, the value of the wet mill by-products (corn gluten feed, corn gluten meal, and corn oil/germ) is subtracted from the corn feedstock cost and is shown as the "net corn" cost. The graph also shows the dramatic impact that the 1996 drought had on corn prices and its negative impact on ethanol economics.

159. The passage of the National Energy Act of 1978 established the first federal excise tax subsidy for ethanol production. Since then, every time the subsidy has been set to expire, Congress has extended it. During most of the 1990s, the federal subsidy amounted to 54¢/Gal. of ethanol blended into gasoline. However, starting in 2001, this has been gradually reduced to 45¢/Gal., as of January 2009.[140] Evidence indicates that throughout the 1980s and 1990s, the construction and continued operation of ethanol plants occurred only where both federal *and* state tax subsidies were available, i.e., in the agricultural corn producing states. The range of government assistance that has been made available to the ethanol industry includes federal and state gasoline excise tax exemptions, blender tax credits, energy investment tax credits (expired in 1985), loans and loan guarantees, government funding for feasibility studies, and tariffs on imported fuel ethanol.

160. Assurance of continued federal and state excise support was of concern to both ethanol producers and their potential customers when oil refining companies were deciding on the most reliable, efficient, and cost-effective oxygenate to meet RFG gasoline demand.

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[139] Ibid., p. 328, line 8 to p. 329, line 9.

[140] Charles F. Curtis and Neil E. Harl, "Tax Provisions in the Food, Conservation, and Energy Act of 2008 (the Farm Bill)," *Agricultural Law Digest*, Agricultural Law Press Publications, June 13, 2008.

Continuance of the 54¢/Gal. federal ethanol blenders' credit was essential to ensure that many existing ethanol producers could sell their product at a price that allowed them to remain in business. Some large corn-producing states offered a range of economic supports, including blend incentives and direct producer payments. However, each state had different expirations on these programs and, as of 1990, a number had chosen not to renew their incentive programs because of detrimental impacts on state budgets. Mr. Reynolds acknowledged concerns regarding continued government support for the ethanol industry in a 1985 speech he made to an industry alcohol conference. In his speech, Mr. Reynolds said that unlike ethanol, competing oxygenates were, "*...not distorted by a hit or miss network of tax subsidies which could change overnight.*"[141] Despite these statements in the mid-1980s, in his expert report in these cases, Mr. Reynolds fails to acknowledge anywhere that continuation of the federal subsidy was never totally assured.[142]

161. To make matters worse, because of poor ethanol production economics, ethanol facility closures had been widespread in many states. Mr. Reynolds explained at trial in the City of New York Case, how U.S. Government gasoline price controls had helped to prop up uneconomic ethanol facilities in the early 1980s. However, when such regulations were lifted, Mr. Reynolds said, "*The price of crude oil was no longer—there was no longer a floor price, so to speak, because of government controls.*"[143]

162. Exhibit T lists several examples of ethanol production facilities that ceased operation between the mid-1980s and mid-1990s. Many of the plants listed, especially the

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[141] Robert E. Reynolds, *The Marketplace After EPA's Lead (and DuPont) Decisions*, presented to The Fourth Annual Conference for Alcohol as an Octane Enhancer.

[142] Even at the time of this writing, there is strong political opposition to any continuation of the volumetric ethanol excise tax credit (the "VEETC") of 45¢/Gal. The VEETC is the current version of the original excise tax credit for ethanol.

[143] Reynolds Trial Testimony, City of New York Case, p. 4692, lines 16-18.

smaller ones, were constructed with the help of the U.S. Department of Agriculture (USDA) loan guarantee program and/or through other government grants. The U.S. DOE loan guarantee program also facilitated construction of several of the larger ethanol plants. Plants that defaulted on their government guaranteed loans, and whose assets were eventually liquidated, included both small and large facilities. Examples of small facilities that closed included the Sepco, Inc. facility (1 MMGal./Yr. capacity) in Scotland, South Dakota, and the Clinton-Southeast JV facility (3 MMGal./Yr.) in Douglas, Georgia. Larger facilities that were forced to discontinue operations included the Kentucky Agricultural Energy Co. plant (21 MMGal./Yr.) in Franklin, Kentucky, the Tennol, Inc. plant (25 MMGal./Yr.) in Jasper, Tennessee, and the South Point Ethanol plant (60 MMGal./Yr.) in South Point, Ohio.[144]

163. Exhibit U illustrates the ethanol production economics for an efficient wet mill plant operation using 10-year average pricing (from 1981-1990) for corn and by-products. During this period, as shown in the bottom bar of Exhibit U, the total production costs averaged \$1.97/Gal. of ethanol, which included: (a) a corn feedstock cost of \$1.01/Gal.; (b) operating costs of 41¢/Gal.; and (c) capital recovery costs of 55¢/Gal. The top bar in Exhibit U shows the average price that had to be obtained for ethanol (i.e., the breakeven value or "BEV") during this period to just cover the costs of production after accounting for the typical value of 59¢/Gal. for by-products. The BEV is estimated to have been approximately \$1.38/Gal. (84¢/Gal. after deducting the 54¢/Gal. federal subsidy). During the mid-1980s, gasoline prices dropped to a level that forced ethanol market prices well below the \$1.38 BEV. This was the reason that many ethanol plants closed or were not operated during this period.

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[144] One MMGal./Yr. of ethanol equals approximately 65 B/D, or the oxygenate equivalent of approximately 125 B/D of MTBE.

164. Exhibit U serves to illustrate how sensitive the ethanol BEV is to both the price of corn and the ability to sell plant by-products. If fuel-grade ethanol production expands, the volume of by-products that must be sold also expands, and this is likely to result in lower by-product prices because the market for these materials is relatively limited and they are costly to transport. This has the effect of raising the ethanol BEV price. Also, in the early 1990s, about 90% of the domestic corn gluten feed, which is the largest ethanol by-product, was exported to European Economic Community (EEC) countries, which added another risk element to the by-product prices because of potential changes in EEC demand and trade policies.[145]

165. Increased ethanol production increases the demand for corn, and such increased demand has the effect of raising corn prices. Although this effect is extremely difficult to quantify, largely due to changing federal government agricultural policies that sometimes result in large stockpiles of agricultural products, increases in ethanol usage during 2007-2008 resulted in corn prices at times exceeding $7.00 per bushel, or more than three times the average of $2.00 per bushel during the entire 2001-2006 period. Today's corn price of about $6.50 per bushel is 225% higher than that $2.00 benchmark average. If refiners had chosen to use ethanol instead of MTBE in the 1990s to meet the 1990 CAAA fuel requirements, corn prices might have risen to even higher levels. This is because corn production was more than 30% lower in the mid-1990s than it is today, primarily because of a lower yield per acre. Corn price sensitivity was evident in 1996 when a drought caused corn production to drop significantly and raised the spot corn price to a six-month average of $4.64 per bushel between March and August of 1996. This high feedstock cost caused 1996 ethanol production to decline to 20% below the two-year (1994-

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[145] Margot Anderson, *Ethanol Production, Corn Gluten Feed, and EC Trade*, U.S. Department of Agriculture, July 1993, p. 2. In fact, new EEC policies with respect to genetically modified grains have increasingly forced ethanol producers to seek new export markets for their ethanol co-products, leading to downward price pressure on these livestock feed substitutes.

1995) average. If ethanol demand had been even higher during this period, in order to satisfy fuel demand, it is likely that the corn price would have risen further, exacerbating an already problematic situation. Such potential increases in corn prices raised another element of uncertainty with respect to long-term ethanol manufacturing economics.

166. During the 1990s, the manufacturing costs associated with providing oxygenate by way of MTBE were much better than those of providing it through ethanol. In addition, MTBE did not suffer from all of the production, distribution, and political uncertainties that surrounded the widespread use of ethanol. To illustrate the economic advantage that MTBE held over ethanol, Exhibit V compares, for the period 1981-1990, the average BEV for ethanol (see Exhibit U) with the calculated BEV for two types of large-scale MTBE plants—a merchant facility and a refinery-based plant using FCCU-sourced isobutylene.

167. The top two bars of Exhibit V are essentially the same as those that appear in Exhibit U and show the average BEV of $1.38/Gal. for ethanol during that period. The bottom two bars show the average MTBE BEV for the merchant plant and the refinery-based plant, respectively. The merchant MTBE production process had the highest production cost, and the highest MTBE BEV, because it was capital intensive and required three separate processing steps. The average BEV for the merchant plant was 88¢/Gal. of MTBE produced versus 77¢/Gal. for the refinery-based plant. (This comparison does not account for the economic synergies that many refiners enjoyed through building on-site MTBE plants, as discussed earlier.) Although the refinery-based plant had a significant operating and capital cost advantage over the merchant plant, the isobutylene feedstock had a higher value than the merchant plant's butane feedstock because the former was also a valuable potential material for making high-octane alkylate.

168. Most importantly, Exhibit V shows that, over this period, the ethanol BEV, before accounting for the federal tax subsidy, averaged $1.38/Gal., or almost 60% more than the merchant plant BEV. Thus, the federal excise tax subsidy was absolutely essential during this period in order for ethanol to be an economic proposition. Even after accounting for the 54¢/Gal. subsidy, the ethanol BEV averaged 84¢/Gal., which was still above the cost of refinery-based MTBE supplies, and only slightly lower than merchant plant supplies. However, these are *production costs* only and do not take into account any costs associated with ethanol's higher transportation and handling costs. Exhibit V also shows that an ethanol plant's cost of corn feedstock alone, even when corn prices were in the relatively low $2.25 per bushel range, exceeded the entire production cost for MTBE. This dependency on corn prices, as well as the prices that could be obtained for agricultural-based by-products, proved a significant concern for potential investors in new ethanol facilities, especially those that were not familiar with agricultural economics. MTBE production economics were much easier to predict and did not rely on corn or any uncertain by-product sales that were unrelated to gasoline prices. As Mr. Reynolds confirmed in one of his depositions, "*...if you were pricing off of corn and that's going to be the cost, it may or may not move in relationship to gasoline and crude oil.*"[146]

169. A simple metric commonly used in the ethanol industry to reflect ethanol manufacturing economics is the so-called "crush spread." By definition, the crush spread is the wholesale price of ethanol, in $/Gal., times the gallons of ethanol produced per bushel of corn (currently about 2.8), less the cost of one bushel of corn. The derivation of this term relates to the difference (the "spread") between the ethanol revenue derived from a bushel of corn and the cost of a processed ("crushed") bushel. The higher the crush spread, the better the economics of

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[146] Reynolds Deposition, Suffolk Case, August 3, 2007, p. 336, lines 21-23.

converting corn to ethanol. Exhibit W shows how the ethanol crush spread has varied from the early 1990s to the 2000s. From 1992-1998, the crush spread averaged only about 47¢/bushel, and at times was negative. Since January 2000, however, it has averaged approximately $1.85/bushel with one spike to over $8.00/bushel. Between October 2008 and April 2009, when corn prices averaged $3.84 per bushel, and ethanol prices averaged $1.61/Gal., the crush spread fell to only 68¢/bushel. In order to sustain profitability at most ethanol plants, the crush spread usually needs to exceed $1.00/bushel. The extreme variability in the crush spread is indicative of the fact that the price of ethanol and the cost of corn are totally independent variables that are affected by different economic and market factors.

170. Finally, the economic fortunes of the fuel ethanol production industry often tend to rise and fall with the absolute price of gasoline—a parameter that, as noted above, is unrelated to the cost of corn feedstock or the price that can be obtained for ethanol plant by-products. Exhibit X shows how the wholesale and retail price of regular grade gasoline (conventional gasoline pre-1995 and RFG post-1995) has varied for the period 1990-2011. Throughout most of the 1990s, when wholesale gasoline prices averaged only about 50¢/Gal., ethanol producers struggled to survive. However, as gasoline prices gradually increased in the 2000s, ethanol economics significantly improved. Then, in late 2008 and early 2009, following the recession-induced collapse of oil prices from their July 2008 peaks, many new ethanol facilities were forced into bankruptcy or liquidation. Stubbornly poor ethanol manufacturing economics during most of the 1990s was a key factor that constrained expansion of ethanol capacity during this period.

(4) Supply Reliability and Quality Issues

171. As already discussed, during the 1990s time frame, there were serious concerns by ethanol producers and consumers alike about the long-term economic viability and security of

supply from existing ethanol producers. Many ethanol plants, large and small, had been unable to survive the volatile markets for their feedstocks and their products. For refiners and other gasoline manufacturers seeking reliable long-term oxygenate supplies to comply with the new RFG regulations, entering into long-term contracts to purchase ethanol from such potentially unreliable sources naturally raised significant concerns.

172. In addition to the foregoing, the larger wet mill ethanol processing plants (which comprised a large portion of production capacity in the 1990s) have the ability to "swing" production from ethanol to high-fructose corn syrup used in soft drink and food products. Swinging from one product to the other is based on market pricing. Thus, during periods of poor ethanol prices and high-fructose corn syrup prices, ethanol production from such plants can decline precipitously. This added another element of uncertainty to the reliability of ethanol production and was a potential concern to gasoline refiners and blenders seeking to secure long-term oxygenate volumes.

173. Due to strict RFG compliance regulations, it was essential that refiners had an oxygenate source that they knew would be available to them when needed, and in the quantities required. They also wanted, to the extent possible, to maintain control of the gasoline product delivered to customers throughout the supply chain in order to ensure that the product delivered met the oxygenated fuel quality specifications. The issues of reliability and quality control were important factors that helped "tip the scales" in favor of MTBE versus ethanol. Having their own source of oxygenate at the refinery, or purchasing it under contract from a world-scale merchant oxygenate plant, offered refiners much greater assurance that the material would be available when and as needed. Ethanol, with its transportation problems, its unfavorable economics, and its production concentrated in small isolated facilities, offered no such

assurances. From a quality control standpoint, MTBE allowed the refiner to test and certify the final gasoline blend *at the refinery* before transfer into the distribution system for delivery to the ultimate customer. In the case of ethanol blending, the final product was not tested and certified after the ethanol was added. Thus, the supplier had to rely on the tank truck driver to properly add and mix the correct volume of ethanol. Even today, product quality control for ethanol blends relies on the testing of RBOB (or CARBOB) blended with fuel-grade ethanol in the refinery laboratory. This increases the possibility of delivering off-specification gasoline to customers. Mr. Reynolds recognized this when, in describing some of the obstacles that ethanol faced, he said, in one of his depositions, "*...some refiners might have a preference to add something at the refinery and sort of be done with it there as opposed to finishing it at a terminal.*"[147]

(5) Consumer Acceptance Issues

174. In the first decade of significant ethanol usage (i.e., starting in the late 1970s), there were a number of fuel quality issues that arose and caused concern among consumers over the use of ethanol-blended gasolines. These concerns carried over into a general public perception that ethanol-blended gasoline was an inferior product. Not only did ethanol have a propensity to loosen fuel system deposits, causing clogged engine parts, but if water entered a vehicle's fuel tank, the ethanol was leached out. This lowered the octane rating of the fuel and led to poor driving conditions, including knocking or sluggish performance. Ethanol blends quickly gained a reputation for causing clogged fuel injectors, leaking fuel systems, corroded fuel lines, poor hot weather performance, and lower gas mileage.[148,149]

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[147] Reynolds Deposition, Suffolk Case, August 3, 2007, p. 531, line 23, to p. 532, line 1.

[148] *Q&A Oxygenated Fuels*, Motor Vehicles Manufacturers Association, August 1988.

[149] *Fuel Ethanol and Agriculture: An Economic Assessment*, U.S. Department of Agriculture, August 1986, p. 4.

175. The experience of Chevron in attempting to market gasoline/ethanol blends in Kentucky and Tennessee during the 1980s exemplifies the problem of negative consumer perceptions with respect to ethanol-blended fuel. Despite the company's investment in infrastructure specifically designed to ensure delivery of on-specification fuel using ethanol, in 1988 dealers expressed their concern that they were losing a significant amount of business (almost 20%) due to consumers' reluctance to purchase these fuels. Following approximately five years of attempting to sell ethanol-blended gasoline in these states, Chevron "*...had to make the decision to withdraw from that market in 1988 because* [its] *dealers felt that they were losing business.*"[150] According to Mr. Reynolds, CITGO experienced similar problems involving the negative image of ethanol, and some of the company's "field management" expressed their desire to cease ethanol blending.[151]

176. These quality perceptions became so pronounced that, in the mid-to-late 1980s, some automobile manufacturers' owners' manuals recommended *against* the use of ethanol-blended gasolines. For example, vehicle literature for Chrysler model years 1986 and 1987 states, "*Chrysler does not recommend using fuels containing alcohol because some gasoline/alcohol blends may degrade the starting, driveability and fuel efficiency of your vehicle.*"[152] American Motors literature for model years 1984–1987 states, "*Exclusive use of gasohol* [defined as 90% unleaded gasoline and 10% ethanol] *is not recommended. Vehicle tests have shown that significant fuel system corrosion can result when gasohol is used exclusively.*"[153] Peugeot, in the early 1980s, instructed owners not to use fuels containing ethanol, claiming, "*It has been determined that Ethanol or Methanol which are commonly found in the blends of*

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[150] Deposition of Mr. Bruce Odiel Beyaert, Suffolk Case, June 19, 2007, pp. 109-110.
[151] Reynolds Deposition, Suffolk Case, November 9, 2007, p. 122, line 24, to p. 123, line 6.
[152] Chrysler vehicle owner's manuals, model years 1986-1987.
[153] American Motors vehicle owner's manuals, model years 1984-1987.

Gasohol and fuel systems additives will have a negative effect on the fuel system hoses, gaskets, seals, and other components."[154] The owner's manual for the 1983 BMW 318i warns, "*Operate the engine with unleaded gasoline only. Gasohol will damage the fuel system.*"[155] A number of other manufacturers, including Ford (models 1984–1989) and Nissan (models 1987–1989), also alerted their customers to potential driveability and/or fuel system problems that could result from gasohol, and recommended that its use be discontinued if such problems arose.[156,157] Thus, even as warranty-related issues were resolved, the automobile manufacturers still recognized a need to maintain warnings for their customers' benefit.

177. Although, by the early 1990s, most automobile manufacturers had made production modifications to their new car lines to allow the use of ethanol, and fully supported the use of ethanol blends, some of ethanol's tarnished image continued on in the minds of consumers. Also, some older vehicles that predated the manufacturers' modifications continued to have problems running satisfactorily on ethanol-blended fuels. It is important to note that in any given year, new model year registrations will typically comprise only 8% to 9% of the total car population. Annual fleet age profiles indicate that vehicles added to the car population as long as 15 years ago continue to comprise a substantial portion of vehicles on the road. Reflecting this vehicle longevity, from 1980 to 1993, the median age of the U.S. automobile fleet was in the range of 6 to 7.3 years.[158] Thus, it takes many years for the vehicle fleet to fully "turn-over" after production modifications are made. Illustrating these vehicle population characteristics, Exhibit Y depicts the U.S. automobile fleet age profile as of July 1, 1994.

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[154] Peugeot vehicle owner's manuals, Model 505 fuel injection, undated.

[155] BMW 318i owner's manual, model year 1983.

[156] Ford vehicle owner's manuals, model years 1984-1989.

[157] Nissan vehicle owner's manuals, model years 1987-1989.

[158] *Transportation Energy Data Book: Edition 23*, U.S. DOE, October 2003, Table 3-8, p. 3-11.

178. Mr. Reynolds acknowledged in one of his depositions that many vehicle owners' manuals in the mid-to-late 1980s contained specific warnings to consumers about the use of alcohol-blended fuels, and that many of the automobiles produced during this period would have still been on the road after manufacturers had made appropriate fuel system modifications to their new vehicles in the 1990s. However, Mr. Reynolds states that, "*...likely there wouldn't be any warranty implications because they* [the 1980s vehicles] *would be out of—out of warranty.*"[159] Mr. Reynolds misses the point. Even if the vehicles were out of warranty, if their fuel systems had not been modified to handle alcohol-blended fuels, it was still a distinct possibility that they would encounter the same operating and maintenance problems that had resulted in consumer resistance to the use of alcohol-blended fuels. Also, mere expiration of the manufacturer's warranty would not be a reason for the vehicle owner to suddenly begin the use of alcohol-blended fuels if there were specific warnings against such use in his owner's manual.

179. The fact that ethanol must be blended at the wholesale terminal locations, rather than at the refinery, also led initially to some consumer quality issues related to proper blending and mixing. Incidents of so-called "mis-blending" resulted in additional negative publicity for ethanol-blended fuels. There are several well-documented examples of such improper alcohol blending, including incidents that occurred in St. Louis, Missouri; Phoenix, Arizona; and Torrance, California.[160,161]

(6) Limited Availability of Alternative Oxygenates

180. During most of the 1990s and into the early 2000 time period, there were several commercially available oxygenates—other than MTBE and ethanol—that were occasionally

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[159] Reynolds Deposition, Suffolk Case, August 3, 2007, p. 534, lines 17-19.

[160] *St. Louis Post Dispatch* articles in the October 7, 1982, October 20, 1982, and January 18, 1983, issues.

[161] *Washington Post*, article in the July 8, 1991, issue.

manufactured and/or used by refiners to blend RFG gasoline. These included both ethers and alcohols. However, all of these alternative oxygenates were used in only very limited quantities for a variety of reasons. The EPA estimated that in year 2000 these materials provided only approximately 5% of the oxygenate used in RFG manufacture.[162]

181. The alternative ethers that were available were ETBE, TAME, and DIPE. The processes for making ETBE and TAME are very similar to that for making MTBE. In all cases, a light olefin material is catalytically reacted with an alcohol to produce an ether. ETBE involves the reaction of isobutylene and ethanol (versus the methanol used in MTBE). As an alternative oxygenate blending agent, ETBE suffered from many of the same issues that were associated with the use of ethanol itself. Large volumes of ethanol would have been required to be manufactured, handled, and distributed to produce enough ETBE to meet the projected RFG requirements.

182. TAME is manufactured by reacting isoamylenes with methanol. Because MTBE and TAME chemical reactions are so similar, MTBE commercially sold during the 1996 to 2002 time frame occasionally contained 1 to 2 Wt.% TAME, which was likely caused by small amounts of isoamylenes in the isobutylene feed to the MTBE unit.[163] In regards to the production of TAME, isoamylenes are only available at refineries in very limited quantities and there was no established commercial process to produce additional volumes. Thus, TAME volumes produced at U.S. refineries always remained relatively small and no commercial trade for TAME ever developed.

183. ETBE and TAME, as alkyl ethers, belong to the same chemical family as MTBE. Thus, it is likely that these materials, had they been used in place of MTBE in substantial

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[162] *Oxygenate Type Analysis – 1995-2000 Reformulated Gasoline (RFG) Survey Data*, U.S. EPA, pp. 15-18.

[163] Laboratory analysis of MTBE receipts at the Chevron El Segundo refinery from 1996 to 2002.

quantities, would have exhibited similar solubility and groundwater characteristics. Although ETBE and TAME exhibit lower blending RVPs than MTBE, which can be helpful in the gasoline blending process, this benefit is more than offset by their higher costs of production. Also, as shown in Exhibit D, both ETBE and TAME have lower oxygen contents than MTBE. This meant that greater volumes were needed to meet the RFG oxygen requirements, adding further to costs. For these reasons, ETBE and TAME were never manufactured in quantities that made them a realistic or competitive alternative for the oxygenate requirements of the federal OFP or RFG programs.[164]

184. DIPE is produced in small quantities as a by-product from the manufacture of isopropyl alcohol, and minor volumes have occasionally been blended into gasoline. A DIPE manufacturing process involving the reaction of propylene and water was never commercially successful, primarily because the propylene needed in the process had a higher value as a feedstock for the production of polymers. Although DIPE has a lower RVP than MTBE, and can be an acceptable gasoline oxygenate blending component, none has ever been manufactured in commercial quantities. DIPE is approximately half as soluble in water as MTBE, but had it ever been used in place of MTBE in substantial quantities, it likely would have exhibited similar physical characteristics as MTBE.[165]

185. Apart from ethanol, there were two alcohols that were potential candidates for use in blending RFG gasoline—methanol and TBA. However, like all alcohols, these materials possessed many of the same disadvantages commonly associated with the use of ethanol. These

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[164] *Petroleum Supply Annual,* EIA, 1992, Volume 1, Tables 50 and 52; 1993, Volume 1, Tables 50 and 52; and 1994, Volume 1, Tables 52 and 54.

[165] The California CaRFG regulations banning the use of MTBE in California gasolines, which became effective on December 31, 2003, also prohibited the use of other ethers, including TAME, ETBE, and DIPE. [CARB Section 2262.6(c)(4).]

included primarily water miscibility, relatively high RVPs (when blended with gasoline), and the need for segregated shipping, handling, and distribution.

186. Methanol had the advantage of being plentiful and relatively cheap. It was—and still is—manufactured directly from natural gas in large quantities and is widely used in the chemical industry to produce adhesives, plastics, and fibers.[166] However, despite its high octane, methanol's use as a "neat" gasoline blendstock was even more problematic than ethanol because of its high toxicity, excessive vapor pressure, and water miscibility. Methanol is also highly corrosive to engine fuel system components. For these reasons, the EPA, under its 1981 "substantially similar" rules, limited neat methanol blending to a maximum of 0.3 Vol.%.[167] Waivers were later granted for the use of higher volumes if the methanol was first blended with a "co-solvent" alcohol such as TBA, as discussed earlier in this Report. As more experience was gained with such blending agents, it became clear that it was much more feasible and attractive to employ methanol in the production of direct hydrocarbon-blendable ethers such as MTBE.

187. TBA is a co-product from the manufacture of propylene oxide (PO), an important chemical building block for many consumer products. TBA was initially used in small quantities by some refiners (especially those that had integrated petrochemical operations making PO) as an octane-enhancing gasoline blendstock, and later, as noted previously, as a co-solvent in combination with methanol. However, TBA was never available in the volumes needed to make it a viable oxygenate substitute for either MTBE or ethanol in RFG gasoline. TBA, like Oxinol, was rejected by the industry as a gasoline blendstock. Most co-product TBA was channeled into the manufacture of isobutylene for MTBE production or into higher value uses in the chemicals or solvents industry.

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[166] Sami Matar and Lewis F. Hatch, *Chemistry of Petrochemical Processes*, Gulf Publishing, 1994, pp. 145-151.
[167] *The Energy Information Administration's Assessment of Reformulated Gasoline*, EIA, p. 152.

