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Impact of Renewable Fuels Standard/MTBE Provisions of S. 1766

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Contacts

This report was prepared by the staff of the Office of Integrated Analysis and Forecasting of the Energy Information Administration. General questions concerning the report may be directed to Mary J. Hutzler (202/586-2222, mhutzler@eia.doe.gov), Director, Office of Integrated Analysis and Forecasting, or James Kendell (202/586-9646, james.kendell@eia.doe.gov), Director, Oil and Gas Division. Specific questions about the report may be directed to the following analysts:

Han-Lin Lee	202/586-4247	hlee@eia.doe.gov
Stacy MacIntyre	202/586-9795	smacinty@eia.doe.gov

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Impact of Renewable Fuels Standard/MTBE Provisions of S. 1766 Requested by the Senate Energy Committee

Introduction

On December 20, 2001, Sen. Frank Murkowski, the Ranking Minority Member of the Senate Committee on Energy and Natural Resources, requested an analysis of selected portions of Senate Bill 1766 (S. 1766, the Energy Policy Act of 2002) and House Bill H.R. 4 (the Securing America's Future Energy Act of 2001).[1] This request was further refined in a follow-up letter of February 6, 2002.[2] In response, the Energy Information Administration (EIA) has prepared a series of analyses showing the impacts of each of the selected provisions of the bills on energy supply, demand, and prices, macroeconomic variables where relevant, import dependence, and emissions. The analysis provided is based on the *Annual Energy Outlook 2002*[3] (*AEO2002*) midterm forecasts of energy supply, demand, and prices through 2020.

Because of the rapid delivery time requested by Sen. Murkowski, each requested component of the Senate and House bills was analyzed separately, that is, without analyzing the interactions among the various provisions. Because of the approach taken:

- The combined impact of the individual policies cannot be determined by simply adding the individual policy impacts together. For example, a provision establishing a renewable portfolio standard (RPS) for electricity production, and one that establishes a biodiesel program for transportation fuels, each increases the use of biomass. The simultaneous enactment of the two provisions would be likely to increase biomass costs because of the competition for land and other needed resources. The estimated fossil energy displaced would, therefore, be lower than the sum of the two individual policy impacts because of the higher resource costs. Stated another way, the impacts of multiple simultaneous policies are non-linear.

- Some policies will interact to increase the overall response while others may interact to mitigate the impacts of each other. For example, when two separate policies increase demand and, consequently, production of an advanced technology, the reductions in manufacturing costs expected from increased production are likely to be accelerated, making the technology even more attractive in later years. The total adoption of the advanced technology in this case could be greater than the sum of the parts.

[1] Letter from Sen. Murkowski to Mary J. Hutzler, dated December 20, 2001. See Appendix A.
[2] Letter from Sen. Murkowski to Mary J. Hutzler, dated February 6, 2002. See Appendix A.
[3] *Annual Energy Outlook 2002, With Projections to 2020,* U.S. Department of Energy, Energy Information Administration, DOE/EIA-0383(2002), December 2001.

In addition, some aspects of the bills cannot be modeled because of lack of specificity. For example, several provisions of the bill require the Department of Energy (DOE) to evaluate the desirability of setting standards for stand-by power and other electronic devices. Because the legislation does not state what the standards will be, EIA cannot quantitatively analyze them.

EIA's projections are not statements of what will happen but what might happen, given known technologies, technological and demographic trends, and current laws and regulations. Thus, *AEO2002* provides a policy-neutral Reference Case that can be used to analyze energy policy initiatives. EIA does not propose, advocate or speculate on future legislative or regulatory changes. Laws and regulations are assumed to remain as currently enacted or in force in the Reference Case; however, the impacts of emerging regulatory changes, when clearly defined, are reflected.

Models are simplified representations of reality because reality is complex. Projections are highly dependent on the data, methodologies, model structure and assumptions used to develop them. Because many of the events that shape energy markets are random and cannot be anticipated (including severe weather, technological breakthroughs, and geo-political disruptions), energy market projections are subject to uncertainty. Further, future developments in technologies, demographics and resources cannot be foreseen with any degree of certainty. These uncertainties are addressed through analysis of alternative cases in the *AEO2002*.

Specifications of this Study

This paper addresses the Renewable Fuels Standard (RFS)/methyl tertiary butyl ether (MTBE) provisions of S. 1766. H.R. 4 contains no RFS/MTBE provisions. The "S. 1766" Case reflects provisions of S. 1766 including a renewable fuels standard (RFS) reaching five billion gallons by 2012, a complete phase-out of MTBE within four years,[4] and the option for States to waive the oxygen requirement for reformulated gasoline (RFG). It reflects provisions for a cellulose ethanol credit, an allowance for merchant MTBE plants to convert to other uses, and accounts for biodiesel as a renewable fuel. This analysis does not include the provision for a credit program; due to a lack of specificity about the structure of the program. The following provisions were not modeled in this analysis due to time constraints: the reduction of the maximum distillation index to 1200, or the removal of the one pound per square inch waiver of the Reid vapor pressure (RVP) limit for ethanol blended conventional gasoline east of the Mississippi.

Senator Murkowski also requested analysis of a variation on the RFS/MTBE provisions in S. 1766 which assumes the same RFS requirements and a Federal waiver of the oxygen requirement on RFG, but requires no ban on MTBE. This case is referred to as the "RFS/No MTBE Ban" Case. In neither case are the regional impacts of the bill evaluated due to the timing of the request for the results. The reader should be aware that there will

[4] This analysis assumes the ban is effective in 2006.

be seasonal and localized impacts that differ from those of this analysis, because this analysis is based on average annual values at the national level.

Background

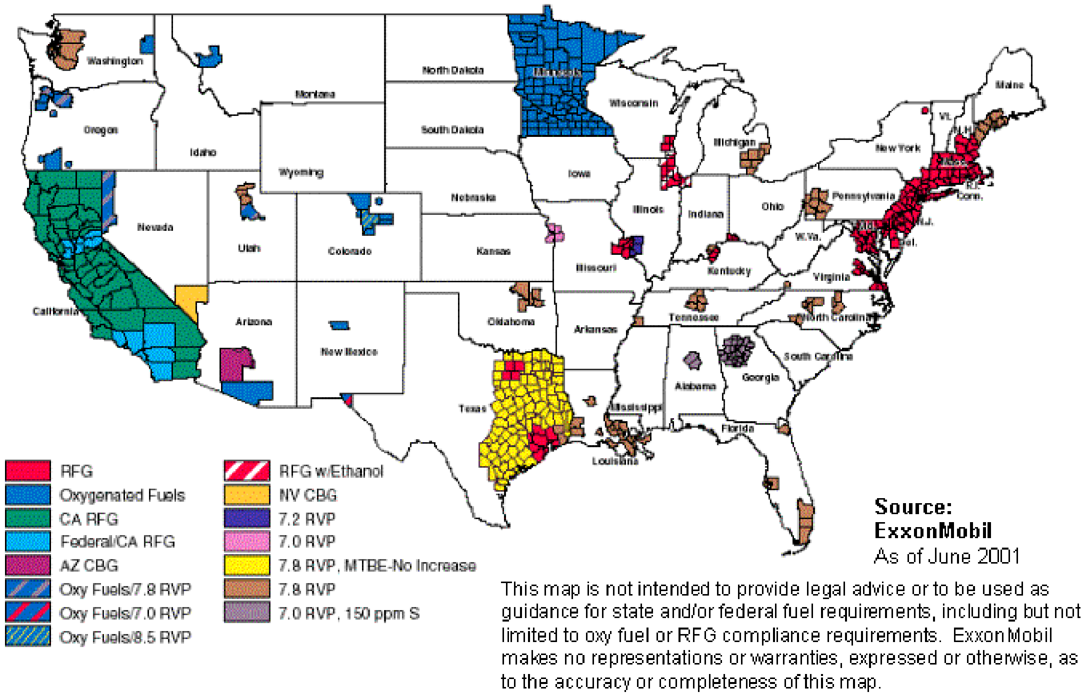
As a result of the Clean Air Act Amendments of 1990 (CAAA90), the year-round use of reformulated gasoline has been required in cities with the worst smog problems since 1995 (Figure 1). One of the requirements of RFG specified by CAAA90 is a 2-percent oxygen requirement, which is met by blending with "oxygenates" including MTBE and ethanol. MTBE is the oxygenate used in almost all RFG used outside of the Midwest. Ethanol is currently used in the Midwest as an oxygenate in RFG and as an octane booster and volume extender in conventional gasoline.

Several years ago, MTBE was detected in water supplies scattered throughout the country, but predominantly in areas using RFG. MTBE from RFG was apparently making its way through leaking pipelines and storage tanks into ground water. The discovery of MTBE in ground water touched off a debate about the use of MTBE in gasoline, and subsequently the oxygen requirement itself. Discussions of removing the oxygen requirement on RFG have often been linked to the concept of a renewable fuels standard that would assure a certain level of ethanol blending.

Legislation that would ban or restrict the use of MTBE in gasoline, between 2003 and 2004, has already been passed in 13 States: Arizona, California, Colorado, Connecticut, Iowa, Illinois, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, and Washington**.** In addition, Maine has passed legislation that contains a goal of phasing-out MTBE. Of these States, only California, Connecticut, and New York currently rely on MTBE as an oxygenate for RFG. California petitioned the U.S. Environmental Protection Agency (EPA) to waive the Federal oxygen requirement for areas of the State required by CAAA90 to use RFG, but the waiver request was denied by EPA. California has its own formulation of gasoline outside of the Federally mandated areas that does not have an oxygen requirement. Since the EPA denied the waiver request, California officials have been considering postponement of the MTBE ban due to concerns about the availability and price of gasoline without MTBE. A recent report commissioned by the California Energy Commission (CEC) highlights the possibility of short-term supply shortfalls and associated price spikes if MTBE is banned without adequate lead-time.[5]

[5] Stillwater Associates, *MTBE Phase Out in California- Draft Study for the California Energy Commission,* February 18, 2002.

