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The Potential for Low Petroleum Gasoline

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ORNL-6835

Energy Division

THE POTENTIAL FOR LOW PETROLEUM GASOLINE

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TABLE OF CONTENTS

LIST OF TABLES v

LIST OF FIGURES ix

ACRONYMS AND ABBREVIATIONS xi

ACKNOWLEDGEMENTS xv

ABSTRACT xvii

EXECUTIVE SUMMARY S-1

1. LEGISLATIVE BASIS FOR LOW PETROLEUM GASOLINE 1

2. THE CLEAN AIR ACT AMENDMENTS OF 1990 1

3. THE ORNL REFINERY YIELD MODEL 3
   - 3.1 ORNL-RYM Capabilities 3
   - 3.2 Representation of Non-linear Emissions Models in a Linear Program 5

4. PREMISES FOR LOW PETROLEUM STUDY 7
   - 4.1 Gasoline Performance Specifications 7
   - 4.2 Product and Crude Slates 9
   - 4.3 Limits on Transportation Fuel Properties 9
   - 4.4 Raw Material and Product Value Assumptions 10
   - 4.5 Treatment of Capital Cost Recovery 11
   - 4.6 Base Cases (Cost Reference Cases) 11

5. LOW PETROLEUM GASOLINE COMPONENTS 12
   - 5.1 NGL Composition 13
   - 5.2 Location and Quantity of NGLs 13
   - 5.3 NGL Quality 14
   - 5.4 NGL Extraction/Production Methods and Associated Costs 14
     - 5.4.1 Straight Refrigeration 14
     - 5.4.2 Cryogenic Refrigeration 15
   - 5.5 NGL Transportation Modes and Associated Costs 15
   - 5.6 Projection of Future Resource Availability 16

6. PRODUCTION OF LOW PETROLEUM SUMMER GASOLINE 17
   - 6.1 Direct Blending of Alcohols 17
     - 6.1.1 Methanol 17
     - 6.1.2 Ethanol 18

TABLE OF CONTENTS (continued)

6.2 Ethers 24
6.2.1 Methyl Ethers 24
6.2.2 Ethyl Ethers 30
6.3 Vegetable Oil 36

7. COMPARISON OF LOW PETROLEUM SUMMER GASOLINE OPTIONS 42

8. PRODUCTION OF LOW PETROLEUM WINTER GASOLINE 45

9. GREENHOUSE GAS EMISSIONS OF LOW PETROLEUM GASOLINES 49

10. CONCLUSIONS 51

11. REFERENCES 55

APPENDIX A. RAW MATERIAL SUPPLY CURVE ESTIMATION A-1

APPENDIX B. BLENDSTOCKS, PROPERTIES, PROCESS INVESTMENTS, AND FUEL USE FOR SUMMER GASOLINE PRODUCTION B-1

APPENDIX C. HYDROGEN REPLACEMENT FUEL CREDITS C-1

APPENDIX D. BLENDSTOCKS, PROPERTIES, PROCESS INVESTMENTS, AND FUEL USE FOR WINTER GASOLINE PRODUCTION D-1

APPENDIX E. LOW PETROLEUM COST CHANGE FOR CG RVP INCREASE TO 8.7 PSI E-1

LIST OF TABLES

Table 1. Formula and emissions performance standards for the federal RFG program 2

Table 2. Key refinery process characterization for year 2010 4

Table 3. Complex model representation in ORNL-RYM by linear delta method 6

Table 4. Emissions performance targets for reformulated gasoline produced in PADD III low petroleum study 7

Table 5. Historical PADD III summer gasoline properties 8

Table 6. Quality of crude oil processed by PADD III refineries 9

Table 7. Product price differentials 11

Table 8. Octane and RVP for RFG and blendstocks 18

Table 9. PADD III low petroleum components for the year 2010 summer: **Ethanol blends** . . 21

Table 10. PADD III low petroleum costs for the year 2010 summer: **Ethanol blends** 22

Table 11. PADD III low petroleum effects on distillate blendstock: **Ethanol blended gasoline cases** 23

Table 12. PADD III low petroleum components for the year 2010 summer: **Methyl ether oxygenates** 26

Table 13. PADD III low petroleum price elasticity variations for the year 2010 summer: **Methyl ether oxygenates** 28

Table 14. PADD III low petroleum effects on distillate blendstocks: **Methyl ether oxygenated gasoline cases** 29

Table 15. PADD III low petroleum components for the year 2010 summer: **Ethyl ether oxygenates** 32

Table 16. PADD III low petroleum price elasticity variations for the year 2010 summer: **Ethyl ether oxygenates** 34

Table 17. PADD III low petroleum effects on distillate blendstocks: **Ethyl ether oxygenated gasoline cases** 35

Table 18. Range of blending properties of rapeseed-associated FCC naphthas 37

LIST OF TABLES (continued)

Table 19. PADD III low petroleum components for the year 2010 summer: **Rapeseed oil feedstock** 39

Table 20. PADD III low petroleum price elasticity variations for the year 2010 summer: **Rapeseed oil feedstock** 40

Table 21. PADD III low petroleum effects on distillate blendstocks: **Rapeseed oil feedstock cases** 41

Table 22. PADD III input/output comparisons 44

Table 23. PADD III low petroleum components for the year 2010 winter 47

Table 24. PADD III low petroleum price elasticity variations for the year 2010 winter 48

Table 25. Greenhouse gas emissions of gasoline components 50

Table 26. Fuel replacement 52

Table B-1. PADD III base case blendstocks for year 2010 summer B-1

Table B-2. PADD III base case gasoline properties for the year 2010 summer B-2

Table B-3. RFG blendstocks in PADD III for the year 2010 summer: **Ethanol blends** B-3

Table B-4. CG blendstocks in PADD III for the year 2010 summer: **Ethanol blends** B-4

Table B-5. PADD III RFG properties for the year 2010 summer: **Ethanol blends** B-5

Table B-6. PADD III CG properties for the year 2010 summer: **Ethanol blends** B-6

Table B-7. PADD III process capacity investments for the year 2010 summer: **Ethanol blends** B-7

Table B-8. PADD III low petroleum refinery fuel use for the year 2010 summer: **Ethanol blends** B-8

Table B-9. RFG blendstocks in PADD III for the year 2010 summer: **Methyl ether oxygenates** B-9

Table B-10. CG blendstocks in PADD III for the year 2010 summer: **Methyl ether oxygenates** B-11

LIST OF TABLES (continued)

Table B-11. PADD III RFG properties for the year 2010 summer: **Methyl ether oxygenates** B-13

Table B-12. PADD III CG properties for the year 2010 summer: **Methyl ether oxygenates** . . . B-15

Table B-13. PADD III process capacity investments for the year 2010 summer: **Methyl ether oxygenates** B-17

Table B-14. PADD III low petroleum refinery fuel use for the year 2010 summer: **Methyl ether oxygenates** B-19

Table B-15. RFG blendstocks in PADD III for the year 2010 summer: **Ethyl ether oxygenates** B-20

Table B-16. CG blendstocks in PADD III for the year 2010 summer: **Ethyl ether oxygenates** B-21

Table B-17. PADD III RFG properties for the year 2010 summer: **Ethyl ether oxygenates** B-22

Table B-18. PADD III CG properties for the year 2010 summer: **Ethyl ether oxygenates** B-23

Table B-19. PADD III process capacity investments for the year 2010 summer: **Ethyl ether oxygenates** B-24

Table B-20. PADD III low petroleum refinery fuel use for the year 2010 summer: **Ethyl ether oxygenates** B-25

Table B-21. RFG blendstocks in PADD III for the year 2010 summer: **Rapeseed oil feedstock** B-26

Table B-22. CG blendstocks in PADD III for the year 2010 summer: **Rapeseed oil feedstock** B-27

Table B-23. PADD III RFG properties for the year 2010 summer: **Rapeseed oil feedstock** . . . B-28

Table B-24. PADD III CG properties for the year 2010 summer: **Rapeseed oil feedstock** B-29

Table B-25. PADD III process capacity investments for the year 2010 summer: **Rapeseed oil feedstock** B-30

Table B-26. PADD III low petroleum refinery fuel use for the year 2010 summer: **Rapeseed oil feedstock** B-31

LIST OF TABLES (continued)

Table D-1. PADD III base case blendstocks for year 2010 winter D-1

Table D-2. PADD III base case gasoline properties for the year 2010 winter D-2

Table D-3. RFG blendstocks in PADD III for the year 2010 . . . . . D-3

Table D-4. CG blendstocks in PADD III for the year 2010 winter D-4

Table D-5. PADD III RFG properties for the year 2010 winter D-5

Table D-6. PADD III CG properties for the year 2010 winter D-6

Table D-7. PADD III process capacity investments for the year 2010 winter D-7

Table D-8. PADD III low petroleum refinery fuel use for the year 2010 winter D-8

Table E-1. PADD III low petroleum cost change for CG RVP increase to 8.7 psi: **Ethanol blends** E-1

Table E-2. PADD III low petroleum cost change for CG RVP increase to 8.7 psi: **Methyl ether oxygenates** E-2

Table E-3. PADD III low petroleum cost change for CG RVP increase to 8.7 psi: **Ethyl ether oxygenates** E-3

Table E-4 PADD III low petroleum cost change for CG RVP increase to 8.7 psi: **Rapeseed oil feedstock** E-4

LIST OF FIGURES

Figure 1. Crude oil supply curve for PADD III 59
Figure 2. Natural gas supply curve for PADD III 60
Figure 3. Corn-derived ethanol supply curve 61
Figure 4. Low Petroleum Gasoline: Possible Petroleum Displacement Sources 62
Figure 5. RFG and blendstock VOC emissions values 63
Figure 6. NOx and VOC sensitivity to oxygen from methyl ethers 64
Figure 7. Toxics emissions sensitivity to oxygen from methyl ethers 65
Figure 8. Toxics emissions sensitivity to oxygen from ethyl ethers 66
Figure 9. Refining cost increases for low petroleum gasoline 67
Figure 10. Refining cost increase for low petroleum gasoline cases 68
Figure 11. Non-petroleum share for low petroleum gasoline cases 72
Figure 12. Cost to reduce crude oil use in low petroleum gasoline policy 73
Figure 13. Cost to reduce crude oil use in low petroleum gasoline cases 74
Figure 14. Crude oil use reduction in low petroleum gasoline policy 75
Figure 15. Crude oil use reduction in low petroleum gasoline cases 76
Figure 16. Low petroleum refinery fuel use 77
Figure 17. Refinery fuel use in low petroleum gasoline cases 78
Figure 18. Refinery investment for low petroleum gasoline policy 79
Figure 19. Refinery investment in low petroleum gasoline cases 80
Figure 20. Greenhouse gas emissions for low petroleum gasoline 81
Figure 21. Greenhouse gas emissions for low petroleum gasolines relative to base gasolines 82
Figure 22. Cost increases for low petroleum gasoline, CG RVP max = 8.7 psi 83
Figure 23. Price elasticity effect on cost to reduce crude oil use in low petroleum gasoline 84
Figure 24. Year-round refining cost increase for near-30 percent non-petroleum in gasoline 85
Figure 25. Year-round refining cost to reduce crude oil use for near-30 percent non-petroleum in gasoline 86
Figure 26. Year-round relative greenhouse gases for near-30 percent non-petroleum in gasoline 87

ACRONYMS AND ABBREVIATIONS

API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BTU	British Thermal Unit
C	Centigrade
CAAA	Clean Air Act Amendments of 1990
CG	Conventional gasoline
CO_2	Carbon dioxide
DOE	Department of Energy
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPACT	Energy Policy Act
ETBE	Ethyl tertiary butyl ether
EtOH	Ethanol
E200	The cumulative volume percent evaporated at 200°F in ASTM test D86-67: Distillation of Petroleum Products
E300	The cumulative volume percent evaporated at 300°F in ASTM test D86-67: Distillation of Petroleum Products
F	Fahrenheit
FCC	Fluid catalytic cracker
GE	Gasoline energy equivalent
GHG	Greenhouse gas
GTBA	Gasoline grade tertiary butyl alcohol

ACRONYMS AND ABBREVIATIONS (continued)

LCO	Light cycle oil
M	Motor octane number
MBD	Thousand barrels per day
MCF	Thousand cubic feet
mg/mi	Milligrams per mile
MMSCFD	Million standard cubic feet per day
MTBE	Methyl tertiary butyl ether
NA	Not applicable
NGL	Natural gas liquid
NOx	Nitrogen oxide
ORNL-RYM	Oak Ridge National Laboratory Refinery Yield Model
PADD	Petroleum Administration for Defense District
ppm	Parts per million
psi	Pounds per square inch, absolute
R	Research octane number
RFG	Reformulated gasoline
ROI	Return on investment
RVP	Reid vapor pressure
TAEE	Tertiary amyl ethyl ether
TAME	Tertiary amyl methyl ether
TAP	Toxic air pollutant
THEE	Tertiary hexyl ethyl ether

ACRONYMS AND ABBREVIATIONS (continued)

THME	Tertiary hexyl methyl ether
T50	The temperature at which 50 percent of a fuel is evaporated in ASTM test D86-67: Distillation of Petroleum Products
T90	The temperature at which 90 percent of a fuel is evaporated in ASTM test D86-67: Distillation of Petroleum Products
VOC	Volatile organic compound
vol	Volume
wt	Weight

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ABSTRACT

The Energy Policy Act requires the Secretary of Energy to determine the feasibility of producing sufficient replacement fuels to replace at least 30 percent of the projected consumption of motor fuels by light duty vehicles in the year 2010. The Act also requires the Secretary to determine the greenhouse gas implications of the use of replacement fuels. A replacement fuel is a non-petroleum portion of gasoline, including certain alcohols, ethers, and other components. The Oak Ridge National Laboratory Refinery Yield Model has been used to study the cost and refinery impacts for production of "low petroleum" gasolines, which contain replacement fuels. The analysis suggests that high oxygenation is the key to meeting the replacement fuel target, and a major contributor to cost increase is investment in processes to produce and etherify light olefins. High oxygenation can also increase the costs of control of vapor pressure, distillation properties, and pollutant emissions of gasolines. Year-round low petroleum gasoline with near-30 percent non-petroleum components might be produced with cost increases of 23 to 37 cents per gallon of gasoline, and with greenhouse gas emissions changes between a 3 percent increase and a 16 percent decrease. Crude oil reduction, with decreased dependence on foreign sources, is a major objective of the low petroleum gasoline program. For year-round gasoline with near-30 percent non-petroleum components, crude oil use is reduced by 10 to 12 percent, at a cost $48 to $89 per barrel. Depending upon resolution of uncertainties about extrapolation of the Environmental Protection Agency Complex Model for pollutant emissions, availability of raw materials and other issues, costs could be lower or higher.

THE POTENTIAL FOR LOW PETROLEUM GASOLINE

EXECUTIVE SUMMARY

The Energy Policy Act (EPACT) requires the Secretary of Energy to determine the feasibility of producing sufficient replacement fuels to replace at least 30 percent of the projected consumption of motor fuels by light duty vehicles in the year 2010. EPACT also requires the Secretary to determine the greenhouse gas emission implications of increasing the use of replacement fuels. EPACT defines replacement fuel as "the portion of any motor fuel that is methanol, ethanol, or other alcohols, natural gas, liquified petroleum gas, hydrogen, coal derived liquid fuels, fuels (other than alcohol) derived from biological materials, electricity (including electricity from solar energy), ethers, or any other fuel the Secretary determines, by rule, is substantially not petroleum and would yield substantial energy security benefits and substantial environmental benefits."

Gasoline is the predominant fuel for light duty vehicles. The Oak Ridge National Laboratory Refinery Yield Model (ORNL-RYM) has been used to study the potential for production of gasoline with high percentages of replacement fuels in the year 2010. Like all highway gasolines, these "low petroleum" gasolines must comply with requirements of the Clean Air Act Amendments of 1990 (CAAA). ORNL-RYM represents the production of gasolines which satisfy CAAA emissions constraints described in terms of the Environmental Protection Agency's final Complex Model.

The low petroleum gasoline study investigates replacement of petroleum by:

- Direct blending or conversion of alcohols:

  Methanol (derived from natural gas) and ethanol can be directly blended into gasoline for replacement fuel credit. Gasoline grade tertiary butyl alcohol is directly blended as a cosolvent with methanol. Methanol and ethanol can also be converted into ethers.

- Direct blending of ethers:

  Replacement fuel credit is given for purchased methyl tertiary butyl ether and ethyl tertiary butyl ether, which are assumed to be derived from non-petroleum sources.

  For ethers produced in the refinery, the associated alcohol is credited as a replacement fuel.

- Hydrogenation:

  Hydrogen derived from non-petroleum sources and used in hydrogenation processes can be credited as a replacement fuel in gasoline. However, there should be deductions for hydrogen used in desulfurization, fuel gas, and in hydrogenation of blendstocks for products other than low petroleum gasoline.

- Conversion of vegetable oil:

  It is assumed that rapeseed oil can be used as a feedstock for future cracking technologies. The rapeseed oil component of gasoline blendstocks is credited as replacement fuel.

Replacement fuel credit is also given for purchased components of natural gas liquids (NGLs include ethane, propane, butanes and natural gasoline). These non-petroleum components may be used in the production of ethers, alkylate, reformate and other gasoline blendstocks. If large volumes of ethers are used in low petroleum gasoline, production costs could be particularly sensitive to the availability of NGL component raw materials for ether production.

The analysis of year 2010 summer production of low petroleum gasoline suggests that the 30 percent replacement fuel target can be achieved at a high cost. Incremental costs to meet the 30 percent replacement fuel target could be more than three times the incremental costs to produce Phase II reformulated gasoline in the U.S. Gulf Coast refining system. High oxygenation is the key to meeting the replacement fuel target, and a major contributor to cost increase is investment in processes to produce and etherify light olefins. High oxygenation can also increase the costs of control of vapor pressure, distillation properties, and pollutant emissions of gasolines. Crude oil reduction, with decreased dependence on foreign sources, is a major objective of the low petroleum gasoline program. In the analysis, crude oil use is reduced by 10 to 17 percent.

There are uncertainties in the premises for study of low petroleum gasoline production, and costs can be considerably different for alternative premises. There could be large cost impacts with different assumptions about:

Availability of cellulosic ethanol.

Extrapolation of the Complex Model beyond valid limits.

Availability of raw materials for ether production.

Availability and costs of imported ethers.

The vapor pressure of conventional gasoline.

Gasoline distillation specifications and engine operability with high percentages of ethers in gasoline.

Gasoline component blending properties.

Technology capability to process raw materials such as vegetable oils, and the quality of products of those technologies.

The accounting for low petroleum credit.

Distribution costs for ethanol.

The cost of capital.

Price assumptions.

Compared with summer gasolines, emissions constraints are less stringent for winter gasolines, and production costs are lower. If the winter gasoline production season is 6.5 months, then year-round low

petroleum gasoline with near-30 percent non-petroleum components might be achieved by combinations of cases, with refining cost increases in the range of 23 to 37 cents per gallon of gasoline.

A refiner would not choose to produce low petroleum gasoline unless the average cost of crude in the base case is at least the cost of crude oil reduction in the low petroleum case. For year-round gasoline with near-30 percent non-petroleum components, crude oil use is reduced by 10 to 12 percent, at a cost $48 to $89 per barrel of crude. Depending upon resolution of uncertainties about extrapolation of the Complex Model, availability of raw materials and other issues, the cost increases could be lower or higher.

With the year-round low petroleum gasolines, there are greenhouse gas emissions changes between a 3 percent increase and a 16 percent decrease. The maximum estimated greenhouse gas reduction of 16 percent is achieved with use of cellulosic ethanol and with ethers produced from cellulosic ethanol.

A mix of strategies could be less costly than any of the cases examined in this study. For example, costs might be lower with production of regional mixes of ether-based and ethanol-based gasolines in the winter, and with mixes of ether-based gasolines in the summer.

1. LEGISLATIVE BASIS FOR LOW PETROLEUM GASOLINE

In 1992, the Energy Policy Act (EPACT, P.L. 102-486) was enacted to provide a comprehensive national energy policy. One goal of EPACT is to increase U.S. energy security in ways that are both cost-effective and environmentally prudent. Consistent with this goal, one EPACT objective is to decrease U.S. dependence on foreign oil. To meet this objective, Section 502 of EPACT requires the Secretary of Energy to establish a program to determine the feasibility of reducing imported oil by 30 percent by the year 2010.

A large part of the mandated reductions in foreign oil dependence is expected to be achieved by reducing the consumption of fuels for light duty motor vehicles, through the use of alternative and replacement fuels. Alternative fuels, such as ethanol, are those motor fuels that are "substantially not petroleum," being derived from sources other than crude oil.

A replacement fuel is also substantially not petroleum, but it replaces only a portion of a petroleum-derived motor fuel. For example, ethanol is a replacement fuel in a gasoline containing 10 percent ethanol. EPACT requires the Secretary of Energy to determine the feasibility of producing sufficient replacement fuels to replace at least 10 percent of the projected consumption of motor fuels by light duty vehicles in the year 2000, and the feasibility of replacing at least 30 percent in the year 2010. EPACT also requires the Secretary to determine the greenhouse gas emission implications of increasing the use of replacement fuels.

In its marriage with petroleum-derived fuels, the replacement fuel concept depends on the continuing existence and technical development of the petroleum refining infrastructure. Gasoline is the predominant fuel for light duty vehicles, and this report focuses on refinery production of "low petroleum" gasolines. Like all highway gasolines, low petroleum gasolines must comply with requirements of the Clean Air Act.

2. THE CLEAN AIR ACT AMENDMENTS OF 1990

The Clean Air Act Amendments of 1990 (CAAA) include programs for oxygenated gasoline and for reformulated gasoline (RFG). The oxygenated gasoline program requires that, beginning November 1, 1992, gasoline with a minimum oxygen content of 2.7 weight (wt) percent must be sold during winter months in about 40 cities not in compliance with carbon monoxide standards. RFGs are required by January 1, 1995, in nine areas with extreme or severe ozone pollution problems. RFG formula and emissions performance standards are shown in Table 1.

Emissions modeling provides a means for predicting the emissions performance of a gasoline, given other properties of the gasoline. The Complex Model of the Environmental Protection Agency (EPA) is a set of equations that predicts emissions of VOCs, TAPs, and NOx in terms of gasoline properties including RVP, E200, E300, benzene, oxygen, sulfur, aromatics, and olefins contents. The Complex Model must be used after March 1, 1997, to certify the emissions performance of gasolines.

Table 1. Formula and emissions performance standards for the federal RFG program		
Standard	Phase I CAAA standards (beginning January 1, 1995)	Phase II Environmental Protection Agency final rule standards (Beginning January 1, 2000)
Oxygen content	2 wt percent minimum	
Benzene content	1 vol percent maximum	
Additives	No additives with heavy metals	
Volatile Organic Compounds (VOCs include all oxygenated and non-oxygenated hydrocarbons except for methane and ethane)	Must be reduced by at least 15 percent during the summer high-ozone season, compared with the calculated VOC emissions from the use of the statutory baseline gasoline.	Must be reduced during the summer by 25.9 percent on a per-gallon basis or by 27.4 percent on an averaged basis.[a] A greater percentage reduction is required in southern states.
Toxic Air Pollutants (TAPs consist of benzene, 1,3 butadiene, formaldehyde, acetaldehyde, and polycyclic organic matter)	Must be reduced by at least 15 percent during the entire year, compared with the calculated TAP emissions from the use of the statutory baseline gasoline.	Must be reduced year-round by 20 percent on a per-gallon basis or by 21.5 percent on an averaged basis.
Nitrogen Oxides (NOx)	Must not increase relative to the emissions of the statutory baseline gasoline.	Must be reduced during the summer by 5.5 percent on a per-gallon basis or by 6.8 percent on an averaged basis. Must not increase during the winter on a per-gallon basis and must be reduced by 1.5 percent on an averaged basis.

[a]For the per-gallon standard, every gallon of every batch of RFG produced at the refinery must meet the same emissions-performance requirements. For the averaged standard, different batches may vary within limits, as long as the refinery's total RFG output meets the specified average emissions performance requirement.

The nine areas in the extreme and severe ozone nonattainment categories currently comprise about 25 percent of the nation's gasoline market. However, because of the gasoline distribution system, surrounding areas may receive RFG as well. Other areas are allowed to petition the EPA to opt-in to the RFG program. States may decide that, compared with other alternatives, the best strategy for achieving compliance with clean air standards is to require the use of clean gasolines to reduce vehicular emissions. The total national market for RFG could exceed 60 percent by the end of the century.[1]

In fact, all gasolines will be affected by the CAAA. Besides requiring RFG in the covered ozone nonattainment areas, the CAAA require that gasoline in all other areas not be any more polluting than it was in 1990. Without this "anti-dumping" provision, the potential exists for emissions from conventional gasoline (CG) to worsen as polluting fuel components are removed from RFG.

3. THE ORNL REFINERY YIELD MODEL

3.1 ORNL-RYM Capabilities

The potential for low petroleum gasoline production has been analyzed with the Oak Ridge National Laboratory Refinery Yield Model (ORNL-RYM), a refinery linear program. ORNL-RYM is an enhanced personal computer version of the Refinery Yield Model of the Refinery Evaluation Modeling System.[2-5]

ORNL-RYM tracks octane, RVP, oxygen content, sulfur, benzene, aromatics, total olefins, distillation points, VOC, TAP, and NOx on all gasoline component streams. In separate data tables in ORNL-RYM, blending components for each gasoline grade are identified; blending values are assigned to over 140 components; and blending targets (i.e., specifications with blending margins) are set.

Properties for distillates and jet fuels are handled conceptually the same as for gasoline. Properties can include gravity, aromatics content, paraffins content, naphthenes content, sulfur content, freezing point, luminometer number (which is correlated with smoke point), heat of combustion, hydrogen content, light cycle oil content, hydrocracked stocks content, surface tension, pour point, cetane index, flash point, viscosities, RVP, distillation points, and diesel ignition improver content. The model also provides for jet fuel additives for anti-icing, corrosion inhibition, and other functions.

Changes in crude feedstock are described in tables for crude quantity and assay. ORNL-RYM includes 48 refining processes, which can be used to produce 40 different products from more than 100 crude oils. Individual process units can have several modes of operation, each mode with different feedstocks and different yields. An investment module provides for the addition of processing capacity. Potentially key processes in ORNL-RYM for the production of CAAA-compliant low petroleum gasolines are listed in Table 2. These processes are grouped in the table by functions which are important for:

- CAAA compliance (through reduction of RVP, benzene, sulfur, aromatics);
- Oxygenate production for CAAA compliance and low petroleum credit (through light olefins production and etherification). With the addition of processes like dehydrogenation and dimerization of ethylene, the refinery becomes "more petrochemical" in character.
- Hydrogenation for low petroleum credit.

Table 2. Key refinery process characterization for year 2010

(processes of potentially greater importance in the production of CAAA-compliant low petroleum gasolines)

Process	Function	Potential importance
Naphtha hydrotreating	Desulfurization, reformer feed preparation	**CAAA compliance**
FCC feed hydrofining	Desulfurization, FCC feed preparation	
Reformate splitting	Separation of naphthas with high benzene, high aromatics contents	
Alkylation/ Alkylation of benzene	Production of alkylate with low emissions	
Aromatics recovery	Separation of naphthas with high benzene, high aromatics content	
Fluid catalytic cracking/ FCC gasoline splitting/ Ether production	Olefins production/ Olefins separation/ Ether production	**Satisfying CAAA oxygenate standard** and for **low petroleum credit**
Naphtha hydrocracking	Production of C4s from naphthas	Production of feedstocks used to produce oxygenate for **low petroleum credit**
Butane isomerization	Isomerization of normal C4 for subsequent dehydrogenation	
C2-C5 dehydrogenation	Production of light olefins	
Thermal cracking (gas)	Production of light olefins	
Cryogenic fractionation/ Dimerization of ethylene	Recovery of ethylene/ Production of butylene	
Hydrogen production	Hydrogen production from non-petroleum source (natural gas)	Hydrogenation for **low petroleum credit**
Gas oil hydrocracking	Production of naphthas	

ORNL-RYM can be used to represent various regional refining configurations. The model assumes that all refineries within a large region are interconnected. Consequently, ORNL-RYM has a tendency to over-optimize refinery operations. The over-optimization problem can be mitigated by focusing on changes in refining variables, rather than relying on the model to predict exact outcomes. When ORNL-RYM is used to analyze novel refining scenarios, it is advisable to interpret results with a more qualitative perspective.

3.2 Representation of Non-linear Emissions Models in a Linear Program

ORNL-RYM represents gasoline blending to satisfy emissions constraints defined by EPA's final Complex Model.[6] The non-linear Complex Model presents difficult adaptation problems for use in refinery linear programs. Each gasoline blending component has VOC, TAP, and NOx blending values that vary with overall gasoline composition. The Complex Model is represented in ORNL-RYM by the linear delta method shown in Table 3. Off-line software computes Δemissions/ΔPROPERTY coefficients. These coefficients are then used in the off-line software to compute emissions blending values for the gasoline blending components. ORNL-RYM is solved iteratively, until convergence of the coefficients.

Table 3.
Complex model representation in ORNL-RYM by linear delta method

An emission value for NOx, VOC, TAP is represented as a base value plus small linear emissions changes due to small changes in gasoline properties. NOx is illustrated with the Phase II Complex Model:

Step 1: Choose a base gasoline. The base gasoline (for summer use in Region C) might have the following base PROPERTY values: MTBE oxygen=2.1; RVP=7.2; sulfur=140; aromatics=25; olefins=10; E200=49.9; E300=85.1; benzene=0.7; NOx = 1240.89.

Step 2: Develop the blending equation.

$$
\begin{aligned}
NOx = {} & NOx_{base} \\
& + (\Delta NOx/\Delta oxygen) \times (oxygen - oxygen_{base}) \\
& + (\Delta NOx/\Delta RVP) \times (RVP - RVP_{base}) \\
& + (\Delta NOx/\Delta sulfur) \times (sulfur - sulfur_{base}) \\
& + (\Delta NOx/\Delta aromatics) \times (aromatics - aromatics_{base}) \\
& + (\Delta NOx/\Delta olefins) \times (olefins - olefins_{base}) \\
& + (\Delta NOx/\Delta E200) \times (E200 - E200_{base}) \\
& + (\Delta NOx/\Delta E300) \times (E300 - E300_{base}) \\
& + (\Delta NOx/\Delta benzene) \times (benzene - benzene_{base})
\end{aligned}
$$

The $\Delta NOx/\Delta PROPERTY$ is an original coefficient ($W_{original}$). To determine ($\Delta NOx/\Delta olefins$) for the base gasoline in Step 1 (olefins=10 and NOx=1240.89), calculate NOx for that gasoline with olefins decreased by 0.1% (olefins=9.9 and NOx=1240.33):

$$(\Delta NOx/\Delta olefins) = (1240.89 - 1240.33)/(10 - 9.9) = 5.6$$

Step 3: Solve the linear program using the NOx constraint equation. For example,

$$NOx \leq 1232.8 \text{ (for an 8 percent NOx reduction)}$$

$$
\begin{aligned}
NOx = {} & 1240.89 \\
& - 1.31864 \times (oxygen - 2.1) \\
& + 3.65489 \times (RVP - 7.2) \\
& + 0.54643 \times (sulfur - 140) \\
& + 3.23156 \times (aromatics - 25) \\
& + 5.6 \times (olefins - 10) \\
& + 1.15442 \times (E200 - 49.9) \\
& - 0.55387 \times (E300 - 85.1) \\
& + 0 \times (benzene - 0.7)
\end{aligned}
$$

Calculate the NOx values for each gasoline blendstock and load the values in a gasoline component blending table.

Step 4: Given the linear program solution PROPERTY values, calculate new coefficients (W_{new}). Compare the original ($W_{original}$) and the new (W_{new}) coefficients for each PROPERTY. At convergence, **ACCEPT LINEAR PROGRAM SOLUTION and STOP.** Otherwise, choose a new base gasoline with PROPERTY values equal to the linear program solution values, and **Go to Step 2.**

4. PREMISES FOR LOW PETROLEUM GASOLINE STUDY

4.1 Gasoline Performance Specifications

The averaged basis standards for VOC and NOx are used in the low petroleum cases for the summer of year 2010. To provide allowances for enforcement compliance, refiners may add blending margins to the emissions standards. Table 4 shows the regionally weighted emissions targets, with and without arbitrary blending margins.

Table 4. Emissions performance targets for reformulated gasoline produced in PADD III low petroleum study (percent reductions relative to statutory baseline)

Controlled emissions	Standard weighted by end-use region share	Weighted standard plus margin
VOC	28.4	30.0
NOx (summer)	6.8	7.8
NOx (winter)	0.0	1.0
TAP (summer)	25.0	26.5
TAP (winter)	15.8	16.8

To satisfy the anti-dumping provision of the CAAA, CG is produced with no increase in emissions, relative to gasoline produced in PADD III in 1990. The 1990 model-derived summer gasoline properties for 1990 are compared to survey properties for 1989 in Table 5.[a] For year 2010 CG, 1 percent margins are applied to the model-derived emissions properties. The maximum allowable RVP for summer CG is assumed to be 7.9 psi.[b]

[a]1990 emissions for winter gasolines produced in PADD III are based on winter gasoline properties reported in reference 7.

[b]In the summer Base case (cost reference case), the 7.9 psi RVP specification for CG correctly represents standards of the current Phase II RVP program. However, a 7.9 psi RVP for summer CG is a misspecification for the full opt-in assumptions of the low petroleum cases. With allowance for blending margins, the CG RVP specification should be 8.7 psi, since CG is used in ozone attainment areas. The CG RVP misspecification was discovered after completion of model runs. *In high oxygenation cases, the misspecification does not matter, because the CG RVP is not a binding constraint.* An 8.7 psi RVP sensitivity case is examined for the case with the highest cost of RVP reduction. Marginal costs of RVP reduction are used to estimate refining costs for the other cases with CG RVP changed to 8.7 psi.

Table 5. Historical PADD III summer gasoline properties		
	1990 RYM	1989 Survey[8,9]
(R+M)/2	89.1	87.2-92.6
Aromatics, vol %	33.3	31.6
Oxygen, wt %	0.22	0.22
Olefins, vol %	12.2	13.2
Benzene, vol %	1.53	1.64
Sulfur, ppm	314	305
RVP, psi	9.4	9.4
E200, vol %	44.0	44.0
E300, vol %	88.4	80.5
API gravity	59.5	56.4-59.3
NOx, mg/mi	1360	1365
TAP, mg/mi	80.0	80.1
VOC, mg/mi	1588	1596

4.2 Product and Crude Slates

ORNL-RYM has been used to study low petroleum gasoline production in Petroleum Administration for Defense District III (PADD III, the U.S. Gulf Coast) during the year 2010. It is assumed that seasonal gasoline and distillate demand will be the same as in 1989, with gasoline demand adjusted to account for fuel economy differences, and with full opt-in by ozone non-attainment areas.[10,11] RFG production is assumed to be 62 volume percent of total gasoline production. It is also assumed that 60 percent of RFG produced in PADD III will be consumed in region 1 (typically northern areas), and 40 percent will be consumed in region 2 (typically southern areas).[12]

Total product output is fixed, except for coke and sulfur production. For the low petroleum cases, crude quality is constant. Recently reported crude quality is compared to crude quality in the low petroleum study in Table 6.