188. Other potential gasoline oxygenates, including higher alcohols such as isopropyl alcohol and normal butanol, were never used to any significant degree due to a combination of factors, such as: (1) water solubility; (2) higher value uses in other markets; and (3) excessively high production costs.[168]

189. The costs, benefits, and risks associated with using one oxygenate versus another in a particular marketplace affected all suppliers in that market in essentially the same way. Thus, the advantages and disadvantages of ethanol versus other oxygenates, including MTBE, were assessed on the basis of similar criteria and generally similar conclusions tended to be reached. Primarily because of the higher costs and limited availability of alternative oxygenates, as discussed above, the decision of which oxygenate to use basically came down to the choice of MTBE or ethanol. However, the oxygenate chosen for use in a particular market, i.e., MTBE or ethanol, tended to be the same for all suppliers. This facilitated the continued use of product exchange transactions in the marketplace, which would have been more complicated (and costly) if both oxygenates had been employed. It is not surprising that when comparative cost, benefit, and market risk assessments were made, most suppliers chose the same oxygenate for use in a particular market area.

Impact of Ethanol on Overall Gasoline Supply

190. Perhaps one of the most important issues affecting consideration of expanded usage of ethanol as an oxygenate in the early 1990s was its potential impact on overall gasoline supplies. Compared to MTBE, ethanol would have directly reduced available gasoline supplies through a combination of three factors. This reduction would have come at a time when both

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[168] The California CaRFG regulations banning the use of MTBE in California gasolines, which became effective on December 31, 2003, also prohibited the use of alcohols (other than ethanol), including methanol, propanols, butanols, and pentanols. [CARB Section 2262.6(c)(4).]

consumers and legislators were concerned about rising gasoline prices.

191. First, whether ethanol was blended at the 5.7 Vol.% level (the level required to meet the minimum federal RFG requirements), or at the 10 Vol.% level (the maximum level permitted in any gasoline), it added significantly less volume to the domestic gasoline pool than MTBE. The comparative levels for MTBE were 11 Vol.% (for RFG requirements) and 15 Vol.% (the OFP level and the maximum permitted). Thus, the use of MTBE effectively expanded gasoline volume relative to ethanol. The additional MTBE also helped dilute the effect of "dirty" gasoline components, such as olefins and aromatics, and helped refiners meet the new stringent RFG emissions regulations.

192. Second, as previously discussed in this Report, the high blending RVP of ethanol requires that some lighter gasoline components, primarily butanes and pentanes, be removed from the base gasoline to meet RFG requirements, especially in the warmer summer months—usually the periods of greatest gasoline demand. These lost volumes must be replaced by processing more crude oil or by importing gasoline from foreign sources. In the Reynolds Suffolk Report, Mr. Reynolds admits that additional volumes of butanes and pentanes must be removed from the gasoline pool to accommodate ethanol blending.[169] However, he incorrectly asserts that these materials are not lost from the gasoline supply, "*...but can be used in other areas or other seasons and/or used for refinery feedstocks.*"[170] Mr. Reynolds' statement might be true if the overall supply of such refinery feedstocks was restricted—but this is not the case. Throughout the year there are always more than ample supplies of these materials from natural gas and refinery production sources that are seeking a higher value use in the gasoline pool. In fact, contrary to Mr. Reynolds' assertion, the only outlet for such light materials that are "backed

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[169] Reynolds Suffolk Report, Section 9.1, p. 24, Paragraph 4.
[170] Ibid., Paragraph 5.

out" of the gasoline pool in California is to export them or burn them as refinery fuel—providing a low economic value. The net result is a loss in total gasoline volume.

193. Third, and finally, the energy content of ethanol is less than that of either hydrocarbon gasoline or MTBE. It is approximately one-third less than hydrocarbon gasoline and about 20% less than MTBE. Since a fuel's volumetric energy content is directly related to the mileage that can be achieved in an internal combustion engine, substitution of hydrocarbon gasoline or MTBE with ethanol requires that more fuel volume be burned for the same miles driven. The net effect is the same as for the removal of light ends from gasoline—the incremental gasoline volume must be made up by refiners processing more crude oil or through gasoline imports.

194. If refiners must process more crude oil to produce the same volume of gasoline, the cost of producing gasoline increases. Increased imports of gasoline not only increase the cost of the gasoline supplies, but also raise important issues regarding long-term security of supply. Although the impact of ethanol on gasoline supply may vary, both on a refiner to refiner and on a temporal basis, it would have been clear to most refiners considering alternative oxygenate materials in the early 1990s that ethanol would negatively impact their overall gasoline production and make them less competitive from a pricing standpoint.

Summary of MTBE versus Ethanol Considerations

195. Each gasoline refiner was faced with the decision of how and where to source the large volumes of oxygenates that were projected to be required in RFG and OFP designated areas. As has been explained in this Report, there were many factors to be considered in making this decision. Although there were a number of different types of ethers and alcohols that could be used, the fundamental choice was between MTBE and ethanol. For many of the reasons

discussed above, most refiners generally opted for MTBE. The following paragraphs summarize the key issues that directed that decision.

196. **Ethanol Availability** – Most ethanol plants were small, inefficient, highly leveraged, and concentrated in the Midwest corn producing states, far removed from the areas of largest future RFG/OFP demand. There were few ethanol plants being planned or under construction because the economics did not justify it. Ethanol imports were limited by a tariff and by the "cap" on CBI nation volumes. In contrast, capacity for MTBE was growing rapidly, both at refineries and through merchant plant construction. The latter relied on low-cost butanes, the very materials that were rapidly being displaced from the gasoline pool due to restrictive RVP regulations.

197. **Ethanol Distribution and Blending** – Ethanol's water miscibility precluded it from being blended at the refinery and transported by pipeline. Reliance on ethanol as the source of oxygenate in major East Coast and West Coast RFG markets would have resulted in substantial rail transportation costs, as well as major new investments in segregated rail off-loading facilities, terminal storage tanks, and truck rack loading and blending systems. Ethanol's high blending RVP required refiners to produce a special low RVP RBOB (or CARBOB in California), complicating the refining process, adding additional expense, and reducing gasoline volume. The latter could only be made up by processing more crude oil or importing high-cost gasoline from foreign sources. When the EPA denied requests to provide ethanol-blended RFG gasoline with an RVP "waiver" (which it gave for conventional gasoline), any plans for new ethanol capacity essentially came to an end.[171] In denying the waiver, the EPA was concerned that the expanded use of ethanol in RFG gasolines would increase emissions in those areas that

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[171] "Ethanol Producers Battle EPA Proposal on Clean Air," *The Wall Street Journal*, May 1, 1992, p. 84.

already had the "dirtiest" air. When asked about this fact at trial in the City of New York Case, Mr. Reynolds confirmed, "*I believe that's why they* [the EPA] *said they would not grant it* [the waiver] *for all their RFG areas, yes.*"[172] In comparison, both inside and outside of the refinery, MTBE behaved like any other refinery gasoline blendstock and did not suffer from any excessive RVP, blending, transportation, or distribution problems.

198. **Ethanol Economics** – Even with the help of generous federal subsidies, the cost of producing ethanol in the early 1990s made it only marginally competitive with other oxygenate sources, such as MTBE. Additional state subsidies or incentives were needed to encourage expanded production. Ethanol's fundamental economics, with a high dependency on corn prices, raised uncertainty about the long-term viability of the ethanol industry. In 1994, the U.S. General Accountability Office (GAO), the audit arm of the U.S. Congress, reported that despite a federal law requiring large federal agencies to use renewable fuels, the agencies had substantially failed to comply.[173] The high price of ethanol was cited as a key reason. MTBE, in contrast, was not only much cheaper to produce, but also offered economic synergies with other refinery processes such as alkylation. Also, MTBE production costs were directly related to other energy costs, not based on the price of a totally unrelated farm crop and agricultural by-products the way ethanol was.

199. **Supply Reliability and Quality Control** – If a refiner chose ethanol as its oxygenate source, it often had to enter into a contract with a relatively small supplier with an unknown "track record." A refiner did not want to be dependent on oxygenate sourced from potentially unreliable suppliers operating in an economically challenged, subsidized industry.

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[172] Reynolds Trial Testimony, City of New York Case, p. 4715, lines 12-13.

[173] *Advanced Technology Program - Federal Agencies' use of Gasohol Limited by High Prices and Other Factors*, U.S. GAO, Report to the Honorable Byron L. Dorgan, U.S. Senate, December 1994.

The refiner was essentially taking on the risk of default in supply, the cost of which could be substantial. However, refiners themselves had no interest in owning or operating ethanol plants, which represented an entirely different line of business. The choice of ethanol also introduced issues of product quality control. RFG regulations required that gasoline meet all specifications at the point of retail delivery to the consumer. By choosing ethanol as the oxygenate source, refiners were, in effect, transferring part of the gasoline manufacturing process—the need to blend the correct volume of ethanol just prior to delivery—to entities over which they had little or no control. Unlike ethanol, MTBE could be reliably manufactured and blended at the refinery and the final blend certified at the time of production, in accordance with strict quality control procedures. Absent some unusual pipeline or terminal operating problem, the refiner knew that the product delivered to the retail station met the RFG regulations. The use of MTBE offered more product quality assurance and less risk of violation of those regulations.

200. **Consumer Acceptance** – Because ethanol had been linked to various fuel quality and vehicle performance issues when initially used, a perception had arisen that ethanol-blended fuels were inferior and to be avoided. MTBE bore no such consumer acceptance problems. Indeed, by 1990, MTBE had been proven to be an economic, easily used, high-octane, and reliable gasoline blendstock that could be blended, transported, and delivered like any other gasoline blendstock.

VII. COMPARISON OF ETHANOL CIRCUMSTANCES TODAY VS. THE 1990s

201. It has often been asserted that the fact that ethanol is in such widespread use in the U.S. today is ample proof that all U.S. refiners and marketers could have, if they had chosen to, met the oxygenate requirements of the 1990 CAAA using ethanol alone. I do not agree with this

assertion. The technical and commercial circumstances 15-20 years ago were very much different than they were in the early to mid-2000s when U.S. refiners started to transition from MTBE to ethanol. Of course, no one can know for certain what could have been accomplished 15-20 years ago. However, given that ethanol producers and refiners would at that time have had, at best, only three to four years to build a large number of new ethanol plants, as well as substantially modify both refineries and distribution systems to accommodate ethanol on a nationwide basis, I find it unreasonable to assume that such a rapid expansion of the ethanol industry could have been achieved. Ethanol blending confronted gasoline suppliers with a multiplicity of risks, uncertainties, and added costs in the early 1990s. To assume that suppliers would have simply ignored such factors is, in my opinion, unrealistic.

202. Instead, I am of the opinion that individual refiners did exactly what can be anticipated from any competitive business enterprise. They kept their options open until they knew what the actual regulations would be and then made the most prudent investments and/or operational changes needed to ensure that they remained competitive in their markets. Since MTBE held so many technical and economic advantages over ethanol, and entailed much lower supply risk, it is not surprising that it became the oxygenate of choice outside the Midwest ethanol production areas. It is unreasonable to assume that refiners would have made large investments to expand RBOB production, or potential ethanol suppliers would have invested in large new production facilities, when neither knew the role that ethanol would eventually play in meeting the 1990 CAAA. Gasoline marketing is highly competitive. Each refiner was faced with an individual decision as to which federally approved oxygenate to use. As discussed in more detail in this section, an individual refiner facing such a choice would also be aware that its competitors were facing a similar choice. It would be reasonable for a refiner to assume that its

competitors would not undertake the risks of using ethanol, and no refiner would want to "go it alone" for the reasons already outlined.

203. In considering this matter, it must also be noted that the transition from MTBE to ethanol in the mid-2000s occurred over an extended period of time, during which refiners had ample warning of impending MTBE phaseouts in certain market areas. This gave them time to seek out ethanol supplies and make any refinery or terminal modifications. As the transition accelerated, it became clear that the government intended to mandate the use of ethanol in some form. This enabled refiners to plan ahead for eventual implementation of the RFS mandating the use of certain volumes of ethanol in gasoline. Also, from a competitive standpoint, refiners knew that there would be a "level playing field" because all gasoline manufacturers were mandated to use ethanol. These circumstances did not exist in the late 1980s and early 1990s.

204. As evidenced in a paper published by the EIA in July 1994, the federal government, as well as all the other stakeholders, knew and accepted that meeting the 1990 CAAA emissions regulations was going to require more than one type of oxygenate be used.[174] Plaintiff's expert Mr. Reynolds knew that the EPA itself anticipated that the new regulations would need to be met by a combination of both ethanol and MTBE. When asked in one of his depositions if this is what the EPA actually anticipated, he answered, "*Yes.*"[175] The EIA, when commenting on the outlook for the adequacy of oxygenate supplies, stated, "*The new Federal oxygenated and reformulated motor gasoline programs stimulated a dramatic increase in MTBE production capacity within the last few years. On the other hand, ethanol shipping costs, gasohol nonfungibility with motor gasoline, and limited State tax incentives helped to restrain growth in*

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[174] Tancred Lidderdale, *Demand, Supply, and Price Outlook for Reformulated Motor Gasoline 1995*, Monthly Energy Review, EIA, July 1994.

[175] Reynolds Deposition, City of New York Case, March 16, 2009, p. 53, lines 18-20.

ethanol production capacity."[176] This development was the logical consequence of refiners and other suppliers making their own individual decisions as to which oxygenate to use. Those decisions resulted in different oxygenates being used based on refiner-specific economics, as well as differences in regional supply patterns. If *all* refiners had, for whatever reasons, chosen to use ethanol, the nation's gasoline supply would have been put in jeopardy in order to meet the 1990 CAAA.

205. Some of the key differences that existed in the early 1990s versus the mid-2000s include: (1) the use of ethanol eventually became mandated by federal law, which reduced investor risk and altered the economics of ethanol production; (2) significant technological advances were incorporated into current ethanol plants; (3) the ethanol industry is less concentrated today; (4) the emergence of ethanol plant cooperatives has allowed easier capital raising; (5) improvements in corn yields has led to expanded production; (6) better consumer acceptance of ethanol; (7) expanded RBOB (and CARBOB) production capacity and terminal blending capacity; (8) an improved and more certain regulatory climate for ethanol; and (9) very different macro-economic factors exist today versus the early 1990s. I believe the foregoing factors make it abundantly clear why one cannot extrapolate from today's gasoline operations and assume that the circumstances favoring ethanol today could have existed 15-20 years ago. Despite the differences between the early 1990s and today, there is one notable similarity: the volatility of ethanol production economics that resulted in multiple bankruptcies within the ethanol industry during both the 1980s and over the last several years.

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[176] Tancred Lidderdale, *Demand, Supply, and Price Outlook for Reformulated Motor Gasoline 1995*, Monthly Energy Review, EIA, July 1994, p. 8, Paragraph 2 of Column 2.

206. Notwithstanding the differences between today and the 1990s, it is, in my view, somewhat irrelevant as to whether or not refiners could have physically acquired and shipped enough ethanol to meet RFG and OFP requirements. In a free market competitive environment, individual refiners make investment and operational decisions in their own best interest to create the highest value for their shareholders. As explained previously, in most RFG and OFP regions, MTBE was the preferred oxygenate in terms of performance, effectiveness, safety, quality, cost, and the environment. Unless under a federal mandate as today's refiners are, a refiner-blender would be extremely unlikely to choose an inferior product and accept the risk of loss of market share. The majority of refiners chose MTBE over ethanol because it made the most technical and economic sense in their particular operations—not how it performed on some "industry-wide" basis.

207. In the sections that follow, I briefly explain each of the key differences listed above, and how conditions in the mid-2000s enabled refiners to make the transition to widespread domestic ethanol blending—something which would have been highly unlikely under the conditions that existed in the late 1980s and early 1990s.

The Ethanol Mandate

208. The single most important difference between today's situation and the one that existed in the early 1990s is that today ethanol blending is mandated under the federal government's RFS. The mandated use of ethanol in CaRFG3 actually predated the RFS requirement by several years. Completion of the California MTBE phaseout in January 2004 was a "de facto" ethanol mandate after the EPA denied California's waiver request in 2001 to eliminate the oxygenate requirement for federal RFG.[177] Thus, the use of ethanol was effectively

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[177] Christine Todd Whitman, EPA Administrator, Letter to California Governor Gray Davis, June 12, 2001.

mandated in California from January 2004 until the first federal RFS became effective in May 2006.

209. The RFS mandates the use of certain increasing volumes of ethanol on a nationwide and annualized basis. The mandate removes from the "choice" equation any consideration of the economic, quality, consumer, and other preferences that might exist relative to potential alternatives. A mandate forces the coordinated action of all companies towards a common policy goal and demands that each individual company do whatever is necessary to achieve it. No such mandate existed in the early 1990s in connection with the use of oxygenates.

210. The ethanol mandate has also affected potential investors' perception of the risks inherent in investing in ethanol production facilities with regards to a minimum (and increasing) demand for ethanol. The mandate created a guaranteed minimum market volume for ethanol, which lowered investors' concerns during the 2005-2007 time period. Had such a mandate been imposed in the early 1990s, it is likely that additional time would have been needed to allow producers, refiners, and marketers to make the required investments. It is difficult to estimate how much time would have been needed, but based on my knowledge, I anticipate that it would have had the effect of postponing the ultimate implementation of the 1990 CAAA. It is doubtful whether such a delay would have been politically acceptable at the time.

Improvements in Ethanol Technology

211. It is unreasonable to assume that what is being achieved today in ethanol production technology could have been achieved 15-20 years ago. Since the late 1980s, there have been significant reductions in both the capital and operating costs of modern ethanol plants, as well as improvements in technology. Such improvements are common in the refining or chemical industries, as knowledge expands during the course of growth of a business line. In 2006, the

USDA sponsored a study[178] to examine how information technology had affected the structure, organization, and operations of the fuel ethanol industry. The study observed that, "*The most prominent business development in the industry is the rise of the ethanol "franchise." These so-called "cookie-cutter" ethanol plants are offered principally by two design/build firms, Broin, Fagen/ICM, who have adopted, developed, and now capitalize on two IT-enabled innovations – process design technology and distributed control systems (DCS). Using standardized designs, these firms and others build these cookie-cutter plants that they can put down quite easily in almost any location. They can offer an entire package – from feasibility study to turn-key and beyond. This prospect didn't exist in the early 1990s, when there were still a lot of questions on what was the right way to build a plant.*"[179]

212. The study also observed that, from a cost perspective in relation to 10-15 years ago, the standardized design technology and approach has reduced the cost of construction and the non-energy portion of the operations by one-half. The following table summarizes some of the particulars from the study.[180]

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[178] *The Role of Information Technology in the Fuel Ethanol Industry*, USDA Study, May 2006.
[179] Ibid., pp. 8-9.
[180] Ibid., Table 1, p. 3.

Ethanol Plant Change	Mid-1980s to early 1990s	2005
Plant Construction Cost, $/Gal. of production capacity	2.5	0.98
Ethanol produced per bushel of corn, Gals.	2.2	2.8
Plant labor requirements, full-time staff members	52 (1998)	32 (2005)
Plant labor costs, $/Gal. of ethanol	0.15 (1998)	0.05 (2005)
Operating days per year	310-320	350-360
Other Changes		Energy input per gallon down 50% in 20 years

213. One of the key reasons for the lower ethanol plant construction cost today versus the mid-1980s to early 1990s has to do with economies of scale. In the early 1990s, according to the USDA study, a new ethanol plant typically had a capacity in the range of 40 MMGal./Yr.[181] (This compares to Mr. Reynolds' optimistic assumption that plants built during this period would have typically had a capacity in the range of 50-75 MMGal./Yr.)[182] In contrast, plants constructed during the period 2005-2007 typically have had capacity in the range of 100 MMGal./Yr. Larger plants commonly cost less per gallon of capacity than smaller plants.

214. The foregoing data show what significant changes have occurred in the cost and performance of ethanol production facilities. It is important to understand that one cannot take today's circumstances and extrapolate them back 15-20 years and conclude that the same "could have" been achieved then. There is a "learning curve" associated with all such processing

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[181] Ibid., p. 4, subheading "Low-priced Corn."

[182] Reynolds Deposition, Suffolk Case, August 2, 2007, p. 260, lines 20-21.

technologies. Therefore, one should not expect that what can be done today would have been done within the ethanol industry 15-20 years ago. Even Mr. Reynolds acknowledges the ethanol technology changes that have evolved over the years. He described many of them in one of his depositions in the Suffolk Case.[183]

Ethanol Industry Concentration

215. The ethanol industry in the early 1990s was much more concentrated than it is today. The ethanol was also much more concentrated than the MTBE industry was in the early 1990s.[184] When asked if he agreed that the U.S. ethanol industry was more concentrated in the early 1990s than in the mid-2000s, Mr. Reynolds responded, "*Yes.*"[185] In the early 1990s, the top four U.S. ethanol producers (out of a total of 32) comprised over 75% of the market.[186] In such a highly concentrated industry, the barriers to entry for new producers are higher because the large existing suppliers are usually well positioned to defend their market share. For example, during the early 1990s time period, a company contemplating penetration of the fuel ethanol market would have faced significant volume risk from the likes of ADM or Minnesota Corn Processors, two large ethanol producers who used wet mill technology. As noted previously, such producers could easily swing from high-fructose corn syrup production to fuel ethanol and put market pressure on a new, smaller ethanol producer. This increased the risk of new market entrants.

216. In comparison, in 2006, the U.S. Federal Trade Commission (FTC) reported that the U.S. ethanol industry was not concentrated or, at most, only moderately concentrated under its

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[183] Reynolds Deposition, Suffolk Case, August 3, 2007, p. 502, line 5, to p. 503, line 8.

[184] The Herfindahl-Hirschman Index (HHI) is a measure of the level of competition within an industry. An HHI greater than 0.18 is indicative of a concentrated, less competitive industry, while a value less than 0.18 indicates a high degree of competition. In 1993, the HHI of the ethanol industry was 0.36, while that of the MTBE industry was only 0.11. Thus, the ethanol industry was much more highly concentrated.

[185] Reynolds Deposition, Suffolk Case, August 3, 2007, p. 504, lines 11-14.

[186] *Petroleum Supply Annual 1992,* U.S. EIA, Volume 1, Table 49.

merger guidelines.[187] Industries with low concentration provide little incentive or ability for existing producers to act in a non-competitive manner against new entrants. This reduces the risk of new suppliers entering the market. Thus, competitive entry barriers for ethanol producers in the mid-2000s were much less than in the early 1990s.

217. Market concentration also allows dominant supplier firms to exert significant leverage on their customers in terms of price, supply flexibility, reliability, and other terms. In such cases, purchasers may have a bias against purchasing from a supplier who wields significant market power. For example, a refiner faced with the choice, in the early 1990s, of being tied to buying ethanol from ADM versus manufacturing its own MTBE at its refinery, might be expected to choose the latter to be free from such market power. Of course, the availability of multiple supplier options maintains healthy competition between suppliers and permits customers to switch suppliers if quality or reliability problems arise. However, such multiple options were much less prevalent in the early 1990s than they are today. In my opinion, the large ethanol producers in the early 1990s would have fiercely resisted the entry of new, more efficient fuel ethanol competitors.

Investment Capital and the Role of Cooperatives

218. One of the most significant recent changes to occur within the fuel ethanol industry has been the advent of the farmer-owned cooperatives in the mid-to-late 1990s.[188] This "co-op" structure has increased the pool of investment capital directed towards the ethanol industry and enabled farmers to join together to build larger and more efficient plants than would otherwise have been possible. Such co-ops are also better positioned to tolerate corn price volatility through the ethanol plants' integration with the farmers' own corn production. In a high corn price environment, the co-op owners do not suffer as much from the negative economic

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[187] *2008 Report on Market Concentration*, U.S. FTC, November 17, 2008, p. 14.

[188] A farm cooperative is autonomous association in which farmers pool their resources to achieve greater operational and marketing efficiencies.

consequences as a stand-alone ethanol producer does. Such large ethanol co-ops were virtually non-existent in the late 1980s and early 1990s.

Corn Availability and Supply

219. Since the late 1980s and early 1990s, there has been a significant improvement in the yield of corn per acre of farmland, as shown in Exhibit Z. This improvement has resulted from a variety of factors, including the development of improved pesticides, the introduction of genetically-engineered varieties of corn, as well as better farming practices. Exhibit Z shows that since the decade of the 1980s, the U.S. corn yield has risen from approximately 100-110 bushels per acre to 153 bushels per acre in 2010—an approximate 50% increase. Combined with an increase in ethanol yield per bushel, ethanol yield per acre has increased by over 80%. The additional corn production has made it possible to divert more corn to fuel ethanol production, although not without periods of major upsets in grain and food businesses and an attendant rise in food prices. The improvements in corn production and yield have taken many years, and it is unlikely they could have been achieved during the three to four year period that was available to refiners to meet the 1990 CAAA requirements. In fact, as shown in the graph, corn yield, measured in bushels per acre, only increased very marginally during the period from 1990-1996.

220. The rapid expansion of ethanol as a gasoline blendstock, as required by the RFS, has created a corresponding upward pressure on the price of corn, as an ever increasing percentage of the U.S. corn crop has been diverted away from food uses and into ethanol production. Exhibit AA shows that for the 2010-2011 crop year, ethanol production will likely consume almost 40% of the U.S. corn crop—up from only about 6% in 2000.[189] This increasing diversion of corn to ethanol production has had the inevitable effect of driving up corn prices.

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[189] A corn "crop year" runs from September of one year to August of the following year.

The average 2007-2008 corn price of $4.13 per bushel was more than twice the 2004-2005 average of only $2.03 per bushel. The U.S. GAO stated in a 2009 report that, "*Higher corn prices, resulting in part from increased ethanol production, have likely contributed to domestic and international food price increases.*"[190] It remains to be seen whether today's elevated corn price of about $6.50 per bushel will be sustained into the future.

Better Consumer Acceptance

221. Since the late 1980s and early 1990s, consumers have been educated regarding the various attributes of fuel ethanol and the automobile manufacturers have modified their vehicle fuel systems to accommodate ethanol blends and avoid the problems that were previously encountered. With minor exceptions, the public perception of ethanol as a "dirty" fuel is gone. However, this has taken over 20 years to achieve. It is unrealistic to assume that the public's negative perceptions regarding ethanol could have changed overnight during the implementation of the 1990 CAAA.

Increased RBOB Supply and Terminal Blending Capacity

222. The problems many refiners faced in producing sufficient RBOB in the 1990s, as well as installing ethanol blending at terminals, have already been discussed at length. What is often overlooked is that, in the late 1980s and early 1990s, refiners had little concept of what producing RBOB (or in the case of California, CARBOB) might entail, because it was the blenders of gasohol (conventional gasoline plus 10% ethanol) who received the benefit of an RVP waiver, i.e., they could produce gasohol that exceeded the otherwise minimum RVP limits. It was not until 1992, when the EPA made clear that ethanol-blended RFG would not receive the same waiver that the focus turned to how to best make RBOB at the refinery for use in ethanol

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[190] *Biofuels - Potential Effects and Challenges of Required Increases in Production and Use*, U.S. GAO, GAO-09-446, August 2009, p. 43.

areas. The industry's capability to produce more RBOB more efficiently has evolved over a number of years, and was assisted by significant investments in refinery upgrading over the past 10-15 years. Just because refiners make ample volumes of RBOB today is no reason to conclude that this upgrading could have been adequately accomplished by the early years of the RFG era.