Figure 1. U.S. Gasoline Requirements



MTBE is an important blending component for RFG because it adds oxygen, extends the volume of the gasoline and boosts octane, all at the same time. In order to meet the 2 percent (by weight) oxygen requirement for Federal RFG, MTBE is blended into RFG at approximately 11 percent by volume, thus extending the volume of the gasoline. When MTBE is added to a gasoline blend stock, it has an important dilution effect, replacing undesirable compounds such as benzene, aromatics, and sulfur. The dilution effect is even more valuable in light of a ruling by the EPA that will require the sulfur content of gasoline to be reduced substantially by 2004, and by EPA's Mobile Source Air Toxics (MSAT) regulatory program, which will maintain benzene at 1998-2000 levels on an individual refinery basis. In addition, MTBE is a valuable octane enhancer. Its high octane helps offset the Federal limitations on other high-octane components such as aromatics and benzene. If the use of MTBE is reduced or banned, refiners must find other measures to maintain the octane level of gasoline and still meet all Federal requirements.

Ethanol currently receives a Federal excise tax exemption of 53 cents per gallon, which is scheduled to decline to 52 cents in 2003, and 51 cents in 2005. Legal authority for the Federal tax exemption expires in 2007, but because this exemption has been renewed several times since it was initiated in 1978, the *AEO2002* Reference Case assumes that the exemption will be extended at the 51-cent (nominal) level through 2020 and it is included in the cases presented in this report. Blending with ethanol, which is primarily produced from corn, is also encouraged by tax incentives in 17 States to help bolster agricultural markets. Some of the characteristics of ethanol have made it less attractive to refiners than MTBE as an oxygenate. Ethanol results in higher emissions of smog-forming volatile organic compounds (VOCs) than MTBE. Its higher volatility makes it more difficult to meet emissions standards, especially in the summertime when RFG must meet VOC emissions standards. To accommodate the use of ethanol, other gasoline components, such as pentane, which are highly volatile, must be removed from gasoline to balance the addition of ethanol.

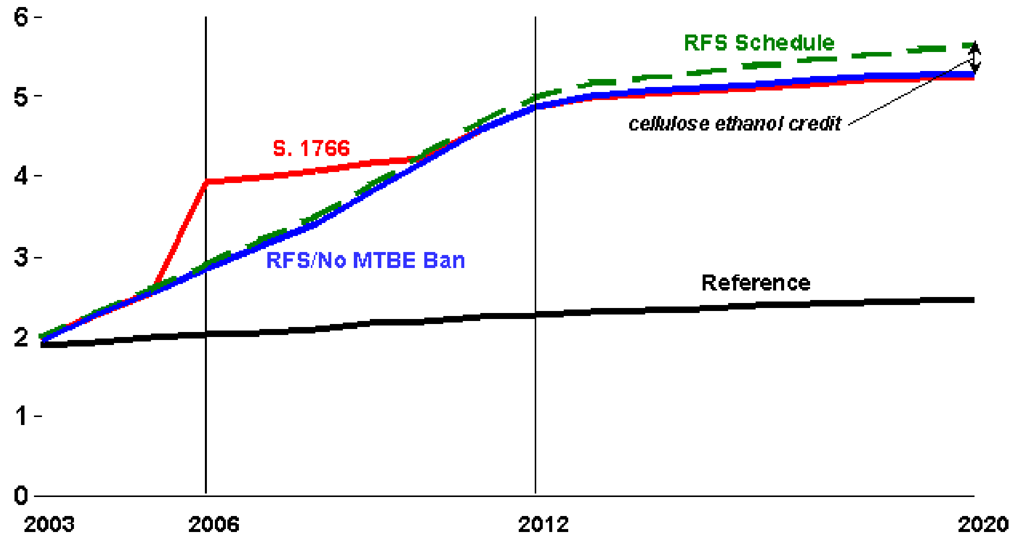
In addition to being more volatile than MTBE, ethanol contains more oxygen. As a result, only about half as much ethanol is needed to produce the same oxygen level in RFG that is provided by MTBE. The volatility of ethanol discourages refiners from blending ethanol into RFG beyond the volume that is required to fulfill the oxygen requirement. The result is that the other half of the displaced MTBE volume must generally come from other petroleum-based gasoline components. Ethanol is slightly higher in octane than MTBE is, but because only one-half as much ethanol is blended, a net loss in octane occurs when ethanol is used to replace MTBE. Blending with ethanol also results in a slight increase in emissions of toxics, which must be compensated by other blending changes in order to comply with "antibacksliding" regulations under MSAT.

Summary of Results

All analysis in this report is compared to a Reference Case that reflects no State-level restrictions on MTBE. Legislation in 13 States that would restrict the use of MTBE in gasoline between 2003 and 2004, included in the *AEO2002* Reference Case, was excluded from this analysis to evaluate the impact of the requested cases in relation to the current market. In the S. 1766 Case, all changes from the Reference Case can be attributed to provisions of S. 1766, and in the RFS/No MTBE Ban Case, changes can be solely attributed to the RFS.

Both the S. 1766 and the RFS/No MTBE Ban Cases reflect the RFS requirement specified in Section 818 of S. 1766, after an adjustment for a 1.5 gallon credit for every gallon of cellulose (biomass) ethanol. The RFS schedule requires 2.0 billion gallons of renewable fuels by 2003, increasing to 5.0 billion gallons by 2012. S. 1766 does not specify RFS targets after 2012, but requires renewable fuels to maintain the same percentage of transportation fuels that was achieved in 2012. Given the volume of cellulose-based ethanol that could be produced, the credit for cellulose ethanol would reduce the amount of renewable fuels required in the RFS schedule by about 10 million gallons in 2003 growing to 130 million gallons by 2012, and about 370 million gallons by 2020 (Figure 2). S. 1766 includes a provision that would ban MTBE nationally within four years of passage and is assumed to occur in 2006. Ethanol blending is projected to increase significantly as a result of the MTBE ban, exceeding the 2006 RFS target by more than 1 billion gallons. The gap between ethanol blending and the RFS targets specified in S. 1766 disappears by 2010 due to increasing RFS targets. Beginning in 2010, the level of ethanol blending is effectively determined predominantly by the RFS schedule (adjusted for the cellulose credit) rather than the assumed MTBE ban. In the RFS/No MTBE Ban Case, the level of ethanol blending is effectively set by the adjusted

Figure 2. Total Renewable Fuels Consumption For Transportation For Three Cases, 2003-2020 (billion gallons per year)



Source: Energy Information Administration, National Energy Modeling System runs R1aeo02z.d027002a, R1i1m0b0.d028002b, Rzi0mXb0.d022702a

RFS in all years because no Federal MTBE ban, requiring increased ethanol blending requirements, is assumed.

The S. 1766 Case is projected to result in U.S. annual average gasoline prices that are about 4 cents per gallon (real 2000 dollars) higher, and average RFG prices that are between 9.0 and 10.5 cents per gallon higher than the Reference Case, after the MTBE ban in 2006. The higher prices reflect the loss of volume, oxygen, and octane associated with the MTBE ban. Ethanol can only partially compensate for these blending qualities and is more expensive to use than MTBE. There is a greater price impact in areas of the country required to use RFG than for areas that can use conventional gasoline. The RFS/No MTBE Ban Case is projected to result in average national prices that are up to one-half cent per gallon higher for all gasoline, and up to one cent per gallon higher for RFG, compared to the Reference Case. The price impact of the RFS/No MTBE Ban Case is mitigated by the shift of ethanol blending into conventional gasoline and away from RFG blending. The S. 1766 price differentials are higher than those in the RFS/No MTBE Ban Case because the MTBE ban requires more ethanol blending into RFG to partially offset the loss of MTBE which is relatively less expensive. In the RFS/No MTBE Case additional ethanol for RFG blending is not required, and the RFS standard can be met by blending ethanol into conventional gasoline.

These cases only assess changes in the average annual prices of gasoline at the national level and do not analyze any localized or seasonal price changes that could result from such policy changes, which would likely result in some higher price differentials. In addition, investment decisions are assume perfect foresight and adequate lead times for implementing policy changes. Also, any further legislation that would change gasoline requirements on a State-by-State basis would serve to further fragment the gasoline market and could increase the likelihood of localized price volatility.

The higher gasoline prices projected in the S. 1766 Case translate into a higher annual cost to consumers of $6.37 billion on average between 2006 and 2020, compared to the Reference Case. By comparison, the RFS/No MTBE Ban Case is associated with a higher annual consumer cost of $281 million for the same time period. In addition to the impact on consumers, the additional ethanol consumption would impact tax revenues collected by the Federal government due to the tax exemption provided to ethanol-blended gasoline. Due to the increased use of ethanol, EIA estimates that S. 1766 would result in lower annual excise tax collections of $892 million on average between 2006 and 2020 for the S. 1766 Case, and $814 million for the RFS/No MTBE Ban Case, compared to Reference Case tax collections.

Methodology

This analysis was performed using the Petroleum Market Module (PMM) of the National Energy Modeling System (NEMS).[6] The PMM represents domestic refinery operations and the marketing of petroleum products to consumption regions. PMM solves for petroleum product prices, crude oil and product import activity (in conjunction with the international energy module and the oil and gas supply module), and domestic refinery capacity expansion and fuel consumption. PMM is a regional, linear programming representation of the U.S. petroleum market. Refining operations are represented by a three-region linear programming formulation of the five Petroleum Administration for Defense Districts (PADDs). PADDs I (East Coast) and V (West Coast) are each treated as single regions, while PADDs II (Midwest), III (Gulf Coast), and IV (Rocky Mountains) are aggregated into one region. Each region is considered as a single firm for which more than 80 distinct refinery processes are modeled. Refining capacity is allowed to expand in each region over each non-overlapping 3-year period. That is, in 2002 the model looks ahead to 2005 to determine how much new capacity is required and then allows additions of new capacity in 2003, 2004, and 2005. The capacity planning decisions begin anew for 2008 at the end of 2005. As a result, cumulative investment for any given year includes investment to meet future expectations of market demand. Investment decisions are based on an assumed return on investment (ROI) of 10 percent with a 10 percent hurdle rate.[7]

In the model, products are produced to annual average specifications and demands with calibrations to account for non-linear blending qualities such as Reid Vapor Pressure

[6] Energy Information Administration, *National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000) (Washington, DC, March 2000).

[7] This assumption is consistent with other refining industry analysis. Hurdle rate is defined as the threshold at which an investment is deemed economical, and the model would proceed with such investment.

(RVP) in motor gasoline. The PMM models EPA's complex model requirements for Phase II RFG through specification constraints on aromatics, benzene, sulfur, RVP, E200, E300, olefins, and oxygen content. The specification constraints conform to EPA's complex model requirements for emissions reductions of VOCs, NOx, and toxics but do not determine these specifications as a model solution.

