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North Dakota Refining Capacity Study

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North Dakota Refining Capacity Study
Final Technical Report

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Abstract

According to a 2008 report issued by the United States Geological Survey, North Dakota and Montana have an estimated 3.0 to 4.3 billion barrels of undiscovered, technically recoverable oil in an area known as the Bakken Formation. With the size and remoteness of the discovery, the question became "can a business case be made for increasing refining capacity in North Dakota?" And, if so what is the impact to existing players in the region. To answer the question, a study committee comprised of leaders in the region's petroleum industry were brought together to define the scope of the study, hire a consulting firm and oversee the study. The study committee met frequently to provide input on the findings and modify the course of the study, as needed. The study concluded that the Petroleum Area Defense District II (PADD II) has an oversupply of gasoline. With that in mind, a niche market, naphtha, was identified. Naphtha is used as a diluent used for pipelining the bitumen (heavy crude) from Canada to crude markets. The study predicted there will continue to be an increase in the demand for naphtha through 2030. The study estimated the optimal configuration for the refinery at 34,000 barrels per day (BPD) producing 15,000 BPD of naphtha and a 52 percent refinery charge for jet and diesel yield. The financial modeling assumed the sponsor of a refinery would invest its own capital to pay for construction costs. With this assumption, the internal rate of return is 9.2 percent which is not sufficient to attract traditional investment given the risk factor of the project. With that in mind, those interested in pursuing this niche market will need to identify incentives to improve the rate of return.

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Executive summary

The objective of this study was to establish whether market dynamics and market access support increasing refining capacity in the state. And if so, which refined products should the refinery produce? It was a two phase study that provided:

- a market analysis
- an economic analysis
- sensitivity and risk analysis
- impact of federal regulations
- project schedules
- inside battery limits process descriptions
- utility balances
- conceptual outside battery limits design
- emission analysis
- preliminary site plan
- site selection criteria
- benefits to North Dakota
- project incentives and barriers.

Key to the success of this project is acceptance by the industry and government that the findings are credible. To help assure this was the case, NDAREC appointed a steering and advisory committee to oversee the study. The steering committee was comprised of oil industry experts and was co-chaired by two state legislators – a Democrat and a Republican. NDAREC was selected as the spokesperson for the project, in that the entity can give an independent, third-party overview of the work accomplished. The advisory committee members represented oil-related associations, government and economic development. The structure of the appointed committee gave all interests in the state's oil industry a chance to have input in the development of a request for proposals (RFP), to learn firsthand the results and to provide input as the study progressed. This work was not completed to serve the interests of a particular business or group, but to help solve the long term dilemma of how to develop the Bakken play into a recoverable resource, both technically and economically.

The NDAREC staff and the committee jointly developed the RFP. Past studies, primarily an ENGlobal study completed in April 2008 and the findings from a previous study group led by two state legislators, were taken into account when writing the request for proposals. The request started where the other studies left off and took into account recommendations from those studies. The steering committee members added the industry's take on what questions would need to be answered before they would consider building a refinery or expanding an existing refinery.

Twelve consulting groups responded to the RFP. Through an evaluation and interview process, the Corval Group, partnered with Purvin and Gertz and Mustang Engineering, was chosen as the group to conduct the study. The study began on Jan. 11, 2010 and was completed on September 30, 2010. The findings were presented to the committee on October 8, 2010 and the results were unanimously approved by the steering committee.

Discussion

Approach

There has been an interest in increasing refining capacity in North Dakota for some time. Both private industry and the public sector have been analyzing opportunities.

In 2006, a study committee headed up by two state legislators set out to determine whether there was an opportunity to enter the refined products market and if there was interest within the private sector to build capacity or whether the government needed to be involved. They heard testimony from companies involved in the oil business, government entities involved in regulating the industry, investors interested in building capacity and engineers who had worked on preliminary studies. They concluded there may be opportunities; however it is a complicated question worthy of further study. None of the existing refiners in our area indicated they would be interested in expanding capacity without conducting a detailed feasibility study.

In 2007 investors interested in building a refinery incorporated a company, Northwest Refining, to study the pre-feasibility of building a refinery in northwest North Dakota. The study, completed by ENGlobal from Houston, TX, looked at the local market for refined products, logistics and access to other product markets, proposed sites and configurations, utility and capital requirements and the economic feasibility.

The study concluded the economics are good; however, further evaluation was needed. It recommended that a 100,000 bpd refinery, rather than 50,000, be the focus of future studies. Additional information on how to enter the market, survive market sensitivities and cash flow a new operation with significant debt service competing with others that have a lower debt service was needed.

Phase I of the study initially targeted 100,000, 50,000 and 20,000 barrel per day scenarios as a starting point. Through Phase I, we learned this market area is oversupplied with gasoline and that if we were to produce more gasoline it does not reduce imports into our country, but rather it affects the refineries in our immediate market area. This is because, at the current time, it is more feasible to import gasoline than to produce it domestically. With these findings, Phase II was modified as follows:

1. A 20,000 bpd business case because there would be less impact on the gasoline and crude market in the region.

2. An alternative configuration for 34,000 bpd that would produce primarily diesel

Results and discussion

The project began by identifying factors that might influence acceptance of the study. The goal was to predict and eliminate any potential controversies. We realized for the study to be worthwhile it needed to be accepted by both the industry and the government, so an important part of this work was to determine which players needed to be a part of the project. Two committees, a steering committee and an advisory committee were appointed. The steering committee was comprised of oil industry executives representing refineries, oil producers, and pipeline and distribution companies operating in our state as well as a spokesperson. The spokesperson was selected based on his ability to provide a non-biased overview of the project to the public. The advisory committee included representatives from oil related associations, legislators, government officials and economic development professionals. The advisory committee was designed to bring additional expertise to the table and to help educate others on the work accomplished. The following were the committee members:

Steering committee members
Co-chair, Representative Kenton Onstad (D), District 4
Co-chair, Senator Rich Wardner (R), District 37
Brad Aman, Continental
Ron Day, Tesoro
Mel Falcon, Northwest Refining
Dennis Hill, NDAREC (Spokesperson)
Dennis Krueger, Farstad
Mike McCann, Tesoro Pipeline
John Paganis, Murex
Rick Ross, Whiting
John Traeger, Cenex

Advisory committee members
Gaylon Baker, Stark County Development
Lori Capouch, NDAREC Rural Development
Pat Downs, NDAREC Rural Development
Mike Fladeland, ND Department of Commerce
Robert Harms, Northern Alliance of Independent Producers
Representative Patrick Hatlestad (R), District 1
Lee Kaldor, Deputy State Director for Senator Byron Dorgan
Representative Shirley Meyer (D), District 36
Dr. Frank Mosley, Minot State University
Ron Ness, North Dakota Petroleum Council
Tom Rolfstad, City of Williston Economic Development
Mike Rud, North Dakota Petroleum Marketers Association
John Skurupey, McKenzie Electric Cooperative
Gene Veeder, McKenzie County Jobs Development Authority
Mark Watne, ND Farmers' Union Economic Development

Once the committees were in place, a Request for Proposals was drafted and issued to consulting firms. The study committee was responsible for drafting the Request for Proposals, selecting the consulting firm and providing due diligence as the study progressed.

Corval Group, Inc., partnered with Purvin and Gertz and Mustang Engineering was the selected consulting group. The accepted proposal addressed the following:

Phase I

Market analysis. This task will develop a review of the gasoline, diesel and byproducts market potentially served by the proposed refinery.

1. Light refined products market review – will provide a review of light refined products markets within the study region, based on its most current supply/demand balances.

2. Infrastructure analysis – this will include a review of the regional crude oil transportation options into and out of the study region; identification of available pipeline capacities; and a summary of pending projects that would expand or alter pipeline capacity.

3. Liquefied petroleum gases (LPG) and fuel oil market review - A market analysis for LPG in the study region would be prepared, covering regional infrastructure, supply and demand fundamentals/trends, pricing, and product quality issues.

4. Refinery crude supply analysis – based on input from others relating to the current crude production in the study region, an assessment of whether the target crude slate would be available in sufficient volume to supply the prospective grassroots refinery.

5. Competitive analysis – using a simulation model for the deemed crude slate and a configuration agreed on by the study committee, the group will estimate yields of the major light refined products and byproducts. The objectives are to maximize light refined products yield and minimize fuel oil yield.

6. Partnerships – local, regional, national and North American groups will be considered and analyzed for potential partnerships with the final refinery ownership.

7. Deliverables
    - Meetings: weekly progress reports will be provided by email during the course of engagement.
    - Reports will be provided in written form with an understanding oral reports may be required.

This is a go/no-go decision point.

Phase II

Economic and refining analysis, refinery plot plan and benefits to North Dakota

1. Refinery configuration analysis – the group will develop a set of charge and yields for a logical set of configuration options based on the results from the Phase I market analysis. The relative demands for gasoline versus distillate fuels will drive the choice of vacuum gas oil processing, while the need for residual fuels will help select the proper bottoms destruction technology to be employed.

2. Generate project schedule – a family of project schedules will be developed to bound the schedule between best case and worst case scenarios.

3. Economic analysis of key scenarios – using in-house refinery process cost estimating tools, the group will develop costs limits that will have an accuracy of no more than +/- 40 percent.

4. Refinery utility analysis, support analysis – refinery utility balances will be developed to address the utilities portion of the operating costs for the refinery.

5. Site location/plot plan analyses – a refinery site selection basis will be prepared which will identify criteria used to locate the refinery. This basis will be used to identify and recommend several suitable locations, and the relative advantages and disadvantages of each location will be discussed in the report.

6. Emissions estimate – The expected emissions from the refinery will be estimated.

7. Benefits to North Dakota analysis – this analysis will focus on examining jobs, tax basis, refinery support business development, economic development, and other key factors that would have a positive impact on North Dakota assuming there would be a decision to build the refinery.

8. Impact of federal regulations – the group will look at the various Federal regulations that have been announced which may have an impact on either the design or operations of the proposed facility, including the Renewable Fuels Standard and a potential carbon dioxide emissions regulation which could include a cap and trade program.

Phase I findings:

Market Analysis

- PADD II gasoline demand begins to decline by 2015.
- Reflects mandated vehicle efficiency improvements.
- Reflects ethanol growth.
- The trend for PADD II mirrors overall U.S. demand projections.
- PADD II diesel demand is projected to grow in line with underlying economic growth.
- Projections are consistent with Energy Information Administration (EIA) and U.S. Department of Energy (DOE) trends.

Economic Analysis

- None of the specified refining capacity additions (20,000, 50,000 or 100,000 bpd) appear to achieve adequate capital recovery to support traditional project finance.

North Dakota gasoline balance

- North Dakota's demand for light refined products represents a small fraction of the overall PADD II total.
- North Dakota is a conventional gasoline market with some ethanol blending.
- The market balances on net transfers out of the state.
- Excludes ethanol.

North Dakota diesel balance

- The diesel market relies on increasing net transfers into North Dakota.
- Relative consumption of gasoline to diesel is lower than both the overall U.S. and PADD II markets because of the diesel consumption in the agriculture sector.

Phase II modifications

- Replace the 100,000 BPD case with a 20,000 BPD case due to its lower impact in the existing market and potentially better return on investment.
- Add an alternate naphtha refinery case, eliminating the production of gasoline. (Reasoning – gasoline supply in North Dakota exceeds demand; this configuration would maximize diesel production based on market demand; and, there is an existing market for naphtha in Alberta.)

Phase II findings:

- Naphtha
  - Naphtha is used as a diluent for pipelining Bitumen (heavy crude).
  - Growth in the Canadian bitumen production has created a demand for naphtha.
  - Canadian import of hydrocarbon streams such as naphtha is the expedient short term option for increasing the supply of diluents to meet the demand created by the growth in heavy crude production.

- Pipeline transportation
  - Enbridge Southern Lights project allows up to 180,000 BPD of diluents components to be shipped from Chicago to Edmonton, Canada.
  - The pipeline is expandable to more than 300,000 BPD.
  - Currently the tariffs for uncommitted shippers are not economical compared to rail transportation.
  - Currently batches cannot originate at Clearbrook.

- Rail transportation – rail is the most expedient short term option for importing diluents into Canada.

- LP modeling yields
  - The 20,000 bpd configuration provides a 92% yield of gasoline, jet and diesel. This configuration is much more complex than the naphtha configuration with capital costs estimated at $650 million, which have been adjusted for a ND location and have 40% accuracy.
  - The 34,000 BPD naphtha configuration provides 15,000 BPD of naphtha and a 52 percent refinery charge for jet and diesel yield. Capital costs, once again adjust are estimated at $700 million.

- Condensate Naphtha pricing – Naphtha is co-mingled with other condensate streams which together comprise the Enbridge pooled condensate. The C5+ price, the price of

Enbridge pooled condensate is expected to increase though 2015 and continue an increasing slope through 2030 due to increases in the demand of diluent.

- Benefits to North Dakota
    - New refinery capacity would provide employment to
        - An estimated 75 operations personnel with an average salary of $80,000
        - An estimated 80 maintenance positions with an average salary of $75,000
        - An estimated 55 professional and administrative jobs with an average salary of $85,000
    - The personal income from these jobs is estimated to be about $16.6 million per year.
    - Increased economic activity required to provide goods and services to the refinery would result from the spending of this new personal income.
    - 16,000 BPD of diesel fuel supply into the local market would potentially reduce supply disruptions.
    - Citizens of the state would realize benefits due to the lower cost diesel fuel.
    - During construction of the refinery an estimated $220-250 million could be paid for labor and some local fabrication work.
    - Increased crude netback prices for a period of 3-5 years may positively affect severance taxes and royalty payments.

- Opportunities to improve project viability
    - Expand an existing refinery instead of building a "grass roots" facility.
    - Evaluate use of extensive modular construction.
    - Explore the potential for obtaining, relocating and installing existing process equipment.
    - Optimize return of a grassroots refinery through the site selection process to improve the contribution margin.
    - Debt financing options may provide opportunities to improve the internal rate of return.

Conclusions

- The growth in Canadian heavy crude production has created a demand for naphtha. Naphtha is used as a diluent for pipelining the heavy crude from Canada to crude markets. The Canadian import of naphtha is the most expedient short-term option to meet the growing need for the diluents. The consulting group predicts that naphtha from a new refinery may find the diluents market an attractive alternative to the sale of gasoline in a locally oversupplied market.

- The 34,000 BPD diesel and naphtha refinery produces a higher return on investment than the 20,000 BPD refinery producing gasoline and diesel.

- Overall, total operating costs per barrel for the 34,000 bpd case is more favorable than the 20,000 bpd case. The fixed and variable costs are similar for each case but the high labor costs for the 20,000 bpd is the primary difference in the operating cost per barrel. The larger refinery enjoys some economies of scale in its projected operating cost per barrel.

- The 34,000 BPD naphtha refining product provides a nominal 9.2 percent IRR. Further alternatives could be explored to improve the return on investment.

- The financial analysis was completed assuming that the sponsor would invest its own capital to pay for the construction of the refinery. The returns from the study are based on this equity finance model. Sponsors generally set return guidelines that must be met before they will invest their capital in a project. Depending on the sponsor's cost of capital and other strategic objectives, a project must meet a minimum level of return on investment. An investment that has a higher internal rate of return than the minimum level of return will add value to the company. If the sponsor were able to borrow money at a lower interest rate than the cost of equity then the cost to finance a project would be less and may show a higher IRR on the equity portion of the project. Opportunities for debt financing of the project should be explored in an effort to improve the project return. Due to the potential benefits to North Dakota, the potential to finance part of this project through one of the North Dakota trust funds could be an option.

- The benefits to North Dakota are primarily in the areas of increased state revenues, new employment opportunities and an increased North Dakota production of diesel fuel.

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List of Acronyms and Abbreviations

ACCE	Alida-Cromer Capacity Expansion
AFE	approved for expenditure
B/D	barrels per day
BBL	billion barrels
BGY	billion gallons per year
BPCD	barrels per calendar day
CAA	Clean Air Act
CAFE	corporate average fuel economy
CAPP	Canadian Association of Petroleum Producers
CBOB	conventional blendstock for oxygenate blending
CCPS	Cushing-Chicago Pipeline System
CHS	Cenex Harvest States
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide-equivalent
CPS	cents per gallon
CRF	capital recovery factor
CRW	condensate
DOE	Department of Energy
DOT	U.S. Department of Transportation
E15	15 percent ethanol
E20	20 percent ethanol
E85	85 percent ethanol
EBITDA	Earnings before interest, taxes, depreciation and amortization
EEP	Enbridge Energy Partners, Limited Partnership
EIA	Energy Information Administration
EISA	Energy Independence and Security Act of 2007
ENDPL	Enbridge North Dakota Pipeline
EPA	Environmental Protection Agency
FCC	fluid catalytic cracking
FCC	Fluid catalytic cracking
G/D	gasoline to diesel
GDP	gross domestic product
GFAFB	Grand Forks Air Force Base
GHG	greenhouse gas
GOM	Gulf of Mexico
H_2S	hydrogen sulfide
HCK	hydrocracking
IRR	internal rate of return
ISBL	inside battery limit
kW	kilowatt
LCFS	low carbon fuel standard
LLS	light Louisiana sweet
MACRS	modified accelerated cost recovery

MARPOL	marine pollution
MB/D	million barrels per day
MPG	miles per gallon
MSAT	mobile source air toxins
MSW	Alberta mixed sweet
NDAREC	North Dakota Association of Rural Electric Cooperatives
NDDMR	North Dakota Department of Mineral Resources
NGL	natural gas liquid
NHTSA	National Highway Traffic Safety Administration
NO_x	nitrogen oxide
NPN	National Petroleum News
NPV	net present value
OPEC	Organization of Petroleum Exporting Countries
OSBL	outside battery limit
P	pipeline
PADD	U.S. Petroleum Administration for Defense Districts
PBOB	premium reformulated blendstock for oxygenate blending
PGI	Purvin and Gertz, Inc.
R	access via rail
RBOB	regular reformulated blendstock for oxygenate blending
RFG	reformulated gasoline
RFO	residual fuel oil
RFS	renewable fuel standard
RVP	Reid vapor pressure
SCO	synthetic crude oil
SECA	sulfur dioxide emission control
SO_2	sulfur dioxide
SUV	sport utility vehicle
T	truck
TCPL	TransCanada Pipeline
TEPPCO	TE Products Pipeline Company, Limited Partnership
TMPL	TransMountain Pipeline
ULS	ultra-low sulfur
USGC	U.S. Gulf Coast
VGO	vacuum gas oil
VOC	volatile organic compound
WTI	West Texas Intermediate
WW	waste water
WWFC	worldwide fuel charter
WPPM	parts per million by weight
WWTP	wastewater treatment plant

NORTH DAKOTA REFINING CAPACITY FEASIBILITY STUDY
PHASE I - FINAL REPORT

for

NORTH DAKOTA ASSOCIATION of RURAL ELECTRIC COOPERATIVES

April 21, 2010

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I. INTRODUCTION

Corval Group, Inc., (Corval) along with its partners, Purvin & Gertz, Inc. (PGI) and Mustang Engineers & Constructors, L.P. (Mustang), collectively “the Consultants” or “the study team”, were commissioned by the North Dakota Association of Rural Electrical Cooperatives, Inc. (NDAREC) to produce a study focused on the feasibility and benefits of constructing additional refining capacity in North Dakota (herein referred to as “the study”). The study team collectively has an extensive history of working with refineries and refinery developers performing similar studies throughout the world.

The project focuses on light refined products (defined to include gasoline, jet/kerosene and distillate fuel oil (or diesel)), as well as certain byproducts (natural gas liquids (NGL) and residual fuel oil), which would be generated from additional refining capacity in North Dakota.

The project scope includes the following major tasks:

Phase I: Marketing Analysis: A market assessment for refined petroleum products and other market factor trend analysis (historical, current and forecasts)

Phase II: Economic & Refining Analysis, Refinery Plot Plan, Benefits to North Dakota

The study region for the purposes of this assignment would be defined to include North Dakota and the surrounding states. Unless otherwise noted, the forecast horizon for the assignment would be to 2025. The analysis would exclude consideration of certain products such as asphalt and petrochemical feedstocks.

The impact of varying refinery size has been investigated using proprietary modeling tools developed by the study team. For the purposes of this analysis, three capacity cases have been considered: 100,000 B/D, 50,000 B/D and 20,000 B/D. Of these cases, 100,000 B/D is defined as the Base Case.

The key questions being addressed in Phase I of the study are given below:

- What are the characteristics of the markets for light refined products in the study region?
- What are the opportunities and constraints that arise from consideration of additional refining capacity in the Williston area of North Dakota?
- What would be the markets for the products from such additional refining capacity?
- How would the results of the analysis change as a function of refinery capacity?

ABOUT THIS REPORT

This report was prepared by the Consultants under a contract with NDAREC, which received federal grant funds for the study.

This document and the analysis, opinions and conclusions expressed in this report reflect the reasonable efforts of the Consultants and NDAREC using information available at the time of the oil refinery study and within the resources and timeframe available for this study. Those reviewing this document or other documents related to the oil refinery study should recognize the limitations of the study and understand that any predictions about the future are inherently uncertain due to events or combinations of events, including, without limitation, the actions of government or other entities or individuals. Neither the Consultants, nor NDAREC, or any of their employees, agents, task force members, advisory committee members, or any other representatives of these parties, make any express or implied warranties regarding the information, analysis, opinions, or conclusions contained in this document or other documents related to the oil refinery study, nor do they assume any legal liability or responsibility of any kind for the accuracy, completeness or usefulness of this document or the oil refinery study. No information contained in this document nor any other information released in conjunction with the oil refinery study shall be used in connection with any proxy, proxy statement or solicitation, prospectus, securities statement or similar document without the written consent of Consultants and NDAREC. Although this is a document available for use by the public, there are no intended third party beneficiaries of the agreement between Consultants and NDAREC for the performance of the oil refinery study.

II. SUMMARY & CONCLUSIONS

EXECUTIVE SUMMARY

North Dakota light refined products markets are small and geographically isolated, in relation to the large U.S. Midwest (PADD II) markets. Historical demand trends in the state, which favor diesel over gasoline, are likely to continue. Diesel demand is forecast to increase with underlying economic activity, while gasoline demand will gradually decline, due to cumulative fleet efficiency gains and increased ethanol supply. Despite these divergent demand trends, product balances have been achieved with transfers from neighboring states. PADD II as a whole depends on significant product transfers from the U.S. Gulf Coast (PADD III). Product pricing in the study region has historically shown premia over the large U.S. spot markets, indicative of transportation costs and seasonal supply issues. This study has considered only annual pricing impacts, and focuses on trends at the state level.

Williston Basin crude has been a prolific and growing source of supply to the U.S. Lower 48. High quality crude oil production has grown in western North Dakota, and to a lesser extent in eastern Montana, due to the successful application of advanced drilling and fracturing techniques. Production is expected to continue increasing for a number of years. While infrastructure developments to date have not kept pace with production gains, a number of expansion projects have been completed. Other projects are proposed. Based on representative quality of the Williston Basin sweet crudes, many regional refining centers would be candidates to process this production.

Construction of additional refining capacity in North Dakota has been investigated in this study. Specific project details have not been defined. However, a large-scale refining project of 100,000 barrels per day (B/D) capacity was established as the Base Case, targeting production of finished light refined products (and maximizing diesel) from Williston Basin crude. Market models were developed to investigate the optimum distribution of crude oil and refined products under the premises of additional refining capacity in North Dakota. Current logistical costs were included in the models. The model results were used to estimate crude intake costs and product revenues for the Base Case and two alternative cases (50,000 B/D and 20,000 B/D).

Preliminary analysis of project economics included estimation of variable and net margins for the Base Case and two alternative cases. In general, variable refining margins would be high for all cases, but would decline as project capacity increases. With more product supply in North Dakota, the call on product transfers from the U.S. Gulf Coast would be reduced. The Base Case refining project, while maximizing capital cost economies of scale due to its size, is estimated to realize the lowest net margin, due to the impact of higher transportation costs on product netback prices in the state. Gulf Coast index refinery models provided initial comparative values for project capital cost, and were used to estimate capital recovery factors in North Dakota. None of the refining capacity cases were estimated to achieve a level of capital recovery that is considered adequate to support development of a grassroots project. However, it is noted that the results developed for this study, while generally applicable at the state level, are not specific to any particular project. Further study would be recommended in order to establish economics for a given project based on its unique premises.

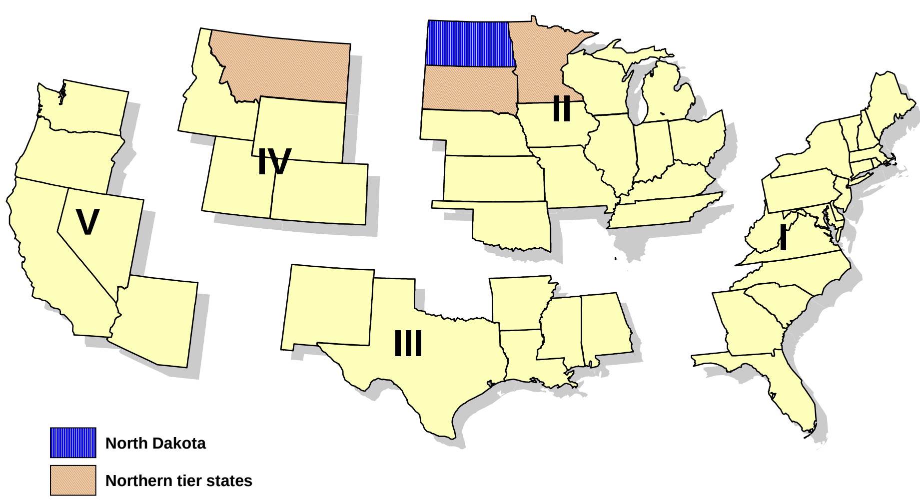
Stakeholders other than the project sponsor would be affected by additional refining capacity in the state of North Dakota. Owners of existing refineries in the study region would realize lower refining margins due to the availability of additional product supply. Crude producers may benefit, albeit temporarily, from higher demand in the vicinity of the Williston Basin. Additional demand in the state may reduce the need for expensive transportation to distant markets, but longer term the crude price will be determined by utilization of cheaper pipeline expansions rather than new local demand. The specific impact on crude oil and refined products pipeline companies cannot be determined within the scope of the Phase I analysis. The state of North Dakota would be expected to benefit from the economic activity associated with the project and its ongoing operation. Finally, citizens of the state would realize benefits due to lower-cost light refined products.

STUDY CONCLUSIONS

LIGHT REFINED PRODUCTS MARKET ANALYSIS

1. **The geographical focus of the study is on U.S. Petroleum Administration for Defense Districts (PADD) II and IV markets.** Figure II-1 presents the U.S. PADD region boundaries, and also illustrates the northern tier U.S. states which are of interest in this study. Analysis of North Dakota light refined product markets is presented, within the context of the PADD II product balance.

FIGURE II-1
PETROLEUM ADMINISTRATION FOR DEFENSE DISTRICTS



2. **PADD II gasoline and diesel market are large and diverse.** The following table summarizes the demand and balance for PADD II gasoline and diesel. It suggests two key conclusions. First, the significant size of the PADD II markets in relation to the overall U.S. demand. Second, it is clear that PADD II depends on supply of product from other regions to meet demand. The dominant source of transferred product is PADD III (the Gulf Coast region).

PADD II LIGHT REFINED PRODUCTS BALANCE, 2008
(Thousand Barrels per Day)

	Gasoline	Total Diesel	Jet / Kero
Supply			
Production	1,937	987	209
Imports	1	5	0
Net Receipts	593	249	74
Adjustments	21	0	0
Total	2,552	1,241	283
Disposition			
Demand	2,544	1,222	275
Exports	19	12	9
Stock Change	-13	7	-2
Total	2,550	1,241	282

Note: (1) Source: DOE Petroleum Supply Annual 2008

3. **PADD II gasoline and diesel market demand outlooks are distinct.** Gasoline demand trends in PADD II show the long-term impact of mandated efficiency improvements for vehicle fuel consumption, with demand projected to decline by about 2015. In this respect, the PADD II trend reflects overall U.S. trends. The growth in non-petroleum supply, specifically ethanol, plays an important part in the PADD II balance. By contrast, diesel demand is projected to grow in line with underlying economic growth. U.S. Department of Energy (DOE) projections (from the Energy Information Administration (EIA) Annual Energy Outlook 2010) call for broadly similar trends in consumption.

4. **North Dakota light refined products markets have some unique characteristics within the broader PADD II region.** State demand for light refined products represents a small fraction of the overall PADD II total. The North Dakota gasoline market is a conventional gasoline market, but some ethanol blending occurs. The market balances on net transfers out of the state. By contrast, the diesel market relies on net transfers into the state, since consumption is greater than production. Relative consumption of gasoline versus diesel (measured by the Gasoline/Diesel, or G/D, ratio) is lower than the overall U.S. or PADD II market, based on higher consumption of diesel in the agricultural sector.

5. **Product transfers are an essential feature of the North Dakota refined products balance.** Because production of light products within the state does not match market demand, transfers are an important mechanism to continuously balance markets. Some product movements may be considered structural, due to common ownership of pipeline refining and pipeline assets. Product transfers are summarized below:

    a. From Montana into western North Dakota on the Cenex Pipeline

    b. From southern PADD II into eastern North Dakota on the NuStar system

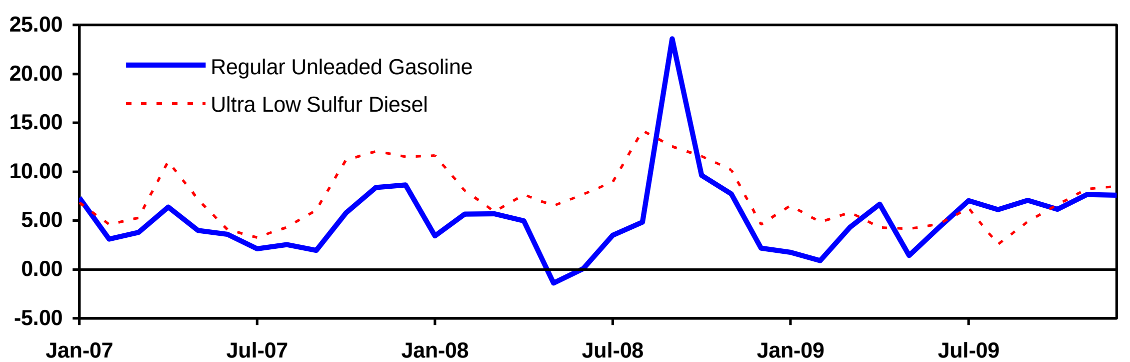
    c. From Minnesota into eastern North Dakota on the Magellan product pipeline system

    d. From Mandan, ND into Minnesota on the NuStar Pipeline

6. **Due to its strong dependence on product transfers, product pricing in PADD II is related to spot markets by transportation costs.** The major spot markets in the U.S. are at the U.S. Gulf Coast and Tulsa, OK (also called Group 3). Minnesota is a large market in the northern tier of the U.S. Its pricing is linked to Group 3.

7. **The U.S. northern tier markets (Montana, North and South Dakota and Minnesota) have historically realized high price differentials relative to spot markets.** Figure II-2 illustrates the recent historical unbranded rack price premiums for gasoline and diesel in North Dakota. Prices approximate the volumetric average for the state. The differential is shown relative to the Minneapolis rack price. Gasoline rack prices in North Dakota have averaged about 5-6 cents per gallon over Minneapolis between 2007 and 2009. Diesel rack prices averaged between 6-9 cents per gallon over Minneapolis during the same period. Historical pricing differentials have been volatile, due in part to supply constraints in the large northern tier region.

FIGURE II-2
NORTH DAKOTA AVERAGE RACK - MINNEAPOLIS RACK
(U.S. Cents per Gallon)



NGL & RESIDUAL FUEL OIL MARKET ANALYSIS

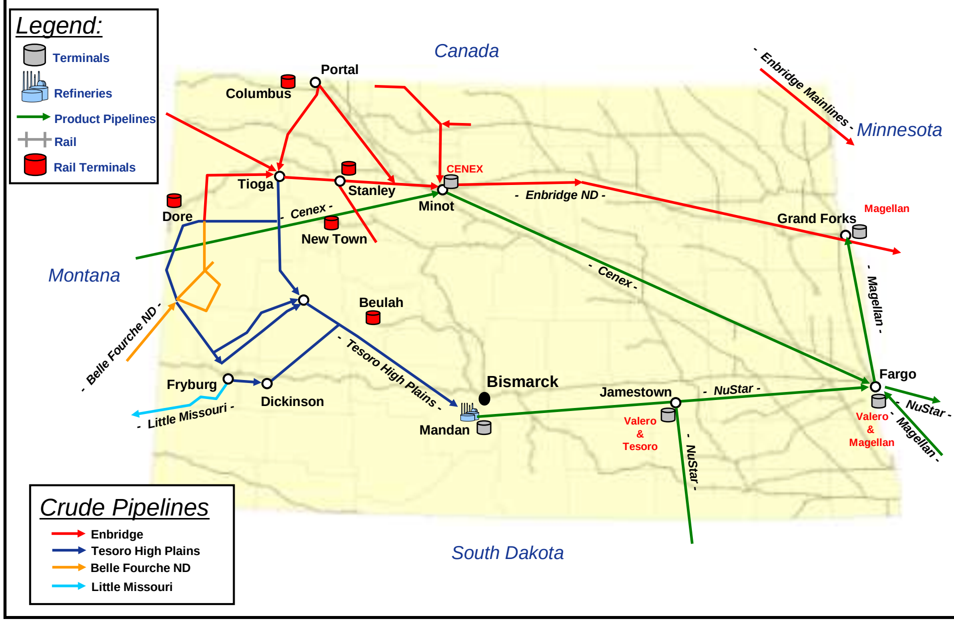
1. **In the study region, natural gas liquid (NGL) demand is significantly higher than local supply.** Propane demand in the Upper Midwest region of PADD II (Minnesota, Wisconsin, North and South Dakota) averages about 78,000 B/D, but this is much higher than production from gas processing and refining (8,700 B/D and 9,000 B/D, respectively, in 2009). Imports from Canada and inter-PADD transfers are both large components of the balance. For butane, the Upper Midwest must rely on imports and inter-PADD transfers to meet demand. Consequently, any incremental production of butane in the region would likely be consumed in the local market.

2. **Residual fuel oil markets in North Dakota are extremely small.** Demand for all sectors of the economy has historically been less than 1,000 B/D. Overall demand in PADD II is the lowest among U.S. PADD regions, in relation to the total demand for petroleum products. Incremental supply from a crude refinery project would likely require transportation by rail to a large market such as the U.S. Gulf Coast.

INFRASTRUCTURE

1. **Petroleum distribution infrastructure in North Dakota consists of gathering and trunkline facilities for crude oil, refined products pipelines and associated terminals, and rail facilities.** Figure II-3 summarizes the major existing petroleum infrastructure in the state. There are a number of projects that have increased (or would potentially further increase) crude oil takeaway capacity. Enbridge North Dakota Pipeline (ENDPL) recently completed its Phase 6 expansion, the Bridger/Butte system has been debottlenecked, and EOG Resources has started up its unit train operation from Stanley, ND to Stroud, OK. Other projects have been proposed, and some may proceed, further increasing crude takeaway capacity. For this study, the Enbridge Portal reversal project, the Bridger Four Bears project and additional rail facilities have been assumed to proceed.

FIGURE II-3
NORTH DAKOTA PETROLEUM INFRASTRUCTURE



2. **There is one petroleum refinery currently operating in North Dakota.** Tesoro owns and operates a refinery at Mandan, ND, with crude distillation capacity of 58,000 barrels per day (B/D). The refinery has a cracking configuration, which means that it does not convert all of the vacuum residue (the heaviest portion of crude oil) to light refined products.

3. **Several small projects to expand refining capacity or conversion capacity in the study region are likely to proceed.** However, these projects would not fundamentally change the refined products balance. Several grassroots refinery projects are considered speculative, based on their current state of development.

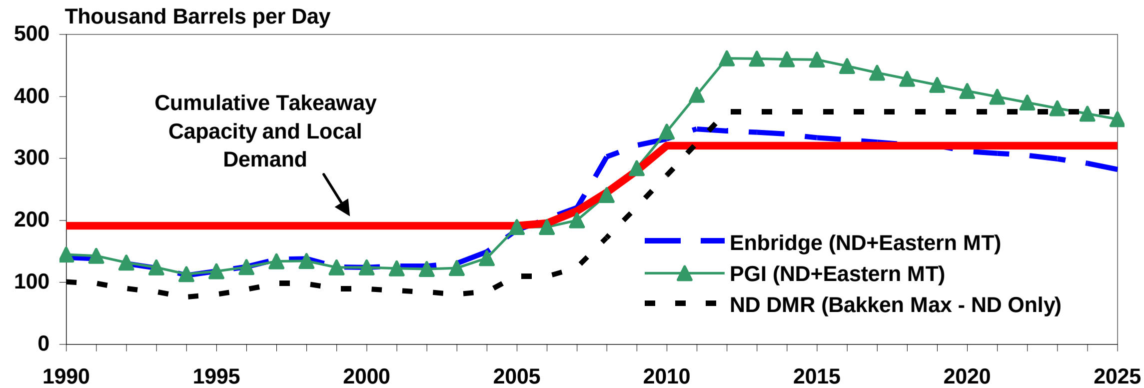
4. **Refineries and distribution infrastructure in the study region are highly integrated and interrelated.** Incremental refined products from new capacity in North Dakota would be expected to strongly influence flows in the eastern part of the study region. In turn, the transfer of products from the PADD III region, which account for a significant portion of supply, would be reduced to accommodate the additional product. The analysis for this study suggests that the refined products infrastructure to the west is comparatively less flexible to adjust to incremental supply from North Dakota.

CRUDE MARKET ANALYSIS

1. **Crude oil production is declining in most producing regions of the U.S., with the exception of the Williston Basin.** In recent years, production in North Dakota and Montana has benefited greatly from advancements in crude production technology. Horizontal drilling and multi-stage fracturing are now regularly applied in

the shale formations of the Williston Basin, mainly Bakken and Three Forks. Forecasts of crude oil production through 2025 in the study region are compared in Figure II-4. PGI's forecast is generally consistent with forecasts presented by the North Dakota Department of Mineral Resources (NDDMR) and Enbridge.

FIGURE II-4
CRUDE PRODUCTION AND PIPELINE CAPACITY



2. **Crude oil production from eastern Montana and North Dakota will serve markets in the state, as well as other refining centers.** Transportation of crude oil by pipeline depends on the ability of existing and future infrastructure to keep pace with regional production. In recent years, the supply of crude from the Williston Basin has grown more rapidly than pipeline capacity additions. As a result, rail transportation has been used to supplement takeaway capacity. Rail is generally a less economic option for transporting crude oil over long distances.

3. **The focus of this analysis is on light sweet crude oil, representative of production from the Bakken shale.** Confidential assay information provided by producers in the Williston Basin serves as a reference for the initial analysis of product yields from incremental refinery capacity. Where this information is not complete, estimates or proxy information from other similar crude oils have been used. Bakken light crude is indicated to be comparable in yield and quality characteristics to West Texas Intermediate (WTI), a widely referenced benchmark mid-continent U.S. crude oil. The following table summarizes the relevant assay information, comparing Bakken light sweet to WTI and Light Louisiana Sweet (LLS), a high quality Gulf Coast crude oil.

LIGHT SWEET CRUDE ASSAY COMPARISON

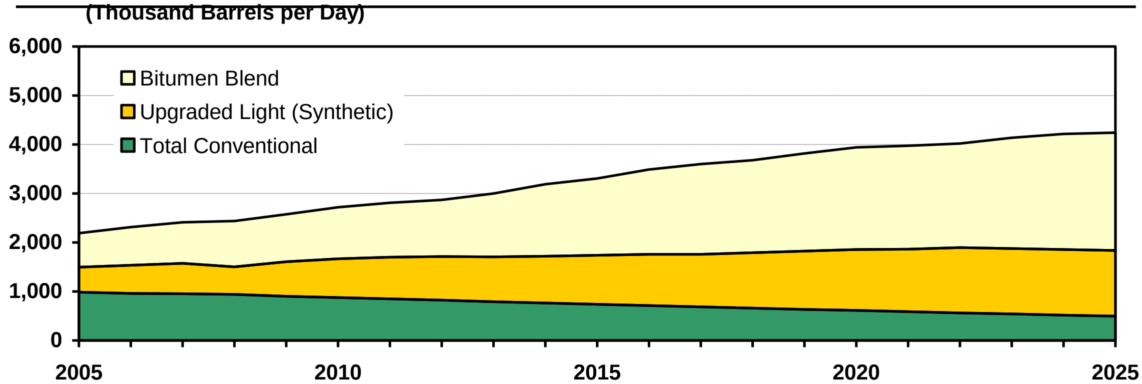
		Bakken [1]	WTI	LLS
API Gravity	Degrees	> 41	40.0	35.8
Sulfur	Weight %	< 0.2	0.33	0.36
Distillation Yield:	Volume %			
Light Ends	C1-C4	3	1.5	1.8
Naphtha	C5-330 ^oF	30	29.8	17.2
Kerosene	330-450 ^oF	15	14.9	14.6
Diesel	450-680 ^oF	25	23.5	33.8
Vacuum Gas Oil	680-1000 ^oF	22	22.7	25.1
Vacuum Residue	1000+ ^oF	5	7.5	7.6
Total		100	100.0	100.0
Selected Properties:				
Light Naphtha Octane	(R+M)/2	n/a	69	71
Diesel Cetane		> 50	50	49
VGO Characterization (K-Factor)		~ 12	12.2	12.0

Note: (1) Properties are approximate, based on available assay information.

4. **Crude oil from the Williston Basin may be expected to price in relation to WTI and other benchmark crude oils.** Quality and transportation adjustments determine the netback price for Williston Basin production in North Dakota. The refining value differential of typical Williston Basin crude is estimated to be higher than WTI. Infrastructure projects will have a significant impact on the forecast netback price, to the extent that they provide economic access to given refining markets. Estimates have been made for these transportation and quality adjustments.

5. **One of the key considerations in the refinery capacity addition cases is the security of crude oil supply.** Processing Bakken (light sweet) crude oil is the base premise for this study. Other sources of crude may be accessible in North Dakota, including synthetic crude oil (SCO) which has been upgraded from bitumen in Alberta (Western Canada). As shown in Figure II-5, supplies of SCO are expected to increase, according to the Canadian Association of Petroleum Producers (CAPP) forecast. SCO may provide suitable feedstock for North Dakota refining capacity as an alternative to conventional crude from the Williston Basin. However, further study would be necessary to address constraints such as pipeline capacity and refinery configuration.

FIGURE II-5
WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST
CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS - 2009 GROWTH CASE



MODELING RESULTS

1. **For the Phase I analysis, initial project premises have been defined for the incremental refinery capacity.** Following are the major study premises relating to the incremental refinery processing cases in North Dakota, relative to a "Reference Case" with no additional capacity:

    a. Process indigenous light crude oils generally representative of production from the Bakken formation in the Williston Basin region.

    b. Capacity addition cases are 100,000 B/D (Base Case); 50,000 B/D; and 20,000 B/D.

    c. Maximize production of finished gasoline, jet and diesel meeting regional specifications, and with consideration of anticipated future specifications.

    d. Maximize light product yield consistent with the anticipated demand forecasts for each product in the study region.

    e. Employ technologies that have been proven in commercial scale operations.

2. **Preliminary estimates of the intake and yield from incremental refining capacity target maximum diesel production.** Intake and yield estimates are summarized in the following table. Based on the above processing premises, the refining capacity would produce a high yield of diesel relative to gasoline (low G/D ratio). The yield of distillate relative to gasoline would be maximized by a vacuum gas oil (VGO) hydrocracking configuration. This is most consistent with the expected demand profile in the state. Fuel oil yield is low relative to light refined products, and consists of low sulfur grade product.

REFINERY INTAKE/YIELD [(1)]
BAKKEN LIGHT SWEET

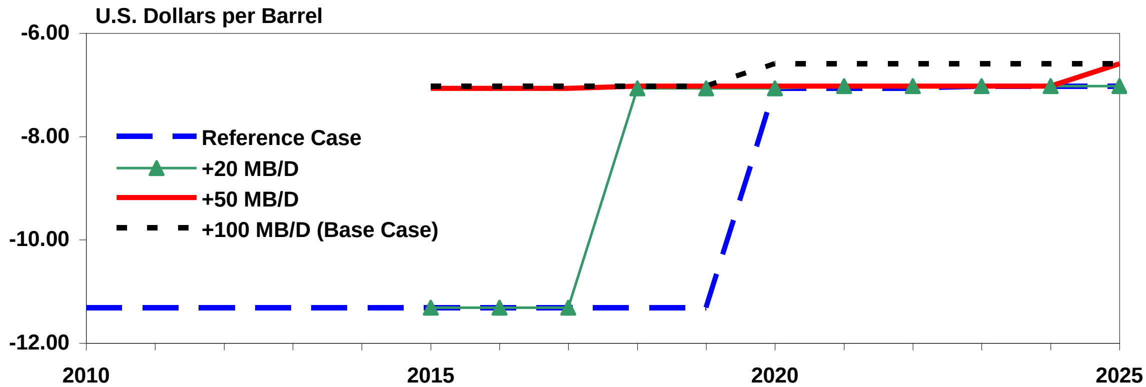
	Volume Percent
Crude	100.0
Total Intake	100.0
Light Ends	7.8
Gasoline	44.1
Jet/Kerosene	5.0
Low Sulfur/ULS Diesel	42.7
1% Sulfur RFO	4.0
3% Sulfur RFO	0.9
Total Yield	104.5
Sulfur (Tonnes)	0.02

Note: (1) VGO hydrocracking configuration.

3. **Models representative of competitive markets for crude oil and light refined products have been developed for this study.** The models optimize distribution of crude oil and light refined products, based on capacity constraints and distribution costs in existing transportation infrastructure. Actual and estimated costs for the movement of crude oil and products between locations are represented in the models. The crude market model estimates the clearing location for surplus Bakken crude oil, and the resulting netback price in North Dakota. The refined products market model was validated using historical gasoline and diesel prices at the wholesale level in North Dakota. It represents the major pipeline systems delivering products from the U.S. Gulf Coast as the source of incremental supply to the northern tier.

4. **Additional refining capacity in North Dakota will strengthen crude prices in the state.** North Dakota crude has been priced significantly below other marker crudes such as WTI at Cushing, OK. The study has addressed the impact of incremental refinery capacity on the price-setting market location for North Dakota crude. Results are shown in Figure II-6 for the Base Case and the refinery-build cases. Prices shown are indicative of field prices realized in North Dakota, and any refinery project would incur some costs for crude gathering and delivery. The 100,000 B/D Base Case has the largest impact on the crude price. The 20,000 B/D case would realize benefits for several years based on advantageous crude pricing. Actual costs for crude oil would vary depending on the specific location of the additional refining capacity within the state.

FIGURE II-6
CRUDE OIL DIFFERENTIALS: ND SWEET (FIELD) MINUS WTI, CUSHING



5. **Additional refining capacity in North Dakota will weaken product prices in the state.** The refined products market model was used to estimate the impact of incremental refinery capacity on wholesale prices. This approach provides indicative results at a generic North Dakota location. Product price premiums over the U.S. Gulf Coast spot market are shown in Figures II-7 and II-8 (for gasoline and diesel, respectively). The 100,000 B/D Base Case has the largest impact on light product prices, and is forecast to result in prices decreasing to approximately the level of the U.S. Gulf Coast. The impact of the 20,000 B/D case is much less significant, particularly for diesel, where prices are almost equal to the reference case over the forecast period. The actual impact on product prices would vary depending on the specific location of the additional refining capacity within the state.