Table 6. Quality of crude oil processed by PADD III refineries

	Year 1993, actual annual[13]	Low petroleum assumption[a]
Sulfur, wt percent	1.23	1.64
Gravity, °API	32.37	31.98

[a]Quality estimated by extrapolation to year 2000

4.3 Limits on Transportation Fuel Properties

The specifications for low petroleum gasoline need to be generally compatible with the ASTM D-486 specifications. Some important considerations include:[14]

Octane: ASTM D-486 sets an octane limit for the average of Research and Motor Octane (R+M)/2, by grade of gasoline. However, the octane sensitivity, R-M, can be an issue with some blends. The sensitivity minimum specification of 7.5 must be augmented with a maximum sensitivity specification of about 15. The maximum specification will avoid problems with knock in particular operating regimes, and is derived from research on methanol which has a high sensitivity.

Reid Vapor Pressure: The RVP is a measure of gasoline volatility, and the RVP specification varies seasonally and geographically. RVP reduction is the most cost-effective mechanism for reducing VOC in summer gasolines. In many cases, RVP will be driven to a lower limit to satisfy the RFG VOC specification. The assumed lower limits are 6.5 for summer and 11.6 for winter, below which there are operability concerns because of insufficient fuel volatility.

Distillation Curve: For the low petroleum study, the distillation temperature ranges for summer RFG have been set at the combined limits for California Phase I and Phase II RFGs. The allowable range for T50 is 200 to 230°F, and 290 to 325°F for T90. These ranges correspond to approximately 35 to 50 percent for E200, and 84 to 92 percent for E300. The distillation ranges for winter gasolines have been set to recently reported maximum and minimum values.[15]

Oxygen Content: The maximum allowable oxygen content is currently 3.5 wt percent for ethanol blends. However, modern vehicles can generally perform adequately with oxygen levels of 5 to 6 wt percent. In the low petroleum cases, the maximum allowable oxygen content is 6 wt percent. *Extrapolation assumptions are required for use of the Complex Model beyond its valid limit of 3.7 wt percent oxygen.*

Energy Content: BTU content is not the sole determinant of fuel economy. Other characteristics of the fuel, as well as vehicle related factors, may also affect fuel economy. Although oxygenates contain less energy than some other gasoline components, their presence in gasoline chemically enleans the air/fuel charge, which can result in more complete combustion of fuel. Depending upon vehicle technology, this improvement in combustion may compensate for the lower BTU value.[16] The costs of fuel economy changes are included in the refining costs for low petroleum gasoline production. These costs could be high because they are based solely on energy content. However, the fuel economy cost effect in the low petroleum cases is usually small compared to the refining cost effects.

Hydroprocessing may be very important in some low petroleum gasoline production cases, with possible side effects on the amounts of severely hydroprocessed stocks blended to distillates. Therefore, specifications have to be imposed on some distillate products to prevent problems with fuel stability and lubricity.

Stability: Light cycle oils (LCOs) are important blendstocks for diesel fuels. LCOs have inferior stability, with tendencies to produce gums and other particulates, resulting from complex interactions between molecular oxygen, and organic compounds containing nitrogen/sulfur/oxygen, reactive olefins, and aromatics compounds. The resulting particulates and gums can cause plugging of diesel engine filters and fouling of fuel injectors.[17] Research has shown rapid degradation in the stability of fuels blended with more than 30 percent LCO in virgin distillate. Therefore, in the low petroleum study, the maximum allowable LCO in highway diesel fuel has been set at 30 percent.[18,19]

Lubricity: Severely hydroprocessed blendstocks could be important in the low petroleum hydrogenation strategies. Severe hydroprocessing can remove naturally occurring impurities such as organic acids and some polynuclear hydrocarbons which impart good lubricity. Poor lubricity military jet fuels have caused wear problems with fuel pumps and fuel control valves. Corrosion inhibiting additives can mitigate lubricity problems. However, to provide additional protection against the lubricity problem in the low petroleum study, upper limits have been placed on the percentage of severely hydroprocessed stocks that can be blended to jet fuels (15 percent for military fuels and 45 percent for civilian fuels).[20]

4.4 Raw Material and Product Value Assumptions

The PADD III refiner price for crude oil is assumed to follow the supply curve in Fig. 1. The derivation of the supply curve is explained in Appendix A. The curve is based on a long-run supply elasticity of 0.3 and a reference crude oil price of $26.49 per barrel (1990 U.S. dollars) for the year 2010.[21] The crude oil price is used to estimate prices for individual refined products, such as those listed in Table 7. The price differentials for the products in Table 7 have remained nearly constant in recent decades, despite a tenfold range of crude oil prices.[22] Ether prices are based on National Petroleum Council estimates.[23]

The PADD III refiner price for natural gas is assumed to follow the supply curve in Fig. 2. The derivation of the supply curve is explained in Appendix A. The curve is based on a long-run supply elasticity of 0.3 and an average dry gas price of $3.17 per MCF (1990 U.S. dollars) for the year 2010.[21]

The PADD III refiner price for corn-derived ethanol is assumed to follow the supply curve in Fig. 3. The derivation of the supply curves for both corn-derived and cellulosic ethanol is explained in Appendix A. The ethanol supply curves include the federal tax credit of 54 cents per gallon.

In the production of low petroleum gasoline, natural gas is often substituted for crude oil. Because of increased gas demand, the price of natural gas increases. With decreased demand for crude oil, the price of crude oil falls. Product prices are affected by a price reduction driven by the falling crude oil price, and a price increase due to the increased costs of natural gas and refining. The low petroleum study assumes that the demand for refined products is constant, regardless of the net price effect. In actual markets, the demand could change with changes in price. The sensitivity of price assumptions is gauged by reporting results for all low petroleum cases in terms of the assumptions stated above ("the elastic price assumption") and for a constant price assumption.

Table 7. Product price differentials[22]

Product	Relationship
Unleaded premium gasoline	4.0 cents per gallon over unleaded regular motor gasoline
Unleaded regular motor gasoline	3.5 cents per gallon over No. 2 fuel oil
Jet A	3.0 cents per gallon over No. 2 fuel oil
No. 2 fuel oil	8% over crude oil
No. 6 fuel oil (0.7% sulfur)	77% of No. 2 fuel oil
Bunker fuel (3% sulfur)	68% of No. 2 fuel oil

4.5 Treatment of Capital Cost Recovery

Capital equipment investment is based on a 15 percent discounted cash flow rate of return on investment (ROI), with account for seasonal process utilization changes. Other studies have used a 15 percent ROI to select optimal process investments, with actual costs based on a 10 percent ROI.[24] The sensitivity of the ROI assumption is discussed in reference 25.

4.6 Base Cases (Cost Reference Cases)

Refining costs (and fuel economy cost effects) are relative to year 2010 seasonal base cases with production of 100 percent CG. The Base cases (cost reference cases) use current refinery capacity plus additional (sunk cost) investment capacity.[13] Summer Base case gasoline blendstocks and properties are shown in Tables B-1 and B-2. Winter Base case gasoline blendstocks and properties are shown in Tables D-1 and D-2.

5. LOW PETROLEUM GASOLINE COMPONENTS

EPACT defines replacement fuel as "the portion of any motor fuel that is methanol, ethanol, or other alcohols, natural gas, liquified petroleum gas, hydrogen, coal derived liquid fuels, fuels (other than alcohol) derived from biological materials, electricity (including electricity from solar energy), ethers, or any other fuel the Secretary [of Energy] determines, by rule, is substantially not petroleum and would yield substantial energy security benefits and substantial environmental benefits."

For the study of low petroleum gasoline production, it is assumed that replacement fuels can become a portion of gasoline by direct blending or by conversion into another form which can be blended into gasoline. For example, ethanol can be blended as is. Hydrogen (derived from "non-petroleum" natural gas and steam) cannot be directly blended into gasoline, but it can enter gasoline in a converted form (for example, through hydrogenation of unsaturated hydrocarbons). Fig. 4 illustrates how the replacement petroleum concept could be merged with conventional refining processes. The low petroleum study investigates replacement of petroleum by:

- Direct blending or conversion of alcohols:

  Methanol (derived from natural gas) and ethanol can be directly blended into gasoline for replacement fuel credit. Gasoline grade tertiary butyl alcohol (GTBA) is directly blended as a cosolvent with methanol. Methanol and ethanol can also be converted into ethers.

- Direct blending of ethers:

  Replacement fuel credit is given for purchased methyl tertiary butyl ether (MTBE) and ethyl tertiary butyl ether (ETBE), which are assumed to be derived from non-petroleum sources.

  For ethers produced in the refinery, the associated alcohol is credited as a replacement fuel. Produced ethers can include MTBE, tertiary amyl methyl ether (TAME), tertiary hexyl methyl ether (THME), ETBE, tertiary amyl ethyl ether (TAEE), and tertiary hexyl ethyl ether (THEE).

- Hydrogenation:

  Hydrogen derived from non-petroleum sources and used in hydrogenation processes can be credited as a replacement fuel in gasoline. However, as shown in Appendix C, there should be deductions for hydrogen used in desulfurization, fuel gas, and in hydrogenation of blendstocks for products other than low petroleum gasoline.

- Conversion of vegetable oil:

  It is assumed that rapeseed oil can be used as a feedstock for future cracking technologies. The rapeseed oil component of gasoline blendstocks is credited as replacement fuel.

Replacement fuel credit is also given for purchased components of natural gas liquids (NGLs include ethane, propane, butanes and natural gasoline).[a] These non-petroleum components may be used in the production of ethers, alkylate, reformate and other gasoline blendstocks. If large volumes of ethers are used in low petroleum gasoline, production costs could be particularly sensitive to the availability of NGL component raw materials for ether production.

5.1 NGL Composition

Natural gas is composed of methane with some entrained light hydrocarbons. NGLs are produced when the non-methane components are extracted from natural gas. The methane portion of produced natural gas varies widely from one deposit to another, and could range from 50 to 99 percent. The remaining 1 to 50 percent is NGLs and other contaminant gases such as carbon dioxide, hydrogen, and nitrogen. On average nationwide, 9 percent of natural gas is NGLs.

Typically, NGLs are about 52 percent ethane, 27 percent propane, 13 percent butane, 5 percent pentane, and 3 percent hexane or heavier hydrocarbons.[26]

5.2 Location and Quantity of NGLs

Natural gas is processed at natural gas plants and at refineries. There are approximately 730 natural gas processing plants and 190 refineries in the United States.[27] Gas processing plants account for about 74 percent of NGL production.[28] Refinery-produced NGLs are crude-derived and are not credited as replacement fuel in this analysis. Gas plant production of propane, the primary commercial NGL, occurs in all gas-productive areas. Refinery production is concentrated in the Gulf area, but it is regionally important in the vicinity of other refinery centers such as Philadelphia, Chicago, and the West Coast. Natural gas and NGL users include petrochemical plants (the largest single user), refineries, other industry, residential, utility, commercial, and agricultural sectors.[27] Over the last 20 years, daily production of NGLs in gas processing plants has averaged about 1.5 million barrels per day.[29] Current domestic daily production of NGLs is about 1.75 million barrels per day or 640 million barrels per year.[30]

Historically, 3 to 5 percent of natural gas has been imported. As recent domestic natural gas demand has risen faster than production, imports are now 9 to 11 percent. Natural gas imports result in the elimination of some volume of NGLs, which would be coproduced if a volume of natural gas equivalent to the imported volume were processed domestically. To the extent that increased demand for natural gas is supplied by imports, some historical volume of NGLs will be lost.

---

[a]Natural gasoline is considered a replacement fuel in this analysis because it is "substantially not petroleum" as required by EPACT and is a logical technical interpretation of the intent of the law. Liquified petroleum gases, explicitly mentioned in the EPACT definition, include ethane, propane, and butanes produced from natural gas processing.

5.3 NGL Quality

"Quality" refers to the relative lack of non-hydrocarbon impurities in natural gas and NGLs. The composition of wellhead natural gas production varies widely. To meet pipeline requirements, wellhead natural gas must often be processed to remove water, NGLs, and non-hydrocarbon gases such as carbon dioxide, hydrogen sulfide, and nitrogen. While technologies exist for removing all common non-methane diluents from natural gases, the processes can be costly and energy intensive, especially when the diluents constitute a large percentage of the gas.

"Subquality" natural gas is characterized by one or more of the following wellhead composition criteria:[31]

- Carbon dioxide greater than or equal to 2 percent
- Nitrogen greater than or equal to 4 percent
- Hydrogen sulfide greater than or equal to 4 ppm.

These categories of gas composition generally require some form of upgrade (processing or blending). Carbon dioxide and hydrogen sulfide, termed "acid gases," are corrosive in pipelines and must be removed when present in even small concentrations. Nitrogen is inert and reduces the heating value of the gas. Removing these impurities to produce pipeline-quality natural gas generates NGLs.

The amount of NGL in natural gas varies with gas type. Associated natural gas, which is found along with crude deposits, typically is higher in NGL content. It is often referred to as "rich" or "wet" gas. Non-associated natural gas is not found alongside crude deposits and tends to be "drier," meaning that the gas contains a lower percentage NGL. Since crude oil production is expected to decrease in the future, less associated natural gas will be produced as well. The trend in natural gas production is toward drier, non-associated gas.

5.4 NGL Extraction/Production Methods and Associated Costs

Gas processing plants have three basic methods of recovering NGLs from natural gas: straight refrigeration, cryogenic refrigeration and lean oil absorption.[32] The first two methods are more common, with lean oil absorption used primarily in older plants.

5.4.1 Straight Refrigeration

The basic process for extracting NGLs from natural gas is cooling. In straight refrigeration, liquid-laden gas is cooled to a temperature between 15°F and -40°F. The lower temperatures are required to remove ethane. About 70 percent of the ethane, 90 percent of the propane, and all of the butanes and pentanes can be recovered through this method. At the higher temperature, 25 to 35 percent of the ethane, 55 to 70 percent of the propane, 80 to 90 percent of the butanes, and at least 97 percent of the pentanes and heavier molecules can be recovered. A 20 million cubic foot per day (inlet) straight refrigeration plant processes gas at a cost of about $0.05 per thousand cubic feet (MCF).

5.4.2 Cryogenic Refrigeration

To achieve greater extraction of ethane, lower temperatures are required than can be achieved through straight refrigeration. Cryogenic refrigeration temperatures can reach between -150°F and -225°F. With these temperatures, about 90 to 95 percent of the ethane and all of the heavier hydrocarbons can be recovered from natural gas. Natural gas is supercooled in a cryogenic unit by increasing the pressure on the gas. This can be done with either a turbo-expander or a Joule-Thomson valve. A 20 million cubic foot per day (inlet) cryogenic refrigeration plant processes gas at a cost of about $0.03 per MCF.

The economics of the straight refrigeration plant versus the cryogenic refrigeration plant depend on the volume of gas to be processed, the amount of NGL present in the gas, the pressure of the incoming gas source, and the intended use of the recovered liquids. Generally, straight refrigeration plants are more economical if a small volume of gas is to be processed, and cryogenic plants are more economical if the gas stream to be processed has a lower NGL content. Since the trend is toward drier gas with a lower NGL content, only use of low-temperature straight refrigeration or cryogenic refrigeration will extract the maximum amount of NGLs from natural gas. From 1991 to 1992, there was a decline in production of ethane as the price of natural gas rose and margins narrowed that in turn decreased production of NGLs. Strong demand for ethane from the petrochemical sector is expected to improve margins in the late 1990s, which should benefit the production of heavier NGLs.

Although the economics of processing leaner gas are generally better in a cryogenic refrigeration plant, there is relatively little benefit to using low-temperature, deeper extraction processing methods to extract more of the heavier NGLs, since even the higher temperature straight refrigeration processing extracts most of the heavier hydrocarbons.

5.5 NGL Transportation Modes and Associated Costs

Small gas processing plants are often unable to fractionate the NGL stream completely. In the case where it is desirable to separate heavier products from the propane stream, the mixed NGL stream is sent to a fractionation center. There are two major storage and fractionation centers in the United States. One is at Mont Belvieu, Texas, and the other is in Conway, Kansas. The fractionation centers are connected to gas processing plants by an extensive pipeline system. There are currently 10 major pipelines with 72,000 miles of lines dedicated to moving NGLs.[32] The average time to move product from Gulf Coast to midwest is 4 to 7 days.

The cost of transporting NGL to Mont Belvieu or Conway and then fractionating it ranges from $0.03 to $0.10 per gallon, with the higher costs associated with transporting from the Rocky Mountains or the northeastern part of Utah.[32] With recently low NGL margins, the cost of moving NGL from some remote regions to the Gulf Coast for fractionation makes it unprofitable to recover heavier NGLs.

After processing, the separated NGL products are transported from the fractionation center to end users or distributors. Generally, only petrochemical plants and refineries receive NGLs directly from the pipeline. Transport trucks or rail cars deliver to utility, industrial, and commercial users (including distributors). The type of transport used depends on the requirements of the specific NGL. Ethane is limited to pressurized pipeline movement because of its high vapor pressure and low density. Propane, butane, and natural gasoline may be moved by any of the above methods. Propane, perhaps the most marketable product in terms of variety of end uses, is often segregated and sold separately from butane

and pentane. Butane, formerly used by refiners to "blend up" gasoline for higher octane, is used widely to make ethers.

5.6 Projection of Future Resource Availability

The future availability of NGLs for low petroleum gasoline does not show significant growth for four key reasons. First, current gas processing techniques are already extracting most of the butanes and heavier hydrocarbons in NGLs. Second, since the trend in future natural gas production is toward drier gas, there will be fewer NGLs in the gas that is processed domestically. Third, future increases in natural gas imports to meet increased natural gas demand does not provide any opportunity to increase the production of NGLs. Fourth, the Energy Information Administration predicts traditional demand for NGLs will remain flat through the year 2010.[33]

In summary, no significant increase in production of NGLs is expected from natural gas processing plants. Any additional NGLs used to produce ethers would likely have to come from refineries or imports.

6. PRODUCTION OF LOW PETROLEUM SUMMER GASOLINE

The low petroleum study does not provide forecasts of the volumes or mix of low petroleum gasolines that will enter the marketplace. Rather, the study examines hypothetical low petroleum gasoline formulations. These low petroleum gasolines are produced by direct blending or conversion of alcohols, direct blending of ethers, hydrogenation, and conversion of vegetable oil.

6.1 Direct Blending of Alcohols

6.1.1 Methanol

With EPA's phasedown of lead in gasoline, there was increased interest in the potential of methanol as an economical replacement for lost octane. In the late 1970s and early 1980s, EPA approved several blends of methanol in gasoline. Correctly produced methanol blends were attractive because they could be substituted for costly gasoline without expensive changes to either automobiles or fuel transport systems.

Without a cosolvent blended with methanol, water can separate from gasoline and accumulate at the bottom of storage tanks. When this water-rich mixture is pumped into an automobile's fuel system, it causes rough idling, stalling, and other problems. Publicity about incorrectly blended methanol contributed to automakers' skepticism about the effect of methanol blends on the engine and fuel system. As a result, several automakers cautioned motorists against using methanol blends and declared that vehicle warranties could be revoked if methanol blends were used. Higher methanol prices and misblending episodes led to the phase out of major methanol programs in the mid-1980s.[34]

Table 8 shows that methanol (with cosolvent) blends have attractive octane blending values, but high RVP blending values. RVP is the major determinant of VOC emissions. Fig. 5 shows that the VOC emissions blending value of methanol (with cosolvent) can be two and a half times the target VOC value for RFG. The RFG VOC specification greatly reduces the viability of methanol as a replacement fuel for gasoline. In fact, for premises of the low petroleum gasoline study, the minimum oxygen requirement for summer RFG cannot be met with methanol without exceeding the VOC emissions limit. Therefore, direct blending of methanol is eliminated as an option in the low petroleum study, but methanol remains important as a non-petroleum feedstock for ether production.

Table 8. Octane and RVP for RFG and blendstocks[a]		
	Octane, (R+M)/2	RVP, psi
Summer RFG	88.6 (minimum)	6.5 -7.0 (typical)
Methanol (with cosolvent gasoline grade tertiary butyl alcohol, GTBA)	107	34+
Ethanol	115	19.5
MTBE	109	9
ETBE	112	4

[a]RFG octane is target specification. RFG RVP is typical value range. Other octane and RVP values are blending values. Blending values can vary with gasoline composition.

6.1.2 Ethanol

Ethanol has seen continued growth as a gasoline component since the late 1970s when it was used as a product extender due to tight gasoline supplies. State and federal benefits can be claimed if a renewable feedstock is used for ethanol production. The current federal excise tax credit is 5.4 cents per gallon of 10 percent ethanol in gasoline, or 54 cents per gallon of ethanol. The excise tax credit can be prorated below the 10 percent ethanol blend. Income tax credits can be claimed for ethers produced from ethanol, if the taxpayer is not paying the Alternate Minimum Tax.[35,36]

More than 95 percent of ethanol is made from corn, and about 6 percent of U.S. corn is used to make ethanol.[37] However, cellulosic ethanol could have substantial cost and emissions benefits in the future. Production of cellulosic ethanol from low-cost and widely available materials, such as wood, could be a long-term solution to the problem of dwindling petroleum reserves, provided no fossil fuel inputs are used during biomass production, harvesting, and transport. It has been argued that use of cellulosic ethanol will result in no net contribution of carbon dioxide (CO_2) to the atmosphere. This is because the CO_2 released during biomass conversion to ethanol and ethanol combustion will be absorbed during the growth of new biomass materials to replace those used during conversion.[38] Other factors that could contribute to lower emissions of CO_2 in the use of cellulosic ethanol include reduced use of fertilizers, pesticides, tillage, and labor.

Gasoline suppliers tend to blend ethanol into gasoline at sites near ethanol producers, predominantly in the Midwest for corn-derived ethanol. Most petroleum pipelines will not carry ethanol or ethanol blends, due to solvency properties. Ethanol can dissolve accumulated sediments, which could reform at valves and other critical points, or in vehicle engines. Pipelines and terminals would need to provide costly treatment to remove impurities and moisture, or need to replace fittings to permit transportation of ethanol or ethanol blends. Therefore, ethanol is usually shipped by truck or rail and blended with gasoline at distribution points, rather than at refineries.[39]

Ethanol-based gasoline demand can be very high in the low petroleum study. Extensive production and marketing would require the introduction of ethanol into pipeline systems. Anhydrous facilities would have to be provided from the point of blending to the point of retail sale. The American Petroleum Institute (API) has estimated that a 10 percent ethanol blend for half the gasoline sold would require an investment of $0.8 to $1.7 billion for upgrading blending, storage and pipeline systems. Annualized capital and operating costs would be about 21 to 24 cents per gallon of ethanol, or about 2 cents per gallon of the ethanol gasoline blend.[39]

As shown in Table 8, ethanol has an attractive octane blending value, but its RVP blending value is considerably higher than the likely RVP of RFG. Ethanol's RVP causes its VOC blending value to be high, as shown in Fig. 5. Another potential problem with ethanol is that RVP can increase through commingling of ethanol-based gasolines with other gasolines (the blending RVP of ethanol can increase as the ethanol concentration decreases). The current maximum allowable concentration of oxygen from ethanol is 3.5 wt percent, equivalent to 10 volume percent of ethanol. In the year 2010 low petroleum cases, the regulatory limit on oxygen is relaxed.

Six cases have been examined in which summer gasoline is oxygenated with ethanol. The non-petroleum share is manipulated in these cases by increasing the oxygen content of gasolines, by decreasing the refinery input of crude oil, and by increasing the use of hydrogen. Sensitivity cases gauge the importance of the VOC and RVP assumptions. Given the large volumes of ethanol-based gasolines, the cases assume that ethanol blending is optimized and performed at the refinery. Major investments in the distribution system would be required to deliver these gasolines to end users. Distribution system investment costs are not included in the estimated refining costs. Tables 9 and 10 summarize case conditions, non-petroleum inputs, and refining costs. Key points related to these tables include:

Refining cost is sensitive to the VOC specification assumption. If the required VOC reduction is relaxed from 30 to 24 percent, the refining cost increase can be cut about half (compare cases 1EA and 2EA).

Refining cost can be sensitive to the RVP specification assumption for CG. RVP for CG is a binding constraint in all ethanol cases. Among all low petroleum cases, RVP reduction is most costly in case 4EA. As a variation of case 4EA, case 5EA shows a refining cost decrease of 4 to 5 cents per gallon of gasoline when the allowable RVP for CG is increased to 8.7 psi.

In terms of increased refining costs, crude oil reduction can be expensive in ethanol blends (compare cases 3EA and 4EA). Low-RVP blend stocks are important in compensating for ethanol's high VOC blending value. Reducing crude input reduces the availability of low-RVP stocks.

The cost of crude oil reduction is the total increase in costs divided by the total reduction in crude oil use. A refiner would not choose to produce low petroleum gasoline unless the average cost of crude in the base case is at least the cost of crude oil reduction in the low petroleum case. In terms of the cost of crude oil reduction, the cases have similar cost-effectiveness. The lowest cost of crude oil reduction is for the CG RVP sensitivity case 5EA.

Crude oil reduction causes an increase in natural gas used as feed to the hydrogen plant (compare cases 3EA and 4EA).

Forced hydrogenation causes an increase in natural gas used as feed to the hydrogen plant (compare cases 3EA and 6EA).

Oxygen levels slightly higher than those shown in the table are not feasible, because there is no market disposition for some naphthas displaced from gasoline. The displacement of naphthas is related to VOC control.

The maximum non-petroleum share is 17 to 18 percent, occurring with high crude oil reduction (cases 4EA and 5EA).

Refining costs are sensitive to assumptions about price elasticity of raw materials and products. In case 5EA with corn-based ethanol, the refining cost increases range from 23 cents (constant prices) to 34 cents (elastic prices) per gallon of gasoline.

Refining costs are sensitive to assumptions about the use of corn-derived and cellulosic ethanol. In case 5EA, the use of cellulosic ethanol can save 3 to 5 cents per gallon compared to the use of corn-derived ethanol.

Gasoline blendstocks (Tables B-3 and B-4), gasoline properties (Tables B-5 and B-6), process capacity investments (Table B-7), and refinery fuel use changes (Table B-8) are shown in Appendix B. Key points related to these tables are:

In crude oil reduction, increased alkylation is required to compensate for the loss of low-RVP inputs (compare cases 3EA and 4EA). Increased natural gas feedstocks are used in expanded hydrogen plant capacity. The increased hydrogen stream is utilized in expanded hydrocracker capacity. There are increases in hydrocrakate blended to gasolines and to distillates (Table 11).

A reduction of crude oil (with reduced availability of low RVP stocks) causes a shift of refinery operations toward building larger molecules from small molecules. For example, lighter hydrocarbons are separated by fractionation and combined in processes such as alkylation, dimerization, and polymerization (compare cases 1EA and 3EA).

Forced hydrogenation causes an increase in natural gas used as feed to expanded hydrogen plant capacity (compare cases 3EA and 6EA). The increased hydrogen output is utilized in expanded hydrocracker capacity. There are increases in hydrocrakate blended to gasolines and to distillates (Table 11).

For comparable cases (EA and 4EA), forced hydrogenation increases the share of hydrogen credited to low petroleum gasoline. However, the maximum hydrogen credit occurs in case 5EA. In the low petroleum study, there are relatively loose constraints on the disposition of hydrogen. Given the method for crediting hydrogen as a replacement fuel (Appendix C), the share of hydrogen could be increased by imposing a constraint on hydrocracked stocks blended to all distillates.

With increased hydrogen production (compare cases 3EA and 6EA) and molecular conversions (compare cases 3EA and 4EA), refinery fuel use increases.

The ethanol cases fall short of the 30 percent replacement goal of EPACT. Section 7 will compare the potential of ethanol strategies with replacement of petroleum by other methods.

Table 9. PADD III low petroleum components for the year 2010 summer: Ethanol blends							
Case:	Base	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%		2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%				3.5	3.5	3.5	3.5
Crude reduction target, vol%				10	15	15	10
Forced hydrogenation?		No	No	No	No	No	Yes
RFG VOC reduction, min%		30	24	30	30	30	30
CG RVP, max psi		7.9	7.9	7.9	7.9	8.7	7.9
Components:							
Crude, MBD	6135	6089	6009	5521	5215	5215	5521
Crude reduction, vol%		0.7	2.0	10.0	15.0	15.0	10.0
Hydrogen from natural gas, MBD (GE)[a]	6.7	29.8	27.3	41.5	79.5	79.7	54.3
Natural gasoline, MBD (GE)	96.1		1.1	96.1	96.1	96.1	96.1
Ethane, MBD (GE)	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Propane, MBD (GE)	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Butanes, MBD (GE)	86.2	163.4	167.5	184.2	198.2	207.0	185.0
Methanol from natural gas, MBD (GE)	6.8						
Ethanol, MBD (GE)		83.7	89.4	196.3	196.3	196.9	196.3
Total non-petroleum, MBD (GE)	205.1	286.1	283.2	527.3	579.2	588.9	540.9
Non-petroleum share, allocated to gasoline, %	6.1	8.5	8.4	15.7	17.3	17.5	16.1

[a]GE is gasoline energy equivalent

Table 10. PADD III low petroleum costs for the year 2010 summer: **Ethanol blends**

Case:	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%	2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%			3.5	3.5	3.5	3.5
Crude reduction target, vol%			10	15	15	10
Forced hydrogenation?	No	No	No	No	No	Yes
RFG VOC reduction, min%	30	24	30	30	30	30
CG RVP, max psi	7.9	7.9	7.9	7.9	8.7	7.9
Costs:	Cost above dotted line is for constant price assumption. Cost below dotted line is for elastic price assumption. Within a cell, the lower cost is for use of cellulosic ethanol. The higher cost is for use of corn-derived ethanol.					
Refining cost increase, cents per physical gallon of gasoline	7.99 to 8.91	3.02 to 4.41	14.65 to 17.66	24.32 to 27.33	19.56 to 22.57	15.07 to 18.08
	8.69 to 10.33	4.49 to 6.31	15.31 to 24.18	33.57 to 38.26	29.02 to 34.03	20.00 to 24.69
Cost of crude reduction, $ per barrel	NA[a]	NA[a]	34.74 to 41.83	38.44 to 43.19	30.90 to 35.66	35.72 to 42.86
	NA[a]	NA[a]	36.29 to 57.31	53.05 to 60.46	45.86 to 53.77	47.41 to 58.53

[a]Not applicable. Cases are not crude reduction strategies

Table 11. PADD III low petroleum effects on distillate blendstock: **Ethanol blended gasoline cases**							
Case:	Base	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%		2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%				3.5	3.5	3.5	3.5
Crude reduction target, vol%				10	15	15	10
Forced hydrogenation?		No	No	No	No	No	Yes
RFG VOC reduction, min%		30	30	30	30	30	30
CG RVP, max psi		7.9	7.9	7.9	7.9	8.7	7.9
Hydrocrackate blended to distillates, MBD	72	160	124	266	553	530	365

6.2 Ethers

Ethanol and methanol produced from non-petroleum feedstocks can be used to produce ethers by reacting the alcohols with tertiary olefins. Table 8 and Fig. 5 show that ethers can have octanes comparable to their parent alcohols, with low RVP and VOC blending values. MTBE, TAME, and ETBE are now limited to a maximum oxygen content of 2.7 wt percent in gasoline. In the year 2010 low petroleum cases, the regulatory limit on oxygen is relaxed, and heavier ethers are allowed.

6.2.1 Methyl Ethers

Seven cases have been examined in which summer gasoline is oxygenated with ethers of methanol. The non-petroleum share is manipulated in these cases by increasing the oxygen content of gasolines, by decreasing the refinery input of crude oil, and by increasing the use of hydrogen. Two sensitivity cases illustrate the importance of assumptions about the availability of imported ethers. Tables 12 and 13 summarize case conditions, non-petroleum inputs, and refining costs. Key points related to these tables include:

The methanol and ether production base includes PADD III refineries and merchant plants.

Assumptions about the availability of imported ethers can have a large impact on refining costs. Except for two sensitivity cases, the maximum allowable volume of imported ethers is proportional to the total ether requirement. The proportionality factor is the ratio of foreign ether plant capacity to total ether plant capacity, existing and planned. When the ether source is restricted to PADD III production, the refining cost increase is almost doubled (compare cases 2M and 3M). It is costly to produce olefins to satisfy the total ether requirement.

In case 6M, ether imports are just enough to preclude investment in PADD III ether plants. With this high level of imported ethers, the refinery cost savings can be 5 to 8 cents per gallon of gasoline (compare cases 6M and 7M). Appendix Table B-13 shows a large reduction in refinery investment for production and processing of C4s (naphtha cracking, C2-C5 dehydrogenation, and ether plant). The refinery costs savings could be overstated to the extent that foreign ether plant investment costs are not reflected in the MTBE price.

Based on the cost of crude oil reduction, the crude oil reduction strategy (case 4M) is more attractive than hydrogenation (case 5M) and oxygenation (case 6M) strategies.

Crude oil reduction causes an increase in natural gas used as feed to the hydrogen plant (compare cases 2M and 4M).

Forced hydrogenation causes an increase in natural gas used as feed to the hydrogen plant (compare cases 2M and 5M).

The maximum non-petroleum share in Table 12 is 28 percent (case 7M) at a refining cost increase of about 44 to 46 cents per gallon of gasoline. This maximum share is achieved with maximum oxygenation. It is possible that the non-petroleum share could be increased by hydrogenation. The hydrogenation possibilities are suggested by case 5M compared to 2M, in which the non-petroleum share is increased by 1 percentage point, at a refining cost increase of about 8 cents per gallon of gasoline.

In the maximum oxygenation cases, the EPA Complex Model is being used far beyond its valid limit of 3.7 wt percent oxygen. Beyond this limit, the Complex Model equations for methyl ethers have near-linear behavior, as shown in Figs. 6 and 7. The analysis of ethyl ethers will show that refining costs can be quite sensitive to assumptions about extrapolation of the Complex Model.

Gasoline blendstocks (Tables B-9 and B-10), gasoline properties (Tables B-11 and B-12), process capacity investments (Table B-13), and refinery fuel use changes (Table B-14) are shown in Appendix B. Key points related to these tables are:

In crude oil reduction (compare cases 2M and 4M), increased natural gas feedstocks are used in expanded hydrogen plant capacity. The increased hydrogen stream is utilized in expanded hydrocracker capacity, with increased volumes of hydrocrackate blended to distillates, as shown in Table 14.

In forced hydrogenation (compare cases 2M and 5M), increased natural gas feedstocks are used in expanded hydrogen plant capacity. The increased hydrogen stream is utilized in expanded hydrocracker capacity. There are increases in hydrocrackate blended to gasolines and to distillates (Table 14).

The reduction of crude oil results in increased utilization of molecule building processes such as polymerization and dimerization (compare cases 2M and 4M).