The "Tier 2" regulation that requires the nationwide phase-in of gasoline with a 30 parts per million (ppm) annual average sulfur content (less than 10 percent of the 1999 pool average) between 2004 and 2007, and the regulation requiring ultra-low-sulfur diesel for on-road use beginning in 2006, are both explicitly modeled.[8]

Revisions to the Petroleum Market Module for this Analysis

Revised AEO2002 Reference Case

The *AEO2002* Reference Case reflects legislation in 13 States that would limit the use of MTBE between 2003 and 2004. The actual timing and implementation of these State restrictions are highly uncertain (see Background) and their inclusion in the Reference Case effectively obscures the impact of the requested scenarios relative to the current market. In order to analyze the impact of the S. 1766 Case and the RFS/No MTBE Ban Case more clearly, a revised Reference Case excluding State-level MTBE restrictions was developed for the purpose of this report. The Reference Case in this study is consistent with H.R. 4, which has no RFS or MTBE ban provisions.

Conversion of MTBE Production

Refineries and petrochemical plants in the United States have at least 242,000 barrels per day of MTBE production capacity that would become inoperable if MTBE is banned.[9] The loss of these assets may be minimized if they can be economically converted to other applications such as ethyl tertiary butyl ether (ETBE), iso-octane, or alkylate production. Conversion to ETBE production is assumed to be infeasible because, like MTBE, it is an ether and because it shares many of the same properties as MTBE, may be subject to similar bans.[10] Along with ethanol, iso-octane and alkylate may serve to offset some of the lost volume and fuel properties associated with the loss of MTBE in the gasoline pool.

The economics of MTBE unit conversion is highly uncertain and would vary from plant-to-plant depending on many market and regulatory conditions, including, the passage of an RFS, and the extent and location of MTBE bans in the United States. Issues related to MTBE conversion are discussed in greater detail below.

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[8] For further details of the PMM, refer to *Petroleum Market Model of the National Energy Modeling System*, Energy Information Administration, February 5, 2001.

[9] Peak production in June 2000, according to EIA-819M, Monthly Oxygenate Telephone Report, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/monthly_oxygenate_report/historical/2001/2001_12/pdf/tabled4.pdf.

[10] In addition to MTBE, California has banned other ethers.

MTBE is typically produced by reacting isobutylene with methanol. It has relatively low vapor pressure compared to ethanol, which helps minimize hydrocarbon vapor losses into the atmosphere. Atmospheric hydrocarbons in the presence of nitrogen oxides and sunlight are believed to form ozone through a sequence of complex chemical reactions.

MTBE is produced in three kinds of plants: refineries, petrochemical plants, and on-purpose plants. The latter two are typically called "merchant plants." On-purpose merchant plants purchase their feedstocks and then react them to produce a saleable commodity. If MTBE is banned, it is unlikely that these plants will find it economical to convert to iso-octane production, because the cost of the inputs (isobutylene and isobutene) is higher than the value of the output (iso-octane). Discussions with producers indicate that even a direct subsidy would probably not induce on-purpose MTBE producers to convert.

Petrochemical plants produce MTBE as a byproduct of another process, such as production of styrene monomer. In this case, conversion of an MTBE plant to iso-octane will depend on the relative economics of the companion process. It might be worthwhile for a petrochemical plant to accept a grant to convert to iso-octane, in order to support its other line of business.

If MTBE is banned, refineries would be more likely to convert an MTBE unit to an iso-octane unit or send the butane now being used to produce MTBE to an existing or expanded alkylation.

If MTBE is banned, MTBE producers would also have the option of exporting their product, since it will continue to be used abroad. But U.S. producers have a competitive disadvantage. They tend to have higher feedstock costs, and risk creating a world surplus and driving down prices. The on-purpose plants and petrochemical plants would likely be squeezed out of the export market before refiners with excess MTBE capacity.

The decision to convert to either iso-octane or alkylate production would depend on individual plant economics. This analysis reflects the ability of MTBE producers to convert to iso-octane, and to divert butane to existing alkylation units. In addition to the capital and operating cost of MTBE unit conversion to iso-octane, an allowance of $250 million for merchant plant conversion was included, reflecting the provisions of Section 828 of S. 1766. However, this analysis results in conversion of only the refinery MTBE units because the projected feedstock costs of the on-purpose units makes conversion uneconomic. The PMM includes no representation of petrochemical MTBE plants, and therefore can give no indication of the behavior of this type of merchant plant. The ability to convert MTBE production to iso-octane is expected to slightly reduce the cost of gasoline production.

Credit for Cellulose Ethanol

Ethanol from corn is currently the most established renewable fuel. It is blended into gasoline to add oxygenate, octane, and volume. The problem is that it is fairly costly to produce. The technology for producing ethanol from corn is mature, so it is unlikely that production cost can be reduced significantly. Attempts to drastically expand corn ethanol output would require more corn to be grown, placing further pressure on costs.

Because of these limitations to the use of corn for ethanol production, there are ongoing experiments to find other feedstocks for ethanol production. Ethanol is the product of fermentation of sugars by yeast. Corn grain contains sugars and starches which may be converted into sugars by enzymes. Wood products, grasses, and agricultural wastes (biomass) contain little starch or sugar but much cellulose. The cellulose can be converted to sugars by treatment with acid or with enzymes. Reduction in the cost of converting cellulose to sugars has been a major focus of various research efforts. Cellulose ethanol production is modeled in NEMS.

To encourage further cellulose ethanol production, Section 818 of S. 1766 credits every gallon of ethanol produced from cellulose (biomass) as 1.5 gallons of renewable fuel. In order to reflect this provision, an adjustment was made to the accounting of biomass ethanol in the PMM. The result of this biomass ethanol credit is a projected renewable fuels level that is somewhat lower than the RFS schedule specified in Section 818 of the Bill. The split between biomass and corn-based ethanol is determined based on the relative economics of the two feedstocks.

Biodiesel as Part of the RFS

Biodiesel is a fuel for compression-ignition, or diesel, engines that is produced from vegetable oil or animal fat. Because the RFS specified in S. 1766 includes biodiesel in addition to ethanol, a representation of biodiesel was added to the PMM for this analysis. As a result, the amount of ethanol required to fulfill the RFS is reduced by the amount of biodiesel that penetrates the market.

In addition to its status as a renewable fuel, the incentives for biodiesel consumption are the credits it generates under the Energy Policy Act of 1992 (EPAct) for State and Federal Governments,[11] its value as a lubricity additive, and its lower particulate emissions. If only the consumption likely to be spurred by EPAct were considered, biodiesel consumption would probably reach 7.3 million gallons in 2020. If biodiesel is able to capture a large share of the market because of its value as a blending additive for improved lubricity, consumption may reach about 630 million gallons in 2020.[12]

EIA estimated the total cost of soybean diesel based on information from other sources.

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[11] Section 153 of H.R. 4 and Section 817 of S. 1766 formalize DOE's January 2001 administrative decision to accept biodiesel for credit under EPAct. See http://www.ott.doe.gov/epact/pdfs/biodiesel_guidance.

[12] Biodiesel demand quantity for the purpose of this analysis was fixed to one of two values, a lower bound quantity due to EPAct or an upper bound quantity due to lubricity demand.

The National Renewable Energy Laboratory (NREL) provided estimates of biodiesel production costs assuming a plant of 10 million gallons of output per year fed by soybean oil. [13] The NREL estimates are based on the technology of methyl alcohol and oil reaction catalyzed by sodium hydroxide. The plant was estimated to cost $1 per annual gallon of capacity, or $10 million total capital costs (in current dollars), with operating expenses of $0.20 per gallon, excluding the cost of the soybean oil. Biodiesel production yields coproduct fatty acids and glycerol. The sale of the fatty acids yields a credit of $0.002 per gallon of biodiesel, and the sale of the glycerol yields a credit of $0.15 per gallon of biodiesel. Using Urbanchuk's projection of a soybean oil feedstock cost of $1.49 per gallon of biodiesel,[14] the average variable cost of soybean biodiesel today is thus $0.20+$1.49-$0.002-$0.15=$1.538 per gallon. The plant is assumed to be financed by equity with an annualized return of 15 percent, and a 20-year plant life. Treating the hypothetical income stream as an annuity over the 20 years, the estimated capital cost is $1.6 million per year, or $0.16 per gallon at full output. Total cost of soybean biodiesel is therefore $1.538+$0.16=$1.698 per gallon at plant output of 10 million gallons per year. This is the plant gate price of biodiesel that pays investors their desired return. If the expected price is at least $1.698 then biodiesel capacity can be expected to expand.

Soybean oil is not the only possible feedstock. According to NREL, " Biodiesel can be produced from recycled restaurant greases called yellow grease. Approximately 13 million gallons of domestic production capacity, or a little more than 50 percent of U.S. biodiesel capacity, can use yellow grease. The average variable cost of producing biodiesel from yellow grease, assuming approximately 1.5 cents per gallon higher operating costs, is equal to $0.613 per gallon. Yellow grease currently sells for 7 cents per pound or $0.54 per gallon of feedstock. The total cost of producing yellow grease biodiesel, including capital, would be $0.773 per gallon. Since more than half of the U.S. biodiesel capacity is capable of producing yellow grease biodiesel, long term reductions in biodiesel costs appear to be promising."[15] The drawback is that yellow grease biodiesel has poorer cold flow properties than soybean biodiesel.[16]

An adjusted Reference Case was produced for this analysis because *AEO2002* did not include projections for biodiesel. The adjusted Reference Case and the scenarios provided in this analysis reflect EIA's estimate of a lower bound for biodiesel demand based on an assessment of potential fleet demand for biodiesel to comply with EPAct. The Act requires that a fraction of new light vehicle purchases for qualified fleets be alternatively fueled vehicles (AFV's). Light vehicles for EPAct purposes have Gross Vehicle Weight Rating (GVWR) less than or equal to 8500 lbs. Federal, State, and alternative fuel providers' vehicles that are capable of being fueled at central locations are qualified fleets. Law enforcement, emergency, and military vehicles are excluded from qualification. The Federal and State Government AFV requirement is 75 percent; alternative fuel providers' AFV requirement is 90 percent. In lieu of an AFV purchase, a

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[13] E-mail from K. Shaine Tyson of the National Renewable Energy Laboratory, Feb. 12, 2002
[14] Urbanchuk, John M. *An Economic Analysis of Legislation for a Renewable Fuels Requirement for Highway Motor Fuels.* November 7, 2001. Posted on National Biodiesel Board website.
[15] E-mail from K. Shaine Tyson of the National Renewables Energy Laboratory, Feb. 12, 2002
[16] Phone call from K. Shaine Tyson of the National Renewables Energy Laboratory , Feb. 11, 2002

fleet operator may purchase 450 gallons of pure biodiesel for use in a vehicle with GVWR over 8,500 lbs. The fleet operator may offset up to half the number of required AFV purchases with biodiesel purchases. Approximately 32,000 new fleet vehicle purchases were covered under EPAct in 2001.[17] Since alternative fuel provider purchases are aggregated with Government purchases, the 75 percent requirement was applied uniformly. The number of vehicle purchases covered under EPAct was assumed to grow at the same rate as that projected for the light vehicle stock in *AEO2002*. Every qualified fleet is assumed to use biodiesel purchases to offset half the AFV requirement. Thus, biodiesel demand under EPAct would reach 6.5 million gallons in 2010 and 7.3 million gallons in 2020.