FIGURE II-7
GASOLINE DIFFERENTIALS: NORTH DAKOTA MINUS GULF COAST

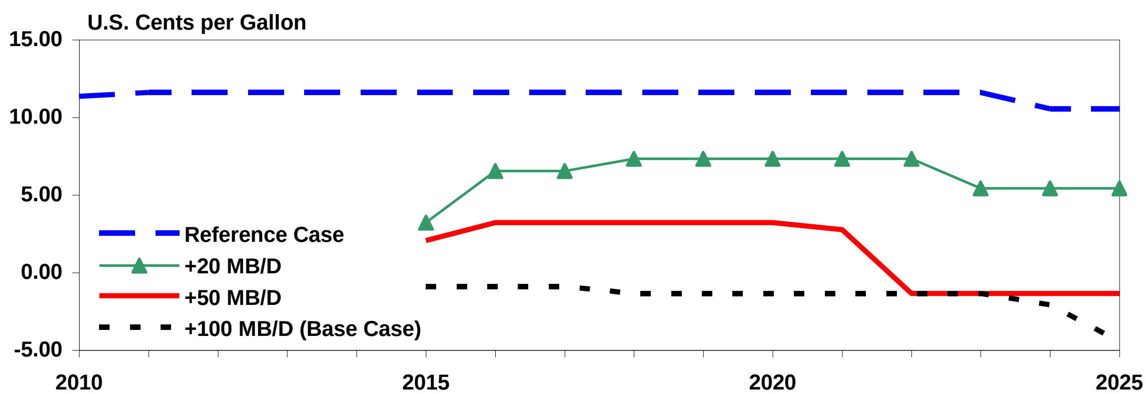
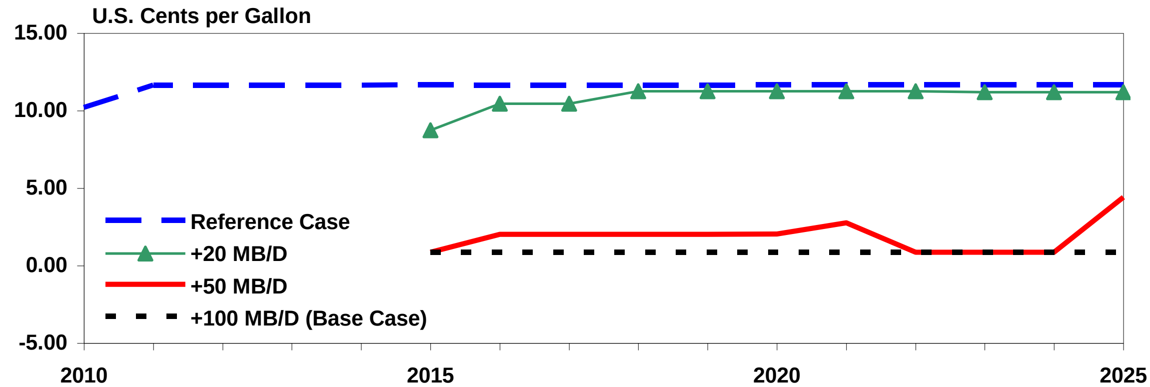
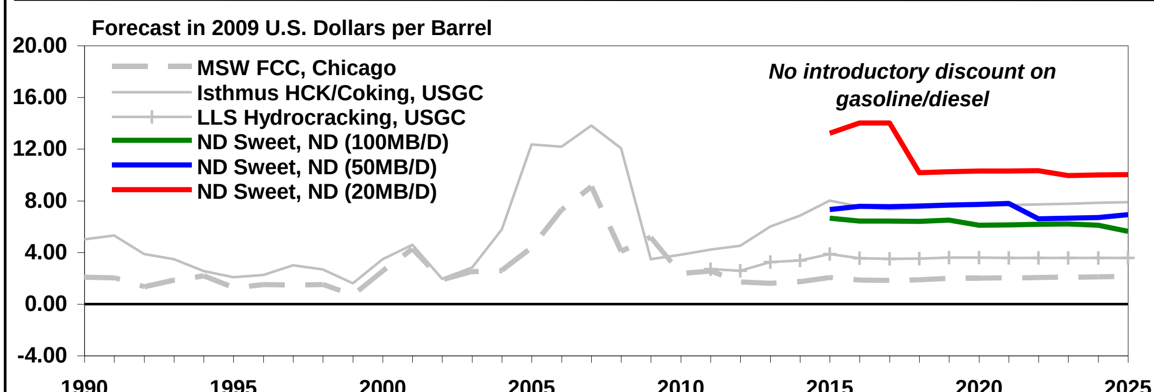


FIGURE II-8
DIESEL DIFFERENTIALS: NORTH DAKOTA MINUS GULF COAST



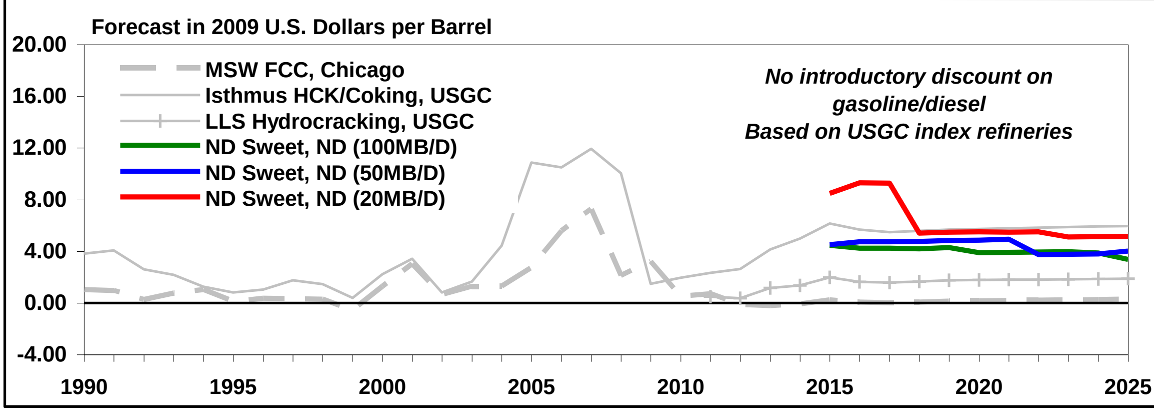
6. **Variable cost refining margins for the additional refining capacity are forecast to be positive.** The results of the crude and product market models have been incorporated into a preliminary refining margin forecast, as shown in Figure II-9. For comparison purposes, margins are shown for Light Louisiana Sweet (LLS) hydrocracking at the USGC, Alberta Mixed Sweet (MSW) fluid catalytic cracking (FCC) at Chicago and Isthmus hydrocracking/coking at the USGC. For the period from 2015 to 2025, the estimated variable cost margin (gross revenue less crude costs and variable costs) is strongly positive for all cases. Variable cost margins are highest for the 20,000 B/D case, particularly in the first few years of the project. The variable cost margin suggests an incentive to process incremental crude oil within the state, but does not include fixed operating costs or any allowance for project capital recovery. The margin forecast does not include any allowance for introductory market discounts on refined products, which may be required for a new entrant to establish a presence in the market.

FIGURE II-9
VARIABLE COST REFINING MARGINS



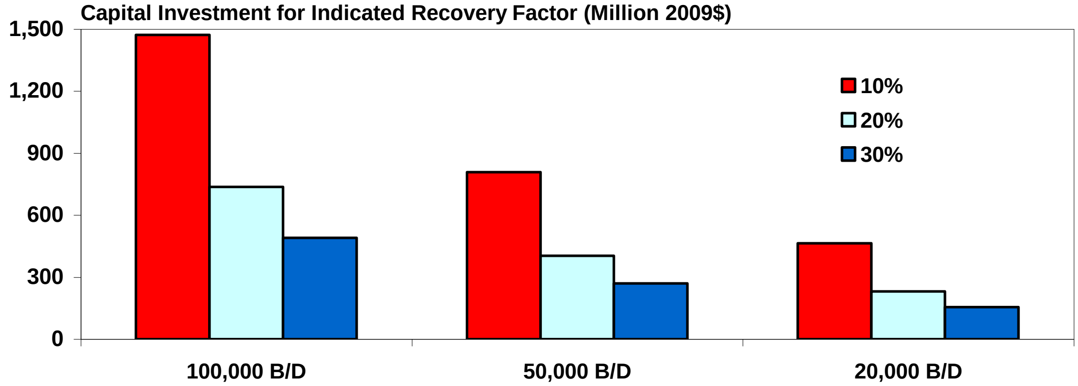
7. **Indicative net refining margins (after fixed and variable costs) for the additional refining capacity are forecast to be positive.** The results of the crude and product market models have been incorporated into a preliminary net refining margin forecast (Figure II-10). For this purpose, Purvin & Gertz has applied fixed cost estimates for a U.S. Gulf Coast index refinery with similar configuration and crude slate to the North Dakota refinery cases, since actual fixed costs for North Dakota were not estimated in Phase I. For the period from 2015 to 2025, the estimated net margin is positive, and highest for the 20,000 B/D case.

FIGURE II-10
NET REFINING MARGINS



8. **None of the refining capacity cases achieved a level of capital recovery that is considered adequate to support development of a grassroots project.** The net refining margin is the source of cash flow for recovery of invested capital. Figure II-11 summarizes the amount of invested capital that is supported by the estimated average net refining margin for the period 2015 to 2025 for each refinery capacity addition case. Capital recovery factors (CRF) were varied from 10 to 30 percent on an annual basis. The CRF is a simplified measure of project economics, based on project cash flows. The estimated capital investment supported by the project is the annual net margin divided by the target CRF. This approach excludes depreciation, tax and other company-specific project premises.

FIGURE II-11
REFINERY CAPITAL BASE (2015-2025)



9. **Significant further analysis would be required to fully evaluate a specific project for North Dakota.** The Phase I study has not been specific as to location of the additional refining capacity, and has been developed based on the above processing premises. Capital costs have not been estimated for the capacity addition cases. A full evaluation is recommended for any specific project concept. Phase II (if undertaken) would provide additional analysis of project capital costs and economics, as well as sensitivity analysis to the key project variables.

COMPETITIVE ANALYSIS

1. **Various stakeholders in North Dakota will be impacted differently by addition of refinery capacity in the state.** A preliminary qualitative assessment of the impact of such a project on key stakeholders was developed for this study. The analysis considered the opportunities and threats to each stakeholder, associated with additional refining capacity. Commitment of capital, human resources, technology and other resources will be required to bring a project to completion. Benefits may be either financial or social in nature. Following are the key conclusions, considered for each stakeholder.

2. **The refinery sponsor must have reasonable expectation of realizing positive operating margins and an acceptable return on invested capital.** The business case for the refining project must include secure supply of suitable crude oil and feasible offtake arrangements. The facility would be likely to access regional crude at an attractive price, and produce a high yield of valuable liquid products. The analysis summarized above (under Modeling Results) indicates positive margin generation potential for the refining capacity addition cases. However, the capital commitments associated with a refinery project are likely to pose significant challenges for the project sponsor. It cannot be concluded that from the Phase I analysis that any of the refining capacity cases would achieve acceptable project returns.

3. **Crude producers would not necessarily realize higher netback prices with additional refinery capacity in North Dakota.** There are several projects at various stages of development to transport Williston Basin crude to other refining locations. Even with a new refinery in North Dakota to capitalize on advantageous access to local crude supplies, excess crude that must be transported (using expensive logistics options) to markets outside of the state would set the price based on competitive refining economics at the clearing location, less the cost of transportation. The impact on crude producers will depend both on the incremental demand within the state, and the change in clearing location that results for the barrels leaving the state. Crude producers would potentially benefit from the diversification of market outlets associated with additional refining capacity in the state.

4. **Crude oil pipeline and transportation companies in North Dakota benefit from the opportunity of transferring surplus crude to other refining locations.** Projects that would increase crude oil transportation capacity have already been implemented, and more may be undertaken. Crude pipeline capacity utilization may be impacted if refinery capacity is added within the state. The location of the capacity additions would determine the impact on gathering and trunkline facilities. Rail system operators may see benefit because they can offer greater flexibility if production is rapidly increasing or decreasing.

5. **Refined products pipeline and terminal operators may be expected to benefit from additional refining capacity in North Dakota.** Increased utilization of existing facilities, or expansion or redeployment of existing facilities would be required. However, depending on the location of the refinery relative to existing refined products infrastructure, utilization of certain segments of existing systems may decrease. In some cases, existing infrastructure may need to be redeployed to accommodate increased product supply in the state.

6. **Existing refiners in the study region would realize lower wholesale prices due to the effect of additional product supply.** Refining economics in the study region are believed to be generally favorable due to a niche location from inland spot markets. Volumes of trade are small and transportation costs are high. Additional product supply would be accommodated by realignment of product transferred from other regions (mainly PADD III), so as to minimize overall transportation costs to serve these locations.

7. **Wholesale marketers in the study region would benefit from the addition of product supply in North Dakota.** The study region is characterized by a number of wholesale market participants. Some are integrated with refining operations, and others are independent marketers. These companies will generally obtain supply from refinery or independent terminal operators. Increased supply within the state would result in lower prices at the wholesale level, as the clearing market would shift to more distant locations. However, wholesale margins may be relatively unaffected.

8. **The State of North Dakota would be expected to benefit due to the increase in economic activity associated with the construction of new refinery capacity.** A large number of skilled jobs (trades) would be created during the project construction period. Operations and maintenance of the refinery process units would create a smaller number of permanent skilled labor jobs, as well as professional and administrative jobs associated with the ongoing management of the facility. Tax revenue derived from corporate and personal income would benefit the state.

III. REFINED PRODUCT MARKET ANALYSIS

This section presents an analysis of the inland U.S. product markets which are relevant to the North Dakota refinery capacity addition study. The analysis is based on Purvin & Gertz' current market outlook for refined products. For this analysis, a brief overview of U.S. petroleum markets is presented, as the basis for more detailed coverage of U.S. Petroleum Administration for Defense Districts (PADDs) II and IV markets. The outlook for North Dakota is presented, within the context of the PADD II product balance.

The focus of this section of the report is supply/demand and trade for the major light refined products (gasoline, jet/kerosene and diesel), as well as byproducts. Major regulatory issues affecting these products are also reviewed.

U.S. REFINED PRODUCTS

Refined products demand grew at an average rate of 0.7 percent from 2000 to 2007. This growth rate, which was lower than the preceding period, can be attributed to a weak economy in 2001/2002, the increase in oil prices in 2004-2007 and a large decrease in fuel oil demand in 2006. In 2008 and 2009, demand dropped significantly in response to high prices and the economic collapse that started in the second half of 2008. Demand is expected to begin recovering in 2010 but not reaching previous peaks until mid-decade. Past 2020, declining gasoline demand is expected to outweigh growth in other products.

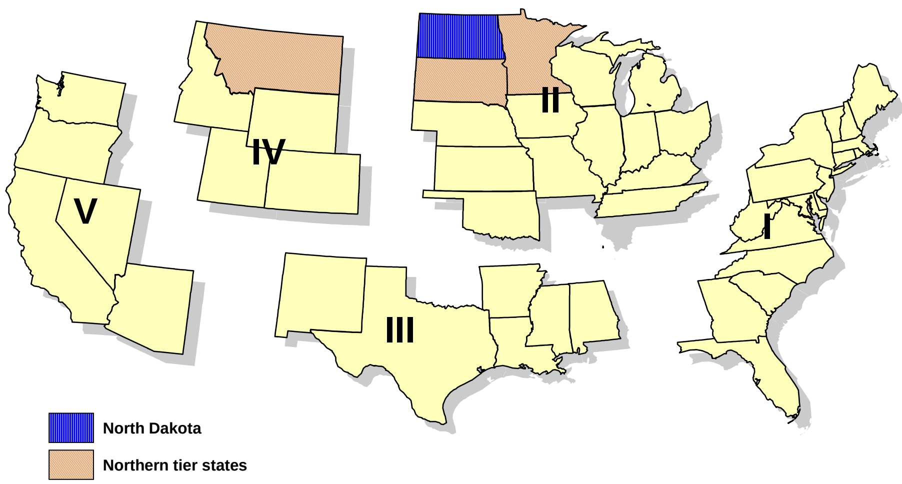
U.S. REFINED PRODUCT DEMAND
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025	Annual % Change 2010-15	Annual % Change 2015-20
Gasoline	9,159	9,253	9,286	8,989	8,992	9,034	9,271	8,936	8,240	0.52	(0.73)
Jet/Kerosene	1,749	1,687	1,655	1,553	1,413	1,460	1,629	1,726	1,809	2.21	1.17
Distillate	4,118	4,169	4,196	3,945	3,645	3,885	4,500	4,888	5,148	2.98	1.67
Residual Fuel Oil	920	689	723	622	518	554	502	475	515	(1.95)	(1.09)
Other Products	3,152	3,111	3,003	2,746	2,462	2,565	2,706	2,805	2,890	1.08	0.73
Total Demand	19,098	18,908	18,862	17,855	17,029	17,497	18,607	18,831	18,602	1.24	0.24
Annual % Change	0.62	(0.99)	(0.24)	(5.34)	(4.63)	2.75	1.24	0.24	(0.24)		

Demand growth for clean transportation fuels will outpace demand growth for residual fuel oil. Despite the sharp drop in 2008-2009, ultra low sulfur diesel is expected to show the greatest increase longer term, with a strong recovery after 2010. Jet fuel growth will be constrained due to more efficient airline fleets and possibly lower airline traffic. Gasoline demand stabilized in 2009 and should grow over the next few years. Increasing supplies of ethanol will displace some petroleum gasoline as a result of the Energy Independence and Security Act of 2007 (EISA), which is described below. Longer term, total gasoline demand recovers through about 2016, but demand then starts to decline as more efficient new vehicles mandated by EISA start to impact the fuel economy of the overall fleet.

Our analysis of supply and demand is by geographic areas known as Petroleum Administration for Defense Districts (PADD). The PADD boundaries are shown in Figure III-1, below. The focus of this study is on the inland markets (PADD II and PADD IV) and in particular, the northern tier states, including North Dakota.

FIGURE III-1
PETROLEUM ADMINISTRATION FOR DEFENSE DISTRICTS



ENERGY INDEPENDENCE AND SECURITY ACT OF 2007

The Energy Independence and Security Act (EISA) was signed into law by President Bush in December of 2007. EISA calls for efficiency improvements in all sectors of the economy (including transportation) through a series of mandates and research programs. Two sections of the law are expected to have the greatest impact on the refined product markets. These are the increase in Corporate Average Fuel Economy (CAFE) standards for new light duty vehicles and a significant increase in the Renewable Fuels Standard (RFS) volumes previously passed into law in 2005. Other sections in EISA have the potential to affect the refining industry, but these are thought to be less significant than the CAFE standards and RFS.

CAFE Standards

EISA called for a gradual increase in new light duty vehicle fuel efficiency requirements up to 35 miles per gallon (MPG) on average by the 2020 model year. The new CAFE requirement is stated as an annual average of all the new vehicles sold by an automaker. This is a very significant change from the previous requirements of 27.5 MPG for cars and 22.5 MPG for light trucks.

On May 19, 2009, President Obama announced a new program to develop new national vehicle standards aimed at reducing greenhouse gas (GHG) emissions and increasing fuel economy at an accelerated rate. The nation-wide program was developed jointly by the U.S. Environmental Protection Agency (EPA) and the National Highway Traffic Safety Administration (NHTSA) on behalf of the U.S. Department of Transportation (DOT) rather than through Congressional action.

The NHTSA and EPA intend to propose two separate sets of standards, each under their respective statutory authorities. EPA and NHTSA have determined that if the automotive industry were to achieve the target level of CO2 emissions through fuel economy improvements alone, this would equate to achieving a level of 35.5 miles per gallon for all new passenger car and light-duty trucks sold in the U.S. These proposed new vehicle standards would accelerate the new vehicle CAFE standards from the 2020 model year established under EISA to the 2016 model year under the current proposal. Increasing the average CAFE requirement from about 25 MPG currently to 35 MPG by 2016 will be challenging for all automakers, but in our view this is achievable given existing technology.

Assumptions for average new vehicle efficiency depend on market shares for gasoline-electric (hybrid) vehicles and diesel-powered vehicles. Hybrid car market share is expected to continue strong growth as automakers will likely offer additional models now that CAFE requirements have increased. Diesel car market share is also expected to improve some, but high pump prices relative to gasoline and higher vehicle acquisition costs will likely keep market share below 5 percent. In the light truck category, however, we expect that automakers will expand offerings of diesel models as a way to meet the new CAFE standards and maintain needed load-carrying and towing performance in this market segment. It is assumed that diesel-powered light trucks will be marketed primarily to commercial pick-up truck users.

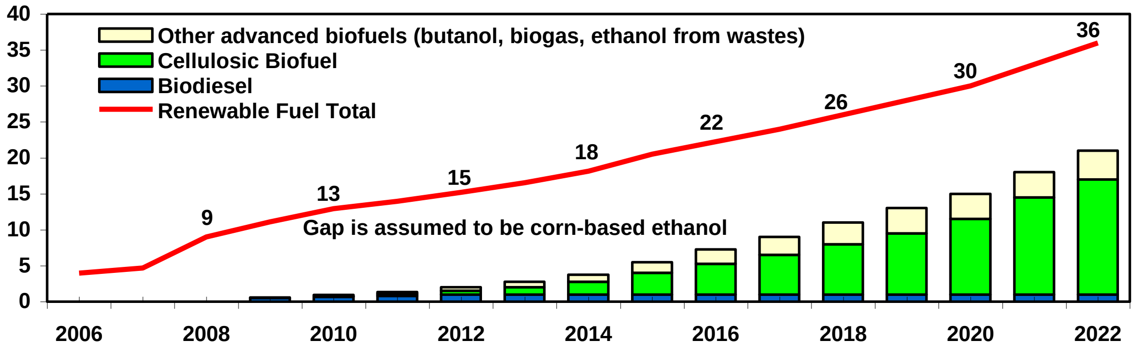
Renewable Fuels Standard

EISA increases the Renewable Fuels Standard volumes previously enacted into law in 2005. The law calls for a total of 36 billion gallons per year (BGY) of renewable fuel by 2022. This includes corn ethanol, cellulosic ethanol, biodiesel, butanol, sugar-based ethanol, biogas and any other fuel that has 50 percent reduction in lifecycle GHG emissions. In February 2010, the EPA issued the RFS2 regulation that changed 2010 requirements and allowed technologies that have a lower reduction in GHG lifecycle emissions.

The cellulosic ethanol requirement is quite aggressive. By 2015, 3 BGY of cellulosic ethanol is required, increasing to 16 BGY by 2022. Several new small-scale demonstration cellulosic ethanol plants are being designed and built with hopes of improving the technologies that have been tested in laboratories. These plants are not expected to startup until 2010 and later. The EPA administrator is given authority under EISA to lower the overall requirement if cellulosic ethanol does not develop into a commercially viable technology. RFS2 lowered the 2010 cellulosic ethanol requirements to 6.5 million gallons from 100 million gallons.

In addition to cellulosic biofuel, EISA also calls for specific volumes of other advanced biofuels to be produced and blended into the fuel supply. These include butanol, ethanol from wastes, sugar-based ethanol, and biogas. A requirement to use biodiesel is also included in the Act beginning in 2009 and continuing through 2012. RFS2 regulations combined the 2009-2010 biodiesel requirement into one for 2010. We have assumed that the biodiesel requirement will continue through the end of our forecast period at the same level. Although there is no specific requirement for corn-based ethanol, it is expected to supply a significant portion of the gap between the total RFS requirement and the advanced biofuel requirement (cellulosic, biodiesel, and other advanced biofuels). Figure III-2 illustrates the renewable fuels requirements.

FIGURE III-2
RENEWABLE FUELS REQUIREMENTS IN EISA
(Billion Gallons per Year)



U.S. GASOLINE DEMAND AND TRADE

Gasoline demand patterns have moved through several distinct periods over the past 30 years. The oil price shocks of the 1970s resulted in strong conservation trends. The price collapse in 1986 accelerated the move towards higher consumption, with the 1990s and early 2000s becoming a period of sustained high growth. Higher prices since 2004 contributed to a slowdown in the rate of gasoline demand growth, and a sharp drop in demand in 2008. Our outlook is for some recovery in gasoline demand until the 2015-2020 period and then a gradual decline in demand as higher efficiency vehicles begin to have an impact. Some of the demand growth is expected to be satisfied with additional ethanol blending.

Recent Trends and Outlook

Following the attacks of September 11, 2001, the economic slowdown and extended high prices hurt gasoline demand growth. However, demand growth averaged 2.8 percent in 2002 resulting in, at that time, an all-time record level consumption of almost 8.9 million B/D. Much of that demand strength is believed to have resulted from a shift from air travel to automobile travel, as also evidenced by the ongoing weakness in jet fuel demand. Higher prices since 2004 contributed to the slowdown in gasoline growth, peaking at 9.3 million B/D in 2007.

The dramatic increase in crude oil and gasoline prices in the first half of 2008 led to an equally dramatic demand response. The economic meltdown that began in late summer contributed to further weakness. As a result, demand is estimated to have declined by roughly 300,000 B/D in 2008. Demand was flat in 2009, with a very modest recovery beginning in 2010.

Gasoline demand growth is expected to average about 0.2 percent per year from 2010 through 2015. After 2015, we expect a plateau and then a gentle decline in demand as the effects of increasing fleet efficiency begin to be seen. Gasoline demand in the U.S. remains significantly higher than gasoline supply resulting in gasoline imports of over 900,000 B/D in 2009. Primary sources are Europe, Canada, and the Caribbean. Imports are expected to fall as new U.S. refinery capacity comes on line in the 2010-2014 timeframe. The table below summarizes gasoline supply and demand balance in the U.S.

U.S. GASOLINE BALANCE
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025
Production	7,902	7,905	7,829	7,436	7,566	7,531	7,765	7,499	6,923
Imports	1,113	1,144	1,165	1,090	941	896	844	754	616
Exports	158	150	142	185	200	185	174	164	155
Ethanol Supplied	265	359	448	632	694	795	835	843	850
Supply Adjustments	37	-6	-15	16	-10	-3	0	5	7
Consumption	9,159	9,253	9,286	8,989	8,992	9,034	9,271	8,936	8,240

U.S. DIESEL/NO. 2 FUEL OIL DEMAND AND TRADE

Consumption trends for diesel have not been subject to the trends in vehicle efficiency that have influenced gasoline demand, but are much more closely tied to economic activity and weather changes. The bulk of diesel fuel demand is used in commercial transportation which moves directly with strength in the economy. Demand for distillate fuel oil in the residential/commercial sectors moves with short-term temperature trends, and has been subject to long-term encroachment by natural gas.

Distillate demand grew at an average rate of 2.2 percent from 2002 to 2007. Demand growth for this product tracks GDP growth closely. Demand fell by over 6 percent in 2008 with the economic downturn, and dropped 7.6 percent in 2009 as the crisis deepened. Annual average growth rates through the next five years are expected to average 0.4 percent.

Distillate Demand by Sector

Distillate fuel oil market growth in the future will come mostly from increases in transportation consumption. Diesel penetration of the personal automobile fleet is expected to be negligible over the next five years. However, continued economic growth will increase the need for trucking and, therefore, diesel fuel. Bunker use of distillate should see moderate increases after 2015 as sulfur dioxide emission control areas (SECAs) are implemented along the U.S. mainland coasts. A shift from residual bunker to gasoil bunker is expected as ships comply with the new requirement. Despite the potential for larger ships to install on-board stack gas scrubbers to allow the use of higher sulfur residual fuels there will still be a substantial portion of vessels that will rely on low sulfur gasoil (<0.15 percent S).

Whereas distillate used for transportation has grown, market shares of distillate in most other sectors have either declined or are growing more modestly. The market for distillate fuel oil in the residential sector has been flat to down over the last few years. The trends of natural gas displacing distillates in the residential, commercial, industrial and electric utility sectors has resumed somewhat as growth in domestic gas supplies has rebounded.

In early 2010, only about 60 percent of the distillate pool is required to meet the ultra-low sulfur specifications, as it is applicable to on-highway product. Even so, many refiners are able to produce 100 percent of this material. Ultra-low sulfur diesel has penetrated other sectors that consume high quality diesel fuel, such as the farming and off-highway sectors, as a result of logistic constraints as well as strong marketing.

Changes in the sulfur level of the distillate pool have come from both shifting demand patterns and regulatory mandates. Faster growth in diesel demand relative to thermal consumption of distillate (residential, commercial, utility, etc.) has resulted in a growing demand share of the 500 ppm on-highway product. Regulations that became effective in June 2006 require 80 percent of on-highway supply to meet the 15 ppm sulfur specification, moving to 100 percent in 2010. Off-road diesel sulfur limits were tightened to 500 ppm in 2007 and will be further tightened to 15 ppm in 2010. These factors, along with expected spill-over of lower sulfur fuels into high-sulfur consumption sectors, will result in the high sulfur demand share falling with the 15 ppm product growing rapidly through 2015.

Distillate Balance

Most of the distillate fuel oil consumed in the U.S. is produced domestically, but imports have been increasing in recent years. This material is primarily imported from the Caribbean to the East Coast. Canada is also a major supplier. Exports have also increased in recent years, primarily to destinations in Latin America. Due to the more robust growth for distillate demand relative to gasoline, refinery production of distillate relative to gasoline will continue to increase.

U.S. DISTILLATE BALANCE
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025
Production	3,954	4,040	4,133	4,294	4,060	4,170	4,615	4,719	4,903
Imports	329	365	304	213	224	233	240	272	293
Exports	138	215	268	528	596	611	414	162	111
Biodiesel Supplied	6	17	23	21	11	38	65	65	65
Supply Adjustments	-33	-38	3	-54	-54	54	-6	-6	-3
Consumption	4,118	4,169	4,196	3,945	3,645	3,885	4,500	4,888	5,148

U.S. AVIATION FUELS DEMAND AND TRADE

The following table summarizes historical and forecast demand for aviation fuels in the U.S. Growth in demand for aviation fuels was historically one of the strongest among the refined products, led by commercial kerosene-type jet fuel. Aviation gasoline usage trends are volatile, but consumption typically averages about 18,000 B/D. Military consumption of jet fuels has been steadily declining.

U.S. AVIATION FUELS DEMAND
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025	Annual % Change 2010-15	Annual % Change 2015-20
Jet A	1,679	1,633	1,622	1,539	1,396	1,443	1,607	1,700	1,778	2.18	1.13
Aviation Gasoline	19	18	17	15	15	15	17	19	21	2.60	2.30
Total Demand	1,698	1,651	1,640	1,554	1,411	1,457	1,624	1,719	1,799	2.18	1.14
Annual % Change	3.12	(2.77)	(0.70)	(5.23)	(9.23)	3.33	2.18	1.14	0.91		

Kerosene-type jet fuel demand grew through the 1990s, with demand exceeding 1.7 million B/D in 2000. However, the September 11th attacks severely disrupted the airline industry late in 2001, changing the consumption pattern immediately. We expect growth to recover after the current recession as airline travel grows. Offsetting increased travel is a continuing trend of more efficient passenger jets replacing less efficient models.

The following table summarizes the jet/kerosene balance for the U.S. The U.S. produces a major portion of its jet fuel requirements, but there is substantial trade. About half of the imports come into PADD I, with PADD V accounting for most of the rest. Exports have historically averaged about 40,000 - 50,000 B/D. Kerosene use for burning is quite small (about 32,000 B/D) and there is minimal trade.

U.S. JET / KEROSENE BALANCE
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025
Production	1,611	1,528	1,484	1,509	1,406	1,396	1,581	1,641	1,718
Imports	197	190	220	105	89	135	134	139	145
Exports	55	44	50	66	67	68	85	53	54
Supply Adjustments	-5	12	1	6	-16	-3	-1	-1	-1
Consumption	1,749	1,687	1,655	1,553	1,413	1,460	1,629	1,726	1,809

There has been some discussion in the environmental and scientific community regarding the reduction of jet fuel sulfur, but no firm regulatory action appears evident. Jet fuel is one of the most globally harmonized fuels with common specifications around the world for the vast majority of consumption. The global nature of the airline industry and jet fuel is a hindrance to quick specification changes. Jet fuel sulfur specifications may be reduced to lower levels at some point in the future.

U.S. RESIDUAL FUEL OIL

The following table summarizes historical RFO demand in the U.S. by sector. Demand for RFO in the utility industry peaked in 1977-1978 at about 1.6 million B/D, but declined to only 206,000 B/D by 1995. With lower prices relative to natural gas, utility demand strengthened in the subsequent decade to 2005. Demand dropped precipitously in 2006 as a result of warm winter periods and ample supplies of natural gas for power generation. Demand recovered somewhat in 2007 before falling sharply in 2008 and 2009.

UNITED STATES RESIDUAL FUEL OIL DEMAND BY SECTOR
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025	Annual % Change 2010-15	Annual % Change 2015-20
Commercial/Other	51	33	34	27	26	25	22	18	15	(2.83)	(3.29)
Industrial	116	99	83	62	56	59	51	43	35	(2.87)	(3.35)
Oil Company	5	4	3	4	4	4	3	3	2	(3.41)	(4.11)
Electric Utility	385	160	161	112	97	121	103	86	68	(3.11)	(3.68)
Railroad	-	-	-	-	-	-	-	-	-	-	-
Vessel Bunkering	360	391	441	416	334	344	322	325	395	(1.33)	0.18
Military	2	1	1	1	1	1	1	0	0	(4.91)	(6.53)
All Other	-	-	-	-	-	-	-	-	-	-	-
Total Demand	919	689	723	622	518	554	502	475	516	(1.95)	(1.09)
Annual % Change	6	(25)	5	(14)	(17)	7	(1.95)	(1.09)	1.64		

Another major use of RFO is in the transportation sector for vessel bunkering. Beginning in 2015 when the marine sulfur regulations are expected to limit sulfur in bunker fuel to 0.1 percent, we expect some of the vessels operating in the U.S. to switch to marine gasoil. Other vessels are expected to achieve compliance by installing stack gas scrubbers that will allow continued use of high sulfur RFO bunkers and this will soften the demand decline in RFO bunkers.

The long-term declines in utility demand and the small amount of industrial demand result in the transportation sector becoming the dominant demand sector for RFO. Our forecast anticipates that residual bunker demand will erode slowly in the mid-term with the growing use of gasoil bunkers as a result of the new MARPOL regulations. Longer term, these trends result in a stabilization of RFO demand.

Of the total RFO demand, about 60 percent of U.S. demand is currently being imported. The Caribbean is the major supply source, but significant volumes of low sulfur RFO are imported from Algeria. We expect imports will vary with demand changes as this is the balancing source of supply with refiners generally viewing this fuel as a by-product.

Gulf Coast refiners use the export market to balance their operations. PADD I is the major deficit market for RFO in the U.S. Therefore, it balances market demand by either importing or transferring material from PADD III. Generally, PADD III serves the southeastern portion of PADD I, whereas foreign imports satisfy Northeast demand. The level of PADD III exports can significantly affect prices in this area. PADD V satisfies its imbalance from the production of RFO by exporting its surplus. However, this surplus has significantly decreased over the years as conversion of residue increased in California.

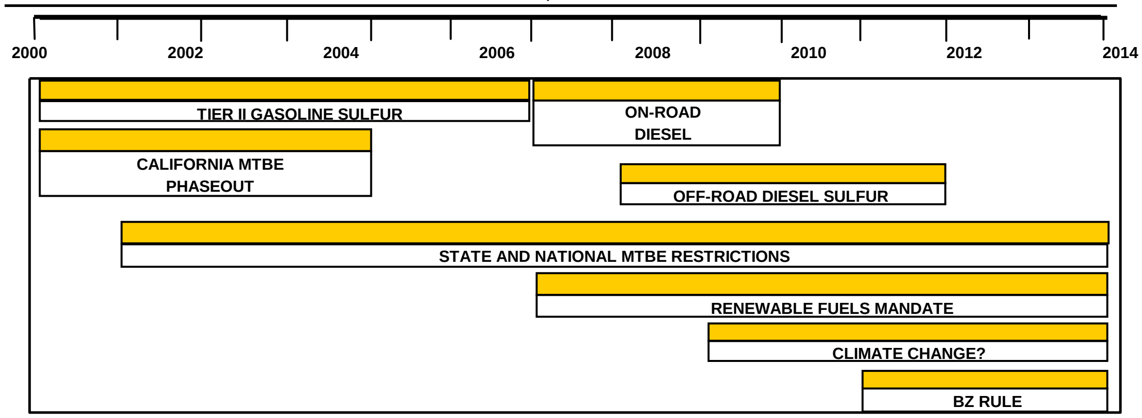
REGULATORY OVERVIEW

EVOLVING MOTOR FUEL SPECIFICATION CHANGES

In addition to the oxygenated and reformulated gasoline programs, the EPA has embarked on a strategy to significantly reduce emissions from on-highway light-duty vehicles, light-duty trucks and heavy-duty vehicles. The regulations focus on gasoline and diesel engines used in large commercial trucks, light-duty trucks, passenger cars and vans, and SUVs in all sizes but will also address emissions from off-road diesel engines. The goal is to reduce emissions of nitrogen oxides and particulate matter in vehicle exhaust by over 90 percent.

Beginning in 2004, tougher on-road tailpipe emission standards took effect. The Tier II program, as adopted in December 1999, limited emissions to 0.07 grams per mile for nitrogen oxides. Standards for vehicles weighing less than 6,000 pounds were phased in by 2007, while those for passenger vehicles weighing between 6,000 to 10,000 pounds were fully phased in by 2009. The EPA has determined that dramatic emission reductions can be achieved with available technology by coupling together tighter tailpipe standards with cleaner fuel standards. The new cleaner fuel measures, to be phased in through 2011, are summarized in Figure III-3.

FIGURE III-3
CUMULATIVE REGULATORY IMPACT ON MOTOR FUELS, 2000-2014



TIER II Gasoline Sulfur

In December 1999, the EPA announced a final rule to provide new Tier II motor vehicle emission and gasoline sulfur standards. As noted above, the Tier II standards adopt stricter tailpipe emission standards for motor vehicles beginning in 2004 and are to be phased in over a ten-year period for larger models.

The gasoline sulfur standard is a nation-wide standard set at 30 ppm, for both conventional and RFG, a 90 percent reduction from previous national levels. The new sulfur standard was phased in beginning in 2004 and reached the final standard in January 2006. Some small refiners, as well as those in some Western states, were given additional time to comply. The regulations set limits on the maximum sulfur content for any batch of gasoline, for refinery annual averages, and for company pool averages. The wording in the final regulations concerning the transition to 30 ppm sulfur gasoline contained special phase-in considerations for refiners in North Dakota, Montana, Idaho, Wyoming, Utah, Colorado, New Mexico, and Alaska.

Gasoline Air Toxics

The EPA issued a final rule to address mobile source air toxics emissions in December 2000. As provided by the Clean Air Act, these regulations address emissions of 21 Mobile

Source Air Toxics (MSAT) from diesel and gasoline engines, including several volatile organic compounds (VOC), metals, and particulates. The December 2000 rulemaking concluded that programs currently in place or underway would significantly reduce MSAT emissions. A new rule was promulgated to require that emissions of MSAT from gasoline be maintained at the 1998-2000 performance level. The EPA also established a plan to research and analyze MSAT issues, and set a deadline of July 2004 to issue final control plans. In December 2004, EPA proposed a rule to adjust the baseline for certain refiners and importers. This is a minor change to the previous regulations.

Benzene Reduction Program

In February 2007, the EPA finalized rule-making activities intended to reduce emissions of hazardous air pollutants from motor vehicles. The regulations require more stringent control of hydrocarbon exhaust emissions at low temperatures, reduced evaporative emissions from portable fuel containers, and lower benzene content in gasoline.

The gasoline benzene controls require that refiners and importers meet an annual average maximum benzene content of 0.62 percent (volume) on all gasoline (both conventional and reformulated). California gasoline is excluded from the program. A nationwide credit banking and trading system is to be established, but no supplier will be allowed to exceed a maximum physical average of 1.3 percent. The new benzene restriction will come into effect on January 1, 2011. At that time, the toxic emissions control programs applying to both RFG and conventional gasoline will be replaced by the new benzene controls.

The EPA has estimated that the current average benzene content of U.S. gasoline is about 1.0 percent, but it varies widely among refiners. The cost of compliance with the new standards will also vary widely, depending on each facility's configuration, feedstocks and operation. An EPA study identified a range of compliance costs from zero to 6.5 cents per gallon, with a national average (overall gasoline production) of 0.27 cents per gallon. The technologies generally used to reduce benzene include prefractionation of reformer feed to eliminate benzene precursors, isomerization of light naphthas to saturate benzene, extraction of benzene from reformate, and saturation of benzene in streams such as FCC naphtha. While margin benefits and operating cost increases may be largely offsetting, a modest level of capital recovery would imply a cost of about 1.0 cent per gallon.

Off-Road and On-Road Diesel Fuel

In April 2003, the EPA announced a plan to reduce sulfur in off-road diesel to 500 ppm in June 2007 and then to 15 ppm in June 2010 except for railroad and marine diesel which would need to be 15 ppm by June 2012. Small refiners would have a 3-4 year extension to meet the deadlines. A final rule was issued in early 2004.

The structure of the Tier II vehicle standards and the diesel fuel and emission standards suggest that the EPA does not wish to encourage greater diesel penetration into the U.S. light duty vehicle fleet. Tier II's common and tighter NOx and particulate standards for diesel and gasoline engines will be much easier for gasoline engines to meet. In addition, the proposed diesel fuel regulations do not require higher cetane number fuel. Acceptable noise levels and performance in light duty diesel engines is difficult to attain with the 40 cetane fuel used by heavy duty engines. In this tilt away from dieselization of the passenger car fleet, the EPA is apparently concerned over the potential for greater NOx emissions and particulates from the light duty diesel fleet, as well as concerns regarding toxicity of diesel fuel particulate emissions.

Likely Evolution of Motor Fuel Specifications

Certainly, not all future changes in specification parameters are known at this time, nor are the issues that may surface related to gasoline and diesel specifications. The world's automobile manufacturers have developed a set of proposed fuel qualities for markets with advanced emission control requirements under their World-wide Fuel Charter (WWFC) initiative. While no such regulations are now in place, it is anticipated that conventional gasoline and RFG qualities will eventually converge, with the possible exception of Reid Vapor Pressure (RVP) for fuels used in sensitive areas. Qualities are likely to approach or exceed the Category 4 specifications of the Charter.

CLIMATE CHANGE

The U.S. signed the Kyoto Protocol in 1998. The treaty called for the U.S. to implement a 7 percent reduction in GHG emissions from 1990 levels between 2008 and 2012. The U.S. did not ratify the Kyoto Protocol, but the Bush administration proposed a program of voluntary steps to increase energy efficiency. The EISA legislation can also be viewed as climate change legislation as its vehicle efficiency and biofuels mandates were based on a GHG reduction from the transportation sector.

With the election of Barack Obama and the Democrat-led Congress, new efforts are being made to advance climate change policies. There are two different approaches being taken. The EPA is advancing a regulatory agenda where GHG would be regulated under existing CAA law. Separate from this, the Congress is working on comprehensive climate change legislation that would regulate GHG emissions, most likely through a cap and trade scheme.

Impacts of any new carbon regulations on refiners could be significant, and would be expected to increase both the cost of operating refineries and the cost of the fuel products. There are significant issues that need to be addressed including the potential for carbon leakage and the emissions from offshore suppliers not subject to similar carbon costs.

It also appears likely that a separate Low Carbon Fuels Standard (LCFS) might be adopted. Generally, a LCFS is a regulatory standard designed to reduce the carbon intensity of motor fuels sold. California implemented LCFS regulations in early 2010 and these are likely to be used as a guide for any Federal program. The California LCFS requires a reduction in the carbon intensity (grams of carbon dioxide equivalent emissions per mega joule, gCO2e/MJ) of motor fuels sold in California by at least 10 percent by 2020. The carbon intensity of a fuel includes all GHG emissions emitted in its production. Therefore, alternatives like advanced biofuels and electric-powered vehicles still have carbon intensities, just somewhat lower than traditional petroleum fuels.

ETHANOL

The EISA requires increased use of biofuels, as discussed previously in this section. Gasoline sold in the U.S. must use a specified volume of biofuels (mostly corn ethanol now and increasing amounts of advanced biofuels in the future). The annual requirement of renewable fuels was 9.0 billion gallons per year in 2008. Volumes are allocated to all refiners, marketers and importers on a prorata basis. Small refiners can qualify for an exemption from the regulation until the end of 2009, but the industry as a whole must fulfill the volume requirements in the law.

The forecast of gasoline consumption includes the ethanol blended into the fuel. Most of the ethanol is currently produced in the Midwest (PADD II) and consumed in the highly populated coastal markets. RFG markets in PADD I, PADD II, Texas and California have been using ethanol for several years. Future growth in ethanol blends is expected to occur in all PADDs as supplies from the U.S. corn belt increase.

Ethanol will make a growing contribution to the U.S. gasoline pool. The EISA contains a target of 36 billion gallons of renewable fuels by 2022, almost 2.5 million B/D. However, much of this requirement is for cellulosic ethanol and other advanced biofuels for which economic production technology does not yet exist.

Ethanol production capacity is expanding at a rapid pace. High corn prices and ethanol distribution constraints led to periods of deep discounts relative to gasoline in 2007 and 2008. The sharp decline in crude prices in late 2008 helped restore the traditional relationship between gasoline and ethanol. Producing large volumes of ethanol from corn and transporting the renewable fuel to demand centers is expected to severely challenge the agricultural industry and fuel delivery systems in the U.S.

We anticipate that ethanol will grow to just under 10 percent of the gasoline pool by 2015, assuming that corn-based ethanol will remain the primary supply. If technological breakthroughs allow cellulosic ethanol to be produced competitively, then the contribution could increase. We have modeled the effects of higher ethanol supply on the U.S. gasoline balance.

ALTERNATIVE FUELS

Alternative fuels such as hydrogen, compressed natural gas (CNG), and liquefied petroleum gas (LPG) have the potential to reduce gasoline demand. Obviously, significant penetration of non-gasoline vehicles would have very important implications for refiners. Reduced gasoline demand would change the outlook for capacity requirements. If rapid changes occurred, there could be a negative effect on industry profitability.

Our analysis still indicates that alternative fuels are not likely to have a significant effect on gasoline demand until after 2020. The extent of impact then is by no means a clear issue at this point. The primary alternative fuels presently at issue include methanol, CNG, LPG, electricity, and hydrogen. LPG (primarily propane) has contributed 30,000 to 40,000 B/D to the transportation sector, and this is projected to grow to about 55,000 B/D during this decade. Though CNG is currently in use, its application is likely to be restricted to fleet vehicles for some time. Fleet vehicles, however, represent only a small portion of the overall fleet, and the effect on gasoline demand, therefore, would likely be small, unless full conversions were made. A major portion of CNG use is also displacing diesel fuel rather than gasoline. Methanol usage is also expected to be inconsequential, taking into account such factors as toxicity, logistics, and economics. Due to these practical difficulties, fuel cell vehicles are not expected to significantly affect gasoline and diesel demand until well into the future.

U.S. NATURAL GAS LIQUIDS MARKETS

The NGL industry in North America is the largest and most complex NGL market in the world. NGL are produced at gas processing plants in the U.S. and Canada and are transported by long-distance pipelines to several major fractionation and storage centers, including Mont Belvieu on the Gulf Coast, Conway in the Mid-Continent, Sarnia in Eastern Canada and Edmonton in Western Canada. From these fractionation and storage centers, NGL products are distributed to various end-use markets across the continent via pipeline, rail and truck transports.

North American NGL are produced primarily from natural gas processing plants and by various operating units in refineries. Gas processing accounts for approximately 70 percent of the total domestic NGL supplies and essentially all of the domestic ethane and natural gasoline supplies. Refinery supplies are about 40 percent of total domestic propane supplies and around 25 percent of total domestic normal butane supplies. In addition, merchant butane isomerization units are a significant source of isobutane supply.

PROPANE

Propane supplies in the U.S. are derived from gas plants, refineries and imports. Imports are brought into the U.S. via pipeline, rail and truck from Canada as well as waterborne imports into Mont Belvieu.

In recent years, gas plants have typically supplied around 40 percent of the total U.S. market for propane. Refinery production of propane/propylene accounts for about 43 percent to 46 percent. Propane imports vary noticeably depending on both U.S. and global market conditions, but generally range from 15 percent to 18 percent of the total U.S. supplies.

There are regional differences in propane/propylene production across the U.S. In PADD I (East Coast) and PADD V (West Coast), production from refineries typically accounts for over 80 percent of the regional supply of propane/propylene. By contrast, refineries in PADD IV only produce about 11 percent of the region’s propane/propylene supplies. Refineries in PADDs II and III approach the national average, producing about 50 percent of regional supply.

Of the total propane/propylene produced by refineries during recent years, propane comprised around 60 percent to 65 percent of the mix. Thus, refinery production of “pure” propane (net of the propylene also produced by refineries) is only about two-thirds of the amount that is produced by gas processing plants in the U.S.

We expect propane extraction in PADD II to shift from conventional to unconventional domestic gas production over the long-term. Additionally, propane production in the region is expected to drop after 2015 with a reduction of liquids extraction anticipated from the gas imported from Canada via the Alliance Pipeline.

Propane Demand

Propane is the most versatile of the NGLs. In North America, demand can be divided into two major market sectors – fuel and petrochemical. Within the fuel sector, propane is used as a heating fuel in several end-use markets, including residential/commercial, industrial, utility, and farm. Propane can also be used as a fuel in internal combustion engines, particularly for fork lifts.

The use of propane as a heating fuel in the residential/commercial end-use sector is currently the largest market for propane. On a regional basis, residential/commercial consumption in both PADDs I and II dwarfs the use of propane as a heating fuel in the other regions. These two regions account for around 75 to 80 percent of the entire propane heating fuels market in the United States. Propane use as a heating fuel in PADD II also dominates other market sectors, accounting for slightly under 60 percent of total demand in the region. The residential/commercial fuel market for propane in the other regions of the U.S. is relatively small. We expect that demand in this sector will grow slowly.

Chemical uses of propane are separated into three segments: ethylene, price sensitive petrochemical feedstock, and other demand. The ethylene category is that portion of ethylene feedstock demand for propane that we consider to be base demand that is relatively insensitive to price. Price sensitive petrochemical feedstock demand accounts for the remaining portion of ethylene plant feedstock use of propane that is not base demand. The “other” chemicals category refers to the refinery-sourced propylene that is sold into the chemicals market.

In PADD II, two fairly large NGL crackers and one small propane-only cracker should continue to consume about 25,000 B/D of propane. We do not envision any plant expansions or construction of new crackers in either region that would change these cracking rates in the future.

PADD II industrial fuel use of propane has averaged 28,000 to 32,000 B/D during the last few years. It is expected that future propane demand in the industrial fuel sector will grow somewhat slower than the overall U.S. economy. Most of this new growth could come from cogeneration plants that may switch to propane when it is an economically attractive fuel.

Propane is consumed in the agricultural sector for a wide variety of uses. During the 1990s, farm use of propane in the U.S. accounted for about 8 percent of the total market. Demand has generally been weak since 2003 due to warm, dry weather. However, we look for demand to rebound to near historical rates over the next few years. Farms in PADD II account for the largest regional use of propane – utilizing nearly two-thirds of all agricultural consumption in the United States. We expect that propane consumption in the agricultural to expand at a reasonably strong pace during the forecast period due, in part, to the impact of the U.S. biofuels program on corn demand.

In the Upper Midwest area of PADD II (Minnesota, Wisconsin, North and South Dakota), propane demand averages about 78,000 B/D. Gas processing production has increased steadily to about 8,700 B/D in 2009 and refinery production is about 9,000 B/D. Approximately 22,000 B/D is imported from Canada and the remainder, approximately 38,000 B/D, is provided from inter-PADD transfers. Overall, demand is almost four times local propane supply.

PADD II must rely on inter-PADD transfers and imports to satisfy its propane requirements. Consequently, any incremental production of propane in the Upper Midwest area of PADD II area (arising from incremental refining capacity) would likely be consumed in the local market.

BUTANE

Several changes occurred in the U.S. NGL market during the 1990s. The EPA's program to reduce summertime gasoline volatility caused profound changes in regional butane markets. Furthermore, the mandated use of reformulated gasoline in many U.S. cities forced many refiners to significantly modify their operations. These changes in the gasoline market impacted both the production of NGL (particularly butane) from refineries as well as demand for butane as a gasoline blendstock and alkylation feedstock.

Increased use of butane for the production of both ethylene and MTBE offsets much of the negative impacts caused by lower gasoline volatility and reformulated gasoline. However, MTBE has been phased out of essentially all regions of the U.S., and increasing quantities of ethanol are being blended into the gasoline pool. Most refineries are net consumers of isobutane. However, some refineries produce slightly more than they consume internally.