Improved Regulatory Climate

223. In the late 1980s and early 1990s, there was a tremendous uncertainty as to whether ethanol would be used in RFG areas because of its high blending RVP. Such regulatory issues are often determined in a highly charged political atmosphere. At the time, there was significant pressure from both the farm and ethanol proponents that RVP waivers should be provided to ethanol-blended fuels, while the EPA was bound by the intent of the 1990 CAAA to reduce auto emissions in highly polluted areas of the nation within certain time frames. With so many differing views, and so many vested interests involved, it was impossible to predict the outcome. As noted earlier in this Report, it was not until the EPA issued its final RFG regulations, in February 1994—less than a year before they were to take effect—that refiners knew with specificity what the ingredients in the RFG "recipe" would be. This uncertainty created significant risk for investors contemplating new ethanol production capacity, as well as for refiners seeking to secure reliable oxygenate supplies. As Mr. Reynolds testified at trial in the City of New York Case, "*…I think the attitude was* [in the 1980s] *will the industry grow and be there on a long term basis.*"[191] In comparison, by the mid-2000s, especially with the implementation of the RFS and better certainty of continued ethanol tax subsidies and import protection, much of this uncertainty was gone. This enabled growth in the ethanol industry that was not possible earlier.

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[191] Reynolds Trial Testimony, City of New York Case, p. 4671, lines 2-4.

Changed Macro-Economic Factors

224. Today, the worldwide oil industry, as well as the U.S. gasoline industry, is profoundly different than it was in the late 1980s and early 1990s. In 1990, the price of crude oil averaged $24 per barrel (/Bbl.)—while in 2006 it averaged $66/Bbl. In 2008, it averaged $100/Bbl., but it had reached almost $150/Bbl. by mid-year, before declining precipitously to $41/Bbl. by the end of the year. In February 2009, the price declined to a low of approximately $35/Bbl., before gradually increasing to approximately $75/Bbl. in the fall of 2010. Since that time, new geopolitical events, including the earthquake/tsunami in Japan, the Libyan crisis, and ongoing turmoil in the Middle East, have contributed to world oil prices near or above $100/Bbl. Assuming a solution is found to the European financial crisis, most oil industry analysts believe that gradually improving world economic conditions will support crude oil prices at or near these levels, particularly when one considers the high cost of finding, developing, and extracting new non-conventional crude oil supplies.

225. In a constant corn price environment, as crude oil prices (and gasoline prices) rise, ethanol production economics should improve, all else being equal. When energy prices are high, investors are more willing to invest in renewable fuels, such as ethanol. If the fundamental economics for producing these fuels are attractive and less reliant on continued U.S. federal and state tax subsidies, then more biofuels will be produced. Thus, the current outlook for the ethanol industry is reasonably positive unless corn prices rise significantly beyond current levels.

226. However, this "bullish" outlook for oil prices and ethanol economics did not exist in the late 1980s and early 1990s. At that time, the U.S. was in an economic recession and the outlook for both crude oil prices and biofuels was even more uncertain. On the other hand, during the 2003 and forward time frame, when significant domestic ethanol capacity was being

added, the U.S. was enjoying a period of robust economic growth, and seemingly limitless capital was available for such projects. The favorable macro-economic conditions that assisted in the rapid expansion of the ethanol industry in the mid-2000s period simply did not exist 15-20 years earlier. Consequently, one cannot conclude that a similar expansion would have been possible during the earlier time frame.

Economic Uncertainties Continue to Plague the Ethanol Industry

227. As stated earlier, during the late 1980s to mid-1990s, the volatility of ethanol production economics led to many closures of ethanol plants. In recent years, this volatility again manifested itself in the financial distress (including in some cases, bankruptcy or liquidation) of a significant number of ethanol producers. It also resulted in a series of corporate restructurings, asset sales, and construction curtailments to deal with ethanol production overcapacity and poor profitability. A few examples include:

- VeraSun Energy Corporation (VeraSun), one of the ethanol industry's largest producers, filed for Chapter 11 bankruptcy protection in October 2008 after reporting third-quarter 2008 losses of $474 million. VeraSun idled 1.2 BGY of ethanol capacity at 11 of its 15 operating plant facilities.[192] In the second quarter of 2009, seven of VeraSun's existing plants and one plant under construction were sold. The plants collectively can produce approximately 750 MMGal./Yr. of ethanol.[193] An additional VeraSun plant in North Dakota with a capacity of 110 MMGal./Yr. was sold in October 2009.

- In late 2008, Aventine Renewable Energy Holdings, Inc. (Aventine) pushed back the construction and start-up schedules by 6–12 months for two new plants with a total capacity of approximately 200 MMGal./Yr.[194] Aventine filed for Chapter 11 bankruptcy protection in April 2009.[195] Aventine emerged from bankruptcy in March 2010 and has completed the construction and start-up of the two delayed plants. These plants are now understood to be in operation at the time of this writing.

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[192] *U.S. Ethanol Projects Falter as Financial Crisis Takes Toll, Chemical Week*, November 24, 2008.
[193] *2009 Ethanol Industry Outlook*, Renewable Fuels Association, February 2009, p. 2 and pp. 10-13.
[194] *U.S. Ethanol Projects Falter as Financial Crisis Takes Toll*, Chemical Week, November 24, 2008.
[195] *Aventine Files Chapter 11 Bankruptcy Protection*," Daily Herald, April 8, 2009.

- Production at ethanol facilities owned by Pacific Ethanol, Inc., (Pacific Ethanol) at Madera, California (40 MMGal./Yr.) and Stockton, California (60 MMGal./Yr.) were suspended in the first quarter of 2009. The subsidiaries that operate these facilities, along with two other plants in Oregon and Idaho, that together have 100 MMGal./Yr. of annual capacity, filed for bankruptcy protection in May 2009. The parent company, Pacific Ethanol, did not file for bankruptcy.[196, 197] The subsidiaries emerged from bankruptcy in June 2010. It is understood that the Stockton plant, as well as the plants in Oregon and Idaho, are back in operation at the time of this writing.

- The Hereford Biofuels, L.P. (Hereford) subsidiary of Panda Ethanol, Inc. (Panda) filed for bankruptcy protection in January 2009, before completion of a 115 MMGal./Yr. plant in Hereford, Texas. The plant was subsequently sold by Panda's senior lenders for $25 million, or approximately 13% of the original estimated plant construction cost of $186 million. The Hereford facility was one of six 115 MMGal./Yr. ethanol plants that Panda had planned to build and operate in Texas, Colorado, Kansas, and Nebraska. In July 2009, Panda announced its dissolution and liquidation.[198,199] The plant has been re-sold and commenced production earlier this year.

- Cascade Grain Products, LLC, which operated a 108 MMGal./Yr. ethanol plant that began operations in June 2008, at Clatskanie, Oregon, filed for Chapter 11 bankruptcy protection in January 2009. The case was converted to a Chapter 7 filing in September 2009, and the plant was sold at auction in December 2009 for $15 million to the plant constructor. However, it has not been restarted.[200,201]

- Northeast Biofuels, LP, completed construction and commenced operations of a $165 million, 100 MMGal./Yr. ethanol plant in Fulton, New York, in August 2008. It filed for Chapter 11 bankruptcy protection in January 2009.[202, 203] The facility was sold at auction for $8.5 million and restarted operations in June 2010.

- White Energy Holding Company, LLC, owner of 245 MMGal./Yr. of ethanol capacity at three plants located in Texas and Kansas, filed for Chapter 11 bankruptcy protection in May 2009.[204] Two plants in Texas, with a combined capacity of 200

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[196] *2009 Ethanol Industry Outlook*, Renewable Fuels Association, February 2009, pp. 2, 10-13.

[197] *Pacific Ethanol Plants Declare Bankruptcy*, The Business Journal – Merced, Kings, Madera, Tulare, May 18, 2009 – or, from website, Magic Valley, ID; Columbia, OR; Stockton, CA; Madera, CA.

[198] *Panda Ethanol to Break Ground on 100 Million Gallon Ethanol Plant in Hereford, Texas*, Panda Ethanol News Release, September 14, 2005.

[199] *Panda Ethanol Announces Dissolution, Liquidation Plan*, Oil Price Information Service, July 17, 2009.

[200] Asset Sale Announcement, IR1 Group.

[201] *Enterprise Zone Deferral*, The Clatskanie Chief, June 23, 2010.

[202] Northeast Biofuels, LLC, Facts & Data, January 1, 2006.

[203] *Bankruptcy Court Approves Northeast Biofuels Auction Sale*, Ethanol Producer Magazine, March 25, 2009.

[204] *White Energy Files Bankruptcy*, DTN Ethanol Center, May 8, 2009.

MMGal./Yr., had just been completed in early 2008.[205] The company emerged from bankruptcy in March 2010 and continues to operate the three plants.

- Renew Energy LLC, owner of a grassroots 130 MMGal./Yr. ethanol plant located in Jefferson, Wisconsin, commenced operations in November 2007 but filed for Chapter 11 bankruptcy protection in January 2009.[206] The plant was sold at auction in December 2009 and is in operation at the time of this writing.

- In February 2011, Southwest Georgia Ethanol LLC, a 90 MMGal./Yr. ethanol facility located in Camilla, Georgia, filed for Chapter 11 bankruptcy protection.[207] The company's filing was reportedly due to insufficient working capital resulting from increasing input costs (i.e., corn) and decreasing product prices stemming from the weak economy. The facility continues to operate while it seeks to reorganize.

- In February 2011, Range Fuels, the owner of a 20 MMGal./Yr. cellulosic ethanol plant in Soperton, Georgia, shut down and laid off most of its employees after producing just one batch of ethanol.[208] The company announced it is seeking to raise more money while it works through various technical issues. Any re-start of the plant remains uncertain.

- In April 2011, Clean Burn Fuels LLC, North Carolina's first ethanol plant, a 60 MMGal./Yr. facility, that started up in August 2010, filed for Chapter 11 bankruptcy and shut down.[209] The company stated that the price of ethanol had not kept up with the surging cost of corn.

228. Developments of this nature underscore the risks and uncertainties that have plagued the domestic ethanol industry since its inception. Even with the benefits of the federal RFS mandate, a generous federal subsidy, and a protective import tariff, many new large and efficient ethanol facilities have been unable to compete in what proved to be a relatively low gasoline price environment during most of 2009. Given what has occurred in the ethanol industry in just the last few years, it is not surprising that gasoline suppliers were reluctant to enter into supply contracts with small and inefficient ethanol producers in the early 1990s.

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[205] *White Energy Opens First 100-Million-Gallon Ethanol Plant in the State of Texas*, White Energy, Inc., Press Release, January 17, 2008.

[206] *Renew Energy files for Chapter 11 Bankruptcy*, Ethanol Producer Magazine, February 5, 2009.

[207] *First United Ethanol Subsidiary Southwest Georgia Ethanol Files for Chapter 11 Bankruptcy,* Biofuels Journal, February 3, 2011.

[208] *The Range Fuels Fiasco,* The Wall Street Journal, February 11, 2011.

[209] *NC Ethanol Plant Files for Bankruptcy, Cites High Corn Prices,* Ethanol Producer Magazine, April 8, 2011.

Conclusion

229. In my opinion, it is totally improper to consider what has been achieved in the ethanol and the refining industries over the last 15-20 years and conclude that the same could have been achieved during the implementation of the 1990 CAAA. Conditions were simply too different across many dimensions. The dynamics of the entire industry were vastly different during the two periods, and there was simply too much uncertainty in the earlier periods to encourage the level of change and investment needed. When individual refiners considered their choice between ethanol and MTBE, it was typically made on the basis of competition, overall economics, and security of oxygenate supply. Since MTBE was generally favored in all categories, it is not surprising that most refiners chose it over ethanol. MTBE phaseouts and ethanol mandates were key drivers in the transition from MTBE to ethanol in the mid-2000s. No such issues were foreseen in the earlier time frames.

VIII. DIMINISHING PUBLIC AND POLITICAL SUPPORT FOR ETHANOL

230. Over the last few years, both public and political support for the expanded use of corn to produce additional fuel ethanol has waned considerably. This has come about as a greater proportion of the population has come to understand the additional costs and unintended consequences of the large-scale use of ethanol in motor fuel. Even former Vice President Al Gore, who was once one of the most ardent advocates of fuel ethanol, has come out against expanded corn ethanol production. He now admits that the benefits of ethanol are "*trivial*."[210] Asked to explain his previous support for ethanol, the former Vice President said, "*One of the reasons I made that mistake* [i.e., supporting corn ethanol] *is that I paid particular attention to*

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[210] "Al Gore's Ethanol Epiphany," *The Wall Street Journal*, November 27, 2010.

the farmers in my home state of Tennessee, and I had a certain fondness for the farmers in the state of Iowa because I was about to run for President."[211] The realities of fuel ethanol have not been lost on others as well. Many environmentalists have turned against it as evidence increases that biofuels may produce more carbon emissions than fossil fuels. The following paragraphs briefly describe some of the more topical issues that have tarnished ethanol's image as a potential solution to the nation's energy problems.

231. **Ethanol's "Life-Cycle" Carbon Emissions** – The EPA measures a fuel's efficacy in reducing carbon emissions based on the *total* emissions over the full life cycle of the fuel source, from production through distribution, marketing and burning. It also addresses issues such as the question of "indirect land use" changes. For example, if an acre of land originally used to produce corn for food is used instead to make ethanol, another acre somewhere in the world needs to be cultivated to replace that food source. This new cultivation often releases large quantities of greenhouse gases held in the soil. Such life-cycle emission calculations reveal that ethanol's image as an environmentally friendly fuel has been significantly overstated compared to other fuel sources.

232. **Ethanol's Overall Energy Balance** – The total energy needed to produce a gallon of fuel ethanol has been the subject of numerous studies and considerable controversy. The controversies have had to do primarily with how the calculation is performed and what is included within the borders of energy "input." For example, there is an ongoing debate over whether the energy needed to feed the farmers that tend and process the corn, erect and repair farm fences, run the tractors, etc., are valid calculation inputs. Notwithstanding these differences, most studies indicate an overall net energy balance for ethanol production ranging

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[211] Ibid.

from slightly positive to slightly negative.[212] A recent study by the USDA updated its ethanol energy balance analysis and estimated that approximately one British Thermal Unit (BTU) of total energy input is needed to produce approximately 1.42 BTUs of energy in the form of ethanol.[213] Thus, according to the USDA study, more than 70% of the energy contained in a gallon of ethanol is consumed in producing, transporting, and marketing it. Based on similar studies of hydrocarbon-based gasoline, the corresponding energy consumption is only estimated to be about 26%.[214] Taking into account the fact that a gallon of ethanol only provides 67% of the energy in a gallon of hydrocarbon gasoline, it can be calculated that at today's ethanol market price of around $2.60/Gal., the "true" cost of replacing hydrocarbon gasoline with ethanol is $9.54/Gal. Such analyses are rapidly eroding support for ethanol as a gasoline substitute.

233. **Ethanol's Water Consumption** – The water consumption attributable to ethanol production is enormously higher than that used in gasoline production. According to a 2009 study by the Argonne National Laboratory, a DOE-managed research facility, the production of one gallon of ethanol requires an average of 78 gallons of water (including the water to irrigate the corn feedstock, as well as the direct in-plant usage).[215] This compares to an average of only about two gallons of water used to produce a gallon of hydrocarbon gasoline.[216] Based on the estimated 2010 ethanol output of 13.2 billion gallons, the incremental 76 gallons of water needed for ethanol production amounts to more than one trillion gallons annually. This is enough water

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[212] A positive net energy balance means less overall energy (in all forms) is needed to produce, transport, and use ethanol than the energy content contained in the fuel. A negative net energy balance means the opposite.

[213] *2008 Energy Balance for the Corn-Ethanol Industry*, Table 3, USDA, June 2010.

[214] *Full Fuel Cycle Assessment Well to Tank Energy Inputs, Emissions and Water Impacts,* California Energy Commission, February 2007, Figure 7-1, p. 7-4.

[215] *Consumptive Water Use in the Production of Ethanol and Petroleum Gasoline*, Argonne National Laboratory, January 2009, Table 5, p. 29. The figure of 78 gallons is a weighted average based on the reported water consumption in the three different regions.

[216] Ibid., Table 16, page 56. From Table 16, approximately 4.5 gallons of water is used per gallon of crude oil processed. Applying the average yield of gasoline from crude oil (47%), this results in a water usage of only about 2.1 gallons for each gallon of gasoline.

to cover the entire City of Fresno (112 square miles) to a depth of 43 feet!

234. **The Food vs. Fuel Argument** – Based on current projections, it is estimated that almost 40% of the 2011 U.S. corn crop will be used in the production of ethanol. In the last 6 months, U.S. corn prices have averaged an increase of more than 70% compared to the 2010 average price—from about $3.80/bushel to around $6.50/bushel. Although there are disagreements among analysts as to how much corn ethanol production has contributed to this increase, there can be no question that the diversion of increasing quantities of corn to fuel ethanol, and away from livestock feed and other food uses, has been a factor. A recent USDA study on agricultural price projections to 2020 states that, "*Although corn prices* [are projected to] *fall from their current high levels, they are projected to remain historically high due to continued demand for corn ethanol production as well as growth in feed use and exports.*"[217] Rising corn prices impact the cost of other feedstocks, as well as increase the cost of meat, poultry, and other commodities that rely on corn as a primary feed source. Stubbornly high food prices are weakening political support for any further expansion of corn ethanol production.

235. **Ethanol Subsidies - The VEETC** – Blenders of ethanol into gasoline currently receive an incentive of 45¢/Gal. (of ethanol blended) in the form of a tax credit. This is known as the volumetric ethanol excise tax credit (VEETC) and it effectively allows purchasers and blenders of ethanol to pay producers more for their product than would otherwise be the case. The VEETC increases ethanol prices and costs the federal government over $6 billion per year in lost revenue. This does not include the costs of grants, loan guarantees, or loss of efficiencies in refineries and marketing operations. Because of federal government budget limitations, there is increasing political opposition to any continuation of the VEETC beyond its expiration on

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[217] *USDA Agricultural Projections to 2020,* USDA, February 2011, p. 64.

December 31, 2011. Elimination of the VEETC would not reduce the quantity of ethanol blended into gasoline since this is mandated by law. However, discontinuance of the VEETC has the potential to significantly alter the economics of ethanol producers.

I reserve the right to amend these opinions if subsequent information becomes available which would materially alter my findings.

JOHN B. O'BRIEN

Date: November 21, 2011

APPENDIX 1

JOHN B. O'BRIEN
DEPOSITION AND EXPERT TESTIMONY
(2007-Present)

Date	*Case*	*Setting*	*Retaining Firm/Attorney*	*Activity*
Nov-11	State of New Hampshire vs. Hess Corporation, et. al.	Superior Court State of New Hampshire	Eimer Stahl Klevorn & Solberg Mr. Nate Eimer, Chicago , IL	Deposition
Sep-11	Motor Fuel Temperature Sales Practices Litigation (Class Action)	U.S. District Court District of Kansas	Eimer Stahl Klevorn & Solberg Mr. Nate Eimer, Chicago , IL	Deposition
Jul-11	City of Merced vs. Chevron U.S.A., et. al.	Superior Court of the State of California	King & Spalding Mr. Charles C. Correll, San Francisco, CA	Deposition
Jul-11	Orange County Water District vs. Unocal Corp., et. al.	U.S. District Court So. District of New York	King & Spalding Mr. Charles C. Correll, San Francisco, CA	Deposition
Mar-11	American Petroleum Institute vs. State of Tennessee	U.S. District Court Middle District of TN	Covington & Burling Mr. T.L. Cubbage, Washington, D.C.	Deposition
Feb-11	Getty Petroleum Marketing, Inc. vs. Bionol Clearfield LLC.	Amer. Arbitration Assoc. Boston. MA	Cooley Manion Jones Mr. Harry Manion, Boston, MA	Testimony
Dec-10	Crescenta Valley Water District vs. Exxon Mobil Corporation, et. al.	U.S. District Court So. District of New York	King & Spalding Mr. Charles C. Correll, San Francisco, CA	Deposition
Nov-10	American Petroleum Institute vs. State of North Carolina	U.S. District Court Eastern District of NC	Covington & Burling Mr. T.L. Cubbage, Washington, D.C.	Deposition
Aug-10	SK Engineering Corp. vs. Petroleos Mexicanos (PEMEX)	ICC Arbitration Mexico City	White & Case Mr. Aloke Ray, London, England	Testimony
Oct-09	Motor Fuel Temperature Sales Practices Litigation (Class Action)	U.S. District Court District of Kansas	Eimer Stahl Klevorn & Solberg Mr. Nate Eimer, Chicago , IL	Deposition
Sep-09	City of New York (Queens County) vs. ExxonMobil Corporation	U.S. District Court So. District of New York	McDermott Will & Emery Mr. Brian McGill, Washington, D.C.	Testimony
Feb-09	Neste Oil OYJ vs. Double K Oil 1996 Limited	LCIA Arbitration London	Dewey & LeBoeuf Mr. David Waldron, London, England	Testimony
Dec-08	Chinese National Petroleum Corp. vs. LaSalle Global Trust Services Ltd.	UNCITRAL Arbitration London	LXL Limited Mr. Ayad Ridha, London, England	Testimony
Feb-08	Suffolk County Water Authority vs. Amerada Hess, et al.	U.S. District Court So. District of New York	McDermott Will & Emery Mr. Brian McGill, Washington, D.C.	Deposition
Jul-07	TransAlaska Pipeline System (TAPS) Quality Bank Litigation	FERC/APUC Hearing Anchorage, AK	Skadden, Arps, Slate, Meagher & Flom Mr. John A. Donovan, Los Angeles, CA	Testimony
May-07	TransAlaska Pipeline System (TAPS) Quality Bank Litigation	FERC/APUC Hearing Dallas, TX	Skadden, Arps, Slate, Meagher & Flom Mr. John A. Donovan, Los Angeles, CA	Deposition

APPENDIX 2

QUALIFICATIONS AND EXPERIENCE

JOHN B. O'BRIEN

Mr. O'Brien is Executive Chairman of Baker & O'Brien, Inc., a professional consulting firm serving the energy, chemical, and related industries. The firm was formed in January 1993 to provide client companies with technical and economic analysis of issues affecting their businesses. Messrs. Baker and O'Brien were previously Vice-Presidents and Directors of Muse, Stancil & Co., a competing firm.

Following graduation from the Texas Military Institute in 1960, Mr. O'Brien attended the Massachusetts Institute of Technology (MIT) as a Eugene McDermott Scholar. Mr. O'Brien was awarded both Bachelor and Master of Science degrees in Chemical Engineering from MIT and began work with the Caltex Petroleum Corporation (Caltex) in New York City in 1965. As an engineer in Caltex's Manufacturing and Engineering Division, his first assignments included studies of improvements in the production economics of gasolines and jet fuels from Caltex refineries around the world. In 1967, he was transferred to Australia to work at Caltex's petroleum refinery near Sydney, Australia. He undertook assignments in both the fuels refinery and the adjacent lubricating oil refinery where his work involved optimization of refinery process unit operations. He was later transferred to the Refined Products Marketing Department of Caltex Australia's Sydney office.

In 1969, Mr. O'Brien was assigned for one year to the Technical Department of Caltex's affiliate in Manila, Philippines, where he provided technical assistance to both refining and marketing operations in the Philippines. Upon returning to Australia in 1970, he assisted in the establishment of the Caltex International Technical Center (CITC). CITC was formed to serve as a technical support group for all Caltex's worldwide refining and marketing affiliates. As Senior Project Engineer, he traveled extensively throughout the Far East, Southeast Asia, and Australia, developing solutions to refinery operational and marketing technical problems. In 1973, he was transferred back to Caltex's New York office as a Group Supervisor in the Manufacturing and Engineering Division.

In 1975, Mr. O'Brien joined the engineering contractor, Pritchard International Corporation in Kansas City, Missouri, as Project Manager. He was assigned to the engineering management of a large gas processing facility being constructed in Algeria. This $250 million project was the largest of its kind ever to be installed anywhere in the world. The assignment involved work in both Algeria and London. In 1975, Mr. O'Brien acted for three months as site Project Manager based in Algeria.

Mr. O'Brien commenced his consulting career in 1976 when he joined the firm of Purvin & Gertz, Inc., of Dallas, Texas. He immediately became involved in a wide variety of petroleum industry assignments, including refineries, gas processing plants,

APPENDIX 2

pipelines, and market studies. He worked on a large number of projects involving the refining and marketing of petroleum products and was called upon on numerous occasions to provide expert evidence in court proceedings. During seven years with Purvin & Gertz, he was promoted to Senior Principal and Houston Office Manager.

In 1983, Mr. O'Brien formed O'Brien, Wetzel & Associates, Inc., an Australian-based company providing energy consulting and project development services to energy companies in Australasia. During 1986/1987, Mr. O'Brien was based in Singapore and served as Director of Energy Consulting in Southeast Asia for Arthur D. Little Far East, a subsidiary the worldwide consulting firm. He supervised energy consulting projects in Singapore, Malaysia, Thailand, and the Philippines. In 1987, he returned to Dallas, Texas, to serve as Vice-President and Director in the consulting firm of Muse Stancil & Co. In 1993, he co-founded Baker & O'Brien, Inc., with Mr. Kenneth Baker. The firm employs approximately 45 full-time staff and associates.

Mr. O'Brien is a registered professional engineer in the State of Texas (#40705), a member of the National Petroleum Refiners Association, the American Institute of Chemical Engineers, and a former fellow of the Australian Institute of Petroleum.

APPENDIX 3

BAKER & O'BRIEN, INC.
CONSULTANTS TO THE OIL, NATURAL GAS, CHEMICALS, AND RELATED INDUSTRIES

Baker & O'Brien is a professional consulting firm serving clients involved in the processing, distribution, and utilization of hydrocarbon fuels and chemicals, and one of the leading consulting firms in the United States dealing with disputes and litigation involving the petroleum industry. Baker & O'Brien's clients include oil refiners, natural gas processors, chemical manufacturers, pipeline companies, and utilities. The firm also advises financial institutions, insurance companies, law firms, and both public and private sector agencies involved with the petroleum industry.

Baker & O'Brien's expertise covers the complete spectrum of the downstream petroleum industry from the wellhead to the consumer. In the natural gas and natural gas products industry, the firm assists clients in finding solutions to a wide range of commercial and technical issues impacting their businesses. Our consultants are experienced in natural gas gathering and transportation, natural gas processing, product supply and demand, product specifications, and marketing. We are typically called upon to combine our technical knowledge with our commercial experience to address a wide range of complex technical, operational, and business matters. We have been engaged on assignments of this kind by some of the largest and most prestigious oil and gas companies in the United States and abroad.