Although not reflected in the scenarios presented in this report, EIA also developed upper bound estimates of the demand for biodiesel as a lubricity additive. As mentioned in Appendix B, low sulfur diesel fuel marketed in the United States has lubricity problems. The move to ultra-low-sulfur diesel is expected to make the problem worse. The upper bound estimates assume that biodiesel is blended into ultra-low-sulfur diesel at one percent by volume to improve lubricity. This yields 470 million gallons of biodiesel in 2010 and 630 million gallons in 2020. Sensitivity analysis of the higher biodiesel penetration rate indicated no significant impact on gasoline prices, but served to reduce ethanol requirements to meet RFS by the higher amount.

Assumptions of this Analysis

Besides the addition of MTBE unit conversion, the merchant plant conversion allowance, and biodiesel methodology, the analysis scenarios were developed by defining different scenario assumptions. Table 1 shows a comparison of the basic assumptions underlying the Reference, S. 1766, and RFS/No MTBE Ban Cases.

Table 1. Comparison of Assumptions for Requested Cases

Case	13 State MTBE ban	Federal MTBE ban	Oxygen Requirement	RFS	Conversion of MTBE units	Grant for Merchant Plant Conversion
Reference (H.R.4)	No	No	Maintained	No	N/A	N/A
S. 1766	No	Yes	Waived, East and West Coast	Yes	Yes	Yes
RFS/No MTBE Ban	No	No	Waived, National	Yes	N/A	N/A

N/A: not applicable to this case

Sources: H.R. 4; S. 1766; letter from Sen. Murkowski to Mary J. Hutzler, dated February 6, 2002 (See Appendix A).

[17] Based on conversations with staff of the U.S. DOE Office of Energy Efficiency and Renewable Energy.

Key Assumptions of "S. 1766" Case

- *Annual RFS requirements as stipulated in Section 818 of S. 1766* (See Table 2). After 2012, the RFS requirement is estimated as the same percentage of highway fuel demand that it represented in 2012.

- *An adjustment is made to credit every gallon of cellulose ethanol as 1.5 gallons of renewable fuel as per S. 1766*.

- *A national ban on MTBE starting in 2006.* S. 1766 specifies a ban four years after passage.

- *States on the East and West Coasts waive the 2.0 percent (weight) oxygen requirement for RFG,* as specified in Senator Murkowski's letter of February 6. Section 824 of the bill grants governors the authority to waive the oxygen requirement but no "backsliding" on air toxics is allowed. This Case assumes that RFG areas that currently use MTBE blended gasoline but have State legislation that would ban MTBE in the future will waive the oxygen requirement.

- *Maintaining toxic emissions benefits.* Air toxic emissions from RFG are assumed to be maintained at current levels on average.

- *The gasoline forecast is based on the AEO2002* Reference Case.

- *Areas that currently use RFG are assumed to continue to use RFG*. In April 2001, the governor of New Hampshire requested that the EPA allow the State to opt-out of the RFG program immediately. The next opportunity for States to legally opt-out of the program is January 1, 2004. This analysis reflects no change to RFG areas since no decision has been made in regard to New Hampshire.

- *The continuation of the ethanol tax exemption is assumed through 2020*. In accordance with the Federal Highway Bill of 1998, the exemption is currently 53 cents per gallon but will be reduced by 1 cent per gallon in 2003 and again in 2005. Legal authority for the tax exemption expires in 2007, but because the exemption has been renewed several times since it was initiated in 1978, this analysis assumes that it will be extended at the 51-cent (nominal) level for 2007 through 2020.

- *MTBE use outside the United States is assumed to continue*. No ban or reduction in the use of MTBE is assumed for other countries.

- *The cost of increased ethanol blending results in an increase in ethanol prices resulting from greater demand*. Additional ethanol requirements are assumed to be met with domestic supply. The level of corn-ethanol production required in this Case is associated with production costs based on a U.S. Department of Agriculture paper analyzing a renewable fuel standard.[18]

- *Biodiesel consumption is assumed to grow from an estimated 5.4 million gallons in 2001 to 7.3 million by 2020.* This growth path is based on consumption in alternative fuel vehicles and is assumed to be used to meet requirements of EPAct. The economics and penetration of biodiesel are highly uncertain and are discussed above.

- *As indicated in S. 1766, merchant MTBE plants are allowed up to $250 million in grants for conversion to other uses between the years 2002 and 2004.*

Key Assumptions of "RFS/No MTBE Ban" Case

The RFS/No MTBE Ban Case uses the same set of assumptions as the S. 1766 Case with the exception of the following:

- No national ban on MTBE is assumed.

- The oxygen requirement on RFG is assumed to be repealed nationally, as indicated in the February 6 letter from Senator Murkowski.

- No conversion of MTBE units is assumed because MTBE is not Federally banned.

- No grant for merchant MTBE plant conversion is assumed.

Provisions of S. 1766 Not Explicitly Modeled

Distillation Index

An additional provision of S. 1766 would require a reduction of the maximum distillation index (also called drivability index or DI) from 1250 to 1200 for summertime at the refinery gate. The DI generally ranges between 1100 and 1300 and is calculated as a function of the temperatures at which 10 percent (T10), 50 percent (T50), and 90 percent (T90) of the gasoline vaporizes. The spread between these ignition temperatures enables the gasoline to be effective in both cold start and warm start situations (when the engine has already been heated). Because efficient cold starting is key to minimizing hydrocarbon (HC) and carbon monoxide (CO) emissions, the automotive industry advocated the creation of the current DI maximum, and is now advocating the 1200 maximum to help meet increasingly stringent exhaust emission standards. The reduction of the DI is expected to make it more difficult to produce gasoline that can be blended with ethanol. At the same time the automotive industry is advocating a change to the

[18] Office of Energy Policy and New Uses, U.S. Department of Agriculture, *An Analysis of Ethanol Production Under a Renewable Fuel Requirement*, September 1, 2000.

calculation of DI that would add further difficulty to achieving even the current standard with ethanol-blended gasoline.[19]

The gasoline representation in the PMM does not currently include a DI parameter. The inclusion of a DI parameter would require a recursive optimization process that could not easily or efficiently be incorporated into the model framework given the time constraints of this study. In addition, the PMM does not differentiate between different grades of gasoline that are critical to DI analysis.

The proposed reduction in DI would be expected to add to the costs projected in the S. 1766 and the RFS/No MTBE Ban Cases; however, the magnitude of the impact is uncertain. A report by the National Petroleum Council provided a wide range of cost estimates for reducing DI based on different assumptions.[20] The NPC analysis was based on a proposal by the Alliance of Automobile Manufacturers which advocated a 1200 DI maximum at the retail level, in contrast to the current standard of 1250 at the refinery gate. The analysis assumed that gasoline would need to meet an 1100 DI at the refinery gate in order to meet 1200 at retail, and resulted in an estimated cost increase of about 7 cents per gallon. A sensitivity analysis, assuming gasoline measuring 1150 at the refinery gate, resulted in additional production costs of only three-fourths of one cent per gallon, compared to the current 1250 DI.[21]

Removal of PSI Allowance for Conventional Gasoline

Section 818 of S. 1766 calls for elimination east of the Mississippi River of the current 1 pound per square inch waiver of the Reid vapor pressure (RVP) limitation for fuel blends containing gasoline and 10 percent ethanol in areas not suffering from high ozone concentration levels. This ethanol waiver was originally allowed to make it easier and more economical to blend ethanol into gasoline, since a 10 percent ethanol blend raises the RVP of gasoline by about one pound. Some environmental organizations advocate elimination of the existing 1-pound RVP waiver, arguing that when hydrocarbon emissions increase, ozone levels increase. PMM does not incorporate lifting the waiver because this change cuts through the middle of a refining region and would require detailed regional estimations. The lifting of the waiver may also result in conventional gasoline blendstock of different qualities on either side of the Mississippi River and may require another category of gasoline blendstock in an already stretched distribution system. This new conventional blendstock could not be modeled within the time constraints of this analysis.

[19] International Fuel Quality Center, *Issues Overview- DI- Driveability/Distillation Index*, (www.ifqc.org), January 2, 2002.
[20] National Petroleum Council, *U.S. Petroleum Refining – Assuring the Adequacy and Affordability of Cleaner Fuels*, Chapter 5, Washington D.C., June 2000.
[21] National Petroleum Council, *U.S. Petroleum Refining – Assuring the Adequacy and Affordability of Cleaner Fuels*, Appendix K, Washington D.C., June 2000.

Credit Trading Provision

Section 818 of S. 1766 mentions a credit program but does not outline the structure of the program. A credit program would be expected to provide flexibility to refineries that are unable to meet individual targets; however, it would not be expected to significantly modify the aggregate results of this analysis. Due to the minimal expected impact and the lack of specific information about the structure of the program, credit trading was not modeled for this analysis.

Local Market and Price Volatility Issues Not Analyzed

The current modeling approach does not capture some of the changes refiners will make and some of the market dynamics that could influence prices to consumers and alter competition among refiners. The proposed legislation could have disparate impacts among different types of refineries and in different regions. The three-region notional or "aggregate" refinery approach that is used by the PMM does not capture some of these distinctions, which in turn, can affect prices to end users. In addition, NEMS operates as a long-run equilibrium model which projects the levels of domestic production and imports necessary to meet demand requirements. Since supply and demand are always in balance, this approach cannot provide insights into price volatility, either during transitions or after transitions. For many issues, this modeling approach is adequate to simulate refiners' behavior and associated price implications to consumers, but under the proposed fuel-specification changes, this approach may not fully capture what refiners' will actually do, particularly on a regional or local basis.