Butane in the U.S. is supplied by natural gas processing plants, refineries and imports. In recent years, gas plants in PADD II have produced 35,000 to 40,000 B/D of normal butane and 15,000 to 17,000 B/D of isobutane. Virtually all of the gas plant butane production is produced as a mix of normal and isobutane. Gas plant production of butane in PADD II should slowly increase in the future.

PADD II refineries have produced about 8,000 to 10,000 B/D of butane. PADD II refinery isobutane demand has averaged around 40,000 B/D in recent years. Similar to propane, the Upper Midwest area of PADD II must rely on imports and inter-PADD transfers to meet isobutane demands. Consequently, any incremental production of isobutane in the Upper Midwest region of PADD II would likely be consumed in the local market.

CONWAY AND MONT BELVIEU

Conway is the NGL market center for the Midwest region of the United States. The NGL storage and fractionation facilities and pipeline connections in the Conway/Hutchison/ McPherson area in Kansas provide the infrastructure to support PADD II NGL demand. The pipeline systems between PADD II and PADD III generally provide the flexibility to balance the supply and demand for NGL in the Midwest region, which results in a general link between NGL pricing in the Conway and Mont Belvieu market centers. Of course, seasonal weather patterns and inventory fluctuations result in short-term variations in the market differentials.

PADD II REFINED PRODUCTS MARKETS

Total demand for refined products in PADD II represents about 25 percent of the U.S. total, with markets ranging from the heavily industrialized Ohio Valley states to the sparsely populated and agricultural Plains states. Historical demand trends in PADD II generally mirror those of the U.S. Demand for refined products peaked in 2005 and has declined since then. A modest recovery in total demand is expected in the near term, but demand will remain below the 2005 peak. Refined products demand for PADD II is presented in Table III-1 and is summarized in the table below.

PADD II REFINED PRODUCT DEMAND
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025	Annual % Change 2010-15	Annual % Change 2015-20
Gasoline	2,626	2,629	2,619	2,544	2,526	2,527	2,547	2,416	2,207	0.16	(1.05)
Jet/Kerosene	370	337	311	274	245	253	277	290	299	1.89	0.88
Distillate	1,249	1,255	1,255	1,222	1,081	1,168	1,333	1,420	1,501	2.68	1.28
Residual Fuel Oil	55	47	42	40	31	33	28	25	22	(2.64)	(2.76)
Other	767	731	709	709	657	695	729	742	754	0.97	0.35
Total Demand	5,068	4,999	4,935	4,789	4,540	4,675	4,915	4,894	4,783	1.01	(0.09)
Annual % Change	2.32	(1.36)	(1.27)	(2.97)	(5.20)	2.97	1.01	(0.09)	(0.46)		

PADD II refineries have traditionally run at relatively high operating rates, averaging around 90 percent in recent years. Idle capacity has been eliminated, and even though there have been a number of refinery closures, expansions have increased operating capacity to near 3.8 million B/D. Around 15-20 percent of PADD II demand for light products is met by pipeline transfers from the Gulf Coast. Product pipelines have been expanded and more pipeline capacity is planned. With increasing demand, refinery operating rates are expected to remain very high and refineries are likely to continue to expand moderately. Product imports account for less than 5 percent of supply.

PADD II GASOLINE

The gasoline balance for PADD II is shown in Table III-1. PADD II accounts for just under 30 percent of U.S. gasoline demand, but its share has been declining for many years. Demand grew at an average rate of about 2 percent in the mid-1990's only to stagnate again in the 1997-2001 period at about 2.45 million B/D. Some growth has occurred in recent years and total gasoline demand is now around 2.5 million B/D.

Slowing population and economic growth, along with continued efficiency gains, are forecast to result in a slow decline in demand. A large proportion of total demand is accounted for by regular grade product, and this should continue.

Figure III-4 summarizes gasoline demand for individual PADD II states. Demand is heavily concentrated in the eastern states of PADD II. The states of North Dakota and South Dakota have small gasoline markets.

FIGURE III-4
GASOLINE SALES, 2009
(Thousand Barrels per Day)

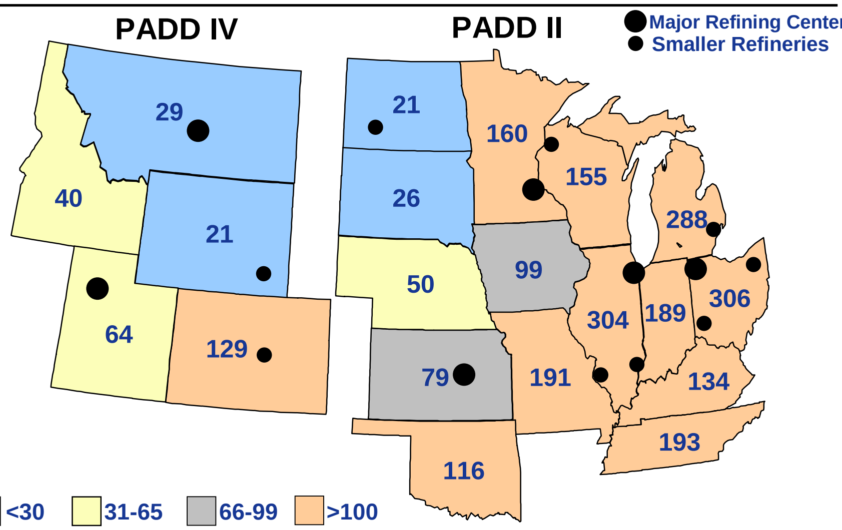
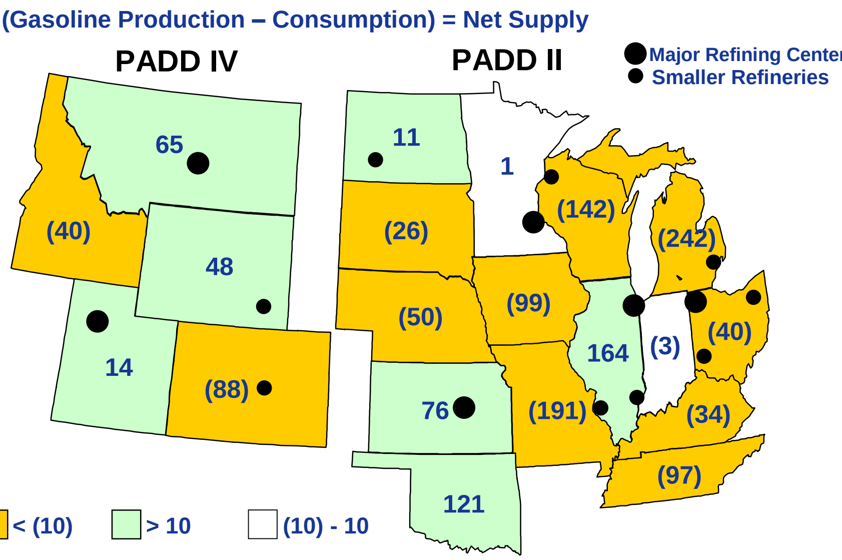


Figure III-5 presents gasoline balances for individual PADD II states. Net supply is defined as the difference between gasoline production and consumption in the state. The states in PADD II that produce significantly more gasoline than they consume are Indiana, Oklahoma and Kansas. Several states in the Upper Midwest and Great Lakes regions of PADD II (notably Michigan, Wisconsin, Missouri and Iowa) are significant net consumers of gasoline.

FIGURE III-5
GASOLINE SALES VS LOCAL SUPPLY, 2009
(Thousand Barrels per Day)



The following table summarizes the gasoline balance for 2008, including reformulated grades. PADD II refineries provide about 75 percent of gasoline demand. PADD II only imports small volumes of gasoline from Canada. The balance of requirements for the region is supplied through deliveries from other areas. About 15 percent of the total PADD II gasoline market demand is for reformulated grades.

PADD II GASOLINE BALANCE, 2008
(Thousand Barrels per Day)

	Total	Reformulated
Supply		
Production	1,937	364
Imports	1	0
Net Receipts	593	-44
Adjustments	21	62
Total	2,552	382
Disposition		
Demand	2,544	381
Exports	19	1
Stock Change	-13	0
Total	2,550	382

Note: (1) Source: DOE Petroleum Supply Annual 2008

The recent historical gasoline balance for PADD II, and the forecast to 2025, is summarized in the following table. See also Table III-1.

PADD II GASOLINE BALANCE
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025
Production	1,816	1,794	1,767	1,708	1,760	1,696	1,695	1,619	1,544
Imports	3	1	2	1	1	1	1	1	1
Exports	0	2	11	18	1	10	6	3	2
Net Receipts	673	691	673	593	546	607	638	585	412
Ethanol Supplied	136	138	179	243	215	232	218	212	249
Supply Adjustments	-2	7	8	18	5	1	2	3	3
Consumption	2,626	2,629	2,619	2,544	2,526	2,527	2,547	2,416	2,207

The Midwest market depends on deliveries from other areas to balance product requirements. The table below summarizes recent history of transfers into and out of PADD II. PADD III deliveries by pipeline account for the majority of transfers into the PADD II. Transfers in from PADD IV are around 20,000 B/D. Projections of transfers in the forecast take into consideration the estimated capability of PADD II refineries to produce gasoline, as well as the competitive incentive for some U.S. Gulf Coast refineries to continue to supply the market. Transfers as a percentage of demand have increased over the years with refinery shutdowns and consolidations.

GASOLINE MOVEMENTS TO / FROM PADD II (Thousand Barrels per Day)	2006	2007	2008
Receipts			
from PADD I	212	215	195
from PADD III	551	526	458
from PADD IV	20	17	20
Total	783	759	674
Shipments			
to PADD I	17	17	17
to PADD III	42	42	37
to PADD IV	32	27	27
Total	92	86	81
Net Receipts	691	673	593

Note: (1) Source: DOE Petroleum Supply Annual

PADD II DIESEL

The diesel balance for PADD II is shown in Table III-1. PADD II diesel consumption trends are dominated by on-highway and agricultural sectors. Refer to Table III-2 for the breakdown of diesel demand by sector for the individual states of PADD II. The transportation sector accounts for about 75 percent of the total demand for distillate in PADD II, and this share is increasing as diesel use grows and heating oil is displaced by alternative heating fuels. The fastest growing segment has been diesel fuel for on-highway use. Demand was affected significantly by the economic slowdown in 2009 but is expected to recover starting in 2010. Although on-road diesel demand is about 65 percent of the distillate market, ultra-low sulfur diesel sales are around 87 percent, indicating market penetration of ultra-low sulfur product into other sectors. High sulfur diesel sales had only a 3 percent market share in 2009.

PADD II DISTILLATE FUEL OIL DEMAND BY SECTOR
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025	Annual % Change 2010-15	Annual % Change 2015-20
Residential	40	33	28	28	20	19	17	15	14	(2.70)	(2.20)
Commercial	34	34	29	35	35	35	32	30	29	(1.40)	(1.23)
Industrial	53	53	47	44	44	43	39	36	34	(1.80)	(1.47)
Oil Company	7	9	9	11	10	9	9	8	8	(1.80)	(1.47)
Farm	122	129	116	124	128	129	134	137	139	0.69	0.51
Electric Utility	10	7	12	14	14	14	15	14	13	0.50	(0.33)
Railroad	98	105	112	83	71	79	92	97	100	3.21	0.96
Vessel Bunkering	30	28	28	14	12	13	15	16	17	3.21	0.96
On-Highway Use	793	806	824	819	704	779	924	1,008	1,086	3.49	1.75
Military	1	1	1	1	1	1	1	1	1	0.33	(0.22)
Off-Highway	62	49	49	50	43	47	55	58	60	3.21	0.96
All Other	-	-	-	-	-	-	-	-	-	-	-
Total Demand	1,249	1,255	1,255	1,222	1,081	1,168	1,333	1,420	1,501	2.68	1.28
Annual % Change	4.19	0.44	(0.01)	(2.63)	(11.54)	8.06	1.24	1.28	1.10		

Agricultural demand accounts for about 9 percent of PADD II distillate consumption. The demand is strongly seasonal, concentrated in the spring planting and fall harvesting cycles. Agricultural use varies, but is expected to increase moderately. Railroads are also an important user of diesel fuel and consumption has remained strong in recent years. Moderate growth is forecast for the long term. In PADD II, diesel bunkering is not a large market.

Distillate is used for heating in the residential sector, but displacement by natural gas will continue. Consumption has declined for many years and is below 30,000 B/D. A small amount of distillate (10,000 B/D) is used in peaking operations in the utility power sector.

Figure III-6 summarizes diesel demand for individual PADD II and PADD IV states. In PADD II, the largest states by diesel consumption are Ohio, Illinois and Indiana. The Great Lakes and southern Midwest states bordering these states are also significant consumers of diesel. This is consistent with the large concentration of economic activity in the region. The states of North Dakota and South Dakota have comparatively small diesel markets.

FIGURE III-6
DISTILLATE SALES, 2009
(Thousand Barrels per Day)

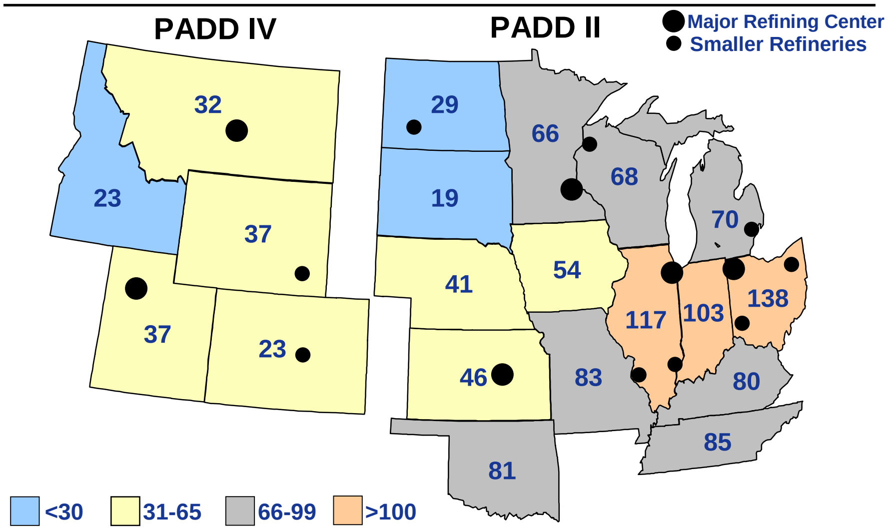
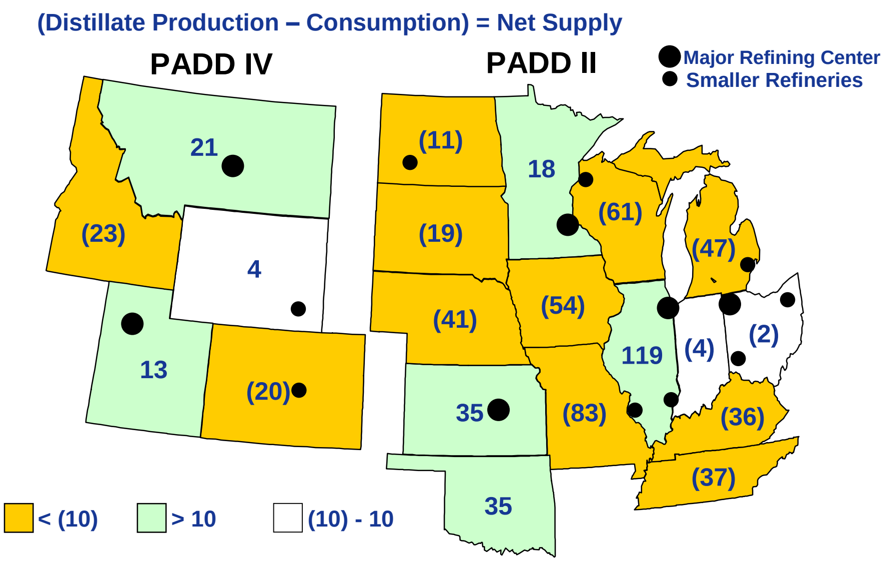


Figure III-7 presents diesel balances for individual PADD II and PADD IV states. Net supply is defined as the difference between production and consumption in the state. The states in PADD II that produce more diesel than they consume are Indiana, Oklahoma and Kansas. Several states in PADD II (Missouri, Wisconsin, Iowa and Michigan) are significant net consumers of diesel.

FIGURE III-7
DISTILLATE SALES VS LOCAL SUPPLY, 2009
(Thousand Barrels per Day)



The 2008 diesel balance for PADD II is shown below. PADD II production of distillate fuel oil has increased as a percentage of refinery intake. Regional refineries now provide about 80 percent of the regional demand. The remainder (except for a very small quantity of imports) is supplied through transfers from PADD III. As capacity rationalization has occurred over the years, the PADD II refiner market share has declined. Increasing supplies of Canadian refinery feedstocks are expected to slow this downward trend through this decade.

PADD II DIESEL & JET/KERO BALANCES, 2008
(Thousand Barrels per Day)

	Diesel Fuel Total	Diesel Fuel ULS	Jet / Kerosene
Supply			
Production	987	874	209
Imports	5	2	0
Net Receipts	249	192	74
Adjustments	0	-4	0
Total	1,241	1,064	283
Disposition			
Demand	1,222	1,050	275
Exports	12	0	9
Stock Change	7	14	-2
Total	1,241	1,064	282

Note: (1) Source: DOE Petroleum Supply Annual 2008

The recent historical diesel balance for PADD II, and the forecast to 2025, is summarized in the following table. See also Table III-1.

PADD II DISTILLATE BALANCE
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025
Production	908	914	927	987	894	927	1,014	1,041	1,067
Imports	4	6	6	5	4	5	10	18	25
Exports	9	2	6	12	6	6	6	6	6
Net Receipts	344	332	336	249	193	224	297	351	396
Biodiesel Supplied	2	5	7	6	3	11	19	19	19
Supply Adjustments	0	0	-15	-13	-8	8	-1	-1	-1
Consumption	1,249	1,255	1,255	1,222	1,081	1,168	1,333	1,420	1,501

As with the other light refined products, a large proportion of the total diesel demand in PADD II is supplied by transfers from other regions. The table below illustrates recent history for diesel transfers into and out of PADD II. PADD III supplies about two-thirds of the transfers into the region. Receipts from PADD IV have been relatively small, and balanced.

DISTILLATE MOVEMENTS TO / FROM PADD II
(Thousand Barrels per Day)

	2006	2007	2008
Receipts			
from PADD I	107	105	99
from PADD III	266	290	215
from PADD IV	11	10	12
Total	384	404	325
Shipments			
to PADD I	8	9	13
to PADD III	23	35	41
to PADD IV	21	24	23
Total	52	68	77
Net Receipts	332	336	249

Note: (1) Source: DOE Petroleum Supply Annual

PADD II AVIATION FUELS/KEROSENE

The jet/kerosene balance for PADD II is shown in Table III-1. Consumption of jet fuel was strong in 2004 and 2005, and demand increased with an improving economy. However, demand has been falling since then. The following table summarizes aviation fuels demand, which is dominated by jet fuel.

PADD II AVIATION FUELS DEMAND
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025	Annual % Change 2010-15	Annual % Change 2015-20
Jet A	359	323	308	274	245	252	277	289	298	1.87	0.86
Aviation Gasoline	6	5	5	5	4	4	5	5	6	3.19	2.75
Total Demand	365	328	313	278	248	256	281	294	304	1.89	0.90
Annual % Change	5.10	(10.04)	(4.60)	(11.09)	(10.69)	3.06	1.89	0.90	0.65		

PADD II refineries provide over 75 percent of the area's jet fuel requirements. Imports and exports are negligible. A large volume of jet/kerosene is supplied annually by transfers in from other regions. The table below indicates that transfers in from PADD III have been large but trending lower in recent years. Transfers from other regions are very small. PADD II supplies about 20,000 B/D annually to PADD IV.

JET FUEL/KERO MOVEMENTS TO / FROM PADD II
(Thousand Barrels per Day)

	2006	2007	2008
Receipts			
from PADD I	18	19	8
from PADD III	122	118	87
from PADD IV	2	2	1
Total	142	138	96
Shipments			
to PADD I	1	1	2
to PADD III	1	1	1
to PADD IV	21	21	20
Total	23	23	23
Net Receipts	119	115	74

Note: (1) Source: DOE Petroleum Supply Annual

PADD II NAPHTHA

A small level of naphtha consumption is reported in this region for petrochemical feedstocks. The naphtha balance for PADD II is shown in Table III-1. Small volumes of excess supplies of naphtha are transferred to PADD III for use as a petrochemical feedstock. In recent years, naphtha exports to Canada for use as a diluent for oil sands production have grown rapidly. This trade is currently estimated at about 40,000 B/D.

PADD II RESIDUAL FUEL OIL

RFO demand in PADD II is very low, having been displaced with gas and other fuels. RFO consumption in PADD II has now declined to under 40,000 B/D on a DOE primary demand basis. Demand is forecast to continue to decline through the forecast period. As noted in the table below, the DOE sector breakdown shows lower levels of local end use consumption due to cross-region transfer anomalies.

PADD II RESIDUAL FUEL OIL DEMAND BY SECTOR
(Thousand Barrels per Day)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Annual % Change 1995-2008
Commercial/Other	1	1	2	2	2	1	2	2	3	3	3	1	1	1	0
Industrial	14	17	14	11	13	14	13	10	12	16	18	15	13	9	(3)
Oil Company	5	2	3	1	1	1	1	1	1	0	0	0	0	0	(21)
Electric Utility	5	6	5	8	7	6	20	5	11	7	6	1	1	1	(15)
Railroad	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Vessel Bunkering	1	2	2	1	1	2	2	2	1	2	2	2	3	2	4
Military	0	0	0	0	0	0	0	0	0	0	-	-	-	-	(100)
Total Demand	27	28	26	24	24	25	38	21	29	29	29	20	18	14	(5)
Annual % Change	(10)	3	(7)	(8)	(0)	7	51	(45)	38	1	1	(33)	(7)	(25)	

Unlike the other PADD regions, the principal use for RFO in PADD II has been in the industrial sector, including oil company use. Demand has been declining because of widespread substitution by natural gas and this trend is expected to continue in the future.

The only other significant use of RFO in PADD II is the utility power sector. However, demand in this sector is 5,000 to 10,000 B/D as the utility power sector has increased its dependence on nuclear and coal. Consumption in this sector is linked to weather patterns.

It has been economically necessary for PADD II refiners to minimize RFO production over the years due to the low level of demand. As a percentage of the product slate, PADD II shows the lowest level of any of the PADDs. Production has stabilized at about 50,000 B/D.

PADD II is essentially in balance, but some transfers have historically occurred with PADD III. The RFO balance for PADD II is shown in Table III-1. When required to balance the market, low sulfur RFO has been transferred in, while small periodic surpluses of high sulfur RFO are transferred out.

PADD IV REFINED PRODUCTS DEMAND

PADD IV encompasses the sparsely populated Rocky Mountain States of Montana, Idaho, Wyoming, Utah, and Colorado. Product demand has increased steadily over the last two decades, but continues to account for a small fraction (about 3 percent) of U.S. demand. Demand trends by product are presented in Table III-3 and summarized in the following table.

PADD IV REFINED PRODUCT DEMAND
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025	Annual % Change 2010-15	2015-20
Gasoline	277	286	294	288	299	302	324	326	313	1.39	0.16
Jet/Kerosene	39	53	56	54	49	51	60	66	70	3.36	1.85
Distillate	173	187	182	181	177	189	219	244	263	3.06	2.11
Residual Fuel Oil	15	15	14	12	10	10	9	9	9	(1.00)	(1.00)
Other	98	94	99	98	87	101	104	106	109	0.59	0.52
Total Demand	603	636	645	633	621	653	717	751	765	1.89	0.95
Annual % Change	(5.55)	5.50	1.42	(1.86)	(1.84)	5.05	1.89	0.95	0.35		

Historically, the region had surplus refinery capacity and operating rates were generally low. Operating rates have improved substantially in recent years, with refinery operating rates around 90 percent. Future growth in operating rates will be limited by the rising volume of product flows into the area from Gulf Coast and Texas Panhandle refineries.

PADD IV GASOLINE

The gasoline balance for PADD IV is shown in Table III-3. Gasoline consumption has been increasing at an annual rate of about 0.8 percent per year through 2007, stimulated by population growth as well as a strong economy. Demand by state is shown in Figure III-4. State demand for gasoline is highest in Colorado and lowest in Wyoming and Montana.

Gasoline consumption fell in 2008, but a return to growth is expected after 2010 as population increases in the region. Though the area is largely rural, population growth has been one of the most robust of any area in the U.S. Premium gasoline sales are about 11 percent of total demand.

Figure III-5 presents gasoline balances for individual PADD IV states. Montana and Wyoming produce gasoline in excess of their state-wide demand, while Colorado is a net recipient of product from other states.

Transfers into PADD IV exceed transfers out due to the addition of products pipeline capacity from the Texas Panhandle refineries to Denver. The table below summarizes the gasoline balance for 2008.

PADD IV GASOLINE BALANCE, 2008
(Thousand Barrels per Day)

	Total	Reformulated
Supply		
Production	296	0
Imports	0	0
Net Receipts	-3	0
Adjustments	-2	0
Total	291	0
Disposition		
Demand	288	0
Exports	0	0
Stock Change	1	0
Total	289	0

Note: (1) Source: DOE Petroleum Supply Annual 2008

Net transfers into PADD IV have been quite small. Growth in deliveries into the Denver area is expected but a proposed pipeline from Salt Lake City to Las Vegas may make PADD IV a net supplier in the future. There is no reformulated gasoline in PADD IV. The recent historical diesel balance for PADD IV, and the forecast to 2025, is summarized in the following table. See also Table III-3.

PADD IV GASOLINE BALANCE
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025
Production	275	277	272	276	282	286	285	278	271
Imports	0	0	0	0	0	0	0	0	0
Exports	0	0	0	0	0	0	0	0	0
Net Receipts	-5	7	5	-3	0	-1	15	18	11
Ethanol Supplied	6	6	11	17	16	18	23	29	31
Supply Adjustments	1	-4	5	-1	0	0	0	0	0
Consumption	277	286	294	288	299	302	324	326	313

PADD IV DIESEL

The diesel balance for PADD IV is shown in Table III-3. Distillate consumption increased moderately through 2007 before falling in 2008. Refer to Table III-2 for the breakdown of diesel demand by sector for the individual states of PADD IV. On-highway use of diesel is the largest market and we expect it to continue to increase after the current slowdown. Industrial, farm, and railroad use are the other major consuming sectors and continued growth is expected.

PADD IV DISTILLATE FUEL OIL DEMAND BY SECTOR
(Thousand Barrels per Day)

										Annual % Change	
	2005	2006	2007	2008	2009	2010	2015	2020	2025	2010-15	2015-20
Residential	1	1	1	1	1	1	1	1	1	(1.00)	(1.00)
Commercial	4	4	3	3	3	3	3	3	3	(1.88)	(1.72)
Industrial	12	12	11	14	14	14	14	14	14	(0.63)	(0.16)
Oil Company	4	9	8	12	12	13	14	14	14	1.83	0.65
Farm	10	11	10	12	12	12	12	13	13	1.00	0.69
Electric Utility	0	1	0	0	0	0	0	0	0	(1.00)	(1.00)
Railroad	13	13	12	8	8	8	10	11	12	3.56	1.99
Vessel Bunkering	0	0	0	0	0	0	0	0	0	0.00	0.00
On-Highway Use	116	127	130	123	119	130	156	178	197	3.81	2.64
Military	0	0	0	0	0	0	0	0	0	0.33	(0.22)
Off-Highway	12	10	7	7	7	7	9	10	11	3.56	1.99
All Other	-	-	-	-	-	-	-	-	-	-	-
Total Demand	173	187	182	181	177	189	219	244	263	3.06	2.11
Annual % Change	(3.39)	7.91	(2.31)	(0.65)	(2.46)	6.92	2.30	1.99	1.58		

Refer to Figure III-6 which summarizes 2008 diesel demand for individual PADD IV states. Demand is relatively consistently distributed across the region.

Figure III-7 presents diesel balances for individual PADD II states. The large net producing states are Montana and Utah.

The 2008 diesel balance for PADD IV is summarized in the table below. PADD IV has been a net recipient of transfers in since the mid-1990's. Imports from Canada are stable at 5,000 to 10,000 B/D with increases projected in the longer-term as increased distillate supplies become available from Canadian oil sands production activities.

PADD IV DISTILLATE BALANCE, 2008
(Thousand Barrels per Day)

	Diesel Fuel Total	Diesel Fuel ULS	Jet / Kerosene
Supply			
Production	168	146	27
Imports	4	3	0
Net Receipts	9	9	26
Adjustments	0	0	-1
Total	181	158	53
Disposition			
Demand	181	159	54
Exports	0	0	0
Stock Change	-1	-1	-1
Total	180	158	53

Note: (1) Source: DOE Petroleum Supply Annual 2008

Refinery output of distillate in PADD IV is quite seasonal, reflecting requirements for diesel fuel for farming, railroad and on-highway/off-highway uses. Thermal uses for distillate are small. Distillate fuels production represents a higher proportion of the product slate in PADD IV than any other region of the country, averaging about 30 percent based on total refinery feed. We expect distillate yields to continue to increase as Canadian crudes become a larger portion of the feed to PADD IV refineries.

The recent historical diesel balance for PADD IV, and the forecast to 2025, is summarized in the following table. See also Table III-3.

PADD IV DISTILLATE BALANCE
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025
Production	171	169	159	168	171	169	183	190	197
Imports	6	8	8	4	6	5	8	13	18
Exports	0	0	0	0	0	0	0	0	0
Net Receipts	-5	10	15	9	2	10	25	38	45
Biodiesel Supplied	0	1	1	1	1	2	3	3	3
Supply Adjustments	1	-2	-1	0	-3	3	0	0	0
Consumption	173	187	182	181	177	189	219	244	263

PADD IV AVIATION FUELS/KEROSENE

Jet/kerosene demand and balance trends for PADD IV are shown in Table III-3. Commercial jet consumption had increased to over 65,000 B/D in 2000, but declined to about 60,000 B/D by 2004 as air travel had not recovered from the impact of September 11. There was a sharp drop reported in product supplied for 2005, but demand rebounded in 2006-07. We expect moderate growth in demand to begin in 2010 following the near-term slowdown.

PADD IV AVIATION FUELS DEMAND
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025	Annual % Change 2010-15	Annual % Change 2015-20
Jet A	38	52	55	53	48	51	60	65	69	3.35	1.83
Aviation Gasoline	0	0	0	0	0	0	0	1	1	15.73	8.71
Total Demand	38	52	56	54	48	51	60	66	70	3.42	1.89
Annual % Change	(5.55)	5.50	1.42	(1.86)	(1.84)	5.05	1.89	0.95	0.35		

Transfers into PADD IV have exceeded local production for many years, and have been about 25,000 B/D recently. We expect jet fuel production and transfers to increase with demand growth. Imports and exports are insignificant in this region. Kerosene for other uses is about 1,000 B/D.

NORTH DAKOTA REFINED PRODUCTS DEMAND

North Dakota refined products demand accounts for a very small fraction of the light refined products demand in PADD II. The following table summarizes historical refined product demand by major product. Demand has increased since 2000, but still accounts for only about 1.5 percent of total PADD II demand. Demand trends for individual products are discussed below.

NORTH DAKOTA REFINED PRODUCT DEMAND
(Thousand Barrels per Day)

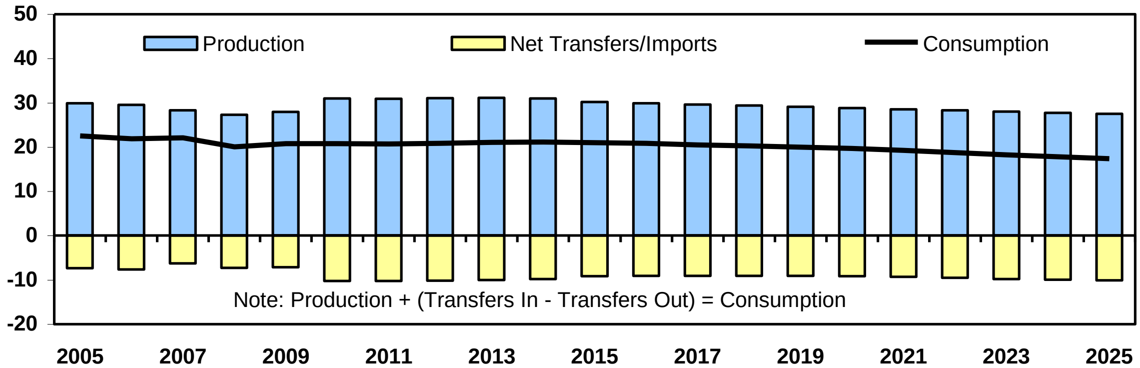
	2005	2006	2007	2008	2009	2010	2015	2020	2025
Gasoline (ex-EtOH)	23	22	22	21	21	21	22	20	18
Jet Fuel/Kerosene	4	4	3	3	3	3	3	3	3
Low Sulfur Diesel	16	16	21	25	27	29	34	37	40
High Sulfur Diesel	12	12	13	7	2	2	1	0	0
Total Light Products	56	55	59	56	53	55	60	61	61
Residual Fuel Oil	2	2	2	2	2	2	2	2	2

In relation to overall PADD II product demand trends, North Dakota has historically had a low G/D demand ratio. The G/D ratio is currently about 0.7, compared to a ratio of nearly 2.0 to 1.0 for the PADD region as a whole.

NORTH DAKOTA GASOLINE

Figure III-8 summarizes the balance for North Dakota gasoline (excluding ethanol blending). North Dakota gasoline consumption has been generally flat to declining in recent years. Demand fell at a moderate rate of about 0.3 percent per year in the decade to 2009. The economic downturn affected gasoline demand in 2008 (down 2.8 percent) and 2009 (down 0.6 percent). Consumption is expected to stabilize in 2010, and then grow for a few years. However, by 2015, a long term decline is expected to take effect, with annual demand declining at around 1.3 percent per year through 2025.

FIGURE III-8
NORTH DAKOTA GASOLINE (ex-EtOH) BALANCE
(Thousand Barrels per Day)



Demand has historically been dominated by regular gasoline grades, but a shift has been noted in recent years to an increasing proportion of midgrade. Regular gasoline accounted for about 73 percent of demand in 2008.

The North Dakota gasoline market is a conventional gasoline market. Some ethanol is blended on an opportunistic basis.

The market balances on net transfers out. It is important to note that gasoline is both transferred into and out of the state, and that only net transfers are shown in Figure III-9. Some transfers occur on equity pipelines, and would therefore be considered structural in nature. Imports from Canada are small, and are expected to remain so.

NORTH DAKOTA DIESEL

Figure III-9 summarizes the balance for North Dakota diesel (all grades). North Dakota diesel consumption has been growing at a strong rate. Since 2005, the average annual growth has averaged 0.6 percent. That period includes the effects of the economic downturn in 2008 and 2009, which left demand well below the peak set in 2007. Consumption is expected to make a strong rebound in 2010, and then grow at a decreasing rate over the balance of the forecast. Between 2010 and 2020, the compound annual growth rate for diesel is forecast to be over 1.9 percent per year.

FIGURE III-9
NORTH DAKOTA DIESEL BALANCE
(Thousand Barrels per Day)

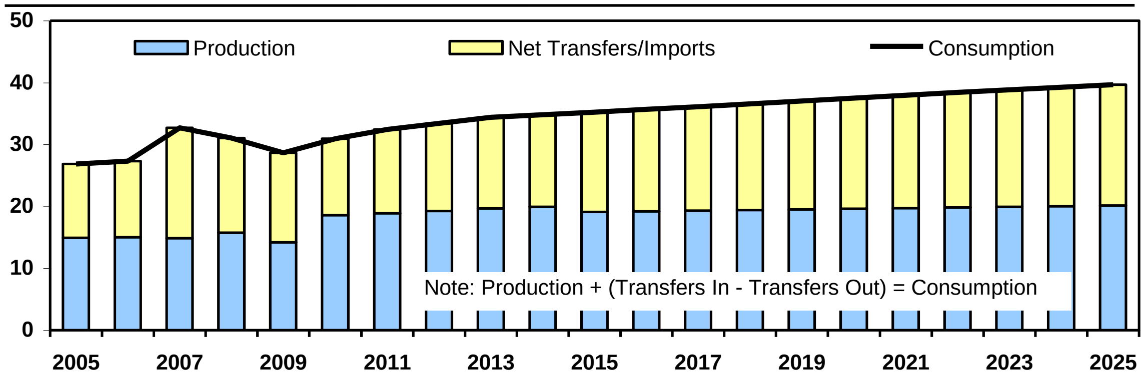


Table III-2 provides a breakdown of diesel demand in North Dakota by economic sector. On-highway demand in North Dakota accounts for about 36 percent of diesel consumption. The second largest demand sector is agriculture, at 27 percent. (The comparable figures for PADD II as a whole are 67 percent and 10 percent, respectively.) Diesel demand in the industrial sector is also significant in North Dakota, at 15 percent. This is due to the high activity level in oil and gas development in the state.

The diesel market relies on net transfers into the state, since consumption is greater than production. Diesel is both transferred into and out of the state, but net transfers in are the balancing mechanism, as shown in Figure III-9. North Dakota receives product from Montana (on the Cenex products pipeline), and from the east and south on the Magellan system. Product is also delivered east into Minnesota on the NuStar system.

NORTH DAKOTA AVIATION FUELS/KEROSENE

The North Dakota aviation fuel market has historically included significant military demand, attributed to Grand Forks Air Force Base (GFAFB). As recently as 2005, GFAFB was the operational base for 40 KC-135 refuelling tanker aircraft. In recent years, the Department of Defense has undertaken significant realignment of its facilities. This program has affected GFAFB, due to the redeployment of these refueling aircraft. As a result, the demand for jet fuel to the military, which was estimated at 8,000 B/D in the past, has been significantly reduced.

Consistent with the PADD II trend, demand for RFO in North Dakota is almost negligible. Total demand in 2008 was 225 B/D, about 1 percent of PADD II consumption. Any incremental production of residual fuel oil from North Dakota would likely need to be transferred to other markets outside of PADD II.

NORTH DAKOTA LIGHT REFINED PRODUCTS BALANCE

Table III-4 is a supply/demand balance for the North Dakota products market, for the period from 2005 to 2025. The balance is based on the PGI product demand forecast. Production is estimated from the Tesoro Mandan refinery at current throughput and crude slate.

TABLE III-1
PADD II REFINED PRODUCT BALANCES
(Thousand Barrels per Day)

	2000	2005	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
Gasoline												
Refinery Production	1,727	1,816	1,708	1,760	1,696	1,692	1,697	1,703	1,693	1,695	1,619	1,544
Inter-PADD Transfers In/(Out)	554	673	593	546	607	613	643	652	654	638	585	412
Imports / (Exports)	1	3	-18	0	-9	-8	-7	-6	-6	-5	-2	-1
Supply Adjustments (1)	155	134	261	220	233	227	218	215	217	219	215	252
Consumption	2,437	2,626	2,544	2,526	2,527	2,525	2,551	2,564	2,558	2,547	2,416	2,207
Kerosene/Jet Fuel												
Refinery Production	246	230	209	206	195	198	203	207	210	215	222	230
Inter-PADD Transfers In/(Out)	126	145	74	53	55	62	61	61	61	59	67	73
Imports / (Exports)	-1	-1	-10	-8	-6	-5	-4	-3	-3	-2	-1	-0
Supply Adjustments	2	-3	2	-5	-0	-1	-0	-0	-0	-0	-0	-0
Consumption	373	370	274	245	253	263	267	271	274	277	290	299
Diesel / No. 2 Heating Oil												
Refinery Production	866	908	987	894	927	941	961	982	994	1,014	1,041	1,067
Inter-PADD Transfers In/(Out)	221	344	249	214	206	240	261	274	270	266	319	365
Imports / (Exports)	6	-5	-8	-4	-3	-3	-2	-1	0	2	10	17
Supply Adjustments	7	1	-7	-15	36	14	17	18	18	18	17	18
Consumption	1,100	1,249	1,222	1,081	1,168	1,224	1,261	1,300	1,316	1,333	1,420	1,501
Refinery LPG												
Refinery Production	124	105	116	120	120	121	122	123	125	127	126	126
Inter-PADD Transfers In/(Out)	58	77	61	80	80	80	80	80	80	80	80	80
Imports / (Exports)	125	97	68	64	65	66	66	67	67	67	69	70
Supply Adjustments	71	83	110	75	78	80	81	82	82	82	87	92
Consumption	378	362	355	339	343	347	349	352	355	356	362	367
Naphtha (Petrochemical Feed)												
Refinery Production	17	27	26	21	21	26	32	38	44	50	58	63
Inter-PADD Transfers In/(Out)	3	(1)	2	3	4	(2)	(8)	(14)	(20)	(26)	(35)	(40)
Imports / (Exports)	1	3	3	3	3	3	3	3	3	3	3	2
Supply Adjustments	0	(0)	0	0	(0)	0	0	0	0	0	0	0
Consumption	21	29	31	26	27	27	27	27	27	26	26	25
Residual Fuel Oil												
Refinery Production	60	55	52	45	50	51	51	52	52	52	49	46
Inter-PADD Transfers In/(Out)	(11)	(3)	(10)	(14)	(9)	(10)	(11)	(12)	(14)	(16)	(19)	(21)
Imports / (Exports)	1	2	(2)	(0)	0	0	(0)	(0)	(0)	(0)	(1)	(1)
Supply Adjustments	(1)	1	0	3	(0)	0	0	0	0	0	0	0
Consumption	49	55	40	31	33	32	31	31	30	28	25	22
Other Products												
Refinery Production	351	348	316	285	292	289	339	344	349	369	388	397
Inter-PADD Transfers In/(Out)	32	29	18	51	54	50	40	54	47	48	34	31
Imports / (Exports)	-7	-7	-11	-4	-1	5	-41	-41	-44	-61	-75	-79
Supply Adjustments	-10	7	0	-8	-1	10	21	15	8	3	21	21
Consumption	366	376	323	292	325	340	342	343	345	346	354	362
Total Refined Products												
Refinery Production	3,391	3,489	3,414	3,330	3,301	3,319	3,406	3,449	3,467	3,521	3,503	3,473
Inter-PADD Transfers In/(Out)	983	1,265	986	933	996	1,034	1,067	1,095	1,079	1,050	1,032	900
Imports / (Exports)	128	92	21	51	48	57	14	18	17	4	2	8
Supply Adjustments	224	223	367	269	346	331	336	329	325	323	340	382
Consumption	4,725	5,068	4,789	4,540	4,675	4,759	4,829	4,888	4,905	4,915	4,894	4,783
Light Refined Products (2)												
Refinery Production	2,839	2,954	2,905	2,860	2,817	2,832	2,861	2,892	2,897	2,923	2,882	2,841
Inter-PADD Transfers In/(Out)	902	1,162	915	813	868	916	966	987	985	963	971	850
Imports / (Exports)	6	-3	-35	-11	-19	-16	-13	-10	-8	-5	6	16
Supply Adjustments	163	133	256	199	268	241	234	232	235	237	232	270
Consumption	3,910	4,246	4,040	3,852	3,947	4,013	4,080	4,135	4,149	4,157	4,127	4,007

Notes: (1) Supply adjustment for gasoline includes ethanol.
(2) Includes gasoline, jet/kerosene and diesel/No.2 heating oil.

TABLE III-2
PADD II & PADD IV DISTILLATE SALES, 2008
(Thousand Barrels per Day, unless noted)

PADD II

Upper Midwest

	MN	ND	SD	WI
Residential	4.6	1.9	0.6	6.3
Commercial [(1)]	16.0	6.0	1.7	11.5
Industrial [(2)]	3.4	5.3	0.3	4.4
On-Highway	72.9	12.6	12.9	48.7
Farm	8.5	9.5	4.7	8.1
Total	105.3	35.3	20.2	79.0

Midcontinent

	IA	KS	MO	NE	OK
Residential	0.7	0.0	0.3	0.2	0.0
Commercial [(1)]	4.7	8.5	7.6	2.7	35.4
Industrial [(2)]	1.2	2.1	2.3	0.6	6.1
On-Highway	41.9	31.3	64.1	26.4	59.0
Farm	12.6	12.6	8.8	15.8	4.3
Total	61.0	54.5	83.1	45.6	104.7

Midwest

	IL	IN	KY	MI	OH	TN
Residential	0.6	1.7	0.7	3.6	6.5	0.5
Commercial [(1)]	19.6	13.1	13.4	8.3	22.8	10.5
Industrial [(2)]	6.6	7.1	14.5	5.1	7.2	2.9
On-Highway	93.4	84.7	53.4	54.6	97.2	65.2
Farm	13.5	9.1	2.0	3.7	9.4	2.0
Total	133.7	115.7	84.1	75.3	143.1	81.1

PADD IV

	CO	ID	MT	UT	WY
Residential	0.0	0.5	0.4	0.0	0.0
Commercial [(1)]	3.8	2.4	2.2	4.2	5.8
Industrial [(2)]	7.4	1.0	2.7	4.6	11.1
On-Highway	36.9	15.9	16.3	29.0	25.1
Farm	2.2	3.1	5.4	0.3	0.6
Total	50.3	23.0	27.0	38.1	42.6

	TOTAL PADD II	TOTAL PADD IV
Residential	28.0	1.0
Commercial [(1)]	181.7	18.6
Industrial [(2)]	69.3	26.8
On-Highway	818.5	123.1
Farm	124.4	11.6
Total	1,221.8	181.0

Notes: (1) Commercial sales include military, off-highway, railroad and vessel bunkering use.
(2) Industrial sales include electric power and oil company use.
(3) Source: Fuel Oil & Kerosene Sales, 2008 (EIA)

TABLE III-3
PADD IV REFINED PRODUCT BALANCES
(Thousand Barrels per Day)

	2000	2005	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
Gasoline												
Refinery Production	266	275	276	282	286	285	285	288	287	285	278	271
Inter-PADD Transfers In/(Out)	9	-5	-3	0	-1	-0	7	8	12	15	18	11
Imports / (Exports)	0	0	-0	0	0	0	0	0	0	0	0	0
Supply Adjustments (1)	0	7	16	16	18	21	22	22	23	23	29	31
Consumption	275	277	288	299	302	307	313	319	322	324	326	313
Kerosene/Jet Fuel												
Refinery Production	31	32	27	28	28	29	30	31	31	32	35	38
Inter-PADD Transfers In/(Out)	37	7	26	23	24	27	27	28	29	30	33	34
Imports / (Exports)	0	0	0	0	0	0	0	0	0	0	0	0
Supply Adjustments	-0	-0	1	-2	-0	-0	-0	-0	-0	-0	-0	-0
Consumption	68	39	54	49	51	55	56	58	59	60	66	70
Diesel / No. 2 Heating Oil												
Refinery Production	148	171	168	171	169	172	175	180	181	183	190	197
Inter-PADD Transfers In/(Out)	17	-5	9	3	7	14	13	15	17	20	30	35
Imports / (Exports)	8	6	3	4	5	5	5	6	7	8	13	18
Supply Adjustments	-0	1	1	-2	6	2	3	3	3	3	3	3
Consumption	172	173	181	177	189	202	205	210	215	219	244	263
Refinery LPG												
Refinery Production	7	4	9	7	7	7	7	7	7	7	7	7
Inter-PADD Transfers In/(Out)	(70)	(65)	(82)	(94)	(92)	(92)	(92)	(92)	(92)	(92)	(92)	(92)
Imports / (Exports)	18	8	6	9	7	7	7	7	7	7	7	7
Supply Adjustments	79	81	109	115	115	115	115	115	115	115	115	115
Consumption	34	28	43	37	37	37	37	37	37	37	37	37
Naphtha (Petrochemical Feed)												
Refinery Production	(0)	0	0	0	0	0	0	0	0	0	0	0
Inter-PADD Transfers In/(Out)	0	0	0	0	0	0	0	0	0	0	0	0
Imports / (Exports)	0	0	0	0	0	0	0	0	0	0	0	0
Supply Adjustments	0	0	0	0	0	0	0	0	0	0	0	0
Consumption	(0)	0	0	0	0	0	0	0	0	0	0	0
Residual Fuel Oil												
Refinery Production	10	15	11	11	10	10	10	10	9	9	9	9
Inter-PADD Transfers In/(Out)	0	0	0	0	0	0	0	0	0	0	0	0
Imports / (Exports)	0	(0)	(0)	0	0	0	0	0	0	0	0	0
Supply Adjustments	0	0	0	0	0	0	0	0	0	0	0	0
Consumption	10	15	12	10	10	10	10	10	10	9	9	9
Other Products												
Refinery Production	64	70	53	56	63	63	63	64	64	65	67	70
Inter-PADD Transfers In/(Out)	0	0	0	5	0	0	0	0	0	0	0	0
Imports / (Exports)	0	0	2	1	1	1	1	2	2	2	2	2
Supply Adjustments	-3	-0	1	-8	-1	-0	-0	-0	-0	-0	-0	-0
Consumption	61	70	55	51	64	64	65	66	66	67	69	72
Total Refined Products												
Refinery Production	526	567	544	554	563	566	570	580	581	582	586	591
Inter-PADD Transfers In/(Out)	-7	-68	-50	-61	-63	-51	-45	-41	-34	-28	-11	-11
Imports / (Exports)	26	15	11	14	14	14	14	15	16	17	22	27
Supply Adjustments	76	89	128	118	138	138	139	139	140	141	147	149
Consumption	621	603	633	621	653	674	686	698	708	717	751	765
Light Refined Products (2)												
Refinery Production	445	477	471	481	483	487	489	499	500	500	503	506
Inter-PADD Transfers In/(Out)	63	-3	32	27	29	41	47	51	58	64	81	80
Imports / (Exports)	8	7	3	4	5	5	5	6	7	8	13	18
Supply Adjustments	-0	8	17	11	24	23	24	25	25	26	32	34
Consumption	515	489	523	524	542	563	575	586	595	604	636	647

Notes: (1) Supply adjustment for gasoline includes ethanol.
(2) Includes gasoline, jet/kerosene and diesel/No.2 heating oil.