With increased hydrogen production (compare cases 2M and 5M), fractionation, and molecular conversions (compare cases 2M and 4M), the refinery fuel use increases.

With the high oxygenation case 6M (with intermediate availability of imported ethers), there is substantial investment in ether plant, and in processes that produce olefins for etherification (e.g., FCC fractionation and C2-C5 dehydrogenation). Relative refinery fuel use is highest in this case.

In the high oxygenation cases (6M and 7M), the very high percentage of MTBE (and other ethers of methanol) is related to:

The high RVP of RFG. In case 6M compared to 1M, MTBE (with blending RVP of 9 psi) has displaced a substantial volume of FCC naphthas (with RVP blending values near 7 psi).

The low sulfur/aromatics content of RFG. Contributors to sulfur/aromatics reduction include dilution with ethers and displacement of high sulfur/aromatics FCC stocks. Sulfur/aromatics reductions compensate for the VOC increase associated with the RVP increase of RFG.

The high NOx value of RFG. The high RFG olefins content, due to a high percentage of polymer gasolines, contributes to NOx. MTBE displacement of FCC naphthas depresses T50. The available olefin feeds can be either alkylated or polymerized. ORNL-RYM selects polymer gasolines because they have higher T50s than alkylates.

The low TAP value of RFG. MTBE dilution and replacement of FCC naphthas reduce sulfur and aromatics. MTBE dilution contributes to benzene reduction. Also, MTBE has a negative blending value for TAP.

Section 7 will compare the potential of methyl ether strategies with replacement of petroleum by other methods.

Table 12. PADD III low petroleum components for the year 2010 summer: **Methyl ether oxygenates**

Case:	Base	1M	2M	3M	4M	5M	6M
RFG oxygen target, wt%		2.1	2.7	2.7	2.7	2.7	6.0
CG oxygen target, wt%			3.5	3.5	3.5	3.5	6.0
Crude reduction target, vol%			10	10	15	10	10
Oxygenate imports allowed, vol%		43	43	0	43	43	43
Forced hydrogenation?		No	No	No	No	Yes	No
Components:							
Crude, MBD	6135	5908	5521	5521	5215	5521	5521
Crude reduction, vol%		3.7	10.0	10.0	15.0	10.0	10.0
Hydrogen from natural gas, MBD (GE)[a]	6.7	16.8	17.2	58.2	34.7	97.8	0
Natural gasoline, MBD (GE)	96.1	96.1	96.1	96.1	96.1	96.1	96.1
Ethane, MBD (GE)	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Propane, MBD (GE)	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Butanes, MBD (GE)	86.2	176.3	181.6	197.4	205.0	150.7	188.9
Methanol from natural gas, MBD (GE)	6.8	41.1	54.8	96.0	54.8	54.8	113.1
MTBE imported, MBD (GE)			199.5		199.5	199.5	409.1
Total non-petroleum, MBD (GE)	205.1	339.5	558.3	456.8	599.3	608.1	816.5
Non-petroleum share, allocated to gasoline, %	6.1	10.1	16.7	13.6	17.8	18.1	24.3

[a]GE is gasoline energy equivalent

Table 12 (continued). PADD III low petroleum components for the year 2010 summer: **Methyl ether oxygenates**	
Case:	7M
RFG oxygen target, wt%	6.0
CG oxygen target, wt%	6.0
Crude reduction target, vol%	10
Oxygenate imports allowed, vol%	71
Forced hydrogenation?	No
Components:	
Crude, MBD	5521
Crude reduction, vol%	10.0
Hydrogen from natural gas, MBD (GE)[a]	0
Natural gasoline, MBD (GE)	
Ethane, MBD (GE)	2.8
Propane, MBD (GE)	6.4
Butanes, MBD (GE)	171.2
Methanol from natural gas, MBD (GE)	54.2
MTBE imported, MBD (GE)	694.7
Total non-petroleum, MBD (GE)	929.3
Non-petroleum share, allocated to gasoline, %	27.7
[a]GE is gasoline energy equivalent	

Table 13. PADD III low petroleum price elasticity variations for the year 2010 summer: **Methyl ether oxygenates**

Case:	1M	2M	3M	4M	5M	6M	7M
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	3.5	6.0	6.0
Crude reduction target, vol%		10	10	15	10	10	10
Oxygenate imports allowed, vol%	43	43	0	43	43	43	71
Forced hydrogenation?	No	No	No	No	Yes	No	No
Costs:	Cost above dotted line is for constant price assumption Cost below dotted line is for elastic price assumption						
Refining cost increase, cents per physical gallon of gasoline	3.97	10.94	19.40	19.75	18.63	49.10	44.41
	6.78	15.03	26.18	27.47	23.08	53.86	46.30
Cost of crude reduction, $ per barrel	NA[a]	25.90	45.89	31.16	44.11	120.17	108.65
	NA[a]	35.60	62.00	43.36	54.66	131.76	113.28

[a]Case is not a crude reduction strategy

Table 14. PADD III low petroleum effects on distillate blendstocks: **Methyl ether oxygenated gasoline cases**

Case:	Base	1M	2M	3M	4M	5M	6M
RFG oxygen target, wt%		2.1	2.7	2.7	2.7	2.7	6.0
CG oxygen target, wt%			3.5	3.5	3.5	3.5	6.0
Crude reduction target, vol%			10	10	15	10	10
Oxygenate imports allowed, vol%		43	43	0	43	43	43
Forced hydrogenation?		No	No	No	No	Yes	No
Hydrocrackate blended to distillates, MBD	72	133	239	144	352	410	375

Table 14 (Continued). PADD III low petroleum effects on distillate blendstocks: **Methyl ether oxygenated gasoline cases**

Case:	7M
RFG oxygen target, wt%	6.0
CG oxygen target, wt%	6.0
Crude reduction target, vol%	10
Oxygenate imports allowed, vol%	71
Forced hydrogenation?	No
Hydrocrackate blended to distillates, MBD	363

6.2.2 Ethyl Ethers

Seven cases have been examined in which summer gasoline is oxygenated with ethers of ethanol. The low petroleum share is manipulated in these cases by increasing the oxygen content of gasolines, by decreasing the refinery input of crude oil, and by increasing the use of hydrogen. Tables 15 and 16 summarize case conditions, non-petroleum inputs, and refining costs. Key points related to these tables include:

A 54 cents per gallon credit has been applied to the ethanol component of ethyl ethers. Currently, such credit may not be available. For example, income tax credits cannot be claimed for ethers made from ethanol if the taxpayer is paying Alternate Minimum Tax.

Based on the cost of crude oil reduction, the crude oil reduction strategy (case 3E) is more attractive than hydrogenation (case 4E) and oxygenation (cases 6E and 7E) strategies.

Crude oil reduction (case 3E) and forced hydrogenation (case 4E) cause an increase in natural gas used as feed to the hydrogen plant (compared to case 2E).

The maximum non-petroleum share in Table 15 is about 32 percent (case 7E) at a refining cost increase of about 41 to 55 cents per gallon of gasoline. This maximum share is achieved with maximum oxygenation and substantial crude reduction. It is possible that the non-petroleum share could be further increased by hydrogenation. The hydrogenation possibilities are suggested by comparing cases 4E and 2E, in which the non-petroleum share is increased by 2 percentage points, at a cost increase of about 7 to 8 cents per gallon of gasoline.

Because of differences in raw material purchases and ether production, the ethyl ether cases (1E through 6E) are not are not similar enough to allow a comparison of refinery cost increases with the methyl ether cases. Ethyl ether case 7E was defined for comparison with methyl ether case 6M; these two cases have comparable hydrocarbon inputs. Tables 13 and 16 show that the refining cost increases for these two cases can be about the same: 49 to 54 cents per gallon for methyl ether case 6M and 47 to 55 cents per gallon for ethyl ether case 7E, with corn-derived ethanol.

Case 7E also provides additional sensitivity on the crude reduction strategy. The cost of crude reduction is much less with 17 percent crude reduction (compare cases 5E and 7E).

Refining costs are sensitive to assumptions about the use of corn-derived and cellulosic ethanol. In cases 5E, 6E, and 7E, the use of cellulosic ethanol can save 6 to 10 cents per gallon compared to the use of corn-derived ethanol.

Gasoline blendstocks (Tables B-15 and B-16), gasoline properties (Tables B-17 and B-18), process capacity investments (Table B-19), and refinery fuel use changes (Table B-20) are shown in Appendix B. Key points related to these tables are:

In crude oil reduction (compare cases 2E and 3E; compare cases 5E and 7E), increased natural gas feedstocks are used in expanded hydrogen plant capacity. The increased hydrogen stream is utilized in expanded hydrocracker capacity, with increased volumes of hydrocrackate blended to gasolines and distillates (Table 17).

In forced hydrogenation (compare cases 2E and 4E), increased natural gas feedstocks are used in expanded hydrogen plant capacity. The increased hydrogen stream is utilized in expanded hydrocracker capacity, with the highest volumes of hydrocrackate blended to gasoline. Increased volumes of hydrocrackate are also blended to distillates, as shown in Table 17.

The reduction of crude oil can result in increased utilization of molecule building processes such as polymerization or dimerization.

With increased hydrogen production, fractionation, and molecular conversions, the refinery fuel use increases.

In the high oxygenation cases, there is substantial investment in ether plant and light olefins production (C2-C5 dehydrogenation) for etherification. Relative refinery fuel use is highest in two of the high oxygenation cases (5E and 7E).

In high oxygenation cases 5E and 7E, the very high percentages of ETBE (and other ethers of ethanol) are related to:

The low RVP of RFG. In cases 5E and 7E, ETBE (with blending RVP of 4 psi) has displaced a substantial volume of FCC naphthas (with RVP blending values near 7 psi).

High levels of acetaldehyde emissions. The valid upper limit for oxygen content in the EPA Complex Model is 3.7 wt percent. Fig. 8 shows that if the Complex Model is used beyond 3.7 wt percent oxygen, there is a greater-than-linear increase in acetaldehyde emissions. Given the high acetaldehyde emissions, the TAP constraint is achieved by very severe reductions in benzene, sulfur, and aromatics.

Contributors to sulfur reduction include dilution with ethers and displacement of high-sulfur FCC stocks.

Contributors to the aromatics and benzene reduction include dilution with ethers and displacement of high-aromatics reformate and FCC stocks.

The low olefins content of RFG. Contributors to the olefins reduction include dilution with ethers and displacement of high-olefins FCC stocks. Olefins reduction also contributes to TAP reduction.

The high utilization of the FCC feed hydrofiner. Hydrofined FCC feeds can have higher yields of olefins which can be used in ether production.

The low VOC value of RFG. Low RVP, low ETBE blending VOC value (Fig. 5), low sulfur and low aromatics contents contribute to the low VOC of RFG.

The low NOx value of RFG. Low sulfur, low olefins, and low aromatics contribute to the low NOx of RFG.

If the acetaldehyde emissions equation were linear, then refining costs would be reduced by a substantial 11 to 12 cents per gallon of gasoline (compare cases 5E and 6E). With the linear extrapolation, there are much-relaxed requirements for reduction of benzene, sulfur and aromatics. Emissions behavior is not known outside the range of the Complex Model, and vehicle testing is required to understand the costs and benefits of low petroleum gasoline with oxygen levels greater than 3.7 wt percent.

Section 7 will compare the potential of ethyl ether strategies with replacement of petroleum by other methods.

Table 15. PADD III low petroleum components for the year 2010 summer: **Ethyl ether oxygenates**

Case:	Base	1E	2E	3E	4E	5E	6E
RFG oxygen target, wt%		2.1	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%			3.5	3.5	3.5	6.0	6.0
Crude reduction target, vol%			10	15	10	10	10
Oxygenate imports allowed, vol%?		43	43	43	43	43	43
Forced hydrogenation?		No	No	No	Yes	No	No
Linear acetaldehyde emissions?		No	No	No	No	No	Yes
Components:							
Crude, MBD	6135	5979	5521	5215	5521	5521	5377
Crude reduction, vol%		2.5	10.0	15.0	10.0	10.0	12.4
Hydrogen from natural gas, MBD (GE)[a]	6.7	36.7	40.3	54.7	167.2	77.7	2.7
Natural gasoline, MBD (GE)	96.1	66.1	96.1	96.1	50.7	96.1	96.1
Ethane, MBD (GE)	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Propane, MBD (GE)	6.4	6.4	6.4	6.4	6.4		
Butanes, MBD (GE)	86.2	165.6	169.5	189.4	150.7	153.4	151.2
Methanol from natural gas, MBD (GE)	6.8						
Ethanol, MBD (GE)		80.1	107.0	107.0	106.9	220.3	220.3
ETBE imported, MBD (GE)			239.4	239.4	239.4	490.1	490.1
Total non-petroleum, MBD (GE)	205.1	357.6	661.5	695.8	724.2	1040.4	963.1
Non-petroleum share, allocated to gasoline, %	6.1	10.6	19.6	20.7	21.5	31.0	28.6

[a]GE is gasoline energy equivalent

Table 15 (Continued). PADD III low petroleum components for the year 2010 summer: Ethyl ether oxygenates		
Case:	Base	7E
RFG oxygen target, wt%		6.0
CG oxygen target, wt%		6.0
Crude reduction target, vol%		17.0
Oxygenate imports allowed, vol%		43
Forced hydrogenation?		No
Linear acetaldehyde emissions?		No
Components:		
Crude, MBD	6135	5072
Crude reduction, vol%		17.3
Hydrogen from natural gas, MBD (GE)[a]	6.7	81.0
Natural gasoline, MBD (GE)	96.1	96.1
Ethane, MBD (GE)	2.8	2.8
Propane, MBD (GE)	6.4	
Butanes, MBD (GE)	86.2	176.5
Methanol from natural gas, MBD (GE)	6.8	
Ethanol, MBD (GE)		220.3
ETBE purchased, MBD (GE)		490.1
Total non-petroleum, MBD (GE)	205.1	1066.7
Non-petroleum share, allocated to gasoline, %	6.1	31.8

[a]GE is gasoline energy equivalent

Table 16. PADD III low petroleum price elasticity variations for the year 2010: **Ethyl ether oxygenates**

Case:	1E	2E	3E	4E	5E	6E	7E
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	6.0	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0	6.0
Crude reduction target, vol%		10	15	10	10	10	17
Oxygenate imports allowed, vol%	43	43	43	43	43	43	43
Forced hydrogenation?	No	No	No	Yes	No	No	No
Linear acetaledhyde emissions?	No	No	No	No	No	Yes	No
Costs:	Cost above dotted line is for constant price assumption. Cost below dotted line is for elastic price assumption. Within a cell, the lower cost is for use of cellulosic ethanol. The higher cost is for use of corn-derived ethanol.						
Refining cost increase, cents per physical gallon of gasoline	6.26 to 7.50	9.00 to 11.81	15.35 to 18.16	16.48 to 19.29	33.85 to 39.39	22.14 to 27.67	41.48 to 47.02
	7.90 to 9.50	11.34 to 15.71	20.43 to 25.39	18.98 to 23.34	34.10 to 44.18	22.26 to 32.44	44.88 to 55.13
Cost of crude reduction, $ per barrel	NA[a]	21.35 to 28.01	24.28 to 28.72	39.08 to 45.75	82.68 to 96.20	43.76 to 54.68	58.48 to 66.30
	NA[a]	26.89 to 37.26	32.32 to 40.15	45.00 to 55.36	83.27 to 107.90	44.00 to 64.11	63.28 to 77.74

[a]Case is not a crude reduction strategy

Table 17. PADD III low petroleum effects on distillate blendstocks: **Ethyl ether oxygenated gasoline cases**

Case:	Base	1E	2E	3E	4E	5E	6E
RFG oxygen target, wt%		2.1	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%			3.5	3.5	3.5	6.0	6.0
Crude reduction target, vol%			10	15	10	10	10
Oxygenate imports allowed, vol%		43	43	43	43	43	43
Forced hydrogenation?		No	No	No	Yes	No	No
Linear acetaldehyde emissions?		No	No	No	No	No	Yes
Hydrocrackate blended to distillates, MBD	72	76	66	186	172	182	307

Table 17 (Continued). PADD III low petroleum effects on distillate blendstocks: **Ethyl ether oxygenated gasoline cases**

Case:	Base	7E
RFG oxygen target, wt%		6.0
CG oxygen target, wt%		6.0
Crude reduction target, vol%		17
Oxygenate imports allowed, vol%		43
Forced hydrogenation?		No
Linear acetaldehyde emissions?		No
Hydrocrackate blended to distillates, MBD	72	198

6.3 Vegetable Oil

Vegetable oils have been used with mixed success as diesel engine fuels. In short term testing in direct injection engines, neat vegetable oils have performed very closely to diesel fuel oil. However, long term testing of vegetable oils in direct injection engines has usually resulted in engine damage or engine failure, caused by fuel filter plugging, carbon buildup in the injection chamber and injector coking. The poor performance of vegetable oils could be explained by the fact that vegetable oils are more unsaturated than diesel fuel oils and polymerize inside the combustion chamber more readily. The high viscosities of vegetable oils could also be a reason for poor performance. Methods tested to solve engine performance problems have included blending vegetable oils with diesel fuels; fumigating vegetable oils with propane and microemulsifying the oils with solvents such as alcohol; and esterification.[42]

Laboratory tests have suggested that vegetable oils, such as rapeseed oil, can be converted to a mixture of liquid and gaseous hydrocarbons, with high conversions, in fixed bed catalytic reactors.[43,44] The possibilities for using rapeseed oil as part of the feedstock for the fluid catalytic cracking process have also been investigated.[45] In these catalytic processes, rapeseed oil is converted to hydrocarbons, water, and oxides of carbon. The hydrocarbon products appear to be suitable for blending to gasoline and distillates.

Several cases have been examined for the production of summer gasoline in which rapeseed oil is used to increase the non-petroleum share. In these cases, it is assumed that by the year 2010, FCC technology can accommodate up to 5 wt percent rapeseed oil in FCC feed. For accounting purposes, it is assumed that each barrel of rapeseed oil feed can be converted into 0.9 barrels of non-petroleum blendstocks for gasoline. The yield assumptions are based on product spectra for fixed bed catalytic conversion of pure vegetable oils.[43,44,46]

The published properties for rapeseed-associated naphtha are based on experimental results reported without reference to a control experiment.[45] The published properties (with inferences about sulfur and aromatics contents) have significant improvements in emissions values ("High quality"), versus typical petroleum-derived FCC naphthas. Additional investigations are required to confirm and explain these property improvements. Given the uncertainty about property values, a sensitivity case is examined in which rapeseed-associated naphtha is assumed to have properties of petroleum-derived naphthas ("Low quality"). Naphtha properties are shown in Table 18.

Table 18. Range of blending properties of rapeseed-associated FCC naphthas		
	Low quality	High quality
Research Octane Number	90.8	94.1
Motor Octane Number	78.8	80.6
RVP, psi	6.9	3.2
Aromatics, vol%	29.0	40.0
Benzene, vol%	1.1	0.7
Olefins, vol%	29.0	25
Sulfur, ppm	285	235
E200, %	28	23
E300, %	76	79
Specific gravity	.7507	.7699
Summer TAP, mg/mi[a]	70	70
NOx, mg/mi[a]	1510	1470
VOC, mg/mi[a]	1090	790
[a]Emissions blending values can vary with case		

The rapeseed oil cases are variations of a methyl ether case with moderate crude reduction (2M) and oxygenation; and an ethyl ether case with moderate crude reduction and high oxygenation (5E). Tables 19 and 20 summarize case conditions, non-petroleum inputs, and refining costs. Gasoline blendstocks (Tables B-21 and B-22), gasoline properties (Tables B-23 and B-24), process capacity investments (Table B-25), and refinery fuel use changes (Table B-26) are shown in Appendix B. Key points related to these tables include:

In the rapeseed oil cases, the non-petroleum share of gasoline is increased.

The use of rapeseed oil causes an increase in refining costs.

For case 1R compared to case 2M, 85 percent of the cost increase is due to the high purchase price of rapeseed oil (estimated to be nearly $70 per barrel[42,47]).

For case 1RX compared to case 2M, the cost of rapeseed oil has been offset by investment and operations cost savings due to the high quality naphtha. In case 1RX, there are reduced costs for meeting specifications for octane, benzene, NOx and VOC. In cases 1R and 1RX, the yield of rapeseed-associated naphtha is ten times the input of rapeseed oil, and 25 percent of gasoline is

rapeseed-associated naphtha. Because of its high percentage in gasoline, rapeseed-associated naphtha can have substantial quality and cost impacts.

For case 2RX compared to case 2E, less than 20 percent of the cost increase is due to the high purchase price of rapeseed oil. Most of the cost increase is related to the cost of maintaining gasoline's minimum RVP of 6.5 psi. With a rapeseed-associated naphtha yield ten times the input of rapeseed oil, nearly 8 percent of gasoline is rapeseed-associated naphtha (RVP blending value of 3.2 psi). Gasoline contains 38 percent ethyl ethers (RVPs of 4 psi or less). The remaining gasoline components must have an average RVP of at least 11.3 psi. The availability of high-RVP butanes is limited because of the demands for ether production.

In case 2RX compared to case 2E, increased natural gas feedstocks are used in expanded hydrogen plant capacity. The increased hydrogen stream is used in expanded naphtha and gas oil hydrocracking capacity. Increased hydrocracking provides increased volumes of C4s for direct blending to gasoline and for production of a greater volume of C4-based ether (with higher RVP than C5/C6-based ethers). Additionally, a higher volume of light hydrocrackate is blended to gasoline. These activities are driven by the minimum RVP specification.

Refining costs are sensitive to assumptions about the use of corn-derived and cellulosic ethanol. In cases 5E and 2RX, the use of cellulosic ethanol can save 6 to 10 cents per gallon compared to the use of corn-derived ethanol.

To increase confidence in the potential for rapeseed oil, more research will have to be reported on process reliability and naphtha quality in FCC rapeseed oil service.

Table 19. PADD III low petroleum components for the year 2010 summer: **Rapeseed oil feedstock**

Case:	Base	2M	1R	1RX	5E	2RX
RFG oxygen target, wt%		2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0
Ether type (M = methyl; E = ethyl)		M	M	M	E	E
Crude reduction target, vol%		10	10	10	10	10
Oxygenate imports allowed, vol%		43	43	43	43	43
Forced hydrogenation?		No	No	No	No	No
Rapeseed oil feed?		No	Yes	Yes	No	Yes
FCC naphtha (rapeseed associated) quality		NA	Low	High	NA	High
Components:						
Crude, MBD	6135	5521	5521	5521	5521	5521
Crude reduction, vol%		10.0	10.0	10.0	10.0	10.0
Hydrogen from natural gas, MBD (GE)[a]	6.7	17.2	10.7	19.0	77.7	104.2
Natural gasoline, MBD (GE)	96.1	96.1	96.1	96.1	96.1	96.1
Ethane, MBD (GE)	2.8	2.8	2.8	2.8	2.8	2.8
Propane, MBD (GE)	6.4	6.4	6.4	6.4		
Butanes, MBD (GE)	86.2	181.6	179.0	175.2	153.4	154.2
Methanol from natural gas, MBD (GE)	6.8	54.8	54.8	54.6		
MTBE imports, MBD (GE)		199.5	199.5	199.5		
Ethanol, MBD (GE)					220.3	221.1
ETBE imports, MBD (GE)					490.1	490.1
Rapeseed oil, MBD (GE)			84.3	84.3		26.4
Total non-petroleum, MBD (GE)	205.1	558.3	633.6	637.8	1040.4	1094.9
Non-petroleum share, allocated to gasoline, %	6.1	16.7	18.9	19.0	31.0	32.6

[a]GE is gasoline energy equivalent

Table 20. PADD III low petroleum price elasticity variations for the year 2010 summer: **Rapeseed oil feedstock**

Case:	Base	2M	1R	1RX	5E	2RX
RFG oxygen target, wt%		2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0
Ether type (M = methyl; E = ethyl)		M	M	M	E	E
Crude reduction target, vol%		10	10	10	10	10
Oxygenate imports allowed, vol%		43	43	43	43	43
Forced hydrogenation?		No	No	No	No	No
Rapeseed oil feed?		No	Yes	Yes	No	Yes
FCC naphtha (rapeseed associated) quality		NA	Low	High	NA	High
Costs:	Cost above the dotted line is for constant price assumption Cost below the dotted line is for elastic price assumption: Within certain cells, the lower cost is for use of cellulosic ethanol. The higher cost is for use of corn-derived ethanol.					
Refining cost increase, cents per physical gallon of gasoline		10.94	14.81	11.98	33.85 to 39.39	38.83 to 44.37
		15.03	18.36	15.05	34.10 to 44.18	38.98 to 49.10
Cost of crude reduction, $ per barrel		25.90	35.06	28.37	82.68 to 96.20	95.05 to 108.61
		35.60	43.49	35.64	83.27 to 107.90	95.41 to 120.19

Table 21. PADD III low petroleum effects on distillate blendstocks: **Rapeseed oil feedstock**

Case:	Base	2M	1R	1RX	5E	2RX
RFG oxygen target, wt%		2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0
Ether type		M	M	M	E	E
Crude reduction target, vol%		10	10	10	10	10
Oxygenate imports allowed, vol%		43	43	43	43	43
Forced hydrogenation?		No	No	No	No	No
Rapeseed oil feed?		No	Yes	Yes	No	Yes
FCC naphtha (rapeseed associated) quality		NA	Low	High	NA	High
Hydrocrackate blended to distillates, MBD	72	239	160	133	182	264

7. COMPARISON OF LOW PETROLEUM SUMMER GASOLINE OPTIONS

Fig. 9 shows the relationship between refining cost increase and non-petroleum share for all summer low petroleum cases. For a given non-petroleum share, costs are generally higher for corn-derived ethanol blends, intermediate for cellulosic ethanol and methyl ether blends, and lower for ethyl ether blends. Non-petroleum shares are limited to about 20 percent for ethanol blends. For ethers, the maximum shares are above 30 percent. The maximum non-petroleum share among all cases is 33 percent for high oxygenation with ethyl ethers in combination with high-quality rapeseed-associated naphtha (case 2RX). The refining cost increase for this maximum share case is 39 to 49 cents per gallon of gasoline. The lower cost increase is for use of cellulosic ethanol, and the higher cost increase is for use of corn-derived ethanol with elastic prices.

The cases are ordered according to refining cost increase in Fig. 10. For reference, case descriptions are summarized in the Supplement to Figures, which follows Fig. 10. Increasing cost is almost in the same order as increasing oxygen content. Within a given oxygenation group, refining costs are higher for forced hydrogenation and forced crude reduction. For a case using ethanol, the cost increase can vary greatly, depending upon whether corn-derived or cellulosic ethanol is used.

Refining cost and non-petroleum share have a significant correlation. The cases are ordered according to non-petroleum share in Fig. 11. Increasing share is in the same order as increasing oxygen content. Within a given oxygenation group, the non-petroleum share is higher for forced hydrogenation and forced crude reduction.

Fig. 12 shows the relationship between the cost to reduce crude oil use and the non-petroleum share. For a given non-petroleum share, costs are generally higher for corn-derived ethanol blends, intermediate for cellulosic ethanol and methyl ether blends, and lower for ethyl ether blends. For the maximum non-petroleum share case (2RX), the cost to reduce crude oil use is $95 to $120 per barrel. The lower cost is for use of cellulosic ethanol, and the higher cost increase is for use of corn-derived ethanol with elastic prices.

In Fig. 13, the cases are ordered according to increasing cost to reduce crude oil use. Increasing cost is almost in the same order as increasing oxygen content. Within a given oxygenation group, the cost to reduce crude oil tends to be lower for forced crude reduction. For a case using ethanol, the cost to reduce crude oil use can vary greatly, depending upon whether corn-derived or cellulosic ethanol is used.

Fig. 14 shows the relationship between crude oil use reduction and the non-petroleum share. The maximum reduction of about 17 percent is associated with a non-petroleum share of about 32 percent (case 7E with high oxygenation with ethyl ethers). In Fig. 15, the cases are ordered according to increasing crude oil use reduction. Except for one case, crude oil reduction is at a minimum constraint (the exception is for the high oxygenation case 6E, using an alternate form of the Complex Model).

Fig. 16 shows the relationship between refinery fuel use and the non-petroleum share for summer low petroleum cases. For a given non-petroleum share, refinery fuel use is generally higher for ethanol blends, intermediate for methyl ether blends, and lower for ethyl ether blends. The maximum refinery fuel use among all cases is about 12 percent for intermediate oxygenation with ethanol in combination with forced crude reduction (case 5EA).

The cases are ordered according to refinery fuel use increase in Fig. 17. With several exceptions, refinery fuel use is higher for forced hydrogenation and forced crude reduction. Given the hydrogenation and crude reduction effect, refinery fuel use tends to be lower with higher levels of oxygenation (i.e., with greater purchase of imported ethers).

Table 22 uses the maximum crude reduction case (7E) and the maximum non-petroleum share case (2RX) to illustrate material flow adjustments to a reduction in crude oil. In case 7E, crude oil reduction is balanced by increases in non-petroleum inputs, natural gas for fuel (not credited as a non-petroleum input), and a product output decrease (coke). In case 2RX, crude oil reduction is balanced by increases in non-petroleum inputs and a product output decrease (coke). In both cases, there is a substantial increase in refinery fuel relative to the Base case.

Fig. 18 shows the relationship between refinery investment and the non-petroleum share for all low petroleum cases. For a given non-petroleum share, there is a tendency toward higher investment for ethanol blends, intermediate for methyl ether blends, and lower for ethyl ether blends. The maximum refinery investment is for the maximum crude reduction case (7E).

The cases are ordered according to refinery investment in Fig. 19. Increasing investment tends to be in the same order as increasing oxygen content. Within a given oxygenation group, investment costs tend to be higher for forced hydrogenation and forced crude reduction.

Results suggest that it is technically possible, but expensive, to achieve the 30 percent replacement fuel target in summer gasolines. The lowest cost case (6E, high oxygenation with ethyl ethers, using an alternate form of the Complex Model) achieves a near-30 percent non-petroleum share at a refining cost increase of 22 to 32 cents per gallon of gasoline. In case 6E, the cost to reduce crude oil use is $44 to $64 per barrel. The lower costs are for use of cellulosic ethanol, and the higher costs are for use of corn-derived ethanol with elastic prices.

Table 22. PADD III input/output comparisons

Case:	Base	7E	2RX
RFG oxygen target, wt%		6.0	6.0
CG oxygen target, wt%		6.0	6.0
Crude reduction target, vol%		17	10
Oxygenate imports allowed, vol%		43	43
Forced hydrogenation?		No	No
Rapeseed oil feed?		No	Yes
FCC naphtha (rapeseed associated quality)			High
Linear acetaldehyde emissions?		No	No
Inputs (MBD, gasoline energy equivalent)			
Crude	7097.9	5868.3	6388.0
Non-petroleum	191.8[a]	986.0[b]	990.8[c]
Natural gas for methanol or hydrogen production	17.9	121.8	152.8
Natural gas for fuel	305.2	491.0	153.9
Other inputs	458.4	458.4	458.4
Total inputs	8070.8	7925.5	8146.9
Outputs (MBD, gasoline energy equivalent)			
Products	7327.7	7151.7	7297.3
Refinery fuel	734.3	873.9	929.6
Loss (gain)	8.8	(100.1)	(80)
Total outputs	8070.8	7925.5	8146.9

[a]When added to methanol and hydrogen, total non-petroleum credit for transportation fuel is 205.1
[b]When added to methanol and hydrogen, total non-petroleum credit for transportation fuel is 1066.7
[c]When added to methanol and hydrogen, total non-petroleum credit for transportation fuel is 1094.9

8. PRODUCTION OF LOW PETROLEUM WINTER GASOLINE

Compared with summer gasolines, emissions constraints are less stringent for winter gasolines, and production costs are lower. There is no VOC reduction requirement, and RVP is limited primarily by concern for sufficient volatility in low temperature start-ups. NOx emissions are not allowed to increase relative to the winter statutory baseline gasoline. Winter TAP emissions are to be averaged with summer TAP emissions to achieve a 20 percent annual TAP reduction relative to baseline gasolines.

Three cases have been examined for high levels of oxygenation in winter gasoline. The oxygenates are ethanol, methyl ethers, and ethyl ethers. A minimum crude oil reduction of 10 percent is required, and imports of oxygenates are just enough to preclude investment in PADD III ether plants. Tables 23 and 24 summarize case conditions, non-petroleum inputs, and refining cost increases. Key points related to these tables include:

Non-petroleum shares at or above 30 percent are achieved with high oxygenation with ethers (cases MW and EW).

The maximum non-petroleum share is 37 percent, for high oxygenation with ethyl ethers (case EW).

Oxygenation with ethanol is associated with a relatively low refining cost increase (case EAW), but the non-petroleum share is only 22 percent because of ethanol's high oxygen content. Compared with ethers, a smaller volume of ethanol is required to achieve a given oxygen content in gasoline.

Refining costs are sensitive to assumptions about the use of corn-derived and cellulosic ethanol. In case EW, the use of cellulosic ethanol can save 6 to 14 cents per gallon compared to the use of corn-derived ethanol.

Ethanol winter case EAW does not have a summer counterpart case. In the summer, high oxygenation with ethanol cannot be achieved because of the VOC constraint. Nevertheless, the refining cost increase for high oxygenation in winter case EAW is at least 20 percent lower than the increase for intermediate oxygenation with corn-derived ethanol in summer cases 3EA through 6EA in Table 10. With cellulosic ethanol, the refining cost increase for winter case EAW is at least 67 percent lower than the increase for summer cases 3EA through 6EA.

The premises for methyl ether winter case MW are comparable to summer case 7M (Table 13). The refining cost increase and the cost of crude reduction for the winter case are at least 37 percent lower than the summer case.

Gasoline blendstocks (Tables D-1, D-3, and D-4), gasoline properties (Tables D-2, D-5, and D-6), process capacity investment (Table D-7), and refinery fuel use (Table D-8) are shown in Appendix D. Key points related to these tables are:

Winter TAP is not a binding constraint in any case. Therefore, the summer TAP constraint could be relaxed, with refining cost savings, for several ethyl ether cases (5E, 6E, 7E, and 2RX, as shown in Tables B-17 and B-23).

The cost increase for ethanol case EA is due largely to fuel economy costs and control of distillation properties.

Contributors to the cost increase for ether cases MW and EW include fuel economy costs and control of distillation properties and satisfying a minimum RVP.

Methyl ether production costs are higher than ethyl ether production costs. The assumption for ether imports requires full utilization of refinery ether plant capacity in cases MW and EW.

- In methyl ether case MW, C4s are needed to build blendstocks (e.g., heavier alkylate and polymer gasoline) for control of distillation properties. Therefore C4 availability is reduced, and cost is increased for production of ethers.

- The ethyl ether case EW requires less distillation correction, and C4 availability is greater and cost is lower for ether production.