The firm's professional consulting staff consists primarily of chemical engineers and business analysts with significant industry experience and a high level of commercial acumen. We maintain associate relationships with a wide range of industry specialists who we call on to assist us when the need arises. Since our establishment in 1993, our consultants have been involved in various capacities in over 850 separate projects involving hydrocarbon-based materials in the United States and more than 50 countries. Baker & O'Brien consultants have frequently been retained as consulting and/or testifying experts and have been qualified to offer evidence in many judicial proceedings. We maintain offices in Dallas and Houston, Texas, and London, UK.

APPENDIX 4
SOURCE MATERIALS

Title of Document	*Source*	*Date*
Chemical Engineers' Handbook	Robert H. Perry and Cecil H. Chilton	Jan-73
Ether Ups Antiknock of Gasoline	Hydrocarbon Processing	Dec-77
Application for Waiver for MTBE in Gasoline	Petro-Tex Chemical Corp.	Jun-78
ARCO Position on Non-Exempt Alcohol and Ether Gasoline Blending Components	Frank B. Friedman / ARCO	Jul-78
On-Board Control of Vehicle Refueling Emissions: Study of Feasibility and Desirability	Exxon for the API	Aug-78
ARCO Submission to EPA on Use of up to 7% MTBE in Unleaded Gasoline	ARCO	Aug-78
Support Data for MTBE Waiver	Texaco	Aug-78
Use of MTBE in Concentrations up to 7% in Unleaded Gasoline	ARCO	Sep-78
Statement of Testimony Presented at the Gasohol, MTBE and Arconol Waiver Hearing	General Motors	Sep-78
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APPENDIX 5

Glossary of Terms

ADDITIVE PACKAGE
Selected gasoline additives that are combined together ("packaged") and added to base gasoline to impart special properties, such as oxidation, resistance, or detergency to keep engines running clean and reduce emissions. Branded gasolines generally contain additive packages unique to the brand's owner, while unbranded gasolines contain a "generic" additive package. Additive packages often make each branded gasoline unique, and are added to gasoline at the terminal truck rack just prior to delivery to the service station.

BASE GASOLINE
Gasoline that meets the specifications for a particular grade or geographic region, but which has not yet been blended with an additive package.

BARREL (Bbl. or B)
The standard unit of measure for petroleum and petroleum products, equal to 42 U.S. gallons.

B/D; or MB/D; or MMB/D
Barrels per day (B/D); or thousand barrels per day (MB/D); or million barrels per day (MMB/D). Units commonly used in the petroleum industry to measure volumetric production or refining capacity.

BLENDER (OF GASOLINE)
An entity that purchases gasoline blending components ("blendstocks") and mixes them together in appropriate quantities to make base gasoline for resale. Blenders own or lease storage tanks and blending equipment at petroleum terminals. Blenders of RFG must be registered and approved by the EPA.

BLENDING COMPONENTS (also BLENDSTOCKS)
Hydrocarbon streams produced by refineries that are blended together at the refinery, or by blenders, to produce base gasoline. The proportions of the various blending components will determine the specification of the gasoline. Examples of specifications would include the grade (i.e., regular, premium, etc.) and formulation (i.e., RFG, OFP, or conventional).

BRANDED GASOLINE
Gasoline sold by companies that have a significant national or regional market presence and are usually well recognized by the general public. Branded gasoline often contains an additive package that is unique to the company that owns the brand.

BRITISH THERMAL UNIT (BTU)
A unit of heat energy. Specifically, the amount of heat energy required to raise the temperature of one pound of water one degree Fahrenheit.

CONVENTIONAL GASOLINE
Gasoline that is not required to meet either OFP or RFG regulations under the 1990 Clean Air Act Amendments (CAAA). Conventional gasoline must still comply with its own regulations and specifications.

DISTRIBUTOR (GASOLINE)
An entity that transports or otherwise distributes gasoline along the supply chain. Also see "Jobber."

ETHANOL
An alcohol containing two carbon atoms, one oxygen atom, six hydrogen atoms, and having the chemical formula C_2H_5OH. Ethanol is obtained through the fermentation of sugars and starches. In addition to its uses in beverages and in the chemical industry, it is also used as a gasoline blendstock.

FINISHED GASOLINE
Base gasoline that has been blended with either a proprietary or a generic additive package and is ready to be sold to commercial or retail consumers.

JOBBER
An independent wholesale distributor of petroleum products that sells truckload quantities to both commercial accounts and to retail outlets, both branded and unbranded. Some jobbers own, operate, or lease their own retail service stations.

MTBE
Methyl tertiary butyl ether. A high-octane oxygenated gasoline blending component made by chemically reacting methanol and isobutylene. MTBE has been used extensively since the late 1970s for gasoline octane improvement, as well as to comply with RFG and OFP oxygenate requirements under the 1990 CAAA.

"NEAT" MTBE
Commercially-produced MTBE product sold for use as a gasoline blending component and typically required to contain at least 95% MTBE by volume.

OCTANE
A numerical rating that indicates the resistance of gasoline to "knock" in an engine. The higher the octane, the more resistance to knock.

OLEFIN HYDROCARBON
A hydrocarbon molecule that contains one or more pairs of carbon atoms that are not fully "saturated" with hydrogen atoms. Olefins are rarely found in nature, are chemically reactive, and commonly obtained by the cracking of saturated hydrocarbons at high temperatures.

OFP GASOLINE
Wintertime **O**xygenated **F**uels **P**rogram original areas in California included Los Angeles-Anaheim-Riverside, Chico, Fresno, Modesto, Sacramento, San Diego, San Francisco, and Stockton. Only Los Angeles-Anaheim-Riverside and Imperial County remain in the OFP with the other California areas achieving CO compliance and exiting the federal OFP effective June 1998.

OXYGENATE
A gasoline blending component that contains oxygen in its chemical formula. Examples include alcohols such as ethanol, and ethers such as MTBE.

PETROLEUM TERMINAL
A place where petroleum products, including gasolines, are stored after leaving the refinery, and/or are blended prior to further distribution to consumers. Large terminal facilities, such as a number of those near the San Francisco Bay Area, receive gasoline and gasoline blending components from many different sources, and distribute finished products primarily in wholesale quantities. Smaller terminals, such as those further inland that receive bulk shipments of gasoline from the larger terminals via pipeline, distribute product primarily via tank trucks to retail stations or commercial accounts in more localized areas.

RACK (OR TRUCK RACK)
The place at a refinery or terminal where gasoline is loaded into tank trucks for delivery to the final consumer.

RACK MARKETER
Entity that sells gasoline in truckload quantities from petroleum terminals, either at the truck rack to a jobber or directly to a retailer. The rack marketer purchases product in bulk quantities (usually >10,000 barrels) and sells in tank truck quantities (usually <1,000 barrels). This is called "breaking bulk."

REG NEG
The so-called "regulatory negotiation" process in which various interested stakeholders come together to negotiate an acceptable, common, achievable, and economic way to satisfy some pending regulation.

RETAIL MARKETERS
Entities that sell gasoline to consumers at the retail service station level. Retail marketers can range from large oil companies with thousands of outlets to one-site "mom and pop" operations.

RFG
Reformulated gasoline. Under the 1990 CAAA, gasoline produced by a refiner, blender, or importer was required to contain an average of at least 2.0% (by weight) oxygen in certain geographic areas on a year-round basis. The oxygen requirement was lifted in May 2006, but RFG is still required to meet strict vehicle emissions performance specifications.

TANKER (or TANK) TRUCKS
Tanker trucks transport gasoline from the terminal rack to the retail service station site. A standard tank "truckload" comprises approximately 7,500 gallons (about 180 barrels).

TBA
Tertiary butyl alcohol. TBA is an alcohol by-product from the manufacture of propylene oxide. It is very soluble in both water and hydrocarbons, and is a solid at room temperature. Since it exhibits a high-octane number, it was occasionally used by gasoline suppliers as a replacement for lead additives in the late 1980s. It also has several commercial uses as a process solvent or chemical intermediate. When chemically dehydrated (i.e., has a water molecule removed), TBA is converted into isobutylene, the key feedstock for making MTBE. Thus, following the passage

of the 1990 CAAA, TBA found its primary usage in expanding the availability of isobutylene for processing into MTBE.

TRADER (GASOLINE)
An entity that buys and sells gasoline and/or gasoline blending components in the open market. Some traders are also refiners and blenders.

UNBRANDED GASOLINE
Gasoline sold by an entity that does not have a significant national or regional market presence and is not well known by the general public.

VOLATILITY
When referring to gasoline, a measure of the propensity of the fuel to evaporate.

WHOLESALE GASOLINE DISTRIBUTOR
An entity that acquires product in truckload quantities at petroleum terminals and sells to retailers. (See also "jobber.") Wholesale gasoline distributors typically sell to both commercial accounts and to retail marketers.

APPENDIX 6

Table of Acronyms and Abbreviations Used in this Report

ASTM	American Society for Testing and Materials
Bbl. or B	U.S. barrel equal to 42 U.S. gallons
B/D	Barrels per Day
BEV	Breakeven value
BGY	Billion gallons per year
BTU	British Thermal Unit
BTX	Benzene, toluene, xylenes
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CAFE	Corporate Average Fuel Economy [Standards]
CALNEV	California/Nevada Pipeline
CARB	California Air Resources Board
CARBOB	California Reformulated Gasoline Blendstock for Oxygenate Blending
CaRFG	California Reformulated Gasoline
CaRFG1	California Phase I Reformulated Gasoline
CaRFG2	California Phase II Reformulated Gasoline
CaRFG3	California Phase III Reformulated Gasoline
CBI	Caribbean Basin Initiative [Program]
CCR	California Code of Regulations
CEC	California Energy Commission
CFR	Code of Federal Regulations
CO	Carbon monoxide

¢/Gal.	Cents per gallon
DDGS	Distillers Dry Grain with Solubles
DIPE	Diisopropyl Ether
DOE	Department of Energy
EEC	European Economic Community
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
EPA	Environmental Protection Agency
ETBE	Ethyl tertiary butyl ether
FCCU	Fluid Catalytic Cracking Unit
FTC	Federal Trade Commission
Gal.	Gallon(s)
Gal./Yr.	Gallons per year
GAO	General Accountability Office
LA Basin	Los Angeles Basin
LCFS	Low Carbon Fuel Standard
MB/D	Thousand barrels per day
MM	Million
MMB/D	Million barrels per day
MMGal./Yr.	Million gallons per year
MON	Motor Octane Number
MTBE	Methyl tertiary butyl ether
NAAQS	National Ambient Air Quality Standards
OFP	Oxygenated Fuels Program
%	Percent

PO	Propylene oxide
ppm	Parts per million
psi	Pounds per square inch
(R+M)/2	Average of RON and MON
RBOB	Reformulated Blendstock for Oxygenate Blending
RBOB-M	Reformulated Blendstock for Blending MTBE (M)
RBOB-E	Reformulated Blendstock for Blending Ethanol (E)
RFG	Reformulated Gasoline
RFS	Renewable Fuel Standard
RON	Research Octane Number
RVP	Reid Vapor Pressure
TAME	Tertiary amyl methyl ether
TBA	Tertiary butyl alcohol
TEL	Tetra ethyl lead
U.S.	United States
USDA	U.S. Department of Agriculture
USGC	U.S. Gulf Coast
VOCs	Volatile organic compounds
V/L	Vapor/liquid
Vol.%	Volume percent
Wt.%	Weight percent

APPENDIX 7

Refinery Gasoline Production

Figure A7-1 is a simplified schematic of the process units typically used to manufacture gasoline blending components ("blendstocks") at most major U.S. refineries.

Crude Oil Distillation

Heated crude oil is first pumped into a distillation (or "fractionation") tower where the oil is separated into its major components. The major components, or "fractions," are usually:

- Refinery fuel gas
- Propane and butane (LPG)
- Light naphtha
- Heavy naphtha
- Middle distillates (kerosene, jet fuel, diesel, and home heating oil)
- Gas oils
- Asphalt

The fractions from crude oil distillation listed above range from very light materials (such as propane and butane) to very heavy residues (such as asphalt). Depending on refinery configuration, these materials may be further processed into many different finished products. In the refining process, only some of the crude distillation components are used to make gasoline. These are: (1) light naphtha; (2) heavy naphtha; and (3) gas oils.

Gasoline Blending

As part of the refining process, gasoline is produced through the blending together of various blendstocks produced by different refinery process units. As is shown in Figure A7-1, blendstocks may include one or more of the following process unit streams:

- Isomerate

- Reformate
- Alkylate
- MTBE
- Cat Naphtha
- Hydrocracked Naphtha

Although not all refineries produce MTBE, the diagram shows where in the refinery an MTBE process unit would be located. A brief description of each gasoline blendstock, the corresponding production unit, and how each affects the refinery gasoline "pool" (the total gasoline production from all blendstocks), is given below.

Isomerate

Light naphtha is processed in what is called an isomerization unit. This unit increases the octane rating of the light naphtha so that more of it can be used in gasoline. Isomerization refers to a chemical reaction in which a "straight-chain" hydrocarbon is converted into a "branched-chain" hydrocarbon of the same molecular weight. The blendstock produced in isomerization is called isomerate and typically has an octane rating of 82.

Reformate

Heavy naphtha is normally processed in a catalytic reforming unit. The heavy naphtha stream is not usable as gasoline directly because of its low octane. The term "reforming" stems from the chemical reaction that takes place in the unit that essentially rearranges or "reforms" the structure of the molecules. The gasoline blendstock produced from the reformer is called reformate and has a typical octane rating of 90-95.

Alkylate

Alkylation is a chemical process that combines isobutane with propylene and butylenes to produce a high-octane gasoline blendstock called alkylate. In this process, small, light molecules are combined to make a heavier material (gasoline). The isobutane for alkylation is usually available in the refinery from other process units. The propylene and butylenes are produced by the refinery's FCCU. Alkylation competes with MTBE for the isobutylene made by the FCCU. Alkylate has clean burning properties, low vapor pressure, and a relatively high octane of 92-95.

MTBE

As described in Appendix 8, MTBE is produced by reacting methanol with isobutylene. The isobutylene is produced in the FCCU; methanol is normally a purchased commodity. After the MTBE is formed, it is separated from the unreacted portions of the feedstock stream, including the normal butylene and some small quantities of isobutylene. The unreacted portions exit the MTBE reactor essentially unchanged, except for the removal of the contained isobutylene. These may be sent to alkylation or recycled to the MTBE reactor. The MTBE product, which has high octane and low vapor pressure, is then ready for gasoline blending.

Cat Naphtha

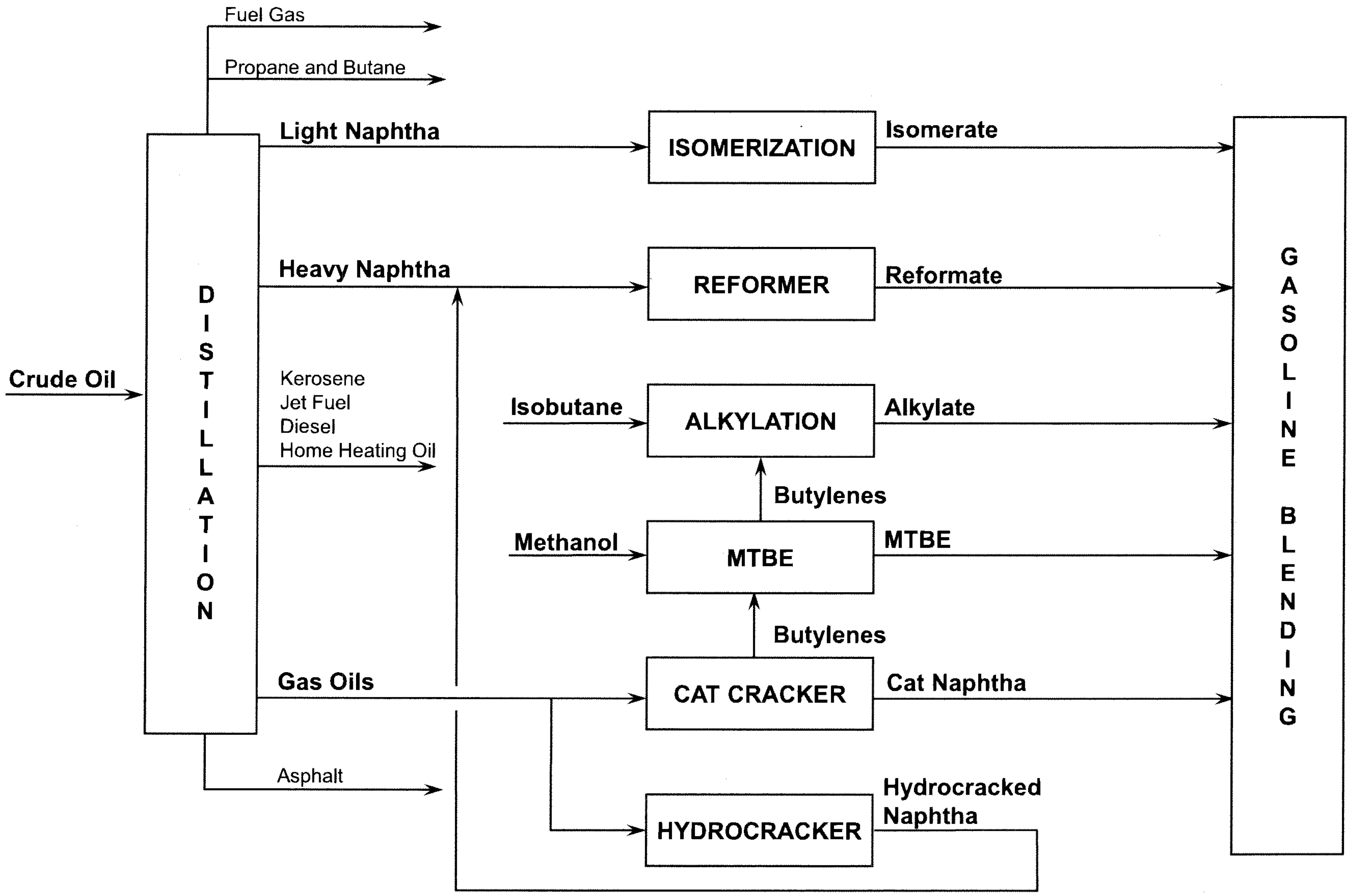
Gas oil, an important component of crude oil, can be used as feedstock to two different types of "cracking" units – the FCCU or the catalytic hydrocracking unit. The term cracking refers to what happens to the oil molecules when processed in these units. In both of these units, long hydrocarbon molecules are broken or "cracked" into two or more smaller molecules that can be used as gasoline directly or (in the case of the very small molecules) recombined in another process to make additional gasoline. In the FCCU, gas oil is converted into a gasoline blendstock known as cat naphtha. Cat naphtha normally has an octane rating of approximately 87. The FCCU also converts about 20% of the gas oil into a light mixed "olefins" stream. This stream comprises the feedstock to both the alkylation and MTBE units.

Hydrocracked Naphtha

The catalytic hydrocracking unit processes gas oil at high temperature and high pressure in the presence of hydrogen over a "fixed bed" catalyst to selectively crack the oil into products that can be made into gasoline or diesel fuels. The gasoline blendstock produced is called hydrocracked naphtha. Hydrocracked naphtha is similar to the naphtha from crude distillation, but is much higher in quality. Light hydrocracked naphtha is similar in quality to isomerate, with an octane rating of about 82. Heavy hydrocracked naphtha is usually processed in the reforming unit to make more reformate.

FIGURE A7-1

Schematic of Gasoline Production at the Refinery



APPENDIX 8

MTBE Manufacturing Processes

MTBE is manufactured through the chemical reaction of methanol with isobutylene. Methanol is the simplest alcohol, a widely available commodity chemical, and is either manufactured or purchased by MTBE producers. Isobutylene is a less common chemical, although it can be readily separated from other chemical streams or manufactured. The source of isobutylene is the distinguishing factor between the four primary production processes for MTBE, which are described briefly below.

Propylene Oxide Co-Product Process

In this process, which was one of the first to be used to make commercial quantities of MTBE, isobutylene is manufactured through the dehydration (water removal) of TBA. TBA is a co-product that is produced during the propylene oxide (PO) manufacturing process. (A co-product is a product made conjointly with the primary product, in this case, PO.) While some TBA is sold for chemical uses, it can also be used to manufacture MTBE. This MTBE production scheme is illustrated in Figure A8-1.

As shown in Figure A8-1, any surplus isobutylene from the dehydration process can be subsequently hydrogenated (hydrogen added) into isobutane, one of the feedstocks needed to make PO. Thus, any co-product TBA produced can be usefully consumed.

Ethylene Plant Co-Product Isobutylene

Isobutylene is also available as a petrochemical co-product from the manufacture of ethylene. Depending upon the type of feedstock utilized to produce ethylene, and the subsequent processing of these co-products, a mixed stream containing between 35-50% isobutylene can be available for MTBE manufacture from ethylene facilities. Many of the large refining complexes on the USGC have, or are affiliated with, petrochemical plants that produce both ethylene and co-product isobutylene. The isobutylene stream can be sold to third parties or used internally by the refinery for MTBE production.

Figure A8-2 shows the process for making MTBE from ethylene plant-derived isobutylene. The primary feedstock often contains butadiene, which is first extracted for other uses. The remaining "mixed butylenes," a mixture of isobutylene and "normal" butylenes (the latter being the "straight chain" molecules), can then either be separated for direct sale or used as a feedstock for MTBE manufacture.

Isobutylene from Refinery Catalytic Cracking Units

The third significant source of isobutylene is from refinery processing. The FCCU was the primary source of isobutylene for the production of MTBE at most refineries. When the FCCU "cracks" heavier hydrocarbons into gasoline components, it also produces some light olefin compounds. A portion of these olefin compounds comprises mixed butylenes, the potential MTBE feedstock. In the MTBE process, only the isobutylene and methanol chemically react, while the normal butylenes pass through unreacted. The latter are separated from the MTBE and used as alkylation plant feedstock. Since alkylate made from normal butylene is higher in octane than that from isobutylene, the refinery's gasoline octane benefited doubly from MTBE manufacture. Figure A8-3 illustrates the processing scheme for refinery MTBE production from FCCU isobutylene. When MTBE was being used as an oxygenate, there were over 30 plants in the U.S. that made MTBE from either FCCU-derived isobutylene or through refinery integrated ethylene plant facilities.

Direct Isobutylene Production from Butane

Because the isobutylene available through both chemical/petrochemical plants and refineries was always insufficient to supply the total demand for MTBE, various companies built plants to produce isobutylene directly from butanes. The high purity isobutylene was then reacted with methanol to make MTBE. As shown in Figure A8-4, in the first step of this process, purchased mixed butanes are chemically converted into a pure isobutane stream by a process called isomerization. Mixed butanes is a widely available commodity hydrocarbon stream that is largely a product of natural gas processing plants. Isobutylene is produced from the direct dehydrogenation (hydrogen removal) of isobutane. The isobutylene stream is then reacted with methanol in the conventional fashion to produce MTBE.

As of early 2001, there were six plants in the U.S. that produced MTBE using this process. Most of the MTBE produced was sold in the merchant market to refineries that needed incremental MTBE for gasoline blending. The MTBE production cost using this process is higher than any of the other three methods. These facilities are very capital and energy intensive. As a consequence, MTBE produced in this way represents the highest cost "incremental" source of supply.