PADD I (East Coast) is an area that could be affected by the disparate effects proposed regulatory changes may have on refineries. PADD I refineries' markets are mainly on the East Coast, where a large amount of reformulated gasoline is used. Some of these refineries produce mostly reformulated gasoline; therefore, the toxic content of their current gasoline would be much lower than required gasoline toxic limits. The recent Mobile Source Air Toxics (MSAT) rule locks those refineries into those low toxic baselines. Under an MTBE ban, and even with removal of the oxygen mandate, ethanol will be used because of its octane content and other properties. However, the properties of MTBE and ethanol are different, and under an MTBE ban, to meet toxic limits and maintain competitive costs, these refineries could find it more economic to produce less reformulated gasoline components and more conventional gasoline. In this case, Gulf Coast refineries with higher toxic baselines would need to fill the reformulated gasoline gap. The PMM does not simulate these types of individual refinery circumstances. If the situation described evolves, it would produce higher prices to consumers than the PMM implies, and would produce a change in the competitive position of the refiners that the PMM is not designed to simulate.

Price volatility, another area of concern to consumers, could arise under some of the proposed fuel regulatory changes. NEMS is an equilibrium model and, by its nature, does not deal with the imbalances in supply and demand that cause price spikes. The regulatory changes being considered have supply implications that could create price volatility during transition periods. For example, both MTBE bans and DI reduction result in a loss of gasoline production capability that, without further refinery investment, could create price pressures as MTBE and DI changes take effect.

For example, there is the loss of MTBE volumes, which ethanol would only partially replace. Also, in order to use ethanol in place of MTBE, some refineries might have to reduce the "light", low-boiling-point gasoline components now being used that have higher RVP in order to keep the ethanol-blended gasoline within RVP limits. Lowering the DI, on the other hand, can cause refiners to reduce the "heavy", high-boiling-point components now being blended into gasoline. Removing these components reduces the amount of gasoline that can be produced without making further investments. Furthermore, imported sources of reformulated gasoline, which are important to the East Coast, are likely to diminish if ethanol-blended reformulated blendstock for oxygenate blending (RBOB) or other formulations not needed abroad are required in the United States. During the transition to a Federal MTBE ban or DI reduction, such supply reductions could add to price volatility. There may not be the time and resources to adjust capacity when engineering and construction resources are likely to be strained meeting the low sulfur fuel requirements alone.

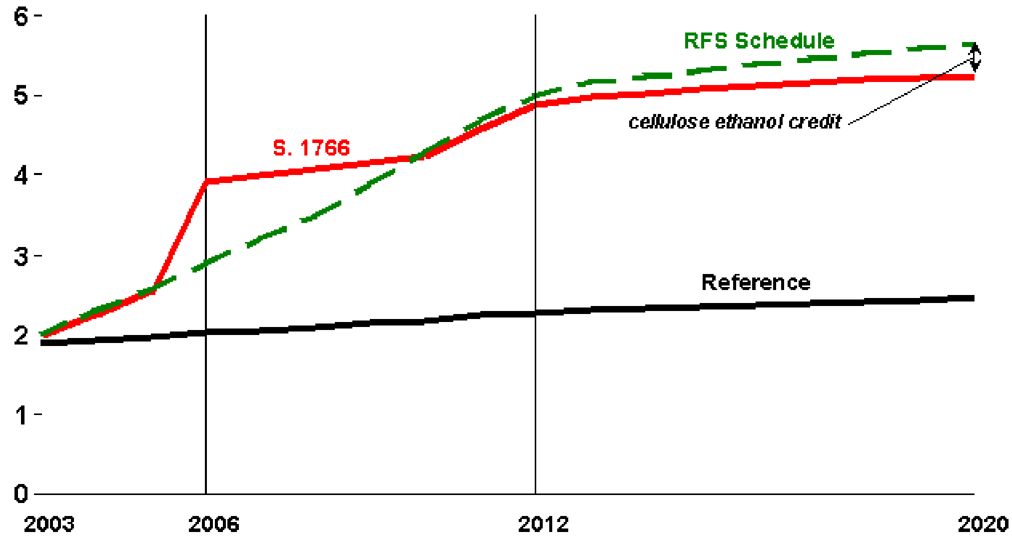
Even after the transition, the East Coast could be subject to more volatility than it has seen historically if it uses ethanol-blended RFG extensively. S. 1766 effectively requires that another major gasoline component be shipped some distance into the Northeast and be stored separately in a distribution system that is working near capacity limits. Whether this increases the potential for volatility requires a more detailed analysis of the distribution system and its potential expansion path along with the implications of increased number of products.

In summary, to comprehensively analyze all of the regional price implications and changes in competitive positions potentially stemming from the proposed legislation requires additional modeling approaches needing more time than was available for this report. The price and volatility implications could be significant, but the magnitude is unknown.

Results of the S. 1766 Case

Although S. 1766 includes a year-by-year schedule for the RFS, EIA's renewables projections for the S. 1766 Case do not coincide with the levels specified in the schedule for a number of reasons (Figure 3).   In 2006 when the Federal MTBE ban is assumed to occur, ethanol blending increases significantly, exceeding the RFS target by more than 1 billion gallons. The higher level of ethanol blending than the RFS target specified in S. 1766 disappears by 2010 due to increasing RFS targets.   Beginning in 2010, the level of ethanol blending is determined predominantly by the RFS schedule rather than the assumed MTBE ban. However, the provision for a cellulose ethanol credit (allowing

Figure 3. Total Renewable Fuels Consumption For Transportation For S. 1766 Case, 2003-2020 (billion gallons per year)



Source: Energy Information Administration, National Energy Modeling System runs R1aeo02z.d027002a, R1i1m0b0.d028002b

each gallon of cellulose ethanol to count as 1.5 gallons of renewable fuels) is projected to reduce the amount of renewable fuels required in the RFS schedule by about 10 million gallons in 2003 growing to 130 million gallons by 2012, and about 370 million gallons by 2020 (Table 2).

The RFS requirements can be met either with ethanol or biodiesel. In this analysis, the RFS is projected to be met predominantly with ethanol which represents at least 99.5 percent of total renewables in all years. Biodiesel is assumed to grow from 5.4 million gallons in 2001 to 7.3 million gallons in 2020, reflecting EIA's estimate of the amount of biodiesel that will be used to fulfill EPAct requirements. As discussed in the Methodology Section, a higher level of biodiesel penetration may occur if it becomes widely used as a lubricating agent for ultra-low-sulfur diesel. Because of the uncertainty in the biodiesel market, "high biodiesel penetration" estimates were developed which could result in 139 million gallons of additional biodiesel and less ethanol used to meet the RFS requirement for 2006, 347 million gallons for 2012, and 625 million gallons for 2020. Given the higher biodiesel penetration assumption, biodiesel would represent 3.5 percent of total renewables in 2006, 7.1 percent in 2012, and 11.9 percent in 2020 in the S. 1766 Case.

S. 1766 is projected to yield carbon emissions from petroleum in the transportation sector which are 4.6 million metric tons lower than those in the Reference Case in 2006, and 7.2 million metric tons lower in 2020. These changes represent a decline of between 0.8 and

1.0 percent of carbon emissions from petroleum used for tranportation from Reference Case levels.

Table 2. Renewable Fuels Consumption by Type and Case, 2003, 2006, 2012, and 2020 (billion gallons)

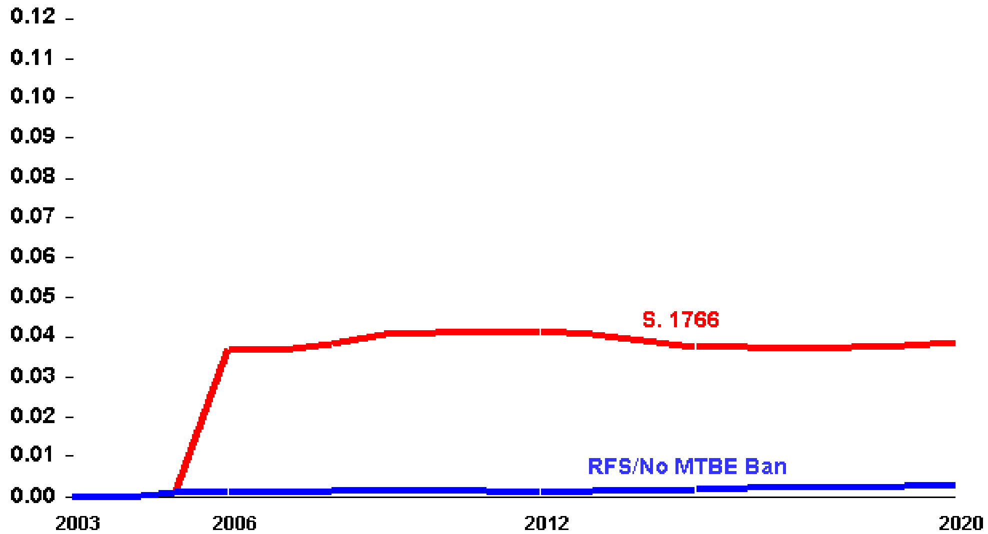
	2003	2006	2012	2020
RFS Schedule	**2.00**	**2.90**	**5.00**	**5.63***
Reference Case				
Total Renewable Fuels	**1.89**	**2.02**	**2.28**	**2.48**
Ethanol from corn	1.88	1.90	2.01	1.72
Ethanol from cellulose	0.01	0.11	0.26	0.75
Biodiesel	0.01	0.01	0.01	0.01
S. 1766				
Total Renewable Fuels	**1.99**	**3.92**	**4.87**	**5.26**
Ethanol from corn	1.96	3.79	4.60	4.51
Ethanol from cellulose	0.02	0.12	0.26	0.74
Biodiesel	0.01	0.01	0.01	0.01
RFS/No MTBE Ban				
Total Renewable Fuels	**1.99**	**2.84**	**4.87**	**5.30**
Ethanol from corn	1.96	2.71	4.61	4.54
Ethanol from cellulose	0.02	0.12	0.26	0.75
Biodiesel	0.01	0.01	0.01	0.01

* Estimated as 2012 renewables percentage of transportation demand, as specified in Section 818 of S. 1766.
Note: Totals may not equal sum of components due to independent rounding.
Sources: S. 1766, Section 818 and the Energy Information Administration, National Energy Modeling System Runs R1aeo02z.d027002a, R1i1m0b0.d028002b, Rzi0mXb0.d0227002a.