Table 23. PADD III low petroleum components for the year 2010 winter				
Case:	Base	EAW	MW	EW
RFG oxygen target, wt%		6.0	6.0	6.0
CG oxygen target, wt%		6.0	6.0	6.0
Oxygenate type		Ethanol	Methyl ethers	Ethyl ethers
Crude reduction target, vol%		10	10	10
Oxygenate imports allowed, vol%		100	66	70
Components:				
Crude, MBD	5763	5187	5187	5015
Crude reduction, vol%		10.0	10.0	13.0
Hydrogen from natural gas, MBD (GE)[a]	5.8			15.4
Natural gasoline, MBD (GE)	90.9	90.9	65.4	90.9
Ethane, MBD (GE)	3.4	3.4	3.4	
Propane, MBD (GE)	5.1	5.1	5.1	
Butanes, MBD (GE)	174.2	186.4	174.2	159.7
Methanol from natural gas, MBD (GE)			56.3	
MTBE imports, MBD (GE)			568.2	
Ethanol, MBD (GE)		355		100.7
ETBE imports, MBD (GE)				708.0
Total non-petroleum, MBD (GE)	279.5	640.5	871.6	1074.7
Non-petroleum share, allocated to gasoline, %	9.5	21.7	29.6	36.5

[a]GE is gasoline energy equivalent

Table 24. PADD III low petroleum price elasticity variations for the year 2010 winter

Case:	EAW	MW	EW
RFG oxygen target, wt%	6.0	6.0	6.0
CG oxygen target, wt%	6.0	6.0	6.0
Oxygenate type	Ethanol	Methyl ethers	Ethyl ethers
Crude reduction target, vol%	10	10	10
Oxygenate imports allowed, vol%	100	66	70
Costs:	Cost above dotted line is for constant price assumption. Cost below dotted line is for elastic price assumption. Within certain cells, the lower cost is for use of cellulosic ethanol. The higher cost is for use of corn-derived ethanol.		
Refining cost increase, cents per physical gallon of gasoline	2.44 to 8.41	28.75	15.21 to 20.09
	4.92 to 19.21	28.97	13.10 to 23.19
Cost of crude reduction, $ per barrel	5.58 to 15.71	66.06	26.78 to 32.90
	11.25 to 46.03	66.34	23.06 to 45.60

9. GREENHOUSE GAS EMISSIONS OF LOW PETROLEUM GASOLINES

Greenhouse gases (GHGs) impede the outward flow of infrared radiation more effectively than they impede incoming solar radiation, causing the earth to be warmer than it would be in the absence of GHGs. Some of the major GHGs which can be emitted by evaporation or combustion of fuels used by light duty vehicles are water vapor, carbon dioxide, nitrous oxide, and methane. Given the concerns about possible adverse effects of global warming, Section 502(b) of EAPCT requires the Secretary of Energy to determine the GHG emission implications of increasing the use of replacement fuels, including an estimate of the maximum feasible reduction in such emissions from the use of replacement fuels..

Although minimization of GHG emissions is not an objective of the low petroleum study, the GHG emissions of low petroleum study gasolines have been estimated with the component emissions data shown in Table 25. GHG emissions of individual gasolines are shown in the property tables of the appendices. Fig. 20 shows GHG emissions for low petroleum cases (with combined effects for RFG and CG). For summer cases:

Emissions are highest for corn-derived ethanol blends.[a]

Emissions are lowest for cellulosic ethyl ether blends.

With use of cellulosic ethanol, emissions decrease as the non-petroleum share of gasoline increases. Cellulosic ethyl ether blends have the greatest rate of decrease for GHG emissions.

For methyl ether blends, emissions decrease slightly as the non-petroleum share of gasoline increases.

Emissions of methyl ether blends are comparable to emissions of cellulosic ethanol blends.

For corn-derived ethanol and ethyl ether blends, emissions increase as the non-petroleum share of gasoline increases.

For winter cases, emissions are lowest for cellulosic ethanol and ethyl ether blends. Emissions are lower for winter cases compared to summer cases.

[a]Since current fuel ethanol production capacity is small in PADD III (about 1 MBD), it is assumed that ethanol is supplied from new sources. GHG emissions for low petroleum gasolines blended with corn-derived ethanol would be lower if ethanol were diverted from existing fuel uses, with ethanol replaced by CG in the original use.

Fig. 21 shows GHG emissions relative to the appropriate seasonal base case gasoline. Compared to the base case gasoline, GHG emissions are reduced for all methyl ether cases except for case 1M, with low oxygenation (2.1 wt percent). Compared to base case gasolines, GHG emissions increase in all corn-derived ethanol and ethyl ether cases, and the increases are substantial for ethanol cases. Compared to base case gasolines, GHG emissions decrease considerably for most cellulosic ethanol and ethyl ether blends. Depending on the mix of renewable ethanols used in low petroleum fuels, the relative change in GHG emissions could lie anywhere in the crosshatch area of a case in Fig. 21.

Fig. 21 shows that cellulosic ethanol could have substantial GHG emissions benefits in the future. CO_2 released during biomass conversion to cellulosic ethanol and ethanol combustion would be absorbed during the growth of new biomass materials to replace those used during conversion. Other factors that could contribute to lower emissions of CO_2 with cellulosic ethanol include reduced use of fertilizers, pesticides, tillage, and labor.

Table 25. Greenhouse gas emissions of gasoline components[46,47]

Component	Greenhouse gas emissions (CO_2 equivalent gm/BTU)
Methyl ethers	0.10133
Ethyl ethers (corn-derived ethanol)	0.11152
Ethyl ethers (cellulosic ethanol)	0.05494
Corn-derived ethanol[a]	0.13390
Cellulosic ethanol	0.00076
Summer hydrocarbon for CG	0.10554
Winter hydrocarbon for CG	0.10304
Summer hydrocarbon for RFG with MTBE	0.10614
Winter hydrocarbon for RFG with MTBE	0.10165
Summer hydrocarbon for RFG with ETBE	0.10574
Winter hydrocarbon for RFG with ETBE	0.10165
Summer hydrocarbon for RFG with corn-derived ethanol	0.11515
Winter hydrocarbon for RFG with corn-derived ethanol	0.10186

[a]GHG emissions for corn-derived ethanol are from the base case in reference 48.

10. CONCLUSIONS

The low petroleum study examines the effects of hypothetical low petroleum gasoline formulations on PADD III refinery operations and costs. *The study cases do not provide forecasts of the volumes or mix of low petroleum gasolines that will enter the marketplace.*

According to a DOE draft report, EPACT's 10 percent replacement fuel target for the year 2000 may be economically achievable through a combination of programs already in place and market incentives for the use of ethanol in some gasolines.[50,51] Table 26 shows the projected components of fuel replacement. The non-petroleum share for the annual projection (with RFGs at 2.2 wt percent oxygen) is similar to the share for low petroleum case 1M, in which methyl ethers are used to oxygenate summer RFG (at 2.1 wt percent oxygen).

The analysis of year 2010 summer production of low petroleum gasoline suggests that the 30 percent replacement fuel target can be achieved at a high cost. Compared to the Base case, incremental costs to meet the 30 percent low petroleum target could be more than three times the incremental costs to produce Phase II reformulated gasoline in PADD III (e.g, compare cases 6E and 1E). High oxygenation is the key to meeting the replacement fuel target, and a major contributor to cost increase is investment in processes to produce and etherify light olefins. High oxygenation can also increase the costs of control of RVP, distillation properties, and pollutant emissions of gasolines. Crude oil reduction, with decreased dependence on foreign sources, is a major objective of the low petroleum program. In the analysis, crude oil use is reduced by 10 to 17 percent.

There are uncertainties in the premises for study of low petroleum fuels production, and costs can be considerably different for alternative premises. There could be large cost impacts with different assumptions about:

Availability of cellulosic ethanol. For all ethanol and ethyl ether cases, costs and GHG emissions are substantially lower for use of cellulosic ethanol compared to corn-derived ethanol.

Extrapolation of the Complex Model beyond valid limits (as illustrated by ethyl ether cases 5E and 6E). Emissions behavior is not known outside the range of the Complex Model, and vehicle testing is required to understand the costs and benefits of low petroleum gasolines with oxygen contents greater than 3.7 wt percent.

Availability of raw materials for ether production and **availability and costs of imported ethers** (as illustrated by cases 2M and 3M).

The RVP for CG. The marginal costs for reduction of RVP have been used to estimate the cost savings for changing the summer CG RVP assumption from 7.9 psi to 8.7 psi (the cost savings will be overstated since the marginal cost should decrease as the RVP is increased). Fig. 22 shows the revised refining cost increases and the associated non-petroleum share. Compared with Fig. 9, the refining costs increases in Fig. 22 are more similar for alcohols and ethers. Appendix E shows that cost revisions range from large for the ethanol cases with intermediate oxygenation to zero for seven cases, *including all high oxygenation cases.*

Table 26. Fuel replacement

Source	Non-petroleum share (percent)	
	Year 2000 annual projection (DOE draft report[50,51])[a]	Low petroleum case 1M for year 2010 summer[b]
RFG and oxygenated gasoline for carbon monoxide control:		
With MTBE	5.2	
With ethanol	0.8	
With ETBE	1.1	
Gasohol (10 percent ethanol in gasoline)	0.3	
Conventional gasoline	2.7	
Alternative fuel vehicles	0.5	
Total	10.5	10.1

[a]This national projection is based on implementation of gasoline programs already in place. Existing domestic capacity is used for production of oxygenates and reformulated gasoline blendstocks. In the projection, 50 percent of gasoline is reformulated and has an average oxygen content of 2.2 wt percent. Sufficient ethanol is used in the CG pool such that total fuel ethanol use is 1.4 billion gallons per year (which is the estimated 1995 domestic ethanol production capacity). The Renewable Oxygenate Standard, which requires that 30 percent of the required oxygen content of RFG be derived from renewable oxygenates, is assumed to be in effect.

[b]Low petroleum study case 1M is for PADD III production of RFG with 2.1 wt percent oxygen and CG with no oxygen. RFG production is 62 percent of total gasoline production.

Gasoline distillation specifications and engine operability with high percentages of ethers in gasoline.

Gasoline component blending properties (as illustrated by the displacement of alkylate with polymer gasoline due to distillation properties in cases 6M and 7M). Over the broad range of oxygenation, it has been assumed that RVP and distillation blending properties are constant for individual oxygenates. Actually, these blending values have some variation.

Technology capability to process raw materials such as vegetable oils, and the quality of products of those technologies (as illustrated by cases 1R and 1RX).

The accounting for low petroleum credit. An arbitrary procedure has been used for estimating the amount of non-petroleum-derived hydrogen that enters low petroleum gasoline.

Increased distribution costs for ethanol. These cost increases, which may be several cents per gallon of gasoline, are not included in the analysis.

The cost of capital.

Price assumptions. Fig. 23 illustrates the price elasticity effect on the cost for crude reduction for ethyl ether cases with use of corn-derived ethanol.

Compared with summer gasolines, emissions constraints are less stringent for winter gasolines, and production costs are lower. If the winter gasoline production season is 6.5 months, then year-round low petroleum gasoline with near-30 percent non-petroleum components might be achieved by combinations of cases, including:

Methyl ether cases 7M (summer, Table 13) and MW (winter, Table 24). Fig. 24 shows that the 7M/MW combination has an annualized refining cost increase of 37 cents per gallon of gasoline (elastic prices) and an annualized non-petroleum share of 29 percent. Crude oil use is reduced by 10 percent, at an annualized cost of $89 per barrel, as shown in Fig. 25. Compared to base case gasolines, the 7M/MW combination reduces GHG emissions by 0.5 percent, as shown in Fig. 26.

Ethyl ether cases 5E (summer, Table 16) and EW (winter, Table 24). Fig. 24 shows that the 5E/EW combination has an annualized refining cost increase of 23 to 33 cents per gallon of gasoline (elastic prices) and an annualized non-petroleum share of 34 percent. Crude oil use is reduced by 12 percent, at an annualized cost of $48 to $68 per barrel, as shown in Fig. 25. The lower costs are for use of cellulosic ethanol, and the higher costs are for use of corn-derived ethanol. Fig. 26 shows that the 5E/EW combination based on corn-derived ethanol increases GHG emissions by 2.8 percent, compared to base case gasolines. However, the 5E/EW combination based on cellulosic ethanol decreases GHG emissions by 15.9 percent, compared to base case gasolines.

For the year-round cases, a refiner would not choose to produce low petroleum gasoline unless the average cost of crude in the base case is somewhere in the range of costs to reduce crude oil use: $48 to $89 per barrel. Fig. 1 shows that these crude oil costs are very high.

Depending upon resolution of uncertainties about extrapolation of the Complex Model, availability of raw materials and other issues, the refining cost increases and the costs to reduce crude oil use could be could be lower or higher.

Finally, a mix of strategies could be less costly than any of the cases examined in this study. For example, costs might be lower with production of regional mixes of ether-based and ethanol-based gasolines in the winter, and with mixes of ether-based gasolines in the summer.

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Fig. 1. Crude oil supply curve for PADD III
Year 2010 (1990 dollars)

$$\ln(46589 + 2.209*Q3) = .3*\ln(P3+1.33) + 10.019$$

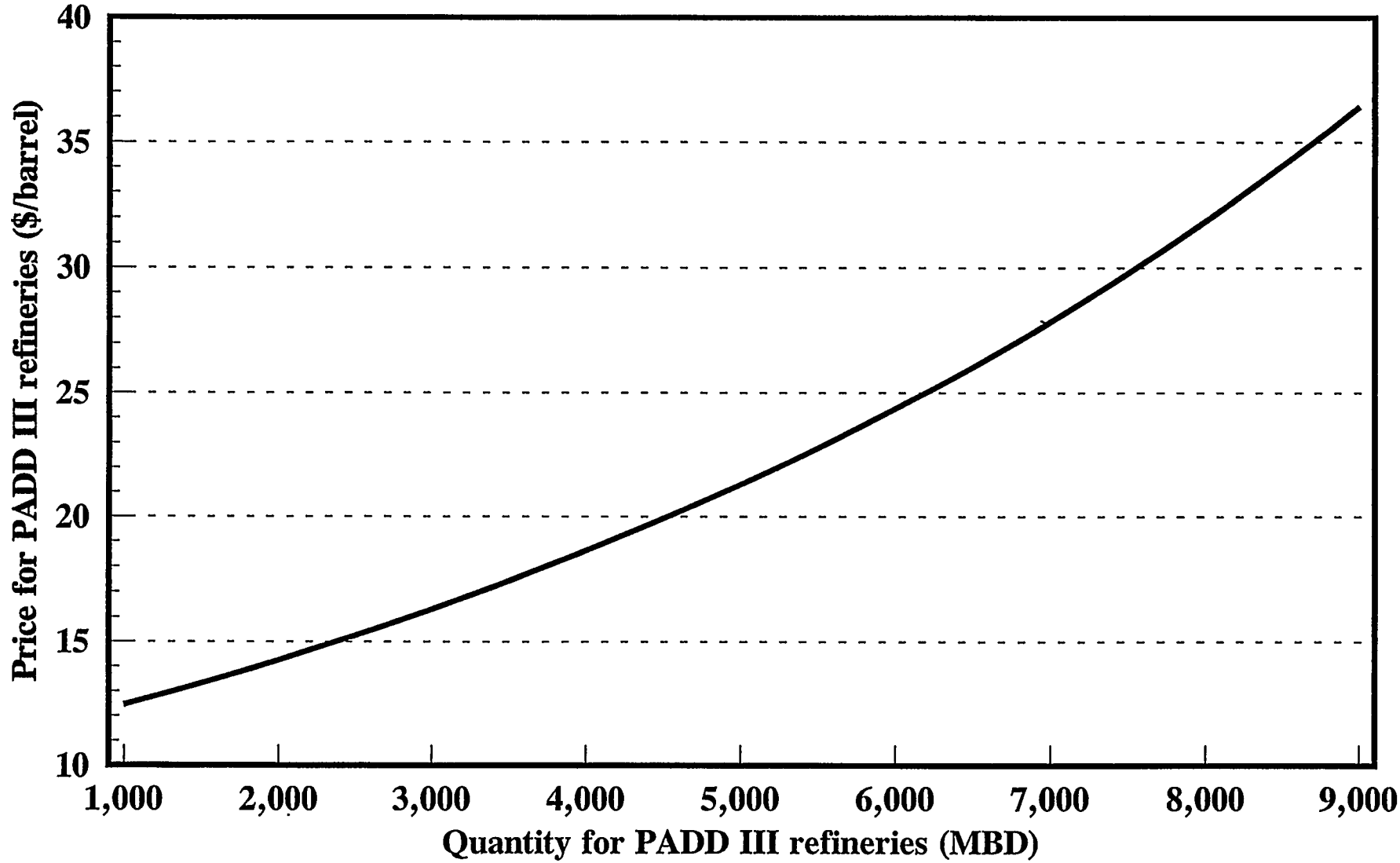


Fig. 2. Natural gas supply curve for PADD III
Year 2010 (1990 dollars)

$$\ln(76066 + 1.47*Q3) = .3*\ln(P3-0.437) + 10.918$$

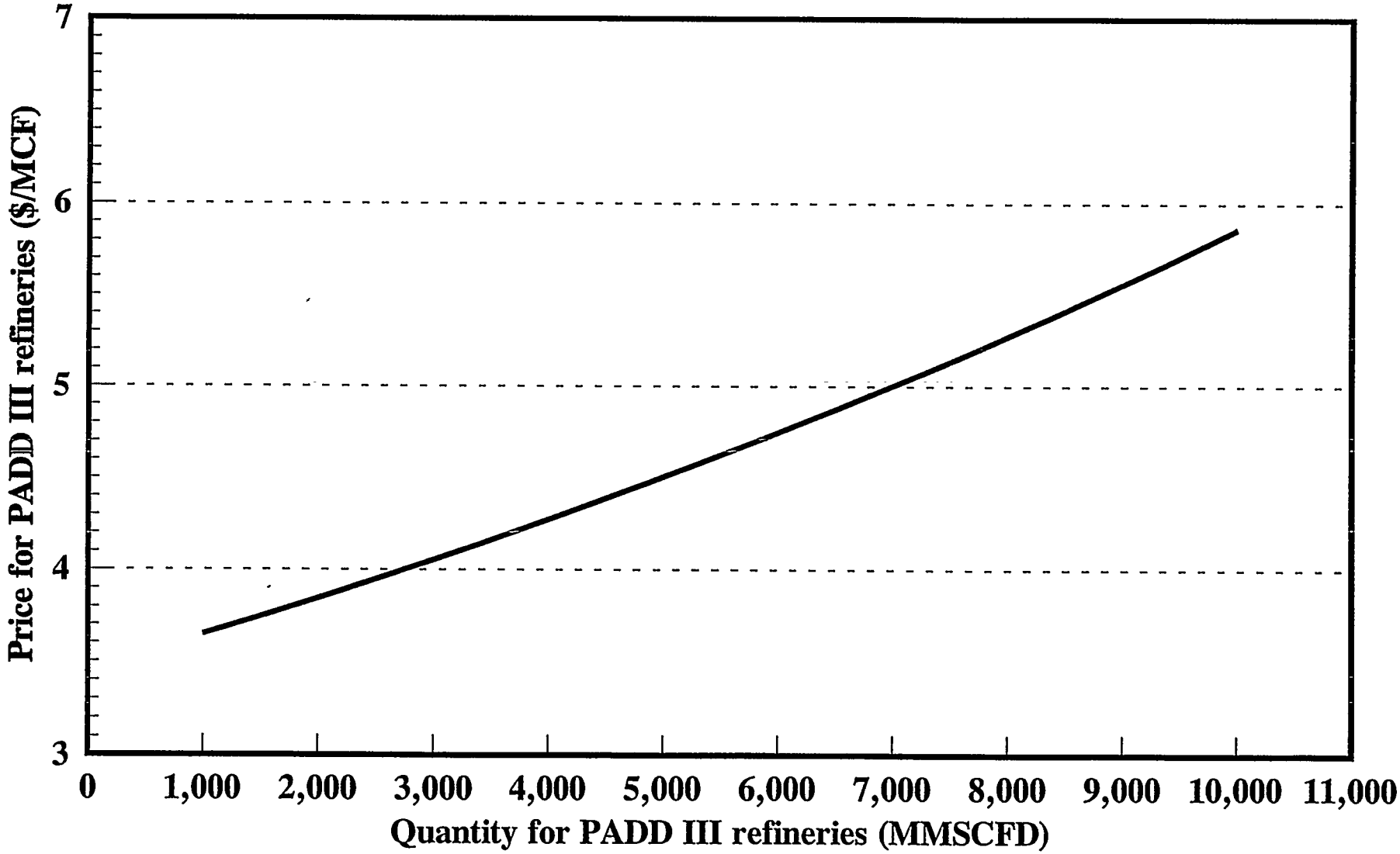


Fig. 3. Corn-derived ethanol supply curve
PADD III, year 2010 (1990 dollars)

$$\ln(2.25*Q3) = 4.35*\ln(P3-17.38)-6.7449$$

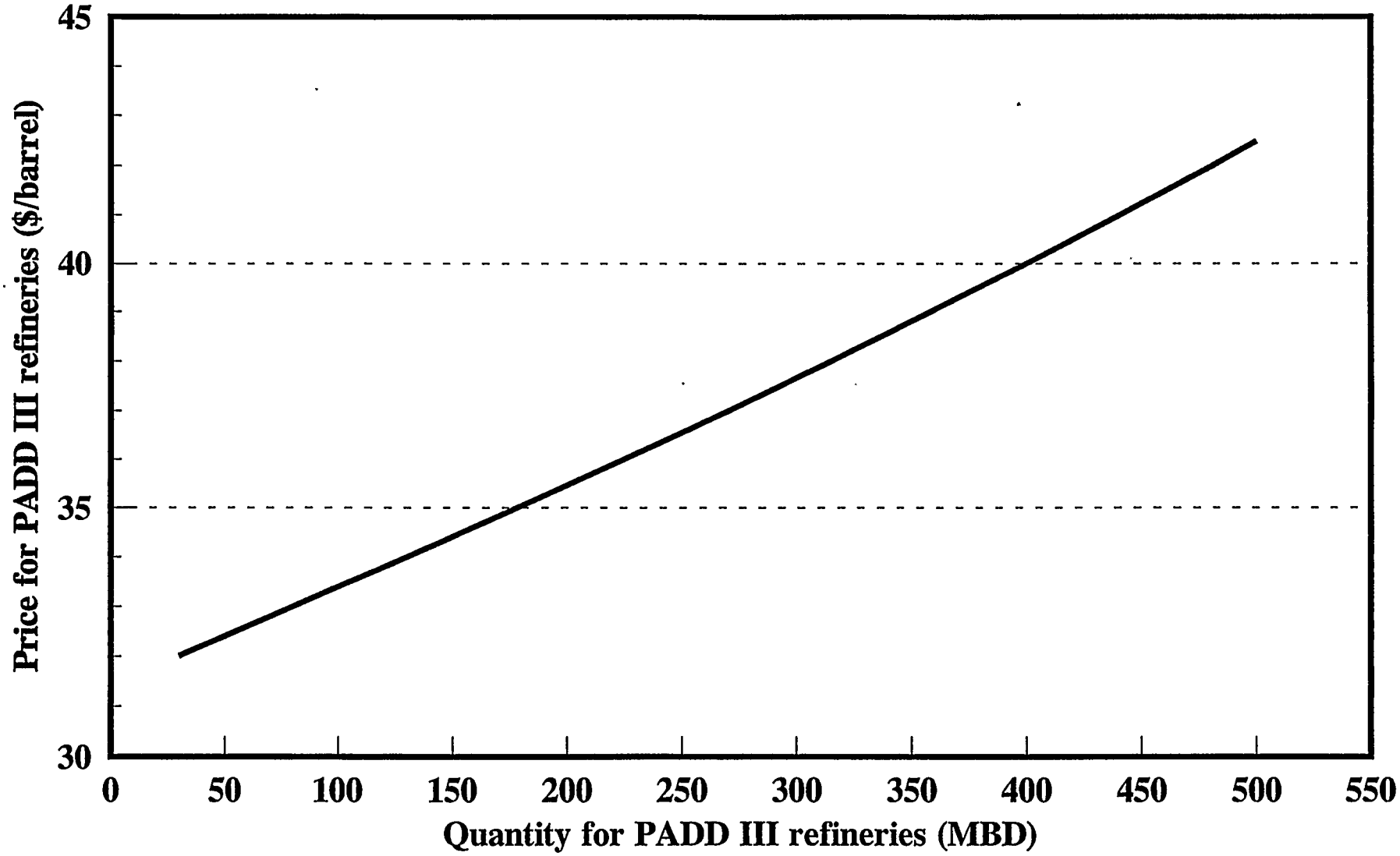


FIGURE 4

Low Petroleum Gasoline: Possible Petroleum Displacement Sources

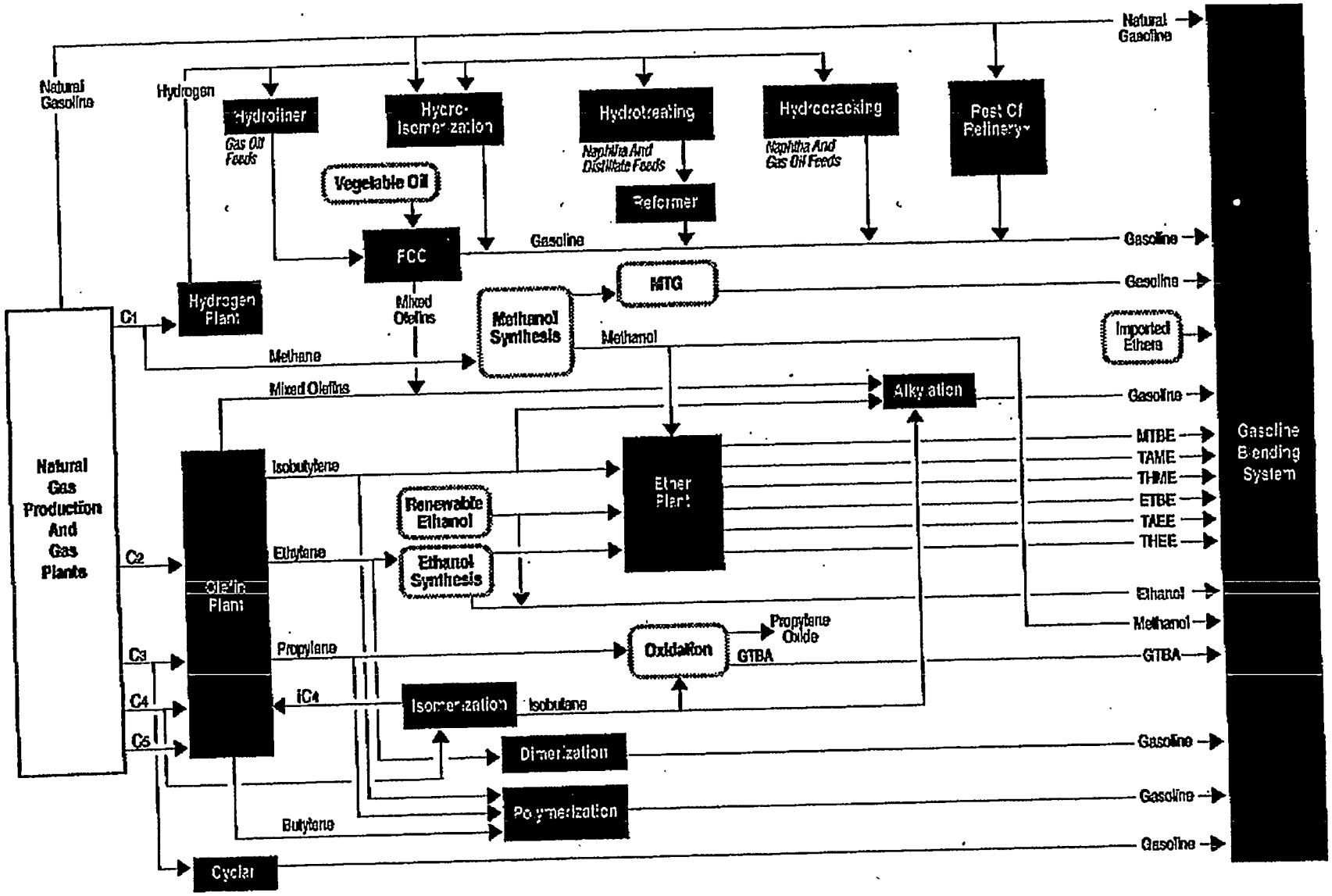
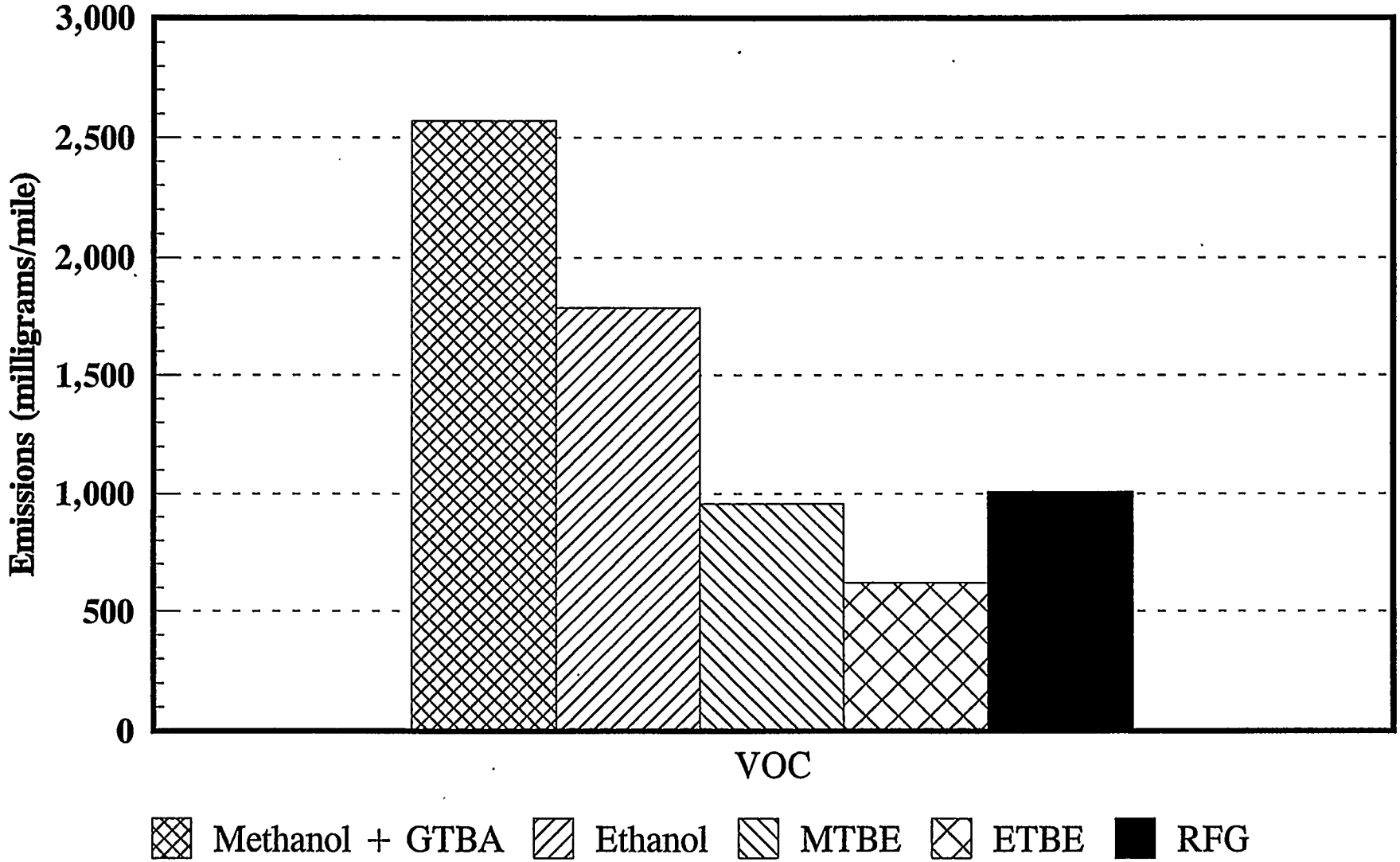


Fig. 5. RFG and blendstock VOC emissions values

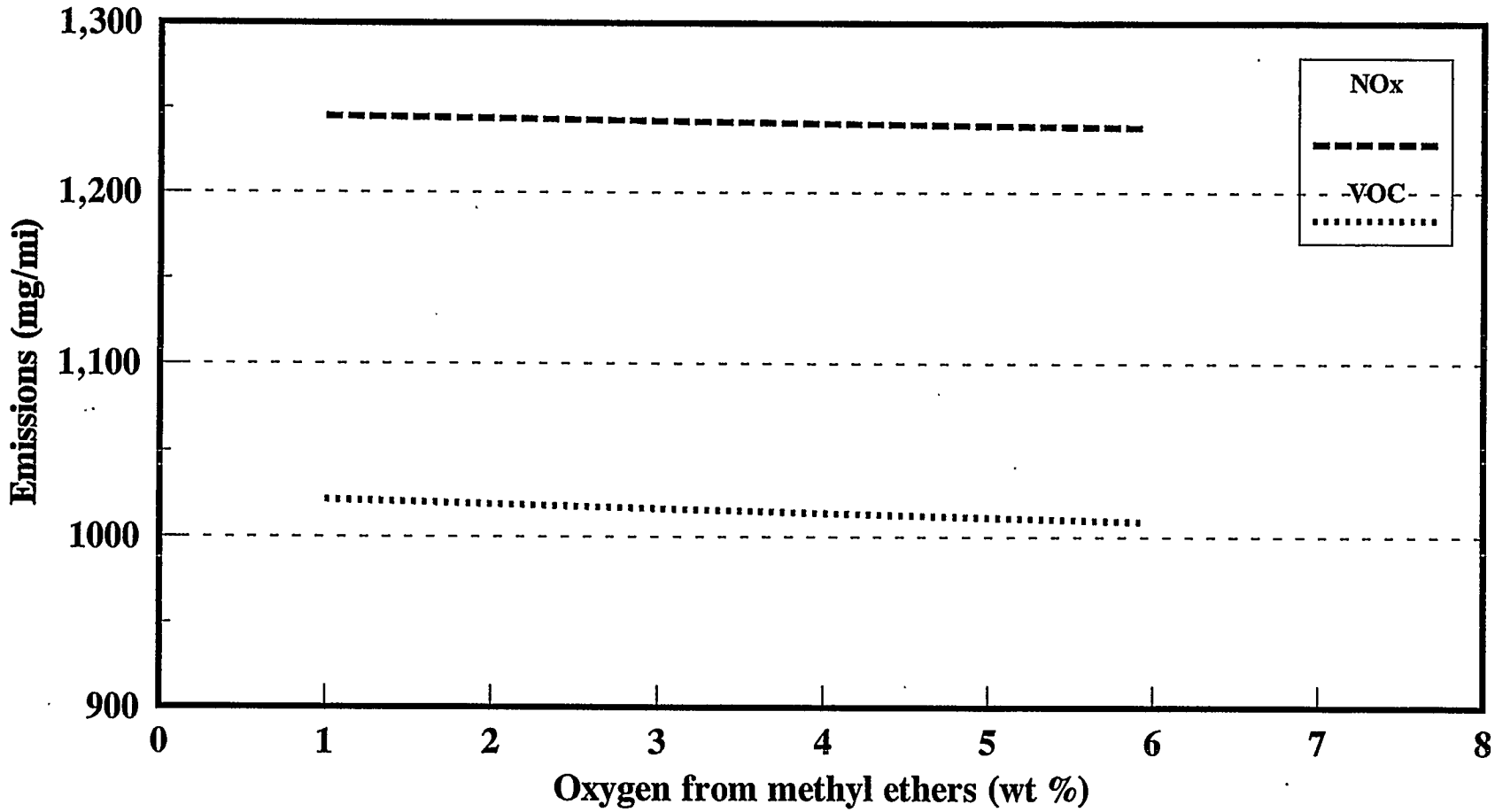
(Some values can vary with case)



RFG emissions are target specifications.
Other emissions are blending values.