FIGURE A8-1

Schematic of MTBE Production from Co-Product TBA

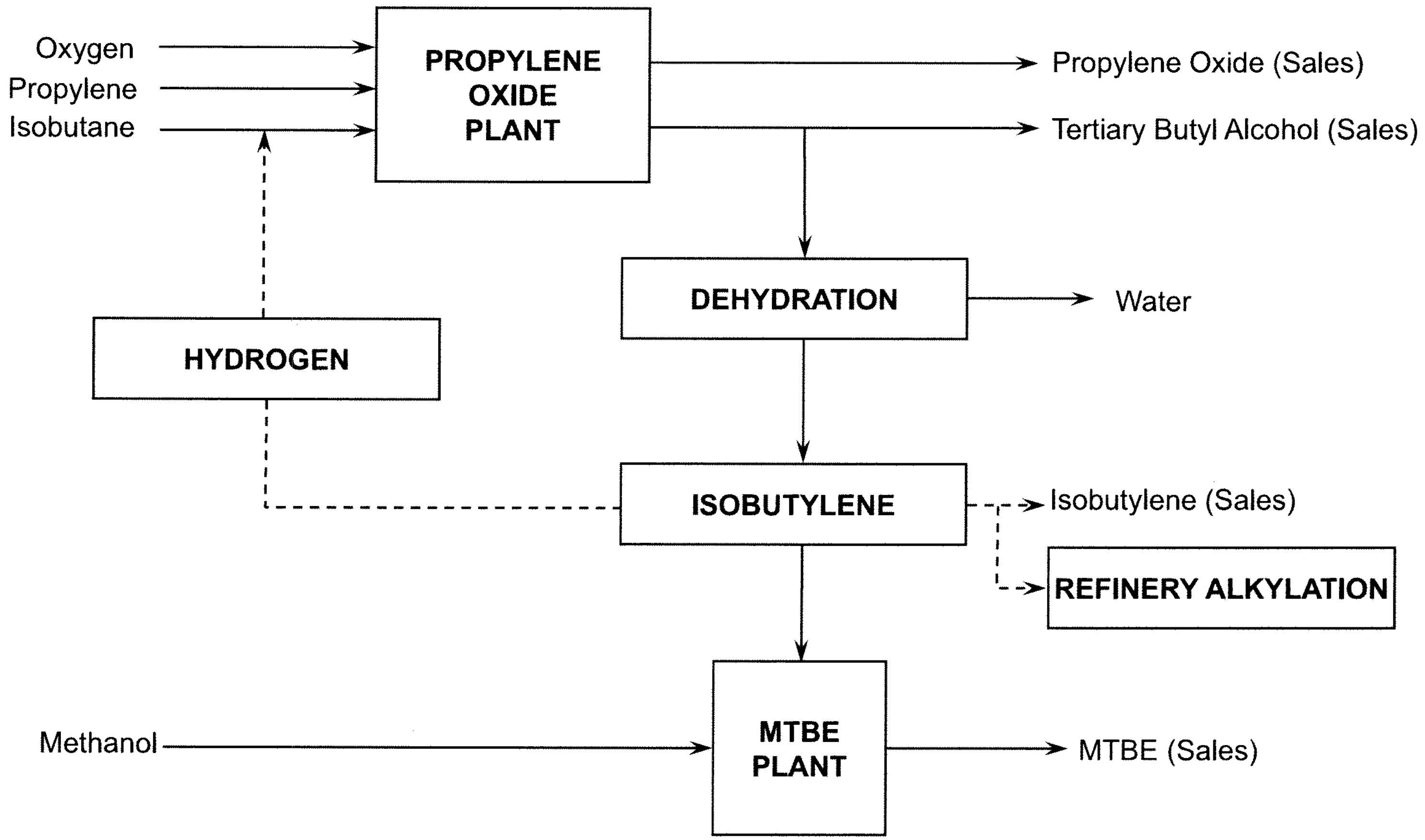


FIGURE A8-2

Schematic of MTBE Production from Ethylene Plant Mixed Butadiene / Butylene Streams

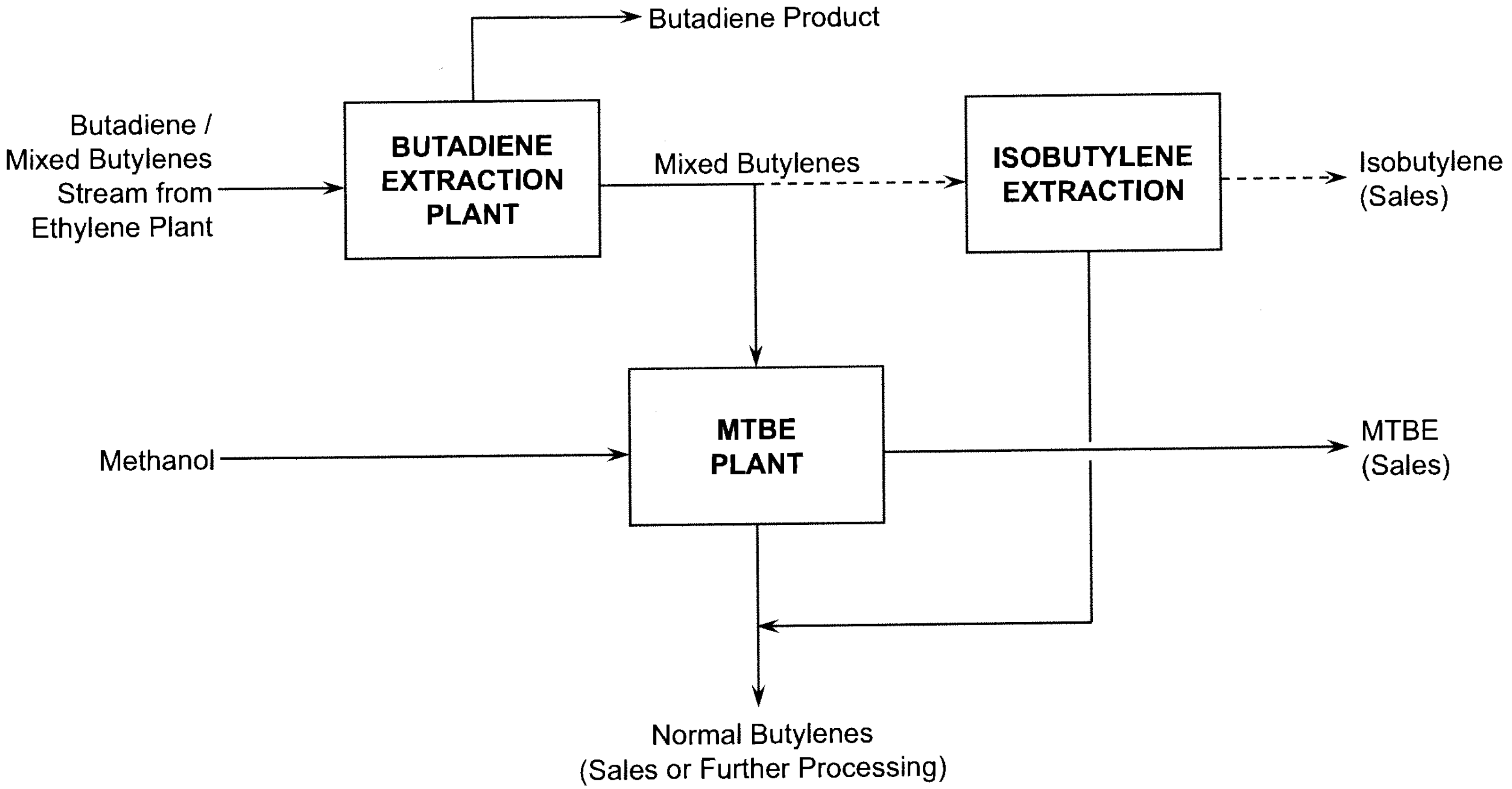


FIGURE A8-3
Schematic of MTBE Production from FCC Unit Mixed Butylenes Streams

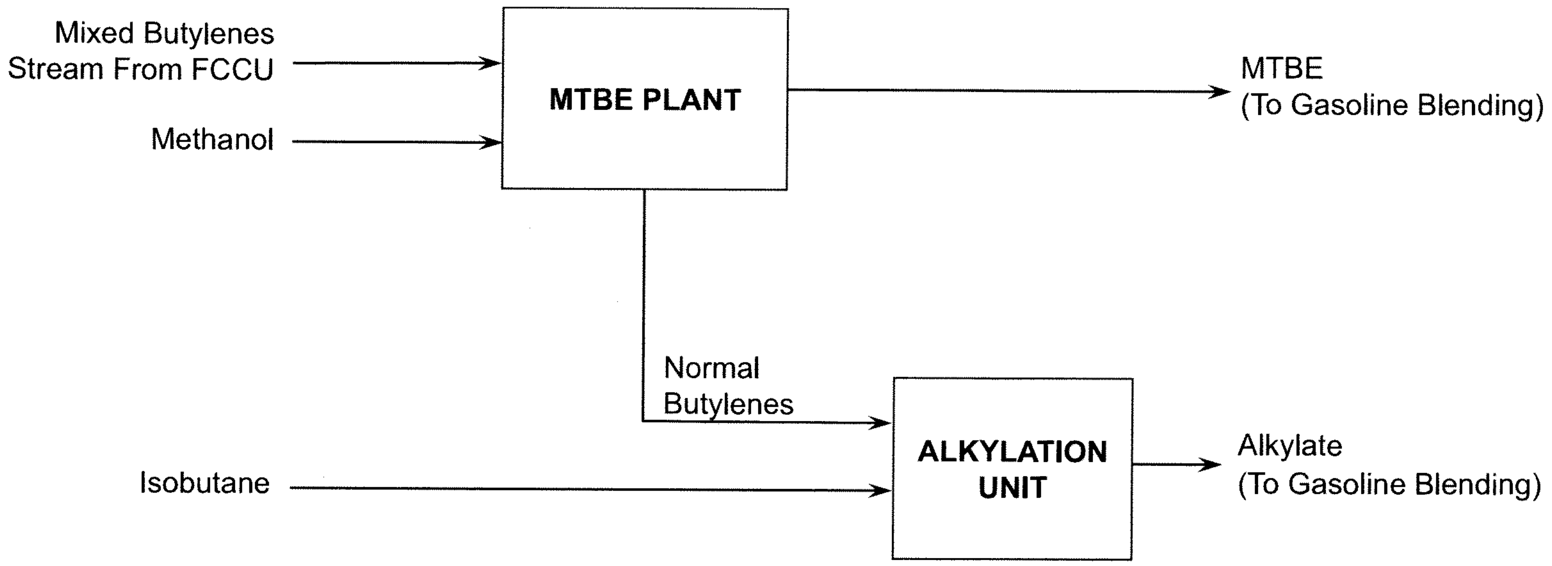


FIGURE A8-4

Schematic of MTBE Production from Butane

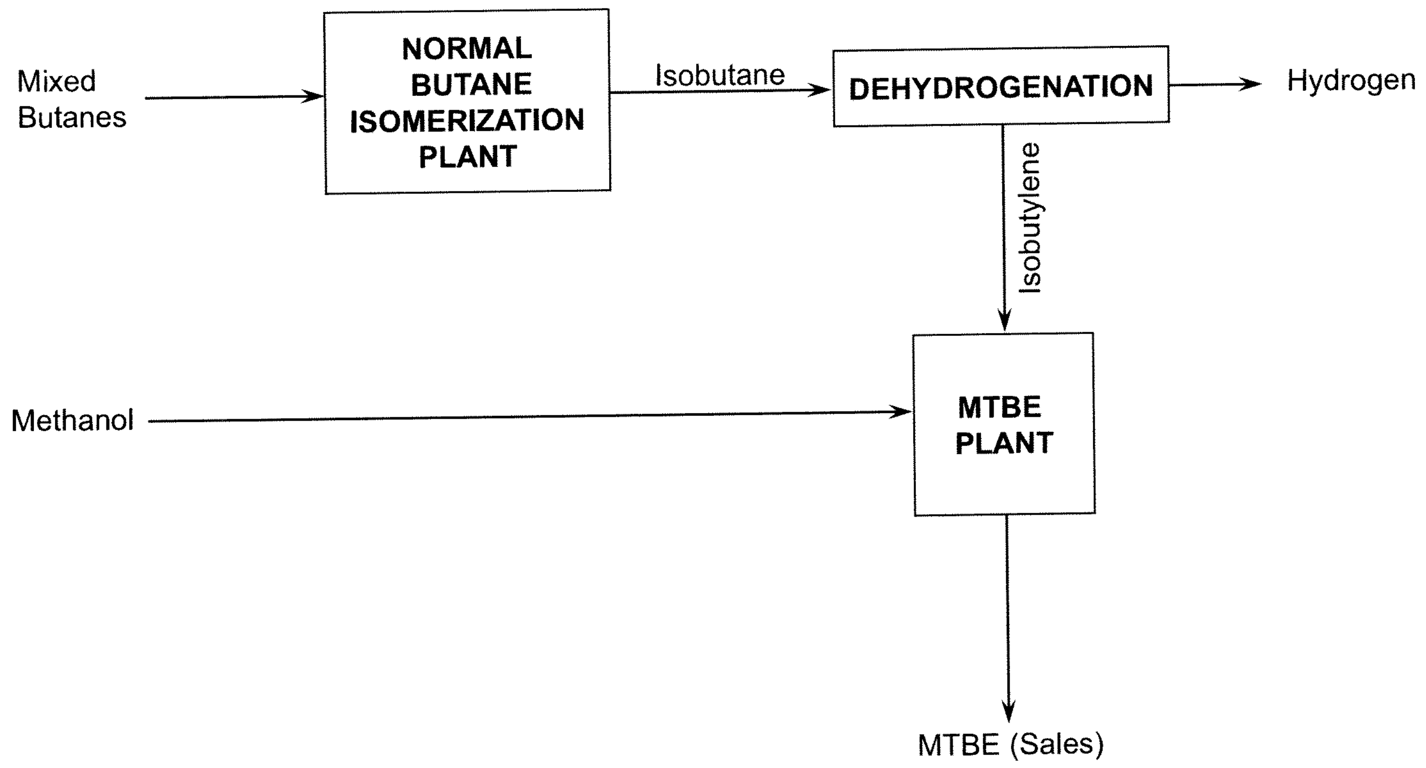


EXHIBIT A

Chemical Structures of Selected Oxygenates

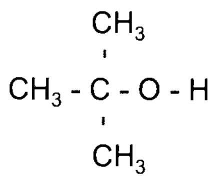
ALCOHOLS

$CH_3 - O - H$

METHANOL

$CH_3 - CH_2 - O - H$

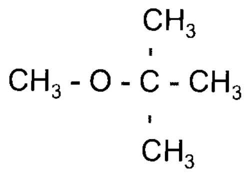
ETHANOL



$CH_3 - \overset{CH_3}{\underset{CH_3}{C}} - O - H$

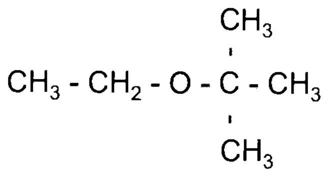
TERTIARY BUTYL ALCOHOL (TBA)

ETHERS



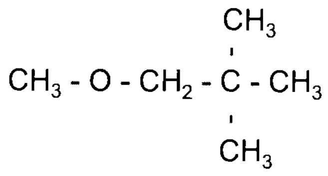
$CH_3 - O - \overset{CH_3}{\underset{CH_3}{C}} - CH_3$

METHYL TERTIARY BUTYL ETHER (MTBE)



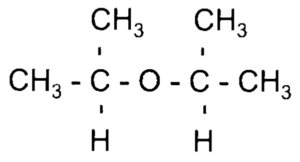
$CH_3 - CH_2 - O - \overset{CH_3}{\underset{CH_3}{C}} - CH_3$

ETHYL TERTIARY BUTYL ETHER (ETBE)



$CH_3 - O - CH_2 - \overset{CH_3}{\underset{CH_3}{C}} - CH_3$

TERTIARY AMYL METHYL ETHER (TAME)

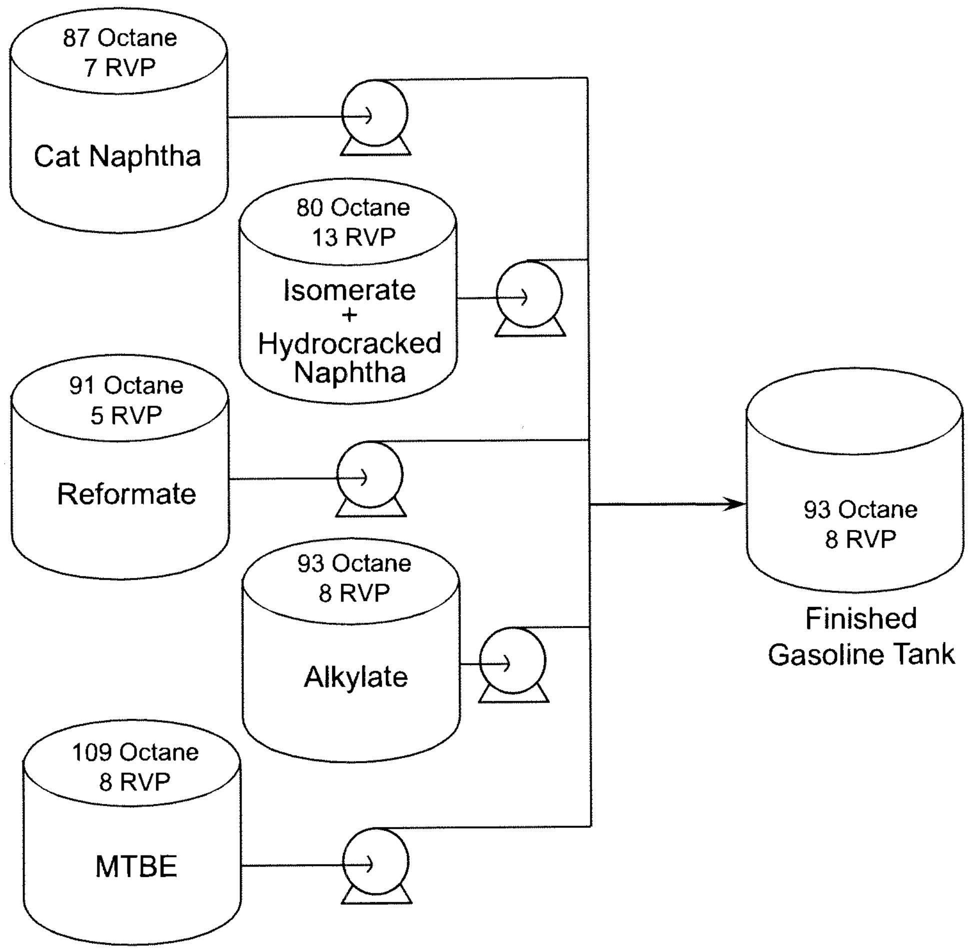


$CH_3 - \overset{CH_3}{\underset{H}{C}} - O - \overset{CH_3}{\underset{H}{C}} - CH_3$

DI-ISOPROPYL ETHER (DIPE)

EXHIBIT B

Schematic of Gasoline Blending "In-Tank" at Refinery



Product	*Octane*	*RVP*	*Vol. %*
Cat Gasoline	87	7	17
Isomerate	80	13	7
Reformate	91	5	17
Alkylate	93	8	44
MTBE	109	8	15
Finished 93 Octane Gasoline	**93**	**8**	**100**

EXHIBIT C

Schematic of In-Line Blending

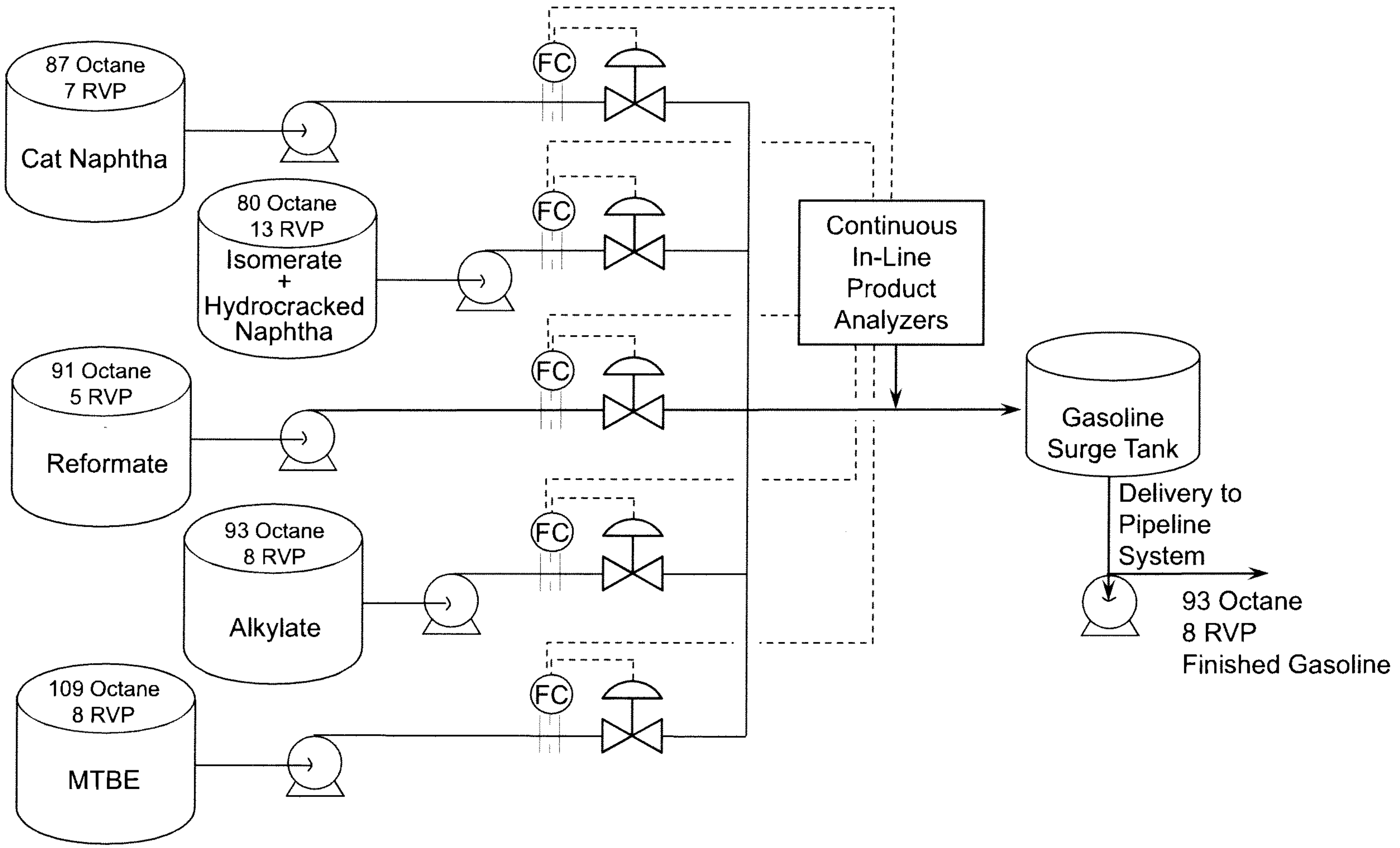


EXHIBIT D
Characteristics of Oxygenates

Property	***Fuel Ethanol***	***TBA***	***MTBE***	***ETBE***	***TAME***	***DIPE***
Oxygen Content (Wt.%)	33.0	21.6	18.2	15.7	15.7	15.7
Amount Required to Achieve 2.0 Wt.% Oxygen in Gasoline (Vol.%)	5.7	9.2	11.0	12.8	12.8	12.8
Amount Required to Achieve 2.7 Wt.% Oxygen in Gasoline (Vol.%)	7.7	12.5	14.8	17.2	17.2	17.2
Solubility in Water (Wt.%)	Miscible	Miscible	4.3	1.2	1.2	2.0
Blending RVP (psi)	18.0	9.0	8.0	4.0	2.5	5.0
Octane Blending (R+M)/2	113	100	110	112	105	105
Vapor Pressure Neat RVP (100 °F)	3.5	1.7	7.8	4.4	1.5	2.9
Boiling Point (°F)	152	181	131	164	187	155
Density @ 60 °F (Lb./Gal.)	6.58	6.60	6.19	6.25	6.41	6.05
Energy Content (MBtu/Gal.)	76.0	94.1	93.5	96.9	100.6	100.0

SOURCES:

Adapted from Technical Appendices, *Supply and Cost of Alternatives to MTBE in Gasoline,* December 1998, California Energy Commission.

Adapted from Interagency Assessment of Oxygenated Fuels, June 1997.

Adapted from National Petroleum Refiners Association 1992 Annual Meeting (AM-92-28) "Hydration of Propylene to Diisopropyl Ether - A New Source of Fuel Oxygen."

Adapted from *Properties of Alcohol Transportation Fuels,* Meridian Corp. prepared for U.S. Department of Energy, July 1991.

Adapted from *Fuel Ethanol - Technical Bulletin,* Archer Daniels Midland Company, 1998.

NOTES:

Wt.% - Weight percent.
Vol.% - Volume percent.
psi - Pounds per square inch.
(R+M)/2 - An arithmetic average of the research and motor octane values.
RVP - Reid Vapor Pressure.
Lb./Gal. - Pounds per gallon.
MBtu/Gal. - Thousand British Thermal Units per gallon
TBA - Tertiary-Butyl Alcohol
MTBE - Methyl Tertiary-Butyl Ether
ETBE - Ethyl Tertiary-Butyl Ether
TAME - Tertiary Amyl Methyl Ether
DIPE - Di-Isopropyl Ether

EXHIBIT E

Timeline of Events Relating to Gasoline Quality

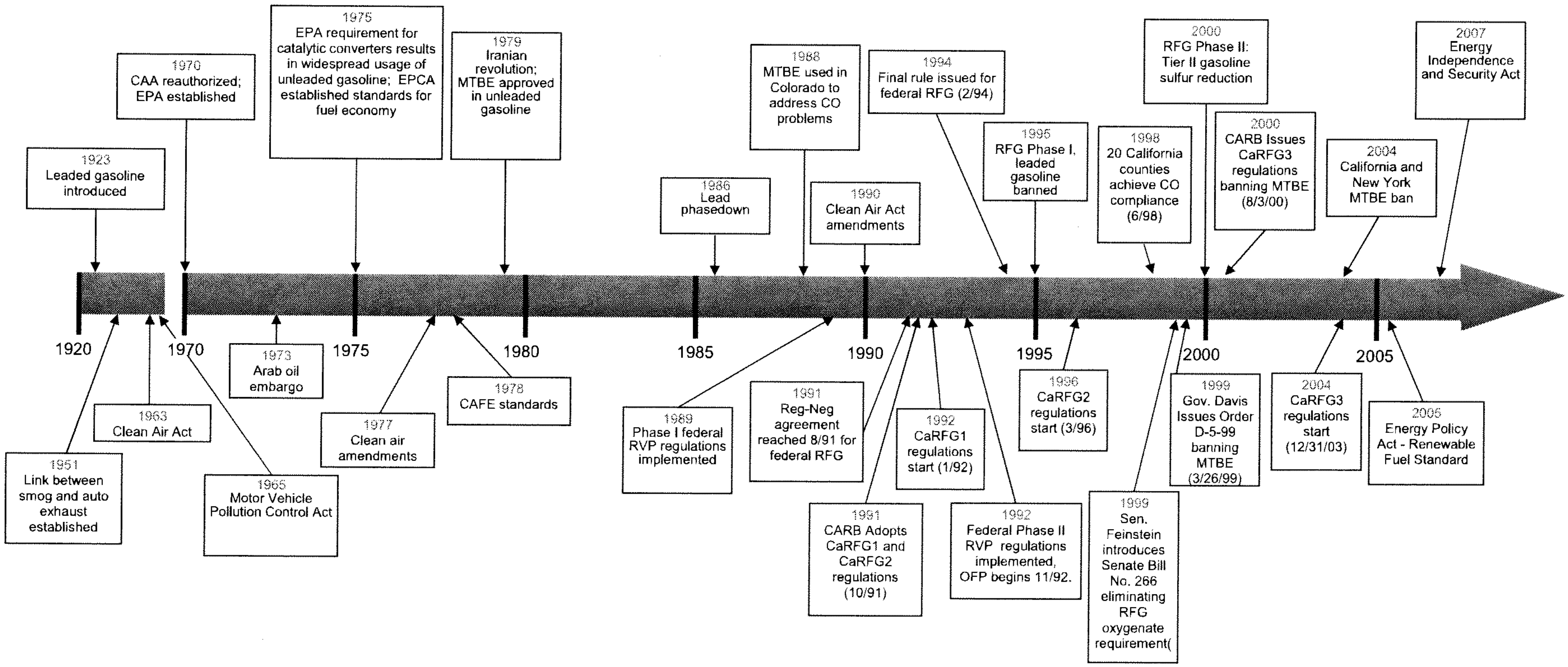
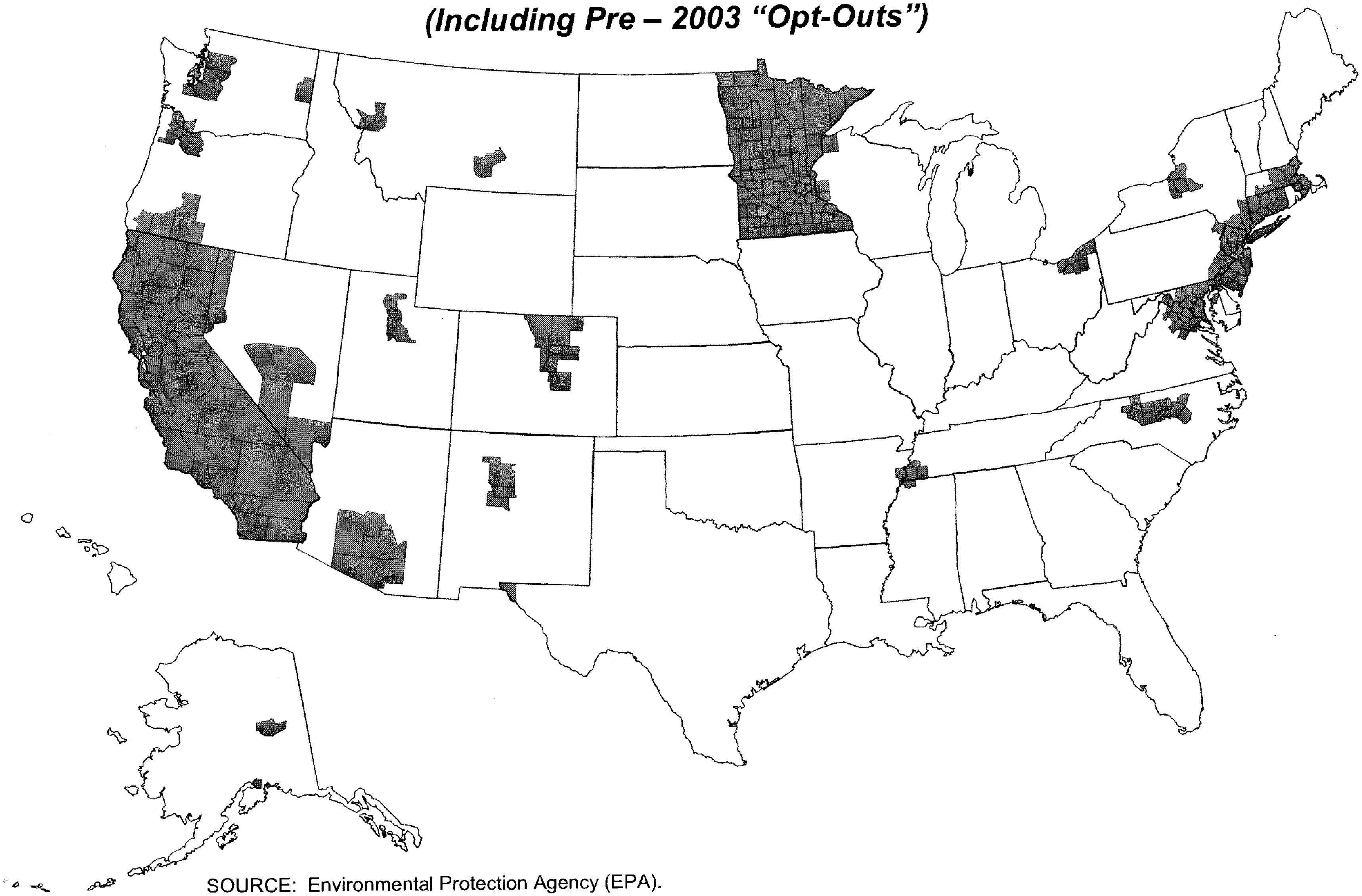


Exhibit F

All Oxygenated Fuel Program (OFP) Areas (Including Pre – 2003 "Opt-Outs")



SOURCE: Environmental Protection Agency (EPA).