In general, net petroleum imports are projected to be about one percent lower than in the Reference Case. Net petroleum imports are 156,000 barrels per day below Reference Case levels in 2006 (decline of 1.2 percent), and 227,000 barrels per day lower in 2020 (a decline of 1.4 percent). The lower import projections translate into a reduction in the import share of petroleum consumption of between 0.4 and 0.7 percent. The net import reductions may be overestimated in this case because it does not reflect any net increase in energy consumption required for the additional renewables/feedstock production. The inability to capture imports of unfinished products, including iso-octane and alkylates that may come into the market may also contribute to an over-estimation of the decline in imports. On the other hand, the net import projections do not account for the possible increase in MTBE exports from the United States to other countries that might occur if domestic use of MTBE is banned.

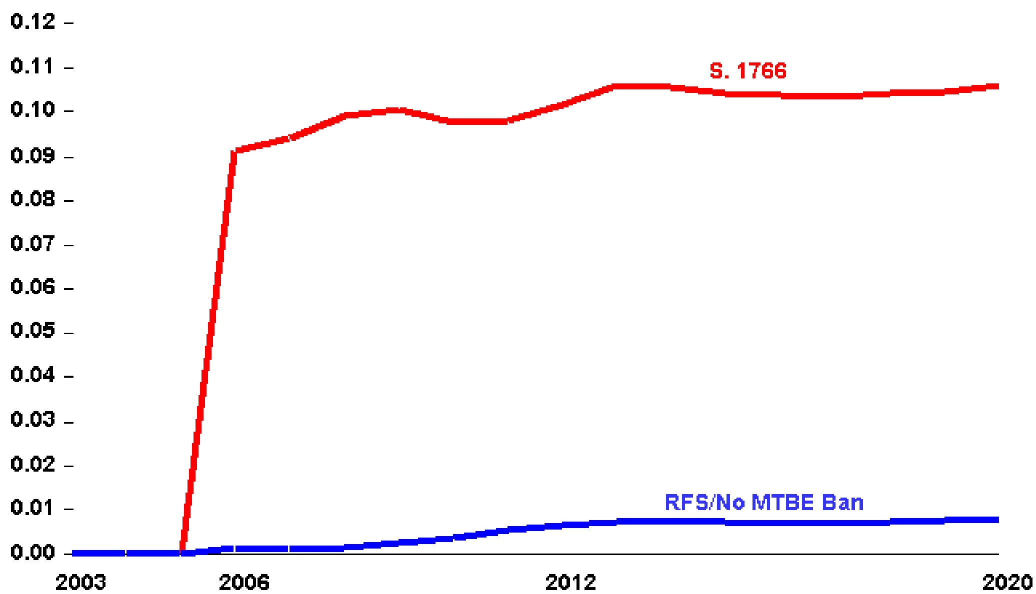
Prior to 2006, projected average national prices of all gasoline and of RFG are not significantly different from the Reference Case. After the Federal MTBE ban is assumed to become effective in 2006, the national average price of all gasoline is projected to be about 4 cents per gallon higher (Figure 4), and the national average RFG price between 9.0 and 10.5 cents per gallon higher relative to the Reference Case (Figure 5). The higher projected prices reflect the loss of volume, oxygen, and octane associated with banning

Figure 4. Average National Gasoline Price Differentials Compared to Reference Case, 2003-2020 (2000 dollars per gallon)



Source: Energy Information Administration, National Energy Modeling System runs R1aeo02z.d027002a, R1i1m0b0.d028002b, Rzi0mXb0.d022702a

Figure 5. Average RFG Price Differentials Compared to Reference Case , 2003-2020 (2000 dollars per gallon)



Source: Energy Information Administration, National Energy Modeling System runs R1aeo02z.d027002a, R1i1m0b0.d028002b, Rzi0mXb0.d022702a

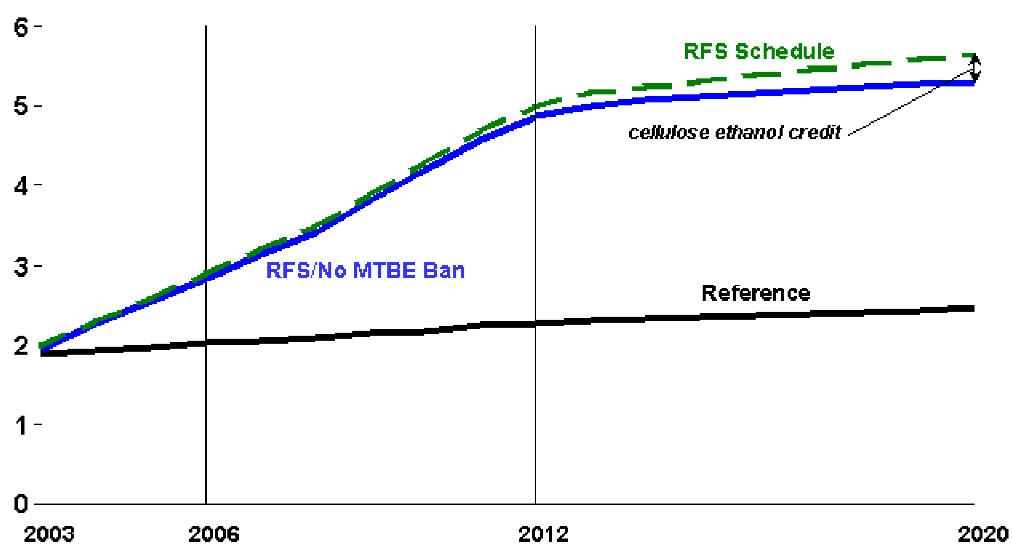
MTBE. Ethanol cannot fully compensate for all of these characteristics and is more expensive than MTBE.

Despite the $250 million allowance for merchant plants to convert MTBE units to other uses provided for in S. 1766, this analysis indicates that conversion may be uneconomic for "on-purpose" plants that do not produce their own feedstocks because the feedstock costs may be prohibitive.

Results of the RFS/No MTBE Ban Case

The RFS/No MTBE Ban Case reflects no Federal MTBE ban, and, therefore, no associated increase in ethanol blending requirements. As a result, the projected level of renewables is effectively set by the RFS schedule. The cellulose ethanol credit and results in actual renewables consumption that is below the RFS target levels (Figure 6). After 2012, the RFS target is determined as the percentage of total highway demand that renewables achieved in 2012. By 2020, total renewables consumption in this case is projected to be 40 million gallons per year higher than in the S. 1766 Case, because the relatively high gasoline prices associated with S. 1766 have a slight dampening effect on gasoline demand which in turn reduces blending.

Figure 6. Total Renewable Fuels Consumption For Transportation For RFS/No MTBE Ban Case, 2003-2020 (billion gallons per year)



Source: Energy Information Administration, National Energy Modeling System runs R1aeo02z.d027002a, Rzi0mXb0.d022702a

Projections of carbon emissions are lower than the Reference Case but not as low as those in the S. 1766 Case. As a percentage of carbon emissions from petroleum transportation fuels in the Reference Case, this Case results in declines ranging from 0.2 to 0.7 percent between 2006 and 2020, compared with declines in the S. 1766 Case ranging from 0.8 to 1.1 percent.

The projected reduction in net petroleum imports is smaller than in the S. 1766 Case. A reduction in petroleum imports of 61,000 barrels per day is projected for 2006, and 189,000 barrels per day for 2020, compared to S. 1766 Case reductions of 156,000 barrels per day in 2006, and 227,000 barrels per day in 2020. Most of this difference can be attributed to MTBE imports which are allowed in this case but are not allowed in S. 1766. As mentioned above, net imports in the S. 1766 Case may not fully capture the potential for imports of unfinished petroleum products such as iso-octane and alkylate. Neither this case nor the S. 1766 Case account for the additional energy that may be used to produce the additional renewables and their feedstocks.

Projected prices in the RFS/No MTBE Ban Case are well below the S. 1766 projections because no Federal MTBE ban is assumed. In the absence of an MTBE ban more ethanol is available to be blended into conventional gasoline, instead of being pulled into RFG blending to help replace MTBE. Beginning in 2006, projected RFG prices in the RFS/No MTBE Ban Case rise gradually to about 1 cent per gallon higher than the Reference Case by 2012, where they remain through 2020. The impact on the price of all gasoline remains below one-half cent per gallon compared to the Reference Case through 2020.

The relatively minor change in national average prices projected in this case may not translate into minor changes in localized markets. Although the aggregate nature of the PMM precludes an analysis of local markets, information about the shift in ethanol blending from RFG toward conventional gasoline would point to possible price increases in conventional gasoline markets that do not currently blend ethanol. After 2012 when the growth of the RFS targets slows, ethanol blending into conventional gasoline is projected to increase up to 2.8 billion gallons per year over Reference Case levels without a Federal MTBE ban, compared to an increase of no more than 0.5 billion gallons per year in the S. 1766 Case which assumes a Federal ban. This higher level of ethanol blending into conventional gasoline occurs because MTBE is still blended into RFG, leaving most of the RFS requirement for ethanol to be absorbed into conventional gasoline markets.

Uncertainty

State MTBE Restrictions

In this analysis, the S. 1766 and RFS/No MTBE Ban Cases are compared to a Reference Case that does not include the implementation of MTBE bans or restrictions in 13 States in the 2003 to 2004 time period. Although MTBE legislation or executive orders have already been passed in these States, there is considerable uncertainty as to when or if these requirements will be implemented. It has been well publicized that California officials have been considering postponing the 2003 ban on MTBE, since EPA officially denied California's oxygen waiver request, and given the high transitional costs reported in a recent study conducted by Stillwater Associates for the CEC. The California Energy Commission highlights the possibility of short-term supply shortfalls and associated price spikes if MTBE is banned without adequate lead-time.[22]

The long-run equilibrium analysis in this report is based on an assumption of sufficient lead-time for investments and an assumption of perfect foresight for investors. In other words, investment decisions are based on a certainty that a given policy change will occur in a given number of years. In reality, some market participants may respond to uncertainty by delaying investment decisions, increasing the likelihood of supply imbalances and price spikes during transition.