Fig. 6. NOx and VOC sensitivity to oxygen from methyl ethers

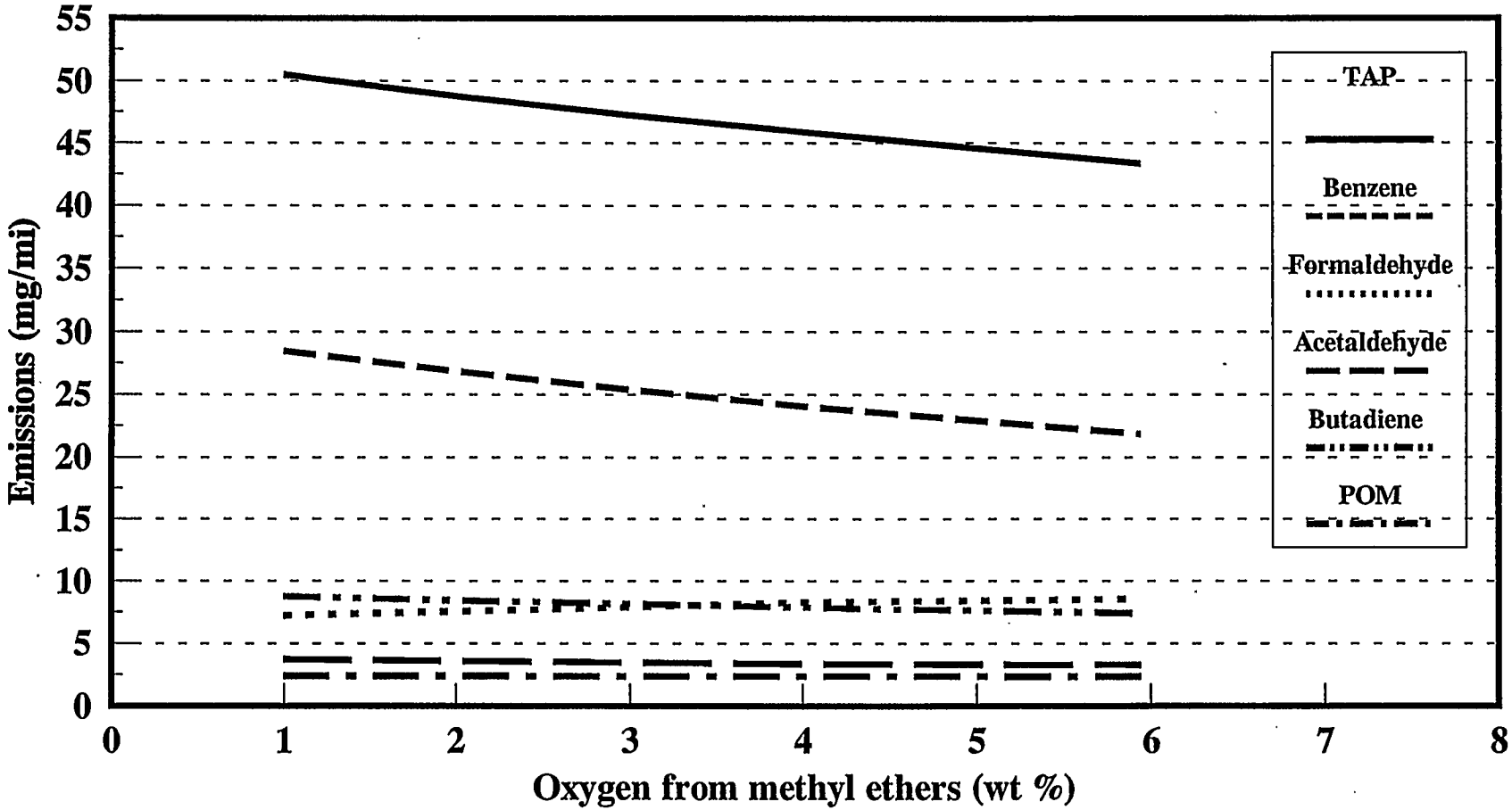
(PADD III, year 2010, Phase II summer)



Oxygen content is varied around case 6M.
Oxygen > 3.7% is outside valid range of Complex Model.

Fig. 7. Toxics emissions sensitivity to oxygen from methyl ethers

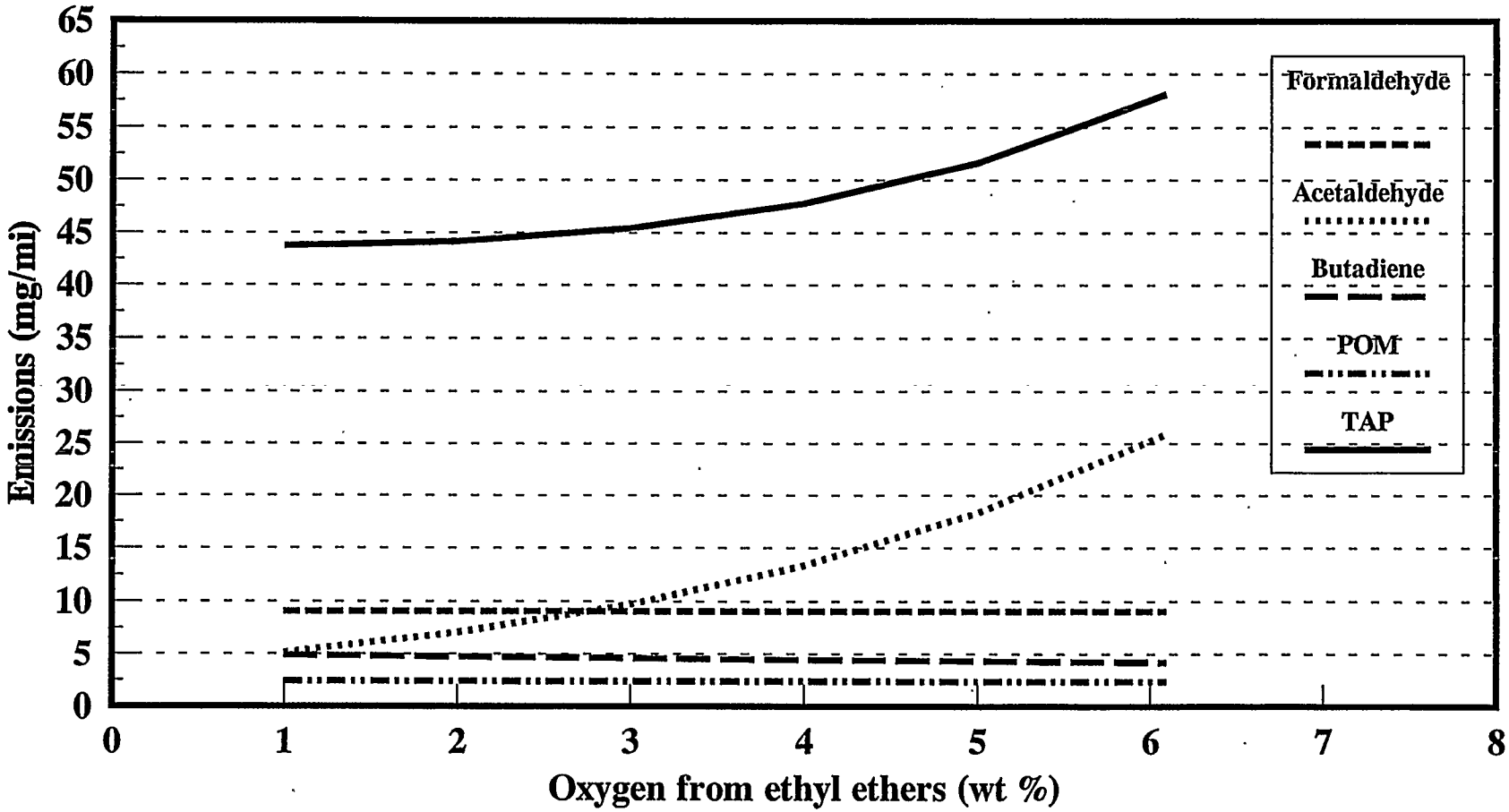
(PADD III, year 2010, Phase II summer)



Oxygen content is varied around case 6M.
Oxygen > 3.7% is outside valid range of Complex Model.

Fig. 8. Toxics emissions sensitivity to oxygen from ethyl ethers

(PADD III, year 2010, Phase II summer)



Oxygen content is varied around case 7E.
Oxygen > 3.7% is outside valid range of Complex Model.

Fig. 9. Refining cost increases for low petroleum gasoline (elastic prices)

PADD III, year 2010, Phase II summer

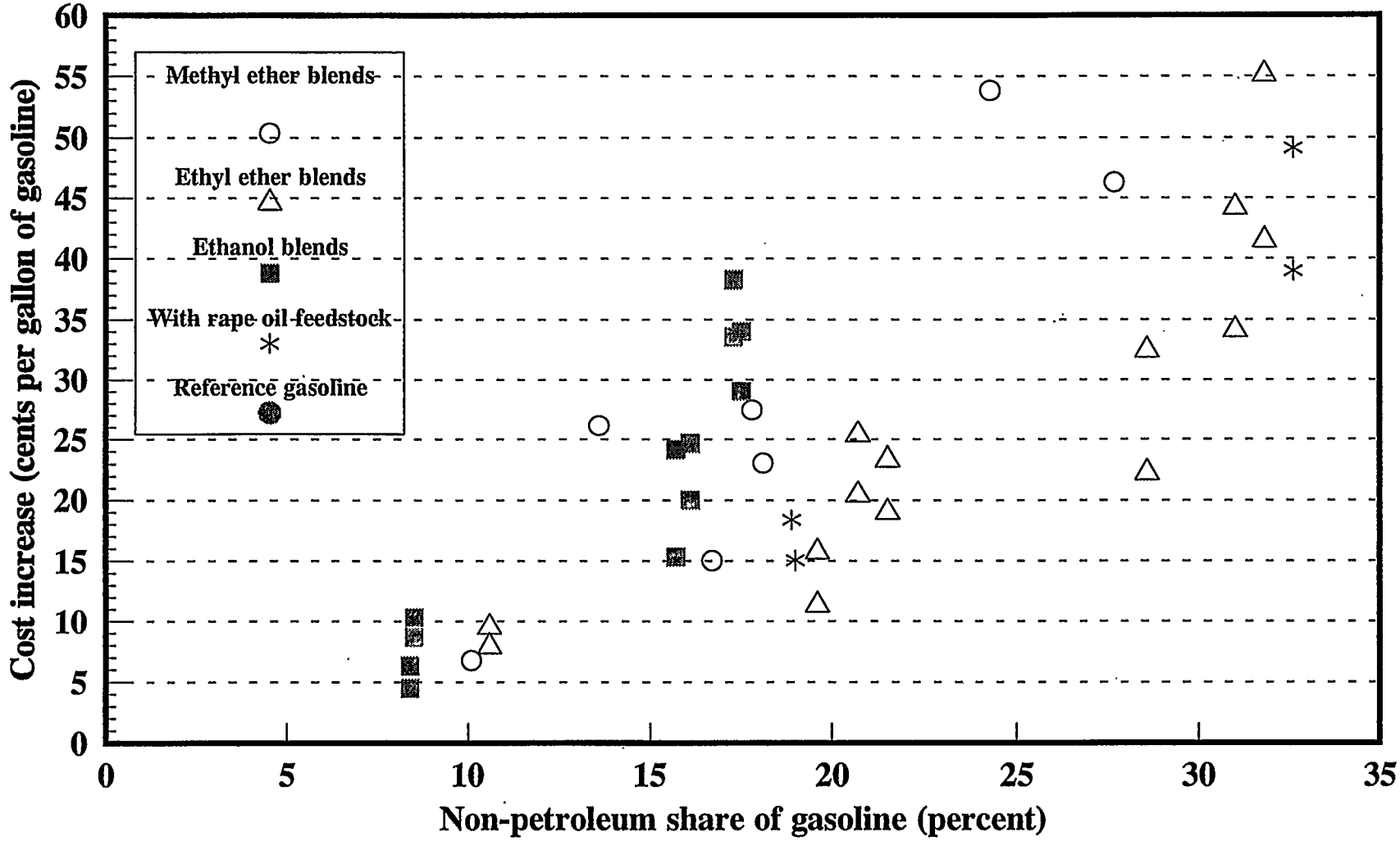
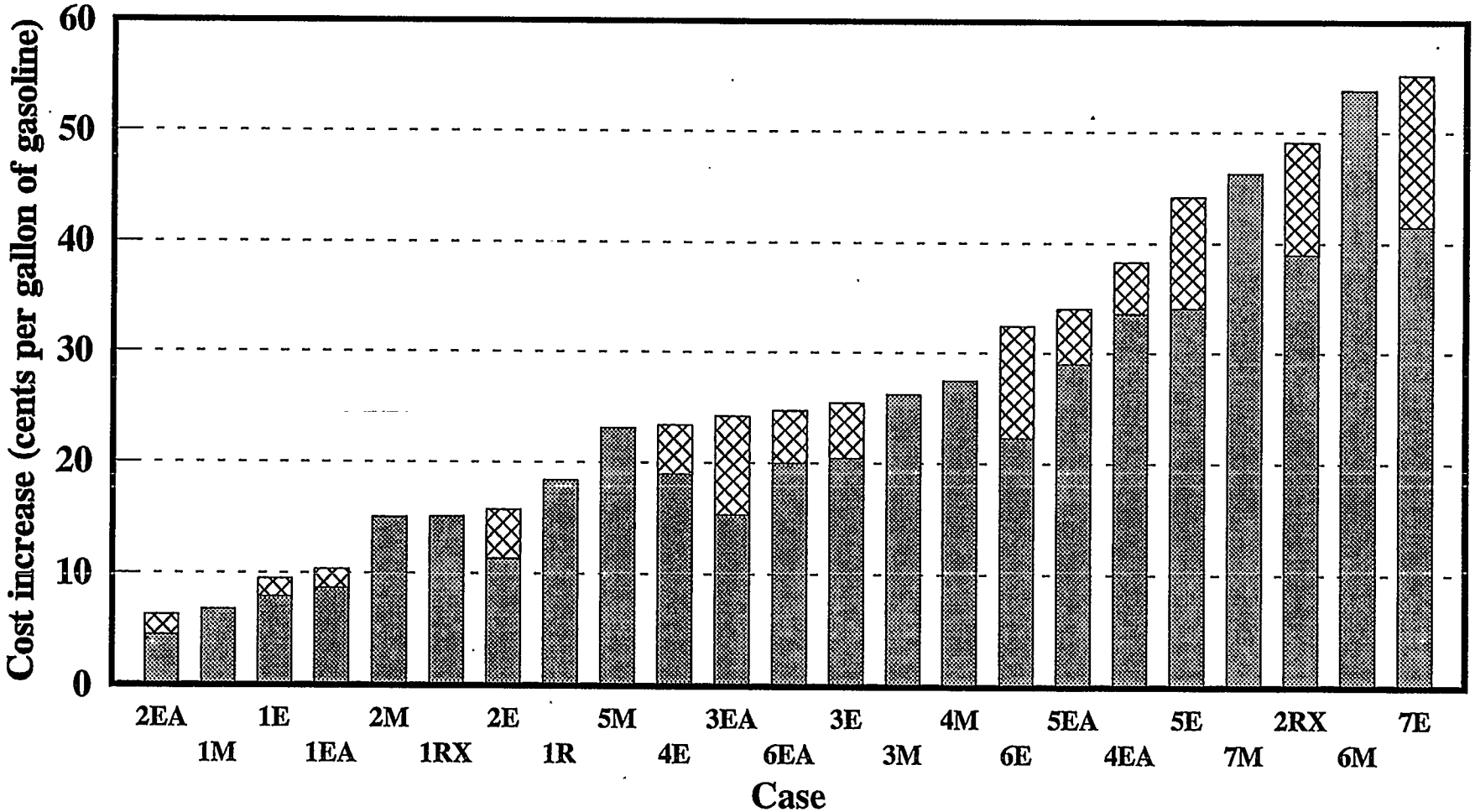


Fig. 10. Refining cost increase for low petroleum gasoline cases (elastic prices)

PADD III, year 2010, Phase II summer



Crosshatch shows cost increase range due to ethanol cost differences. Low end of range: cellulosic; high end of range: corn-derived.

SUPPLEMENT TO FIGURES

Ethanol summer case descriptions						
Case:	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%	2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%			3.5	3.5	3.5	3.5
Crude reduction target, vol%			10	15	15	10
Forced hydrogenation?	No	No	No	No	No	Yes
RFG VOC reduction, min%	30	24	30	30	30	30
CG RVP, max psi	7.9	7.9	7.9	7.9	8.7	7.9

Methyl ether summer case descriptions							
Case:	1M	2M	3M	4M	5M	6M	7M
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	3.5	6.0	6.0
Crude reduction target, vol%		10	10	15	10	10	10
Oxygenate imports allowed, vol%	43	43	0	43	43	43	71
Forced hydrogenation?	No	No	No	No	Yes	No	No

SUPPLEMENT TO FIGURES (Continued)

Ethyl ether summer case descriptions							
Case:	1E	2E	3E	4E	5E	6E	7E
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	6.0	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0	6.0
Crude reduction target, vol%		10	15	10	10	10	17
Oxygenate imports allowed, vol%	43	43	43	43	43	43	43
Forced hydrogenation?	No	No	No	Yes	No	No	No
Linear acetaldehyde emissions?	No	No	No	No	No	Yes	No

Rapeseed summer case descriptions					
Case:	2M	1R	1RX	5E	2RX
RFG oxygen target, wt%	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%	3.5	3.5	3.5	6.0	6.0
Ether type (M = methyl; E = ethyl)	M	M	M	E	E
Crude reduction target, vol%	10	10	10	10	10
Oxygenate imports allowed, vol%	43	43	43	43	43
Forced hydrogenation?	No	No	No	No	No
Rapeseed oil feed?	No	Yes	Yes	No	Yes
FCC naphtha (rapeseed derived) quality	NA	Low	Hig h	NA	High

SUPPLEMENT TO FIGURES (Continued)

Winter case descriptions			
Case:	EAW	MW	EW
RFG oxygen target, wt%	6.0	6.0	6.0
CG oxygen target, wt%	6.0	6.0	6.0
Oxygenate type	Ethanol	Methyl ethers	Ethyl ethers
Crude reduction target, vol%	10	10	10
Oxygenate imports allowed, vol%	100	66	70

Fig. 11. Non-petroleum share for low petroleum gasoline cases

PADD III, year 2010, Phase II summer

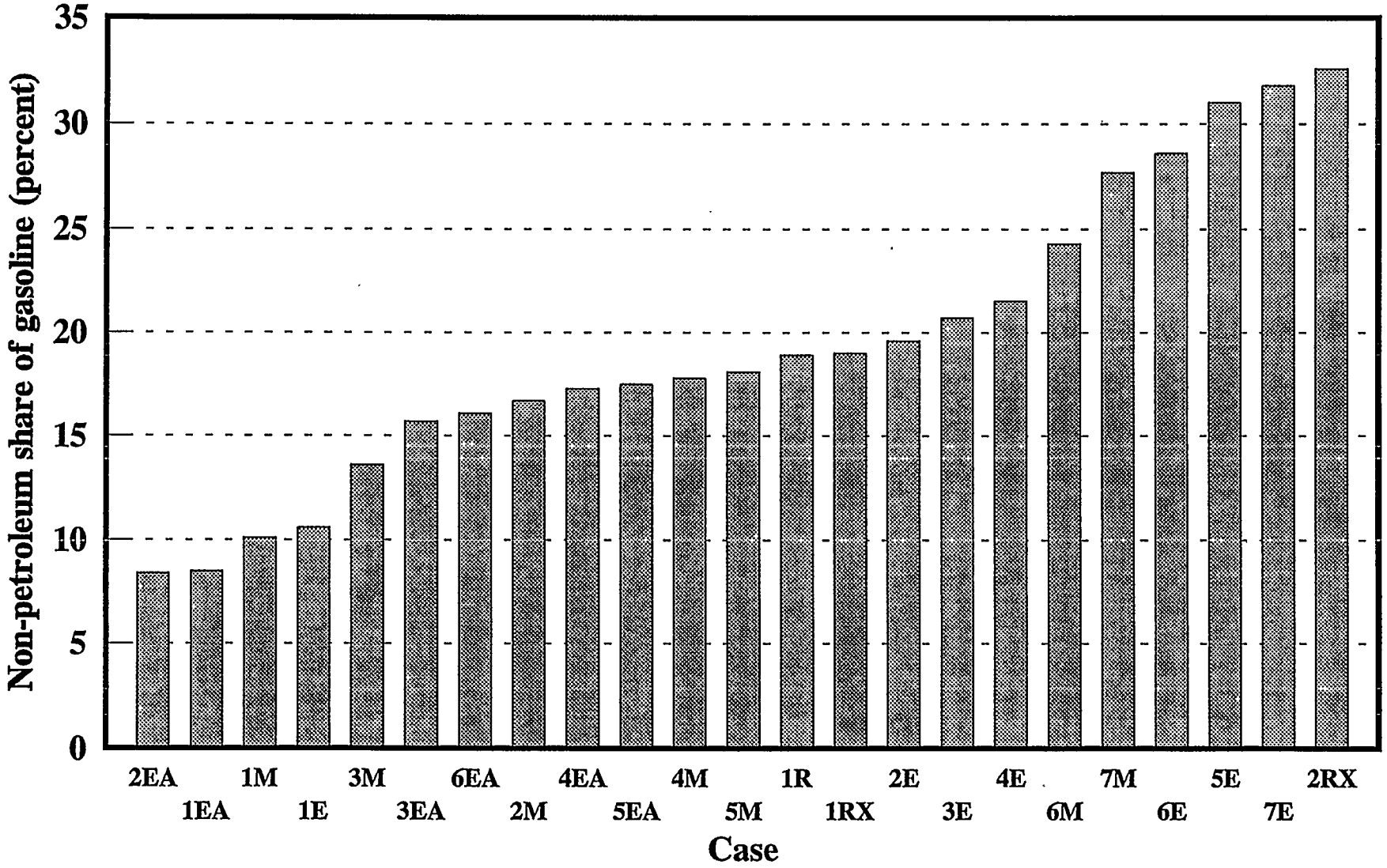


Fig. 12. Cost to reduce crude oil use in low petroleum gasoline policy (elastic prices)

PADD III, year 2010, Phase II summer

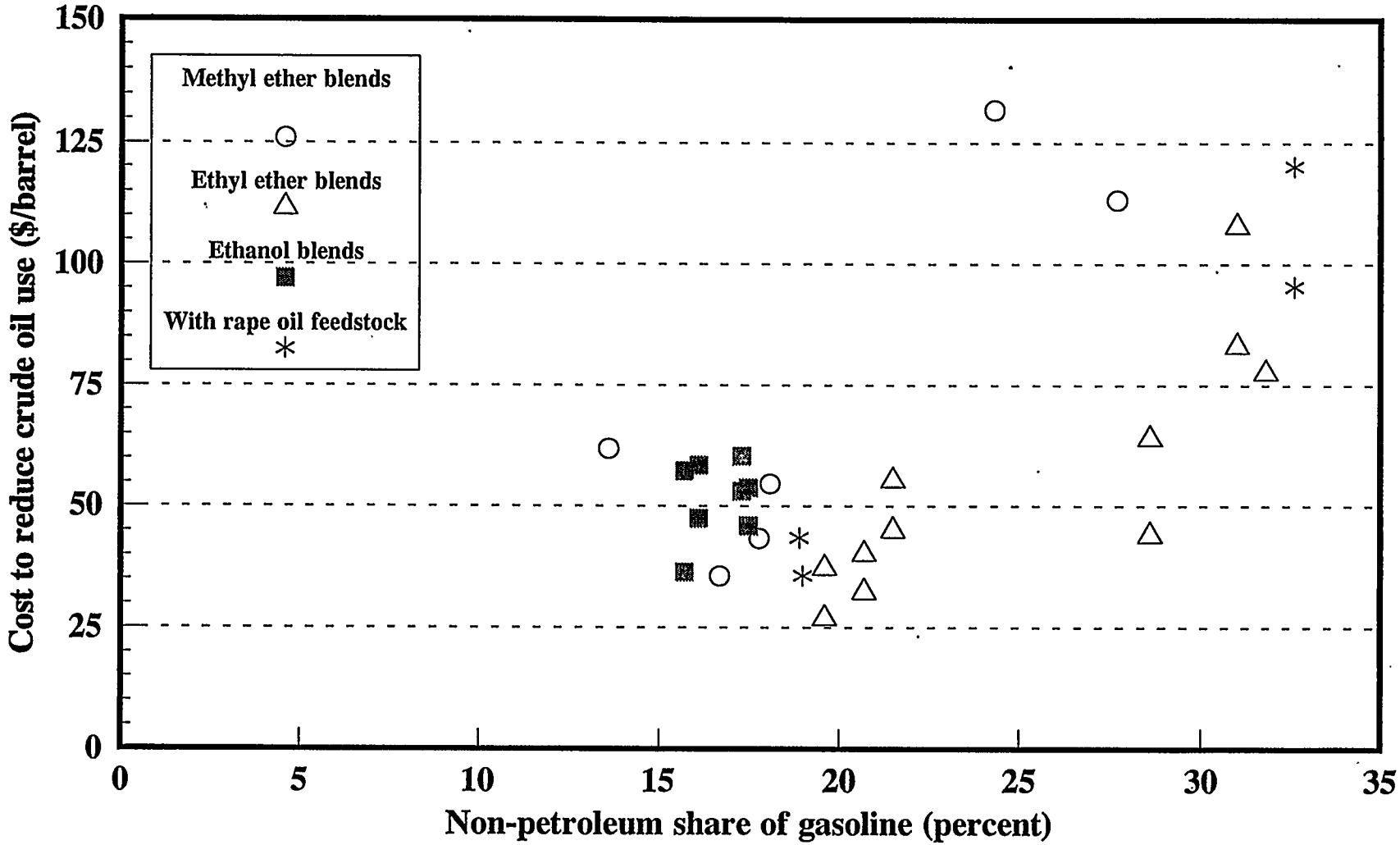
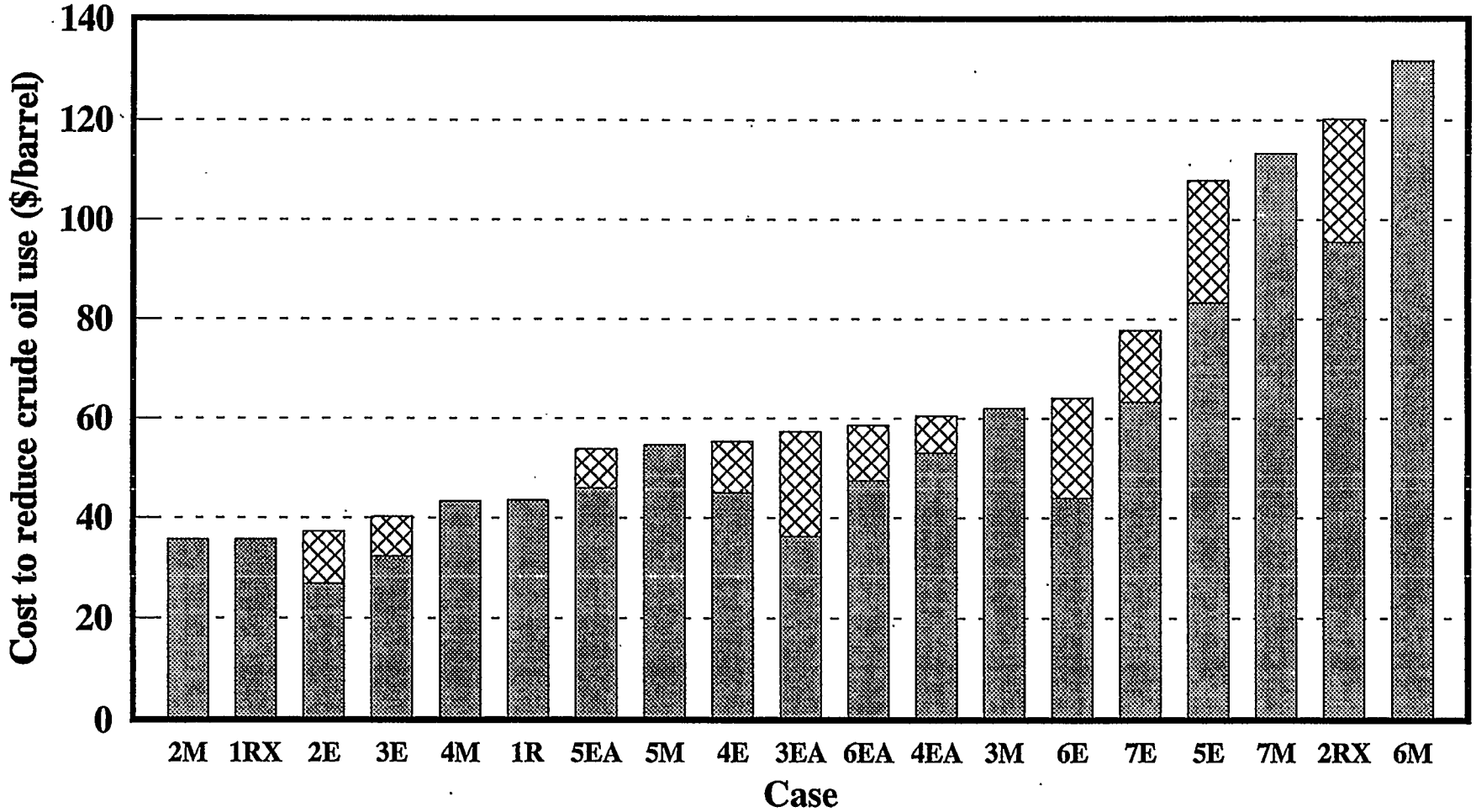


Fig. 13. Cost to reduce crude oil use in low petroleum gasoline cases (elastic prices)

PADD III, year 2010, Phase II summer



Crosshatch shows cost increase range due to ethanol cost differences. Low end of range: cellulosic; high end of range: corn-derived.