NOTE: From November 1992 to February 1996, gasoline sold in all California counties during the winter months was required to contain 1.8 to 2.2 Wt.% oxygen (instead of 2.7 Wt.%) as part of California's EPA-approved State Implementation Plan (SIP).

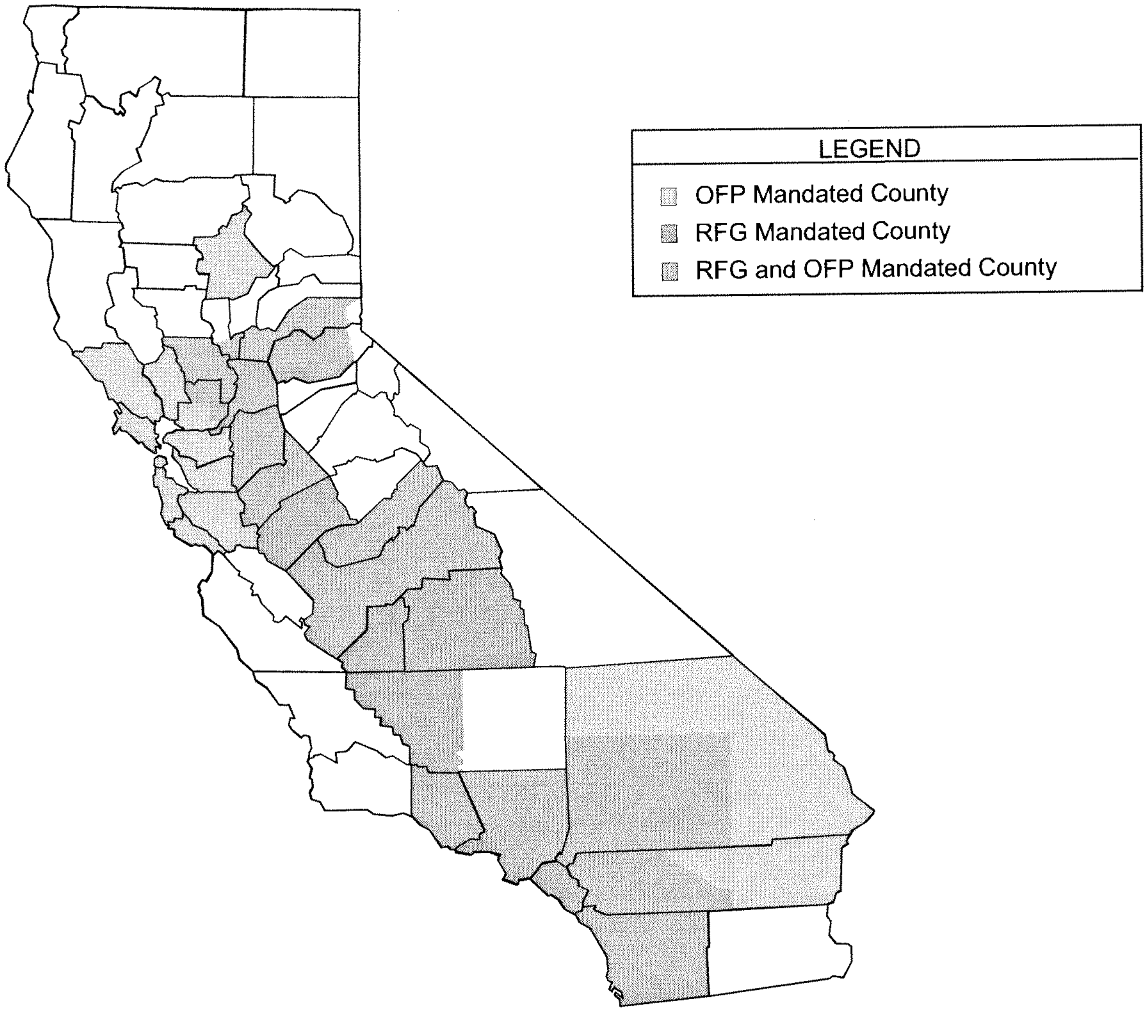
Exhibit G

All Reformulated Gasoline (RFG) Areas

SOURCE: Environmental Protection Agency (EPA).

NOTE: Showing all areas that were required to use federal RFG at any time between 1995 and 2003.

EXHIBIT H
FEDERAL RFG AND OFP MANDATED AREAS IN CALIFORNIA (1)



NOTE: (1) Showing all areas required to use federally mandated RFG or OFP at any time between 1995 and 2003.

EXHIBIT I
Schematic of Gasoline Supply Chain

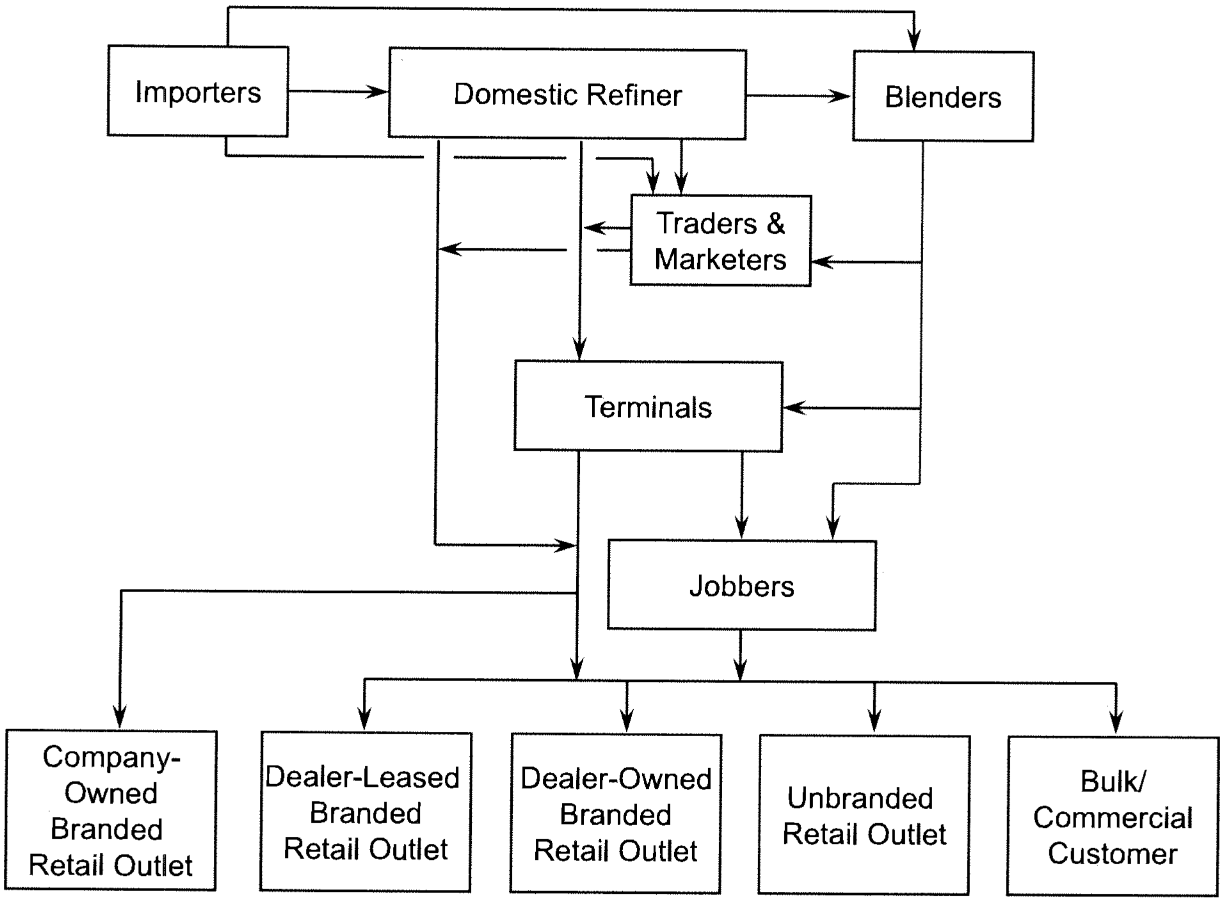
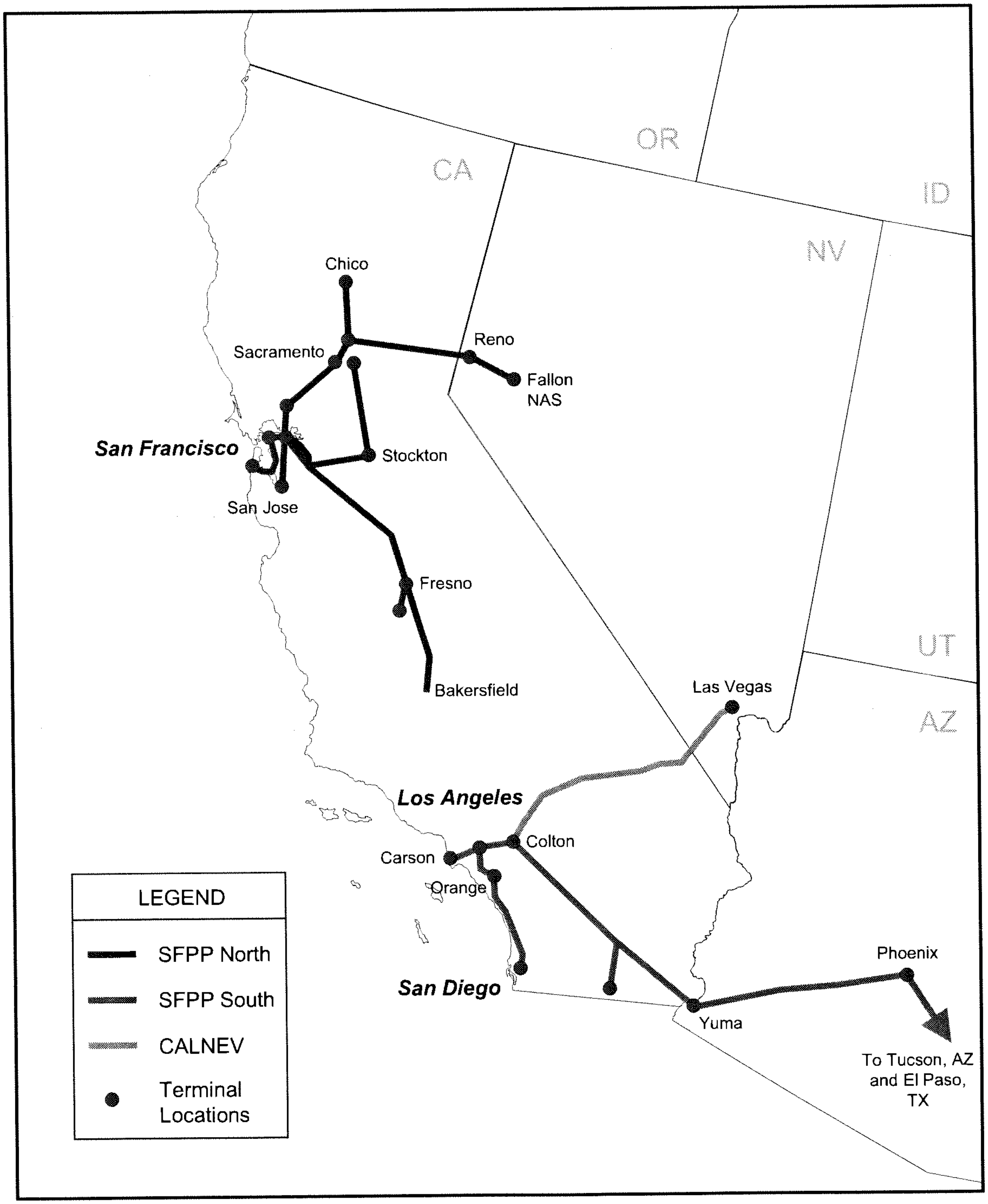


EXHIBIT J

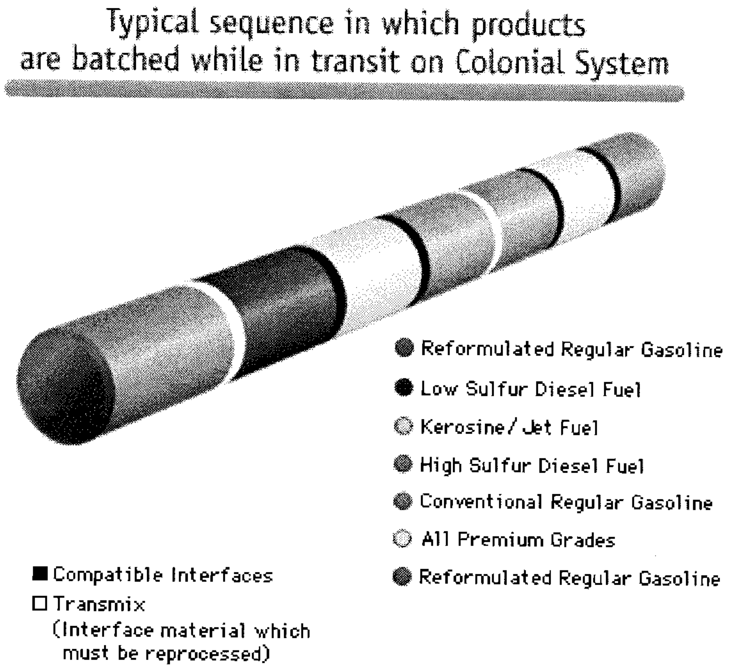
Kinder Morgan SFPP and CALNEV Systems



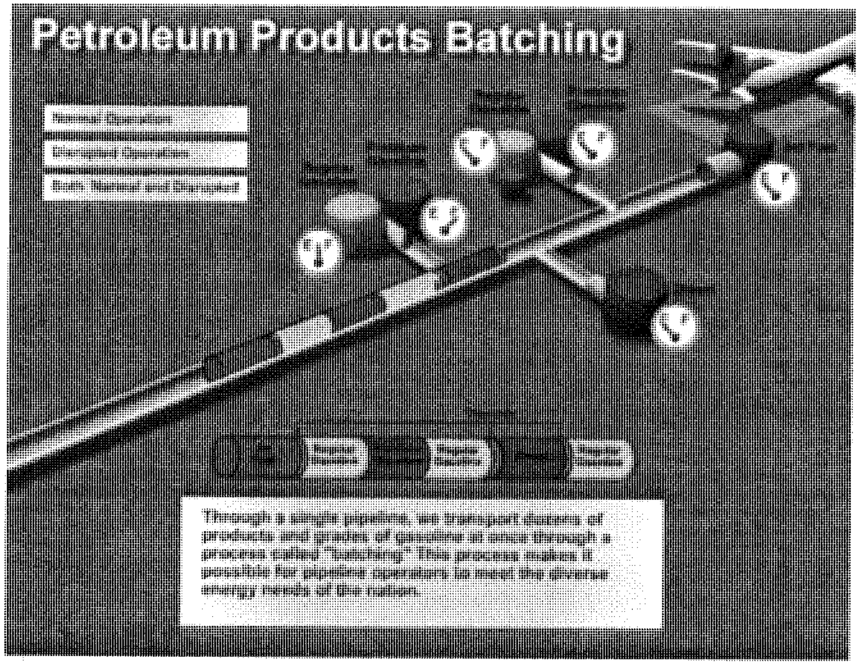
SOURCE: Kinder Morgan, Petroleum Products Pipeline System Map, Pacific Region, August 2009.

EXHIBIT K

Illustration of Liquid Pipeline Product Batches



SOURCE: Colonial Pipeline website (www.colpipe.com/ab_faq.asp)

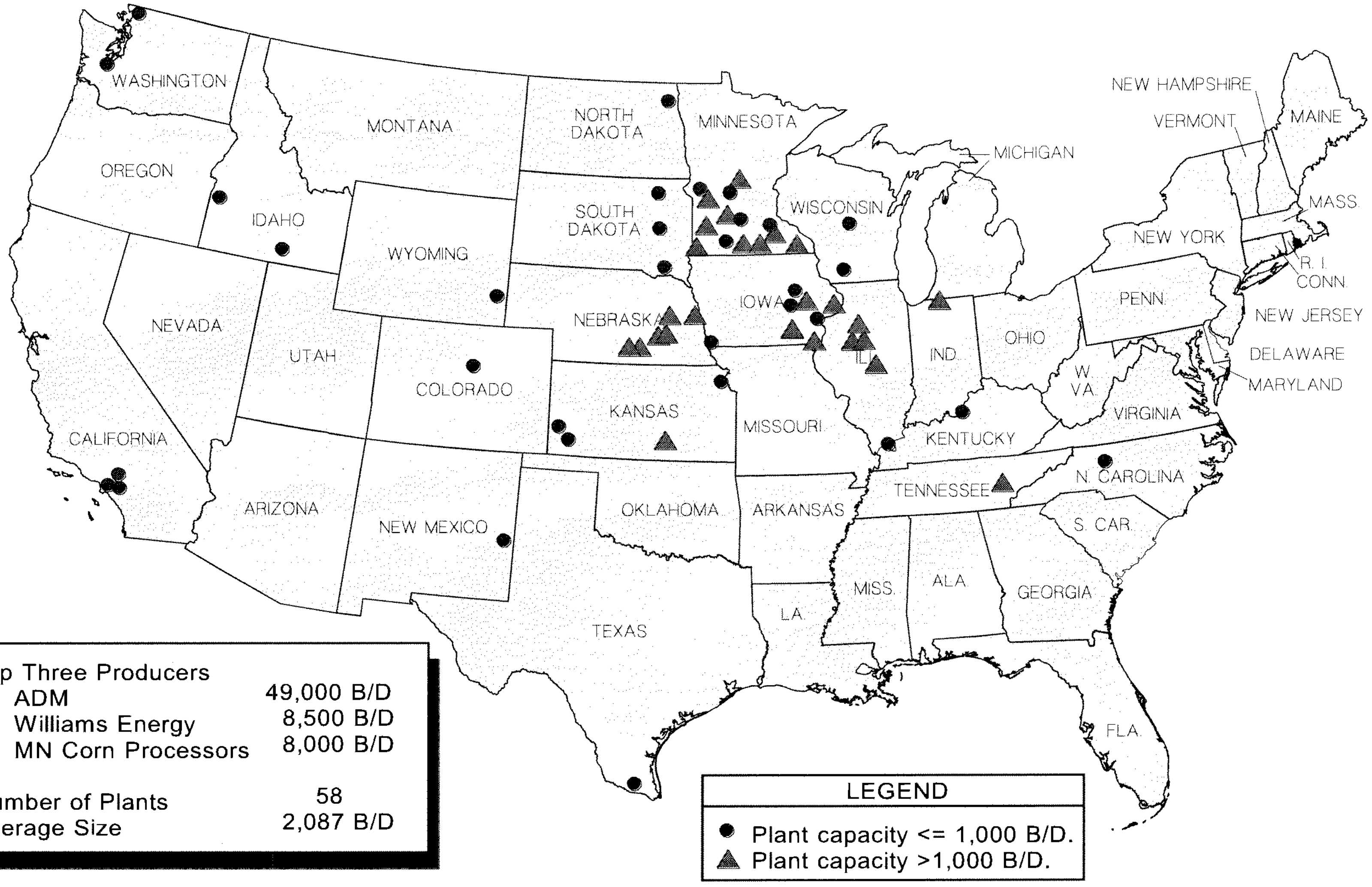


An animation of the graphic above can be viewed by accessing the website www.pipeline101.com and clicking on: →Operating Pipelines →Petroleum Products Batching →Normal Operation.

SOURCE: "Pipeline 101" website (www.pipeline101.com) developed by the oil pipeline industry and the members of the American Petroleum Institute (API) and the Association of Oil Pipe Lines (AOPL).

EXHIBIT L

Location of Ethanol Plants in the US - 2000

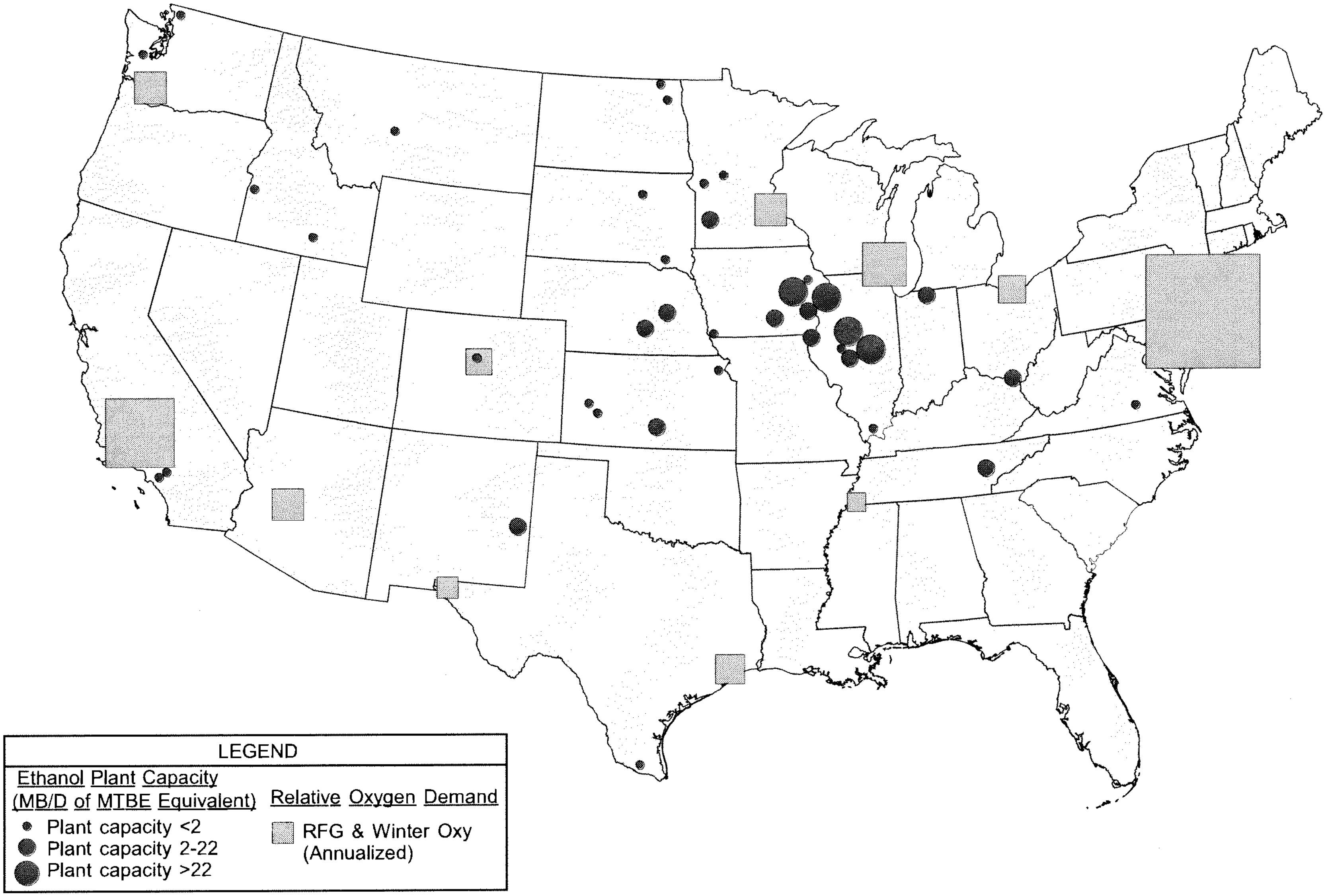


Top Three Producers	
ADM	49,000 B/D
Williams Energy	8,500 B/D
MN Corn Processors	8,000 B/D
Number of Plants	58
Average Size	2,087 B/D

SOURCE: *AUS Consultants / Bryan & Bryan Inc. (BBI)*, "Ability of the U.S. Ethanol Industry to Replace MTBE," US Ethanol Plant Capacity, March 2000.