TABLE III-4
NORTH DAKOTA REFINED PRODUCT BALANCES
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
Gasoline (ex-EtOH)													
Refinery Production	33	33	32	31	32	31	31	31	31	31	30	29	27
Imports (ex Canada)	1	0	1	0	0	0	0	0	0	0	0	0	0
Inter-PADD Receipts	19	20	20	20	20	20	20	20	20	19	15	18	21
Consumption	23	22	22	21	21	21	21	22	22	22	22	20	18
Net Other Receipts / (Deliveries)	(30)	(31)	(30)	(31)	(31)	(30)	(30)	(29)	(29)	(29)	(23)	(26)	(31)
Kerosene/Jet Fuel													
Refinery Production	3	3	3	3	3	3	3	3	3	3	4	4	4
Imports (ex Canada)	0	0	0	0	0	0	0	0	0	0	0	0	0
Inter-PADD Receipts	1	0	0	0	0	0	0	0	0	0	0	0	0
Consumption	4	4	3	3	3	3	3	3	3	3	3	3	3
Net Other Receipts / (Deliveries)	0	1	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)
Low Sulfur Diesel													
Refinery Production	6	6	6	13	16	17	17	18	18	19	18	19	20
Imports (ex Canada)	1	2	2	1	2	2	2	2	2	2	2	2	2
Inter-PADD Receipts	0	0	0	0	0	0	0	0	0	0	0	0	2
Consumption	16	16	21	25	27	29	31	32	33	34	34	37	40
Net Other Receipts / (Deliveries)	9	9	13	11	8	10	11	12	12	13	14	16	15
High Sulfur Diesel													
Refinery Production	12	12	13	7	2	2	1	1	1	1	1	0	0
Imports (ex Canada)	0	0	0	0	0	0	0	0	0	0	0	0	0
Inter-PADD Receipts	0	0	0	0	0	0	0	0	0	0	0	0	0
Consumption	12	12	13	7	2	2	1	1	1	1	1	0	0
Net Other Receipts / (Deliveries)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Light Products													
Refinery Production	55	54	54	54	53	52	53	53	54	54	53	52	51
Imports (ex Canada)	2	2	2	1	2	3	3	3	3	3	3	3	3
Inter-PADD Receipts	20	20	20	20	20	20	20	20	20	19	15	18	23
Consumption	56	55	59	56	53	55	57	58	59	60	60	61	61
Net Other Receipts / (Deliveries)	(21)	(21)	(17)	(19)	(23)	(20)	(18)	(18)	(17)	(16)	(10)	(11)	(16)
Fuel Oil													
Refinery Production	2	2	2	2	2	2	2	2	2	2	2	2	2
Imports (ex Canada)	0	0	1	1	1	1	1	1	1	1	1	1	1
Inter-PADD Receipts	0	0	0	0	0	0	0	0	0	0	0	0	0
Consumption	0	0	1	1	1	1	1	1	1	1	1	1	1
Net Other Receipts / (Deliveries)	2	2	2	2	2	2	2	2	2	2	2	2	2

IV. CRUDE SUPPLY ANALYSIS

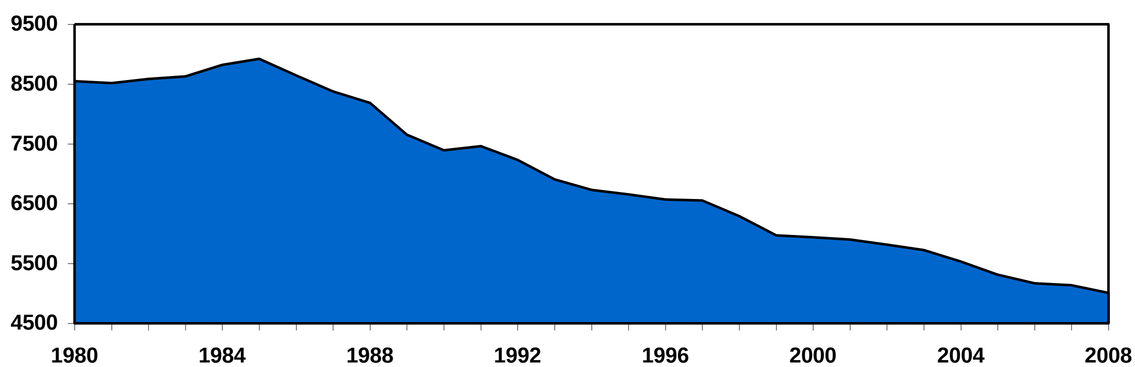
In this section, we describe our outlook for U.S. crude oil production, and provide additional detail for the northern tier study region. This region, and in particular the states of North Dakota and Montana, have benefited from recent advancements in crude production technology. Forecasts of crude oil production are compared.

U.S. CRUDE OIL PRODUCTION

HISTORICAL PERSPECTIVE

U.S. crude oil production as a whole has been in a decades-long decline since peaking in 1985. U.S. crude oil production has fallen more than 40 percent (almost 4 million B/D) from its 1985 level of nearly 9 million B/D, with estimated 2009 production at 5.3 million B/D (Figure IV-1). The decline has been most pronounced in the older producing regions of the Lower 48 states, as well as Alaska and the Gulf of Mexico (GOM) shallow water. These areas have historically been the largest providers of U.S. crude production.

FIGURE IV-1
TOTAL U.S. CRUDE PRODUCTION
(Thousand Barrels per Day)



The majority of U.S. crude oil production has historically come from inland production in the Lower 48 states. The 2009 production figures show that the Lower 48 is still responsible for over 85 percent of the total U.S. output.

Production from the Lower 48 has been in steep decline since the mid-1980s, with decline rates accelerating during the crude oil price collapse in 1998 and 1999. While production responded directly to price increases, the subsequent price recovery during the 2005-2008 period only slowed the rate of production decline. The reserves of light, high quality crude in traditional producing areas have been exploited for decades and are probably in irreversible decline.

Until recently, production declines have been most rapid in PADDs II and IV, where the cost of production is generally higher. The Williston Basin, which covers parts of western North Dakota (PADD II), eastern Montana (PADD IV), and parts of the Canadian provinces of Saskatchewan and Manitoba, has been the one bright spot in the Lower 48. The Williston Basin has seen rapid increases in production due to technological improvements, as explained in the following section.

OUTLOOK

Total U.S. crude output is expected to continue to fall even with the new opportunities and estimated reserve additions available in the GOM deepwater and Lower Tertiary. Purvin & Gertz' outlook is that over the short-term through 2010, U.S. crude oil production will be essentially flat. Longer-term, total U.S. crude oil production is expected to continue a steady decline. The decline to 2020 will likely be at a more rapid rate the previous ten year period. The outlook is for total U.S. crude oil production to decline to 4.6 million B/D by 2015 and about 3.6 million B/D by 2025. For comparison, estimated production was 5.3 million B/D in 2009. U.S. crude oil production is shown by PADD in the following table.

UNITED STATES CRUDE OIL PRODUCTION
(Thousand Barrels per Day)

	2005	2006	2007	2008	2009	2010	2015	2020	2025
PADD I	21	22	21	21	17	16	14	12	11
PADD II	462	458	470	537	591	644	731	653	583
PADD III	2,840	2,838	2,830	2,701	3,027	3,055	2,539	2,112	1,866
PADD IV	359	357	361	357	349	341	306	279	258
PADD V	1,631	1,495	1,453	1,393	1,292	1,232	1,031	918	845
Total U.S.	5,313	5,171	5,134	5,008	5,276	5,288	4,621	3,975	3,562

NORTHERN TIER CRUDE PRODUCTION

BACKGROUND

Production in the northern tier of the U.S. refers mainly to North Dakota and Montana. Montana production more than doubled between 2002 and 2006, to peak at about 100,000 B/D. Currently, production is around 81,000 B/D and declining. In North Dakota, gains in production have been similarly impressive, but were later to materialize. Production in 2009 was approximately 220,000 B/D, compared to only 80,000 B/D in 2003.

The growth in northern tier crude production may be attributed to several factors. The Williston Basin is estimated to contain several hundred billion barrels of oil in place. Revisions to the oil reserves by the US Geological Service in 2008 (ref) have confirmed the Williston Basin to be the largest oil formation in the U.S. Lower 48.

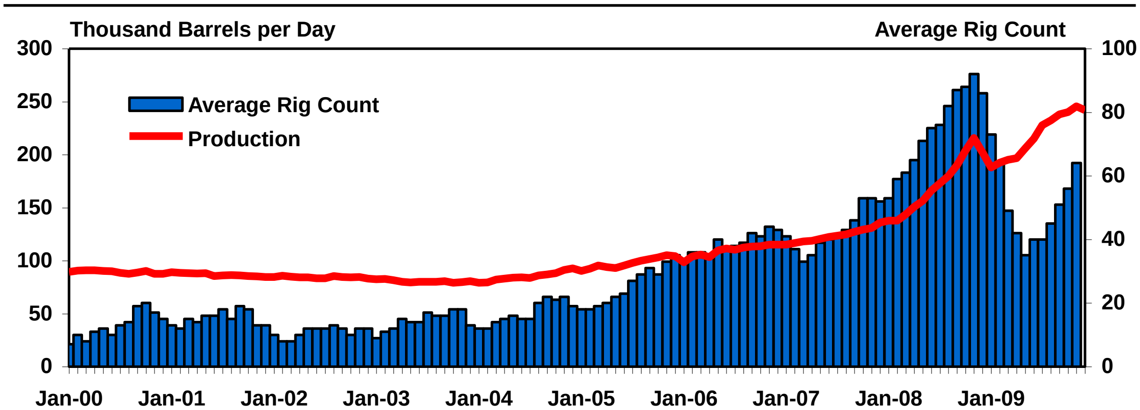
Of the estimated oil in place, about 4 billion barrels of oil is considered recoverable with existing technology, based on US Geological Survey reports. While recent developments in technology have facilitated access to reserves contained within the shale formations of the

Williston Basin, the low porosity of the shale formations still make recovery a challenge. The Bakken geological formation has been the most significant target of Williston Basin exploration activity, but the Three Forks formation (which lies below the Bakken) has also seen significant exploration and development activity.

Higher oil prices since about 2003 have provided a greater incentive to apply the advanced drilling and fracturing techniques to the exploitation of previously uneconomic formations. This is particularly true in the Williston Basin, where the oil recovered from the Bakken and Three Forks formations is typically of very high quality, and therefore of higher inherent value in the oil market.

Figure IV-2 compares the historical production trend for North Dakota with the average rig count in the state. An almost continuous increase in rig count and production has been observed since 2004. The economic downturn in late 2008 significantly affected both the rig count and production. From a high of 92 in November 2008, the active rig count fell to 35 by mid-2009, and had not reached the previous high by year-end. The production trend followed the rig count, declining though mid-2009. However, with a greater emphasis on development (rather than exploration) drilling the production trend had surpassed the previous record monthly average by the end of 2009.

FIGURE IV-2
NORTH DAKOTA CRUDE PRODUCTION AND AVERAGE RIG COUNT



PRODUCTION PROFILE

Figure IV-3 summarizes production for the major North Dakota operators. The figures shown are for 2008, when total state production was 171,800 B/D. Burlington Resources Oil & Gas, EOG Resources and Continental Resources were the top three producers in the state in 2008. The top ten producers in the state accounted for 127,900 B/D, or about 75 percent of total production.

FIGURE IV-3
NORTH DAKOTA MAJOR OIL PRODUCTION OPERATORS, 2008

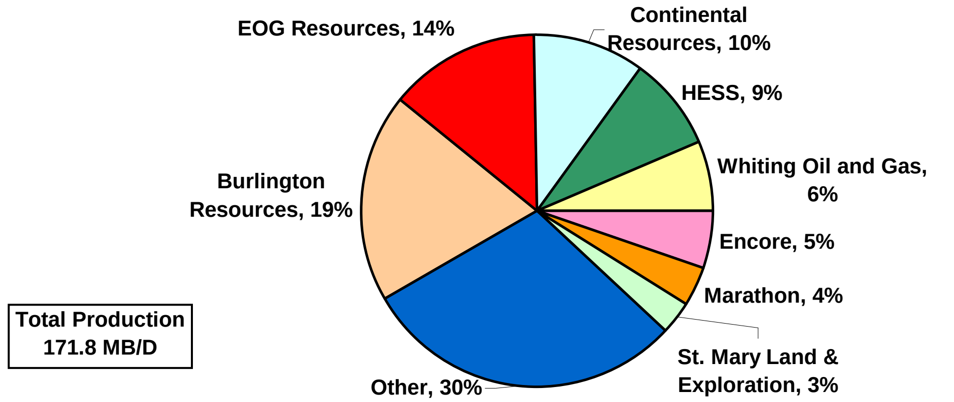
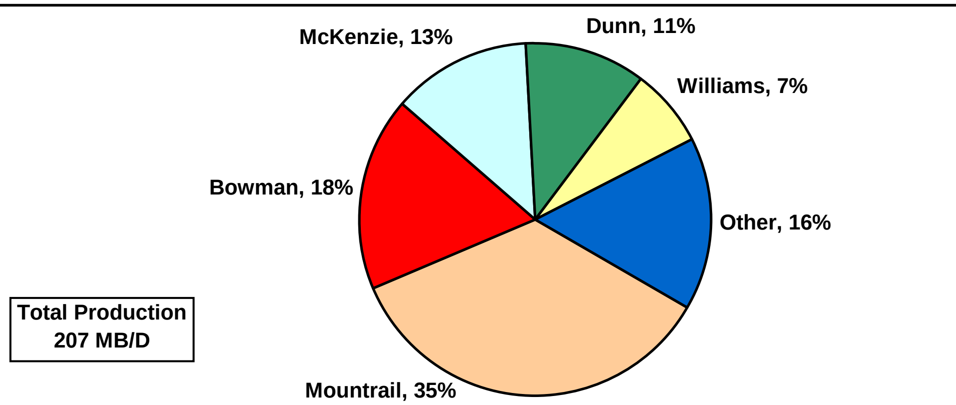


Figure IV-4 summarizes production by county, with data available through November, 2009. Crude production in North Dakota is concentrated in several counties, generally as defined by the extent of the Bakken and Three Forks formations in the Williston Basin. The highest production in recent years (and the most rapid growth) has occurred in Mountrail County, in the north central part of the state. Through November 2009, state production was 207,000 B/D. Of this, approximately 73,000 B/D of crude was produced in Mountrail County, or more than one-third of the state total. Production from Mountrail County has accelerated from less than 1,000 B/D as recently as 2005. The second and third highest production counties in 2009 were Bowman (37,000 B/D, or 18 percent of the state total) and McKenzie (27,000 B/D, or 13 percent).

FIGURE IV-4
NORTH DAKOTA MAJOR OIL PRODUCTION COUNTIES, 2009 (Through November)



OUTLOOK

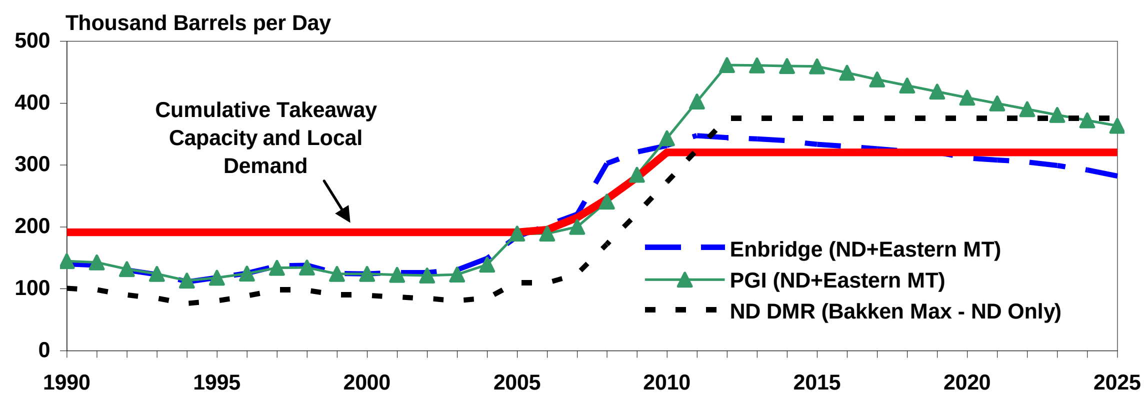
It is clear that production growth from the Williston Basin has accelerated as operators have gained experience with the application of horizontal drilling and advanced fracturing technology to the Bakken shale. Several of the major producers in the region, including EOG

Resources, Continental and Whiting Oil & Gas, have indicated their plans to increase investment and production activity in 2010.

It is acknowledged that the exploitation of the resource is not without challenges. A typical shale oil well is characterized by high initial productivity, but a very steep decline rate. The use of multi-stage fracturing technology requires highly specialized drilling rigs, and consumes high volumes of fresh water for the fracturing operation. Produced water from the fractured well must be disposed of through injection into a deep well.

Due to the factors described above, estimates of oil production from the U.S. Northern Tier vary widely. PGI reviewed available forecasts of production, and prepared its own forecast based on an independent assessment. We currently expect production from North Dakota to peak around 400,000 B/D in the near term, with a relatively stable outlook through 2015, and a subsequent slow decline of between 2.5 and 3 percent per year through the end of the forecast period. See Figure IV-5.

FIGURE IV-5
CRUDE PRODUCTION AND PIPELINE CAPACITY



QUALITY

The crude oil produced in the Williston Basin may cover a range of qualities, depending on the location and geological formation from which it is produced. However, based on our contacting for this assignment, we have determined that the average quality of crude is likely to be consistent with the high quality, light sweet crude that is typically produced from the Bakken formation. The following table summarizes selected key properties of the Bakken crude.

LIGHT SWEET CRUDE ASSAY COMPARISON

		Bakken [1]	WTI	LLS
API Gravity	Degrees	> 41	40.0	35.8
Sulfur	Weight %	< 0.2	0.33	0.36
Distillation Yield:	Volume %			
Light Ends	C1-C4	3	1.5	1.8
Naphtha	C5-330 °F	30	29.8	17.2
Kerosene	330-450 °F	15	14.9	14.6
Diesel	450-680 °F	25	23.5	33.8
Vacuum Gas Oil	680-1000 °F	22	22.7	25.1
Vacuum Residue	1000+ °F	5	7.5	7.6
Total		100	100.0	100.0
Selected Properties:				
Light Naphtha Octane	(R+M)/2	n/a	69	71
Diesel Cetane		> 50	50	49
VGO Characterization (K-Factor)		~ 12	12.2	12.0

Notes: (1) Properties are approximate, based on available assay information.

The bulk characteristics of Bakken crude are indicative of high quality light sweet crude. API gravity is at or above 40, which is higher than West Texas Intermediate (WTI). Sulfur content is very low, at less than 0.2 wt percent, which is lower than WTI. Both of these properties suggest that the crude would be readily processed in a conventional refinery.

The value of a crude oil depends on the aggregate yield of products from processing in a defined refining configuration. The volume and quality of individual cut fractions can be related to analogous end products, after required refinery processing. The assay information shown above indicates that Bakken crude will produce a high yield of light products and a low yield of residual fuel oil. Valuation of the Bakken crude oil for the purposes of this study is discussed in Section VI of the report.

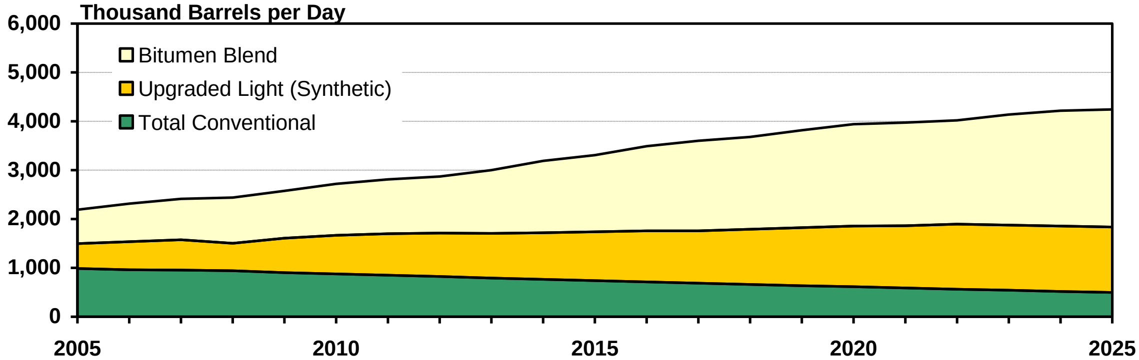
ALTERNATIVE CRUDE SUPPLY

One of the key considerations in the analysis of refinery capacity additions for North Dakota is the security of supply for the refinery. Processing Bakken (light sweet) crude oil is the base premise for this study. However, other sources of crude may be accessible in North Dakota. Perhaps the most feasible source of alternative supply is synthetic crude oil (SCO), which has been upgraded from bitumen in the province of Alberta (Western Canada).

Bitumen reserves in Alberta are widely recognized to be vast. The Alberta Energy Resources Conservation Board (ERCB) estimates initial established reserves at about 177 billion barrels, of which cumulative production (as of June 2009) had reached 6.4 billion barrels. This huge resource potential has encouraged the interest of a wide group of companies to increase production from the oil sands. Many projects have been announced to commence new production of bitumen. Some are underway, while others are in various stages of planning and/or regulatory review. Although many projects were deferred or cancelled in late 2008/early 2009, some have been revived since then.

Figure IV-6 presents the current forecast for conventional crude oil, bitumen blend and upgraded light SCO, according to the Canadian Association of Petroleum Producers (CAPP).

FIGURE IV-6
WESTERN CANADIAN CRUDE OIL SUPPLY FORECAST
CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS - 2009 GROWTH CASE



SCO may provide suitable feedstock for North Dakota refining capacity as an alternative to conventional crude from the Williston Basin. However, further study would be necessary to address constraints such as pipeline capacity and refinery configuration.

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V. INFRASTRUCTURE ANALYSIS

This section describes the existing infrastructure for petroleum transportation, storage and refining in the inland markets centered on North Dakota. The inland region of the U.S. is served by established trunklines for crude oil and refined products transportation. However, there are significant developments in the North American crude oil supply picture that have given rise to a number of projects for expansion of existing infrastructure.

The refining infrastructure in the study region reflects the relatively sparse population density. A summary of refinery capacity and complexity is provided in this section. Major announced projects for additions to refining infrastructure are also presented.

OVERVIEW

Figure V-1, below, will be helpful in understanding the major features of the crude oil and refined products infrastructure in North Dakota. The crude oil and refined products infrastructure includes pipelines, terminal and rail facilities. Facilities are described in more detail in the following sections.

FIGURE V-1
NORTH DAKOTA PETROLEUM INFRASTRUCTURE

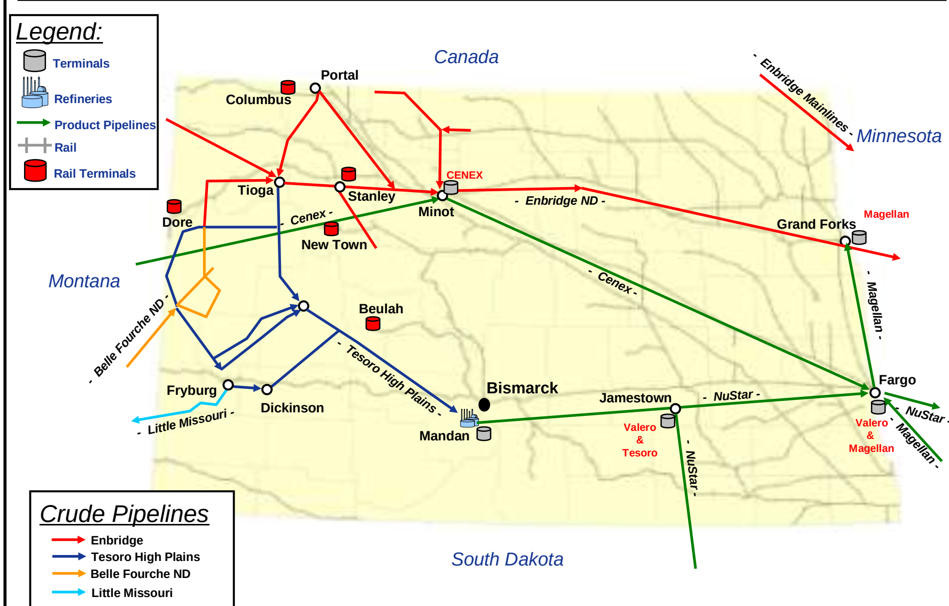
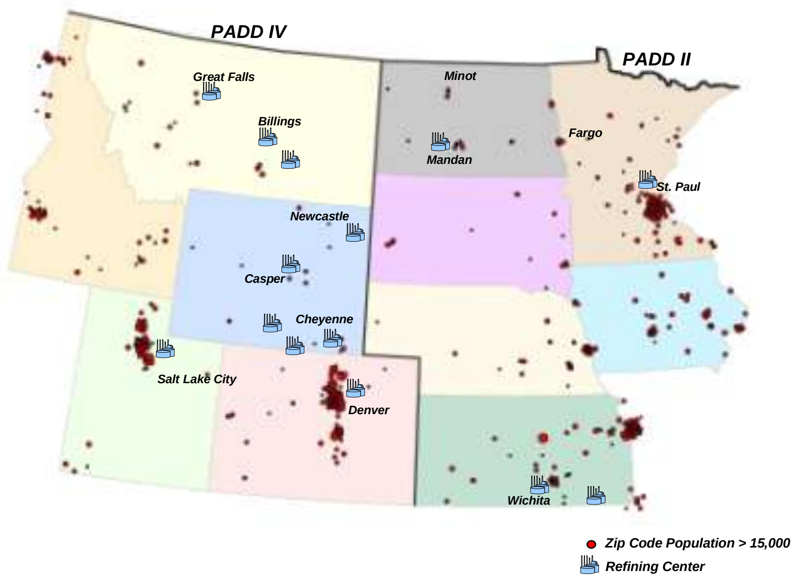


Figure V-2 below identifies the major market locations and refining centers in the broader study region. Population density in the study region is represented by showing zip codes with population greater than 15,000 inhabitants. Major demand centers in the study region (and surrounding states) include Minneapolis, MN (in the Upper Midwest portion of PADD II), and Denver, CO and Salt Lake City, UT in the southern portion of PADD IV. The refinery production centers in the sparsely populated northern tier of PADD II and IV are faced with delivering product to reach end markets with sufficient demand volumes. These end markets are generally isolated from competitive supplies, so market prices tend to reflect the transportation costs incurred. Product prices are discussed in Section VI.

FIGURE V-2
POPULATION DENSITY AND REFINING CENTERS



CRUDE OIL INFRASTRUCTURE

This section describes the major existing pipeline systems, as well as proposed projects, in the inland markets centered on North Dakota. The pipeline systems described here transport Williston Basin crude oil production to markets in the inland U.S. Other important pipeline systems for the study region include those that deliver crude from Western Canada to refineries in the U.S. northern tier and Midwest.

NORTH DAKOTA PIPELINES

Enbridge North Dakota Pipeline

Enbridge North Dakota Pipeline (ENDPL) transports crude oil from producing areas in North Dakota and eastern Montana, including nearby Canadian fields. It delivers crude into the Tesoro High Plains system (serving the Mandan, ND refinery), and east to Clearbrook, MN for onward delivery in the Enbridge mainline system.

Increasing light sweet crude production in eastern Montana (Bakken formation) has overwhelmed the capabilities for moving crude out of the Williston Basin region, either south to

Guernsey on Bridger/Butte or east on ENDPL to Clearbrook. Two major expansion projects on ENDPL raised system capacity to 110,000 B/D from about 85,000 B/D by the end of 2007. A further increase, the Phase 6 Expansion, was recently completed, to increase capacity between Minot and Clearbrook by 51,000 B/D. This project raised the total ENDPL capacity to Clearbrook to 161,000 B/D. At Clearbrook, new volumes will move either on Minnesota Pipeline or on Lakehead Pipeline to reach refinery destinations.

In response to growing production in the Williston Basin, Enbridge has expanded their Westspur feeder system that connects to the mainline at Cromer. Completion of the Alida-Cromer Capacity Expansion (ACCE) project and debottlenecking between Midale and Steelman has raised the Westspur System capacity by 34 percent to 255,000 B/D. A further 129,000 B/D expansion of feeder systems in the area will be completed by 2010.

The "Portal Link" connects Enbridge's Westspur system in Saskatchewan and ENDPL. The Portal Link was broken in 2005 to prevent Midale crude slowing down the ENDPL system. At present, an option to reverse the Portal Link (taking crude north into the Westspur system) is under consideration, as a means of expanding system takeaway capacity from the Williston Basin. The reversal project (named the Enbridge Portal Reversal Project) would allow crude to be delivered north into the Enbridge mainline system.

Belle Fourche/Butte/Bridger Pipelines

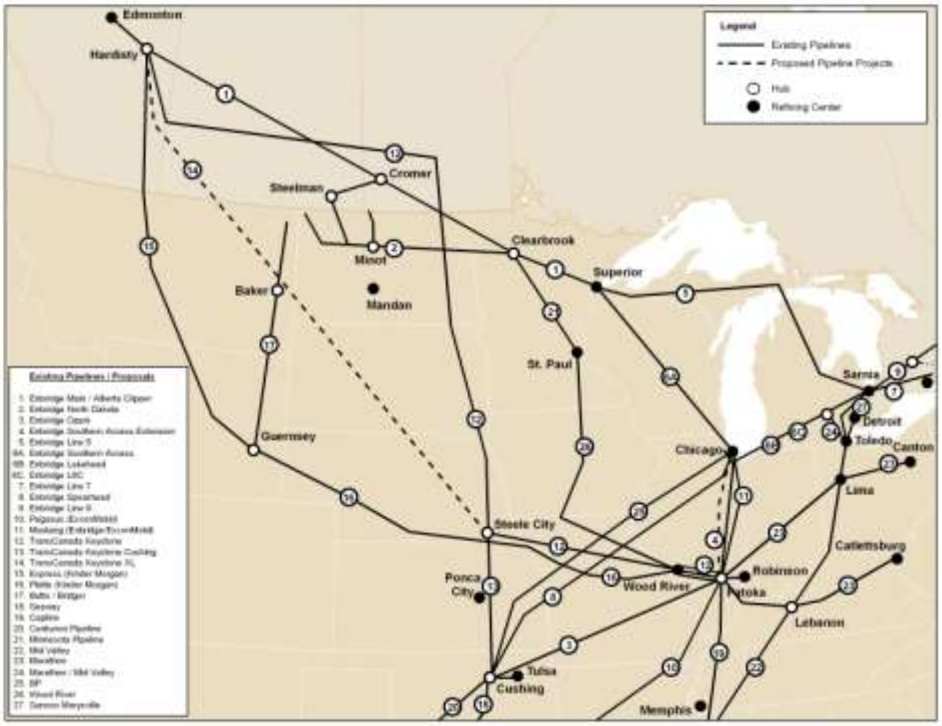
The Belle Fourche and Butte Pipelines are owned and operated by the True companies. Belle Fourche gathers and transports about 50,000 B/D of crude oil in the Williston Basin of western North Dakota and the Powder River Basin of Wyoming. Butte Pipe Line is a 16-inch, 323-mile crude oil pipeline system from Baker, MT to Ft. Laramie and Guernsey, WY.

Butte Pipeline recently expanded its capacity in stages, from 92,000 B/D to 104,000 B/D, and then to 115,000 B/D. This new capacity increment has been achieved through the use of drag reducing agent.

CRUDE OIL PIPELINES FROM WESTERN CANADA

The major export pipeline system from Western Canada is the Enbridge system. Kinder Morgan operates the Express and Trans Mountain Pipe Line (TMPL) systems. In addition to these pipelines, Canadian crude is also exported to the U.S. Northern Tier on the Rangeland, Milk River, and Wascana pipelines. Other new pipelines and expansions are proposed. These pipelines and their relationship to major refinery locations are shown in Figure V-3.

FIGURE V-3
MAJOR CRUDE OIL PIPELINES



Enbridge

The majority of Canadian crude produced in Alberta flows east through the Enbridge Pipeline System (the portion in Canada) and the Enbridge Energy Partners, L.P. System (the connecting Lakehead system portion in the U.S.). Together these two systems have the ability to supply crude directly and indirectly to numerous refineries in Canada and the U.S. The system also receives other crudes along the route in both Canada and the U.S. The Enbridge system delivers crude to the U.S. Midwest as far south as Patoka, IL, Ontario and to Pennsylvania (via New York).

The Enbridge system has been expanded many times, and further expansions are expected. Following is a summary of the major Enbridge export expansion projects:

- The “Southern Access Expansion Program” is an initiative to increase Canadian takeaway capacity from Western Canada and better harmonize the mainline capacity upstream and downstream of Superior, WI. The Canadian portion of the project was completed in 2009. The U.S. portion of this project is also complete and in operation.

- In 2007, Enbridge announced industry support to proceed with construction of two projects that would dovetail with the Southern Access Expansion/Extension projects and would increase export capacity on the Canadian mainline system.

"Alberta Clipper" included construction of new pipe from Hardisty, AB to the U.S. border near Gretna, MB. From Gretna the pipeline proceeds to Superior. The Canadian component of the project was mechanically complete in late 2009. Construction of the U.S. component of the project is nearly complete, so the entire line is expected to be operational during 2010.

- The proposed Southern Access Extension project would run from Flanagan to Patoka. The system is not considered to be "commercially secured" by Enbridge. All regulatory and permitting approvals have yet to be obtained. The U.S. portion of the project would create significant potential capacity ex-Superior.

Enbridge started delivering crude via their wholly owned Spearhead Pipeline which reversed the old Cushing-Chicago Pipeline System (CCPS) in March 2006. Spearhead allows crude to move on the Enbridge system all the way from Edmonton to Cushing, OK. Spearhead capacity does not increase the take-away capacity for Canadian crudes, but does bring Canadian crude to a new market. Shipments on the line have prompted Enbridge to undertake a two-phased expansion of the line. The Phase I expansion (now in service) has increased the capacity from 125,000 B/D to 193,000 B/D by increased pump capacity.

KINDER MORGAN

Kinder Morgan Canada, Inc. owns and operates the Express and Platte pipelines to PADDs IV and II. In 2005, Express Pipeline was expanded from a system capacity of 170,000 B/D to 280,000 B/D and currently moves about 200,000 B/D from Hardisty, AB to Billings, MT and Casper, WY. The connecting Platte Pipeline system originates in Casper and delivers first to Guernsey, WY, where it receives more crude, and then to Wood River, IL. Platte is now running at its capacity of about 145,000 B/D, delivering Express receipts as well as U.S. domestic crude from PADD IV to Guernsey and PADD II.

KEYSTONE PIPELINE

Keystone was developed by TransCanada Pipeline (TCPL). Committed shippers include ConocoPhillips which initially exercised the option to acquire 50 percent of Keystone, but sold its stake back to TCPL in 2009. The project has several components. The first converted an existing TCPL pipeline in Canada from natural gas to crude oil service. A second component required new pipe from Hardisty, AB to Burstall, SK. A third component, the Canadian portion of the new line, reached the U.S. border from Oak Bluff, MB. The fourth component (the U.S. portion of the new line) is a new pipeline from the border to Wood River and Patoka, IL. In total, the capacity of the pipeline is 590,000 B/D. The original long term shipper commitments were for 340,000 B/D. Construction is complete and linefill has begun. The line should be in service by mid-2010.

In July of 2008, the NEB approved Keystone's application for an expansion of the Phase I Keystone system to reach Cushing. This approval allows for expansion of pumping stations to accommodate the expected increase in volume on the Canadian side of the project. It also approves the tolling methodology for new expansion shippers.

This extension of the Keystone system south to Cushing, OK from Nebraska and expansion to 590,000 B/D of capacity is anticipated for late 2010. This expansion/extension to Cushing was the result of a binding open-season process in January 2007 yielding commitments of 155,000 B/D from Hardisty to Cushing above the original commitments of 340,000 B/D (25,000 B/D of which is reserved for uncommitted volumes), bringing known commitments to a total of 495,000 B/D.

OTHER U.S. PADD II SYSTEMS

Minnesota Pipeline

Anticipating growth in heavy Canadian crude supplies, Minnesota Pipeline (MPL) built the MinnCan project. This project comprises 304 miles of new 24-inch pipeline at a cost of $300 million. The initial capacity of approximately 100,000 B/D started up in the fall of 2008. The ultimate capacity on the MinnCan line is 165,000 B/D, which would provide a total capacity from the Enbridge system at Clearbrook to the St. Paul area of over 465,000 B/D using both lines. The MinnCan project will help to increase the U.S. takeaway capacity from the Enbridge pipeline by 100,000 B/D, however some capacity will likely be utilized by expanding crude production from Montana and North Dakota (see above).

Platte Pipeline

The Platte Pipeline originates in Casper, Wyoming and delivers first to Guernsey, Wyoming, where it receives more crude, and then to Wood River, Illinois. Through interconnections with the Kaw and Jayhawk systems, it can also deliver Wyoming or Canadian crude (from Express pipeline) to Midcontinent refiners in Kansas. In 2006 the Platte system was apportioned. Later in 2006, after consultation with shippers, Kinder Morgan published a new prorationing policy. The new apportionment rules are based on historical shipping volumes to prevent nominations from spiraling out of control. Up to 10 percent of the system capacity is reserved for bona fide new shippers (limited to a maximum of 3 percent each). There are limited options to debottleneck Platte. A minor expansion between Guernsey and Holdrege, Nebraska is being considered, but in general, the system currently operates near maximum allowable pressure.

REFINED PRODUCTS INFRASTRUCTURE

INTRA-PADD SYSTEMS

Three systems (Explorer, TEPPCO, and Centennial) provide most of the intra-PADD product transfers from PADD III to PADD II. All three of these systems deliver product to Illinois, and with Ohio deliveries available on the TEPPCO line. Regional pipelines radiate out from the major cities served, St Louis, Chicago, and Indianapolis. Explorer Pipeline Company is a closely-held corporation owned by Chevron, American Capital Strategies, ConocoPhillips, Marathon, Sunoco Logistics and Shell. Centennial Pipeline LLC is a joint venture between Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership (TEPPCO). TEPPCO is the operator. The Centennial system is effectively an augmentation of the original TEPPCO system, in that essentially the same origination and delivery points are available on either line.

Other pipelines delivering product from PADD III include the Magellan and NuStar systems. These are described below.

MAJOR PIPELINE SYSTEMS

Magellan

Historically, the origination point for the Magellan system was in Oklahoma, with deliveries to the so-called “Group 3” market at Tulsa, and the states from Oklahoma to North Dakota and Missouri to Minnesota. The company acquired the Chase and Orion pipeline assets, which serve markets in Kansas, Colorado and Texas.

Magellan owns and operates a large common carrier petroleum products pipeline system, with approximately 8,700 miles of pipeline over a 13-state area. The system extends from the Gulf Coast through the Midwest to Colorado, North Dakota, Minnesota, Wisconsin and Illinois. The pipeline system transports refined petroleum products and LPGs. Products transported in the Magellan system in 2008 averaged close to 900,000 B/D, and comprised 52 percent gasoline, 39 percent distillates (including diesel fuel and heating oil) and 9 percent aviation fuel and LPGs. Product originates from direct connections to refineries and interconnections with other interstate pipelines.

NuStar

The NuStar system serves the western areas of the states from Oklahoma to North Dakota. NuStar owns and operates two inland refined products pipeline systems. The East Pipeline covers 1,900 miles and moves refined products north from the U.S. Midcontinent to the terminus at Jamestown, ND. The East Pipeline system also includes approximately 1.2 million barrels of product storage capacity in Kansas. The East Pipeline transports refined petroleum products to terminals along the system and to receiving pipeline connections in Kansas. The East Pipeline transported about 140,000 B/D in 2008.

The NuStar North Pipeline runs from west to east approximately 440 miles from the Tesoro Mandan, ND refinery to Minneapolis, MN. The North Pipeline interconnects with the East Pipeline near Jamestown, ND. The North Pipeline is supplied primarily by the Tesoro Mandan refinery, but is also capable of delivering or receiving products to or from the East Pipeline. The North Pipeline transported approximately 45,000 B/D in 2008.

Cenex

The Cenex refinery in Laurel, MT refinery produces a range of refined petroleum products. Transportation fuels from the refinery are shipped both west on the Yellowstone Pipeline (to Montana and Washington terminals), south on common carrier pipelines (to Wyoming and Colorado terminals), and east on a wholly-owned pipeline to Glendive, MT as well as to Minot and Fargo, ND. This pipeline has 8-inch diameter. In 2008, total average deliveries were approximately 44,000 B/D.

TERMINALS

The study region is served by a network of refined products terminals owned by refining and pipeline companies. The major terminal facilities are pipeline connected for receipt of product transfers from refineries in PADD III (U.S. Gulf Coast), or from refining centers in the Northern Tier. Magellan and NuStar have extensive terminal networks associated with their pipeline systems, and are the largest independent terminal systems operators in the Upper Midwest. These companies provide storage facilities for the full range of light products.

Several refiners in the Northern Tier region also own and operate terminals. Cenex has terminal facilities at Glendive, MT and at Minot, ND. Flint Hills Resources has a terminal at its Minnesota refinery, as well as several other locations in Wisconsin. Marathon distributes refined petroleum products from its St. Paul Park refinery to terminals in Wisconsin.

The following table summarizes terminal ownership in North Dakota. Approximately 1.9 million barrels of storage is available at six terminals in the state. Magellan's terminals (at Grand Forks and West Fargo) account for about 1.0 million barrels of the total product storage in the state. NuStar's two facilities at Jamestown have total capacity of 315,000 barrels, but these facilities are not interconnected. Tesoro at Mandan has about 310,000 barrels of capacity, as does Cenex (CHS) at Minot. All of these terminals have pipeline and truck access. Only the Magellan terminals and the Mandan refinery terminal have rail access.

NORTH DAKOTA PETROLEUM TERMINALS

Company	Terminal	Product Capacity (Thousand Barrels)	Access (1)
Magellan Pipeline Company, L.P.	Grand Forks	358	R, P, T
	West Fargo	639	R, P, T
NuStar Pipeline Operating Partnership, LP	Jamestown (North)	139	P, T
	Jamestown (East)	176	P, T
Tesoro Refining & Marketing Company	Mandan	310	R, P, T
CHS Petroleum Terminal	Minot	310	P, T

Notes: (1) Access via Rail (R), Pipeline (P), Truck (T)

REFINERIES

PADD II REFINING INDUSTRY OVERVIEW

The PADD II refining industry is comprised of 27 refineries with a combined capacity of about 3.8 million B/D. The PADD II refining industry has gone through significant capacity rationalization since 1981, representing almost 1.3 million B/D of capacity. Most of the majors supply refined products to PADD II via shipments from their USGC refineries, or through exchanges with local refiners. The following table summarizes refining capacity in PADD II by refining configuration and distillation capacity.

PADD II REFINERY CONFIGURATION: JANUARY 2010			
		CAPACITY	
	Number	MB/D	Percent
Coking	13	2,569	68
Cracking	12	1,184	31
Hydroskimming	2	20	1
Topping	-	-	-
Total	27	3,773	100

Many refineries in PADD II were designed to utilize light sweet crude in addition to light and heavy sour crudes. However, there are only a small number of refineries with capacity of 50,000 B/D or more that still run sweet crude exclusively. Sweet crude is still the largest volume crude (1.3 million B/D) and currently accounts for about 42 percent of the PADD II slate in 2009. Over time the availability of light crudes in general is expected to decline and heavier grades will make up the balance.

PADD II CRUDE SLATE						
	2009		2015		2025	
	MB/D	%	MB/D	%	MB/D	%
Light Sweet	1,325	42	1,294	39	1,138	35
Light Sour	973	31	889	27	671	20
Heavy Sour	807	26	1,129	34	1,468	45
High TAN	15	0	12	0	7	0
Total	3,120	100	3,323	100	3,284	100

PADD II refineries are listed by location and type in Table V-1. The PADD II refining industry has a high degree of conversion capability, due to the region's very limited market for residual fuel oil. About half the region's refineries have coking, and the majority of the remaining refineries are in at least a cracking configuration. The average complexity index for PADD II is approximately 9.3, which is consistent with the high conversion capabilities of the regional refineries.

Although PADD II has undergone significant rationalization of refining capacity, overall processing capacity has increased by almost 300,000 B/D since 1992 due to incremental expansions at other plants throughout the region. To illustrate, average refinery capacity has increased from less than 90,000 B/D to about 140,000 B/D over this period. Flint Hills completed an expansion at the Rosemount, MN refinery and Ventura restarted the mothballed Thomas, OK refinery in 2007. At the same time, additional process enhancements and additions were made to accommodate the relatively small market for RFG, and the large low sulfur diesel market in PADD II. Large additions of distillate desulfurization and associated hydrogen generation hardware have been made. Recently, significant VGO desulfurization and gasoline desulfurization capacity has been installed to help meet the changes in gasoline specifications.

With the exception of the major facility upgrading at the Flint Hills Resources refinery (Rosemount, MN), increases in conversion unit capacity (mainly coking and FCC units) have been achieved by small expansions at many facilities. New distillation desulfurization capacity was brought online in addition to expansions and revamps to increase severity of operations. There were several conversions of semi-regenerative reformers into continuous regeneration units, allowing the facilities to lower reactor pressures and increase reformate yield and hydrogen production at the same time. Hydrogen production is a crucial concern to all refiners making RFG, because of the reduced demand for octane from reformers and increased desulfurization requirements.

Upper Midwest Refineries

This subregion includes the northern PADD II states of North Dakota, South Dakota, Wisconsin and Minnesota. We use this regional definition for consistency with the Energy Information Administration (EIA) data sources. The Upper Midwest includes 4 refineries with a combined capacity of about 484,000 B/D. Refer to Table V-1 for summary information about the capacity and complexity of the Upper Midwest refineries.

Refineries in the Upper Midwest subregion utilize a range of crude oils. However, crude runs are dominated by heavy crude, due to the Flint Hills Resources refinery (Rosemount, MN), which accounts for almost 60 percent of the region's total capacity. It runs a high proportion of heavy crude. Two other refineries in the Upper Midwest region (Murphy at Superior, WI and Marathon at Saint Paul Park, MN) currently process a mixed crude slate, with some sour crude processing capability.

North Dakota is included in the Upper Midwest subregion of PADD II. There is one refinery in North Dakota, Tesoro at Mandan. This refinery processes mainly light sweet crude oil, in a cracking configuration. The capacity of the Mandan refinery is 58,000 B/D. The refinery does not have residue processing, and it appears that the light crude slate may allow the processing of atmospheric residue in the FCC unit. Tesoro Mandan does not produce asphalt.

PADD IV REFINING INDUSTRY OVERVIEW

The 16 refineries in PADD IV have a total capacity of about 610,000 B/D, with most refineries ranging in size from 20,000 to 60,000 B/D. In 2005, Suncor acquired Valero's refinery in Denver and consolidated it with operations at its adjacent refinery. A summary of refining operations in PADD IV by processing configuration and capacity is shown in the following table.

PADD IV REFINERY CONFIGURATION: JANUARY 2010

		CAPACITY	
	Number	MB/D	Percent
Coking	6	333	55
Cracking	7	260	43
Hydroskimming	3	17	3
Topping	-	-	-
Total	16	610	100

PADD IV capacity is dominated by cracking and coking capacity. The refineries processing the region's production of very light/sweet crudes can typically process much of their residual production through the FCC, with asphalt production consuming the remaining bottoms. As the region's production of those crudes declines and alternate sources develop, the industry may come under pressure to increase utilization of heavier and more sour supplies. Currently, over half of the region's capacity is in refineries designed to process a predominantly sweet slate. PADD IV refineries are listed by location and type in Table V-2.

PADD IV has no demand for reformulated gasoline at this time. This has minimized the amount of investment regional refiners have had to make during this period. The primary investments made to meet environmental regulations were for distillate hydrotreating and associated hydrogen production.

Crude capacity utilization in PADD IV averaged about 90 percent in 2008. Utilization trends in the region tend to be strongly seasonal, following demand trends. As noted above, the population density in the northern states of the region is low. As a result, the refineries in Montana depend on product transfers to adjacent states.

STUDY REGION REFINING PROJECTS

Project announcements for refineries are monitored around the world. Additions to existing capacity are based on projected completion dates, to develop estimated future capacities. Experience confirms that project announcements and completion dates tend to be optimistic. Many planned projects are delayed or abandoned. As a result, crude distillation project announcements are screened using a series of criteria to help identify which projects are likely to be completed. These criteria include the financial strength of project sponsors, the status of project approval and development, history of building similar projects, political stability, access to crude oil supply, local demand for refined products, and other key factors.

In the study region, several crude distillation project announcements have been identified. Of these, we have classified the projects in Table V-3 as either “Most Likely” or “Probable”. Other announced projects, not shown in the table, are considered to be “Speculative”. While some of this capacity considered “Speculative” may eventually be built, projects classified as speculative have not yet progressed sufficiently to be included in our outlook for available future capacity. The categorization of specific projects or their start-up timing may change as major milestones for these projects are met.

Inevitably, some capacity additions are added that never appear on project lists. We refer to this capacity expansion as "capacity creep.” Capacity creep can occur as the result of projects completed by maintenance groups, efficiency gains due to operating changes, catalyst improvement, etc. The rate of capacity creep is generally between 0.5 and 1.0 percent per year.

NGL INFRASTRUCTURE

Gas Processing Plants

NGL is produced at eleven gas processing plants in North Dakota. The gas processing and NGL production is dominated by two large plants, namely Amerada Hess' Tioga facility and Bear Paw Energy/Oneok's Grasslands facility, which together produce approximately 90% of the state's total NGL production.

Cochin Pipelines Limited

The Cochin Pipeline is 100 percent owned by Kinder Morgan, subsequent to purchasing BP's 50 percent interest in 2007. This 12-inch light hydrocarbon pipeline extends from salt cavern storage at Fort Saskatchewan, AB, through the U.S. (south of the Great Lakes) and back into Canada at Windsor, ON (near Detroit). The pipeline is used to carry surplus Alberta ethane to eastern markets. The Cochin Pipeline also transports specification-grade propane to the U.S. Midwest and eastern Canadian markets.

Ethylene was shipped on the Cochin Pipeline until March 2006, when a voluntary pipeline pressure restriction precluded the transport of ethylene. Ethane shipments were suspended in 2007. The restriction on ethylene and ethane shipments is of indefinite duration. Depending on market considerations, the pipeline can also transport field grade butane and propane-plus NGL mix, but reports indicate butane has not been shipped since 2002.