Fig. 14. Crude oil use reduction in low petroleum gasoline policy

(PADD III, year 2010, Phase II summer)

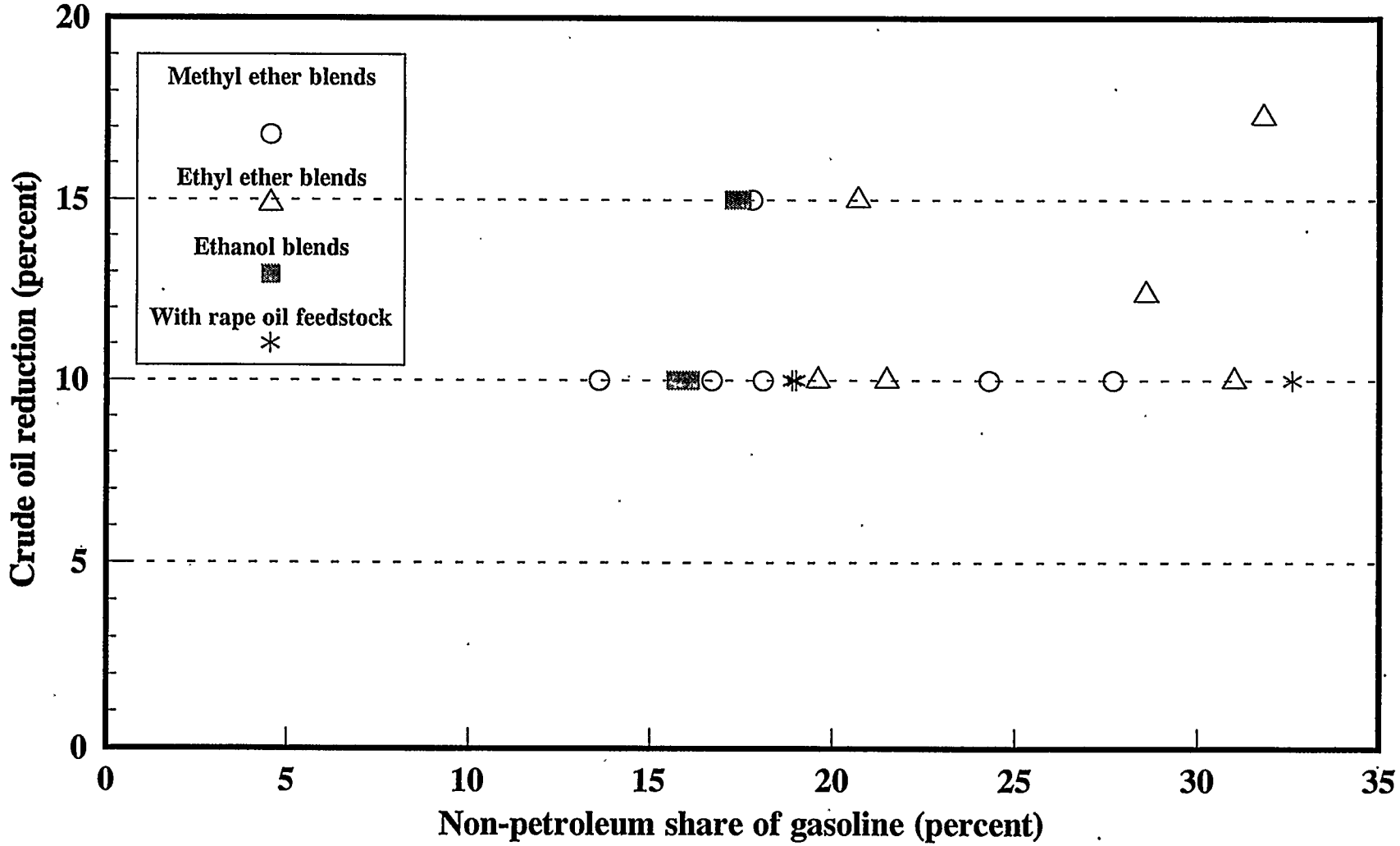


Fig. 15. Crude oil use reduction in low petroleum gasoline cases

PADD III, year 2010, Phase II summer

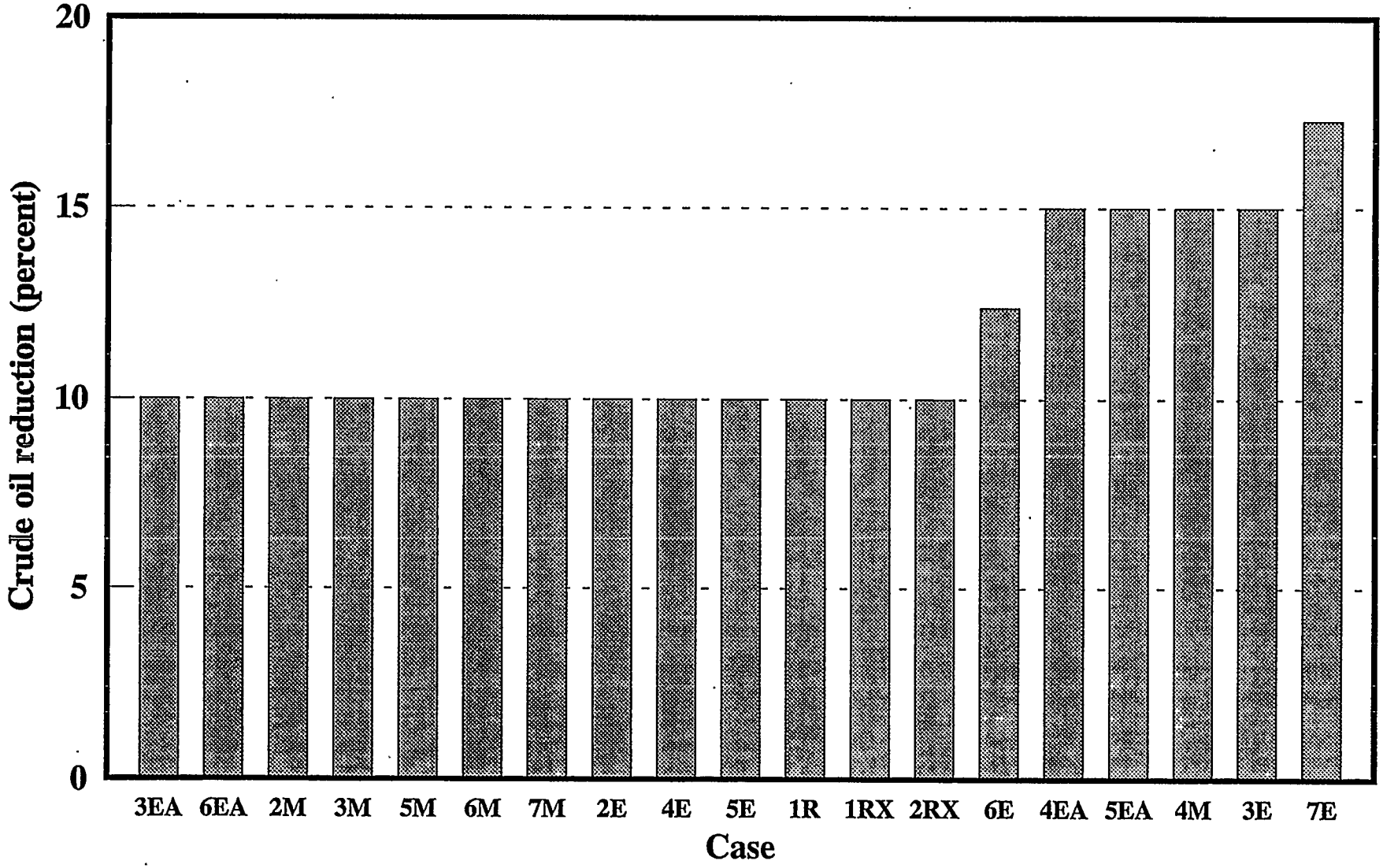
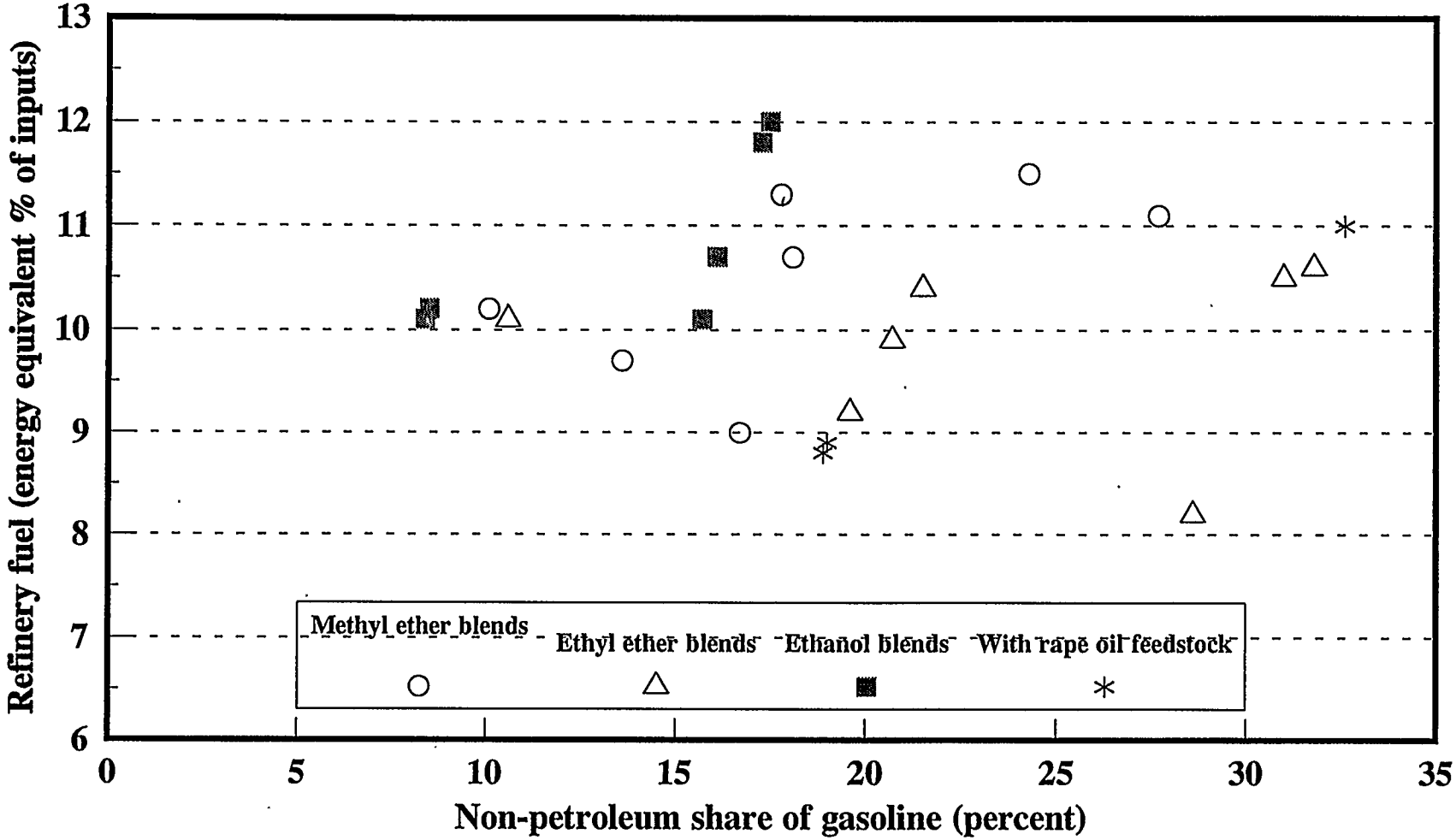


Fig. 16. Low petroleum refinery fuel use

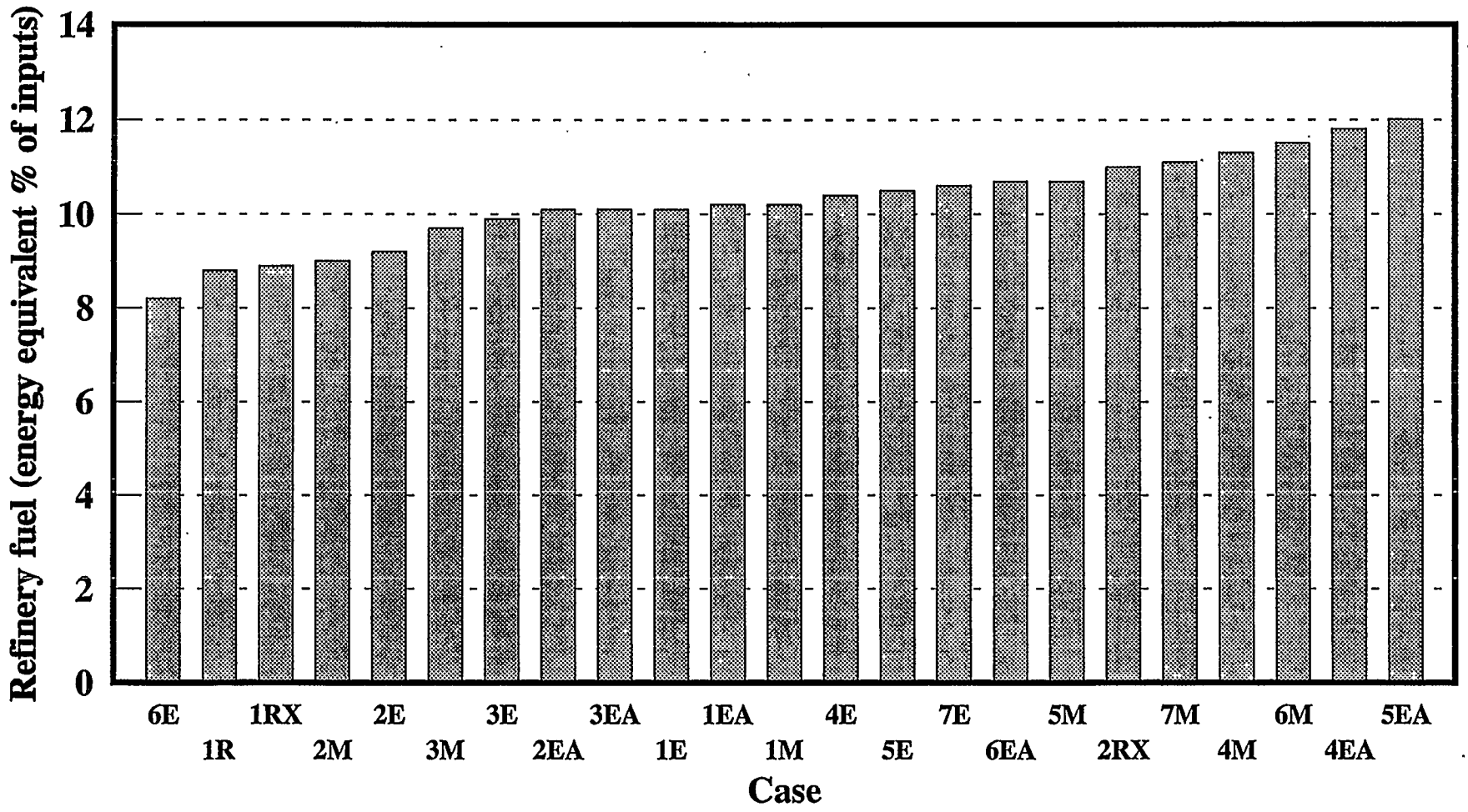
(PADD III, year 2010, Phase II summer)



Energy to produce methanol, ethanol, rapeseed oil, and purchased ethers not included in inputs.

Fig. 17. Refinery fuel use in low petroleum gasoline cases

PADD III, year 2010, Phase II summer



Energy to produce methanol, ethanol, rapeseed oil, and purchased ethers not included in inputs.

Fig. 18. Refinery investment for low petroleum gasoline policy

(PADD III, year 2010, Phase II summer)

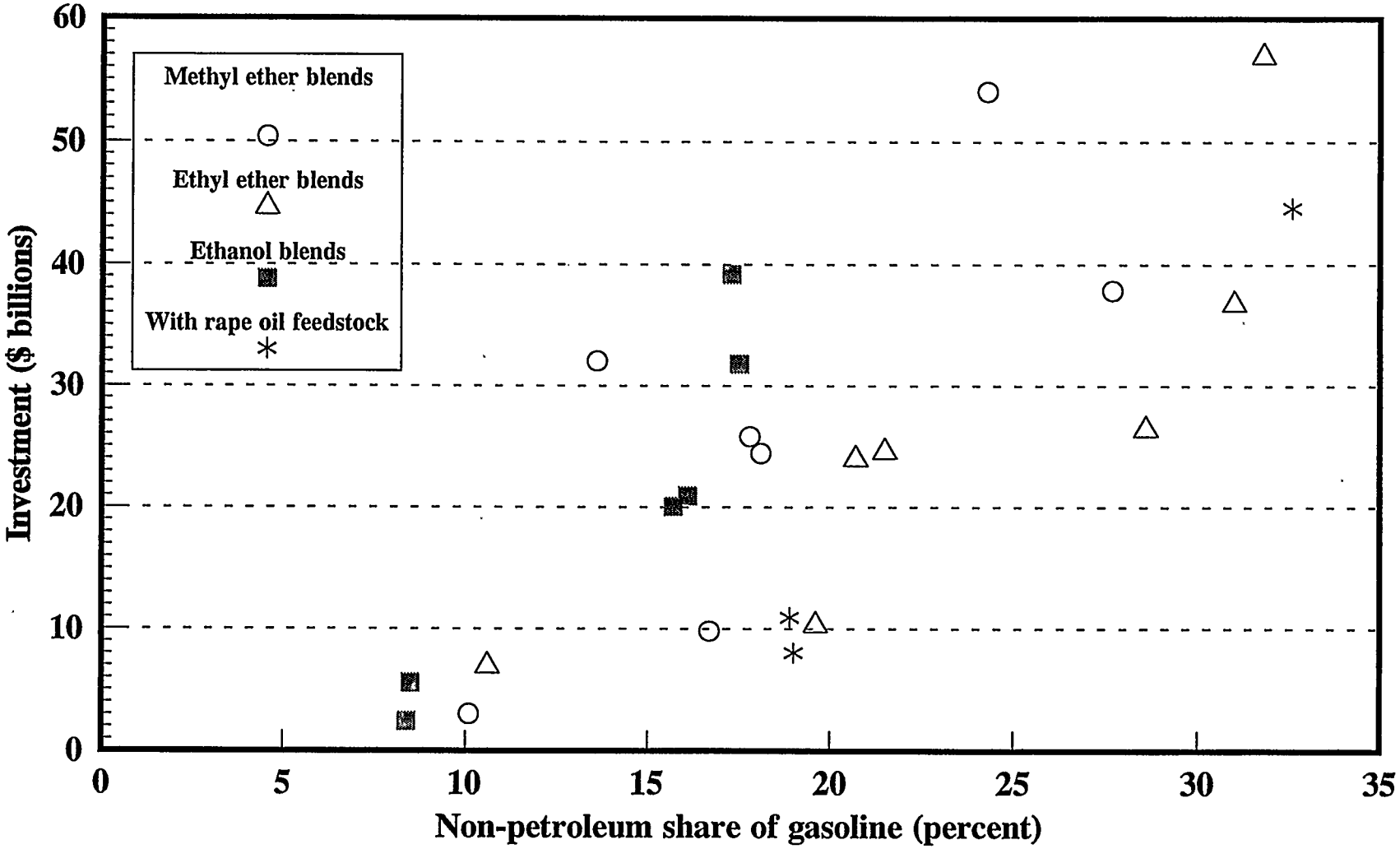


Fig. 19. Refinery investment in low petroleum gasoline cases

PADD III, year 2010, Phase II summer

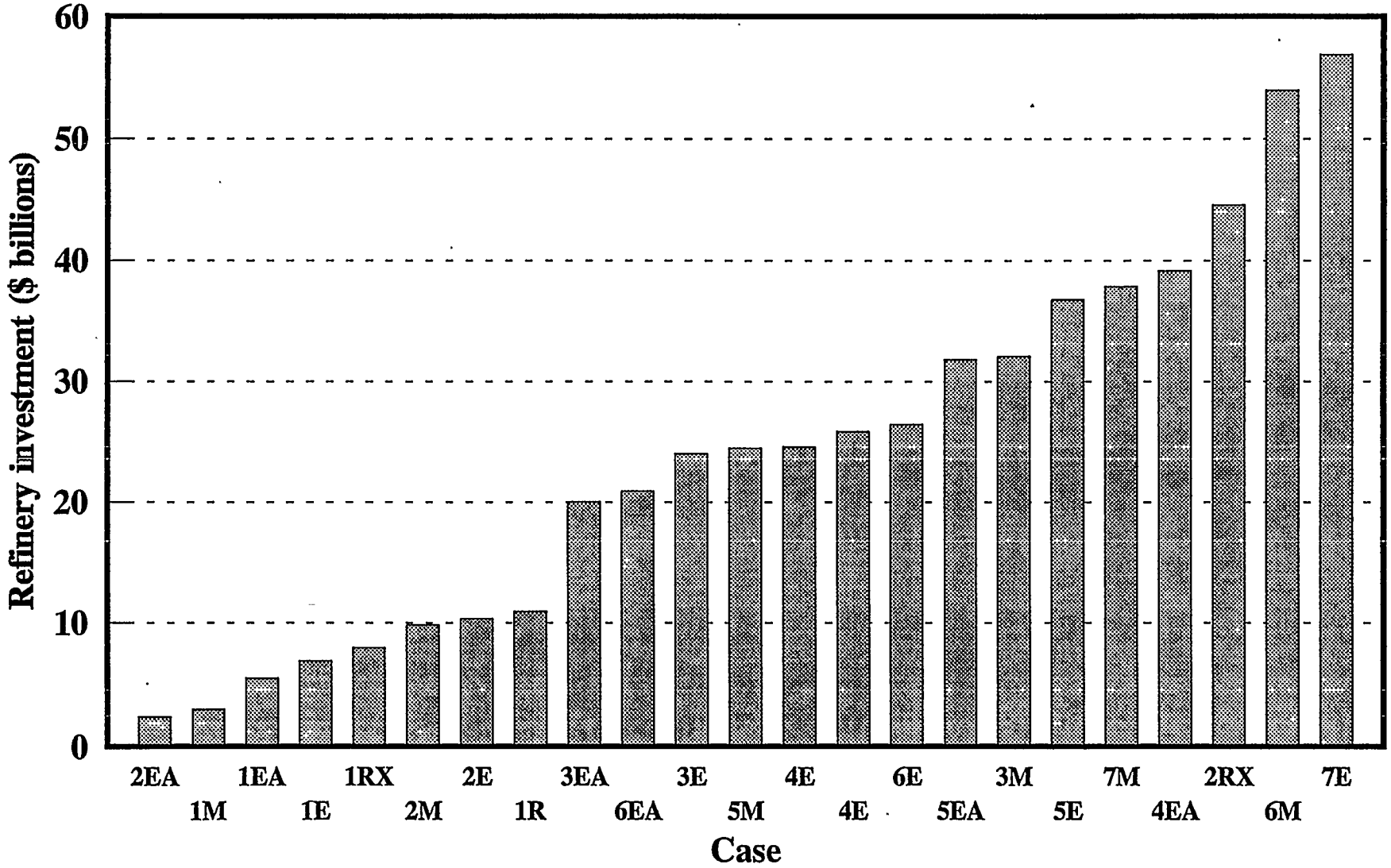
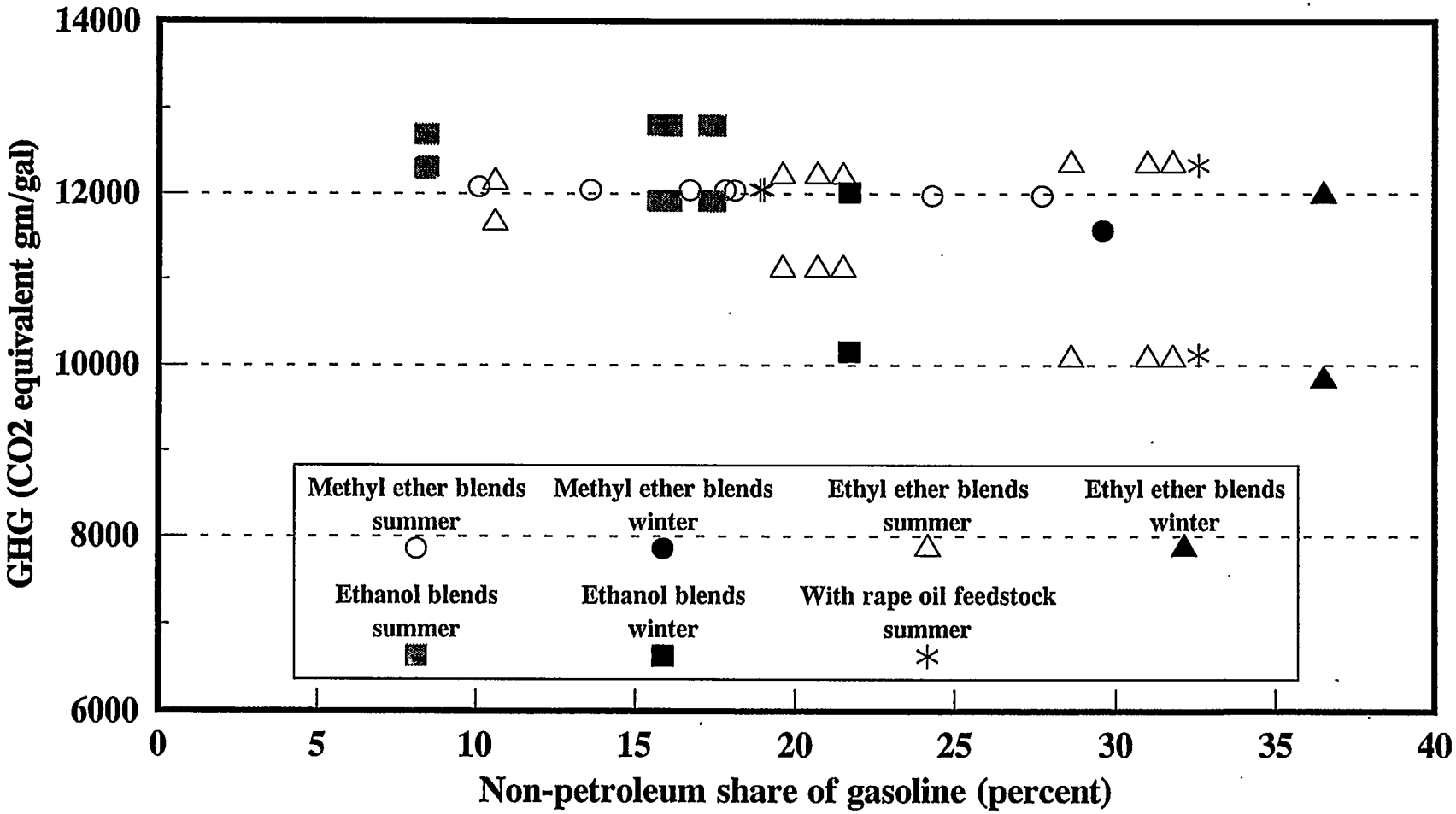


Fig. 20. Greenhouse gas emissons for low petroleum gasoline

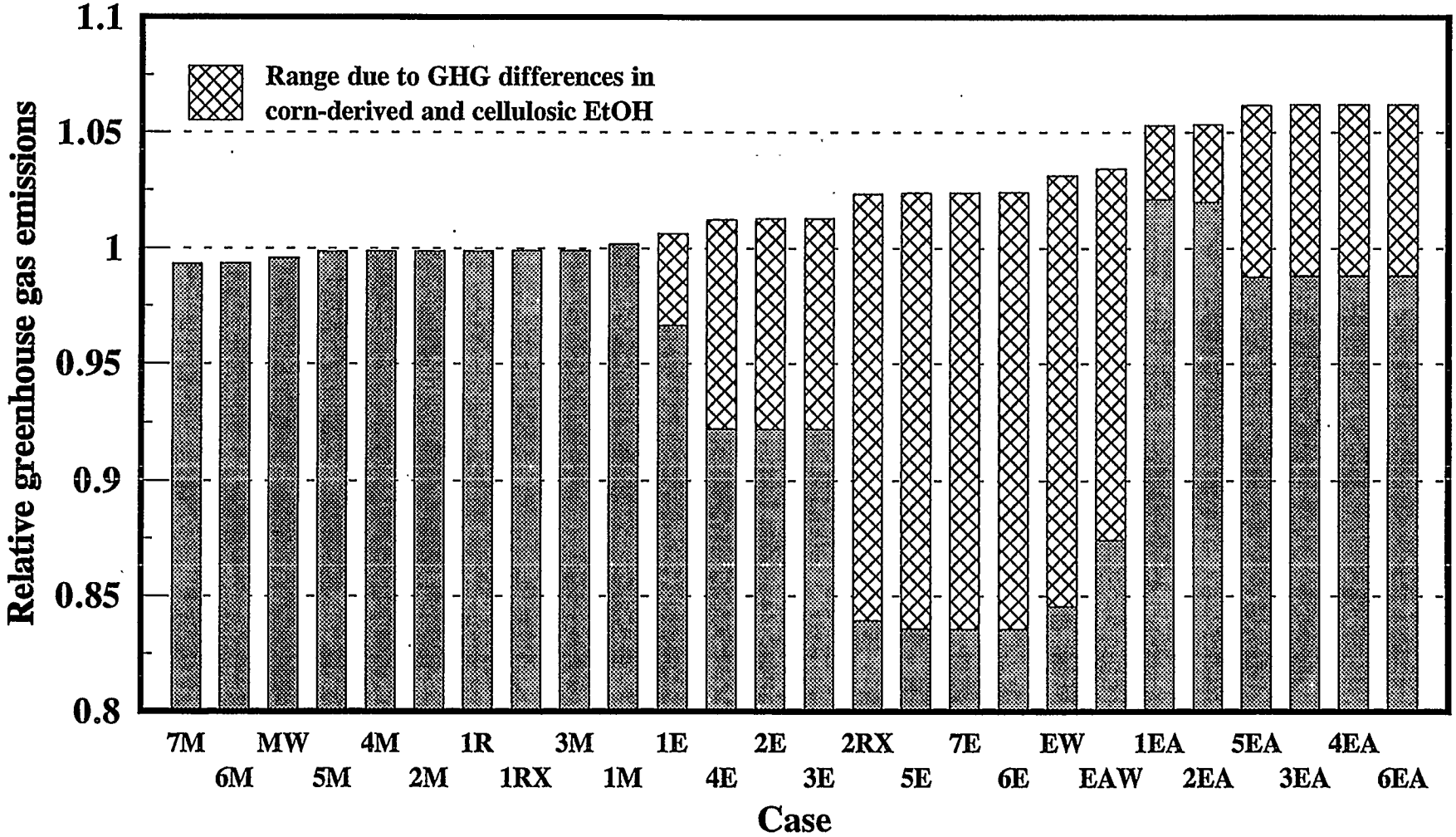
PADD III, year 2010, Phase II summer and winter



Emissions are for gasoline with energy equivalent to seasonal base case gasoline.

Fig. 21. Greenhouse gas emissions for low petroleum gasolines relative to base gasolines

PADD III, year 2010, Phase II summer and winter



Emissions are for gasoline with energy equivalent to seasonal base case gasoline.

Fig. 22. Cost increases for low petroleum gasoline, CG RVP max = 8.7 psi (elastic prices)

PADD III, year 2010, Phase II summer

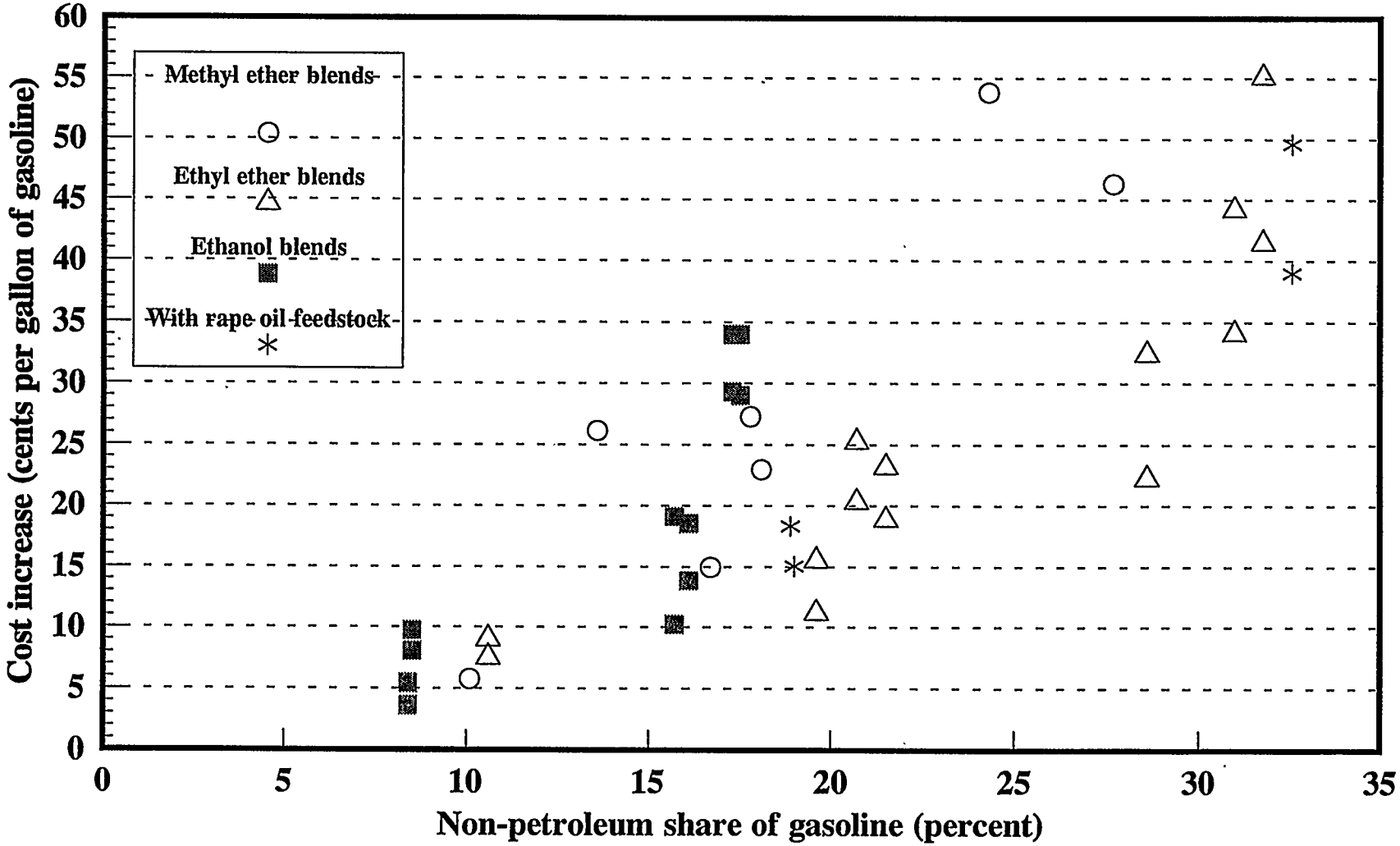
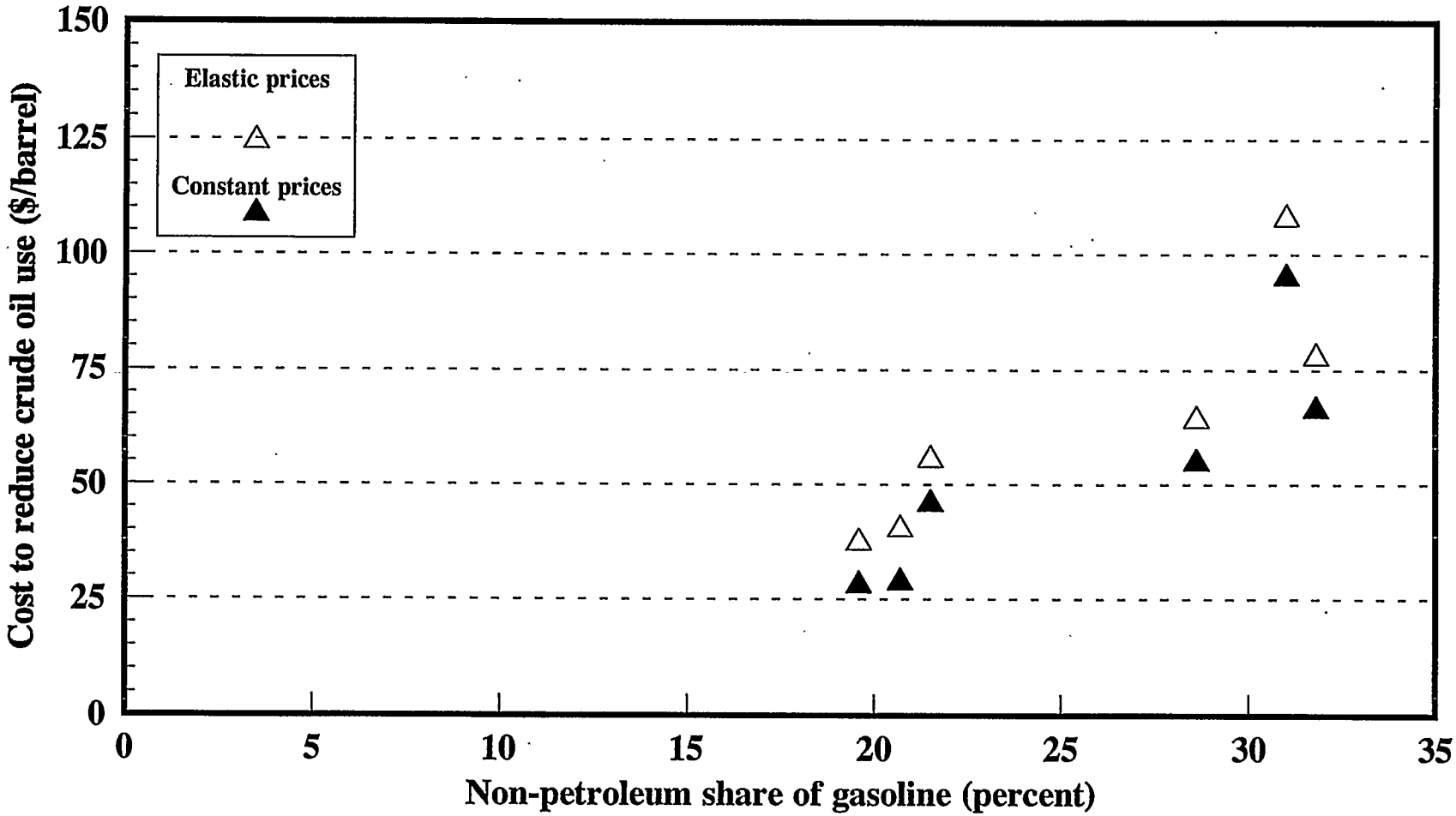


Fig. 23. Price elasticity effect on cost to reduce crude oil use in low petroleum gasoline

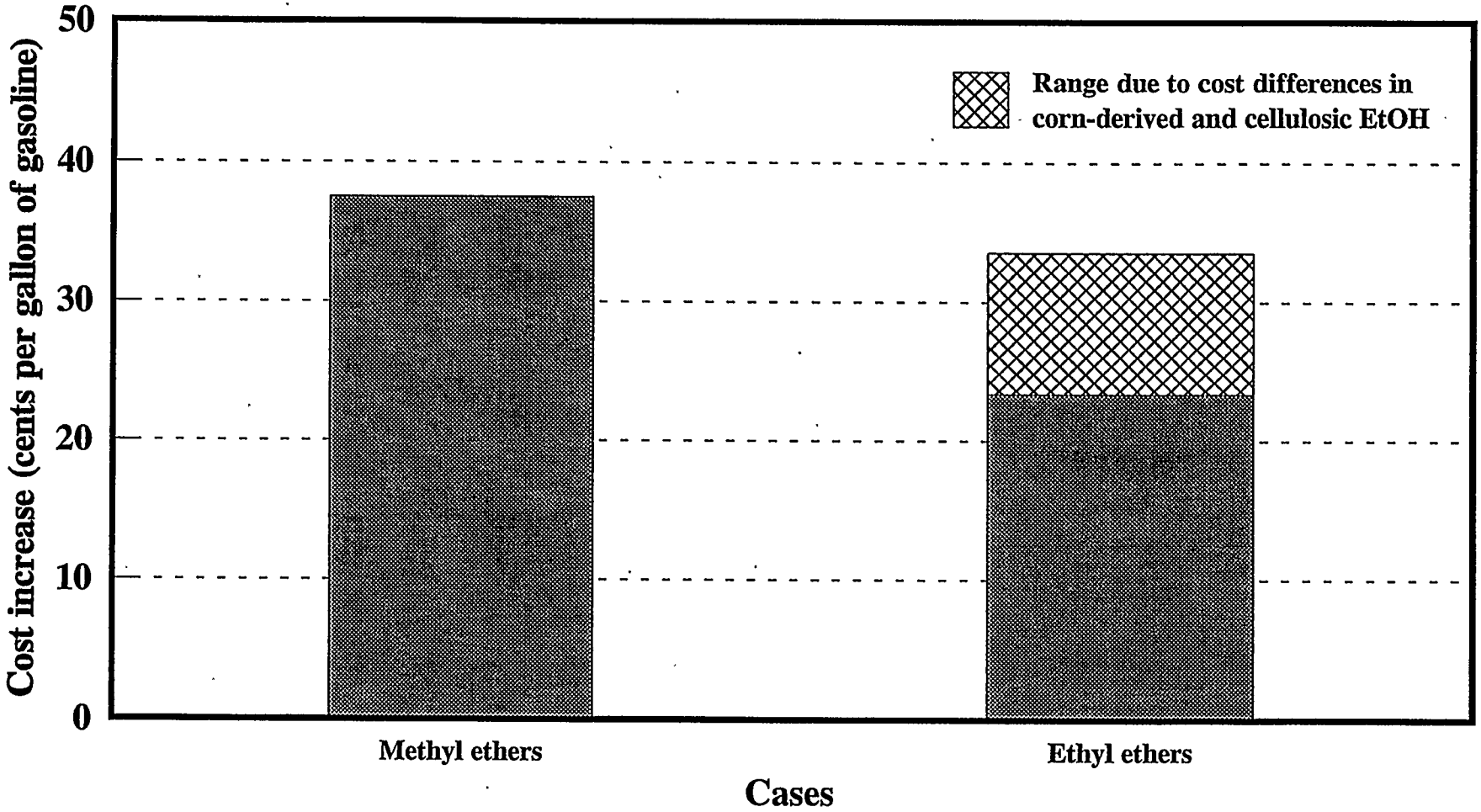
PADD III, year 2010, Phase II summer



Ethyl ether blends.
Corn-derived ethanol.