Ethanol tax exemption

Ethanol currently receives a Federal excise tax exemption of 53 cents per gallon, which is scheduled to decline to 52 cents in 2003 and 51 cents in 2005. Legal authority for the Federal tax exemption expires in 2007 and poses considerable uncertainty for this analysis. The exemption has been renewed several times since it was initiated in 1978 and is assumed to be extended at the 51-cent (nominal) level through 2020, in all cases of this analysis. The costs associated with the S. 1766 and RFS/No MTBE Ban Cases are highly dependent on this assumption. Without this tax exemption, ethanol-blended gasoline would cost consumers an additional 5.1 cents per gallon for a 10 percent blend of ethanol, and 2.9 cents per gallon for 5.6 percent RFG blends. Regardless of this higher ethanol cost, the RFS requirement leaves little flexibility to reduce ethanol blending. If the tax exemption is assumed to expire in 2007, the S. 1766 average price differential for all gasoline between 2006 and 2020 is projected to be 4.5 cents per gallon, compared to 4.0 cents per gallon when the exemption is assumed to continue. The average projected differential for RFG is 12.0 cents per gallon without the exemption in comparison to 10.0 cents per gallon with the continuation of the exemption.

Structure of credit trading

This analysis does not reflect any representation of the credit program mentioned in S. 1766 because of the lack of specific information about the structure of the program. For instance, it is not clear whether trading would occur nationally or only between regions, or how credits would be allocated to individual refineries. A credit program would be expected to provide flexibility to refineries that are unable to meet individual targets; however, it would not be expected to modify the aggregate results of this analysis except possibly to dampen the market demand for ethanol in the S. 1766 Case in those years that it rises above the level specified by the RFS. Given the specifics of the proposed credit program, the extent to which market demand for ethanol could be reduced by credit trading could not be quantified without an in-depth analysis of State tax incentives for ethanol blending.

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[22] Stillwater Associates, *MTBE Phase Out in California- Draft Study for the California Energy Commission,* February 18, 2002.

The DI and Removal of the Rvp Waiver

Due to the rapid delivery schedule for results for this study, this analysis does not explicitly model the impact of either the reduction to 1200 DI or the removal of the 1 psi waiver for ethanol-blended conventional gasoline east of the Mississippi River, as specified in S. 1766. Both of these changes would tend to make it more difficult to blend gasoline with ethanol, at the same time more ethanol blending is being required by the RFS. Although the magnitude of the impact on the cost of gasoline blending is unknown, these changes would tend to increase costs relative to those reflected in this analysis. A report by the National Petroleum Council provided a wide range of cost estimates for reducing DI based on different assumptions.[23] The NPC analysis was based on a proposal by the Alliance of Automobile Manufacturers which advocated a 1200 DI maximum at the retail level, in contrast to the current standard of 1250 at the refinery gate. Note that the S. 1766 provision would require 1200 at the refinery gate. The analysis assumed that gasoline would need to meet an 1100 DI at the refinery gate in order to meet 1200 at retail, and resulted in an estimated cost increase of about 7 cents per gallon. Sensitivity cases included in the NPC study that resulted in costs as low as one-half cent per gallon a 1150 at the refinery gate requirement is assumed and refineries are allowed the greatest flexibility in reallocating naptha streams.[24]

States' Ability to Waive the Oxygen Requirement on RFG

S. 1766 grants Governors the ability to waive the oxygen requirement on RFG in their States but toxic emissions benefits must be maintained. The follow-up letter from Senator Murkowski of February 6, 2002 directed EIA to assume that States on the East and West Coast waive the oxygen requirement. This assumption makes sense because the RFG areas currently using MTBE are predominantly on the East Coast and in California, and would be the most likely to want a waiver. However, the feasibility of getting a waiver given the requirement of maintaining air toxic emissions is uncertain. Air toxic emissions from RFG are assumed to be maintained at current levels on average. In reality some refineries might require further investments to achieve this goal while others might not, resulting in more disparate impacts than reflected in this analysis.

Biodiesel Market Penetration

The biodiesel projections in this analysis reflect offline estimates of the amount of biodiesel that will be used to meet EPAct requirements. All cases of this analysis reflect growth in biodiesel from 5.4 million gallons in 2001 to 7.3 million gallons in 2020. In order to quantify the uncertainty associated with biodiesel, EIA developed "high biodiesel penetration" estimates that assume biodiesel becomes widely used as a lubricating agent for ultra-low-sulfur-diesel. The "high biodiesel penetration" estimates resulted in 139 million gallons of additional biodiesel and less ethanol used to meet the

[23] National Petroleum Council, U.S. Petroleum Refining – Assuring the Adequacy and Affordability of Cleaner Fuels, Chapter 5, Washington D.C., June 2000.
[24] National Petroleum Council, U.S. Petroleum Refining – Assuring the Adequacy and Affordability of Cleaner Fuels, Appendix K, Washington D.C., June 2000.

RFS requirement for 2006, 347 million gallons for 2012, and 625 million gallons for 2020.

Return On Investment

Investment decisions are based on an assumed return on investment (ROI) of 10 percent with a 10 percent hurdle rate. Although the assumed ROI is standard to refining industry analysis, returns have historically fallen below these levels. Based on EIA's Financial Reporting Survey System the average estimated after-tax ROI for refiners between 1977 and 2000 was closer to 6 percent. A lower ROI/hurdle rate assumption would tend to make investment decisions less favorable and lower capacity expansion. Because the Reference, S. 1766, and RFS/No MTBE Ban Cases use the same investment assumptions, the impact of a lower ROI would be similar in all cases.

Appendix A:

Initial Letter of Request from Senator Frank Murkowski, Dec. 20, 2001.
Second Letter of Request from Senator Frank Murkowski, Feb. 6, 2002.

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES

WASHINGTON, DC 20510-6150

ENERGY.SENATE.GOV

December 20, 2001

Dr. Mary Hutzler
Acting Administrator
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC, 20585

Dear Acting Administrator Hutzler:

The Senate is considering comprehensive legislation to update U.S. national energy strategy in light of the volatility of energy markets in calendar year 2000 and the growing energy security concerns in light of recent events that highlight our dependence on foreign imported oil. To this end, there have been several legislative proposals introduced in the 107th Congress on the subject of national energy policy, and the Majority Leader has indicated that the Senate will debate energy policy early in the next session of Congress. Our decisions will benefit from an analysis of the strengths and weaknesses of the various energy policy proposals that have been introduced to date.

With that in mind, I request that the Energy Information Administration (EIA) analyze the potential costs and benefits of proposed legislation to update and revise our national energy strategy, namely, H.R. 4 as passed by the House of Representatives in August 2001, and S. 1766 as proposed by Senators Daschle and Bingaman earlier this month. I understand that EIA has the ability to conduct such analysis, including the use of both sectoral and economy-wide energy models. Using the most recent *Annual Energy Outlook 2002* as a reference case, I ask that EIA assess the impacts of these energy policy proposals on, at minimum:

- macroeconomic indicators (jobs, Gross Domestic Product, trade balance, etc.);
- energy supply and demand by fuel and process;
- energy prices to consumers (residential, industrial, and commercial) by fuel;
- dependence on foreign oil imports and impacts on energy security;
- impacts on energy infrastructure (transmission, pipelines, refineries, etc.); and
- emissions of greenhouse gases and air pollutants.

As the Daschle/Bingaman bill (S. 1766) contains several "placeholders" reserved for future legislative proposals, I ask that for the purposes of your analysis, you include for Section 801 of S. 1766, S. 804, introduced by Senators Feinstein, Snowe and Reed making changes to the Corporate Average Fuel Economy (CAFE) program. For Section 1821 of S. 1766, use the provisions contained in S. 1746, introduced by Senator Reid on nuclear facility security. Also, to ensure a consistent comparison, please exclude from your analysis of H.R. 4 the amendments to the tax code contained in Division C of that bill. I expect to request from EIA a follow-up analysis of the tax-related proposals contained in H.R. 4 and an expected Senate Finance Committee mark at a subsequent date.

When assessing the costs and benefits of these legislative proposals, please be sure to point out which specific policy actions have the most significant positive or negative impacts on the factors outlined above. In order to inform our deliberations on national energy policy which are due to begin in the next several weeks, I ask that the requested information be made available by January 23, 2002. In addition, I request that a briefing of your results prior to release of any written report.

If you have any questions regarding this request, or desire further clarification with respect to translating legislative proposals into assumptions you will use in your analysis, please contact Bryan Hannegan with my Senate Energy and Natural Resources Committee staff at 224-7932. Thank you for your timely attention to this request, and for your efforts to ensure that our Nation's energy policy decisions are informed with the best available analysis.

Sincerely,

Frank H. Murkowski

Frank H. Murkowski
Ranking Member

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

ENERGY.SENATE.GOV

February 6, 2002

Dr. Mary Hutzler
Acting Administrator
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC, 20585

Dear Acting Administrator Hutzler:

As a follow-up to my letter of December 20, 2001 in reference to analysis of comprehensive energy legislation, please find below additional information to assist you in your analysis of key portions of S. 1766 and H.R. 4 identified as follows:

Renewable Portfolio Standard (RPS): For H.R. 4, assume no changes in current law. For S. 1766, assume a 2.5% mandate for new renewable electricity starting in 2005, increasing 0.5% each year through 2020 (10% new renewables by 2020). In addition, please provide analysis of a new scenario that reflects a 20% RPS by 2020 under the same provisions as in S. 1766. Key analysis questions include: whether or not such amounts of new renewable energy are possible with reasonable technology improvements, what renewable technologies benefit most, whether consumer retail electricity costs are affected by the RPS, and how the higher incremental costs of renewable electricity generation are absorbed by generators, utilities and/or consumers. Also, please describe the effect of the civil penalty imposed for failing to meet the RPS and whether that affects estimates of renewable electricity production, economic impacts, and macroeconomic effects.

Alaska Oil Production: For S. 1766, please provide your baseline Annual Energy Outlook 2002 (AEO) forecast without production from ANWR and compare it with several scenarios for H.R. 4: (1) median USGS ANWR production estimate and AEO 2002 world oil prices; (2) high-range USGS ANWR production estimate and AEO 2002 world oil prices; (3) high-range USGS estimate, using your "High Oil Price" side case; and (4) high-range USGS estimate, using your AEO 2002 "High Technology" side case that assumes rapid transportation technology development. Key variables to consider include the percentage of U.S. foreign oil dependence, and a summary of crude oil supply, demand, and disposition.