System capacity is reported at 112,000 B/D. Recent reports indicate the pipeline still operates well below capacity. Propane has always been the dominant product for Cochin, historically taking anywhere from 60-75 percent of the shipped volume. Connections to other pipelines gives Cochin shippers access to terminals on the Enterprise (formerly Williams/MAPCO) pipeline system, including deliveries to Conway, KS, thereby allowing shippers access to Enterprise points further downstream.

Kinder Morgan has presented the concept of using the Cochin Pipeline to transport crude oil from the Williston Basin to refiners in the U.S. Midwest. Given the configuration of the system, the pipeline would have provided access to a limited number of PADD II refiners. An open season was conducted in 2009, but failed to attract sufficient interest. Kinder Morgan is understood to be considering other options, and may re-introduce the concept in the future.

Enbridge Energy Partners, L.P.

Enbridge Energy Partners L.P. (EEP), an affiliate of Enbridge, Inc., owns and operates petroleum liquids and natural gas transportation businesses in the United States. Their efforts are focused on crude, gas and refined products, but several system can handle NGLs. Enbridge Inc.

EEP's Lakehead system spans approximately 1,900 miles in the U.S., from the international border near Neche, ND to the international border near Marysville, MI with an extension across the Niagara River into the Buffalo, NY area. Another Enbridge, Inc. subsidiary owns the Canadian portion of Lakehead. Lakehead is primarily used to ship crude oil, but also transports a propane-plus NGL mix in batches through the system. NGL products shipped in the pipeline come from the refineries in Edmonton, NGL plants in Alberta, and terminals and storage en-route. The NGL is shipped in batches from Fort Saskatchewan to Sarnia, where it is fractionated, stored in salt caverns, and marketed. NGL breakout storage is located at Superior, Wisconsin, where some of the NGL is fractionated into propane for the local market. The system also has access to a storage facility at Marysville, Michigan with an adjacent fractionation and butane splitting facility. In 2007, the Lakehead system delivered about 4,000 B/D in the U.S., and 95,000 B/D in Ontario.

TABLE V-1
PADD II REFINING CAPACITY & TYPE [(1)]

Company	Location	Crude Distillation Capacity (B/CD)	Refinery Type	Complexity Index
Flint Hills Resources	Rosemount, MN	317,300	Coking	9.90
Marathon	St. Paul Park, MN	74,000	Cracking	8.76
Tesoro Petroleum	*Mandan, ND*	*58,000*	*Cracking*	*6.92*
Murphy Oil	Superior, WI	34,300	Cracking	6.85
SUBTOTAL (Upper Midwest)		***483,600***		***9.15***
BP	Whiting, IN	410,000	Coking	9.37
ExxonMobil	Joliet, IL	238,500	Coking	9.76
BP/Husky	Toledo, OH	160,000	Coking	10.11
CITGO	Lemont, IL	167,000	Coking	9.77
Sunoco Inc.	Toledo, OH	180,000	Cracking	9.19
Marathon	Detroit, MI	102,000	Cracking	7.66
SUBTOTAL (Great Lakes)		***1,257,500***		***9.43***
WRB Refining (COP/Cenovus)	Wood River, IL	306,000	Coking	8.54
Marathon	Catlettsburg, KY	226,000	Cracking	11.95
Marathon	Robinson, IL	204,000	Coking	9.04
Valero Energy Corp.	Memphis, TN	180,000	Cracking	7.36
Husky Energy	Lima, OH	166,400	Coking	9.50
Marathon	Canton, OH	78,000	Cracking	7.63
Countrymark Cooperative, Inc.	Mt. Vernon, IN	26,000	Cracking	7.32
Somerset Energy Refining	Somerset, KY	5,500	Hydroskimming	2.69
SUBTOTAL (Southern Midwest)		***1,191,900***		***9.11***
ConocoPhillips	Ponca City, OK	194,000	Coking	9.54
Coffeyville Resources LLC	Coffeyville, KS	122,000	Coking	7.41
Frontier Oil & Ref.	El Dorado, KS	118,000	Coking	11.04
Holly Corp	Tulsa, OK	85,000	Coking	9.99
Valero Energy Corp.	Ardmore, OK	83,640	Cracking	10.84
Cooperative Refining LLC	McPherson, KS	81,200	Coking	12.79
Holly Corp	Tulsa, OK	70,300	Cracking	8.06
Gary-Williams Energy Corp.	Wynnewood, OK	71,700	Cracking	7.93
Ventura Refining	Thomas, OK	14,000	Hydroskimming	2.07
SUBTOTAL (Midcontinent)		***839,840***		***9.55***
TOTAL (PADD II)		***3,772,840***		***9.32***

Note: (1) As of January 1, 2010. Excludes asphalt topping plants.

TABLE V-2
PADD IV REFINING CAPACITY & TYPE [1]

Company	Location	Crude Distillation Capacity (B/CD)	Refinery Type	Complexity Index
ConocoPhillips	Billings, MT	60,000	Coking	12.39
ExxonMobil	Billings, MT	60,000	Coking	10.29
Cenex	Laurel, MT	55,000	Coking	10.47
Connacher Oil & Gas	Great Falls, MT	9,500	Cracking	8.16
Frontier Oil & Ref.	Cheyenne, WY	47,000	Coking	8.58
Northcut Refining LLC	Douglas, WY	4,000	Hydroskimming	5.67
Sinclair Oil / Little America	Evansville, WY	24,500	Cracking	7.04
Silver Eagle Refining Inc.	Evanston, WY	3,000	Hydroskimming	7.23
Sinclair Oil	Sinclair, WY	66,000	Coking	10.29
Wyoming Refining	Newcastle, WY	12,500	Cracking	7.07
TOTAL (Northern PADD IV)		***341,500***		***9.96***
Suncor Energy	Denver, CO	94,000	Cracking	7.20
Tesoro West Coast	Salt Lake City, UT	60,000	Cracking	6.15
Chevron	Salt Lake City, UT	45,000	Coking	10.09
Silver Eagle Refining Inc.	Woods Cross, UT	10,250	Hydroskimming	4.25
Big West Oil (Flying J)	Salt Lake City, UT	29,400	Cracking	7.03
Holly Corp	Woods Cross, UT	30,000	Cracking	10.75
TOTAL (Southern PADD IV)		***268,650***		***7.72***
TOTAL (PADD IV)		***610,150***		***9.00***

Note: (1) As of January 1, 2010. Excludes asphalt topping plants.

TABLE V-3
STUDY REGION REFINERY PROJECTS
(Thousand Barrels per Day, Unless Otherwise Noted)

Project Type	Company	City	State	PADD	2010	2011	2012	2013	2014	2015	2016	2017
Crude	ConocoPhillips	Billings	MT	IV	-	-	-	10	-	-	-	-
Vacuum	ConocoPhillips	Billings	MT	IV	-	-	-	14	-	-	-	-
Coker-Delayed	Flint Hills Resources	Rosemount	MN	II	-	4	-	-	-	-	-	-
Hydrotreater-Diesel	Tesoro Petroleum	Mandan	ND	II	2	-	-	-	-	-	-	-
Hydrotreater-Gasoline	ConocoPhillips	Billings	MT	IV	-	-	-	19	-	-	-	-

VI. CRUDE AND PRODUCT PRICING

The pricing of crude oil is addressed in this section. We provide a summary of the crude pricing methodology and the current forecast of key benchmark crude oils. Crude oils produced from the Williston Basin are expected to price in relation to these benchmark crude oils through quality and transportation adjustments.

Product price forecasts form the basis of subsequent analysis of the North Dakota refinery capacity addition projects. In this section, PGI's methodology for product price forecasting, and the current product price forecasts are presented. Inland market prices may be related to those in key spot market, such as the U.S. Gulf Coast.

The anticipated impact of additional refining capacity in North Dakota on crude netback pricing and product pricing is addressed in Section VII.

CRUDE PRICING ANALYSIS

The Purvin & Gertz forecast of crude oil prices is discussed in this section. The long term price trend is developed based on the cost of finding, developing and producing new reserves. Because of the need for additional production in the face of the natural decline in many of the world's producing areas, a large amount of new reserves must be developed.

PRICE CYCLES

The long-term level of crude oil prices is set by the cost of finding, developing and producing the required new production sources. If prices are too high, supplies will increase because economics favor developing new reserves or producing existing reserves at higher rates. At the same time, demand is decreased by use of alternative and by conservation efforts. The resulting imbalance of supply versus demand forces prices back down. In the same manner, if prices are too low, demand is stimulated, alternative energy supply development is constrained, new reserve additions become less economical, and natural decline rates quickly reduce production capacity. Ultimately, low prices cause demand to approach capacity limits on production, and the resulting competition for supply drives prices back up.

The behavior pattern above suggests that capital investment cycles will lead to price cycles. When prices are high, the combination of lower demand and increasing production will eventually produce surplus supply and declining prices. Low prices then reduce industry cash flow and capital expenditures, and the stage is set for another cycle to begin. The high decline rate of existing production results in a fairly rapid capital cycle.

COST OF REPLACING AND PRODUCING RESERVES

The cost of developing and producing crude oil is an important benchmark in understanding the sustainable level of prices. These costs effectively establish a floor price for crude oil. If crude oil prices fall below this level and remain there for a sustained period of time, supplies will not be adequate to meet demand and prices will be driven upward. Likewise, if prices exceed costs by a large margin, excess supplies are likely to be developed, forcing prices back down.

As prices increase, costs also tend to increase. Demand for production supplies and services increases, service companies are able to raise rates, leasing costs increase, and governments find new ways to tax. Conversely, when prices weaken, costs are squeezed. Income tax varies with the price of oil and gas, and is a significant cost for production operations. Since the return on capital is estimated by applying a factor to the F&D cost, increases in F&D costs have a disproportionate impact on the total replacement cost. While cost pressures now appear to be easing, the run-up in the underlying cost basis suggests that prices will not return to the much lower levels of the 1990s.

DEMAND AND PRICES

Longer term, crude oil prices need to remain high enough to encourage sufficient investment in supply. Industry capital costs have escalated rapidly, and alternative supply sources will be needed to close the balance for petroleum supply. Alternative energy supplies and unconventional oil development will both need strong prices to remain economic.

Even with continuing growth in alternative energy supply and unconventional oil, energy demand growth will need to be constrained to remain in balance with global supplies. Unless some vast new form of energy is developed, such as a breakthrough in solar or fusion, global energy supplies are unlikely to be adequate to meet the needs of the world’s population if historical growth patterns remain in place. Instead, continuing increases in energy consumption efficiency will be needed to restrain growth.

Petroleum growth is driven primarily by the transportation and petrochemical feedstocks sectors. Substitution of other energy sources for petroleum, such as coal, gas, nuclear or renewables, is limited by the overall energy supply challenge and existing infrastructure. Given the energy supply/demand balance, petroleum is expected to remain the most economic and dominant transportation fuel option, although alternatives will gain market share from traditional crude sources.

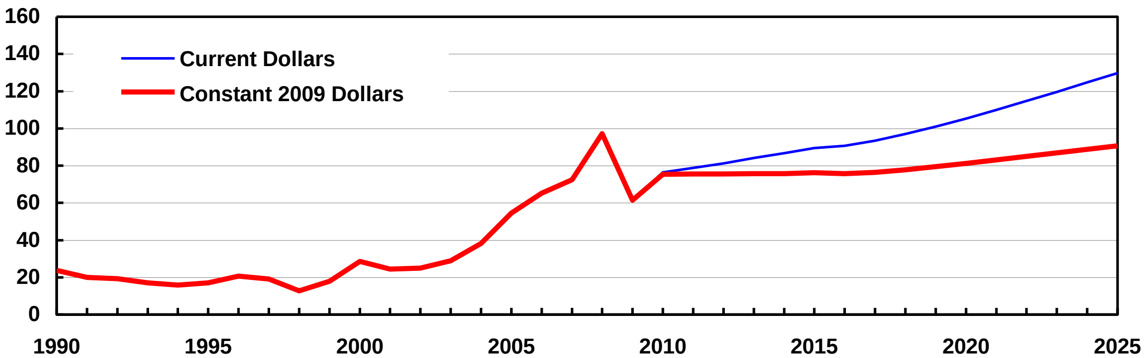
LONG-TERM FORECAST

The analysis of the cost of finding, developing and producing new reserves shows that oil prices above $50 (in constant dollar terms) are needed to support the necessary development of new reserves. Most new non-OPEC reserves will be in hostile environments such as deepwater or Arctic areas, or will have high operating costs such as synthetic crudes from oil sands. Through 2003, technological improvements were sufficient to keep costs from increasing substantially. The recent high price environment resulted in rapidly escalating costs. With the price decline, costs are expected to stabilize in the $50-70 range, after adjustment for inflation.

The price of Dated Brent (light, sweet) crude oil, FOB Sullom Voe is used as the starting point for forecasting the prices of major world crude oils. North Sea crudes now serve primarily

European markets, but compete directly with the Middle Eastern and African crude oils that serve all major markets. Prices have shown much more volatility than costs, but a review of historical Brent prices shows a close relationship with costs over time. In our forecast, prices remain at levels that are more consistent with the long-term cost trend, with Dated Brent prices stabilizing around $75 (in constant dollars) before trending higher after 2020. See Figure VI-1 and Table VI-1.

FIGURE VI-1
DATED BRENT CRUDE OIL PRICE FORECAST
(Dollars per Barrel)



A crude price of $75 crude (in constant dollars) may have been almost unthinkable relative to the $30 price regime experienced as recently as 2004. However, the early 2008 market created price expectations that made $75 seem like a catastrophic price collapse. In our view, the forecast price level is consistent with our view of future market fundamentals. The forecast price level is sufficiently high to support ongoing development of conventional and unconventional energy sources as well as encouraging continued improvement in consumption efficiency. However, the price is sufficiently low to prevent the severe demand reductions of the kind seen in the 1980s.

Later in the forecast, a slow rise in price is anticipated. The level of upward movement is uncertain, but continuing strengthening is likely to be required to encourage supply and constrain consumption. A higher outlook for crude prices in real terms is needed to develop more difficult supply sources and to limit demand growth rates. In order to expand production to the extent necessary and make up for the natural decline in mature producing areas, large and continuing capital investments will be required. With limited spare capacity, all increases in production, even in the Middle East, will require major investments.

A large rate of new discoveries and field extensions are required just to offset decline. Production in many OPEC countries has now reached the mature stage, requiring major capital infusions to maintain or expand existing production levels. Even in countries with known untapped reserves, the development costs are high. Future prices will have to be sufficiently strong to attract these large capital investments. In the Canadian oil sands, for example, world prices in excess of $60 (in constant dollars) appear necessary to maintain a continuing flow of development capital.

The price forecast reflects the tighter balance between demand and supply and the continuing need to develop new and alternative energy supplies. The level of future prices will depend on the success of technology development to supplement traditional energy supplies, and to increase the efficiency of energy consumption. Based on the success of technology development over the past several decades, we anticipate that the forecast price track will be sufficient. If significant technological breakthroughs are achieved, energy prices could fall further. However, if technological advancement slows, much larger increases in energy prices would be required in order to induce the necessary investments in energy conservation and development. Regardless, the future price track will continue to exhibit the volatility and instability that have characterized the market for many years.

REGIONAL MARKER CRUDE PRICES

Prices of other important world crude oils relative to the price of Dated Brent are developed based on competitive price equalization points, transportation costs, and refining values. The competitive equalization points are established based on a detailed analysis of regional supply/demand and trading patterns. Transportation costs and other factors related to equalization such as tariffs and duties are also taken into consideration. Relative refining values for crude oils are developed by calculating substitution economics for typical refineries in the relevant region.

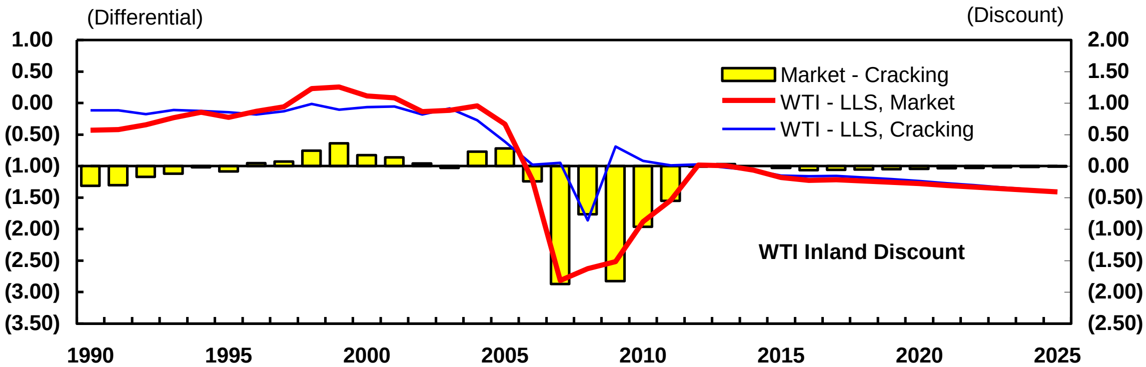
WTI (West Texas Intermediate) and Dated Brent continue to be the most actively traded spot crude oils in both the physical and paper markets. In the U.S. market, Light Louisiana Sweet (LLS) is an important Gulf Coast crude oil although the volume of trade (physical and paper) is much less than for WTI.

U.S. INLAND MARKET CRUDE PRICING

WTI is used as a measure of U.S. inland crude oil prices. It is also the most widely traded crude oil in the world and thus has importance well beyond its physical volume. The traded volume is many times the physical volume, but futures transactions values are tied to the physical deliveries. Local market conditions in the U.S. Midcontinent determine the differential of WTI relative to LLS and to international crude oils from the Gulf Coast. The pricing of WTI is quite complex as it depends on the direction of marginal crude flows within the inland region. Thus, the adjustments reflect the declining volume of WTI, changes in pipeline capacities and flows from the Gulf Coast and from Western Canada, and many other factors.

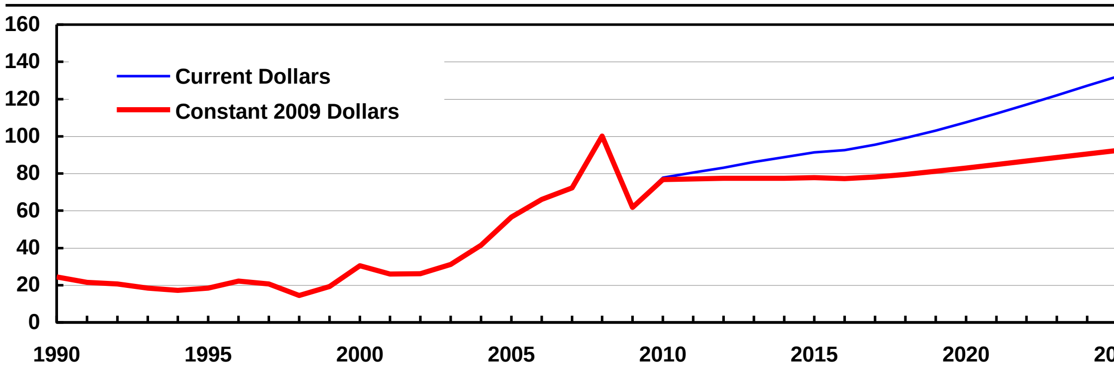
The historical and forecast relationship between WTI at Cushing and LLS on the Gulf Coast is shown in Figure VI-2. The differentials shown incorporate both quality differences and location differences between the two crudes. WTI prices were depressed in early to mid-2007 by high Midcontinent inventories and new supplies from Canada, but recovered later in the year. In 2009, high Midcontinent inventories also depressed WTI prices relative to the Gulf Coast. The forecast WTI differential is consistent with the ongoing need for imports to satisfy inland markets.

FIGURE VI-2
WTI, CUSHING/LLS, USGC DIFFERENTIAL
(Forecast in Constant 2009 Dollars per Barrel)



The resulting forecast for WTI at Cushing is shown in Figure VI-3, in current and constant 2009 dollars. Refer also to Table VI-1.

FIGURE VI-3
WTI, CUSHING CRUDE OIL PRICE FORECAST
(Dollars per Barrel)



NORTH DAKOTA CRUDE PRICE FORECAST

Traditional crude oil valuation methodology establishes a refinery parity price for a crude oil, which assumes that a refiner is indifferent to which crude is processed at the calculated price level. In general, this approach is valid for crude oils of similar quality without unusual characteristics. For the case of light sweet crude oil in North Dakota, an initial crude value may be determined based on a cracking value parity methodology. The cracking value parity is appropriate for a conventional light crude oil that is processed in a refinery with fluid catalytic cracking (FCC) for conversion of vacuum gas oil (VGO). The crude oil from North Dakota may be delivered to different inland U.S. markets, where a cracking configuration is considered to be the marginal (or price-setting) configuration. For the purposes of this preliminary evaluation, a cracking differential to WTI is deemed appropriate, as crude oil that is surplus from North Dakota may compete with WTI delivered to these markets.

Consistent with the above methodology, the value of North Dakota light sweet crude can be related to other marker crude oils through analysis of refining differentials. The competitive equalization points for North Dakota crude in the base case (i.e. without additional refining capacity in the state) may be estimated using PGI's standard methodology.

Bakken crude will produce a high yield of light products and a low yield of residual fuel oil. Crude oil from the Williston Basin may be expected to price in relation to WTI and other benchmark crude oils. Quality and transportation adjustments determine the netback price for Williston Basin production in North Dakota.

For illustrative purposes, we have presented a crude price for North Dakota sweet crude based on sales at a Midcontinent location (Tulsa, OK region), competing with WTI in a cracking configuration. Results are summarized in the following table, in terms of the cracking differential and resulting "field netback" value, based on cracking parity.

NORTH DAKOTA CRUDE PRICES (CUSHING PARITY BASED ON RAIL TRANSPORT)
(CRACKING PARITY/NETBACK SCENARIO)

	2009	2010	2011	2012	2013	2014	2015	2020	2025
Last Revised Dec 2009									
Current Dollars per Barrel									
WTI Spot, Cushing	61.73	76.67	77.14	77.37	77.42	77.43	77.77	82.90	92.34
ND Swt minus WTI, Cracking Value	0.59	0.82	1.00	1.13	1.50	1.77	2.05	2.28	2.63
ND Swt Discount to WTI (1)	(10.81)	(11.69)	(11.92)	(12.16)	(12.46)	(12.73)	(12.96)	(13.98)	(15.15)
ND Netback Price (1)	51.51	65.80	66.22	66.33	66.46	66.47	66.87	71.20	79.82

Note: (1) Estimated field acquisition price in North Dakota excluding gathering costs to reach new capacity
Transportation basis is rail to Cushing.

A netback crude price in North Dakota based on this market pricing scenario is also shown in the table above. The transportation route is using rail to the Midcontinent. The crude market model develops a more sophisticated Reference case based on actual forecasts for the market clearing location and the marginal transportation route. These change over time.

Price forecasts have been developed for the refinery capacity addition cases. The have been established based on an optimized analysis of transportation routes and costs. The results of the analysis are presented in Section VII of this report.

REFINING MARGINS

METHODOLOGY

Product price forecasts are developed from a forecast of refining margins in selected regions, as a function of refinery complexity. The key variables in this analysis are the margin for the marginal refinery and the regional light/heavy differential. Refinery economics establish various grade differentials among products once the light/heavy spread has been determined.

Refinery profitability is driven by supply/demand pressures. Capacity utilization is the best measure of these supply/demand pressures. If an industry needs to operate near capacity to meet demand, margins generally are good. On a short term basis, high utilization rates make it difficult to respond quickly to unexpected market imbalances and can cause prices to be bid up to attract supplies. On a longer-term basis, high utilization rates provide the margins needed to justify adding new capacity.

The margin for the marginal refinery in a region is related to overall refinery capacity utilization. The increase in margin for more complex refineries depends on the light/heavy differential, which in turn depends on the utilization of conversion capacity.

As a result of the growing transparency and efficiency of worldwide markets for crude oil and products, refinery economics are closely linked around the globe. Local factors can still affect regional markets, but worldwide capacity utilization has become a key driver of margins. The rapid response of the crude oil market to regional imbalances in heavy product supply and demand is the most important balancing mechanism. Because of this, markets tend to move together.

PGI's general approach to forecasting refinery margins is presented in this section. Gulf Coast margins are considered indicative of the outlook for the study region.

MARGINAL REFINERY ECONOMICS

Purvin & Gertz' methodology for prediction of reference refining margins is to consider the global balance between product demand and refining capacity. We compare year-to-year changes in global demand for light refined products with year-to-year changes in the capacity to produce light refined products. We also consider the average margin for cracking refinery operations in the major world markets, expressed in terms of capital recovery factor (CRF). The CRF is the net cash margin divided by the refinery replacement cost, and is thus a measure of the return on refining investment.

When capacity and demand grow at different rates, economic pressures to rebalance the global system arise. These pressures are reflected in refining returns. Thus, the net year-to-year balance, defined as the change in demand less the change in capacity, shows a strong relationship with the average CRF. An imbalance between demand and capacity growth occurred in 2004, leading to an increase in refining profitability and a period of strong margins which lasted several years. More recently, a drop in demand, coupled with capacity expansions in 2009, has brought margins to low levels worldwide.

Over the next few years, the light product balance indicates that margins should remain well below recent levels. Margins are forecast to move through a period of multi-year weakness before moving back toward long-term equilibrium (cycle-average) levels. The sensitivity of refining margins to small supply/demand imbalances suggests that margins may move through sharp downward corrections as the market rebalances, and that refiners must be prepared for continued volatility in profitability.

GULF COAST REFINING MARGINS

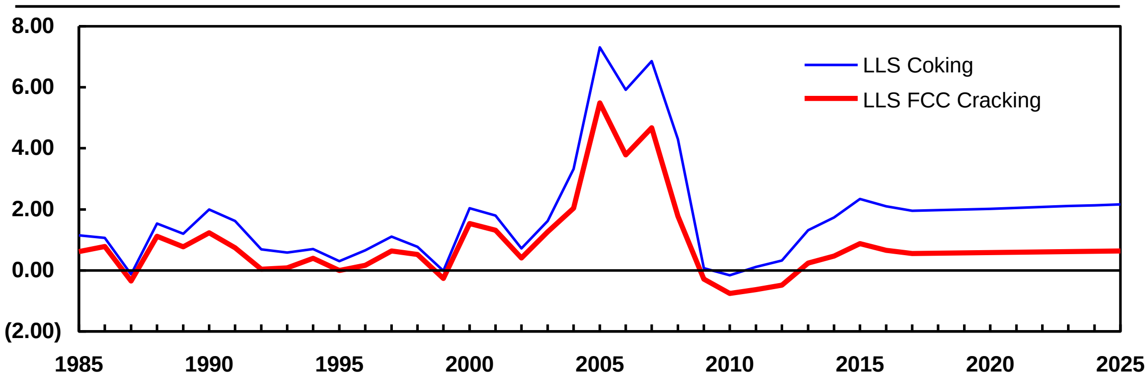
The marginal U.S. Gulf Coast refinery has continually become more efficient and has reduced the output of its lowest value product (residual fuel oil). Our analysis shows that virtually all U.S. Gulf Coast refineries have some form of residue upgrading (resid destruction), ranging from direct catalytic cracking of “clean” resids to hydroprocessing and coking. Today, the cracking configuration represents the marginally available capacity in a more complex facility, and so must only recover variable costs plus an incentive element. We monitor margins for cracking of Light Louisiana Sweet (LLS) crude oil, which is perhaps the best indicator of crude values on the Gulf Coast.

Annual average margins after variable costs for the LLS cracking refinery are determined as an indicator of the incentive to process additional crude oil. Variable cost margins for LLS cracking have fallen to levels that recover only a portion of fixed cash costs and sustaining capital. Sweet crude cracking margins turned very weak in 2009. The very weak economic situation, coupled with new refining capacity in Asia and the U.S. that comes on-stream in 2009-2012, will result in a relatively deep down cycle that will last for several years before returning to the long-term cycle average levels.

Refining economics are analyzed in terms of both net margin (margin after variable and fixed cash costs) and CRF, which is a measure of simple financial return on replacement cost. Net margins for LLS in cracking (marginal) and coking configurations are shown in Figure VI-4. Refer to Table VI-2 for margin history and forecasts for the U.S. Gulf Coast LLS refining configurations. Figure VI-4 incorporates the impact of ultra-low sulfur gasoline in 2005, ultra-low sulfur diesel production in 2007, low benzene gasoline in 2011 and has a modest level of gasoline to distillate yield shift from 2006-2011. The use of CRF provides an inflation-adjusted measure of refining profitability. Simple financial returns are also measured on the difference in margin and replacement cost between two types of notional refineries, referred to as incremental CRF. For example, the incremental CRF between catalytic cracking and coking gives an indication of the simple return for the upgrading investment of adding coking capability to a cracking refinery.

FIGURE VI-4
USGC LLS REFINING MARGINS
(Forecast in Constant 2009 Dollars per Barrel)

Last Revised Dec 2009



We expect margins to remain weak for the next several years before returning to equilibrium levels, which are stronger in dollar per barrel terms due to higher energy and operating costs. At the levels anticipated, some degree of refinery capacity rationalization is expected, which should help improve utilization and restore margins in the longer term. A modest uptick is projected in 2015 due to the expected effect of lowering bunker fuel sulfur in the U.S. and European ECA areas.

REFINED PRODUCT PRICES

FORECAST METHODOLOGY

Refined product prices are a function of feedstock costs and the projected level of refinery profitability. The prices of individual light products are a function of supply/demand factors and refining economics. The relationship between light and heavy products is related to global trends in conversion utilization as well as local factors.

Product prices in the U.S. are determined in an iterative fashion. Two key variables -- refining margins for a cracking refinery, and the incremental coking return at the U.S. Gulf Coast for a light sour crude refinery -- are input to the pricing models, along with the crude oil price forecast. The model then iteratively adjusts light product prices and residual fuel oil prices until converging on the single set of prices for these products that satisfies the input economic variables that have been derived through projected local and global fundamentals. Prices of other light products, including various grades of gasoline, are related to conventional unleaded regular gasoline based on refining economics and trends in supply requirements. Likewise, the prices of fuel oils of other grades are calculated to be consistent with these same factors.

GULF COAST PRODUCT PRICES

The forecasts for U.S. Gulf Coast product prices in current and constant dollars are shown in Tables VI-3, in current and constant 2009 dollars. The prices are spot pipeline prices for light products and waterborne prices for residual fuel oil. All prices are the mean of the high-low quotations. These prices are developed through an iterative procedure from the forecast margins discussed above and product price relationships, which take into account the impact of specification changes.

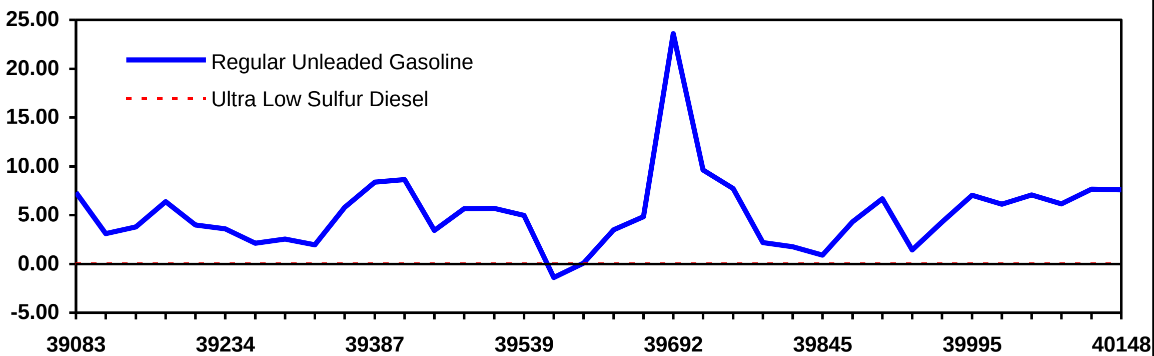
NORTH DAKOTA PRODUCT PRICES

Due to its strong dependence on product transfers, product pricing in PADD II is related to spot markets (the U.S. Gulf Coast or Tulsa, OK) by transportation costs. Minnesota is a large market in the northern tier of the U.S., and its pricing is generally linked to Group 3.

The U.S. northern tier markets (Montana, North and South Dakota and Minnesota) have historically realized high price differentials relative to spot markets. Figure VI-5 illustrates the recent historical unbranded rack price premiums for gasoline and diesel in North Dakota. Prices approximate the volumetric average for the state, based on annual average rack pricing from Minot, Mandan and Fargo. The differential is shown relative to the Minneapolis rack price. Gasoline rack prices in North Dakota have averaged about 5-6 cents per gallon over

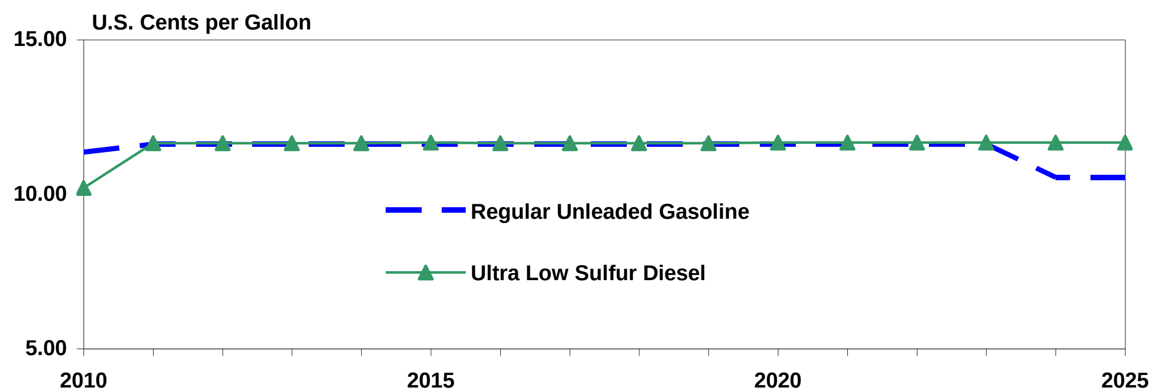
Minneapolis between 2007 and 2009. Diesel rack prices averaged between 6-9 cents per gallon over Minneapolis during the same period. Historical pricing differentials have been volatile, due in part to supply constraints in the large northern tier region.

FIGURE VI-5
NORTH DAKOTA AVERAGE RACK - MINNEAPOLIS RACK
(U.S. Cents per Gallon)



Forecast prices for the light refined products have been estimated. For reference purposes, prices are shown as differentials to the U.S. Gulf Coast spot market, as shown in Figure VI-6.

FIGURE VI-6
LIGHT PRODUCT DIFFERENTIALS: NORTH DAKOTA (RACK) MINUS GULF COAST (SPOT)



NGL Product Prices

Table VI-4 presents historical and forecast prices for propane and butane at the USGC. The supply/demand outlook for natural gas liquids (NGL) products is found in Section III of this report. Marginal propane supplies in the Upper Midwest area of PADD II are Canadian imports and inter-PADD transfers. Typically, Canadian pricing is at a discount from prices at Conway, KS which is the closest large market center. Prices and discounts vary seasonally. In recent years, Edmonton, AB prices have averaged 8 to 10 cents per gallon below Conway prices although discounts were lower in 2009 due to limited supplies. A similar pricing relationship may be expected for the Upper Midwest area of PADD II. Netback prices in this area are forecast to be discounted from Conway prices by 3 to 5 cents per gallon.

Butane is usually priced at a discount to Mont Belvieu on the US Gulf Coast (USGC). North Dakota pricing could be expected to be several cents per gallon discount from Mont Belvieu prices.

Residual Fuel Oil (RFO) Prices

Pricing of RFO is summarized in Table VI-4. The price at a North Dakota refinery location could be expected to be set based on realized prices in the U.S. Gulf Coast or other large market, less transportation from the refinery location to the clearing location. For this purpose it has been assumed that rail transportation would be employed to complete such deliveries. The cost of transportation is estimated to approach $10 per barrel in 2009 dollars.

TABLE VI-1
INTERNATIONAL CRUDE OIL PRICES

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
Last Revised Dec 2009													
Current Dollars per Barrel													
Dated Brent, FOB	54.52	65.14	72.39	97.26	61.39	76.44	78.77	81.22	84.16	86.77	89.41	105.27	129.67
Dated Brent, USGC	56.14	66.77	73.41	99.21	62.70	77.75	79.98	82.01	84.90	87.49	90.13	106.23	130.58
LLS, St. James	57.04	67.48	75.26	102.79	64.17	79.67	82.15	84.41	87.48	90.15	92.91	109.34	134.45
WTI Spot, Cushing	56.59	66.04	72.20	100.06	61.73	77.82	80.49	83.15	86.12	88.71	91.33	107.49	132.18
Forecast in Constant 2009 Dollars per Barrel													
Dated Brent, FOB	54.52	65.14	72.39	97.26	61.39	75.31	75.50	75.58	75.66	75.74	76.14	81.19	90.58
Dated Brent, USGC	56.14	66.77	73.41	99.21	62.70	76.60	76.65	76.31	76.32	76.37	76.75	81.93	91.22
LLS, St. James	57.04	67.48	75.26	102.79	64.17	78.49	78.73	78.54	78.64	78.68	79.11	84.33	93.92
WTI Spot, Cushing	56.59	66.04	72.20	100.06	61.73	76.67	77.14	77.37	77.42	77.43	77.77	82.90	92.34

TABLE VI-2
U.S. GULF COAST LIGHT SWEET CRUDE MARGINS

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
Last Revised Dec 2009													
Current Dollars per Barrel													
Light Sweet FCC Cracking Refinery													
Product Sales Realization	65.11	73.82	82.86	108.04	66.94	81.92	84.77	87.24	91.22	94.34	97.75	114.56	140.69
Crude Cost	56.92	67.26	75.02	102.69	64.25	79.72	82.10	84.20	87.23	89.93	92.72	109.15	134.20
Gross Margin	8.19	6.56	7.84	5.35	2.70	2.20	2.67	3.04	4.00	4.41	5.03	5.41	6.49
Variable Costs	1.15	0.95	1.12	1.37	0.81	0.90	1.15	1.33	1.44	1.53	1.60	1.98	2.57
Fixed Costs	1.55	1.83	2.05	2.20	2.17	2.06	2.18	2.23	2.29	2.35	2.40	2.68	3.01
Net Refining Margin	5.49	3.78	4.67	1.77	(0.28)	(0.77)	(0.65)	(0.52)	0.26	0.53	1.03	0.75	0.91
Interest on Working Capital	0.32	0.47	0.53	0.44	0.18	0.23	0.34	0.50	0.55	0.53	0.51	0.56	0.68
Return, % of Replacement Cost	18.96	9.30	9.77	2.89	(1.06)	(2.57)	(2.50)	(2.50)	(0.70)	0.00	1.20	0.40	0.40
Light Sweet FCC Coking Refinery													
Product Sales Realization	67.33	76.37	85.51	111.07	67.74	82.95	86.02	88.62	92.96	96.35	100.03	117.09	143.67
Crude Cost	56.92	67.26	75.02	102.69	64.25	79.72	82.10	84.20	87.23	89.93	92.72	109.15	134.20
Gross Margin	10.41	9.10	10.49	8.38	3.49	3.23	3.92	4.42	5.74	6.42	7.31	7.94	9.47
Variable Costs	1.28	1.05	1.24	1.52	0.89	0.99	1.28	1.48	1.60	1.70	1.77	2.20	2.87
Fixed Costs	1.82	2.13	2.38	2.56	2.52	2.40	2.53	2.60	2.67	2.73	2.79	3.12	3.51
Net Refining Margin	7.31	5.92	6.86	4.30	0.07	(0.16)	0.12	0.34	1.46	1.99	2.75	2.62	3.09
Interest on Working Capital	0.32	0.48	0.54	0.45	0.18	0.24	0.35	0.50	0.56	0.54	0.52	0.56	0.69
Return, % of Replacement Cost	22.01	13.15	12.86	7.20	(0.21)	(0.88)	(0.50)	(0.34)	1.86	2.92	4.40	3.61	3.69
Light Sweet Incremental Capital Recovery Factors (%)													
Hydroskimming/FCC Cracking	44.16	43.98	34.51	25.53	12.17	14.41	14.60	15.63	19.02	21.74	23.74	23.43	24.31
FCC Cracking/FCC Coking	40.76	37.07	32.27	34.16	5.16	9.63	11.45	12.63	17.16	20.39	23.54	22.79	23.41
Forecast in Constant 2009 Dollars per Barrel													
Light Sweet FCC Cracking Refinery													
Product Sales Realization	65.11	73.82	82.86	108.04	66.94	80.71	81.24	81.18	82.01	82.34	83.24	88.35	98.28
Crude Cost	56.92	67.26	75.02	102.69	64.25	78.55	78.68	78.35	78.42	78.49	78.95	84.18	93.75
Gross Margin	8.19	6.56	7.84	5.35	2.70	2.16	2.56	2.83	3.59	3.85	4.28	4.17	4.54
Variable Costs	1.15	0.95	1.12	1.37	0.81	0.89	1.10	1.24	1.30	1.34	1.36	1.53	1.80
Fixed Costs	1.55	1.83	2.05	2.20	2.17	2.03	2.09	2.08	2.06	2.05	2.04	2.07	2.10
Net Refining Margin	5.49	3.78	4.67	1.77	(0.28)	(0.75)	(0.63)	(0.49)	0.24	0.47	0.88	0.58	0.63
Interest on Working Capital	0.32	0.47	0.53	0.44	0.18	0.23	0.33	0.46	0.50	0.47	0.44	0.43	0.48
Return, % of Replacement Cost	18.96	9.30	9.77	2.89	(1.06)	(2.57)	(2.50)	(2.50)	(0.70)	0.00	1.20	0.40	0.40
Light Sweet FCC Coking Refinery													
Product Sales Realization	67.33	76.37	85.51	111.07	67.74	81.73	82.44	82.46	83.57	84.10	85.18	90.30	100.36
Crude Cost	56.92	67.26	75.02	102.69	64.25	78.55	78.68	78.35	78.42	78.49	78.95	84.18	93.75
Gross Margin	10.41	9.10	10.49	8.38	3.49	3.18	3.76	4.11	5.16	5.61	6.23	6.12	6.61
Variable Costs	1.28	1.05	1.24	1.52	0.89	0.98	1.22	1.38	1.44	1.49	1.51	1.70	2.00
Fixed Costs	1.82	2.13	2.38	2.56	2.52	2.36	2.43	2.42	2.40	2.38	2.38	2.40	2.45
Net Refining Margin	7.31	5.92	6.86	4.30	0.07	(0.16)	0.11	0.32	1.32	1.74	2.34	2.02	2.16
Interest on Working Capital	0.32	0.48	0.54	0.45	0.18	0.23	0.33	0.47	0.50	0.47	0.44	0.44	0.48
Return, % of Replacement Cost	22.01	13.15	12.86	7.20	(0.21)	(0.88)	(0.50)	(0.34)	1.86	2.92	4.40	3.61	3.69
Light Sweet Incremental Capital Recovery Factors (%)													
Hydroskimming/FCC Cracking	44.16	43.98	34.51	25.53	12.17	14.41	14.60	15.63	19.02	21.74	23.74	23.43	24.31
FCC Cracking/FCC Coking	40.76	37.07	32.27	34.16	5.16	9.63	11.45	12.63	17.16	20.39	23.54	22.79	23.41

Note: Margin projections incorporate production of ultra-low sulfur gasoline (30 ppm) in 2005, ultra-low sulfur diesel (15 ppm) in 2007, and low-benzene gasoline in 2011.

TABLE VI-3
U.S. GULF COAST PRODUCT PRICES

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
Current Cents per Gallon													
Propane	91.25	101.16	120.81	142.12	84.14	113.06	118.65	124.03	128.61	131.76	134.99	160.78	198.07
Isobutane	115.37	123.52	148.50	173.01	104.42	137.59	141.92	147.68	153.65	158.79	163.89	194.91	238.49
Normal Butane	107.53	119.62	141.36	167.75	104.42	137.58	141.46	146.44	151.79	156.59	161.51	191.77	234.89
Natural Gasoline	125.98	143.67	167.88	210.03	129.85	169.74	173.47	178.27	184.17	189.39	194.81	227.58	277.28
Premium Unleaded Gasoline	170.87	204.92	221.41	261.88	174.48	205.31	211.12	216.42	226.78	234.72	242.55	285.05	349.06
Mid-grade Unleaded Gasoline	164.54	192.57	211.65	254.82	168.62	200.13	205.82	211.21	221.37	229.11	236.73	278.33	340.91
Regular Unleaded Gasoline	160.32	184.33	205.14	250.12	164.79	196.68	202.29	207.73	217.76	225.36	232.85	273.85	335.48
Jet/Kerosene	171.36	192.34	212.62	296.43	165.79	208.02	216.00	222.13	233.61	242.20	252.59	295.27	362.55
Diesel/No. 2 Fuel Oil	162.35	180.73	200.34	281.89	161.23	201.64	210.11	216.33	227.21	235.67	245.93	287.79	354.02
0.05% S Diesel	168.32	186.73	205.83	287.64	162.20	202.94	211.29	219.73	231.15	239.68	249.99	292.48	359.60
Ultra - Low Sulfur (15 ppm) Diesel	------	198.06	214.31	293.06	165.87	207.16	217.10	224.17	235.81	244.51	255.00	298.26	366.47
1% Sulfur Residual Fuel Oil ($/BBL)	43.75	47.30	55.62	78.35	58.50	71.59	72.48	73.85	74.19	74.52	75.03	89.15	110.81
3% Sulfur Residual Fuel Oil ($/BBL)	36.53	45.58	53.09	72.93	55.78	68.28	69.05	69.82	69.83	69.98	70.60	85.11	106.04
Reformulated Gasoline													
Premium Unleaded Gasoline	175.70	------	------	------	------	------	------	------	------	------	------	------	------
Mid-grade Unleaded Gasoline	169.28	------	------	------	------	------	------	------	------	------	------	------	------
Regular Unleaded Gasoline	165.00	------	------	------	------	------	------	------	------	------	------	------	------
Reformulated Blendstock for Oxygenate Blending													
Premium (PBOB)	172.85	209.96	223.67	267.18	177.55	205.50	212.63	218.27	228.76	236.78	244.68	287.50	352.05
Regular (RBOB)	160.65	188.32	207.63	253.70	165.15	198.30	204.13	209.58	219.73	227.42	234.98	276.30	338.48
Gulf Coast Ethanol Prices													
Terminal Prices (before Tax Credit)	180.02	270.79	215.42	233.83	183.82	218.06	228.51	237.95	251.24	266.37	278.25	321.23	383.37
After-tax Price	129.02	219.79	164.42	182.83	138.82	173.06	183.51	192.95	206.24	221.37	233.25	276.23	338.37
Conventional Blendstock for Oxygenate Blending													
Regular (CBOB)	------	------	------	249.46	164.02	195.30	199.80	204.27	214.17	221.63	228.98	269.35	330.00
Forecast in Constant 2009 Cents per Gallon													
Propane	91.25	101.16	120.81	142.12	84.14	111.39	113.72	115.40	115.62	115.00	114.95	124.00	138.36
Isobutane	115.37	123.52	148.50	173.01	104.42	135.56	136.02	137.41	138.13	138.60	139.55	150.32	166.59
Normal Butane	107.53	119.62	141.36	167.75	104.42	135.54	135.58	136.26	136.46	136.68	137.53	147.90	164.08
Natural Gasoline	125.98	143.67	167.88	210.03	129.85	167.23	166.25	165.87	165.57	165.30	165.89	175.52	193.69
Premium Unleaded Gasoline	170.87	204.92	221.41	261.88	174.48	202.28	202.33	201.37	203.88	204.87	206.54	219.85	243.84
Mid-grade Unleaded Gasoline	164.54	192.57	211.65	254.82	168.62	197.17	197.25	196.52	199.01	199.97	201.58	214.67	238.15
Regular Unleaded Gasoline	160.32	184.33	205.14	250.12	164.79	193.77	193.87	193.29	195.77	196.70	198.28	211.21	234.35
Jet/Kerosene	171.36	192.34	212.62	296.43	165.79	204.94	207.01	206.68	210.01	211.39	215.09	227.73	253.26
Diesel/No. 2 Fuel Oil	162.35	180.73	200.34	281.89	161.23	198.66	201.37	201.29	204.27	205.70	209.42	221.96	247.30
0.05% S Diesel	168.32	186.73	205.83	287.64	162.20	199.95	202.49	204.45	207.81	209.20	212.88	225.58	251.20
Ultra - Low Sulfur (15 ppm) Diesel	------	198.06	214.31	293.06	165.87	204.10	208.06	208.59	211.99	213.42	217.14	230.04	256.00
1% Sulfur Residual Fuel Oil ($/BBL)	43.75	47.30	55.62	78.35	58.50	70.53	69.46	68.71	66.69	65.05	63.89	68.76	77.41
3% Sulfur Residual Fuel Oil ($/BBL)	36.53	45.58	53.09	72.93	55.78	67.27	66.18	64.97	62.77	61.08	60.12	65.64	74.07
Reformulated Gasoline													
Premium Unleaded Gasoline	175.70	------	------	------	------	------	------	------	------	------	------	------	------
Mid-grade Unleaded Gasoline	169.28	------	------	------	------	------	------	------	------	------	------	------	------
Regular Unleaded Gasoline	165.00	------	------	------	------	------	------	------	------	------	------	------	------
Reformulated Blendstock for Oxygenate Blending													
Premium (PBOB)	172.85	209.96	223.67	267.18	177.55	202.47	203.78	203.09	205.65	206.67	208.35	221.74	245.93
Regular (RBOB)	160.65	188.32	207.63	253.70	165.15	195.37	195.64	195.01	197.54	198.49	200.09	213.10	236.44
Gulf Coast Ethanol Prices													
Terminal Prices (before Tax Credit)	180.02	270.79	215.42	233.83	183.82	214.84	219.00	221.40	225.87	232.50	236.94	247.75	267.80
After-tax Price	129.02	219.79	164.42	182.83	138.82	170.51	175.87	179.53	185.41	193.22	198.62	213.05	236.37
Conventional Blendstock for Oxygenate Blending													
Regular (CBOB)	------	------	------	249.46	164.02	192.41	191.49	190.07	192.54	193.44	194.98	207.74	230.53

Note: Gasoline and RBOB changed to ultra-low sulfur in 2005 and to low benzene in 2011
0.05% S Diesel based on off-road price beginning in 2006

TABLE VI-4
NORTH DAKOTA PRODUCT PRICES (REFERENCE CASE)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
Inflation Factor (2009 = 1.00)	1.00	1.00	1.00	1.00	1.00	1.02	1.04	1.07	1.11	1.15	1.17	1.30	1.43
Current Cents per Gallon													
Propane	84.24	91.64	110.62	130.94	72.28	103.65	108.87	114.05	118.33	121.22	124.20	148.91	184.83
Isobutane	111.91	120.36	144.41	162.19	104.46	139.37	141.89	145.65	149.08	153.25	157.35	185.89	228.51
Normal Butane	99.69	107.99	127.50	145.47	85.71	122.63	126.10	132.50	138.27	143.60	149.93	178.99	220.54
Ethanol (before Tax Credit)	182.02	264.45	211.48	233.87	190.57	224.92	235.57	245.22	258.77	274.12	286.20	329.99	393.04
Premium Unleaded Gasoline	182.23	216.28	233.03	273.24	184.57	216.85	223.24	228.91	239.71	248.04	256.19	300.12	364.16
Regular Unleaded Gasoline	171.68	195.69	216.76	261.48	174.88	208.21	214.41	220.22	230.68	238.67	246.49	288.91	350.59
Jet/Kerosene	169.58	192.56	215.82	289.94	164.23	208.35	216.04	224.28	236.17	244.71	255.04	297.86	365.48
Diesel/No. 2 Fuel Oil	173.75	192.13	212.00	292.10	170.16	212.00	222.27	228.85	240.18	249.03	259.65	302.92	370.74
0.05% S Diesel	179.72	198.13	217.49	297.85	171.13	213.31	223.45	232.25	244.12	253.04	263.71	307.62	376.32
Ultra - Low Sulfur (15 ppm) Diesel	------	209.46	225.97	303.27	174.80	217.52	229.26	236.70	248.77	257.87	268.71	313.40	383.18
1% Sulfur Residual Fuel Oil ($/BBL)	34.99	38.14	46.11	67.78	48.95	61.44	62.09	63.16	63.18	63.24	63.48	76.48	96.70
3% Sulfur Residual Fuel Oil ($/BBL)	27.76	36.43	43.58	62.36	46.23	58.13	58.66	59.14	58.82	58.70	59.06	72.44	91.93
Forecast in Constant 2009 Cents per Gallon													
Propane	84.24	91.64	110.62	130.94	72.28	102.12	104.34	106.12	106.38	105.80	105.76	114.85	129.12
Isobutane	111.91	120.36	144.41	162.19	104.46	137.32	135.99	135.53	134.02	133.76	133.99	143.37	159.63
Normal Butane	99.69	107.99	127.50	145.47	85.71	120.82	120.85	123.29	124.31	125.34	127.67	138.05	154.06
Ethanol (before Tax Credit)	182.02	264.45	211.48	233.87	190.57	221.60	225.77	228.17	232.64	239.26	243.71	254.51	274.56
Premium Unleaded Gasoline	182.23	216.28	233.03	273.24	184.57	213.64	213.95	212.99	215.50	216.49	218.16	231.47	254.39
Regular Unleaded Gasoline	171.68	195.69	216.76	261.48	174.88	205.14	205.49	204.91	207.39	208.32	209.90	222.83	244.91
Jet/Kerosene	169.58	192.56	215.82	289.94	164.23	205.27	207.05	208.69	212.32	213.59	217.17	229.73	255.31
Diesel/No. 2 Fuel Oil	173.75	192.13	212.00	292.10	170.16	208.87	213.02	212.94	215.92	217.35	221.10	233.63	258.98
0.05% S Diesel	179.72	198.13	217.49	297.85	171.13	210.15	214.15	216.10	219.46	220.86	224.56	237.25	262.88
Ultra - Low Sulfur (15 ppm) Diesel	------	209.46	225.97	303.27	174.80	214.31	219.72	220.24	223.65	225.07	228.82	241.71	267.68
1% Sulfur Residual Fuel Oil ($/BBL)	34.99	38.14	46.11	67.78	48.95	60.54	59.50	58.77	56.80	55.20	54.06	58.98	67.55
3% Sulfur Residual Fuel Oil ($/BBL)	27.76	36.43	43.58	62.36	46.23	57.28	56.22	55.03	52.88	51.24	50.29	55.87	64.22

Note: Gasoline changed to low benzene in 2011
0.05% S Diesel based on off-road price beginning in 2006

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VII. MARKET ANALYSIS

In this section, we describe the market analysis associated with new North Dakota refinery capacity. Market models have been developed for this study, to provide scoping level estimates of the price impacts of additional refining capacity on both crude and major refined products markets. The study methodology is described in this section. Results for the market modeling work for crude oil and refined products have been presented in detail. The market analysis is based on state level markets and does not deal with finer levels of geographic detail. This is reasonable where no specific location for the new capacity is presupposed.