Fig. 24. Year-round refining cost increase for near-30 percent non-petroleum in gasoline

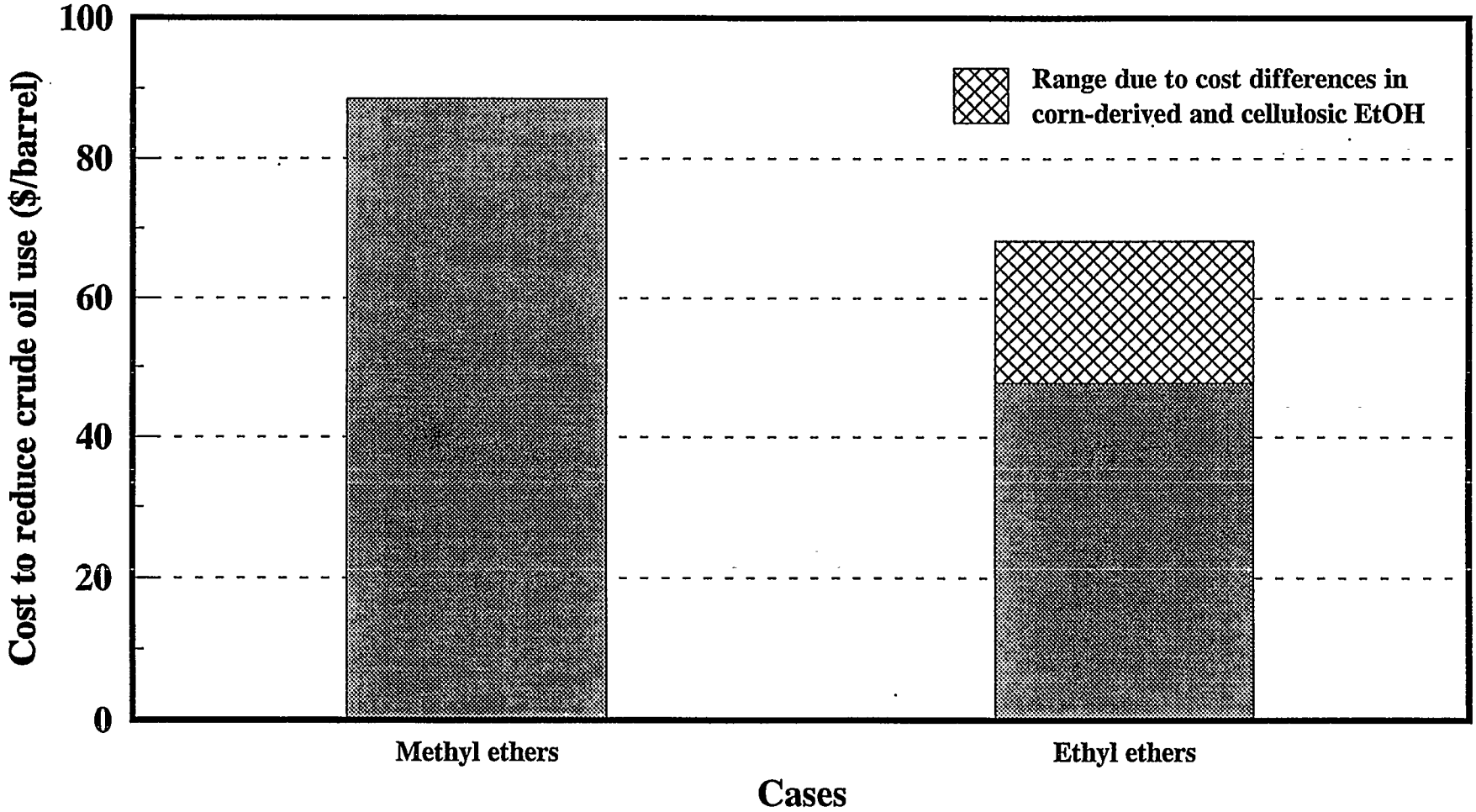
PADD III, year 2010



6.5 month winter season.
Methyl ethers: cases 7M and MW (29% non-pet).
Ethyl ethers: cases 5E and EW (34% non-pet).

Fig. 25. Year-round cost to reduce crude oil use for near-30 percent non-petroleum in gasoline

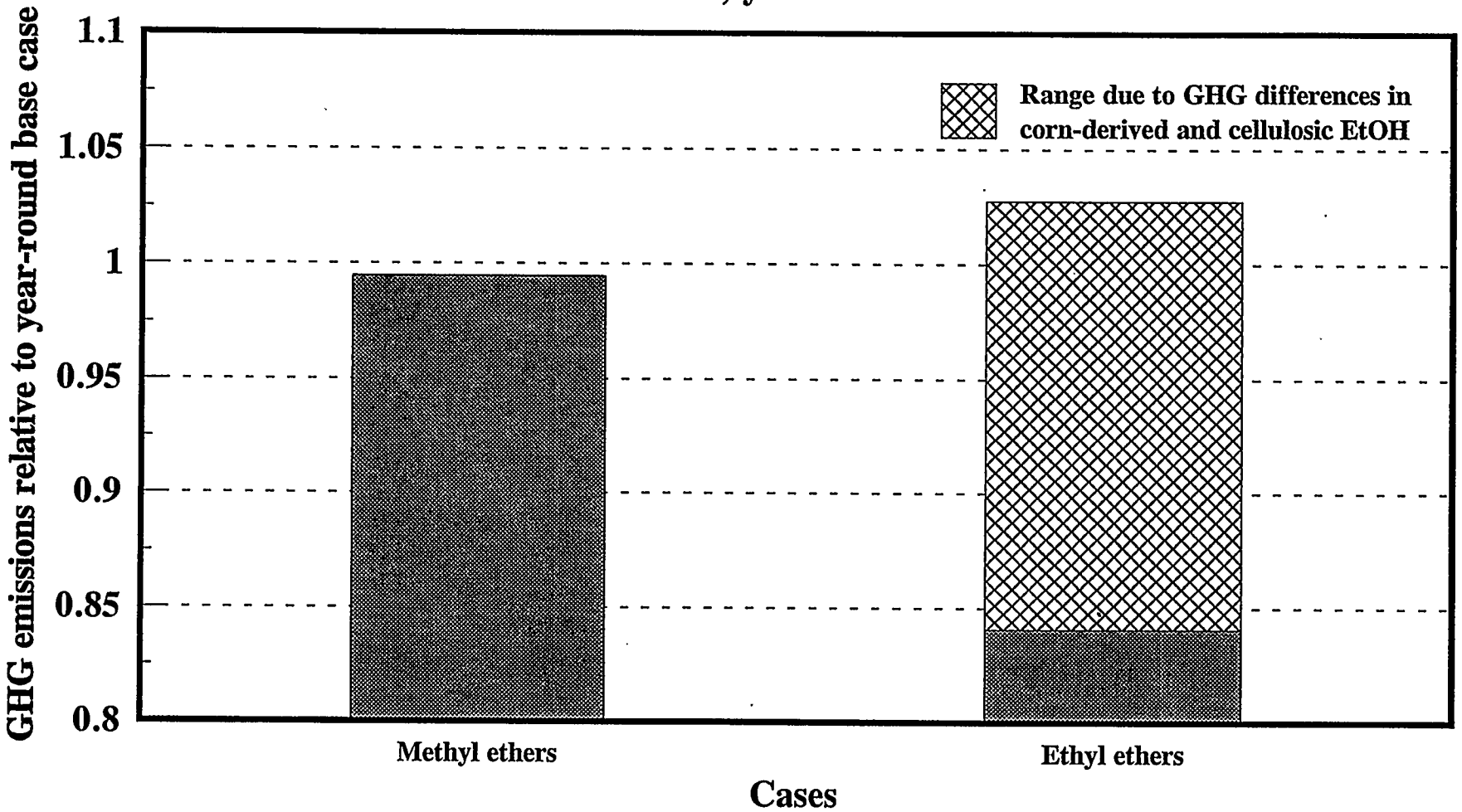
PADD III, year 2010



6.5 month winter season.
Methyl ethers: cases 7M and MW (29% non-pet).
Ethyl ethers: cases 5E and EW (34% non-pet).

Fig. 26. Year-round relative greenhouse gases for near-30 percent non-petroleum in gasoline

PADD III, year 2010



6.5 month winter season.
Methyl ethers: cases 7M and MW (29% non-pet).
Ethyl ethers: cases 5E and EW (34% non-pet).

APPENDIX A
RAW MATERIAL SUPPLY CURVE ESTIMATION

The crude oil supply curve for PADD III (Fig. 1)

The crude oil supply base is assumed to be global, at 60,000 MBD. The projected world reference price for crude oil in the year 2010 is $26.49/barrel (1990 dollars).

The crude oil supply elasticity is assumed to be 0.3. Assume that

$\ln(Q) = \text{elasticity}*\ln(P) + C$, where Q is global supply and P is the world reference price.

Then,

$\ln(60000) = .3*\ln(26.49) + C,$

and $C = 10.019.$

The desired supply curve is for PADD III refineries. The assumed reference supply conditions are Q3 = 6070 MBD for PADD III refineries. Assume the low petroleum program effects in PADD III refineries are proportional to effects in all other PADDs. The reference supply condition for refineries in all PADDs is 13411 MBD. To scale the crude effect from PADD III to refineries in all PADDs, use $Q3*13411/6070 = 2.209*Q3$.

Let Q = crude supply for non-US refinery uses + supply for US refinery uses. Then

$Q = (60000 - 13411) + 2.209*Q3.$

$Q = 46589 + 2.209*Q3.$

The PADD III crude slate for year 2010 is relatively heavy, high sulfur crude, with a weighted reference price of P3 = $25.16/barrel. Then, the reference price for world oil is P3 + $1.33, and the supply curve becomes

$\ln(46589 + 2.209*Q3) = .3*\ln(P3+1.33) + 10.019.$

The natural gas supply curve for PADD III (Fig. 2)

The natural gas supply base supply base for the US is assumed to be the US, Canada, and Mexico.

Assume that US consumption is 85 percent of supply. Therefore the supply Q = 66301 MMSCFD/.85 = 78001 MMSCFD. The year 2010 reference price for dry natural gas is assumed to be $3.17/MCF, derived from raw material price relationships reported by the National Petroleum Council.

The natural gas supply elasticity is assumed to be 0.3. Assume that

ln(Q) = elasticity*ln(P) + C, where Q is supply and P is the reference price for dry natural gas.

Then,

ln (78001) = .3*ln(3.17) + C,

and C = 10.918.

The desired supply curve is for PADD III refineries. Assume the reference supply conditions are Q3 = 1317 MMSCFD for PADD III refineries. Assume the low petroleum program effects in PADD III refineries are proportional to effects in all other PADDs. The reference supply condition for refineries in all PADDs is 1935 MMSCFD. To scale the natural gas effect from PADD III to refineries in all PADDs, use Q3*1935/1317 = 1.47*Q3.

Let Q = supply for non-refinery uses + supply for refinery uses. Then

Q = (78001 - 1935) + 1.47*Q3.

Q = 76066 + 1.47*Q3.

The price P3 of gas to PADD III refineries is the dry gas reference price P, with a regional refinery price adjustment of +$0.437/MCF. Then, the reference price is P = P3 + $.437/MCF, and the supply curve becomes

ln(76066 + 1.47*Q3) = .3*ln(P3 -0.437) + 10.918.

The corn-derived ethanol supply curve for PADD III (Fig. 3)

The feedstock component of the price for corn-derived fuel ethanol is reported in "Estimation of Supply Curve for Ethanol with Corn as the Feedstock." In this report, the average elasticity for the year 2005 and 2015 ethanol feedstock curves is 4.35. Assume in the base case that the feedstock component is $0.30/gallon or $12.6/barrel. Assume that the base price of ethanol, with credit for the federal subsidy, is $29.98 per barrel. Assume in the base case, 80 percent of ethanol production capacity is used = 72 MBD.

Assume that only the feedstock component is price sensitive. Assume that

$\ln(Q) = \text{elasticity}*\ln(P) + C$, where Q is supply and P is the price.

Then,

$\ln(72) = 4.35*\ln(12.6) + C$,

and $C = -6.7449$

Assume regional supply of fuel ethanol is proportional to regional gasoline production. Then $Q = 2.25*Q3$, where Q3 is supply of fuel ethanol for PADD III. The fuel ethanol price P3 includes the non-feedstock price component, so the feedstock price = P3 - 17.38. The supply curve becomes

$\ln(2.25*Q3) = 4.35*\ln(P3-17.38) - 6.7449$.

The supply curve for cellulosic ethanol

The price of cellulosic ethanol is the sum of (1) the feedstock cost from the nearly flat supply curve presented in Figure 2-6 of reference 51, (2) the cost of manufacturing conversion from the same report, with (3) credit for the federal subsidy. Over the range of cases in the low petroleum study, the cellulosic ethanol price is in the range of $16.24 to $16.88 per barrel.

APPENDIX B
BLENDSTOCKS, PROPERTIES, PROCESS INVESTMENTS, AND FUEL USE FOR SUMMER GASOLINE PRODUCTION

Table B-1.
PADD III base case blendstocks for year 2010 summer

Blendstock	Percent
Butane	1.7
Reformate	30.4
Straight run naphtha	1.2
C5+ isomerate	2.9
FCC naphtha	34.4
Coker naphtha	1.4
Hydrocrackate	7.1
Alkylate	14.4
Polymer gasolines	1.0
Dimate	0.1
MTBE	1.2
Toluene/xylene	1.3
Natural gasoline	0.8
Pyrolysis gasoline	
Raffinates	1.3
Other	2.1

Table B-2. PADD III base case gasoline properties for the year 2010 summer	
Octane, (R+M)/2	88.7
RVP, psi	7.9
Aromatics, vol%	32.4
Benzene, vol%	2.05
Olefins, vol%	11.4
Sulfur, ppm	409
E200, %	46.0
E300, %	82.9
Specific gravity	.7434
Summer TAP, mg/mi	87.1
NOx, mg/mi	1378
VOC, mg/mi	1270
GHG, CO_2 equivalent gm/gal	12053

Table B-3.
RFG blendstocks in PADD III for the year 2010 summer:
Ethanol blends

RFG minimum emissions reduction %: VOC 30; summer TAP 26.5; NOx 7.8
RFG production share = 62%

Case:	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%	2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%			3.5	3.5	3.5	3.5
Crude reduction target, vol%			10	15	15	10
Forced hydrogenation?	No	No	No	No	No	Yes
RFG VOC reduction, min%	30	24	30	30	30	30
CG RVP, max psi	7.9	7.9	7.9	7.9	8.7	7.9
Blendstocks, vol%:						
Butane	1.5	1.5	1.5	1.5	1.5	1.5
Reformate	35.8	26.7	36.0	33.8	34.8	37.4
Straight run naphtha	2.0	2.4	0.9	0.6		0.5
C5+ isomerate	3.9	4.6	7.3	8.4	7.0	7.5
FCC naphtha	7.9	21.2	0.6	1.7	1.7	1.4
Coker naphtha						
Hydrocrackate	10.0	7.8	8.4	10.1	13.6	10.2
Alkylate	12.2	13.9	18.5	22.4	24.0	17.9
Polymer gasolines	4.6	8.0	7.3	5.0	4.8	6.3
Dimate	6.1	0.2	4.6	2.9		2.1
Toluene/xylene	4.4	4.0	0.3			0.3
Natural gasoline						
Pyrolysis gasoline						
Raffinates	4.0	3.4	4.1	4.1	3.2	4.7
Other	1.7	0.1	2.8	1.8	1.6	2.5
Ethanol	6.0	6.1	7.8	7.8	7.8	7.8

Table B-4.
CG blendstocks in PADD III for the year 2010 summer:
Ethanol blends

Case:	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%	2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%			3.5	3.5	3.5	3.5
Crude reduction target, vol%			10	15	15	10
Forced hydrogenation?	No	No	No	No	No	Yes
RFG VOC reduction, min	30	24	30	30	30	30
CG RVP, max psi	7.9	7.9	7.9	7.9	8.7	7.9
Blendstocks, vol%:						
Butane	1.5	1.5	1.5	1.5	1.5	1.5
Reformate	22.2	24.7	25.6	29.9	30.8	25.6
Straight run naphtha	2.3	3.2	10.5	8.4	9.4	10.5
C5+ isomerate	3.2					
FCC naphtha	43.2	43.5	24.9	17.4	17.9	24.9
Coker naphtha				2.0	2.0	
Hydrocrackate		8.3	13.4	17.9	13.0	13.4
Alkylate	18.4	16.3	10.4	10.6	5.0	10.4
Polymer gasolines			3.6	1.8	9.7	3.6
Dimate						
Toluene/xylene				0.4	0.6	
Natural gasoline						
Pyrolysis gasoline						
Raffinates	2.5	1.8				
Other	6.8					
Ethanol		0.6	10.1	10.1	10.1	10.1

Table B-5.
PADD III RFG properties for the year 2010 summer:
Ethanol blends

RFG minimum emissions reduction %: VOC 30; summer TAP 26.5; NOx 7.8
RFG production share = 62%

Case:	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%	2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%			3.5	3.5	3.5	3.5
Crude reduction target, vol%			10	15	15	10
Forced hydrogenation?	No	No	No	No	No	Yes
RFG VOC reduction, min%	30	24	30	30	30	30
CG RVP, max psi	7.9	7.9	7.9	7.9	8.7	7.9
Properties:						
Octane, (R+M)/2	89.0	88.8	89.2	89.5	89.6	89.3
RVP, psi	6.8	7.4	6.9	6.8	6.8	6.8
Aromatics, vol%	27.9	26.7	22.6	21.8	21.0	23.9
Benzene, vol%	0.90	0.90	0.90	0.90	0.90	0.90
Olefins, vol%	14.9	12.3	14.9	10.3	7.0	11.4
Sulfur, ppm	56	96	43	44	44	45
E200, %	49.9	49.9	49.9	49.9	49.9	49.9
E300, %	88.6	87.5	89.3	89.3	89.5	89.3
Oxygen, wt%	2.21	2.24	2.73	2.89	2.90	2.87
Specific gravity	.7538	.7464	.7447	.7425	.7423	.7470
Summer TAP, mg/mi	57.6	57.8	58.2	54.0	53.5	55.0
NOx, mg/mi	1234	1236[a]	1235	1170	1153	1185
VOC, mg/mi	1006	1093	1008	1006	1007	1005
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	13084[b]	13083	13115	13115	13112	13115
	12459[c]	12456	12307	12307	12307	12307

[a]Underlined emissions are binding constraints
[b]Entry above dashed line is for corn-derived ethanol
[c]Entry below dashed line is for cellulosic ethanol

Table B-6.
PADD III CG properties for the year 2010 summer:
Ethanol blends

Case:	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%	2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%			3.5	3.5	3.5	3.5
Crude reduction target, vol%			10	15	15	10
Forced hydrogenation?	No	No	No	No	No	Yes
RFG VOC reduction, min%	30	24	30	30	30	30
CG RVP, max psi	7.9	7.9	7.9	7.9	8.7	7.9
Properties:						
Octane, (R+M)/2	88.6	88.6	88.6	89.0	88.6	88.6
RVP, psi	7.9	7.9	7.9	7.9	8.7	7.9
Aromatics, vol%	32.8	32.7	32.7	32.4	31.8	32.8
Benzene, vol%	1.60	1.60	1.50	1.51	2.08	1.55
Olefins, vol%	8.2	9.1	7.6	5.1	13.6	7.9
Sulfur, ppm	360	356	337	177	199	230
E200, %	47.0	43.1	49.9	49.9	49.9	49.9
E300, %	81.6	81.3	88.2	89.0	89.0	88.6
Oxygen, wt%	0.00	0.23	3.66	3.66	3.68	3.66
Specific gravity	.7422	.7440	.7587	.7587	.7574	.7587
Summer TAP, mg/mi	79.1[a]	79.1	73.5	69.5	79.1	71.6
NOx, mg/mi	1348	1346	1333	1259	1317	1292
VOC, mg/mi	1277	1290	1221	1199	1337	1202
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	12060	12072[b]	12301	12301	12296	12301
		12032[c]	11269	11269	11262	11269

[a]Underlined emissions are binding constraints
[b]Entry above dashed line is for corn-derived ethanol
[c]Entry below dashed line is for cellulosic ethanol

Table B-7. PADD III process capacity investments for the year 2010 summer: Ethanol blends						
Case:	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%	2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%			3.5	3.5	3.5	3.5
Crude reduction target, vol%			10	15	15	10
Forced hydrogenation?	No	No	No	No	No	Yes
RFG VOC reduction, min%	30	24	30	30	30	30
CG RVP, max psi	7.9	7.9	7.9	7.9	8.7	7.9
Process capacity investments, MBD:	15 percent ROI					
FCC feed hydrofiner		264				
FCC gasoline fractionation	482	7	725	357	444	671
Polymerization	65	138	160	99	200	151
Dimersol	125		94	58		40
Butane isomerization			35	87	51	30
Butylene isomerization	14		16	96		
C5/C6 isomerization	49		108	151	98	112
Resid desulfurizer			49	217	217	80
Resid cracker			156	513	450	177
Thermal cracker (gas feed)			7	76	77	101
Cryogenic fractionation			198	247	251	
Dimerization (of ethylene)			118	179	144	55
Gas oil hydrocracker	252	110	444	822	808	580
Hydrogen production (MMSCFD)			351	2122	2035	907
Naphtha cracker				29	17	
Distillate deep hydrotreater	1	9		239	71	62
Sulfur plant, tons per day			0.1	0.5	0.5	
Alkylation		9	31	123	87	24
Alkylation of benzene	101					
Reformer	23		720	852	238	794
Reformate splitter	87		29	39		78
Investment cost ($MM)	5,523	2,413	20,056	39,186	31,795	20,902

Table B-8. PADD III low petroleum refinery fuel use for the year 2010 summer: **Ethanol blends**

Case:	Base	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%		2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%				3.5	3.5	3.5	3.5
Crude reduction target, vol%.				10	15	15	10
Forced hydrogenation?		No	No	No	No	No	Yes
RFG VOC reduction, min%		30	24	30	30	30	30
CG RVP, max psi		30	24	30	30	8.7	7.9
Refinery fuel, energy equivalent % of inputs	8.8	10.2	10.1	10.1	11.8	12.0	10.7

Table B-9.
RFG blendstocks in PADD III for the year 2010 summer:
Methyl ether oxygenates

RFG minimum emissions reduction %: VOC 30; summer TAP 26.5; NOx 7.8
RFG production share = 62%

Case:	1M	2M	3M	4M	5M	6M
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	2.7	6.0
CG oxygen target, wt%		3.5	3.5	3.5	3.5	6.0
Crude reduction target, vol%		10	10	15	10	10
Oxygenate imports allowed, vol%	43	43	0	43	43	43
Forced hydrogenation?	No	No	No	No	Yes	No
Blendstocks, vol%:						
Butane	1.5	1.5	1.5	1.5	1.5	1.5
Reformate	26.9	21.3	26.0	24.6	25.0	18.9
Straight run naphtha	0.6	3.9		6.7	0.5	
C5+ isomerate	6.9	8.3		6.4	9.1	2.8
FCC naphtha	25.9	24.0	20.4	10.9	18.2	1.2
Coker naphtha						
Hydrocrackate	6.3	5.5	10.9		10.3	
Alkylate	11.4	8.7	11.6	19.8	13.3	
Polymer gasolines	2.5	7.3	10.1	9.4	3.3	19.9
Dimate	1.3					
Toluene/xylene	0.3	0.3	0.2	0.4	0.3	6.5
Natural gasoline						
Pyrolysis gasoline						
Raffinates	3.4	3.2	3.2	3.2	2.6	15.0
Other	0.3	0.2	0.5	1.5	0.4	
MTBE	5.8	8.9	11.0	10.3	10.7	25.9
TAME	6.6	6.9	4.5	5.2	4.7	7.7
THME	0.1					0.5

Table B-9 (continued).
RFG blendstocks in PADD III for the year 2010 summer:
Methyl ether oxygenates

RFG minimum emissions reduction %: VOC 30; summer TAP 26.5; NOx 7.8
RFG production share = 62%

Case:	7M
RFG oxygen target, wt%	6.0
CG oxygen target, wt%	6.0
Crude reduction target, vol%	10
Oxygenate imports allowed, vol%	71
Forced hydrogenation?	No
Blendstocks, vol%:	
Butane	1.5
Reformate	15.8
Straight run naphtha	
C5+ isomerate	3.8
FCC naphtha	3.5
Coker naphtha	
Hydrocrackate	
Alkylate	1.2
Polymer gasolines	21.3
Dimate	
Toluene/xylene	1.7
Natural gasoline	
Pyrolysis gasoline	
Raffinates	16.7
Other	
MTBE	24.2
TAME	8.6
THME	1.8

Table B-10.
CG blendstocks in PADD III for the year 2010 summer:
Methyl ether oxygenates

Case:	1M	2M	3M	4M	5M	6M
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	2.7	6.0
CG oxygen target, wt%		3.5	3.5	3.5	3.5	6.0
Crude reduction target, vol%		10	10	15	10	10
Oxygenate imports allowed, vol%	43	43	0	43	43	43
Forced hydrogenation?	No	No	No	No	Yes	No
Blendstocks, vol%:						
Butane	1.5	2.5	1.5	2.5	2.9	1.5
Reformate	31.9	24.0	25.0	40.8	41.4	0.2
Straight run naphtha	3.3	5.2	4.8	2.0	4.0	
C5+ isomerate	1.7					
FCC naphtha	36.0	34.5	26.8	19.3	17.4	38.7
Coker naphtha	3.1	2.0	2.3	2.0	2.2	
Hydrocrackate	4.7	0.4	11.6	9.6	9.7	
Alkylate	17.7	11.1	3.9	0.6	2.4	13.7
Polymer gasolines			4.1			12.4
Dimate						
Toluene/xylene						
Natural gasoline		0.9		3.3		
Pyrolysis gasoline						
Raffinates						
Other						
MTBE		19.1	15.2	16.6	15.1	31.3
TAME		0.2	4.4	2.0	4.6	2.2
THME			0.3	1.3	0.2	

Table B-10 (continued).
CG blendstocks in PADD III for the year 2010 summer:
Methyl ether oxygenates

Case:	7M
RFG oxygen target, wt%	6.0
CG oxygen target, wt%	6.0
Crude reduction target, vol%	10
Oxygenate imports allowed, vol%	71
Forced hydrogenation?	No
Blendstocks, vol%:	
Butane	1.5
Reformate	0.6
Straight run naphtha	
C5+ isomerate	
FCC naphtha	35.4
Coker naphtha	
Hydrocrackate	
Alkylate	9.8
Polymer gasolines	10.8
Dimate	
Toluene/xylene	8.9
Natural gasoline	
Pyrolysis gasoline	
Raffinates	
Other	
MTBE	33.0
TAME	
THME	

Table B-11.
PADD III RFG properties for the year 2010 summer:
Methyl ether oxygenates

RFG minimum emissions reduction %: VOC 30; summer TAP 26.5; NOx 7.8
RFG production share = 62%

Case:	1M	2M	3M	4M	5M	6M
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	2.7	6.0
CG oxygen target, wt%		3.5	3.5	3.5	3.5	6.0
Crude reduction target, vol%		10	10	15	10	10
Oxygenate imports allowed, vol%	43	43	0	43	43	43
Forced hydrogenation?	No	No	No	No	Yes	No
Properties:						
Octane, (R+M)/2	88.7	88.6	88.6	89.2	89.3	91.7
RVP, psi	6.6	6.8	6.9	6.8	6.7	7.1
Aromatics, vol%	23.8	21.0	21.2	20.1	20.4	16.8
Benzene, vol%	0.90	0.90	0.90	0.90	0.90	0.57
Olefins, vol%	10.4	14.3	15.3	13.1	8.5	19.6
Sulfur, ppm	139	104	87	115	103	48
E200, %	49.9	48.9	48.9	49.4	49.4	49.4
E300, %	85.1	86.4	87.3	87.7	87.1	88.6
Oxygen, wt%	2.14	2.74	2.72	2.74	2.74	5.94
Specific gravity	.7426	.7395	.7413	.7386	.7378	.7535
Summer TAP, mg/mi	54.0	51.7	51.8	51.3	50.9	43.4
NOx, mg/mi	1236[a]	1234	1235	1225	1191	1239
VOC, mg,mi	1008	1005	1008	1006	1004	1009
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	12085	12070	12073	12064	12062	11995

[a]Underlined emissions are binding constraints

Table B-11 (continued).
PADD III RFG properties for the year 2010 summer:
Methyl ether oxygenates

RFG minimum emissions reduction %: VOC 30; summer TAP 26.5; NOx 7.8
RFG production share = 62%

Case:	7M
RFG oxygen target, wt%	6.0
CG oxygen target, wt%	6.0
Crude reduction target, vol%	10
Oxygenate imports allowed, vol%	71
Forced hydrogenation?	No
Properties:	
Octane, (R+M)/2	90.7
RVP, psi	7.3
Aromatics, vol%	11.2
Benzene, vol%	0.61
Olefins, vol%	21.5
Sulfur, ppm	49
E200, %	48.9
E300, %	89.5
Oxygen, wt%	6.02
Specific gravity	.7448
Summer TAP, mg/mi	42.3
NOx, mg/mi	1235[a]
VOC, mg,mi	1008
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	11989

[a]Underlined emissions are binding constraints

Table B-12.
PADD III CG properties for the year 2010 summer:
Methyl ether oxygenates

Case:	1M	2M	3M	4M	5M	6M
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	2.7	6.0
CG oxygen target, wt%		3.5	3.5	3.5	3.5	6.0
Crude reduction target, vol%		10	10	15	10	10
Oxygenate imports allowed, vol%	43	43	0	43	43	43
Forced hydrogenation?	No	No	No	No	Yes	No
Properties:						
Octane, (R+M)/2	88.6	88.6	88.6	88.6	88.6	94.9
RVP, psi	7.9	7.9	7.7	7.9	7.9	7.8
Aromatics, vol%	31.6	25.2	24.2	30.0	27.6	21.7
Benzene, vol%	1.66	1.11	1.34	1.63	1.57	0.56
Olefins, vol%	8.6	7.6	9.9	3.9	4.4	16.9
Sulfur, ppm	351	419	385	244	290	247
E200, %	49.9	51.9	50.4	52.4	51.4	50.9
E300, %	82.2	84.4	84.9	84.4	84.9	61.5
Oxygen, wt%	0.00	3.47	3.49	3.43	3.45	5.97
Specific gravity	.7422	.7473	.7463	.7587	.7558	.7452
Summer TAP, mg/mi	78.5[a]	60.2	61.3	65.5	64.3	47.7
NOx, mg/mi	1349	1343	1339	1291	1304	1343
VOC, mg/mi	1256	1223	1172	1216	1216	1147
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	12060	11991	11995	12000	11996	11944

[a]Underlined emissions are binding constraints

Table B-12 (continued).
PADD III CG properties for the year 2010 summer:
Methyl ether oxygenates