EXHIBIT M

1990 Ethanol Plants vs. 1995 Projected Oxygenate Demand



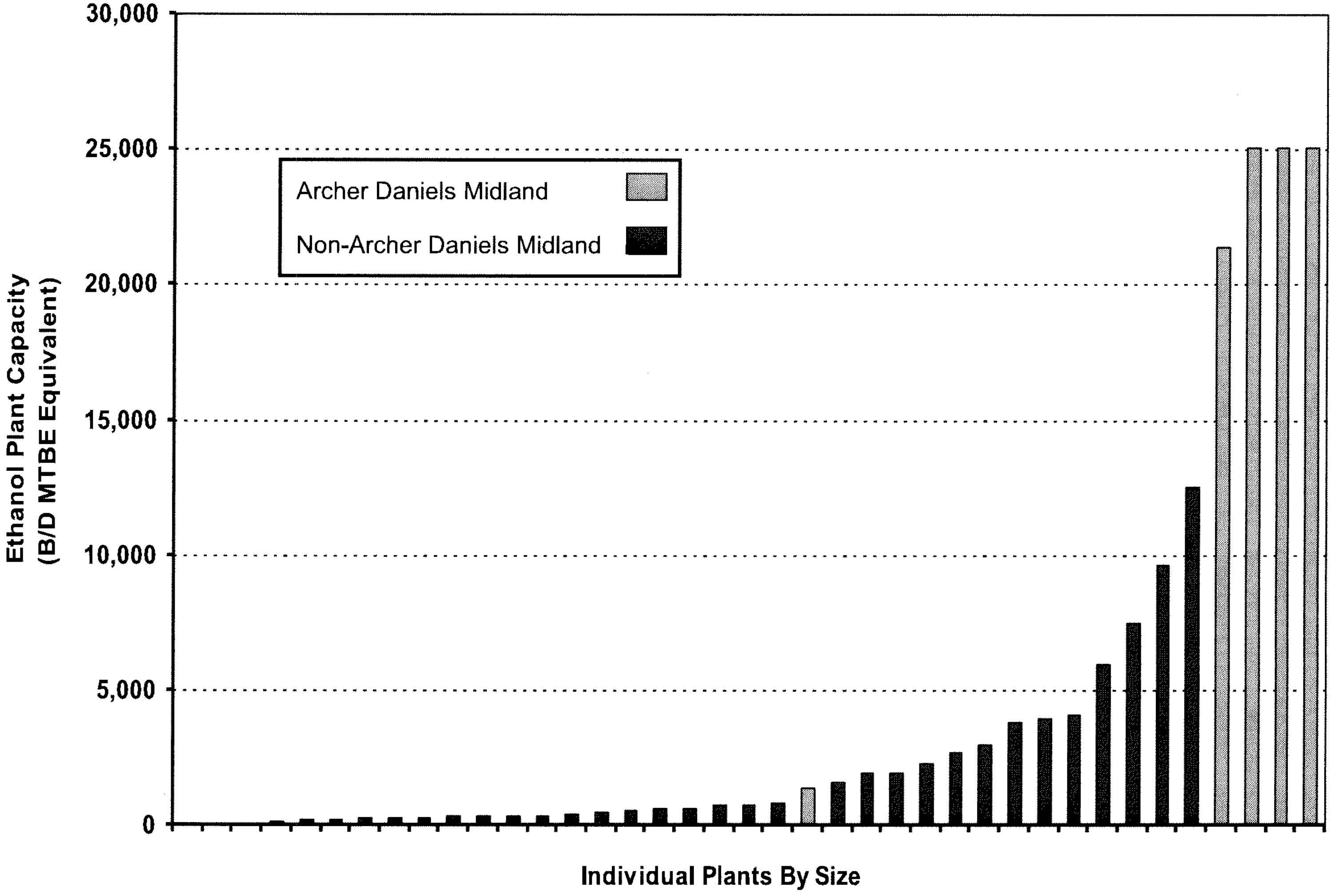
SOURCE: EIA, *Petroleum Supply Annual*, 1992.

EXHIBIT N
U.S. ETHANOL PRODUCTION CAPACITY

			1990 Estimated Capacity	
Company	***City***	***State***	***Ethanol (B/D)***	***MTBE Equivalent (B/D)***
Archer Daniels Midland	Peoria	IL	13,046	25,571
Archer Daniels Midland	Decatur	IL	13,046	25,571
Archer Daniels Midland	Cedar Rapids	IA	13,046	25,571
Archer Daniels Midland	Clinton	IA	11,155	21,863
Wiliams Energy Services	Pekin	IL	5,219	10,229
New Energy Corp.	South Bend	IN	5,000	9,800
South Point Ethanol	South Point	OH	3,914	7,671
A.E. Staley	Loudon	TN	3,095	6,066
Minnesota Corn Processors	Marshall	MN	2,129	4,173
Minnesota Corn Processors	Columbus	NE	2,073	4,063
Cargill	Eddyville	IA	2,000	3,920
Grain Processing Corp.	Muscatine	IA	1,566	3,069
Hubinger	Keokuk	IA	1,425	2,793
High Plains Corporation	Colwich	KS	1,200	2,352
Giant Refining	Portales	NM	1,000	1,960
Chief Ethanol	Hastings	NE	1,000	1,960
Midwest Grain	Pekin	IL	833	1,633
Archer Daniels Midland	Wahalla	ND	726	1,423
Alchem	Grafton	ND	428	839
Manildra Energy	Hamburg	IA	405	794
Midwest Grain	Atchison	KS	397	778
Georgia-Pacific	Bellingham	WA	333	653
Butterwood Farms	Wilsons	VA	333	653
Heartland Grain Fuels	Aberdeen	SD	294	576
Denco, LLC	Morris	MN	260	510
J.R. Simplot	Heybern	ID	229	449
Parallel Products	Rancho Cucamonga	CA	196	384
J.R. Simplot	Caldwell	ID	196	384
Broin Assoc.	Scotland	SD	196	384
Golden Cheese of CA	Corona	CA	190	372
Reeve Agri-Energy	Garden City	KS	157	308
Alcotech	Ringling	MT	142	278
Permeate Products	Hopkinton	IA	132	259
Kraft, Inc.	Melrose	MN	105	206
MMI/ETOH	Golden	CO	103	202
Pabst Brewing	Olympia	WA	65	127
ESE Alcohol	Leoti	KS	48	94
Vienna Correctional	Vienna	IL	33	65
Jonton Alcohol	Edinburg	TX	33	65
Total U.S. Capacity			**85,749**	**168,067**

SOURCES: *EIA* , "Petroleum Supply Annual," 1992; AUS Consultants / Bryan & Bryan Inc. (BBI), "Ability of the U.S. Ethanol Industry to Replace MTBE," U.S. Ethanol Plant Capacity.

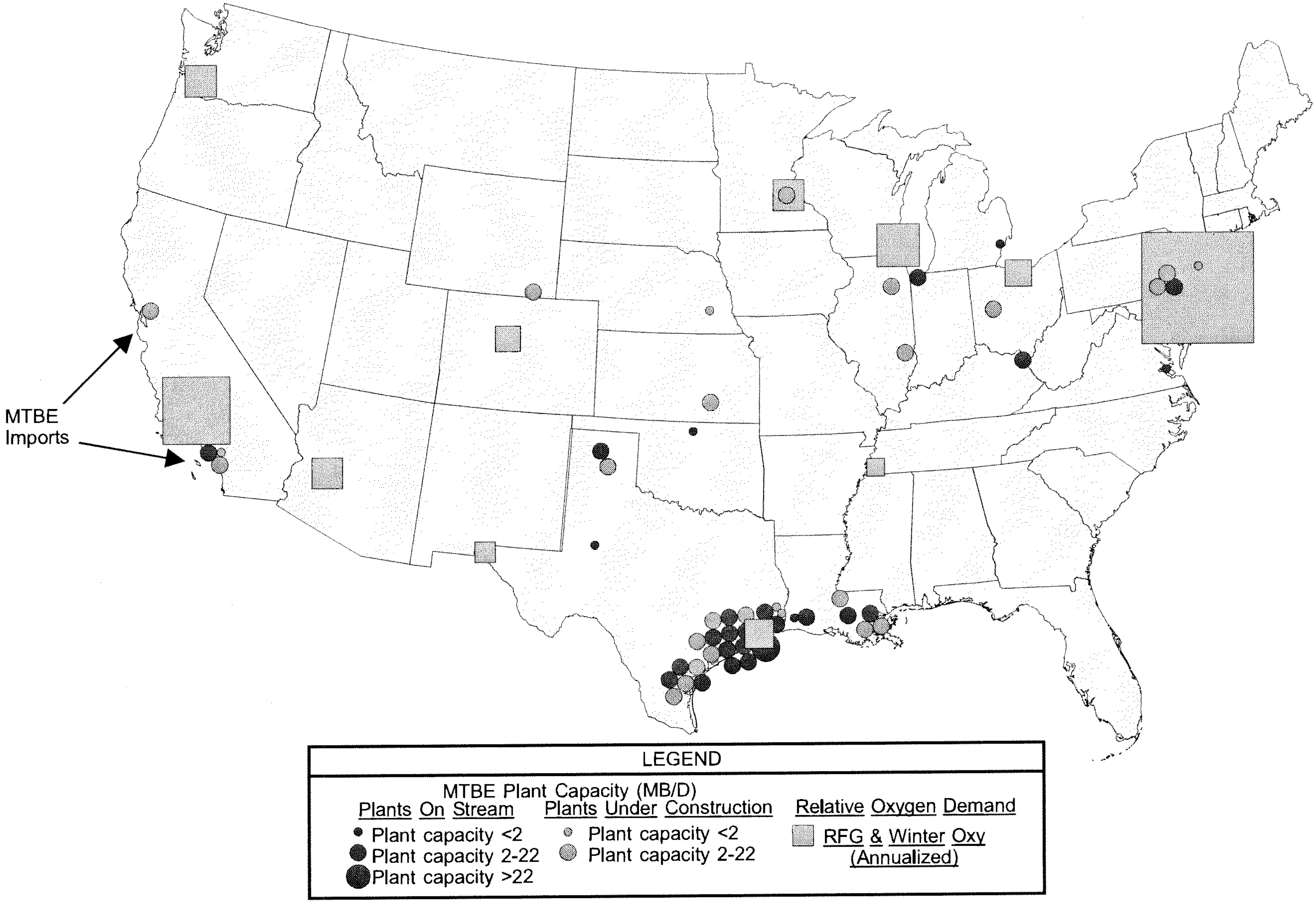
EXHIBIT O
U.S. Ethanol Plants as of 1990



SOURCES: *EIA*, "Petroleum Supply Annual," 1992; *AUS Consultants / Bryan & Bryan Inc. (BBI),* "Ability of the U.S. Ethanol Industry to Replace MTBE," U.S. Ethanol Plant Capacity, March 2000.

EXHIBIT P

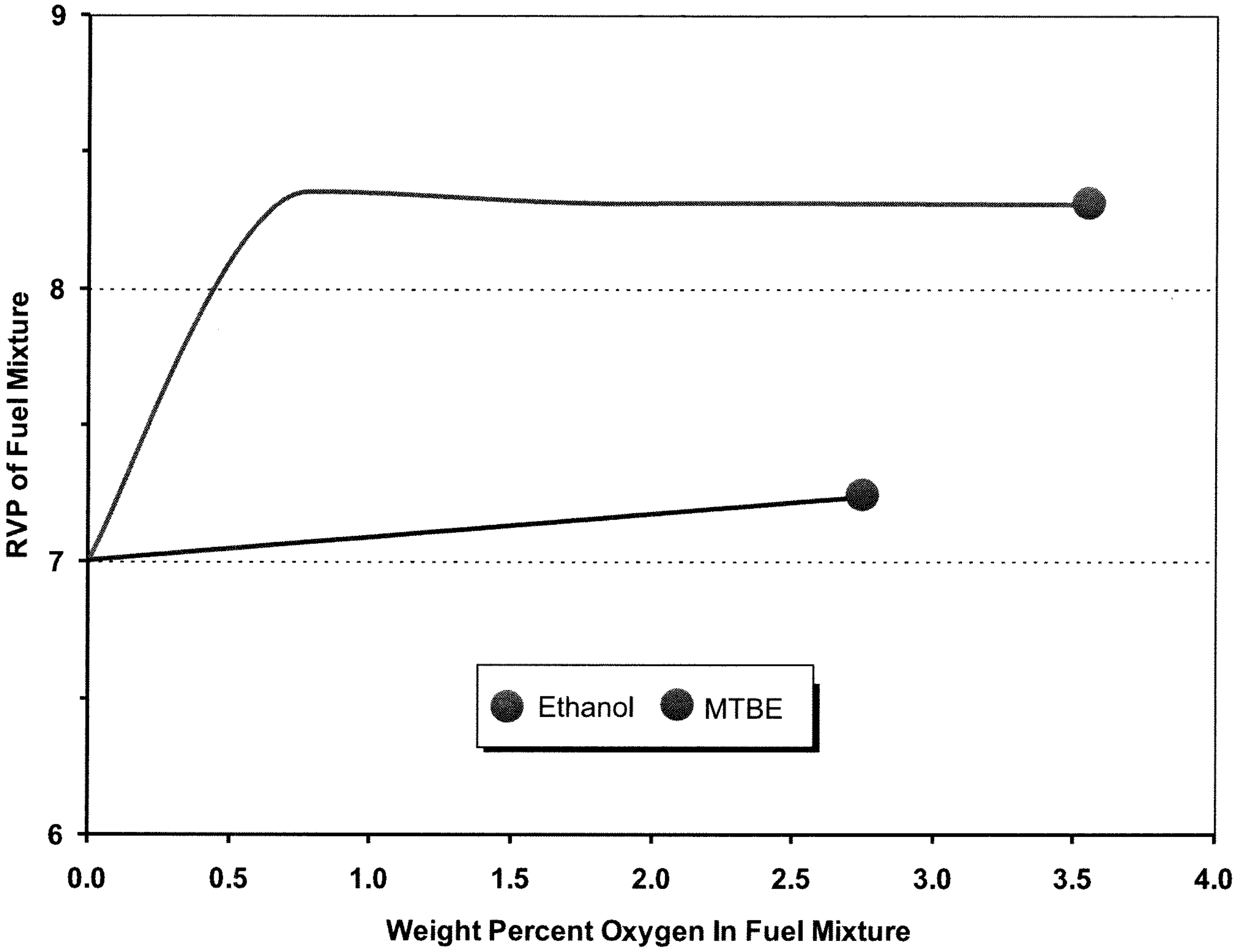
1990 MTBE Plants vs. 1995 Projected RFG and Oxygenated Fuel Demand



SOURCE: NPRA, *Survey of MTBE Manufacturing Facilities*, 1990.

EXHIBIT Q

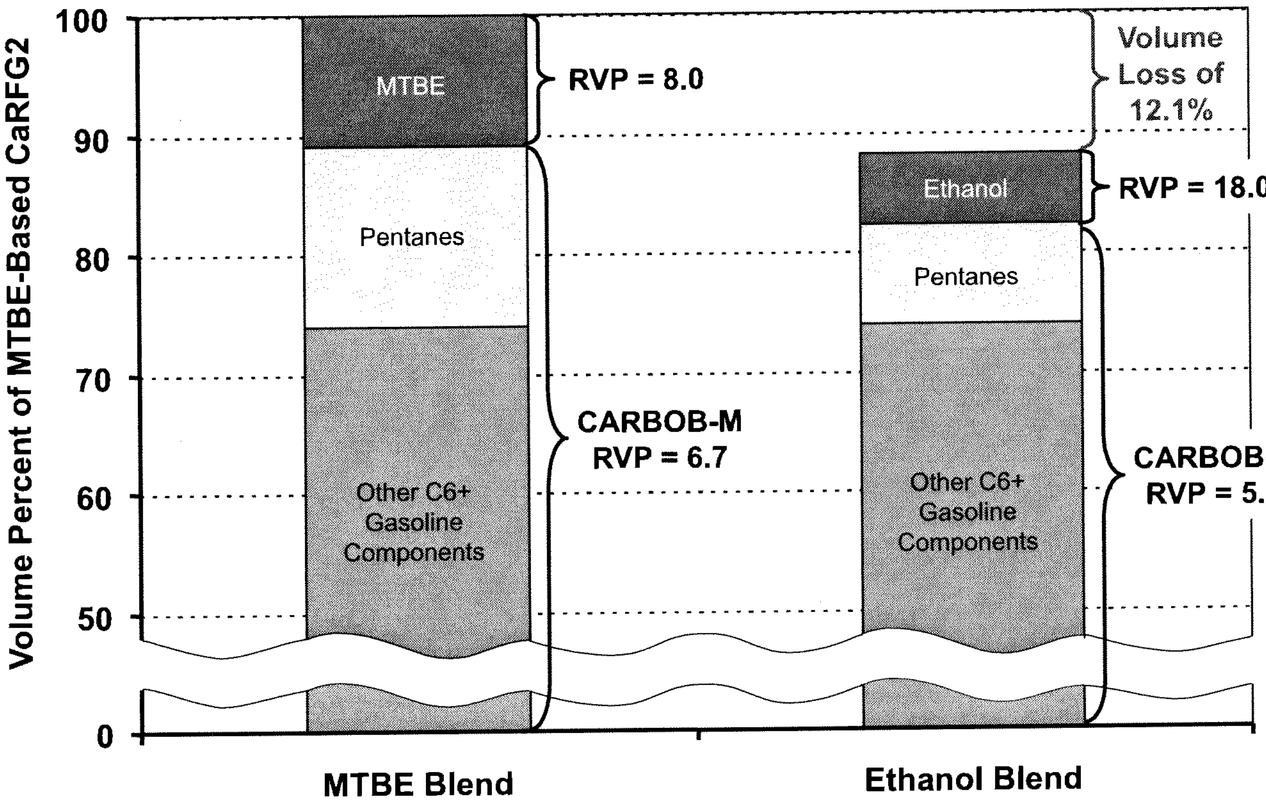
RVP Effects of Adding Oxygenates to 7 RVP Fuels



SOURCES: Adapted from Piel, W.J. & Thomas, R.X., “Ethers: A Key Ingredient For Reformulated Gasoline,” *National Conference on Octane Quality & Reformulated Fuels*, 1990, Figure 9; EIA, “Supply Impacts of An MTBE Ban”, September 2002.

EXHIBIT R

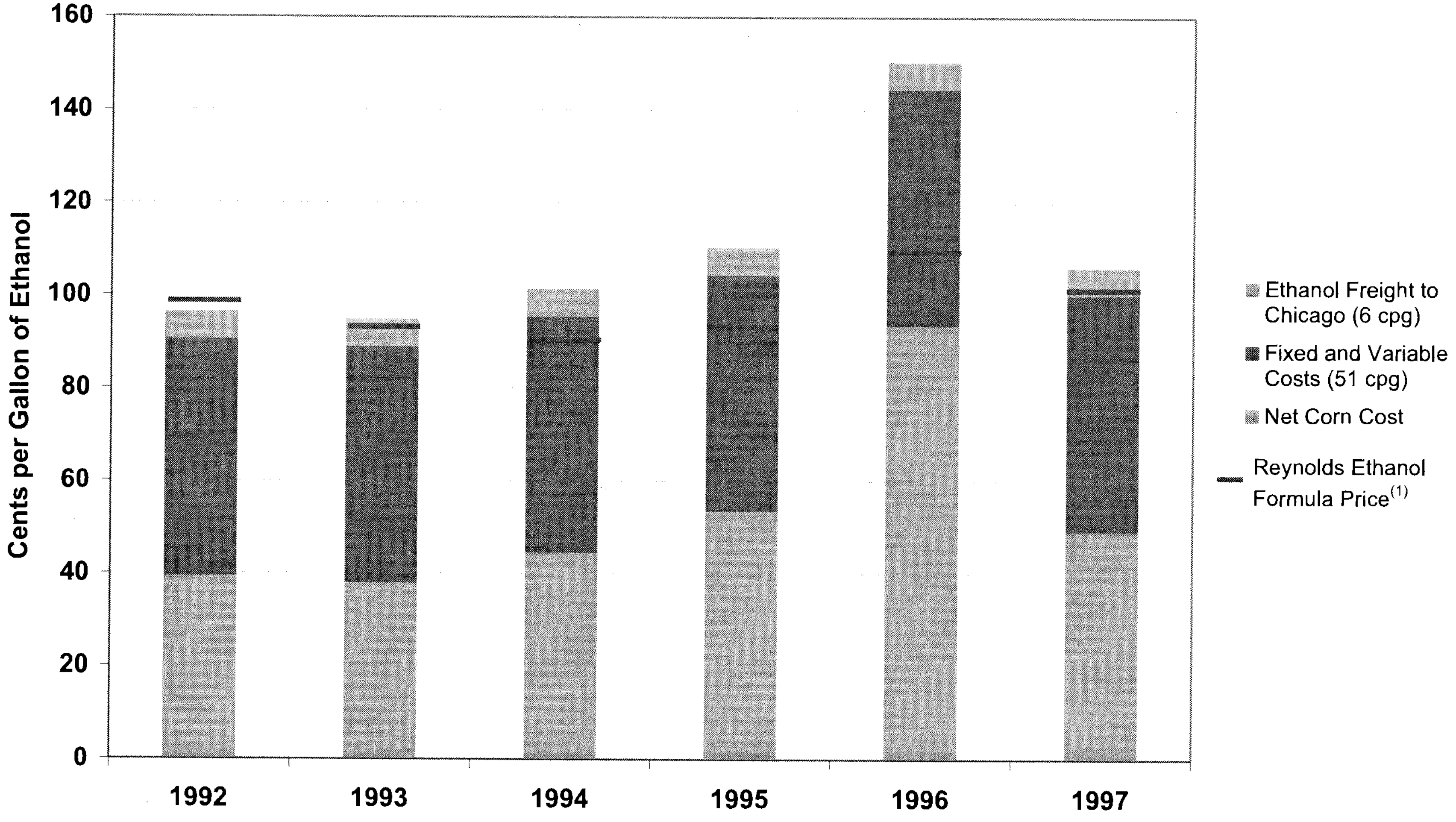
RVP Blending Effects on CARBOB Composition
Summer Blends for 1996 CaRFG2
6.9 RVP Specification



SOURCES: *EIA*, "Supply Impacts of an MTBE Ban," September 2002; Baker & O'Brien estimates.

EXHIBIT S

Analysis of Reynolds' Suggested Ethanol Formula Price 1992-1997
Wet Mill Cost Basis



NOTE: (1) Mr. Reynolds Ethanol formula price is Platts Tank Car / Truck Transport Chicago Regular Unleaded Gasoline, plus subsidy (54 cents per gallon), minus 15 cents per gallon (cpg), (Reynolds Deposition, August 3, 2007, pp. 328-330).

SOURCES: "Supply and Cost of Alternatives to MTBE in Gasoline, Technical Appendices", California Energy Commission, December 1998, pp. 76-78; Platts; BNSF rail quote.

EXHIBIT T

Examples of Ethanol Plant Closures

Company	***Location***	***Plant Rated Capacity (Millions of Gallons Per Year)***
Clinton-Southeast JV [1]	Douglas, GA	3.0
Idaho Fuels [1]	Boise, ID	0.4
Farm Fuel Production [1]	Storm Lake, IA	2.3
Kentucky Agricultural Energy Co. [2]	Franklin, KY	21.0
Boucher Rural Products [1]	Ravenna, NE	0.2
South Point Ethanol [3]	South Point, OH	60.0
Carolina Alcohol [1]	Kingstree, SC	0.5
Coburn Enterprises [1]	Sherman, SD	1.0
Sepco, Inc. [1]	Scotland, SD	1.0
Tennol, Inc. [4]	Jasper, TN	25.0

SOURCES:

Sally M. Kane and John M. Reilly, *Economics of Ethanol Production in the United States*, Agricultural Economic Report 607, United States Department of Agriculture, March 1989.
Chemical Market Reporter, *Chemical Profile - Ethanol*, January 25, 1988.
Chemical Market Reporter, *Chemical Profile - Ethanol*, March 25, 1991.
Chemical Market Reporter, *Chemical Profile - Ethanol*, February 21, 1994.
Chemical Market Reporter, *Chemical Profile - Ethanol*, March 10, 1997.

NOTES:

[1] Closed by 1989, Per March 1989 USDA Report.

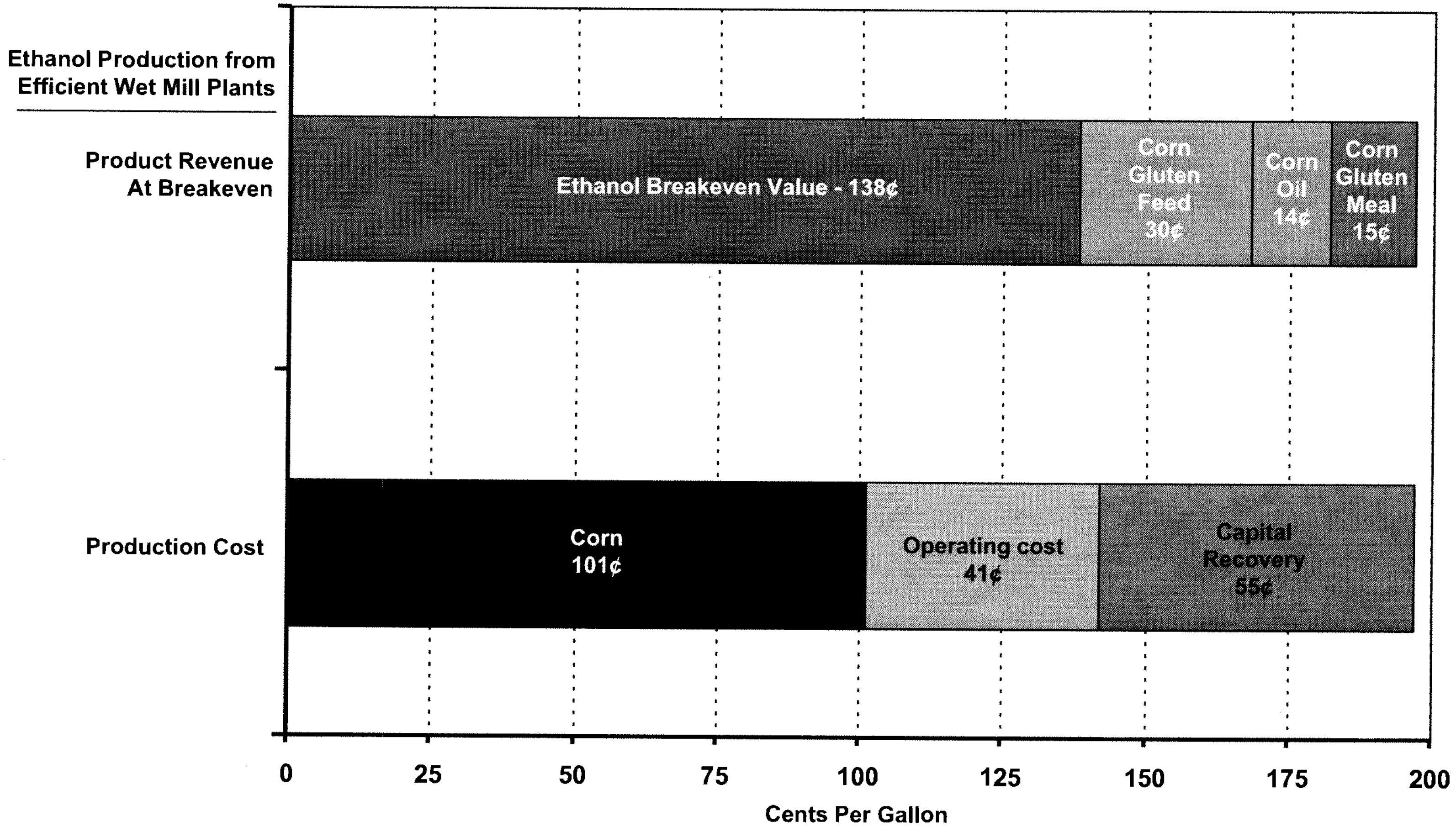
[2] Closed by 1994, Per Chemical Market Reporter, February 21, 1994.