PROJECT PREMISES

Following are the general premises for a potential incremental refining capacity project in North Dakota, as considered by the Corval team for this study. It is noted that the study parameters did not stipulate details pertaining to the refinery, other than the nameplate capacity in the Base Case. The location was not specified. The study team therefore established the following set of premises based on reasonable estimates of the market opportunities and constraints in the region.

- Process 100,000 barrels per calendar day (BPCD or B/D) of indigenous light crude oils generally representative of production from the Bakken formation in the Williston Basin region. This is the Base Case for refinery capacity addition.

- The refinery configuration is of medium complexity, including conversion of vacuum gas oil (VGO). No vacuum residue conversion processing was considered.

- The refinery should maximize production of finished light refined products (gasoline, jet/kerosene and diesel) meeting regional specifications, and with consideration of anticipated future specifications.

- The refinery should maximize light product yield consistent with the anticipated demand forecasts for each product in the target markets in accordance with the market study conclusions.

- The refinery should employ technologies that have been proven in commercial scale operations.

It should be recognized that the scope of analysis for Phase I of the study does not include detailed configuration analysis for the refinery capacity addition project. However, to complete the required competitive analysis, it was necessary to establish the incremental supply of refined products derived from such capacity. The initial premises for the refinery, as outlined above, provided a basis for estimating product yields.

LOCATION

It should be clear that the location of a 100,000 B/D refinery is a significant project decision. For Phase I, the approach taken to the analysis was not specific to a given location in the state. However, there are several parameters that are relevant when considering the location decision. First, it is more cost effective to transport crude oil by pipeline than it is to transport finished products. Second, overall crude oil and refined product transportation costs should be minimized. These considerations may dictate that refining capacity be located as close to the end market as possible. However, the study region, and North Dakota in particular, have very low population density, as illustrated in Section V. The nearest large product market in PADD II is at Minneapolis.

PROJECT BASIS

The Phase I scope of work did not address the project basis for refinery capacity addition. The project may be considered either a grassroots or brownfield facility. A grassroots refinery project would be sited at a previously undeveloped industrial location. All utilities and offsites facilities would be included in the project. By comparison, a brownfield facility would be sited at a previously developed location, having some amount of site preparation and existing industrial infrastructure. It may be possible in the latter situation to utilize existing utilities and offsites facilities.

In the Base Case (100,000 B/D) it would likely be necessary to treat the project as a grassroots project, regardless of its location. The considerable size and scale of the project would represent a major addition to existing industrial facilities (refineries) in the study region. There is only one refinery in North Dakota, (Tesoro at Mandan, with existing crude distillation capacity of 58,000 B/D), so the 100,000 B/D Base Case capacity addition would be essentially a grassroots project, even if it were to be built at the existing Tesoro refinery site.

The alternative cases, at 50,000 B/D and 20,000 B/D, are also large projects. A refining capacity addition project, even in these lower capacity cases, would require significant developed land, utilities and offsites, rights of way, and other supporting infrastructure. It may be possible in these cases to expand an existing industrial facility to accommodate the project(s). However, the project basis would be unique to each location, and it is not possible in the Phase I analysis to determine the extent to which project capital costs could be reduced by taking advantage of existing infrastructure.

CRUDE PROCESSING

Preliminary estimates of the intake and yield from incremental refining capacity were developed, in order to proceed with the market analysis. It was assumed that the intake and yield would be proportional to the individual crude processing capacity for each case. In all cases, the processing objective was to maximum diesel production.

Preliminary intake and yield estimates are summarized in the following table. The yield of distillate relative to gasoline would be maximized by a vacuum gas oil (VGO) hydrocracking configuration. This is most consistent with the expected demand profile in the state, and the results of the market analysis completed for this study. Fuel oil yield is low relative to light refined products.

REFINERY INTAKE/YIELD [1] BAKKEN LIGHT SWEET	Volume Percent
Crude	100.0
Total Intake	100.0
Light Ends	7.8
Gasoline	44.1
Jet/Kerosene	5.0
Low Sulfur/ULS Diesel	42.7
1% Sulfur RFO	4.0
3% Sulfur RFO	0.9
Total Yield	104.5
Sulfur (Tonnes)	0.02

Note: (1) VGO hydrocracking configuration.

Based on the above processing premises, the refining capacity would produce a high yield of diesel relative to gasoline (low G/D ratio).

MODELING ANALYSIS

APPROACH & METHODOLOGY

The crude and product models are separate. Each model incorporates yearly forecasts to 2025 for production, supply and demand, respectively, of crude and finished petroleum products at a state level. The pipeline logistics structure which enables these markets to balance is also represented in each model. All state level details are included for PADD II and IV. Major pipeline connections within the study region, and between the study region and the large refining hub on the U.S. Gulf Coast (USGC) are incorporated. A fundamental premise of both models is the assumption of competitive economic markets.

All logistics options utilize public tariff data where available. In some cases, estimates of truck and rail costs based on proprietary cost models are used. The large and rapid changes in the Williston Basin crude market in the last several years make it difficult to precisely rationalize observed changes in North Dakota crude pricing; however, in the long run, costs should tend toward those established by transportation rates once any necessary infrastructure changes are in place. The models provide a rational basis for estimating the price impact of large changes to the crude and product markets, not necessarily to forecast absolute market prices. More important is the margin between products and crude in North Dakota and changes in that margin under various new capacity addition scenarios. These results are discussed in detail.

OVERVIEW

One of the primary objectives of the Phase I study is assessing the impact new refinery capacity might have on crude and product markets in the study region. Of interest are the changes in movements of material and price. The project team believes the relationship between market prices in different locations can be explained by supply, demand and logistics costs associated with balancing a particular market. This perspective is often not applicable on a monthly or shorter range basis where a great deal of price volatility can be found. There are many short run influences (loss of supply, unexpected changes in capacity, contractual limitations, etc.) on a market which can shift the balance of supply and demand and result in price swings. These short run price swings are not meaningful to a perspective that must extend over decades. Instead, longer run market prices and changes in those prices due to new refinery capacity are the output desired for subsequent analysis here, and market models based on supply/demand fundamentals are the recommended solution to that problem.

Each market model has similar main components: market boundaries, supply and demand for the commodity (product or crude) over time in each market region, a representation of the major price-driving logistics options available to balance all of the markets in each time period of the model. For the refined product models we have used each state within PADDs II and IV (see Section III for a definition of the PADD regions) as a separate market boundary. More geographically focused refinery centers are used in the case of the crude model; 11 centers in all. The applicable estimates of supply and demand are described below as well as the logistics options considered.

The market models are solved (balanced) using linear programming. By minimizing the cost of satisfying the market, linear programming models can economically balance each year of each model. The model solutions show how each market is balanced and what changes in the flow of crude and product result from different assumptions of the size for the new refinery capacity. A benefit of the use of the linear programming formulation is direct access to market prices consistent with the competitively balanced market condition. As it is somewhat simpler, the crude model is discussed first, followed by the refined product model. The refined product model is complicated because three separate products (gasoline, jet and diesel fuel) are considered in detail simultaneously. Because all three products may compete for room on the pipeline system, it is slightly more difficult to keep product movements within pipeline capacity limits. In situations where a pipeline does not currently transport a product (jet fuel for example), the assumption being made is that addition of new tankage and segregation facilities would allow that movement to be made with only modest increases in tariff. Within the accuracy of the modeling work, this was deemed sufficient. After a review of all the model inputs, the results are presented.

CRUDE MODEL INPUTS

CRUDE SUPPLY AND REFINERY DEMAND

See Section IV for an extended discussion of the crude supply forecast basis. The refinery centers used in the crude model and the individual refineries included in each are listed here:

CRUDE MODEL INPUTS

Refining Center	Refineries
North Dakota	Tesoro Petroleum (Mandan)
Pine Bend	Flint Hills (Rosemount)
St. Paul	Marathon (St. Paul Park)
Superior	Murphy (Superior)
Chicago	BP (Whiting), ExxonMobil (Joliet), CITGO (Lemont)
Toledo	BP/Husky (Toledo), Sunoco (Toledo)
Southern Midwest	Marathon (Robinson, Canton), Husky Energy (Lima)
Wood River	WRB Refining (COP/Encana at Wood River)
Denver	Suncor Energy (Denver)
Sarnia	Imperial Oil (Sarnia, Nanticoke), Shell Canada (Sarnia), Suncor Energy (Sarnia), Novacor Chemicals (Corunna)
Group 3	Coffeyville Resources (Coffeyville), NCRA (McPherson), Frontier (El Dorado), ConocoPhillips (Ponca City), Gary-Williams Energy (Wynnewood), Sinclair Oil (Tulsa), Sunoco (Tulsa)

Of the Group 3 refineries, only NCRA (McPherson) is assumed to be served from the Platte/Jayhawk pipeline system, otherwise the crude must arrive at Cushing via rail/truck or on the Spearhead (Enbridge) system via Chicago.

In presenting and illustrating results, the following aggregations are used: Upper Midwest (Pine Bend, St. Paul and Superior), Great Lakes (Chicago and Toledo), and Southern PADD II (Southern Midwest and Wood River). Details for some regions are unchanged: North Dakota, Denver, Sarnia and Group 3.

Bakken crude will compete with alternate supplies of light sweet crude in these refining markets of PADD II and IV. We have estimated the ultimate amount of light sweet crude that is likely to be consumed in each of these refineries. The aggregate demand for each refining center then represents the maximum amount of Bakken that could be supplied to that center. Table VII-1 shows the estimated potential demand of each refinery center for light sweet crude. The changes in potential demand reflect expected refinery projects through 2015 and speculative changes in later years. The expected demand shifts are for Wood River, down 10,000 B/D in 2015 and in the Chicago refinery center, down 70,000 B/D in 2013. The speculative change in Southern PADD II is a loss of 100,000 B/D in 2016 reflecting the potential for refinery closures and/or projects to accommodate a shift toward either sour crude or synthetic crude oil (SCO) from Canada.

Light sweet crude from other sources (foreign, Canadian, or other US domestic sources) displaced by Bakken due to cost advantages, is assumed to redistribute to other markets. The Bakken crude supply is constant across all the scenarios examined, so increased runs of Bakken in new North Dakota refinery capacity means a lower Bakken crude run in other refining centers. If sweet crude runs in the U.S. outside of North Dakota are maintained it would require increased imports of foreign sweet crude. The foreign sweet crude would be moving to refineries in Southern PADD II already importing sweet crude. The ability to move more foreign sweet crude on current import routes (such as Capline) to the Midwest from the USGC, means this market shift is not a high cost adjustment and additional volumes can accommodate reductions in Bakken availability from North Dakota across all scenarios. The consumption of 20,000 B/D, 50,000 B/D and 100,000 B/D of Bakken in North Dakota will require the import of similar volumes of foreign light sweet crude in each scenario.

CRUDE LOGISTICS OPTIONS AND COSTS

The crude market model uses crude tariffs shown in Table VII-6 which are based on 2009 figures. For simplicity the crude market model uses the 2009 tariff as a “constant dollar” estimate across the entire time period. Because the Enbridge Pipeline system is expected to undergo some loss of volume due to the start up of new competing pipeline capacity (Keystone and Keystone XL pipelines), we have included an estimate for the effect on Enbridge tolls in Canada and the U.S. affecting potential Bakken crude movements.

PRODUCT MODEL INPUTS

FINISHED PRODUCT PRODUCTION

The state-level production of each finished product type in the product market model is shown in Tables VII-9 (Gasoline, ex-Ethanol), VII-10 (Jet/Kero) and VII-11 (Diesel). These production volumes are for the Reference Case. The production volumes only change in North Dakota in the alternate scenarios. Finished product volumes assumed from new capacity in North Dakota are shown below. The yield of finished products is the same in all three capacity scenarios and is based on the gas oil hydrocracking configuration.

FINISHED PRODUCT YIELDS FROM NEW REFINERY CAPACITY
(Thousand Barrels per Day)

New Crude Capacity, Thousands of Barrels Per Day	**+20**	**+50**	**+100**
Finished Products			
Gasoline	10.8	27.0	54.1
Jet/Kero	1.0	2.5	5.0
Diesel	7.7	19.3	38.6
Total	19.5	48.9	97.7

FINISHED PRODUCT DEMAND

The state-level demand for each finished product type in the product market model is shown in Tables VII-12 (Gasoline, ex-Ethanol), VII-13 (Jet/Kero) and VII-14 (Diesel). These demands are assumed to be unchanged from the level in the Reference Case in alternate scenarios.

PRODUCT LOGISTICS OPTIONS AND COSTS

The product market model is also based on public tariffs shown in Table VII-7. Unlike the adjustments made to crude tariffs to account for expected increases, these tariffs have been taken as indicative of the longer term as "constant dollar" estimates. In the Base Case scenario with significant amounts of new products moving there may be a need for new pipeline capacity. Due to the Phase I assumption that specific locations would not be selected until after Phase II analysis, we have treated the need for new pipeline capacity in a generic fashion. In cases where significant new product volume would exceed existing pipeline capacities, we have made a provisional estimate of what new pipeline capacity would cost for comparison with existing tariffs. To move 45,000 B/D of production from Mandan (as an arbitrary point of reference) to Fargo on a new 8-inch pipeline we estimate a tariff of about 4 cents per gallon (cpg) as shown in Table VII-8. This is comparable or below some of the existing tariffs and is taken as a justification for using existing tariffs, since they appear sufficient to justify new capacity (North Dakota to South Dakota for example). Some of the existing regional product tariffs are relatively high, possibly due to low volume movements and/or the need to seasonally reverse portions of the pipeline system.

FIGURE VII-1
BAKKEN CRUDE LOGISTICS (REFERENCE CASE)

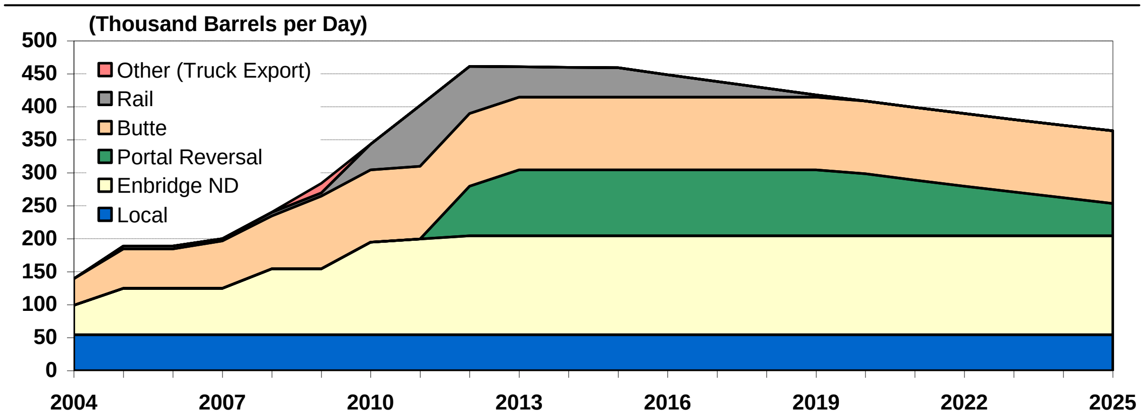


FIGURE VII-2
BAKKEN CRUDE CONSUMPTION (REFERENCE CASE)

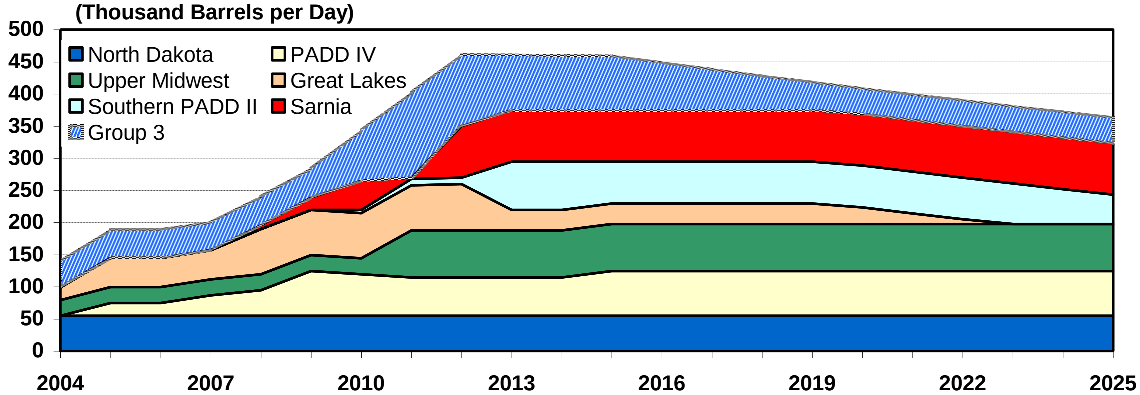
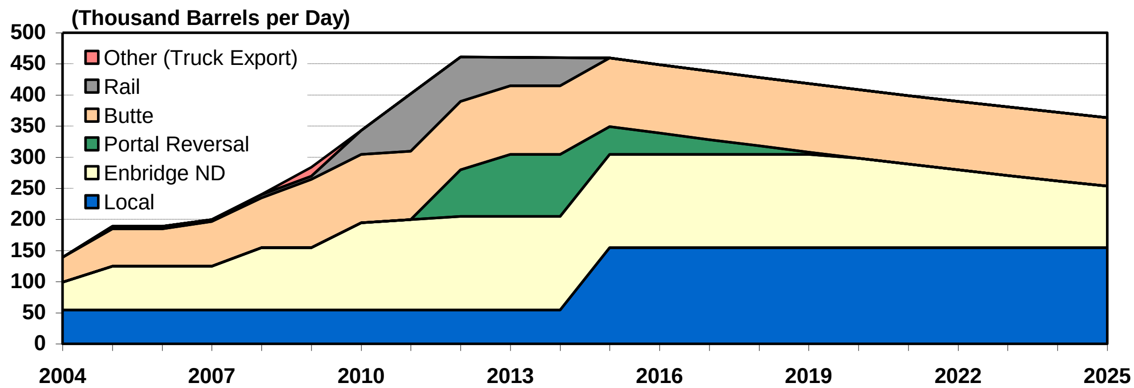


FIGURE VII-3
BAKKEN CRUDE LOGISTICS (BASE CASE)



The important pipeline capacities used in the product market model are shown in Table VII-16. In some cases these are not the capacities associated with specific pipelines, but are “corridor” capacities representing multiple pipelines. In the Reference Case where forecast changes in the flow of product in the study region requires new or expanded pipeline capacity, these have been allowed to increase. For example, the Chase system from Kansas to Colorado is assumed to be debottlenecked to 70,000 B/D by 2015. This increase is assumed to be achieved within the limits of the existing pipeline (10-inch) by addition of pumping capacity with the new volume providing sufficient revenue at existing tariff rates. In one case, the Holly/Sinclair UNev pipeline system provides new capacity from Salt Lake City to Las Vegas (including a terminal at Cedar City, UT) beginning in 2011.

MODEL CASES AND RESULTS

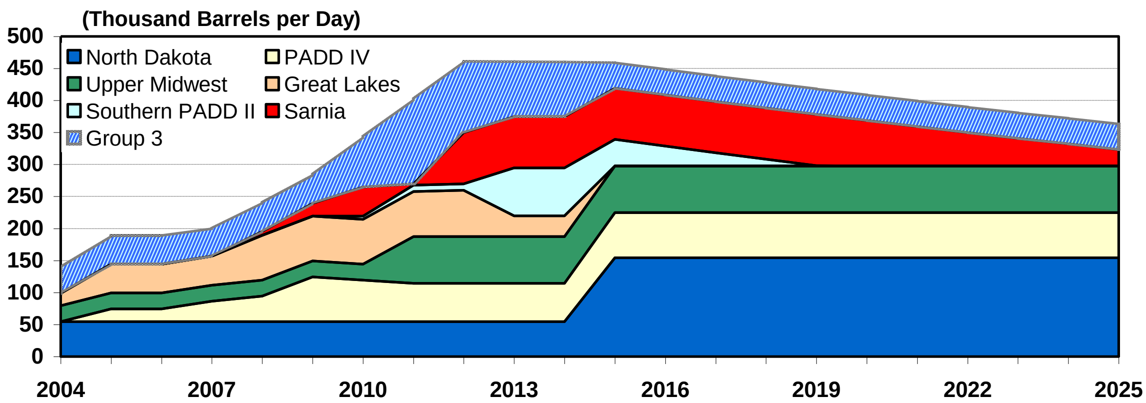
CRUDE MARKET MODEL RESULTS

Optimization of the crude market model to maximize the field netback in North Dakota provides details on the movements, ultimate disposition of Bakken production, and field netback price in North Dakota for each year of the forecast period. As discussed in the section on model input, the potential demand for light sweet crude in eleven different refinery centers is what drives the call on Bakken crude. Each refinery center must compete for the Bakken volume and pay the necessary transportation costs to obtain the crude. Most of the logistics options, with a few exceptions like rail transport to Cushing and Enbridge mainline capacity, are constrained by available capacity. In some cases the pipeline capacity available for Bakken requires an estimate of the amount of other sour or heavy crude moving on the system, for example Platte Pipeline moving Bakken from Guernsey to Holdrege and Wood River.

The final disposition of Bakken crude to major market regions is shown in Tables VII-2 (Reference Case), VII-3 (20,000 B/D Capacity Case), VII-4 (50,000 B/D Capacity Case) and VII-5 (100,000 B/D Capacity Case, or Base Case). For convenience the refinery consumption of Bakken in the alternate cases is also shown as a delta to the Reference Case at the bottom of each table. The results are also shown graphically in Figure VII-2 (Reference Case) and Figure VII-4 (Base Case).

The volumes moved on each major logistics system is shown in Figure VII-1 (Reference Case) and VII-3 (Base Case).

FIGURE VII-4
BAKKEN CRUDE CONSUMPTION (BASE CASE)



2015 Crude Markets

The lowest netback market locations in the Reference Case are the price setting markets from which barrels to run in new North Dakota refining capacity would be taken. Prices would be bid up if necessary to make Bakken uneconomic in the marginal Reference Case markets. For example, in 2015 the Cushing region is forecast to be running 85,000 B/D of Bakken, 45,000 B/D is delivered by rail. If 20,000 B/D of additional Bakken is required in North Dakota, it is the Cushing market rail deliveries which would be reduced based on incremental cost/benefit considerations. Demand for 50,000 B/D of Bakken would take all of the Bakken delivered by rail to Cushing (45,000 B/D) and also begin to take volume away from the Great Lakes market (5,000 B/D). Note that the pipeline Bakken deliveries to Cushing are forecast to remain. Marginal markets are defined by the combination of market location and transportation costs, not location alone. The 100,000 B/D case in 2015 would take Cushing rail volumes, all of the Great Lakes volume (32,000 B/D) and also 23,000 B/D from Southern PADD II markets.

Over time, the locations which relinquish Bakken to allow for increased refinery runs in North Dakota change. There are several reasons for these changes. First, the crude supply is changing over time. In the study forecast, Bakken production (North Dakota plus Eastern Montana) peaks in the 2012 to 2015 time period. Second, the logistics options available are changing over time, most significantly, the Enbridge Portal Reversal project is forecast to provide an additional 75,000 B/D of pipeline export capacity in 2012, ramping to 100,000 B/D in 2013 and beyond. More modest pipeline capacity on the Mustang and Platte pipeline systems is expected to be available beginning in 2011 as committed movements of heavy crude on Keystone Pipeline diverts crude from existing transportation options (including Enbridge mainline). Third, relative pipeline tariffs are forecast to change somewhat over time as rolled-in tariffs on the Enbridge system suffer due to loss of volume to Keystone and Keystone XL pipelines. Of course, the particular scenario being considered, Reference Case (with no Bakken diverted from Reference Case markets) all the way up to Base Case (100,000 B/D Bakken diverted), obviously is a significant factor is changing the market clearing location and the North Dakota price of Bakken. Pricing of Bakken is considered in further detail below.

2020 Crude Markets

By 2020, Bakken production is down slightly from 2015, but enough to eliminate the need for rail delivery to Cushing in all scenarios given the pipeline capacity expansion projects expected to be in place. 2020 is the first year in the Reference Case without a need for rail transportation. In the 20,000 B/D refinery capacity case, rail is only needed through 2017. All other capacity cases would eliminate rail movements to Cushing upon their startup in 2015 (recall that about 45,000 B/D is forecast to be shipped by rail to Cushing in 2015). Without railed volumes to draw from, the 20,000 B/D refinery capacity case in 2020 will take that volume from the Great Lakes refinery market (see Table VII-3). The 50,000 B/D case would divert all of the Bakken in the Great Lakes market (26,000 B/D) and need a further 24,000 B/D from Southern PADD II (Table VII-4). Finally, the Base Case would take all of the Great Lakes market (24,000 B/D), all of the Southern PADD II market (65,000 B/D), and a further 9,000 B/D from Sarnia in 2020. Note that though a market may be unable to compete for Bakken volume in various scenarios, it is assumed they would continue to run alternate light sweet crude with relatively minimal impact to their overall crude slate costs.

2025 Crude Markets

The continued gradual decline in Bakken production by 2025 is forecast to eliminate rail deliveries to Cushing, pipeline movements to the Great Lakes markets, and supply 46,000 B/D to the Southern PADD II market. This market is the marginal price setting location for Bakken in 2025 and the source of Bakken for a 20,000 B/D refinery capacity case in North Dakota. The 50,000 B/D case requires all the Southern PADD II market (46,000 B/D) and 4,000 B/D from Sarnia (see Table VII-4). The 100,000 B/D Base Case would divert 46,000 B/D from Southern PADD II and 54,000 B/D from Sarnia (see Table VII-5). Sarnia would be the price-setting location for Bakken in the Base Case scenario in 2025 given all of the assumptions made.

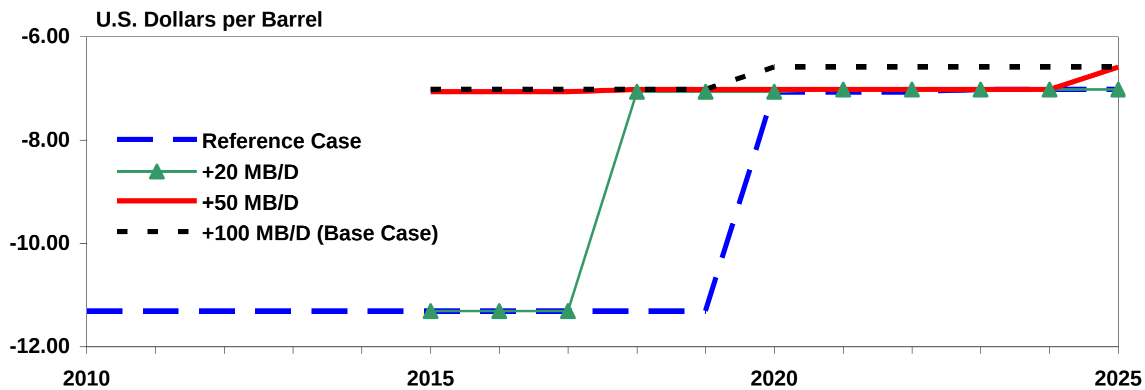
Prices

Generally speaking, the changes in market clearing location for Bakken in different years under different scenarios does not have a major influence on the North Dakota price - with one important exception. Because of the relatively high cost of rail movements from North Dakota to Cushing, this option generates a low netback price in North Dakota. Only distressed export trucking options (observed in 2008 and 2009) are thought to result in lower netbacks. If more economic pipeline alternatives are available, such that no spot movements via rail at incremental rates are required, the benefit to the producer in North Dakota should be a higher netback price. In rough terms, the benefit estimated in the crude market model is approximately $4 dollars per barrel. The netback improvement is dependent on assumptions made for crude supply and the capacity of economic pipeline alternatives to reach desired market centers.

Compared to the elimination of rail transport discounts, shifts in the market-clearing location have a secondary influence on netback pricing. Changes in the market-clearing location can still contribute an additional 50 cents per barrel however. Figure VII-5 shows the Bakken field price in North Dakota output by the crude market model for all cases. Note that the field price is not the same as a plant gate price suitable for refinery margin calculations.

Transportation to a notional North Dakota location has been assumed and appropriate costs included in the margin calculations.

FIGURE VII-5
CRUDE OIL DIFFERENTIALS: ND SWEET (FIELD) MINUS WTI, CUSHING



PRODUCT MARKET MODEL RESULTS

The product market model operates in a similar fashion to the crude model already discussed. Optimization of the product market model to minimize the cost to supplying finished product demands for gasoline, jet fuel and diesel fuel in each state of the study region (here PADD II and IV) provides the results from a competitive market perspective. The results include details on the individual product movements and the market prices for each product in each state for each year of the study horizon. The model does not differentiate one company's finished products from others. In other words, the model detail does not extend beyond fungible product markets at the wholesale level.

As discussed in the section on model input, the market demand for three finished product types: gasoline (without ethanol, or ex-ethanol), jet fuel and diesel fuel in 20 states (15 in PADD II and 5 in PADD IV) are satisfied by competitively delivering the lowest cost supply available. Logistics costs and limits are imposed on these transfers. As discussed in Section III, the region does not produce enough light products to satisfy demand and transfers product from the USGC. The cost of delivering finished products from the USGC is an important driver of the ultimate cost of finished products in PADD II and IV, though it is not the only competitive pricing mechanism. States within the study region, for example North Dakota, are long certain products (gasoline in this example), consequently the North Dakota price for gasoline is then set by the competition of excess production in other markets like Minnesota. The market prices generated by solution of the market model are consistent with the transfers which balances all the state markets. Even pipelines which are operating at their capacity limit may have an influence on prices in their connected markets. This is because with multiple products independently moving on the pipelines, transfer of one product type may go down to accommodate the movement of another product type. This is different from the crude market model which only was only concerned with the movement of one commodity.

FIGURE VII-6
GASOLINE DIFFERENTIALS: NORTH DAKOTA MINUS GULF COAST

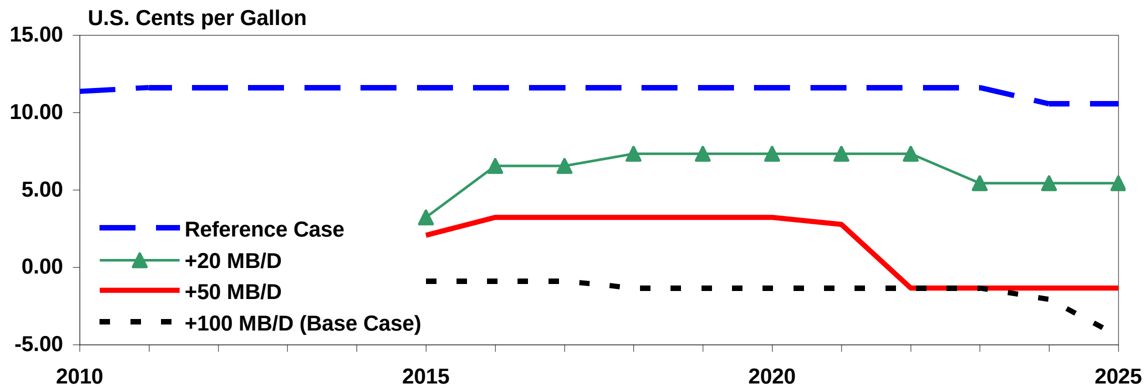
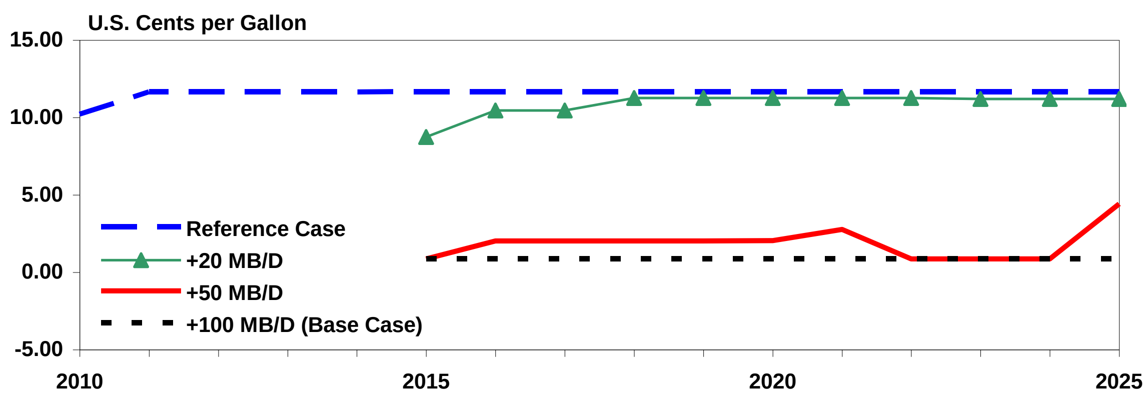


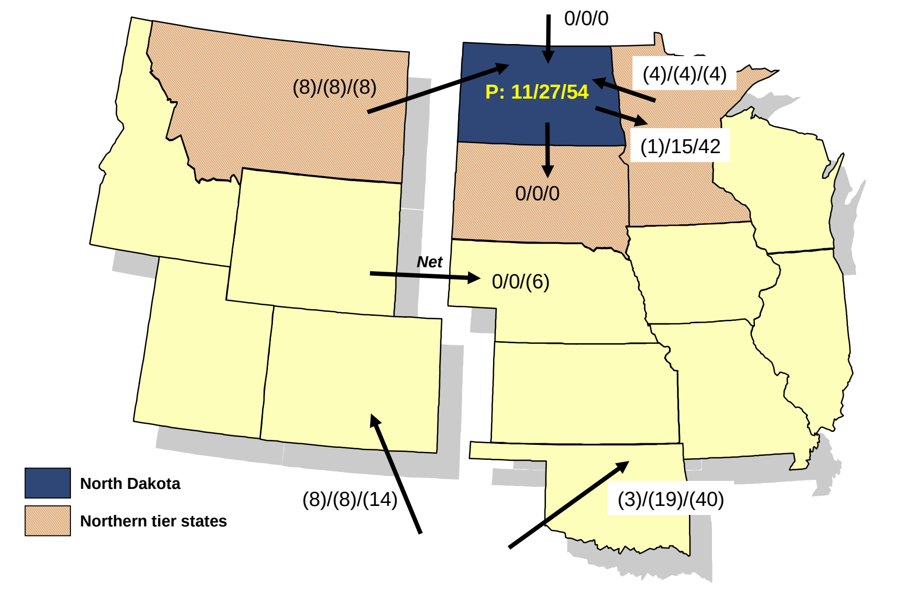
FIGURE VII-7
DIESEL DIFFERENTIALS: NORTH DAKOTA MINUS GULF COAST



2020 Product Markets

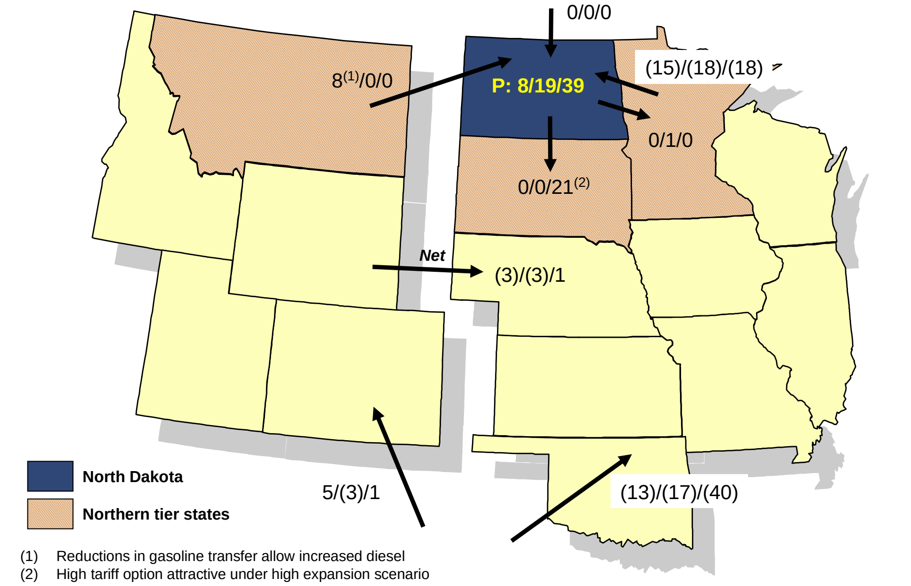
The rebalancing of the gasoline market in 2020 is shown in Figure VII-8. All three refinery capacity cases are shown on the same figure. Figure VII-8 is solely concerned with the changes in product movements and production relative to Reference Case which has no new refinery capacity. New production volumes shown on Figure VII-8 in North Dakota are prefixed with a P to distinguish them from product transfers. In the order of the new capacity cases, 20,000 B/D, 50,000 B/D and 100,000 B/D, the new gasoline volume is: 11,000 B/D; 27,000 B/D and 54,000 B/D (P: 11/27/54). More detail is given around North Dakota as these are the key movements with the potential to influence the average price of gasoline in the state. The new gasoline produced in North Dakota ultimately results in a reduction of the amount of gasoline shipped into PADD II and IV from the USGC (PADD III). In general the reduction in transfers is greater on the pipeline systems reaching into the Midwest. This is the area with the greatest shortfall of product and it is the main region into which new North Dakota production is being placed. The net movement of gasoline from North Dakota into Minnesota is accomplished by two mechanisms, reduction of the gasoline volume moving into North Dakota (Magellan and Cenex systems) and an increase in the volumes leaving North Dakota (NuStar system). Depending on the particular capacity case and the volume of gasoline involved, this will require lower prices in North Dakota to discourage the transfer of gasoline into the state and make it more attractive to transfer gasoline out of the state. The pricing details are discussed below.

FIGURE VII-8
2020 GASOLINE MARKET REBALANCING (Case: 20/50/100)



Rebalancing of the diesel markets in 2020 is shown in Figure VII-9. As with the gasoline diagram, all three refinery capacity cases are shown on the same figure and the values are all **changes** relative to the Reference Case. The new diesel production volumes in North Dakota are: 8,000 B/D, 19,000 B/D and 39,000 B/D. Similar market dynamics are involved in placing the new diesel production. Reductions in the average state-level wholesale price of diesel fuel reduce the volume of diesel fuel transferred in from Minnesota. In the 100,000 B/D refinery capacity case, there is a significant volume of diesel fuel (21,000 B/D) found to be economic for shipment to South Dakota on the NuStar system, a debottlenecked NuStar system, and/or a new pipeline system. A composite tariff from points in North Dakota (Mandan and Minot) into South Dakota (Yankton and Sioux Falls) on the NuStar and Magellan systems is approximately 11 cpg. Based on the estimated tariff for a new 8-inch pipeline capable of moving 45,000 B/D of finished products from Mandan to Fargo (4 cpg), the assumption that the existing composite tariff would support new pipeline capacity if needed is justified. In the 100,000 B/D refinery capacity case, the South Dakota market becomes an attractive option due to relatively high price discounting of diesel fuel in North Dakota.

FIGURE VII-9
2020 DIESEL MARKET REBALANCING (Case: 20/50/100)



(1) Reductions in gasoline transfer allow increased diesel
(2) High tariff option attractive under high expansion scenario

Prices

The expected price changes needed to rebalance the main finished product markets for all three refinery capacity cases are shown in Figure VII-6 (Gasoline) and Figure VII-7 (Diesel Fuel). In both figures the dashed blue line is the Reference Case average North Dakota wholesale price relative to the relevant USGC spot market price. Section VI outlines the historical finished product prices observed in North Dakota. The price basis used for North Dakota is an annual average of rack pricing from Minot, Mandan and Fargo. Annual premiums relative to Tulsa spot pricing during 2007 to 2009 were from 8 to 11 cpg for gasoline, and 13 to 18 cpg for diesel fuel. On the same basis of prices relative to Tulsa spot, the product market model predicted North Dakota wholesale price differentials of 10 cpg for gasoline and 8 to 10 cpg for diesel fuel. Given the assumptions and scope and intended use of the market model, this validation of the historical time period is adequate.

Figure VII-6 shows the price impact of new refinery capacity on average wholesale gasoline prices in North Dakota in 2020 ranges from about 4 cpg (+20,000 B/D refinery capacity) to as much as 13 cpg (+100,000 B/D refinery capacity). These discounts relative to the Reference Case markets is required to make shipment and sale of the new gasoline volume in more distance markets economic. The large price drop also discourages the transfer of gasoline into the state which helps rebalance that market. The ripple effects continue all the way to the USGC where no significant price effect is expected to allow that very large and liquid market to accommodate the change.

Figure VII-7 shows the same price changes caused by new refinery capacity in 2020 for diesel fuel in North Dakota. For the lowest refinery capacity addition, 20,000 B/D, the impact on diesel fuel prices is modest, less than 1 cpg. In the 50,000 B/D and 100,000 B/D refinery capacity cases, the diesel fuel price is projected to drop by 10 to 11 cpg as the additional diesel fuel production requires more extreme market shifts to accommodate the volume. As discussed above for the 100,000 B/D refinery capacity case, about 21,000 B/D of diesel fuel is transferred to South Dakota and given the high (aggregate) pipeline tariff of 11 cpg, the high price discount in North Dakota is needed. These market price changes do not include any initial market discount to allow new entrants into the wholesale market. These price discounts might add a further 1-2 cpg price reduction for some number of years as the competitive rebalancing will most likely not occur immediately.

For convenience the changes in gasoline and diesel fuel product and transfers are shown in absolute terms and as a delta to the Reference Case volumes in Table VII-15.

The North Dakota product price forecasts for all expansion cases are given in Table VI-17 (100,000 B/D Base Case), Table VI-18 (50,000 B/D Case) and Table VI-19 (20,000 B/D Case). North Dakota product prices for the Reference Case are given in Section VI.

CAPACITY ADDITION MARGIN RESULTS AND REVIEW

Preliminary estimates have been prepared for refining margins based on the crude and product price forecasts developed for the refinery capacity addition cases. The key variables in this analysis are the crude and product price forecasts for each case, as derived from the market model results.

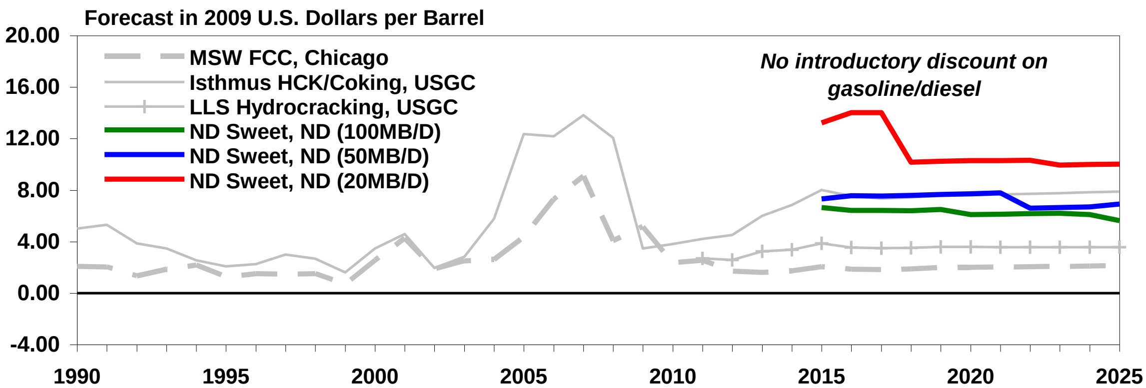
VARIABLE COST MARGINS

The variable cost margin measures the incentive to process incremental crude oil within a refinery, as it is a measure of product revenue less crude costs and variable operating costs. Components of variable costs include fuel, power, catalysts and chemicals, and water. The consumption of each of these components will vary with crude throughput.

The variable cost margins for the North Dakota refinery capacity addition cases have been estimated for this study. The results of the crude and product market models have been incorporated into a preliminary refining margin forecast, as shown in Figure VII-10. For comparison, variable cost margins for three refinery configurations are presented. Each of these refineries has capacity of 100,000 B/D. The configurations are described below, with the rationale for inclusion in Figure VII-10:

- Light Louisiana Sweet (LLS) hydrocracking configuration at the USGC, with similar crude quality and processing configuration as the prospective North Dakota refining capacity.
- Alberta Mixed Sweet (MSW) fluid catalytic cracking (FCC) configuration at Chicago. Crude quality is similar to the expected quality of North Dakota crude.
- Isthmus hydrocracking/coking configuration at the USGC. This is a highly complex configuration, processing light sour crude.

FIGURE VII-10
VARIABLE COST REFINING MARGINS



Variable cost refining margins for the additional refining capacity are forecast to be positive. For the period from 2015 to 2025, the estimated variable cost margin (gross revenue less crude costs and variable costs) is strongly positive for all cases. In fact, variable cost margins are generally comparable to the Isthmus hydrocracking/coking configuration, and higher than the LLS hydrocracking configuration. It is noted that the variable cost margins do not include fixed operating costs or any allowance for project capital recovery.

Variable cost margins are highest for the 20,000 B/D case, particularly in the first few years of the project (assumed to start up in 2015). This case has higher variable cost margins than the Isthmus configuration. In the early years of the forecast after 2015, the 20,000 B/D case realizes a margin increase due to the effects of crude price discounts which persist despite the presence of the additional demand in the state. In this case only, the market clearing mechanism is based on higher cost transportation alternatives.

Variable cost margins for the 50,000 B/D and 100,000 B/D cases are reduced in the early years of the forecast (after 2015), relative to the 20,000 B/D case. Both of these cases are sufficiently large to eliminate the need for higher cost transportation alternatives, resulting in higher crude prices within the state.