Case:	7M
RFG oxygen target, wt%	6.0
CG oxygen target, wt%	6.0
Crude reduction target, vol%	10
Oxygenate imports allowed, vol%	71
Forced hydrogenation?	No
Properties:	
Octane, (R+M)/2	96.1
RVP, psi	7.6
Aromatics, vol%	30.16
Benzene, vol%	0.407
Olefins, vol%	14.6
Sulfur, ppm	243
E200, %	52.9
E300, %	85.1
Oxygen, wt%	5.85
Specific gravity	.7587
Summer TAP, mg/mi	49.6
NOx, mg/mi	1343[a]
VOC, mg/mi	1134
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	11948

[a]Underlined emissions are binding constraints

Table B-13. PADD III process capacity investments for the year 2010 summer: Methyl ether oxygenates						
Case:	1M	2M	3M	4M	5M	6M
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	2.7	6.0
CG oxygen target, wt%		3.5	3.5	3.5	3.5	6.0
Crude reduction target, vol%		10	10	15	10	10
Oxygenate imports allowed, vol%	43	43	0	43	43	43
Forced hydrogenation?	No	No	No	No	Yes	No
Process capacity investments, MBD:	15 percent ROI					
FCC feed hydrofiner	322	231				501
FCC gasoline fractionation	82	25	112	497	86	1029
Polymerization	20	122	237	168	37	576
Dimersol	23					
Butane isomerization	78	85	127	121		
Butylene isomerization	44				8	
C5/C6 isomerization	78	148	159	73	180	
Resid desulfurizer		77	214	27	217	432
Resid cracker		100	149	322	191	
Thermal cracker (gas feed)		59	77	86	122	431
Cryogenic fractionation		192	251	279	35	312
Dimerization (of ethylene)		101	256	198	15	309
Gas oil hydrocracker			310	516	816	125
C2-C5 dehydrogenation			244			332
Ether plant			237			350
Hydrogen production (MMSCFD)			496	1362	2721	1413
Naphtha cracker				2	129	735
Distillate deep hydrotreater				12	689	79
Sulfur plant, tons per day			0.1	0.2	0.2	0.8
Coker (fluid)						260
Reformer						21
Reformate splitter						11
Hydrogenation of C5/C6 olefins						155
LPG aromatization						156
Investment cost ($MM)	3,016	9,829	32,064	25,811	24,435	54,038

Table B-13 (continued). PADD III process capacity investments for the year 2010 summer: Methyl ether oxygenates)	
Case:	7M
RFG oxygen target, wt%	6.0
CG oxygen target, wt%	6.0
Crude reduction target, vol%	10
Oygenate imports allowed, vol%	71
Forced hydrogenation?	No
Process capacity investments, MBD:	
FCC feed hydrofiner	513
FCC gasoline fractionation	927
Polymerization	585
Butane isomerization	
Butylene isomerization	15
C5/C6 isomerization	32
Resid desulfurizer	432
Thermal cracker (gas feed)	508
Cryogenic fractionation	312
Dimerization (of ethylene)	223
Gas oil hydrocracker	105
C2-C5 dehydrogenation	29
Ether plant	
Hydrogen production (MMSCFD)	1611
Naphtha cracker	594
Distillate deep hydrotreater	77
Sulfur plant, tons per day	0.8
Coker (fluid)	260
Reformer	72
Reformate splitter	13
Hydrogenation of C5/C6 olefins	156
LPG aromatization	152
Aromatics recovery	10
Investment cost ($MM)	37,865

Table B-14. PADD III low petroleum refinery fuel use for the year 2010 summer: **Methyl ether oxygenates**

Case:	Base	1M	2M	3M	4M	5M	6M
RFG oxygen target, wt%		2.1	2.7	2.7	2.7	2.7	6.0
CG oxygen target, wt%			3.5	3.5	3.5	3.5	6.0
Crude reduction target, vol%			10	10	15	10	10
Oxygenate imports allowed, vol%		43	43	0	43	43	43
Forced hydrogenation?		No	No	No	No	Yes	No
Refinery fuel use, energy equivalent % of inputs	8.8	10.2	9.0	9.7	11.3	10.7	11.5

Table B-14 (continued). PADD III low petroleum refinery fuel use for the year 2010 summer: **Methyl ether oxygenates**

Case:	7M
RFG oxygen target, wt%	6.0
CG oxygen target, wt%	6.0
Crude reduction target, vol%	10
Oygenate imports allowed, vol%	71
Forced hydrogenation?	No
Refinery fuel use, energy equivalent % of inputs	11.1

Table B-15.
RFG blendstocks in PADD III for the year 2010 summer:
Ethyl ether oxygenates

RFG minimum emissions reduction %: VOC 30; summer TAP 26.5; NOx 7.8
RFG production share = 62%

Case:	1E	2E	3E	4E	5E	6E	7E
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	6.0	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0	6.0
Crude reduction target, vol%		10	15	10	10	10	17
Oxygenate imports allowed, vol%	43	43	43	43	43	43	43
Forced hydrogenation?	No	No	No	Yes	No	No	No
Linear acetaldehyde emissions?	No	No	No	No	No	Yes	No
Blendstocks, vol%:							
Butane	1.5	1.5	1.5	1.5	3.2	2.2	2.7
Reformate	25.6	19.7	12.2	19.7	14.2	21.0	13.5
Straight run naphtha	4.4	9.4	5.0	1.8			
C5+ isomerate	4.6	4.2	4.6	5.8	4.2	9.6	2.6
FCC naphtha	22.1	25.6	21.6	20.1		19.0	
Coker naphtha	1.7						
Hydrocrackate	6.2	1.4	10.7	19.7	8.5		8.5
Alkylate	6.7	11.7	14.6	8.7	20.6		24.1
Polymer gasolines	1.5	2.8	7.9	1.5	3.5	5.0	3.7
Dimate	3.5	2.0	0.2			0.2	
Toluene/xylene	2.8	0.1		0.1	0.1		
Natural gasoline						1.2	
Pyrolysis gasoline							
Raffinates	4.7	3.0	3.3	2.8	7.4	1.9	6.7
Other	0.7	0.9	0.8	1.1		0.8	
ETBE	8.9	14.2	13.9	16.7	38.2	31.8	38.2
TAEE	4.9	3.2	3.7	0.6		7.0	
THEE	0.1	0.2				0.2	

Table B-16.
CG blendstocks in PADD III for the year 2010 summer:
Ethyl ether oxygenates

Case:	1E	2E	3E	4E	5E	6E	7E
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	6.0	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0	6.0
Crude reduction target, vol%		10	15	10	10	10	17
Oxygenate imports allowed, vol%	43	43	43	43	43	43	43
Forced hydrogenation?	No	No	No	Yes	No	No	No
Linear acetaldehyde emissions?	No	No	No	No	No	Yes	No
Blendstocks, vol%:							
Butane	1.5	2.9	2.4	2.5	1.6	1.5	1.5
Reformate	30.3	14.7	23.1	34.4		0.5	
Straight run naphtha		4.5	5.1	5.5		8.6	
C5+ isomerate					0.5		3.3
FCC naphtha	39.6	33.5	28.2	10.4	40.9	43.3	40.8
Coker naphtha	0.5	4.8	4.0	4.8	4.6	4.6	3.2
Hydrocrackate		17.0	9.6	16.7	5.7	1.3	6.3
Alkylate	16.0						
Polymer gasolines	9.8						
Dimate							
Toluene/xylene	2.3		0.2				
Natural gasoline			4.9	2.7		0.7	
Pyrolysis gasoline							
Raffinates					2.8	0.6	1.8
Other					3.8		2.8
ETBE		20.0	20.2	17.5	25.6	33.6	24.0
TAEE		2.6	2.1	5.0	11.9	5.2	15.0
THEE			0.3	0.5	2.6		1.2

Table B-17.
PADD III RFG properties for the year 2010 summer:
Ethyl ether oxygenates

RFG minimum emissions reduction %: VOC 30; summer TAP 26.5; NOx 7.8
RFG production share = 62%

Case:	1E	2E	3E	4E	5E	6E	7E
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	6.0	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0	6.0
Crude reduction target, vol%		10	15	10	10	10	17
Oxygenate imports allowed, vol%	43	43	43	43	43	43	43
Forced hydrogenation?	No	No	No	Yes	No	No	No
Linear acetaldehyde emissions?	No	No	No	No	No	Yes	No
Properties:							
Octane, (R+M)/2	89.0	88.8	89.3	89.4	96.7	93.3	97.1
RVP, psi	6.6	6.7	6.9	6.7	6.5	6.5	6.5
Aromatics, vol%	24.6	20.8	13.7	16.7	10.0	15.2	10.0
Benzene, vol%	0.90	0.90	0.69	0.90	0.09	0.52	0.09
Olefins, vol%	1.1	12.6	14.2	7.6	3.9	9.8	4.1
Sulfur, ppm	126	138	122	130	23	182	23
E200, %	48.4	48.4	47.5	48.0	47.0	47.0	47.0
E300, %	85.7	85.7	88.8	87.3	91.9	89.3	91.9
Oxygen, wt%	2.13	2.74	2.79	2.75	6.09	6.06	6.10
Specific gravity	.7441	.7397	.7263	.7327	.7335	.7418	.7316
Summer TAP, mg/mi	57.9	57.2	52.8	55.1	58.1[a]	58.2	58.2
NOx, mg/mi	1234	1237	1205	1184	1078	1206	1078
VOC, mg/mi	1007	1005	1011	1008	964	984	964
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	12173[b]	12198	12201	12193	12340	12350	12340
	11396[c]	11218	11218	11242	10133	10070	10133

[a]Underlined emissions are binding constraints
[b]Entry above dashed line is for ethers produced from corn-derived ethanol
[c]Entry below dashed line is for ethers produced from cellulosic ethanol

Table B-18.
PADD III CG properties for the year 2010 summer:
Ethyl ether oxygenates

Case:	1E	2E	3E	4E	5E	6E	7E
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	6.0	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0	6.0
Crude reduction target, vol%		10	15	10	10	10	17
Oxygenate imports allowed, vol%	43	43	43	43	43	43	43
Forced hydrogenation?	No	No	No	Yes	No	No	No
Linear acetaldehyde emissions?	No	No	No	No	No	Yes	No
Properties:							
Octane, (R+M)/2	88.6	88.6	88.6	89.2	94.0	91.1	93.5
RVP, psi	7.9	7.9	7.9	7.9	6.5	6.5	6.5
Aromatics, vol%	31.6	20.1	23.2	22.8	20.4	17.6	15.8
Benzene, vol%	1.59	1.15	1.36	1.71	0.92	0.72	0.76
Olefins, vol%	8.3	8.4	7.2	4.0	12.3	10.0	14.2
Sulfur, ppm	379	542	451	297	500	550	461
E200, %	42.6	48.0	48.4	48.0	42.1	46.5	42.1
E300, %	82.2	85.3	84.9	87.3	84.9	87.9	85.3
Oxygen, wt%	0.00	3.55	3.52	3.53	6.04	6.05	6.08
Specific gravity	.7441	.7372	.7418	.7436	.7487	.7414	.7449
Summer TAP, mg/mi	79.2	69.3	71.2	71.5	78.1	67.3	74.8
NOx, mg/mi	1346[a]	1343	1336	1285	1346	1327	1332
VOC, mg/mi	1289	1237	1231	1210	1056	1046	1033
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	12060	12220[b]	12219	12214	12342	12333	12342
		10951[c]	10949	10913	9976	10074	9969

[a]Underlined emissions are binding constraints
[b]Entry above dashed line is for ethers produced from corn-derived ethanol
[c]Entry below dashed line is for ethers produced from cellulosic ethanol

Table B-19. PADD III process capacity investments for the year 2010 summer: **Ethyl ether oxygenates**

Case:	1E	2E	3E	4E	5E	6E	7E
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	6.0	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0	6.0
Crude reduction target, vol%		10	15	10	10	10	17
Oxygenate imports allowed, vol%	43	43	43	43	43	43	43
Forced hydrogenation?	No	No	No	Yes	No	No	No
Linear acetaldehyde emissions?	No	No	No	No	No	Yes	No
Process capacity invest., MUD:	15 percent ROI						
FCC feed hydrofiner	234	76					
FCC gasoline fractionation	173	32	21	60	955	31	645
Polymerization		28	135		44	77	
Dimersol	70	39					
Butane isomerization		70	95		221	95	263
Butylene isomerization	52			21			
C5/C6 isomerization						215	69
Resid desulfurizer			217	205			217
Resid cracker			108	6			174
Thermal cracker (gas feed)	84	22	62	112			27
Cryogenic fractionation	221	190	204				89
Dimerization (of ethylene)			118				60
Gas oil hydrocracker			212	739	203		225
C2-C5 dehydrogenation	41	129	209	108	410	416	681
Ether plant	192	287	288	285	702	703	703
Hydrogen production (MMSCFD)		3	564	2,721	1,354		1,495
Naphtha cracker				37	788	143	840
Distillate deep hydrotreater				631			
Alkylation							91
Reformate splitter					522		496
Hydrogenation of C5/C6 olefins							57
LPG aromatization					7		88
Investment cost ($MM)	6,913	10,322	23,965	24,569	36,769	26,406	56,925

Table B-20. PADD III low petroleum refinery fuel use for the year 2010 summer: **Ethyl ether oxygenates**								
Case:	Base	1E	2E	3E	4E	5E	6E	7E
RFG oxygen target, wt%		2.1	2.7	2.7	2.7	6.0	6.0	6.0
CG oxygen target, wt%			3.5	3.5	3.5	6.0	6.0	6.0
Crude reduction target, vol%			10	15	10	10	10	17
Oxygenate imports allowed, vol%		43	43	43	43	43	43	43
Forced hydrogenation?		No	No	No	Yes	No	No	No
Linear acetaldehyde emissions?		No	No	No	No	No	Yes	No
Refinery fuel use relative to Base	8.8	10.1	9.2	9.9	10.4	10.5	8.2	10.6

Table B-21. RFG blendstocks in PADD III for the year 2010 summer:
Rapeseed oil feedstock
RFG minimum emissions reduction %: VOC 30; summer TAP 26.5; NOx 7.8
RFG production share = 62%

Case:	2M	1R	1RX	5E	2RX
RFG oxygen target, wt%	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%	3.5	3.5	3.5	6.0	6.0
Ether type (M = methyl; E = ethyl)	M	M	M	E	E
Crude reduction target, vol%	10	10	10	10	10
Oxygenate imports allowed, vol%	43	43	43	43	43
Forced hydrogenation?	No	No	No	No	No
Rapeseed oil feed?	No	Yes	Yes	No	Yes
FCC naphtha (rapeseed derived) quality	NA	Low	High	NA	High
Blendstocks, vol%					
Butane	1.5	1.5	2.6	3.2	3.7
Reformate	21.3	21.7	23.6	14.2	7.6
Straight run naphtha	3.9	3.3	5.7		
C5+ isomerate	8.3	8.6	4.6	4.2	
FCC naphtha	24.0	28.1	27.9		
Coker naphtha					
Hydrocrackate	5.5	4.2	4.8	8.5	11.6
Alkylate	8.7	9.2	7.5	20.6	20.6
Polymer gasolines	7.3	3.7	5.2	3.5	
Toluene/xylene	0.3	0.3	0.2	0.1	4.1
Raffinates	3.2	3.6	3.2	7.4	14.2
Other	0.2				
MTBE	8.9	8.8	14.8		
TAME	6.9	7.0			
ETBE				38.2	38.2

Table B-22. CG blendstocks in PADD III for the year 2010 summer: Rapeseed oil feedstock

Case:	2M	1R	1RX	5E	2RX
RFG oxygen target, wt%	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%	3.5	3.5	3.5	6.0	6.0
Ether type (M = methyl; E = ethyl)	M	M	M	E	E
Crude reduction target, vol%	10	10	10	10	10
Oxygenate imports allowed, vol%	43	43	43	43	43
Forced hydrogenation?	No	No	No	No	No
Rapeseed oil feed?	No	Yes	Yes	No	Yes
FCC naphtha (rapeseed derived) quality	NA	Low	High	NA	High
Blendstocks, vol%:					
Butane	2.5	2.1	2.7	1.6	1.8
Reformate	24.0	18.2	15.2		
Straight run naphtha	5.2	5.1	3.0		
C5+ isomerate				0.5	
FCC naphtha	34.5	38.3	41.4	40.9	48.6
Coker naphtha	2.0	2.3	2.3	4.6	
Hydrocrackate	0.4		0.3	5.7	9.4
Alkylate	11.1	12.0	5.4		
Polymer gasolines		2.4	1.4		
Toluene/xylene					0.3
Natural gasoline	0.9		8.2		
Raffinates		0.3		2.8	
Other				3.8	1.1
MTBE	19.1	19.2	14.1		
TAME	0.2		5.9		
ETBE				25.6	35.8
TAEE				11.9	1.8
THEE				2.6	1.1

Table B-23. PADD III RFG properties for the year 2010 summer: **Rapeseed oil feedstock**
RFG minimum emissions reduction %: VOC 30; summer TAP 26.5; NOx 7.8
RFG production share = 62%

Case:	2M	1R	1RX	5E	2RX
RFG oxygen target, wt%	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%	3.5	3.5	3.5	6.0	6.0
Ether type (M = methyl; E = ethyl)	M	M	M	E	E
Crude reduction target, vol%	10	10	10	10	10
Oxygenate imports allowed, vol%	43	43	43	43	43
Forced hydrogenation?	No	No	No	No	No
Rapeseed oil feed?	No	Yes	Yes	No	Yes
FCC naphtha (rapeseed derived) quality	NA	Low	High	NA	High
Properties:					
Octane, (R+M)/2	88.6	88.6	88.6	96.7	95.1
RVP, psi	6.8	6.7	6.7	6.5	6.5
Aromatics, vol%	21.0	22.2	25.7	10.0	10.0
Benzene, vol%	0.90	0.9	0.90	0.09	0.07
Olefins, vol%	14.3	12.1	12.3	3.9	0.5
Sulfur, ppm	104	109	104	23	22
E200, %	48.9	49.4	49.4	47.0	46.5
E300, %	86.4	85.5	86.6	91.9	91.2
Oxygen, wt%	2.74	2.73	2.67	6.09	6.06
Specific gravity	.7395	.7422	.7470	.7335	.7364
Summer TAP, mg/mi	51.7	52.0	53.9	58.1[a]	58.1
NOx, mg/mi	1234	1224	1234	1078	1077
VOC, mg/mi	1005	1008	1008	964	972
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	12070	12067	12074	12340[b]	12342
				10133[c]	10135

[a]Underlined emissions are binding constraints
[b]Entry above dashed line is for ethers produced from corn-derived ethanol
[c]Entry below dashed line is for ethers produced from cellulosic ethanol

Table B-24. PADD III CG properties for the year 2010 summer: Rapeseed oil feedstock					
Case:	2M	1R	1RX	5E	2RX
RFG oxygen target, wt%	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%	3.5	3.5	3.5	6.0	6.0
Ether type (M = methyl; E = ethyl)	M	M	M	E	E
Crude reduction target, vol%	10	10	10	10	10
Oxygenate imports allowed, vol%	43	43	43	43	43
Forced hydrogenation?	No	No	No	No	No
Rapeseed oil feed?	No	Yes	Yes	No	Yes
FCC naphtha (rapeseed derived) quality	NA	Low	High	NA	High
Properties:					
Octane, (R+M)/2	88.6	88.7	89.1	94.0	95.9
RVP, psi	7.9	7.9	7.9	6.5	6.5
Aromatics, vol%	25.2	22.0	24.1	20.4	20.6
Benzene, vol%	1.11	1.01	0.98	0.92	0.81
Olefins, vol%	7.6	12.8	11.7	12.3	11.5
Sulfur, ppm	419	353	369	500	473
E200, %	51.9	51.9	49.9	42.1	47.5
E300, %	84.4	84.6	85.1	84.9	85.3
Oxygen, wt%	3.47	3.48	3.51	6.04	6.02
Specific gravity	.7473	.7433	.7445	.7487	.7443
Summer TAP, mg/mi	60.2	56.5	57.4	78.1	75.6
NOx, mg/mi	1343[a]	1346	1347	1346	1342
VOC, mg/mi	1223	1190	1205	1056	1035
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	11911	11996	11993	12340[b]	12329
				9976[c]	10089

[a]Underlined emissions are binding constraints
[b]Entry above dashed line is for ethers produced from corn-derived ethanol
[c]Entry below dashed line is for ethers produced from cellulosic ethanol

Table B-25. PADD III process capacity investments for the year 2010 summer: Rapeseed oil feedstock

Case:	2M	1R	1RX	5E	2RX
RFG oxygen target, wt%	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%	3.5	3.5	3.5	6.0	6.0
Ether type (M = methyl; E = ethyl)	M	M	M	E	E
Crude reduction target, vol%	10	10	10	10	10
Oxygenate imports allowed, vol%	43	43	43	43	43
Forced hydrogenation?	No	No	No	No	No
Rapeseed oil feed?	No	Yes	Yes	No	Yes
FCC naphtha (repeseed derived) quality	NA	Low	High	NA	High
Process capacity investments, MBD:			15 percent ROI		
FCC feed hydrofiner	231	620	610		
FCC gasoline fractionation	25			955	385
Polymerization	122	78	97	44	
Butane isomerization	85	92	56	221	271
Butylene isomerization		20			46
C5/C6 isomerization	148	160			
Resid desulfurizer	77	21	125		
Resid cracker	100	150	162		
Thermal cracker (gas feed)	59	57			
Cryogenic fractionation	192	186	177		
Dimerization (of ethylene)	101	98	23		
Gas oil hydrocracker				203	447
C2-C5 dehydrogenation				410	489
Ether plant				702	685
Hydrogen production (MMSCFD)				1,354	2,106
Naphtha cracker				788	1,025
Distillate deep hydrotreater		18	13		
Reformate splitter		50		522	279
LPG aromatization				7	106
Investment cost ($MM)	9,829	10,941	8,013	36,769	44,596

Table B-26. PADD III low petroleum refinery fuel use for the year 2010 summer: **Rapeseed oil feedstock**

Case:	Base	2M	1R	1RX	5E	2RX
RFG oxygen target, wt%		2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0
Ether type (M = methyl; E = ethyl)		M	M	M	E	E
Crude reduction target, vol%		10	10	10	10	10
Oxygenate imports allowed, vol%		43	43	43	43	43
Force hydrogenation?		No	No	No	No	No
Rapeseed oil feed?		No	Yes	Yes	No	Yes
FCC naphtha (rapeseed derived) quality		NA	Low	High	NA	High
Refinery fuel use, energy equivalent % of inputs	8.8	9.0	8.8	8.9	10.5	11.0

APPENDIX C
HYDROGEN REPLACEMENT FUEL CREDITS

Hydrogen derived from non-petroleum sources is credited to low petroleum gasoline according to the following arbitrary procedure:

To determine the percentage of total hydrogen that enters refined product, deduct hydrogen used in desulfurization or in fuel gas:

Fraction of H_2 used in desulfurization and fuel gas = f, where

f = (H_2 to H_2S + H_2 to fuel gas)/(Total H_2)

Percent H_2 to product = 100*(1 - f)

Of the H_2 that enters product, assume that the percentage that enters low petroleum gasoline is proportional to the percentage of hydrocracked stocks that enter gasoline:

Percent H_2 that enters low petroleum gasoline = s, where

s = 100*(1-f)*(hydrocracked stocks that enter gasoline/total hydrocracked blend stocks)

Finally, assume that the percentage of hydrogen derived from non-petroleum sources, which can be credited to low petroleum gasoline, is:

s*(Non-petroleum-derived H_2/Total purchased and generated H_2).

APPENDIX D
BLENDSTOCKS, PROPERTIES, PROCESS INVESTMENTS, AND FUEL USE FOR WINTER GASOLINE PRODUCTION

Table D-1.
PADD III base case blendstocks for year 2010 winter

Blendstock	Percent
Butane	8.8
Reformate	27.1
Straight run naphtha	1.4
C5+ isomerate	6.1
FCC naphtha	33.3
Coker naphtha	1.4
Hydrocrackate	3.8
Alkylate	10.8
Polymer gasolines	5.1
Dimate	0.1
MTBE	
Toluene/xylene	0.2
Natural gasoline	0.6
Pyrolysis gasoline	
Raffinates	1.4
Other	

Table D-2. PADD III base case gasoline properties for the year 2010 winter	
Octane, (R+M)/2	88.7
RVP, psi	12.5
Aromatics, vol%	30.0
Benzene, vol%	2.04
Olefins, vol%	13.3
Sulfur, ppm	361
E200, %	53.3
E300, %	82.9
Specific gravity	.7284
Winter TAP, mg/mi	115.4
NOx, mg/mi	1578
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	11613

Table D-3.
RFG blendstocks in PADD III for the year 2010

RFG minimum emissions reduction %: winter TAP 16.8; NOx (no increase)
RFG production share = 62%

Case:	EAW	MW	EW
RFG oxygen target, wt%	6.0	6.0	6.0
CG oxygen target, wt%	6.0	6.0	6.0
Oxygenate type	Ethanol	Methyl ethers	Ethyl ethers
Crude reduction target, vol%	10	10	10
Oxygenate imports allowed, vol%		66	70
Blendstocks, vol%:			
Butane	7.8	8.8	9.5
Reformate	4.5	23.4	
Straight run naphtha	9.8		
C5+ isomerate			4.0
FCC naphtha	36.1	18.4	32.0
Coker naphtha	0.3		1.8
Hydrocrackate			4.3
Alkylate	14.4	2.6	
Polymer gasolines	6.9	13.4	4.7
Dimate			
Toluene/xylene	0.4	0.4	
Natural gasoline			
Pyrolysis gasoline			
Raffinates	2.3		5.5
Other	0.2		
MTBE		32.5	
THME		0.6	
Ethanol	17.3		
ETBE			38.2

Table D-4.
CG blendstocks in PADD III for the year 2010 winter

Case:	EAW	MW	EW
RFG oxygen target, wt%	6.0	6.0	6.0
CG oxygen target, wt%	6.0	6.0	6.0
Oxygenate type	Ethanol	Methyl ethers	Ethyl ethers
Crude reduction target, vol%	10	10	10
Oxygenate imports allowed, vol%		66	70
Blendstocks, vol%:			
Butane	9.4	9.2	10.2
Reformate	43.4		30.4
Straight run naphtha	1.8		
C5+ isomerate	0.2	7.1	8.5
FCC naphtha	8.9	20.6	4.7
Coker naphtha	2.0		
Hydrocrackate			
Alkylate	5.5	6.8	
Polymer gasolines	2.9	15.1	
Dimate			
Toluene/xylene			5.0
Natural gasoline	8.7		
Pyrolysis gasoline			
Raffinates		3.6	3.1
Other		3.0	
MTBE		24.0	
TAME		8.9	
THME		1.8	
Ethanol	17.3		
ETBE			38.2

Table D-5.
PADD III RFG properties for the year 2010 winter

RFG minimum emissions reduction %: winter TAP 16.8; NOx (no increase)
RFG production share = 62%

Case:	EAW	MW	EW
RFG oxygen target, wt%	6.0	6.0	6.0
CG oxygen target, wt%	6.0	6.0	6.0
Oxygenate typ	Ethanol	Methyl ethers	Ethyl ethers
Crude reduction target, vol%	10	10	10
Oxygenate imports allowed, vol%		66	70
Properties:			
Octane, (R+M)/2	89.6	94.6	94.1
RVP, psi	14.0	11.6	11.6
Aromatics, vol%	14.3	20.2	10.1
Benzene, vol%	0.59	0.90	0.57
Olefins, vol%	16.9	16.4	15.2
Sulfur, ppm	295	260	261
E200, %	60.2	56.3	55.8
E300, %	91.45	88.6	89.7
Oxygen, wt%	6.32	5.97	6.18
Specific gravity	.7268	.7437	.7221
Winter TAP, mg/mi	76.0	67.7	82.9
NOx, mg/mi	1519	1528[a]	1448
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	11969[b]	11523	11938
	10109[c]		9827

[a]Underlined emissions are binding constraints
[b]Entry above dashed line is for corn-derived ethanol or for ethers produced from corn-derived ethanol
[c]Entry below dashed line is for cellulosic ethanol or for ethers produced from cellulosic ethanol

Table D-6.
PADD III CG properties for the year 2010 winter

Case:	EAW	MW	EW
RFG oxygen target, wt%	6.0	6.0	6.0
CG oxygen target, wt%	6.0	6.0	6.0
Oxygenate type	Ethanol	Methyl ethers	Ethyl ethers
Crude reduction target, vol%	10	10	10
Oxygenate imports allowed, vol%		66	70
Properties:			
Octane, (R+M)/2	89.9	93.6	97.4
RVP, psi	14.0	11.6	11.6
Aromatics, vol%	24.0	11.8	22.7
Benzene, vol%	1.35	0.30	0.92
Olefins, vol%	6.7	20.6	1.9
Sulfur, ppm	216	123	138
E200, %	60.7	56.3	55.8
E300, %	92.3	91.2	92.1
Oxygen, wt%	6.36	6.20	6.02
Specific gravity	.7503	.7239	.7422
Winter TAP, mg/mi	84.3	55.9	84.9
NOx, mg/mi	1445	1461[a]	1387
GHG, CO_2 equivalent gm/gal (energy equivalent to base case gasoline)	12086[b]	11637	12041
	10226[c]		9810

[a]Underlined emissions are binding constraints
[b]Entry above dashed line is for corn-derived ethanol or for ethers produced from corn-derived ethanol
[c]Entry below dashed line is for cellulosic ethanol or for ethers produced from cellulosic ethanol

Table D-7. PADD III process capacity investments for the year 2010 winter			
Case:	EAW	MW	EW
RFG oxygen target, wt%	6.0	6.0	6.0
CG oxygen target, wt%	6.0	6.0	6.0
Oxygenate type	Ethanol	Methyl ethers	Ethyl ethers
Crude reduction target, vol%	10	10	10
Oxygenate imports allowed, vol%		66	70
Process capacity investments, MBD:	15 percent ROI		
FCC feed hydrofiner		272	
FCC gasoline fractionation		969	71
Polymerization	18	289	
Resid desulfurizer	104	85	
Resid cracker		4	
Thermal cracker (gas feed)		71	
Cryogenic fractionation	206	234	
Dimerization (of ethylene)	157	193	
C2-C5 dehydrogenation		78	
Hydrogen production (MMSCFD)	135		248
Naphtha cracker	175	318	358
Hydrogenation of C5/C6 olefins		22	
LPG aromatization			105
Investment cost ($MM)	7,224	16,181	4,219

Table D-8. PADD III low petroleum refinery fuel use for the year 2010 winter				
Case:	Base	EAW	MW	EW
RFG oxygen target, wt%		6.0	6.0	6.0
CG oxygen target, wt%		6.0	6.0	6.0
Oxygenate type		Ethanol	Methyl ethers	Ethyl ethers
Crude reduction target, vol%		10	10	10
Oxygenate imports allowed, vol%			66	70
Refinery fuel use, energy equivalent % inputs	8.8	7.2	8.3	7.8

APPENDIX E
LOW PETROLEUM COST CHANGE FOR CG RVP INCREASE TO 8.7 PSI

Table E-1. PADD III low petroleum cost change for CG RVP increase to 8.7 psi: **Ethanol blends**

Case:	1EA	2EA	3EA	4EA	5EA	6EA
RFG oxygen target, wt%	2.1	2.1	2.7	2.7	2.7	2.7
CG oxygen target, wt%			3.5	3.5	3.5	3.5
Crude reduction target, vol%			10	15	15	10
Forced hydrogenation?	No	No	No	No	No	Yes
RFG VOC reduction, min%	30	24	30	30	30	30
CG RVP, max psi	7.9	7.9	7.9	7.9	8.7	7.9
Costs:	Cost above dotted line is for constant price assumption Cost below dotted line is for elastic price assumption					
Refining cost increase, cents per physical gallon of gasoline	-0.54	-0.87	-3.71	-4.76[b]	0	-4.53
	-0.63	-0.88	-5.09	-4.23[b]	0	-6.18
Cost of crude reduction, $ per barrel	NA[a]	NA[a]	-8.80	-7.53[b]	0	-10.73
	NA[a]	NA[a]	-12.05	-6.69[b]	0	-14.65

[a]Cases are not crude reduction strategies
[b]From sensitivity case 5E (all other estimates based on marginal cost of RVP reduction)

Table E-2. PADD III low petroleum cost change for CG RVP increase to 8.7 psi: **Methyl ether oxygenates**

Case:	1M	2M	3M	4M	5M	6M	7M
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	2.7	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	3.5	6.0	6.0
Crude reduction target, vol%		10	10	15	10	10	10
Oxygenate imports allowed, vol%	43	43	0	43	43	43	71
Forced hydrogenation?	No	No	No	No	Yes	No	No
Costs:	Cost above dotted line is for constant price assumption Cost below dotted line is for elastic price assumption						
Refining cost increase, cents per physical gallon of gasoline	-0.59	-0.06	0	-0.11	-0.09	0	0
	-1.01	-0.08	0	-0.15	-0.11	0	0
Cost of crude reduction, $ per barrel	NA[a]	-0.13	0	-0.17	-0.20	0	0
	NA[a]	-0.18	0	-0.24	-0.25	0	0

[a]Case is not a crude reduction strategy

Table E-3. PADD III low petroleum cost change for CG RVP increase to 8.7 psi: **Ethyl ether oxygenates**

Case:	1E	2E	3E	4E	5E	6E	7E
RFG oxygen target, wt%	2.1	2.7	2.7	2.7	6.0	6.0	6.0
CG oxygen target, wt%		3.5	3.5	3.5	6.0	6.0	6.0
Crude reduction target, vol%		10	15	10	10	10	17
Oxygenate imports allowed, vol%	43	43	43	43	43	43	43
Forced hydrogenation?	No	No	No	Yes	No	No	No
Linear acetaledhyde emissions?	No	No	No	No	No	Yes	No
Costs:	Cost above dotted line is for constant price assumption Cost below dotted line is for elastic price assumption						
Refining cost increase, cents per physical gallon of gasoline	-0.39	-0.16	-0.09	-0.13	0	0	0
	-0.49	-0.20	-0.12	-0.15	0	0	0
Cost of crude reduction, $ per barrel	NA[a]	-0.38	-0.14	-0.31	0	0	0
	NA[a]	-0.47	-0.18	-0.36	0	0	0

[a]Case is not a crude reduction strategy

Table E-4. PADD III low petroleum cost change for CG RVP increase to 8.7 psi: **Rapeseed oil feedstock**

Case:	1R	1RX	2RX
RFG oxygen target, wt%	2.7	2.7	6.0
CG oxygen target, wt%	3.5	3.5	6.0
Ether type (M = methyl; E = ethyl)	M	M	E
Crude reduction target, vol%	10	10	10
Oxygenate imports allowed, vol%	43	43	43
Forced hydrogenation?	No	No	No
Rapeseed oil feed?	Yes	Yes	Yes
FCC naphtha (rapeseed derived) quality	Low	High	High
Costs:	Cost above dotted line is for constant price assumption Cost below dotted line is for elastic price assumption		
Refining cost increase, cents per physical gallon of gasoline	-0.04	0	0
	-0.05	0	0
Cost of crude reduction, $ per barrel	-0.10	0	0
	-0.13	0	0

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