[3] Closed by 1997, Per Chemical Market Reporter, March 10, 1997.

[4] Closed by 1991, Per Chemical Market Reporter, March 25, 1991.

EXHIBIT U

Ethanol Production Cost Breakeven Values
BASIS: 10-Year Average Pricing
(1981–1990)



SOURCES: *NPC*, "U.S. Petroleum Refining, Meeting Requirements for Cleaner Fuels and Refiners," 1993; *USDA* "Ethanol: Economic and Policy Tradeoffs," April 1988, AER-585.

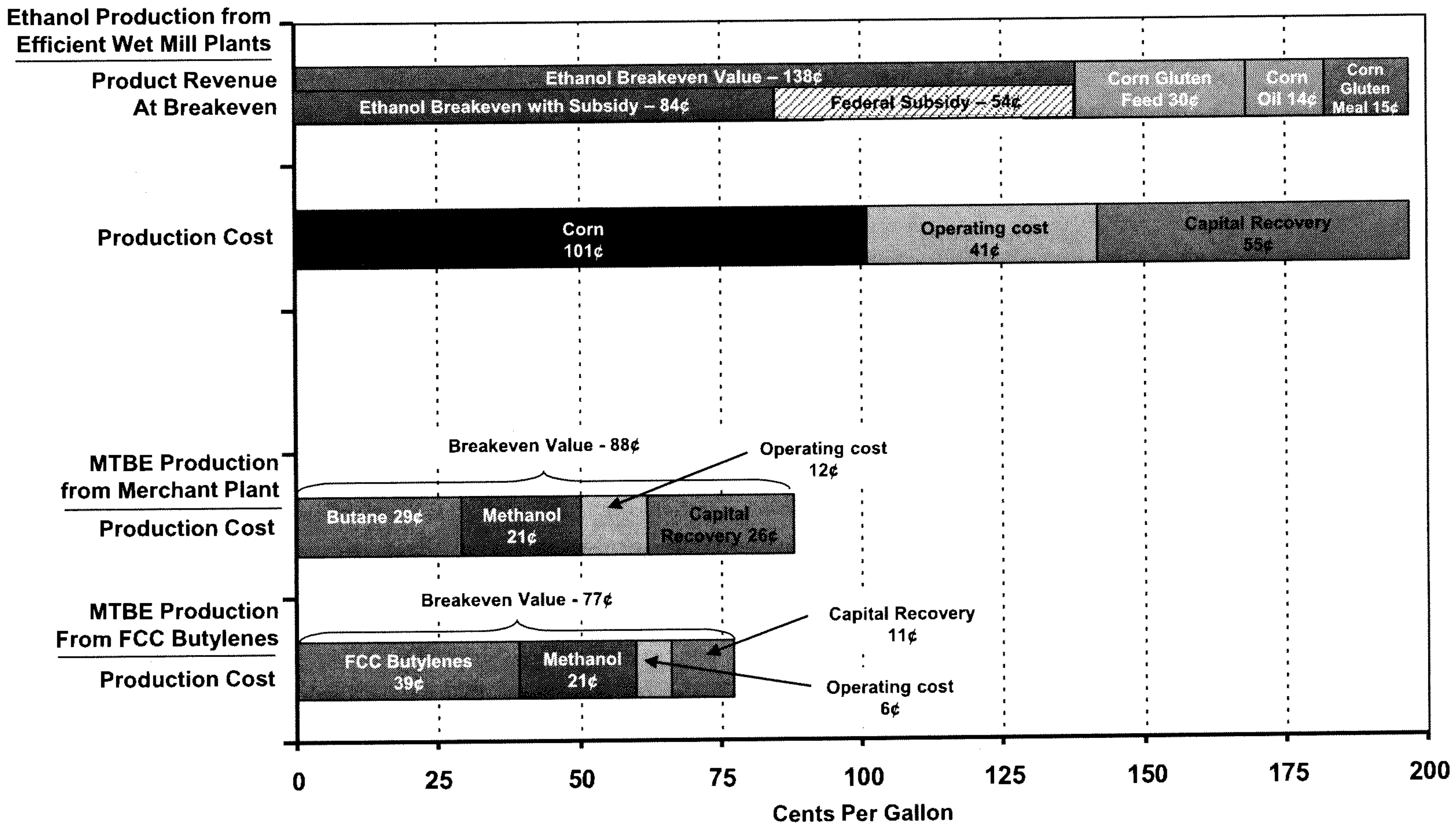
NOTE: Excludes cost of working capital.

EXHIBIT V

Ethanol and MTBE Production Cost Breakeven Values

BASIS: 10-Year Average Pricing

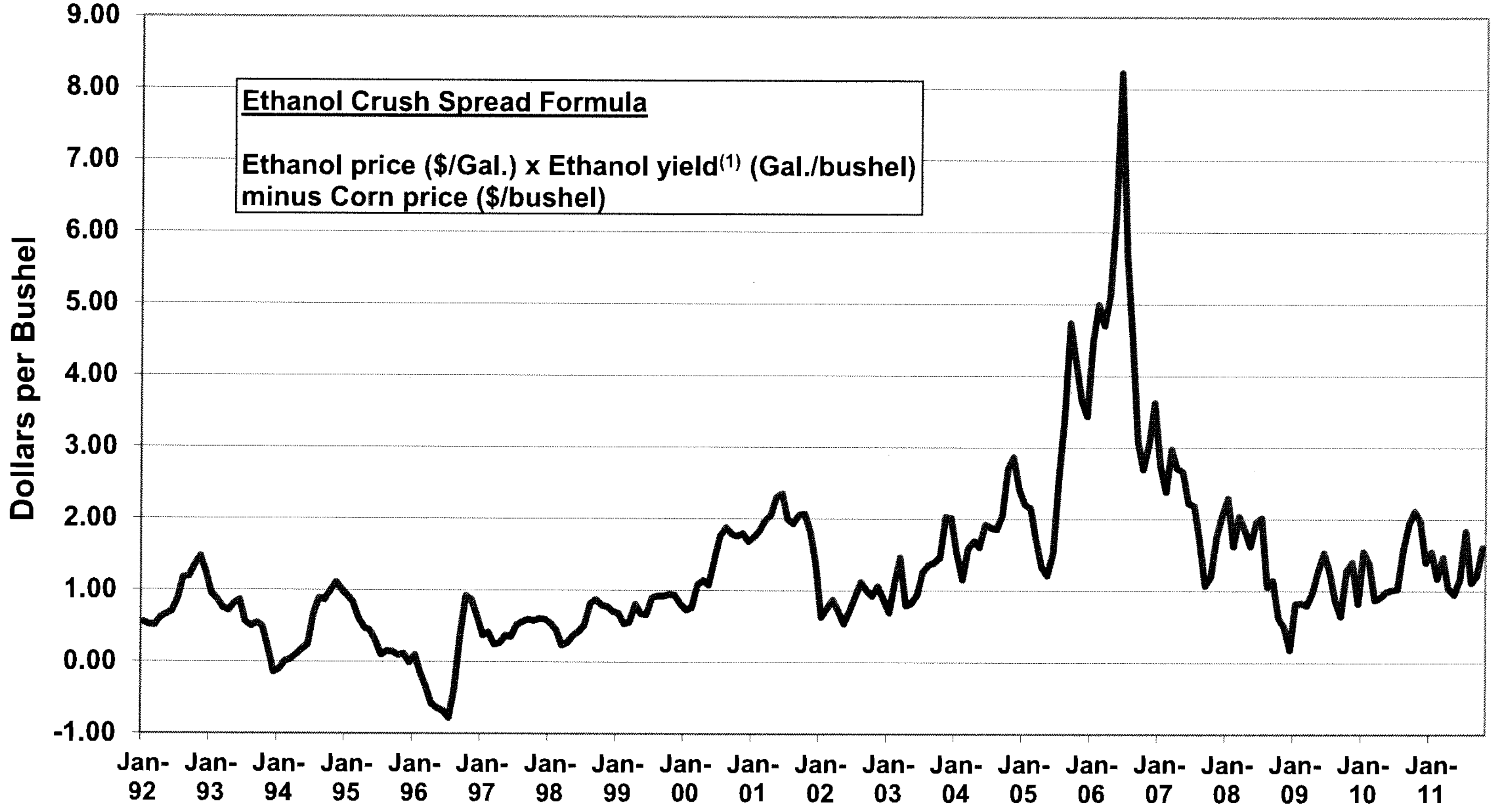
(1981–1990)



SOURCES: *NPC*, "U.S. Petroleum Refining, Meeting Requirements for Cleaner Fuels and Refiners," 1993; *USDA* "Ethanol: Economic and Policy Tradeoffs," April 1988, AER-585.

NOTE: Excludes cost of working capital.

EXHIBIT W
Ethanol Crush Spread

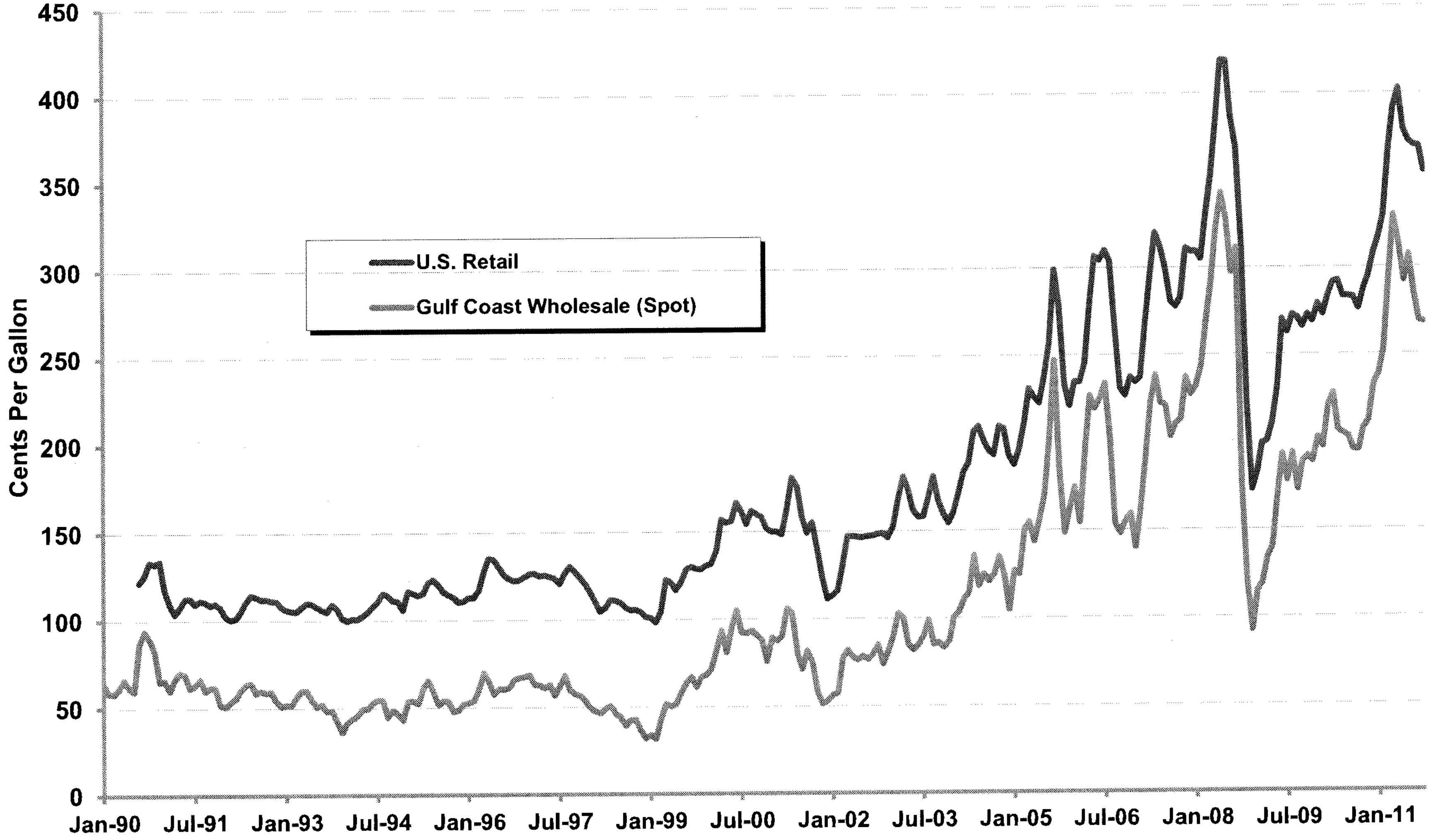


SOURCES: USDA National Agricultural Statistics Service and Platts, Oilgram Price Report.

NOTE: (1) Ethanol yield has ranged from 2.5 Gal./bushel in 1992 to 2.8 Gal./bushel currently.

EXHIBIT X

Monthly Average Regular Gasoline U.S. Retail[1] and Gulf Coast Wholesale Prices[2]



SOURCES: Retail, EIA *Petroleum Navigator;* Wholesale, Platts, Oilgram Price Report, 1990 through August 2011.

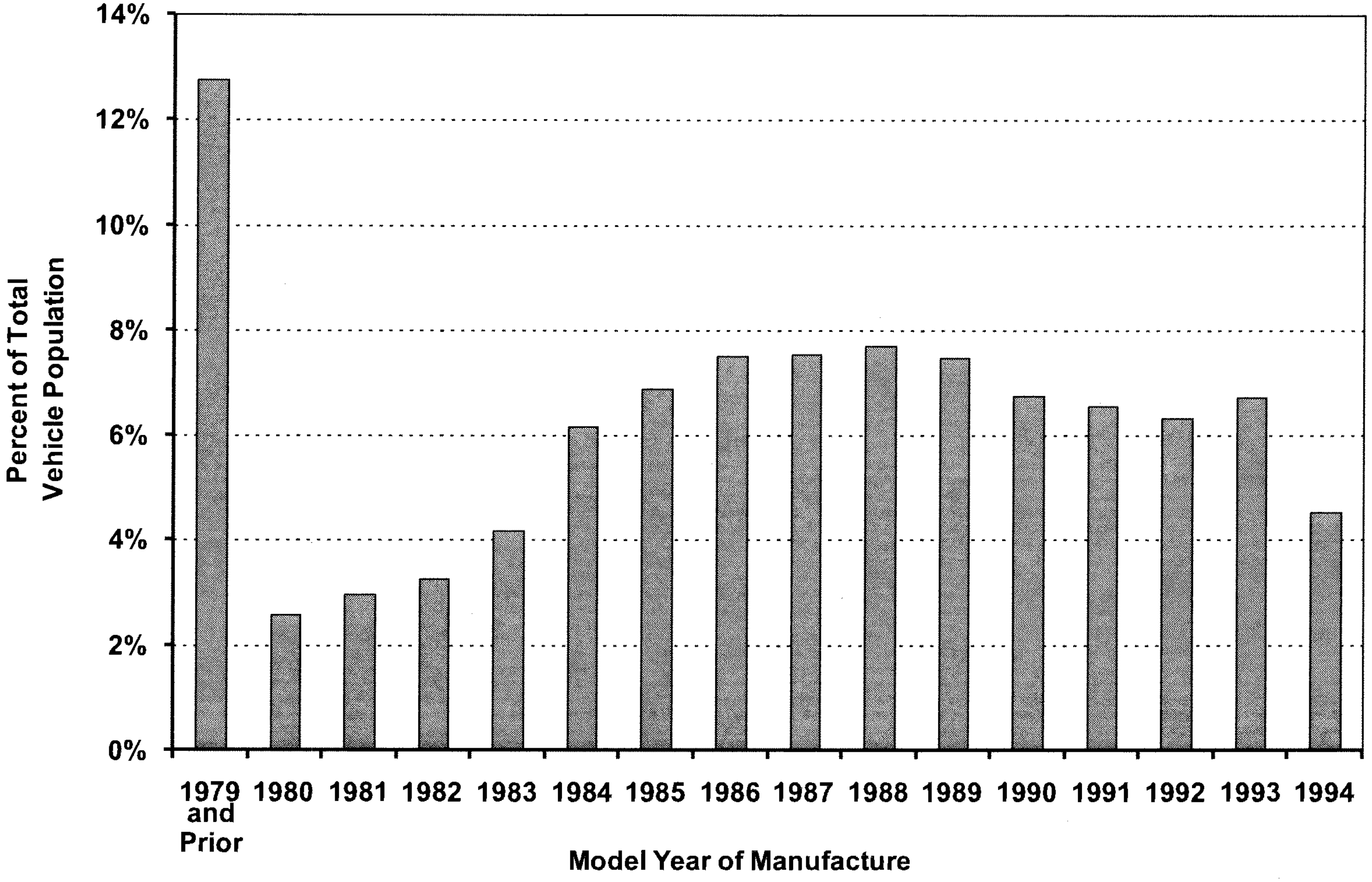
NOTES:

(1) Monthly average for U.S. regular gasoline (conventional pre-1995; RFG post-1995). EIA data begins August 1990.

(2) U.S. Gulf Coast regular gasoline spot price pipeline (conventional pre-1995; RFG 1995 to June 2006; RBOB July 2006 through October 2011.)

EXHIBIT Y

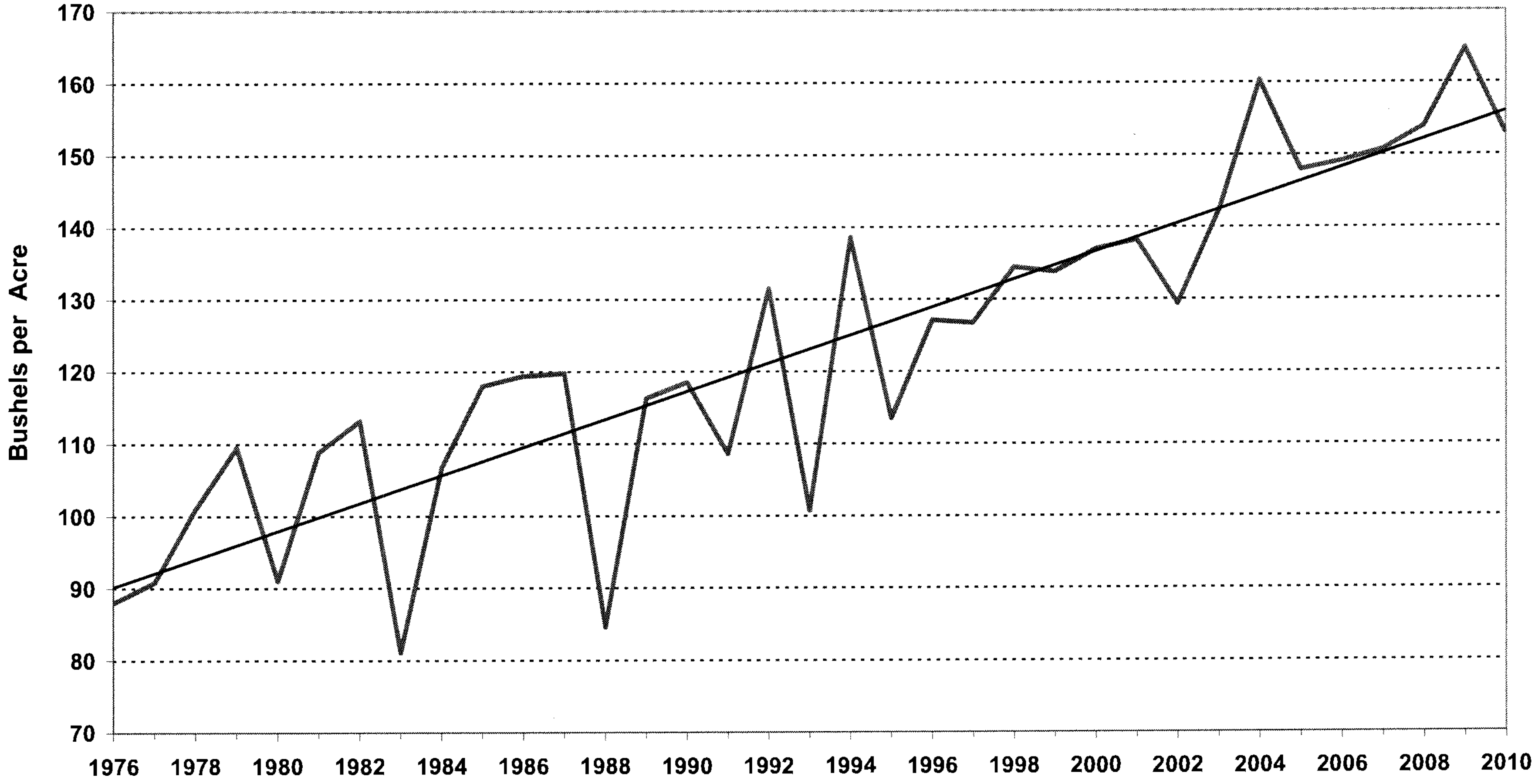
United States Automobile Population Age Profile July 1994



SOURCE: American Automobile Manufactures Association, *Motor Vehicle Facts and Figures*, 1995, p. 39.

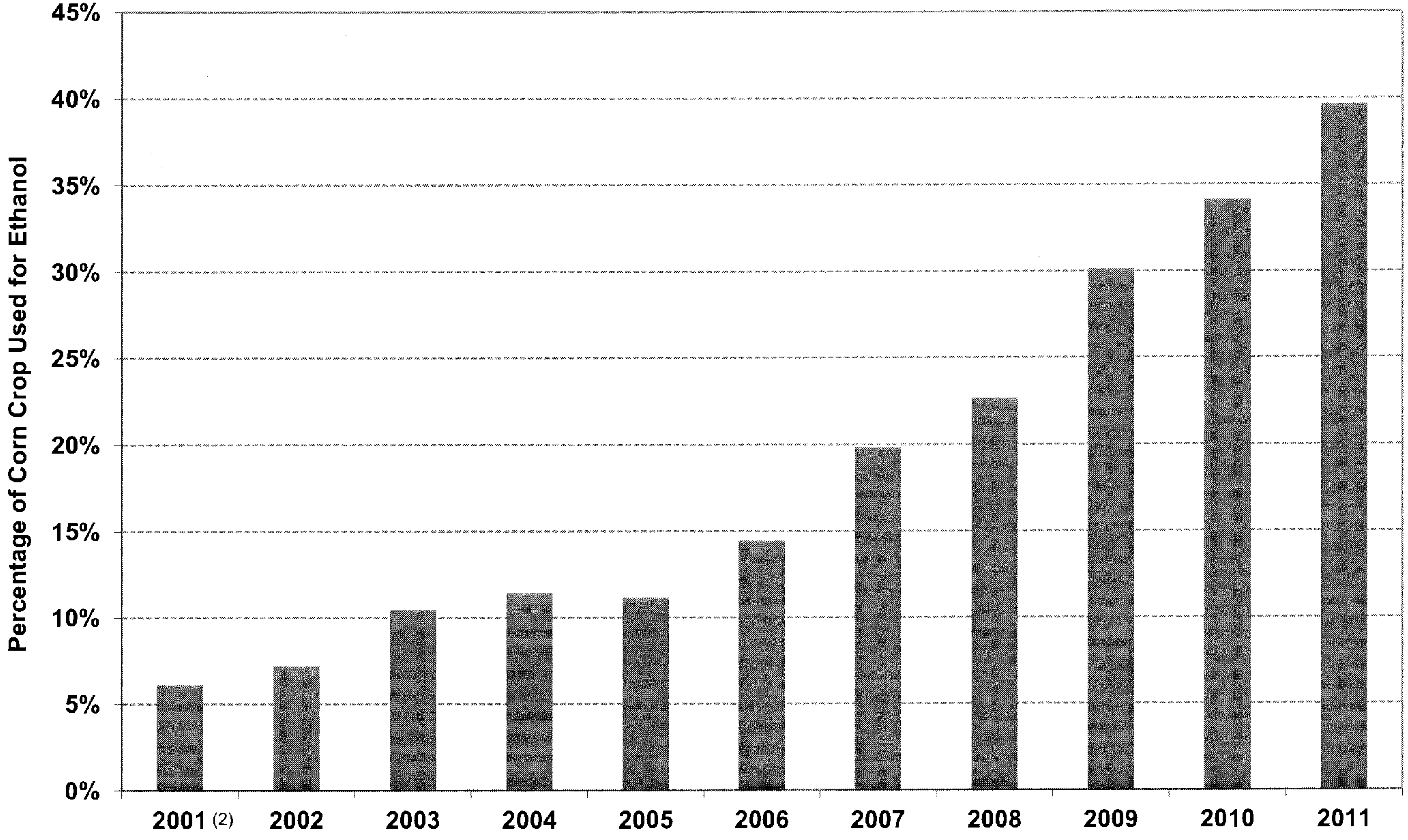
EXHIBIT Z

U.S. Corn Yield, 1976 - 2010



SOURCE: U.S. Department of Agriculture, *Crop Production Historical Track Records*, April 2011, pp. 26-27.

EXHIBIT AA
PERCENTAGE OF CORN CROP USED FOR ETHANOL(1)



SOURCES: Corn production from Table 1, USDA Yearbook Tables; Ethanol production from EIA-819 Monthly Oxygenate Report, September 2000 to December 2008 and EIA Petroleum Supply Monthly, January 2009 to August 2011.

NOTES: (1) Based on average ethanol yield of 2.8 gallons per bushel.
(2) Years displayed are corn marketing years. For example, year 2001 is the period from September 2000 to August 2001.