The margin forecast does not include any allowance for introductory market discounts on refined products, which may be required for a new entrant to establish a presence in the wholesale refined product markets. It is entirely possible that such price discounts might be required. The extent and duration of any introductory discounts are difficult to estimate. However, several factors may be considered. Given the supply imbalance that is expected to apply in the gasoline market, a further 1-2 cpg price discount may be necessary for a number of years as the competitive rebalancing of the market to accommodate additional supply will most likely not occur immediately. Introductory market discounts for diesel may be smaller, applicable for a shorter period, or both.

FIXED COST MARGINS

The fixed cost margin (or net margin) is indicative of the cash profit generated by the potential refining capacity projects. It is the source of cash flow for recovery of capital invested in the project. Fixed cost components generally include maintenance, taxes and insurance, labor, as well as miscellaneous and allocated general and administrative costs. Over the long term, fixed cost margins must remain positive to support the ongoing operation of a facility as a going concern.

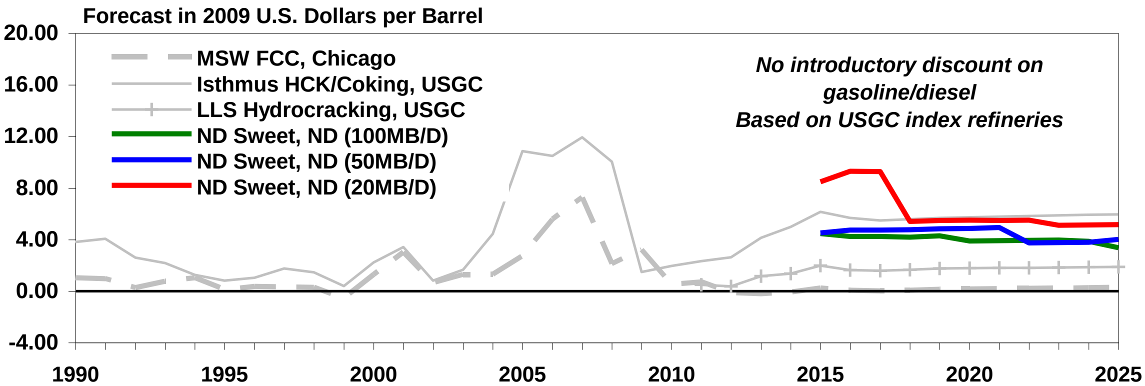
The fixed cost margins for the North Dakota refinery capacity addition cases have been estimated for this study. However, the scope of the Phase I analysis excluded determination of fixed cost estimates for the North Dakota capacity addition cases. To address this, Purvin & Gertz applied fixed cost estimates for a USGC index refinery with similar configuration and crude slate to the North Dakota refinery cases. The details for the USGC index refinery fixed cost margins are summarized in the table below.

NET REFINING MARGIN FOR USGC INDEX REFINERY
LLS HYDROCRACKING in 2020
(Current Dollars)

	North Dakota Project		
US Dollars per Barrel	**+100**	**+50**	**+20**
Product Sales Realization	118.99	118.99	118.99
Less LLS Spot USGC	109.15	109.15	109.15
Gross Refining Margin	9.84	9.84	9.84
Less Operating Costs			
Variable Costs	5.20	5.20	5.19
Fixed Costs	2.86	3.69	6.21
Subtotal	8.06	8.89	11.40
Net Refining Margin	1.78	0.95	-1.57

Indicative net refining margins (after fixed and variable costs) for the additional refining capacity are forecast to be positive. The results of the crude and product market models have been incorporated into a preliminary net refining margin forecast (Figure VII-11).

FIGURE VI-11
NET REFINING MARGINS



For the period from 2015 to 2025, the estimated net margin is positive, and highest for the 20,000 B/D case. However, the fixed costs for the 20,000 B/D case are highest per barrel of capacity. This has the effect of narrowing the advantage for this case relative to the larger capacity cases. As with the variable cost margin, there is a shift to lower fixed cost margins for this refining case several years after the assumed 2015 startup.

Net margins for the North Dakota projects are generally comparable to the Isthmus hydrocracking/coking configuration, and higher than the LLS hydrocracking configuration. It is noted that the net margin for the LLS hydrocracking configuration is generally positive. The MSW refinery at a Chicago location has approximately breakeven net margin, which is indicative of the marginal refining configuration in this market.

The Base Case (100,000 B/D) refining project would be expected to maximize capital cost economies of scale (relative to the smaller cases). The source of the economies of scale is that larger equipment costs less per unit of capacity than smaller equipment, up to the limits of design practice. The Base Case for this study would be considered well within the practical design limits for commercial refineries, approaching the scale of the average refinery in PADD II. This project would therefore benefit from economies of scale. However, despite this relative advantage, the Base Case project is estimated to realize the lowest net margin of the cases considered. The detrimental impact of higher transportation costs on product netback prices in the state more than offsets the economies of scale associated with the project.

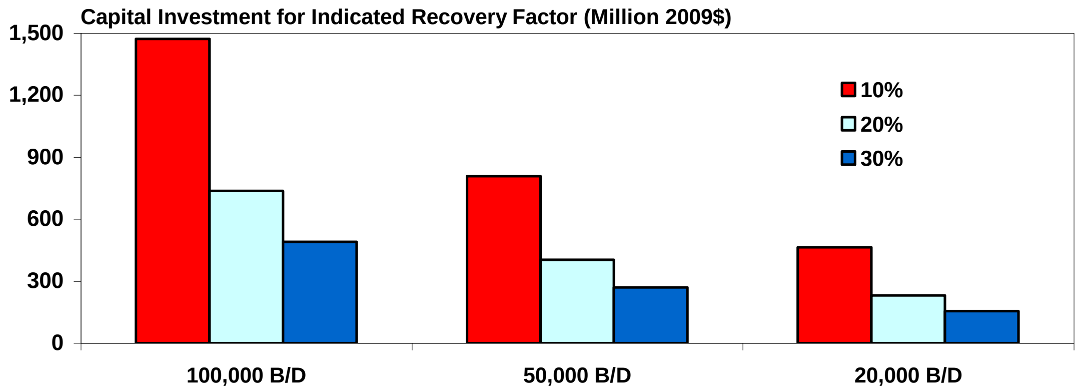
CAPITAL INVESTMENT

As noted above, the net refining margin is the source of cash flow for recovery of invested capital. For this study the Capital Recovery Factor (CRF) has been used as a simple measure of project return on a cash basis. It is defined as the annual change in margin over the capital cost associated with a project. The CRF excludes taxes, working capital, depreciation, amortization, and any other non-cash items. It is indicative of the general feasibility of project. Unlike traditional Net Present Value (NPV) methods, the CRF estimates are not company-specific. For the above reasons, CRF is well-suited to the preliminary evaluation of North Dakota refining capacity additions.

It is noted that actual capital costs for a project in North Dakota will depend on many factors. These include, but are not limited to: labor rates and productivity, capital equipment delivery and taxation, mobilization costs, land, permits and government-related costs, environmental standards, and any unique characteristics of the location in question that would influence the ability to execute the project. The capital cost of the refinery will vary with throughput, location, technology selection and applicable engineering design standards.

For this study, the amount of capital has been determined for a range of CRF values. Figure VII-12 summarizes the amount of invested capital that is supported by the estimated net refining margin for the period 2015 to 2025 for each refinery capacity addition case. Capital recovery factors (CRF) were varied from 10 to 30 percent. The amount of invested capital required to achieve a target CRF will decrease, as the target CRF increases.

FIGURE VII-12
REFINERY CAPITAL BASE (2015-2025)



The results of the 100,000 B/D refinery addition case suggest that the range of capital investment will vary between about $490 million (at 30 percent CRF) and $1.47 billion (at 10 percent CRF). For the same range of target CRF's, the 50,000 B/D refinery addition case would support capital investments of between about $270 million (at 30 percent CRF) and $810 million (for 10 percent CRF). Finally, the 20,000 B/D refinery addition case would support capital investments of between about $150 million (at 30 percent CRF) and $460 million (for 10 percent CRF).

The following table summarizes the results of the capital project cost analysis. The North capital investment supported by the North Dakota refinery projects has been compared to the implied capital for the USGC index refineries of approximately comparable configuration.

CAPITAL INVESTMENT (2015-2025)
USGC INDEX REFINERY vs. NORTH DAKOTA
(2009 Billion Dollars)

	North Dakota Project		
(Thousand B/D) :	**+100**	**+50**	**+20**
Capital supported at CRF of:			
10%	1.47	0.81	0.46
20%	0.74	0.40	0.23
30%	0.49	0.27	0.15
U.S. Gulf Coast Index Refinery Capital	1.73	1.02	0.52

CONCLUSION

Based on the results in the table, none of the refining capacity addition cases would achieve a level of capital recovery that is considered adequate to support development of a grassroots project. However, it may be possible to realize lower capital costs or otherwise mitigate the significant commitment associated with developing a grassroots project. For example, alternative processing configurations may be used, or it may be attractive to produce predominantly intermediate feedstocks or blendstocks rather than finished products. Depending on a particular project sponsor's objectives, other justifications may be important such as the strategic nature of the investment. Refinery project costs in North Dakota will likely be higher than the estimates presented above for the USGC index refineries. It was outside the scope of the Phase I study to develop an optimum refinery configuration.

Further analysis would be required to fully evaluate any specific project concept for North Dakota. The current study has not been specific as to location of the additional refining capacity. Capital costs will vary by location, and it is typical to use factor estimates that allow a USGC cost estimate to be adjusted for another location. The actual process configuration will depend on the quality of crude processed by the refinery and the design yield of individual products. It is recommended that preliminary capital cost estimates be prepared, taking into account these factors.

TABLE VII-1
REFINERY REGIONS LIGHT SWEET CRUDE DEMAND
(Thousand Barrels per Day)

	2005	2010	2015	2020	2025
Potential Demand					
North Dakota	55	55	55	55	55
PADD IV	71	71	71	71	71
Upper Midwest	73	73	73	73	73
Great Lakes	216	216	146	146	146
Sarnia	80	80	80	80	80
Southern PADD II	305	305	295	195	195
Group 3	386	386	386	386	386
Total	1186	1186	1106	1006	1006

TABLE VII-2
REFINERY REGIONS BAKKEN CONSUMPTION ESTIMATE
REFERENCE CASE
(Thousand Barrels per Day)

	2005	**2010**	**2015**	**2020**	**2025**
Bakken Consumption					
North Dakota	55	55	55	55	55
PADD IV	20	65	70	70	70
Upper Midwest	25	25	73	73	73
Great Lakes	45	70	32	26	0
Sarnia	0	45	80	80	80
Southern PADD II	0	5	65	65	46
Group 3	44	78	85	40	40
Total	189	343	459	408	363
Bakken's Estimated Share of Study Region Light Sweet Crude Demand					
	16%	29%	42%	41%	36%

TABLE VII-3
REFINERY REGIONS BAKKEN CONSUMPTION ESTIMATE
20 MB/D CAPACITY ADDITION CASE
(Thousand Barrels per Day)

	2005	**2010**	**2015**	**2020**	**2025**
Bakken Consumption					
North Dakota	55	55	75	75	75
PADD IV	20	65	70	70	70
Upper Midwest	25	25	73	73	73
Great Lakes	45	70	32	6	0
Sarnia	0	45	80	80	80
Southern PADD II	0	5	65	65	26
Group 3	44	78	65	40	40
Total	189	343	459	408	363

Changes Relative to Reference Case

	2005	**2010**	**2015**	**2020**	**2025**
Bakken Consumption					
North Dakota	0	0	20	20	20
PADD IV	0	0	0	0	0
Upper Midwest	0	0	0	0	0
Great Lakes	0	0	0	(20)	0
Sarnia	0	0	0	0	0
Southern PADD II	0	0	0	0	(20)
Group 3	0	0	(20)	0	0
Total	0	0	0	0	0

TABLE VII-4
REFINERY REGIONS BAKKEN CONSUMPTION ESTIMATE
50 MB/D CAPACITY ADDITION CASE
(Thousand Barrels per Day)

	2005	**2010**	**2015**	**2020**	**2025**
Bakken Consumption					
North Dakota	55	55	105	105	105
PADD IV	20	65	70	70	70
Upper Midwest	25	25	73	73	73
Great Lakes	45	70	27	0	0
Sarnia	0	45	80	80	76
Southern PADD II	0	5	65	41	0
Group 3	44	78	40	40	40
Total	189	343	459	408	363

Changes Relative to Reference Case

	2005	**2010**	**2015**	**2020**	**2025**
Bakken Consumption					
North Dakota	0	0	50	50	50
PADD IV	0	0	0	0	0
Upper Midwest	0	0	0	0	0
Great Lakes	0	0	(5)	(26)	0
Sarnia	0	0	0	0	(4)
Southern PADD II	0	0	0	(24)	(46)
Group 3	0	0	(45)	0	0
Total	0	0	0	0	0

TABLE VII-5
REFINERY REGIONS BAKKEN CONSUMPTION ESTIMATE
100 MB/D CAPACITY ADDITION CASE (BASE CASE)
(Thousand Barrels per Day)

	2005	**2010**	**2015**	**2020**	**2025**
Bakken Consumption					
North Dakota	55	55	155	155	155
PADD IV	20	65	70	70	70
Upper Midwest	25	25	73	73	73
Great Lakes	45	70	0	0	0
Sarnia	0	45	80	71	26
Southern PADD II	0	5	42	0	0
Group 3	44	78	40	40	40
Total	189	343	459	408	363

Changes Relative to Reference Case

	2005	**2010**	**2015**	**2020**	**2025**
Bakken Consumption					
North Dakota	0	0	100	100	100
PADD IV	0	0	0	0	0
Upper Midwest	0	0	0	0	0
Great Lakes	0	0	(32)	(26)	0
Sarnia	0	0	0	(9)	(54)
Southern PADD II	0	0	(23)	(65)	(46)
Group 3	0	0	(45)	0	0
Total	0	0	0	0	0

TABLE VII-6
CRUDE TARIFF (2009)

TRANSFERS FROM NORTH DAKOTA (From field unless noted)	USD Per Barrel	Note
to Mandan	**2.27**	Estimated gathering cost on Tesoro High Plains with local trucking to feeder inlets
to Clearbrook via Cromer	**4.00**	Portal Reversal estimate
to Clearbrook via END	**3.84**	END FERC 64 includes Phase 6 surcharge and gathering from Rosebud area to Williams county
to Clearbook via Cromer (distressed trucking)	**11.00**	Truck estimate plus Enbridge Cromer to Clearbrook
to WoodRiver via Butte/Platte	**4.21**	Various Butte, Bridger and Platte tariffs
to Denver via Butte/Suncor	**3.49**	Various Butte and Bridger tariffs, and estimated cost on Suncor system
to Toledo via Butte/Platte/MAP	**4.89**	Various Butte, Bridger, Platte tariffs and estimated cost on Marathon
Clbrk to Pine Bend via Minn P/L	**0.47**	Minnesota P/L (est)
Clbrk to St. Paul via Minn P/L	**0.47**	Minnesota P/L (est)
Clbrk to Superior via Enbridge	**0.47**	Annual average based on FERC 35, 36 and 37
Clbrk to Chicago via Enbridge	**0.71**	Enbridge FERC 37 (Uncommitted)
Clbrk to Toledo via Enbridge	**1.49**	Enbridge FERC 37 (Uncommitted) and Enbridge Toledo FERC 30
Clbrk to Patoka via Enbridge/Mustang	**1.35**	Enbridge to Chicago plus Mustang P/L (FERC 14 and 19 annual average)
Clbrk to Sarnia via Enbridge	**0.90**	FERC 37 plus NEB 296, plus END
Clbrk to Cushing via Enbridge/CCPS	**3.49**	Joint Tariff, Enbridge and CCPS FERC 33, plus END (Light, Uncommitted, Effective April 2010)
to Cushing via Butte/Platte/Jayhawk	**4.56**	Various Butte, Bridger, Platte and Jayhawk tariffs
to Cushing via rail	**10.81**	Rail cost model + truck to Bridger spur + Bridger + Cushing connection fees

TABLE VII-7
PRODUCT TARIFFS (2009)

INTER-PADD TRANSFERS	Pipeline Co.	Average (cpg)	Note
PADD III to OK	Explorer	**3.40**	FERC 96, Pasadena to Tulsa
PADD III to MO	Explorer	**3.74**	FERC 96, Pasadena to St. Louis
PADD III to IL	Explorer	**3.93**	FERC 96, Pasadena to Peotone
PADD III to IN	Explorer	**4.96**	FERC 96, Pasadena to Griffith plus local distribution
PADD III to OH (TEPPCO)	TEPPCO	**4.85**	TEPPCO FERC 70, Texas City to Lima
PADD III to PADD II			
PADD III to CO	Conoco	**2.54**	FERC 207, McKee to Denver
PADD III to PADD IV			
KS to CO (Magellan)	Magellan	**2.62**	FERC 112, El Dorado to Denver
PADD II to PADD IV			
MT to ND (Cenex)		**4.04**	FERC 13, Laurel MT to Minot ND
WY to SD (RM)		**3.63**	FERC 157, Casper to Rapid City SD
WY to NE (Conoco)		**2.35**	FERC 185, Cheyenne WY to Sidney NE (Average of Frontier Refinery and RM rates)
PADD IV to PADD II			
MT to PADD V	COP (Yellowstone)	**4.92**	MT PSC No. 47+FERC 111+estimate for rail (50 cpb)
ID to PADD V	Chevron	**4.05**	FERC 1097, SLC to Pasco Station WA minus SLC to ID
PADD IV to PADD V			
PADD III to TN (Colonial)	Colornial	**2.70**	FERC 94, Colonial Houston to TN
PADD I to OH	Sunoco	**3.82**	FERC 124, Montello to Akron
PADD I to PADD II			

TABLE VII-7 (Cont'd)
PRODUCT TARIFFS (2009)

INTRA-PADD TRANSFERS	Pipeline Co.	Average (cpg)	Note
IL to MI (Wolverine)		**2.59**	Wolverine FERC 159, Lemont to Detroit
OH to MI (Wolverine)	Buckeye	**1.20**	Buckeye FERC 406 Lima to Detroit
IN to IL (West Shore)		**0.88**	West Shore FERC 68, Hammond to Des Plaines
IL to WI (West Shore)		**1.84**	West Shore FERC 68, Lemont to Madison
OK to IA (Kaneb/Heartland)	Magellan	**2.99**	FERC 21 and FERC 59 Average of Heartland and Kaneb PL - Ponca City, OK to various locations in IA
UT to ID (Chevron)		**2.52**	Chevron FERC 1097 average of several ID locations
IL to KY (Marathon)		**1.54**	Marathon FERC 246, Robinson to Louisville
ND to MN (NuStar)	NuStar	**4.51**	NuStar FERC 12 (average to Mn)
MN to ND (Magellan)	Magellan	**3.92**	Magellan Website, Ave. of Minneapolis to Fargo and Grand Forks, FERC 126/128/112
ND to SD (Magellan)	NuStar & Magellan	**11.44**	Mandan to Yankton/Sioux Falls SD; Kaneb/NuStar FERC 14 and Minot to Sioux Falls via Magellan
MN to WI (Magellan)	Magellan	**2.15**	Magellan Website, Ave. of Minneapolis to Chippewa Falls, Superior and Wausau
IA to MN (Magellan)	Magellan	**1.37**	Magellan website, Wynnewood to Minneapolis minus Wynnewood to Iowa City
WY to UT (Pioneer)	COP Pioneer	**4.18**	COP Pioneer , Carbon County WY to North SLC UT, FERC 58
WY to CO (RM)		**2.78**	RM FERC 157 Casper WY to Commerce City and Fountain CO
MT to WY (COP)	COP	**4.26**	COP FERC 188, Billings to Carbon County WY
OK to KS (Explorer/Magellan)	Magellan	**3.58**	Magellan Website, Ave. of Central and Wynnewood to Kansas City, Central to El Dorado
KS to NE (Magellan/Valero)	Magellan	**4.17**	Magellan Website, Ave. of KS to Doniphan, Lincoln & Omaha
KS to IA (Magellan)	Magellan	**4.92**	Magellan Website, Ave. of KS to Des Moins, Fort Dodge & Iowa City
NE to SD (Valero)	Valero	**1.17**	FERC 59, Ave. of Conway KS to Aberdeen SD (Or Wolsey SD) minus Conway KS to North Platte NE,
SD to NE (reversed Valero)	Valero/NuStar	**4.50**	estimate

TABLE VII-8
PIPELINE COST ESTIMATES FOR NEW PRODUCT LINE FROM MANDAN TO FARGO
(Current 2010 U.S. Dollars)

Capital Cost (inch-mile): 90,000

Pipeline Route	Distance (kilometers)	Pipeline Size (Inches)	Capacity (MB/D)	Capital Cost (1) (MM$)	Capital Recovery 15%/yr (cpb)	Operating Cost (cpb)	Total Cost (cpb)
Products	320	8	45	143.2	130.7	24.8	155.6
							3.7 cpg

Note: (1) Looping of the existing NuStar system between Mandan and Jamestown might be sufficient if the Jamestown south system is reversed permanently

Table VII-9
GASOLINE PRODUCTION FORECAST (Reference Case, ex-Ethanol)
(Thousand Barrels Per Day)

	2005	2010	2015	2020	2025
Illinois	483	451	468	447	426
Indiana	192	179	174	167	159
Iowa	0	0	0	0	0
Kansas	160	149	145	139	132
Kentucky	104	97	94	90	86
Michigan	48	45	59	57	54
Minnesota	166	155	151	144	137
Missouri	0	0	0	0	0
Nebraska	0	0	0	0	0
North Dakota	33	31	30	29	27
South Dakota	0	0	0	0	0
Ohio	274	256	249	238	227
Oklahoma	244	228	222	212	202
Tennessee	99	93	90	86	82
Wisconsin	13	12	11	11	10
Total PADD II	1,816	1,696	1,695	1,619	1,544
Colorado	40	42	42	41	40
Idaho	0	0	0	0	0
Montana	92	96	96	93	91
Utah	76	79	79	77	75
Wyoming	66	69	69	67	66
Total PADD IV	275	286	285	278	271

Table VII-10
JET/KERO PRODUCTION FORECAST (Reference Case)
(Thousand Barrels Per Day)

	2005	2010	2015	2020	2025
Illinois	56	50	57	59	61
Indiana	18	16	20	21	22
Iowa	0	0	0	0	0
Kansas	20	18	18	18	19
Kentucky	14	12	12	13	13
Michigan	5	4	6	7	7
Minnesota	20	18	22	22	23
Missouri	0	0	0	0	0
Nebraska	0	0	0	0	0
North Dakota	3	3	4	4	4
South Dakota	0	0	0	0	0
Ohio	36	32	36	37	38
Oklahoma	32	28	28	29	30
Tennessee	13	11	11	12	12
Wisconsin	1	1	2	2	2
Total PADD II	219	195	215	222	230
Colorado	5	4	5	5	6
Idaho	0	0	0	0	0
Montana	9	8	9	10	11
Utah	8	8	9	10	10
Wyoming	8	7	8	9	9
Total PADD IV	30	27	30	33	36

Table VII-11
DIESEL PRODUCTION FORECAST (Reference Case)
(Thousand Barrels Per Day)

	2005	2010	2015	2020	2025
Illinois	240	244	276	284	291
Indiana	101	103	107	110	112
Iowa	0	0	0	0	0
Kansas	82	84	91	93	96
Kentucky	45	46	50	51	53
Michigan	24	25	41	42	43
Minnesota	86	88	90	93	95
Missouri	0	0	0	0	0
Nebraska	0	0	0	0	0
North Dakota	18	19	19	20	20
South Dakota	0	0	0	0	0
Ohio	138	141	148	152	156
Oklahoma	118	120	130	133	137
Tennessee	49	50	54	56	57
Wisconsin	7	7	7	8	8
Total PADD II	908	927	1,014	1,041	1,067
Colorado	27	27	29	30	31
Idaho	0	0	0	0	0
Montana	52	52	56	59	61
Utah	50	50	54	56	58
Wyoming	41	41	44	46	48
Total PADD IV	171	169	183	190	197

Table VII-12
GASOLINE DEMAND FORECAST (ALL Cases, ex-Ethanol)
(Thousand Barrels Per Day)

	2005	2010	2015	2020	2025
Illinois	327	302	304	283	249
Indiana	207	188	191	180	160
Iowa	108	98	98	92	80
Kansas	77	79	80	76	67
Kentucky	144	134	136	129	116
Michigan	322	286	289	272	239
Minnesota	168	161	167	162	149
Missouri	209	192	196	188	171
Nebraska	56	50	50	47	41
North Dakota	23	21	22	20	18
South Dakota	27	26	26	25	22
Ohio	336	302	302	281	244
Oklahoma	124	113	114	108	96
Tennessee	200	191	197	191	172
Wisconsin	162	154	157	150	134
Total PADD II	2,490	2,295	2,329	2,204	1,958
Colorado	126	130	140	140	135
Idaho	36	40	41	40	38
Montana	29	29	29	28	25
Utah	60	65	69	69	66
Wyoming	20	20	21	20	18
Total PADD IV	271	284	300	297	283

Table VII-13
JET/KERO DEMAND FORECAST (ALL Cases)
(Thousand Barrels Per Day)

	2005	2010	2015	2020	2025
Illinois	68	48	52	54	55
Indiana	18	12	13	14	14
Iowa	7	5	5	6	6
Kansas	8	5	6	6	6
Kentucky	37	20	22	24	24
Michigan	43	28	31	32	33
Minnesota	30	20	23	24	26
Missouri	26	19	21	22	23
Nebraska	8	6	6	6	6
North Dakota	4	3	3	3	3
South Dakota	5	4	4	4	5
Ohio	40	27	29	30	30
Oklahoma	17	12	14	14	15
Tennessee	38	27	31	33	34
Wisconsin	22	15	16	17	18
Total PADD II	370	253	277	290	299
Colorado	19	26	31	34	36
Idaho	4	5	6	7	7
Montana	5	6	7	7	7
Utah	9	11	14	15	16
Wyoming	2	3	3	3	4
Total PADD IV	39	51	60	66	70

Table VII-14
DIESEL DEMAND FORECAST (ALL Cases)
(Thousand Barrels Per Day)

	2005	2010	2015	2020	2025
Illinois	140	126	141	148	155
Indiana	128	111	127	135	142
Iowa	60	59	66	69	72
Kansas	53	50	57	61	65
Kentucky	92	87	100	107	113
Michigan	88	76	86	91	96
Minnesota	77	72	84	92	100
Missouri	97	90	104	112	119
Nebraska	48	44	50	53	56
North Dakota	29	31	35	38	40
South Dakota	20	20	23	25	27
Ohio	156	148	166	174	181
Oklahoma	82	87	100	107	114
Tennessee	101	93	108	118	127
Wisconsin	80	73	84	90	96
Total PADD II	1,249	1,168	1,333	1,420	1,501
Colorado	45	50	60	68	75
Idaho	26	25	29	32	35
Montana	30	34	38	41	43
Utah	35	40	48	54	60
Wyoming	36	40	45	49	52
Total PADD IV	173	189	219	244	263

TABLE VII-15
MARKET MODEL FLOW SUMMARY - 2020
(Thousand Barrels Per Day)

					Delta to Reference		
	Reference	**+20**	**+50**	**+100**	**+20**	**+50**	**+100**
Gasoline							
PIII to PII	349	346	330	309	(3)	(19)	(40)
PIII to PIV	75	68	67	61	(8)	(8)	(14)
Other IV to II (Net)	3	3	3	(3)	-	(0)	(6)
ND Production	29	40	56	83	11	27	54
MT to ND (Cenex)	18	10	10	10	(8)	(8)	(8)
ND to MN	24	23	39	66	(1)	15	42
MN to ND	4	-	-	-	(4)	(4)	(4)
ND to SD	6	6	6	6	-	-	-
ND Demand	20	20	20	20	-	-	-
ND Balance (S-D)	-	-	-	-	-	-	-
Diesel							
PIII to PII	242	230	226	203	(13)	(17)	(40)
PIII to PIV	52	57	49	53	5	(3)	1
Other IV to II (Net)	3	-	-	4	(3)	(3)	1
ND Production	20	27	39	58	8	19	39
MT to ND (Cenex)	-	8	-	-	8 (1)	-	-
ND to MN	-	-	1	-	-	1	-
MN to ND	18	3	-	-	(15)	(18)	(18)
ND to SD	-	-	-	21	-	-	21 (2)
ND Demand	38	38	38	38	-	-	-
ND Balance (S-D)	-	-	-	-	-	-	-

Notes: (1) More space for diesel on Cenex
(2) High tariff option to SD becomes attractive @100 MB/D

TABLE VII-16

PIPELINE CAPACITY LIMITS ON TOTAL LIGHT PRODUCTS

(Thousand Barrels Per Day)

	2005	2010	2015	2020	2025
INTER-PADD P/L LIMITS					
PADD III to CO (Valero/COP)	100	100	125	125	125
Panhandle trucks to CO	25	25	25	25	25
KS to CO (Magellan/Chase)	55	55	70	70	70
MT to ND (Cenex)	20	20	25	30	30
WY to SD (RM)	17	17	17	17	17
WY to NE (Conoco)	22	22	22	22	22
MT to PADD V (YS)	64	64	64	64	64
UT to NV (Holly/Sinclair)	0	0	60	60	60
ID to PADD V (Chevron)	80	80	80	80	80
INTRA-PADD P/L LIMITS					
IL to MO	70	70	70	70	70
OH to MI (Wolverine)	250	250	250	250	250
IL to WI (West Shore)	250	250	250	250	250
MN to ND (Magellan)	30	30	30	30	30
ND to MN (NuStar)	75	75	75	75	75
ND to SD (Valero/Kaneb)	75	75	75	75	75
WY to UT (Pioneer)	75	75	100	120	120
WY to CO (Kaneb/Valero)	50	50	50	50	50
MT to WY (COP)	60	60	60	60	60

TABLE VII-17
NORTH DAKOTA PRODUCT PRICES (100,000 B/D BASE CASE)

	2010	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Inflation Factor (2009 = 1.00)	1.02	1.17	1.20	1.22	1.25	1.27	1.30	1.32	1.35	1.38	1.40	1.43
Current Cents per Gallon												
Propane	103.65	124.20	126.19	130.83	136.43	142.63	148.91	155.66	162.75	170.07	177.44	184.83
Isobutane	139.37	157.35	159.52	164.86	171.38	178.47	185.89	193.92	202.33	211.00	219.74	228.51
Normal Butane	122.63	149.93	152.25	157.69	164.25	171.49	178.99	186.81	195.02	203.47	211.99	220.54
Ethanol (before Tax Credit)	224.92	286.20	290.48	298.83	308.41	318.88	329.99	341.84	354.28	367.09	380.07	393.04
Premium Unleaded Gasoline	216.85	241.51	244.88	252.42	261.51	272.07	283.30	295.29	307.88	320.85	332.98	342.71
Regular Unleaded Gasoline	208.21	231.81	235.08	242.35	251.09	261.28	272.10	283.65	295.76	308.26	319.90	329.14
Jet/Kerosene	208.35	255.04	257.39	264.46	274.70	285.91	297.86	310.58	323.91	337.66	351.60	365.48
Diesel/No. 2 Fuel Oil	212.00	246.96	249.24	256.17	266.20	277.20	288.92	301.40	314.48	327.97	341.65	355.28
0.05% S Diesel	213.31	251.02	253.37	260.41	270.59	281.74	293.62	306.27	319.52	333.19	347.04	360.85
Ultra - Low Sulfur (15 ppm) Diesel	217.52	256.02	258.49	265.63	275.99	287.32	299.40	312.25	325.72	339.61	353.69	367.72
1% Sulfur Residual Fuel Oil ($/BBL)	61.44	63.48	64.03	66.75	69.70	72.94	76.48	80.27	84.25	88.37	92.54	96.70
3% Sulfur Residual Fuel Oil ($/BBL)	58.13	59.06	60.38	63.10	65.92	69.03	72.44	76.09	79.93	83.90	87.92	91.93
Forecast in Constant 2009 Cents per Gallon												
Propane	102.12	105.76	105.35	107.08	109.47	112.21	114.85	117.70	120.65	123.60	126.43	129.12
Isobutane	137.32	133.99	133.17	134.93	137.52	140.40	143.37	146.63	149.99	153.35	156.57	159.63
Normal Butane	120.82	127.67	127.10	129.07	131.80	134.91	138.05	141.26	144.57	147.88	151.05	154.06
Ethanol (before Tax Credit)	221.60	243.71	242.51	244.58	247.47	250.86	254.51	258.48	262.63	266.79	270.81	274.56
Premium Unleaded Gasoline	213.64	205.65	204.44	206.60	209.84	214.03	218.50	223.28	228.23	233.19	237.26	239.40
Regular Unleaded Gasoline	205.14	197.39	196.25	198.35	201.48	205.54	209.86	214.48	219.25	224.03	227.93	229.92
Jet/Kerosene	205.27	217.17	214.88	216.45	220.42	224.92	229.73	234.84	240.12	245.40	250.52	255.31
Diesel/No. 2 Fuel Oil	208.87	210.30	208.08	209.67	213.61	218.07	222.83	227.90	233.13	238.36	243.43	248.18
0.05% S Diesel	210.15	213.75	211.53	213.14	217.12	221.64	226.46	231.58	236.86	242.15	247.28	252.08
Ultra - Low Sulfur (15 ppm) Diesel	214.31	218.01	215.79	217.41	221.46	226.03	230.91	236.11	241.46	246.82	252.01	256.87
1% Sulfur Residual Fuel Oil ($/BBL)	60.54	54.06	53.45	54.63	55.93	57.38	58.98	60.69	62.46	64.22	65.94	67.55
3% Sulfur Residual Fuel Oil ($/BBL)	57.28	50.29	50.41	51.64	52.90	54.30	55.87	57.53	59.25	60.97	62.64	64.22

Note: Gasoline changed to low benzene in 2011
0.05% S Diesel based on off-road price beginning in 2006

TABLE VII-18
NORTH DAKOTA PRODUCT PRICES (50,000 B/D CASE)

	2010	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Inflation Factor (2009 = 1.00)	1.02	1.17	1.20	1.22	1.25	1.27	1.30	1.32	1.35	1.38	1.40	1.43
Current Cents per Gallon												
Propane	103.65	124.20	126.19	130.83	136.43	142.63	148.91	155.66	162.75	170.07	177.44	184.83
Isobutane	139.37	157.35	159.52	164.86	171.38	178.47	185.89	193.92	202.33	211.00	219.74	228.51
Normal Butane	122.63	149.93	152.25	157.69	164.25	171.49	178.99	186.81	195.02	203.47	211.99	220.54
Ethanol (before Tax Credit)	224.92	286.20	290.48	298.83	308.41	318.88	329.99	341.84	354.28	367.09	380.07	393.04
Premium Unleaded Gasoline	216.85	244.98	249.81	257.44	267.21	277.88	289.23	300.75	307.88	320.85	334.00	347.12
Regular Unleaded Gasoline	208.21	235.28	240.00	247.37	256.79	267.09	278.03	289.10	295.76	308.26	320.91	333.55
Jet/Kerosene	208.35	255.04	257.39	264.46	274.70	285.91	297.86	310.58	323.91	337.66	351.60	365.48
Diesel/No. 2 Fuel Oil	212.00	246.96	250.62	257.57	267.64	278.66	290.44	303.91	314.48	327.97	341.65	360.36
0.05% S Diesel	213.31	251.02	254.75	261.82	272.02	283.20	295.13	308.77	319.52	333.19	347.04	365.93
Ultra - Low Sulfur (15 ppm) Diesel	217.52	256.02	259.86	267.04	277.42	288.79	300.91	314.76	325.72	339.61	353.69	372.80
1% Sulfur Residual Fuel Oil ($/BBL)	61.44	63.48	64.03	66.75	69.70	72.94	76.48	80.27	84.25	88.37	92.54	96.70
3% Sulfur Residual Fuel Oil ($/BBL)	58.13	59.06	60.38	63.10	65.92	69.03	72.44	76.09	79.93	83.90	87.92	91.93
Forecast in Constant 2009 Cents per Gallon												
Propane	102.12	105.76	105.35	107.08	109.47	112.21	114.85	117.70	120.65	123.60	126.43	129.12
Isobutane	137.32	133.99	133.17	134.93	137.52	140.40	143.37	146.63	149.99	153.35	156.57	159.63
Normal Butane	120.82	127.67	127.10	129.07	131.80	134.91	138.05	141.26	144.57	147.88	151.05	154.06
Ethanol (before Tax Credit)	221.60	243.71	242.51	244.58	247.47	250.86	254.51	258.48	262.63	266.79	270.81	274.56
Premium Unleaded Gasoline	213.64	208.61	208.55	210.71	214.42	218.61	223.07	227.41	228.23	233.19	237.98	242.49
Regular Unleaded Gasoline	205.14	200.35	200.36	202.46	206.05	210.12	214.43	218.60	219.25	224.03	228.66	233.00
Jet/Kerosene	205.27	217.17	214.88	216.45	220.42	224.92	229.73	234.84	240.12	245.40	250.52	255.31
Diesel/No. 2 Fuel Oil	208.87	210.30	209.23	210.82	214.76	219.22	224.00	229.79	233.13	238.36	243.43	251.73
0.05% S Diesel	210.15	213.75	212.68	214.29	218.28	222.79	227.62	233.47	236.86	242.15	247.28	255.63
Ultra - Low Sulfur (15 ppm) Diesel	214.31	218.01	216.94	218.56	222.61	227.18	232.08	238.00	241.46	246.82	252.01	260.42
1% Sulfur Residual Fuel Oil ($/BBL)	60.54	54.06	53.45	54.63	55.93	57.38	58.98	60.69	62.46	64.22	65.94	67.55
3% Sulfur Residual Fuel Oil ($/BBL)	57.28	50.29	50.41	51.64	52.90	54.30	55.87	57.53	59.25	60.97	62.64	64.22

Note: Gasoline changed to low benzene in 2011
0.05% S Diesel based on off-road price beginning in 2006

TABLE VII-19
NORTH DAKOTA PRODUCT PRICES (20,000 B/D CASE)

	2010	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Inflation Factor (2009 = 1.00)	1.02	1.17	1.20	1.22	1.25	1.27	1.30	1.32	1.35	1.38	1.40	1.43
Current Cents per Gallon												
Propane	103.65	124.20	126.19	130.83	136.43	142.63	148.91	155.66	162.75	170.07	177.44	184.83
Isobutane	139.37	157.35	159.52	164.86	171.38	178.47	185.89	193.92	202.33	211.00	219.74	228.51
Normal Butane	122.63	149.93	152.25	157.69	164.25	171.49	178.99	186.81	195.02	203.47	211.99	220.54
Ethanol (before Tax Credit)	224.92	286.20	290.48	298.83	308.41	318.88	329.99	341.84	354.28	367.09	380.07	393.04
Premium Unleaded Gasoline	216.85	246.33	253.80	261.52	272.35	283.12	294.57	306.79	319.61	330.19	343.51	356.83
Regular Unleaded Gasoline	208.21	236.63	243.99	251.44	261.93	272.33	283.37	295.14	307.49	317.59	330.43	343.26
Jet/Kerosene	208.35	255.04	257.39	264.46	274.70	285.91	297.86	310.58	323.91	337.66	351.60	365.48
Diesel/No. 2 Fuel Oil	212.00	256.20	260.73	267.88	279.13	290.39	302.37	315.12	328.48	342.18	356.15	370.07
0.05% S Diesel	213.31	260.26	264.86	272.13	283.52	294.92	307.07	319.99	333.51	347.40	361.54	375.64
Ultra - Low Sulfur (15 ppm) Diesel	217.52	265.26	269.97	277.35	288.92	300.51	312.85	325.98	339.72	353.82	368.19	382.51
1% Sulfur Residual Fuel Oil ($/BBL)	61.44	63.48	64.03	66.75	69.70	72.94	76.48	80.27	84.25	88.37	92.54	96.70
3% Sulfur Residual Fuel Oil ($/BBL)	58.13	59.06	60.38	63.10	65.92	69.03	72.44	76.09	79.93	83.90	87.92	91.93
Forecast in Constant 2009 Cents per Gallon												
Propane	102.12	105.76	105.35	107.08	109.47	112.21	114.85	117.70	120.65	123.60	126.43	129.12
Isobutane	137.32	133.99	133.17	134.93	137.52	140.40	143.37	146.63	149.99	153.35	156.57	159.63
Normal Butane	120.82	127.67	127.10	129.07	131.80	134.91	138.05	141.26	144.57	147.88	151.05	154.06
Ethanol (before Tax Credit)	221.60	243.71	242.51	244.58	247.47	250.86	254.51	258.48	262.63	266.79	270.81	274.56
Premium Unleaded Gasoline	213.64	209.76	211.88	214.04	218.54	222.73	227.19	231.98	236.93	239.97	244.76	249.27
Regular Unleaded Gasoline	205.14	201.50	203.69	205.80	210.18	214.24	218.55	223.17	227.95	230.82	235.44	239.79
Jet/Kerosene	205.27	217.17	214.88	216.45	220.42	224.92	229.73	234.84	240.12	245.40	250.52	255.31
Diesel/No. 2 Fuel Oil	208.87	218.16	217.67	219.25	223.98	228.44	233.21	238.28	243.50	248.69	253.76	258.51
0.05% S Diesel	210.15	221.62	221.12	222.73	227.50	232.01	236.83	241.95	247.24	252.48	257.61	262.41
Ultra - Low Sulfur (15 ppm) Diesel	214.31	225.88	225.38	227.00	231.83	236.41	241.29	246.48	251.84	257.15	262.34	267.20
1% Sulfur Residual Fuel Oil ($/BBL)	60.54	54.06	53.45	54.63	55.93	57.38	58.98	60.69	62.46	64.22	65.94	67.55
3% Sulfur Residual Fuel Oil ($/BBL)	57.28	50.29	50.41	51.64	52.90	54.30	55.87	57.53	59.25	60.97	62.64	64.22

Note: Gasoline changed to low benzene in 2011
0.05% S Diesel based on off-road price beginning in 2006

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VIII. COMPETITIVE ANALYSIS

In this section, we present a competitive analysis of incremental refining capacity in North Dakota. The analysis is directed at addressing indirect impacts of the business case for the project. The analysis presented here is largely qualitative, from the standpoint of potential competitive impacts on stakeholders in the study region. Potential marketability and market entry issues have also been addressed, and where appropriate, other market options for the refinery products have been identified.

STAKEHOLDER ASSESSMENT

Various stakeholders in North Dakota will be impacted differently by addition of refinery capacity in the state. The Phase I mandate refers to assessment of the market issues arising from such development. In this context, a qualitative assessment of the impact of additional refining capacity on key stakeholders is considered below.

PROJECT SPONSOR

The project to add refining capacity is assumed to be undertaken by private interests rather than through public sponsorship or investment. The sponsor must therefore make the decision to commit resources to the project based on a complete and full assessment of the project economics.

As explained in Section VII, refinery profitability is a function of the variable cost refining margin, fixed operating costs and capital cost of the facilities. The variable cost refining margin will depend on the extent to which the facility can access regional crude at an attractive price and produce a high yield of valuable liquid products. It is a measure of the incentive to process incremental crude through a refinery. The refinery must also achieve acceptable net margins after operating costs, to justify ongoing operations. In addition to the ongoing cash flow requirements, the refinery capacity addition project must provide a reasonable return on capital invested.

The capital cost of the project will be very large, particularly if the additional capacity is constructed on a grassroots (or greenfield) site. The capital cost of the refinery will vary with throughput, location, technology selection and applicable engineering design standards. Estimates of project capital cost and return are outside the scope of the Phase I analysis. However, a comparison of the refinery margins to selected index refinery margins has been made for reference. Purvin & Gertz has established index refinery margins for representative refinery configurations, in major market locations. The conclusion drawn in Section VII from the analysis is that the new capacity, depending on the size of the project, might be marginally economic. This conclusion is subject to a variety of uncertainties that would only be addressed in later phases of this project.

In addition to the above economic criteria, a sound business case for the refining project must include secure commercial arrangements for supply of suitable crude oil and product offtakes. This will be an important consideration in financing the project, which is outside the scope of the current study. The issues of crude supply and product offtakes are considered further below, from the perspective of the crude producer and wholesale market participant, respectively.

CRUDE PRODUCERS

Additional refinery capacity has been suggested as a possible solution to prevailing market discounts on North Dakota crude production, relative to benchmarks such as WTI at Cushing. However, it should not be taken as a foregone conclusion that the refinery project will ensure higher netback prices for North Dakota producers. As discussed in Section V, there are several projects at various stages of development to transport Williston Basin crude to other refining locations.

The results of crude market model work (described in Section VII) suggest that pricing dynamics for crude oil depend on the premises for crude supply and available infrastructure projects. Even with additional refining capacity in North Dakota to capitalize on advantageous access to local crude supplies, excess Bakken crude that must be transported to crude markets outside of the state would set the price based on competitive refining economics at the clearing location, less the cost of transportation. A refinery situated near the crude production source could expect to have secure access at the prevailing netback price.

The impact on crude producers of additional refining capacity in the state will depend both on the incremental demand within the state, and the change in clearing location that results for the barrels leaving the state. Based on our analysis, the Base Case project (adding 100,000 B/D of refining capacity) and the 50,000 B/D case will sufficiently increase North Dakota demand to impact the clearing location of crude oil leaving the state. This would have the effect of increasing the crude price in North Dakota, by approximately $4 per barrel in the early years of the project. The 20,000 B/D capacity addition case did not have as much impact on the North Dakota price in the early years of the project, given that its influence on the volume of crude leaving the state and the resultant clearing location would be smaller.

LOGISTICS COMPANIES

Pipeline and transportation companies may be expected to benefit from the opportunity to ship growing supplies of crude and/or refined products from North Dakota. Projects that would increase crude oil transportation capacity have already been implemented, and more may be undertaken. Crude pipeline capacity utilization may be impacted if refinery capacity is added within the state. In the case of assets being constructed for the purpose of transporting an anticipated growing surplus of crude oil, the construction of additional refining capacity may have the effect of reducing utilization of such facilities.

Alternative transportation options, such as rail or truck, are also available to deliver surplus crude supplies out of the state. These options would compete with pipelines, and may affect pipeline utilization. However, if a pipeline option exists for crude transportation, it will generally be more cost effective than rail or truck delivery. Rail system operators may see benefit because they can offer greater flexibility if production is rapidly increasing or decreasing.

Refined products pipeline and terminal operators may be expected to benefit by the construction of additional refining capacity in the state. Additional refining capacity may result in increased utilization of existing facilities, redeployment of existing facilities, or construction of additional capacity. In some cases or for certain facilities, system utilization may decrease if transfers into the state from other states or regions are no longer required at the same level to meet North Dakota demand. However, the actual impact on refined products infrastructure depends on the location of the refinery relative to existing facilities.

OTHER REFINERS

Existing refiners in the study region are believed to have enjoyed generally favorable economics. Refining economics are a function of the variable cost margin, which is the difference between product revenue and all costs associated with processing of crude. Net margin includes the effect of all fixed and variable costs. These margin elements will be examined in turn, before considering the impact of additional refining capacity on the future outlook for margins.

Refined products wholesale prices in the study region have historically realized high differentials relative to inland spot markets such as Tulsa, OK. Price differentials also show significant volatility. These characteristics are somewhat interrelated, because volumes of trade are small and transportation costs are high. The average size of regional refineries is small. The dependence of the PADD II market on transfers in from other regions (mainly PADD III) has grown, as refinery capacity and terminal facilities in PADD II have been rationalized. Furthermore, product specifications have become both more stringent and more regionalized. All of these issues can exacerbate the effect of any disruptions throughout the supply chain, contributing to volatility.

In recent years, the growth in Williston Basin crude supplies has resulted in wide negative price differentials relative to widely reported benchmarks. Pricing of crude close to the supply source is a function of the value realized for the crude in the clearing market location, and the cost of transportation to that location. For existing refineries in the study region, access to local crude supplies is supportive of strong refining margins.

Refinery capacity additions in the study region would increase crude oil demand and product supply. Looking first at the impact of increased crude oil demand, crude oil costs may increase if the local demand is sufficiently high to alter the price-setting mechanism of surplus barrels leaving the state. This increase in crude oil costs may occur immediately if the increment of refining capacity is significantly large. In the case of a small project, as with the 20,000 B/D case considered for this study, it may be possible to defer any impact on crude prices.

Additional product from new refining capacity would have to compete against existing supply. As explained in Section VII, this may be accommodated by realignment of product distribution to wholesale terminals, so as to minimize overall transportation costs to serve these locations. Due to increased competition at the wholesale level, lower product prices may be expected to occur at the refinery gate. Both of these factors would directionally reduce the profitability (net margin) of existing refineries. The duration and extent of these effects would depend on the size of the incremental capacity addition.

WHOLESALE DISTRIBUTORS

The study region is characterized by a number of wholesale market participants. Some are integrated with refining operations, and others are independent marketers. These companies will generally obtain supply from refinery or independent terminal operators. Product distribution may occur through branded or unbranded outlets.

Based on a review of the North Dakota market, it appears that the majority of retail outlets are unbranded. The following table summarizes available data for product distribution, which is limited. In 2009, there were 757 retail facilities distributing product in the state. Of these, less than half are estimated to be branded. The major branded outlets include Cenex and Tesoro. Supply to these outlets would originate at integrated refineries in the region. Other major branded retailers in the state are Sinclair.

DISTRIBUTION OUTLETS IN NORTHERN TIER STATES (1)

	Total Distribution Outlets					Truck Stops
	2005	2006	2007	2008	2009	2009
State						
North Dakota	830	930	922	788	757	45
Montana	1,100	900	400	800	545	64
Minnesota	3,820	3,656	3,649	3,080	3,125	140
South Dakota	1,085	1,073	1,053	1,042	1,018	58

Source: NPN 2009 Survey

Note: (1) NPN state-by-state survey figures include all retail outlets of any kind at which the public can buy gasoline.