Alaska Natural Gas: For H.R. 4, assume no changes in law. For S. 1766, please analyze the impact of the proposed $10 billion loan guarantee (Sec. 6501-6512) on project economics and timing of construction assuming that the "over the top" route for the pipeline is prohibited (Sec. 701). Key analysis variables should include: the date at which natural gas from Alaska is first delivered to market in the Lower 48, the impact of the pipeline on the price of natural gas, and the sensitivity of these variables to higher or lower natural gas prices in the U.S. market.

Automobile Fuel Economy Standards (CAFE): For H.R. 4, assume increases in CAFE standards for model years 2004 through 2010 so as to decrease total gasoline consumption by 5 billion gallons over that period of time. For S. 1766, assume the adoption of provisions of S. 804 (Feinstein) – require 25 mpg for SUVs and light trucks produced between model years 2005 and 2007 and 27.5 mpg for SUVs and light trucks produced thereafter. Use as a reference case technology frozen at model year 2002 levels and performance, and assume further no change in fuel economy for passenger vehicles. Please analyze a second case which assumes a 5% increase in fuel economy standards over model year 2000 levels by model year 2005 for both passenger vehicles and SUVs/light trucks, with a further 5% increase for all vehicles by model year 2010. In all cases, please provide analysis on total net costs to consumers (e.g. up-front additional costs minus life-cycle fuel economy savings), macroeconomic effects on non-agricultural jobs, whether such fuel economy goals can be meet through reasonable technology assumptions, and estimates of carbon dioxide emissions.

Renewable Fuels/MTBE: For H.R. 4, assume no change in current law, and use the Annual Energy Outlook 2002 reference forecast as the base case. For S. 1766, assume a renewable fuel standard of 2.3 billion gallons renewable fuel by 2004 increasing per Section 818 of the legislation to 5.0 billion gallons by 2012. Include in your analysis of S. 1766 a ban on MTBE within four years and assume that, given the opportunity to opt out of the 2% oxygenate requirement, California RFG and East Coast RFG areas do so. Also, please analyze a third case where the renewable fuel standard is as proposed in Section 818 of S. 1766, but assume complete repeal of the 2% oxygenate standard, and that States are given the ability to ban MTBE if they wish starting in 2003 or 2004. Key analysis variables should include effects on motor gasoline and RFG prices and fuel imports, GDP, and energy expenses, and estimates of carbon dioxide emissions.

Air Conditioning/Heat Pump Standard: For H.R. 4, assume a 12 SEER/7.4 HSPF standard for air conditioners and heat pumps manufactured for Federal agency use only on or after date of enactment, and for S. 1766 assume a 13 SEER/7.7 HSPF standard enacted for all air conditioners and heat pumps manufactured on or after January 23, 2006. Key analysis variables include: electricity savings, net energy cost savings (increased up-front stock cost minus life cycle energy bill savings), and carbon dioxide emissions evaluated relative to the current 10 SEER standard.

Other Provisions: Pursuant to my letter of December 20, 2001, please also provide qualitative analyses for the following provisions:

Price-Anderson Act	S. 1766 (Sec 501-508) and H.R. 2983
Energy R& D	S. 1766 (Sec. 1211-1245) H.R. 4 (Corresponding provisions in Division B)
Other Consumer Product Standards	S. 1766 (Sec. 921- 929) H.R. 4 (Sec. 142-143)
Alternative Fuel Programs	S. 1766 (Sec. 811, 812, 814-819) H.R. 4 (Corresponding provisions in divisions A,B)
Hydro Relicensing	S. 1766 (Sec 301-308) H.R. 4 (Sec. 401- 402)

Pursuant to your conversations with my Energy Committee staff, I understand that your analysis will be issued in phases once available, starting with the Air Conditioning/Heat Pump Standard analysis delivered to me on January 23, 2002. As the Senate appears to be moving towards consideration of S. 1766 during the week of February 11th, I hope you can deliver as many of these phases as you and your staff are able to complete prior to that time and brief interested staff and Senators as appropriate at the earliest opportunity.

If you have any further questions regarding this request, or desire further clarification, please contact Bryan Hannegan with my Senate Energy and Natural Resources Committee staff at 224-7932. Thank you for your continued timely attention to this request, and for your efforts to ensure that our Nation's energy policy decisions are informed with the best available analysis.

Sincerely,

Frank H. Murkowski

Frank H. Murkowski
Ranking Member

Appendix B:

Technical Characteristics of Biodiesel

Biodiesel is a solution of chemicals known as esters. Esters are characterized by a carbon atom double bonded to an oxygen atom and single bonded to another oxygen atom. Other organic groups occupy the remaining bonds on the carbon and oxygen. If soybean oil is the raw material for the biodiesel, the organic groups attached to the esters are palmitic, stearic, oleic, linoleic, and linolenic acids.[25] Biodiesel can be produced by several processes. The oil or fat may be converted to fatty acids which are in turn converted to biodiesel. The oil or fat can also be converted to biodiesel directly, using an acid or base to catalyze, or accelerate, a reaction known as transesterification. Base catalyzation is preferred, because the reaction is quick and thorough. It also requires lower temperature and pressure than other processes, which translates to lower capital costs for the biodiesel plant. The most common method is to react animal fat or vegetable oil with methanol in the presence of sodium hydroxide (a base, known as lye or caustic soda). This reaction is a base-catalyzed transesterification. The products of the reaction with methanol are methyl esters and glycerine.[26] If ethanol is substituted for methanol, ethyl esters and glycerine are produced. Methanol is preferred because it is less expensive than ethanol.[27]

All esters contain at least two oxygen atoms per molecule. Thus, biodiesel is an oxygenated fuel. It may be blended with petroleum diesel or used in pure form. The blend most often studied is 20 percent biodiesel and 80 percent petroleum diesel, known as B20. Benefits to B20 and B100 include lower hydrocarbon, carbon monoxide, and particulate emissions.[28] Nitrogen oxide emissions may increase or decrease, depending on the biodiesel properties.[29] Oxides of nitrogen and hydrocarbons are ozone precursors. Carbon monoxide is also an ozone precursor, though to a lesser extent than unburned hydrocarbons or nitrogen oxides. Additional research is needed to determine whether the use of biodiesel will increase or decrease ground-level ozone on balance. The biodiesel emission studies were carried out on existing heavy-duty vehicles. The effects of biodiesel on the emissions of Tier II heavy diesels slated for introduction in model year 2007 has not been determined.

Biodiesel exceeds the performance of petroleum diesel on several important measures. Petroleum diesel typically has a cetane index in the low 40's. The cetane index is a correlate of the cetane number, which is a measure of the ease with which a fuel is ignited. A higher cetane number is more desirable. Graboski and McCormick summarize several experimental studies of biodiesel characteristics. They report a range

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[25] National Biodiesel Board website (www.biodiesel.org), Fuel Facts, Chemical Weight and Formula
[26] National Biodiesel Board website, Fuel Facts, Biodiesel Production and Quality
[27] Graboski, Michael S. and McCormick, Robert L. Combustion of Fat and Vegetable Oil Derived Fuels In Diesel Engines. *Prog. Energy Combustion Sci*. Vol 24, 1998, p. 127.
[28] B100 is shorthand for 100 percent biodiesel.
[29] E-mail from K. Shaine Tyson, National Renewable Energy Laboratory, Feb. 12, 2002

of 40 to 52 cetane index for petroleum diesel. The reported cetane number for biodiesel ranges from 45.8 to 56.9 for soybean oil methyl esters, with an average of 50.9. The authors imply that careful production control will result in product with cetane number on the high end of the range. [30] By contrast, petroleum diesel tends toward the low end of the range as high-cetane streams are instead directly or indirectly blended into gasoline.

Biodiesel is also better at lubrication of diesel fuel system components than petroleum diesel. Fuel injectors and some types of fuel pumps rely on diesel fuel for lubrication. Lubricity is a measure of the lubricating properties of fuel. One study cited by the National Biodiesel Board found that half of its samples of U.S. petroleum diesel sold did not meet the recommended minimum standard for lubricity.[31] Biodiesel has better lubricity than current low-sulfur (500 parts per million sulfur by weight) diesel. The lubricity problem is expected to get worse when ultra-low sulfur (15 parts per million sulfur by weight) diesel is introduced, starting in 2006. A 1 or 2 percent blend of biodiesel, by volume, in low-sulfur diesel improved lubricity substantially.[32]

B100 is less toxic and less flammable than petroleum diesel, making it safer to handle. There are a couple of minor additional benefits to using B100. The exhaust smells better than conventional diesel.[33] Persons who service engines run on biodiesel may experience less skin irritation than with conventional diesel.[34]

One drawback with biodiesel is that it has higher cloud and pour points. Cloud point is the temperature at which a sample of the fuel starts to appear cloudy. The reason for this is wax crystals begin to form. In a vehicle's fuel system, the wax crystals can clog fuel lines and filters. Pour point is always lower than cloud point; it is the temperature slightly below which the fuel will not flow. If the ambient temperature is below the pour point, diesel engines will not run without special precautions. That the cloud and pour points for biodiesel are higher means that vehicles running on biodiesel blends may experience drivability problems at higher temperatures than vehicles running on petroleum diesel.[35] This is a potential concern during the winter in much of the United States. More work is needed to develop biodiesel blends with cold-flow properties comparable to petroleum diesel. Transitioning a vehicle to B20 or B100 requires some care as well. Over time, petroleum diesel forms deposits in vehicle fuel systems. Biodiesel can loosen these deposits, allowing them to migrate and clog fuel lines and filters.[36] Other disadvantages include high production cost per gallon and approximately 11 percent lower energy content per gallon relative to petroleum diesel.[37]

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[30] Graboski and McCormick, pp. 131-132.
[31] National Biodiesel Board website, Fuel Facts, Lubricity Benefits
[32] *Ibid*.
[33] It is said to smell like french fries.
[34] www.afdc.doe.gov/pdfs/Bio_CleanGreen.pdf
[35] Graboski and McCormick, pp. 135-137.
[36] National Biodiesel Board website, Fuel Facts, Biodiesel Usage
[37] www.afdc.doe.gov/pdfs/Bio_CleanGreen.pdf