Increased supply within the state would result in lower prices at the wholesale level, as the clearing market for the additional product would shift to more distant locations. However, it would be less likely that the branded networks operating in the study region would be as flexible to adapt to the incremental supply. A market penetration strategy would be required to adjust regional marketing relationships. It therefore seems likely that a new entrant would need to gain entry through price discounting to attract independent wholesale distributors. Since this sector accounts for the majority of outlets in the state, it should benefit from diversification of supply. The extent and duration of wholesale price discounts would depend on the flexibility of the network to re-optimize, and the competitive response by incumbents. Other aspects of market penetration are considered below.

STATE OF NORTH DAKOTA

The State of North Dakota (the State) would be expected to benefit from the addition of refining capacity. Benefits would arise due to the increase in economic activity associated with project construction and subsequent operations. A large demand for skilled trades would be expected during the project construction period. However, the relatively small population in the State may require that skilled personnel be sourced from larger urban centers such as Minneapolis, Denver and Salt Lake City.

Operations and maintenance of the refinery process units would similarly create demand for skilled labor. Professional and administrative jobs associated with the ongoing management of the facility would also be created. PGI models are used to estimate the refinery staffing levels, based on the size and complexity of process units. The number of permanent skilled labor jobs would be significantly less than the peak that would be expected to occur during the construction phase.

Both direct and indirect benefits arising from employment in the crude oil processing industry have been studied by the Department of Agribusiness and Applied Economics of the North Dakota State University[1]. Crude oil refining expenditures were included with expenditures for pipeline operation and natural gas processing. In-state expenditures in 2005 were estimated to have a direct impact in North Dakota of $132 million, while secondary economic impacts were estimated at $238 million. It is noted that the processing and pipeline transportation industry sector accounts for a relatively small fraction of the total petroleum industry expenditures (about 9 percent in 2005).

Additional measures of the petroleum industry's economic importance to the State include direct employment, personal income, retail sales and tax revenues. Bangsund and Leistritz estimated total full-time employment in the processing segment of the industry at 471 jobs in 2005. Other benefits were estimated to include personal income ($117 million) and government tax revenues ($26 million). Phase 2 (if sanctioned) would provide preliminary estimates of direct employment associated with additional refining capacity. Benefits to the State would be expected to be proportional to the size and complexity of the refining capacity project.

Economic development initiatives have been identified by the State, and are supported by funding to a range of programs. These programs target workforce development, as well as research and development in a diverse range of economic sectors. The State has targeted the energy industry as a key part of its strategic plan.

In addition to the benefits derived from a major refinery addition project, the State may incur costs of an indirect nature to facilitate the project. Some study work has already been undertaken, and more is likely to be required. The focus of these initiatives to date has been on

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[1] Bangsund, D.A. and F.L. Leistritz, "Economic Contribution of the Petroleum Industry to North Dakota", Department of Agribusiness and Applied Economics, North Dakota State University, April 2007

measures that may contribute to stronger pricing for State crude production. The State may undertake to develop educational programs to encourage development of a sufficient pool of skilled trades to support the activities of the petroleum industry.

MARKET PENETRATION STRATEGY

Because of the volume of product that would be produced by a large addition of refining capacity in North Dakota, an independent wholesale market operation is not likely to penetrate the market to a satisfactory extent without creating incentives to change the regional marketing and distribution structure. However, the size of the refinery capacity addition in the Base Case (100,000 B/D) is supported from the perspective of achieving world-scale manufacturing economics and for utilization of available pipeline capacity at an acceptable level. Therefore it is appropriate to consider the market entry strategy.

A potential market entry strategy would be to negotiate with the larger regional net buyers of product for term contract supplies. Preferably this approach would be followed with two or more such buyers, to provide diversification of product offtakes. However, the largest retailers in the study region (measured by number of sites) are not likely to be large net buyers of product, given that they are also refiners. The retail market in North Dakota is characterized by an absence of the major integrated companies, with companies such as BP vacating this sector in recent years.

Some companies view the marketing sector as offering higher returns on capital, and may view the supply relationship as a useful partnership. Tiered pricing that allows the buyer to obtain progressively lower priced supply with increased volumes is an effective mechanism for providing an incentive for retail marketing contract partners to maximize their offtakes under such agreements. The use of introductory price discounting to establish new marketing relationships is also likely to be needed, but this would depend on the actual volumes of new product to be placed.

Several major integrated companies have withdrawn from the North Dakota retail market in recent years. ExxonMobil, Shell and BP are not actively marketing product in the state. There are several large jobbers operating in North Dakota and the surrounding states. These companies would source product from the regional refiners, and may represent the best option for market entry.

Hypermarketers represent a large and growing segment in certain markets. These marketers may offer an opportunity to contract for sales of large volumes of gasoline, as they are likely to be extremely price-sensitive. However, this would more than likely be at the penalty of a lower price, given the nature of the host businesses for these outlets. In North Dakota, companies such as Wal-Mart have established a presence, with 14 outlets.

Product exchanges rather than outright purchase are often used to minimize overall transportation costs. It may be desirable for the owners of incremental refining capacity in North Dakota to do some of this type of business in order to gain market entry, but there are challenges. The further south into the PADD II region that refinery products are sent, the less of a market niche they would possess, given increasing competition and greater supply optionality. In addition, alternative locations and counterparties would be limited if the project sponsor is a new entrant without marketing operations in other locations.

The issues of market entry are related to refinery capacity, and the volume of individual products that the refinery would produce. Smaller capacity additions would facilitate market entry to a greater extent than the base case capacity. In the case of diesel fuel, it may be possible to differentiate product quality if the refinery configuration includes hydrocracking, as this would enhance the low pour properties of the products. On a seasonal basis at least, the availability of low pour blending components from the new refining capacity be a very attractive new source for this material in the region.

The proposed refining capacity is configured to produce a small amount of jet fuel. The airlines that purchase this product represent a much smaller customer base than is the case for other light refined products. Fuel represents a large percentage of airline operating costs, and they consequently negotiate very hard for the lowest price and favored contractual terms. For that reason the refinery may be configured to be able to either produce jet fuel and diesel product, or 100 percent diesel product. There is likely to be small material impact on the refinery capital cost to provide such flexibility. The business operation could then start up producing 100 percent diesel product and, if and when a more attractive jet fuel sales opportunity presents itself, this could be given consideration.

MARKETABILITY ISSUES

ETHANOL – E15 GASOLINE

We anticipate that ethanol will grow to just under 10 percent of the U.S. gasoline pool by 2015, assuming that corn-based ethanol will remain the primary supply. If technological breakthroughs allow cellulosic ethanol to be produced competitively, then the contribution could increase. Over the next five years, the ethanol content in the total U.S. gasoline will approach, then theoretically exceed 10 percent based on the RFS2 mandated volumes and projected gasoline demand. The EPA is considering a partial waiver that would allow higher “mid-level” grades of gasoline to be sold, such as E15 or E20. The current thinking is that the EPA will issue a waiver for late model vehicles (probably 2000 model year and newer), allowing them to fuel with up to 15 percent ethanol (E15). Older vehicles, boats and small engines will most likely not be approved for this new fuel. Therefore, a new fuel grade would be required in the market. There is a major concern amongst refining companies that the E15 grade products could be unintentionally be used in non-approved engines by consumers.

In the time frame for this study out to 2025, we have included the impact of partial penetration of E15 in the Midcontinent and northern tier markets for many states within PADD II, notably North/South Dakota and Minnesota. The PADD IV states are assumed to stay within the aggregate 10 percent blending limit. The new North Dakota refining capacity is assume to take full advantage of the available ethanol blending opportunities.

LOW POUR DIESEL

Seasonal considerations in the cold climate of the northern tier necessitate the use of low pour diesel fuel. It has been economic in the past to import a low pour diesel fuel as a blending component to assist in meeting this specification. Canadian diesel made with higher proportions of aromatic and naphthenic hydrocarbons, often derived from Canadian oil sands resources, has lower pour diesel properties than North Dakota sweet crude. The relatively small level of Canadian imports into the study region has been held constant across all the study scenarios.

PARTNERESHIPS

There are varying levels of potential business alliances that benefit the parties involved. The team researched a range of local and national organizations active in North Dakota from exploration and production companies to distribution companies and wholesaler marketers. Many of these companies have prioritized investment in North Dakota’s petroleum markets as part of their strategic plans.

Based on the competitive analysis, the likely potential partners would be on the product crude supply and in the product distribution sector. These companies provide potential for a variety of partnering opportunities depending on the location and configuration of the increased refining capacity. In the case of a capacity increase at an existing facility the potential for new partnerships is reduced due to existing facilities and established relationships.

NORTH DAKOTA REFINING CAPACITY FEASIBILITY STUDY
PHASE II - FINAL REPORT

for

NORTH DAKOTA ASSOCIATION of RURAL ELECTRIC COOPERATIVES

October 8, 2010

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I. INTRODUCTION

Corval Group, Inc., (Corval) along with its partners, Purvin & Gertz, Inc. (PGI) and Mustang Engineers & Constructors, L.P. (Mustang), collectively “the Consultants” or “the study team”, were commissioned by the North Dakota Association of Rural Electrical Cooperatives, Inc. (NDAREC) to produce a study focused on the feasibility and benefits of constructing additional refining capacity in North Dakota (herein referred to as “the study”). The study team collectively has an extensive history of working with refineries and refinery developers performing similar studies throughout the world.

The project focuses on light refined products (defined to include gasoline, jet/kerosene and diesel fuel), as well as certain byproducts (LPG and residual fuel oil), which would be generated from additional refining capacity in North Dakota. The study region for the purposes of this assignment is defined to include North Dakota and the surrounding states, plus the Oil Sands region in Alberta, Canada. Unless otherwise noted, the forecast horizon for the study is out to 2030.

The project scope includes the following major tasks:

Phase I: Marketing Analysis: A market assessment for refined petroleum products and other market factor trend analysis (historical, current and forecasts)

Phase II: Economic & Refining Analysis, Refinery Plot Plan, Benefits to North Dakota

The goals of Phase II are as follows:

- Identify the most feasible alternatives for increasing the refining capacity in North Dakota.
- Estimate the capital and operating costs, develop schedules, predict financial returns and perform sensitivity analyses, leading to a recommendation of the most attractive refinery configuration.
- Develop plot plans, emissions estimates and site selection requirements for the selected refinery configuration.

ABOUT THIS REPORT

This report was prepared by the Consultants under a contract with NDAREC, which received federal grant funds for the study.

This document and the analysis, opinions and conclusions expressed in this report reflect the reasonable efforts of the Consultants and NDAREC using information available at the time of the oil refinery study and within the resources and timeframe available for this study. Those reviewing this document or other documents related to the oil refinery study should recognize the limitations of the study and understand that any predictions about the future are inherently uncertain due to events or combinations of events, including, without limitation, the actions of government or other entities or individuals. Neither the Consultants, nor NDAREC, or any of their employees, agents, task force members, advisory committee members, or any other representatives of these parties, make any express or implied warranties regarding the information, analysis, opinions, or conclusions contained in this document or other documents related to the oil refinery study, nor do they assume any legal liability or responsibility of any kind for the accuracy, completeness or usefulness of this document or the oil refinery study. No information contained in this document nor any other information released in conjunction with the oil refinery study shall be used in connection with any proxy, proxy statement or solicitation, prospectus, securities statement or similar document without the written consent of Consultants and NDAREC. Although this is a document available for use by the public, there are no intended third party beneficiaries of the agreement between Consultants and NDAREC for the performance of the oil refinery study.

II. SUMMARY & CONCLUSIONS

EXECUTIVE SUMMARY

Phase I of this study analyzed the light refined product markets in the Midwest region and North Dakota and crude production in the US. It also analyzed the crude oil and refined market infrastructure in the region. In addition, a preliminary study of the project economics was completed which included estimation of variable and net margins for a new refinery that would produce finished light refined products from Williston Basin crude.

The findings in Phase I showed that the North Dakota light refined products markets are small and geographically isolated, in relation to the large U.S. Midwest (PADD II) markets. Diesel demand is forecast to increase with underlying economic activity, while gasoline demand will gradually decline, due to cumulative fleet efficiency gains and increased ethanol supply. Despite these divergent demand trends, product balances in North Dakota have been achieved with transfers to/from neighboring states. In addition the Williston Basin crude, a high quality crude oil has been a prolific and growing source of crude supply to the lower 48 states and is expected to continue to increase for a number of years.

Based on these findings, market models were developed to investigate and identify the optimum distribution of crude oil and refined products under the premises of additional refining capacity in North Dakota. Current logistical costs were included in the models. The model results were used to estimate crude intake costs and product revenues for a 100,000 B/D base case and two alternative cases, a 50,000 B/D and 20,000 B/D case. The base case, while maximizing economies of scale, realized the lowest net margin due to the negative impact of higher transportation costs on product netback prices, and increased crude oil prices to local consumers. The alternate cases provided marginally better net margins but were still challenged by product transportation costs and the loss of the economies of scale that benefited the 100,000 B/D case. None of the refining capacity cases were estimated to achieve a level of capital recovery adequate to support development of a grassroots project.

The Phase I findings led the NDAREC steering committee to modify Phase II of the study. The committee replaced the 100,000 B/D case with the 20,000 B/D refinery case because it had the higher return on investment. The committee also added a new refinery configuration. The additional configuration was designed to maximize diesel fuel production and reduce refinery complexity and cost by eliminating gasoline production. Naphtha would be produced instead which is an intermediate stream traditionally used to make gasoline. Production of naphtha would eliminate the need to introduce additional gasoline volume into a local market where supply currently exceeds demand. To support the evaluation of the naphtha configuration, an evaluation of potential naphtha markets along with the evaluation of available infrastructure for moving naphtha to market was added to the study.

PHASE II STUDY CONCLUSIONS

Growth in Canadian bitumen production has created a demand for naphtha. Naphtha is used as a diluent for pipelining bitumen (heavy crude) from Canada to crude markets. Import of hydrocarbon streams such as naphtha is the most expedient short-term option for increasing the supply of diluent to meet the demand created by the growth of bitumen production. Naphtha from new North Dakota refinery capacity may find the diluent market an attractive alternative to the sale of gasoline in a locally oversupplied market.

North Dakota naphtha will receive a premium at Edmonton as determined by the Canadian Association of Petroleum Producers (CAPP) equalization process. Due to the quality of the naphtha from the proposed North Dakota refinery capacity, it is expected to receive a premium when it is comingled with other condensate streams which comprise the aggregated condensate pool in Alberta, Canada.

The price paid for diluent is forecasted to increase through 2015 and continue to increase through 2030 due to increases in demand. Naphtha is comingled with other condensate streams which together comprise the diluent. The price for the Enbridge pooled condensate (CRW), the C5+ price, is forecast to increase in line with overall crude oil prices.

Rail transportation is currently the most expedient short-term option for importing naphtha into Canada from North Dakota. Although the Enbridge Southern Lights pipeline project allows up to 180,000 barrels per day of diluent components to be shipped from Chicago to Edmonton, the current tariffs for uncommitted shippers are not economical compared to unit train transportation.

The 20,000 B/D configuration provides a 92.3% refinery charge yield for gasoline, jet and diesel. The 20,000 B/D refinery configuration is equipped with a hydrocracker and other upgrading units to maximize light product yield. This refinery includes a kerosene/diesel hydrotreater, vacuum gas oil (VGO) hydrocracker, a naphtha hydrotreater, naphtha reformer, hydrogen plant, and benzene saturation and light naphtha isomerization units.

The 34,000 B/D naphtha configuration provides 15,000 B/D naphtha and a 51.6% jet and diesel yield. The 34,000 B/D naphtha configuration is equipped with a VGO hydrocracker, but without naphtha upgrading capability. This refinery includes a distillate hydrotreater and a hydrogen plant

The capital cost for the refineries are estimated to be $650 million and $700 million for the 20,000 B/D and 34,000 B/D refineries, respectively. The capital costs are adjusted for a North Dakota location and have 40% accuracy.

Overall total operating cost per barrel for the 34,000 B/D case are more favorable than the 20,000 B/D case. The fixed and variable costs are similar for each case but the high labor costs for the 20,000 B/D case are the primary difference in the operating cost per barrel. The larger refinery enjoys some economies of scale in its projected operating cost per barrel.

The 34,000 B/D naphtha refining project provides higher rates of return and is the more feasible refinery case. The 20,000 B/D case provides a real IRR of 1.6% and a nominal IRR of 3.7% with a net present value of $-244.4 million, based on a 15% discount rate. The 34,000 B/D case provides a real IRR of 7% and a nominal IRR of 9.2% with a net present value of $-156.7 million. Neither refinery case provides a sufficient return for traditional project financing.

The Refinery Analysis describes the 34,000 B/D refinery with process flow diagrams, utility and emission estimate and the layout shown with a conceptual plot plan. The utility analysis is based on the import of electricity, natural gas and water from a well. It is designed to meet Environmental Protection Agency air emissions standards and calculated emissions are consistent with this objective. The plot plan allows for rail and truck transportation of product to local and regional markets.

Site Selection Criteria highlights the important criteria for selecting a site for the refinery. Transportation and logistics considerations along with the ability to attract skilled labor at a competitive cost and obtain utilities at economic rates are primary considerations for selecting a site.

Benefits to North Dakota are primarily in the areas of increased revenues for the state and new employment opportunities and increased supply of diesel fuel. These benefits would become available due to local production of diesel, and employment primarily through direct employment, construction and the increase in the demand for goods and services due to a new refinery being located in North Dakota.

Project Incentives and Barriers identifies alternate approaches to a "green field" refinery that can be explored to reduce the capital cost for and improve the financial prospects of this project. The "green field" approach for a small refinery has the disadvantage of having to bear the cost of the entire infrastructure and all facilities inside and outside of the battery limit.

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III. MARKET AND CONFIGURATION ANALYSIS

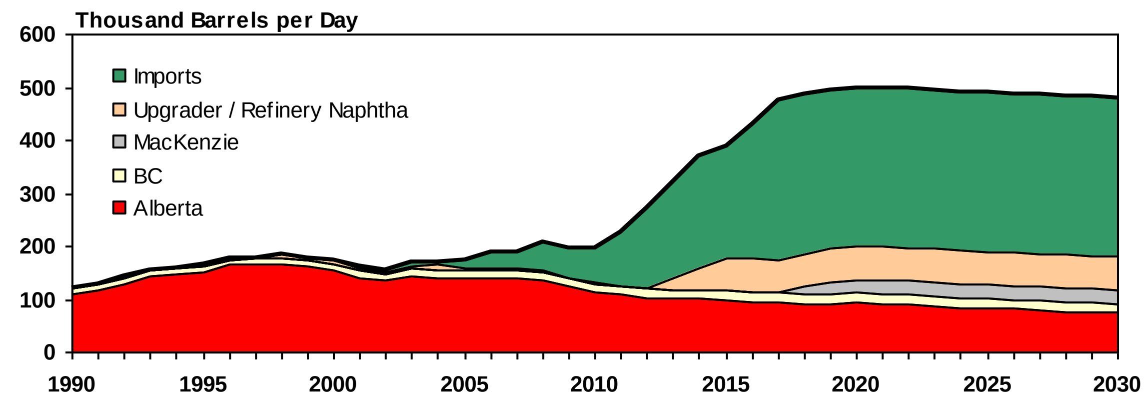
NAPHTHA MARKET ANALYSIS

There is an emerging market for naphtha produced from processing Bakken crude in North Dakota. This market option has been added to the original market outlet considered, finished gasoline, due to the finding in the Phase 1 study that the regional gasoline market was small, already saturated, and subject to level or declining demand over time. The emerging naphtha market described here is much larger than the local gasoline market and would not be as subject to price declines with the additional of new supplies from North Dakota. Production of naphtha instead of gasoline from new refinery capacity also has the benefit of reducing capital costs.

Bitumen produced from oil sands in Western Canada needs diluent for pipelining. The traditional diluent for this material has been C5 and heavier hydrocarbons (C5+), most commonly condensate recovered from processing of raw natural gas. Continued growth in bitumen production has now lead to diluent demand outstripping C5+ supply. Synthetic crude oil (SCO) can be used as a bitumen diluent, but producers have not found the economics to be generally attractive. This is an extended subject outside the scope of this market review. Our market review includes PGI's estimate of SCO utilization as a bitumen diluent. Clearly, without more C5+ or equivalent supply, SCO is forecast to become an increasingly important diluent because of its availability in the Athabasca region. However, startup of the Enbridge Southern Lights pipeline project in mid-2010, allows up to 180 thousand barrels per day of condensate, natural gasoline and refinery naphtha to be shipped from Chicago to Edmonton. Natural gasoline is currently being sourced in the U.S. Rocky Mountains and Midcontinent to various offloading terminals in Alberta via rail. The import of hydrocarbon streams of suitable quality for diluent is the most expedient short term option to increase supply. Naphtha from new North Dakota refinery capacity may find the diluent market an attractive alternative to sale of gasoline into a locally oversupplied market.

Figure III-1 presents our forecast of Western Canadian condensate and naphtha supply through 2030. C5+ supply is forecast to decline until Mackenzie Delta gas liquids are available. This is forecast for around 2020. In this case, the supply of condensate is supplemented by import of an estimated 180,000 B/D by pipeline beginning in 2011, rising to 300,000 B/D by 2017 to help satisfy increased diluent demand due to continued growth in bitumen production. This may require incremental rail imports to supplement an import pipeline, or expansion of import pipeline capacity. An expansion of the import pipeline has been assumed to occur by around 2015.

FIGURE III-1
CONDENSATE AND NAPHTHA SUPPLY



PIPELINE TRANSPORTATION

Enbridge's Southern Lights pipeline project allows up to 180,000 B/D of potential diluent components to be shipped from Chicago back to Edmonton. We understand that committed volumes are 77,000 B/D. The Southern Lights pipeline is expandable to more than 300,000 B/D, if justified. To facilitate construction of the line, Enbridge utilized innovative tolling arrangements which result in higher tariffs for uncommitted shippers which vary as a function of the throughput on the system. In general terms, the uncommitted rates are relatively high (estimated at $14 dollars per barrel from Chicago to Edmonton in 2010). Because of the unpredictability of these terms, the competitive options for rail transportation, and the current inability of batches to originate on the Southern Lights system at Clearbrook which would be the natural pipeline route from North Dakota, we have not based our North Dakota naphtha netback on use of this system. A map of the Enbridge Southern Lights Project is shown in Figure III-2.

FIGURE III-2
ENBRIDGE SOUTHERN LIGHTS PIPELINE PROJECT

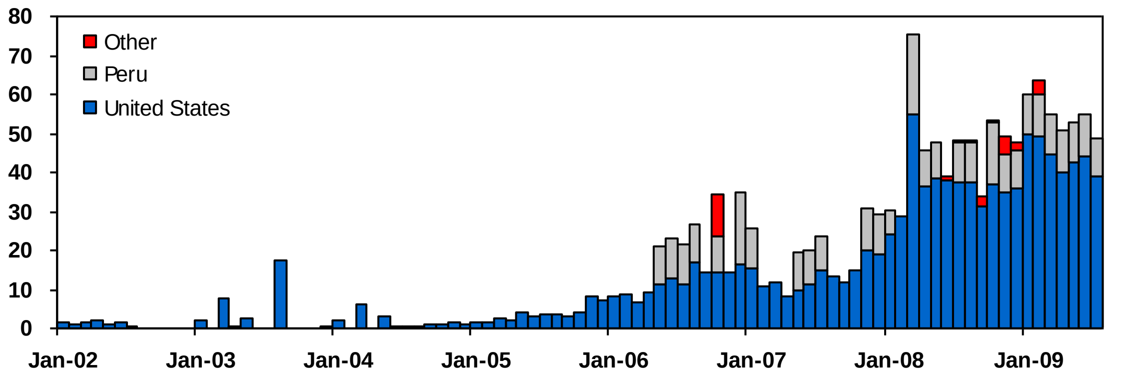
RAIL TRANSPORTATION

The import of hydrocarbon streams of suitable quality for diluent is the most expedient short term option to increase diluent supply. For example, Midcontinent supplies of natural gasoline may be imported to Alberta by rail. This option could reduce demand for SCO as diluent and increase the availability of segregated SCO.

Strong price premiums for condensate in Alberta prompted significant rail imports commencing in 2004. Import sources in the United States may include, in addition to natural gasoline, pentanes plus from NGL recovered at the Aux Sable extraction facilities near Chicago, and condensate from gas and crude oil produced in the Williston Basin or Rocky Mountain regions.

In addition to the above sources, EnCana has been importing condensate by rail through the through the Methanex Kitimat terminal since mid-2006, under a commercial arrangement with Methanex. Based on import statistics, the volume of imported condensate entering Canada through the Kitimat terminal has been 10-15,000 B/D. In all, total rail imports to Alberta are estimated at up to 60,000 B/D, as shown in Figure III-3.

FIGURE III-3
WESTERN CANADA CONDENSATE & NAPHTHA IMPORTS, BY ORIGIN
(Thousand Barrels per Day)



DILUENT QUALITY SPECIFICATIONS

The aggregated condensate pool in Alberta (Edmonton) does impose specifications on diluent streams accepted into the system. Key specifications are summarized below, though these specifications are under review and subject to change. Other specifications may also be imposed on imported diluent streams, although this has not yet been finalized. We have imposed the more basic specifications on naphtha exported from the new North Dakota refinery capacity (in the naphtha configuration).

WESTERN CANADIAN (ENBRIDGE) CONDENSATE POOL
PETROLEUM QUALITY DILUENT ACCEPTANCE PRACTICE [1]

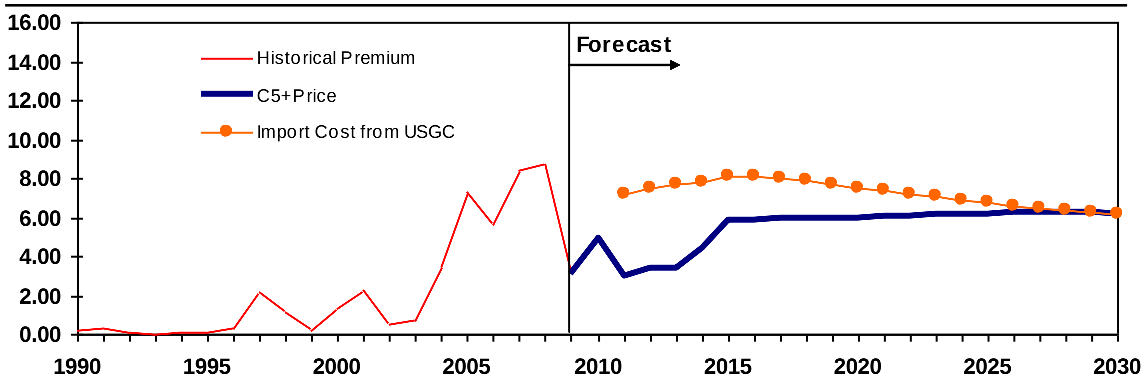
Properties	Units	Limits > Minimum	Limits < Maximum
Gravity, @ 60°F	API	45.4	104.3
Kinematic Viscosity at 45.5°F	cst		2.0
Reid Vapor Pressure	psia		15
Sediment and Water	Vol%		0.5
Organic Chlorides	w ppm		< 1
Sulphur, total	wt%		0.5
Olefins, total	mass %		< 1
MCR	wt%		1.6
Total Acid Number	mg KOH/g		1.1
BTEX (C30+ Comp Analysis)	Vol%	2	--
Benzene [2]	Vol%		3
Hydrogen Sulphide [2]	w ppm		50
Volatile Mercaptan Sulphur [2]	w ppm		500
Mercury [2]	w ppm		1
Selenium [2]	w ppm		1
Oxygenates [2]	wt%		1

Notes: (1) From Enbridge Southern Lights Petroleum Quality Diluent Acceptance Practice, December 9, 2008.
(2) Maximum values are to serve as a guideline and will be subject to review.

CONDENSATE/NAPHTHA PRICING

The price of condensate or C5+ at Edmonton historically tracked the price of Light Sweet crude there. The most common Light Sweet crude type on the Enbridge pipeline system is referred to as MSW (Mixed Sweet). However, C5+ prices were volatile in 1997, 2000/2001 and 2004. The C5+ price, as represented by the combined Enbridge condensate segregation (CRW), has been much higher than MSW since 2005, as shown in Figure III-4. The C5+ premium fell during 2006, but remained comparatively high on a historical basis. One factor contributing to the reduction of the premium in 2006 was the start of offshore imports of condensate by rail from Kitimat.

FIGURE III-4
CRW PREMIUM OVER ALBERTA MSW AT EDMONTON, DILBIT CASE
(Forecast in Constant 2010 U.S. Dollars per Barrel)



As the demand for diluent increases, it is expected that this will continue to keep pressure on the CRW price. The CRW premium over MSW is expected to be in the $3 to $4 range for a few years. By 2015, the CRW price is forecast to be around $6.00 per barrel, based on competitive diluent pricing with SCO, as discussed below. The Southern Lights pipeline project is expected to startup later in 2010. It will deliver diluent from Chicago to Edmonton and allow imports of condensate and natural gasoline from the Gulf Coast via Chicago as well as naphtha recycle from refineries in the Chicago area and elsewhere. We have assumed a Southern Lights pipeline tariff of $6.00 (US) per barrel for uncommitted shippers based on full throughput, and we used imported condensate as a benchmark. Condensate with CRW quality was valued against LLS at the Gulf Coast. This provides a condensate price at Edmonton which is $7 to $8 per barrel over MSW (current dollar basis). However, we expect that this price level will be higher than the value of CRW in Alberta due to the SCO price.

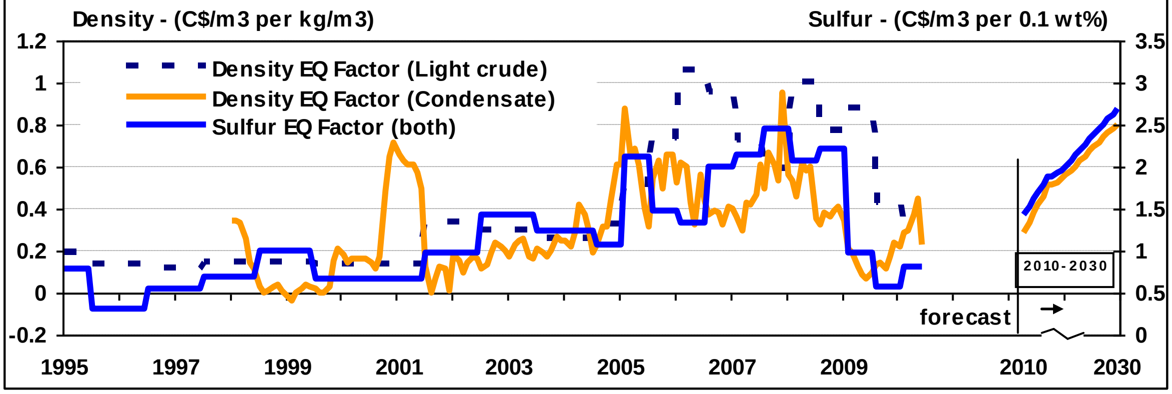
The condensate and naphtha (CRW) diluent pool is comprised of a variety of streams with different qualities contributed by different companies. Once co-mingled at Edmonton, the resulting CRW material is sold and traded on an as-aggregated basis. Contributed streams with qualities differing from the pool average might receive very different market values if sold on their own rather than being blended together. To address potential inequities in this arrangement the equalization process has been adopted to provide consistent "market based" price adjustments to the pool value paid back to producers.

The equalization process approximates the market price or value of streams entering the pool that differ from the average quality of the pool. Anyone contributing material that passes the pool quality specification requirements is agreeing to accept the "equalized" value for that stream. At the current time, three properties of an eligible stream are used to adjust the price received for it: density, sulfur content and butane content. These adjustments are updated periodically and published by the Canadian Association of Petroleum Producers (CAPP). Equalization is based on market prices and reflects the economics of blending diluent with bitumen to produce a blend meeting pipeline specifications. Lighter condensate or naphtha is a more efficient diluent and is given a credit derived from market pricing of various bitumen blends. Diluents with lower total sulfur content also receive a credit based on higher value to a refinery. The condensate sulfur coefficient for equalization is the light crude equalization value derived from statistical analysis of a basket of light sweet and sour crudes. The sulfur equalization "slope" is updated every six months. Equalization is a zero sum adjustment, credits for higher quality coming from a deduction on lower quality material.

Naphtha produced from the special refinery configuration that avoids producing gasoline will have qualities better than the current average CRW pool. Each of the three properties equalized will be as good or better than "reference qualities" that provide the basis for the Edmonton CRW price forecast. Density of the refinery naphtha is estimated to be 715 kilograms per cubic meter (kg/m3), lower (better) than the reference value of 724 kg/m3. Estimated sulfur content, 0.004 weight percent (wt%) is also lower than the reference value of 0.15 wt%. Butane content was adjusted to reach the maximum allowed, 5 volume percent without incurring a penalty.

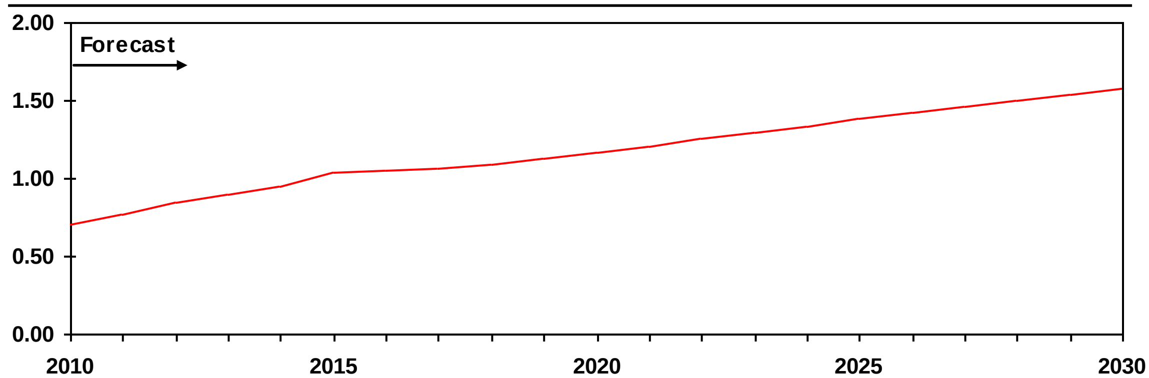
The actual equalization value over the reference CRW price will depend on density and sulfur equalization coefficients. Figure III-5 shows the history of equalization coefficients for the CRW and light sweet crude pool (MSW) in Edmonton. Our forecast for these parameters is based on a regression analysis of the history against marker crude prices. The regression analysis results are applied to forecast prices for the marker crudes to calculate forecasts of the equalization parameters.

FIGURE III-5
CORVAL NAPHTHA EQUALIZATION PREMIUM AT EDMONTON
(Forecast in Current U.S. Dollars per Barrel)



The resulting equalization benefit for North Dakota pricing of the naphtha stream above the base CRW forecast is shown in Figure III-6. With rail transportation subtracted from the overall value in Edmonton, the netback at the refinery gate is obtained and used for the cash flow analysis.

FIGURE III-6
CORVAL NAPHTHA EQUALIZATION PREMIUM AT EDMONTON
(Forecast in Current U.S. Dollars per Barrel)

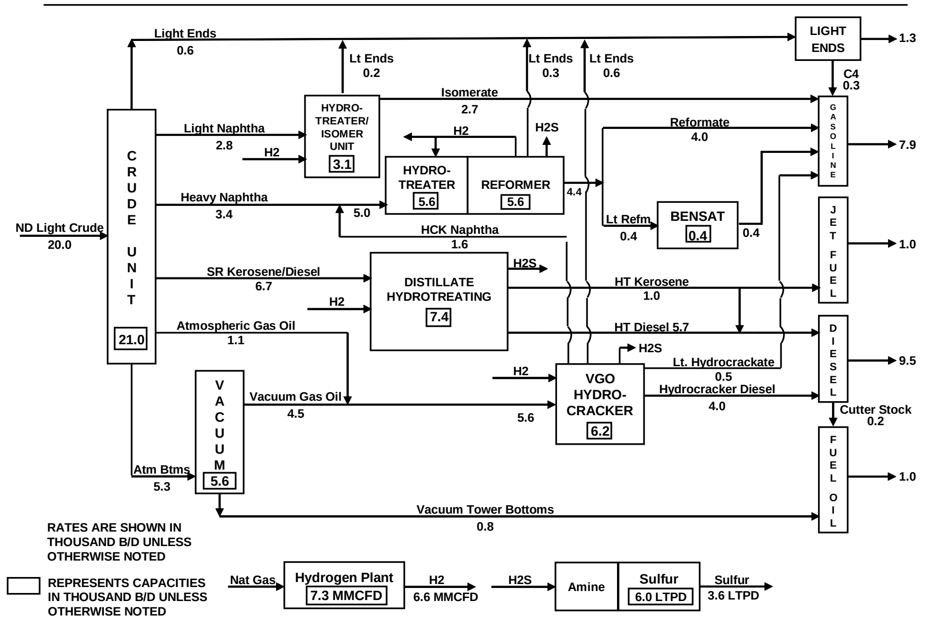


LP MODELING ANALYSIS

Two refinery configurations were considered for Phase II of the North Dakota refinery study. The first configuration considered was a modern 20,000 B/D refinery equipped with a hydrocracker as well as other upgrading units to maximize light product yield including finished gasoline. This configuration had the highest net margin in the Phase I study and was therefore included as part of the Phase II analysis. The 20,000 B/D refinery provided the highest yield of finished light products (gasoline, jet and diesel) at 19,200 B/D or 92.3% of total refinery charge. It required additional units for upgrading the naphtha including two naphtha hydrotreaters, a naphtha reformer, a light naphtha isomerization unit as well as a benzene saturation unit to reduce the finished gasoline benzene content to meet MSAT Phase II gasoline specifications scheduled to go into effect in January of 2011. As a result, this case is characterized by higher capital costs per barrel of throughput as well as higher fixed and variable operating costs per barrel of throughput as discussed later in the report.

A block flow diagram of this configuration is shown in Figure III-7 below.

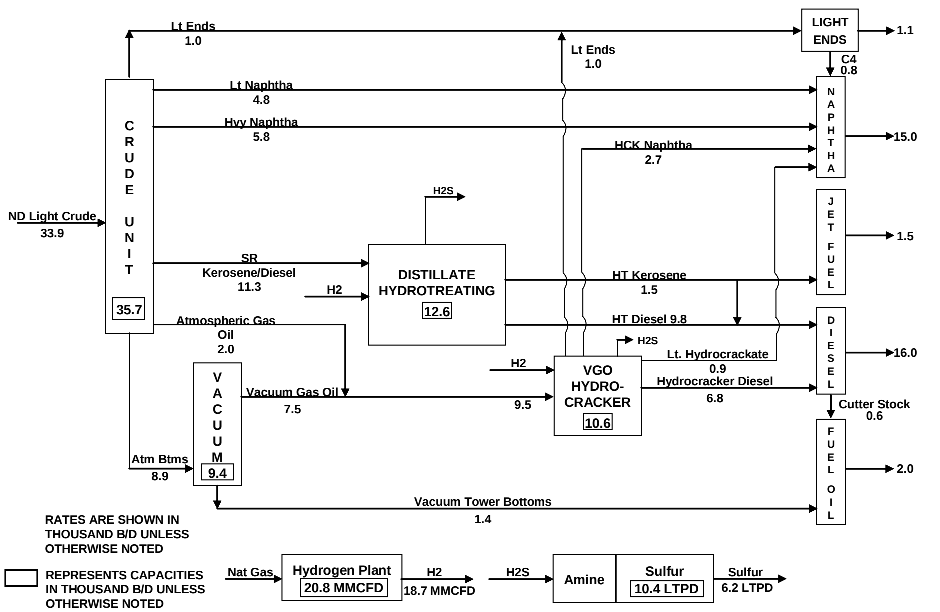
FIGURE III-7
NORTH DAKOTA REFINERY SIMPLIFIED BLOCK FLOW DIAGRAM: 20,000 B/D CASE



The second configuration considered was a 34,000 B/D refinery equipped with a hydrocracker and other upgrading units but without naphtha upgrading capability. This refinery required fewer units (and therefore less capital per barrel of crude charge) with the full range naphtha production assumed to be exported into Canada for use as bitumen diluent. In addition, to capture economies of scale for the project, the refinery size was increased until the diesel production met future expected diesel imports. This provided maximum diesel production at import parity economics. The 34,000 B/D refinery provided the highest yield of distillate (jet and diesel) at 17,500 B/D and 51.6% of total refinery charge. The full range naphtha (combined light and heavy) was assumed to be sent to Canada by rail for blending into bitumen as discussed in the naphtha section above. Based on the forecasted demand for bitumen diluent the entire 15,000 B/D of naphtha production was assumed to be consumed in that market.

A block flow diagram of this configuration is shown in Figure III-8 below.

FIGURE III-8
NORTH DAKOTA REFINERY SIMPLIFIED BLOCK FLOW DIAGRAM: 34,000 B/D CASE



The two configurations described above were simulated using proprietary Purvin & Gertz linear programming (LP) modeling software. The LP model is a mathematical representation of a petroleum refinery in spreadsheet format. Each process unit is defined in terms of feedstock and output with stream qualities tracked all the way from crude input to the final product blending. Production limits, such as diesel volume, and blending specifications are used to drive the model to the optimum configuration that fits the desired operation.

The primary feedstock to the model was Bakken light sweet crude oil. The assay describing the crude oil was taken from a number of sources and detailed in the Phase I market report. A summary of the LP modeling results including yields and unit capacities is shown in Figures III-7 and III-8 above, as well as in the following table.

NORTH DAKOTA REFINERY STUDY
Configuration and Yields (KBPD)

	20 KBPD Refinery	34 KBPD Refinery
Charge and Yield		
Crude Charge		
North Dakota Sweet	20.0	33.9
Other Feedstocks		
Ethanol	0.8	0.0
Total Feedstocks	20.8	33.9
Liquid Yields		
LPG	1.3	1.1
Naphtha	0.0	15.0
Gasoline	8.7	0.0
Kerosene	1.0	1.5
Gasoil/Diesel	9.5	16.0
Fuel Oil (1% S)	1.0	2.0
Total	21.5	35.5
Other Yields		
Sulfur (ltpd)	3.6	6.2
Major Unit Capacities		
Crude	21.0	35.7
Vacuum	5.6	9.4
VGO Hydrocracker	6.2	10.6
Isomerization Unit	3.1	
Semi-Regen Reformer	5.6	
Light Naphtha Hydrotreater	3.1	
Naphtha Hydrotreater	5.6	
Kerosene Hydrotreater	2.2	4.1
Diesel Hydrotreater	5.2	8.5
Bensat Unit	0.4	
Hydrogen Production (MMCFD)	7.3	20.7
Sulfur Recovery (LTD)	6.0	10.4

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V ECONOMIC ANALYSIS

In order to evaluate the expected profitability of a proposed refinery project, a number of assumptions have to be made regarding the cost of construction, throughput rates, operating costs, margins, and financial inputs. This information is used to generate a cash flow projection which then leads to an assessment of potential profitability, usually measured either as a return on investment, or a net present value. Once a base case is developed, then the robustness of the potential returns is tested by making alternative assumptions about the key inputs within a reasonable range. This is done on a single-variable basis and also on a multi-variable basis via Monte Carlo simulation techniques. The following discussion describes the assumptions made in the economic analysis and the results that were derived.

CAPITAL AND OPERATING COSTS

Once the configurations of the two cases were determined, the next step was to estimate the required capital costs for construction and the operating costs of the facilities once they are built and running. As with the LP analysis, Purvin & Gertz proprietary models were used to determine the capital and operating costs for each case.

The methodology used to determine capital costs is based on cost curves developed from historical actual project data. All units have been increased in size by roughly 5% to account for normal downtime under typical operating conditions. For example, a crude distillation unit running 20,000 B/D on a calendar day basis will need a nameplate capacity of about 21,000 B/D on a stream day basis.

There is a relationship between size of a given process unit and the cost per barrel, with larger units normally getting less expensive per barrel. This is known as “economies of scale”. The two cases studied here are both relatively small facilities, therefore they are generally unable to take advantage of the economies of scale that most new facilities enjoy, whether as a grassroots installation or as an expansion of an existing plant. The grassroots basis of these two cases also adds to the capital cost of the plants, as all of the necessary infrastructure for an operating refinery has to be built as part of the project. This can double the cost of a refinery, depending on the size and complexity. It is generally cheaper to add units to an existing plant as opposed to starting from scratch.

CAPITAL COST LOCATION FACTOR ANALYSIS

The following City Cost Index table compares the averaged indexed costs, indexed labor costs and indexed material costs for various USGC cities versus Fargo, North Dakota. These indices are found in Means – Facilities Construction Cost Data.

Means – City Cost Index	Total	Material	Labor
Fargo, ND	89.80	101.40	71.30
Gulf Coast			
Beaumont	82.30	98.40	60.10
Corpus Christi	78.30	98.40	50.40
Galveston	86.00	98.20	69.10
Houston	88.30	100.70	71.20
Baton Rouge	86.10	102.20	63.80
Lafayette	82.60	100.00	58.50
Lake Charles	83.70	100.10	61.10
New Orleans	88.90	102.90	69.60
Biloxi	83.40	98.50	62.60
Mobile	84.50	97.90	65.90
Gulf Coast Avg.	84.41	99.73	63.23
North Dakota vs USGC Avg.	6.4%	1.7%	12.8%

The relative index indicates a nominal cost increase of 6.4% when comparing North Dakota versus USGC city average. This might be reasonable but the study team believes the cost differential would be more in the range of 10 to 15% for the following considerations:

- Study Team experience in North Dakota.
- The Means indices probably do not apply enough weight to winterization of industrial projects such as a grass roots refinery.
- Nor does the index take into consideration the wintertime productivity loss.

A conservative capital location factor of 1.15 is used in this study for economic analysis.

CAPITAL COST ESTIMATE

A summary for the capital cost estimate is shown in the table below.

NORTH DAKOTA REFINERY STUDY
Capital Cost Estimate ($ millions)

	20 KBPD Refinery	34 KBPD Refinery
Direct Construction Costs		
Inside Battery Limits (ISBL)		
Crude	$ 32.5	$ 49.5
Vacuum	$ 13.8	$ 20.6
VGO Hydrocracker	$ 86.7	$ 126.7
Isomerization Unit	$ 30.5	
Semi-Regen Reformer	$ 35.6	
Light Naphtha Hydrotreater	$ 9.8	
Naphtha Hydrotreater	$ 25.9	
Kerosene Hydrotreater	$ 12.7	$ 19.1
Diesel Hydrotreater	$ 30.7	$ 43.0
Bensat Unit	$ 7.0	
Light Ends Recovery	$ 3.4	$ 3.8
Hydrogen Production	$ 24.7	$ 47.2
Sulfur Recovery	$ 9.4	$ 13.6
Total ISBL Costs	$ 322.8	$ 323.5
Outside Battery Limits (OSBL)[1]	$ 150.2	$ 193.0
License and Engineering Fees	$ 15.4	$ 10.3
Initial Catalyst Fills	$ 4.7	$ 5.2
Total Direct Costs	$ 493.0	$ 532.0
Indirect Construction Costs		
Owner's Costs (15% ISBL+OSBL)	$ 70.9	$ 77.5
Contingency (15% Direct+Owner's)	$ 84.6	$ 91.4
Total Indirect Costs	$ 155.5	$ 168.9
Total Capital Costs	$ 648.5	$ 700.9

[1] OSBL costs include tankage, marine facilities, utilities and auxiliary buildings

The total ISBL (inside battery limits) costs for the two cases were within $1 million of each other at around $323 million as the higher ISBL costs for the larger refinery (driven primarily by the larger VGO hydrocracker) were almost exactly offset by the additional naphtha upgrading units in the smaller refinery. The OSBL (outside battery limits) costs were about $43 million higher for the larger refinery, which included tankage, utilities and auxiliary buildings. This was offset somewhat by higher license and engineering fees associated with the naphtha upgrading units for the smaller refinery. The resulting total direct costs for the 34,000 B/D refinery were estimated to be $532 million, which is $39 million higher than the $493 million total direct costs for the 20,000 B/D refinery.

The owner’s costs were estimated at 15% of the ISBL+OSBL costs for both refineries and the contingency was estimated at 15% of the total of direct costs and owner’s costs. The resulting total capital costs for the 34,000 B/D refinery were $700.9 million or about $52 million higher than the $648.5 million total capital costs for the 20,000 B/D refinery.

OPERATING COST ESTIMATE

The reduced number of processing units and the larger size for the 34,000 B/D case also resulted in lower operating costs per barrel. Between the two cases, there are significant economies of scale impacts. The operating costs for both refineries are shown in the next table.

NORTH DAKOTA REFINERY STUDY
Operating Costs ($ millions)

	20 KBPD Refinery	34 KBPD Refinery
Fixed		
Maintenance (incl. T/A + Labor)	11.6	13.3
Labor (except Maintenance)	17.6	14.8
Taxes and Insurance	3.5	3.9
Other	6.1	6.6
Total Fixed Costs	38.9	38.5
Total Fixed Costs ($/bbl Crude)	$5.33	$3.12
Variable		
Fuel	11.3	19.7
Electricity	2.2	2.3
Make-up Water	1.1	1.5
Catalyst and Chemicals	1.2	1.3
Total Variable Costs	15.8	24.7
Total Variable Costs ($/bbl Crude)	$2.16	$2.00
Total Operating Costs	54.7	63.3
Total Operating Costs ($/bbl Crude)	$7.49	$5.11

The total fixed costs for the 20,000 B/D refinery were very close to those of the 34,000 B/D refinery at almost $40 million/yr due to the additional naphtha upgrading units. As a result, the fixed costs per barrel were significantly higher than those for the 34,000 B/D refinery case at $5.33/Bbl compared to $3.12/Bbl for the larger refinery. The largest contributor to this difference was the higher labor cost associated with the higher complexity (additional processing units) of the 20,000 B/D refinery.

The total variable costs per barrel for the two cases were also very close to each other at around $2/Bbl. While the 20,000 B/D refinery required additional utilities for the naphtha upgrading units, the naphtha reforming process provided additional hydrogen which greatly reduced the size of the hydrogen plant and its natural gas (fuel) requirement.

The higher fixed costs associated with the smaller refinery resulted in much higher total operating cost. The total operating costs for the 20,000 B/D refinery were $7.49/bbl or about 45% higher than the total operating costs for the 34,000 B/D refinery, whose total operating costs were estimated at $5.11/bbl.

PROJECT SCHEDULES

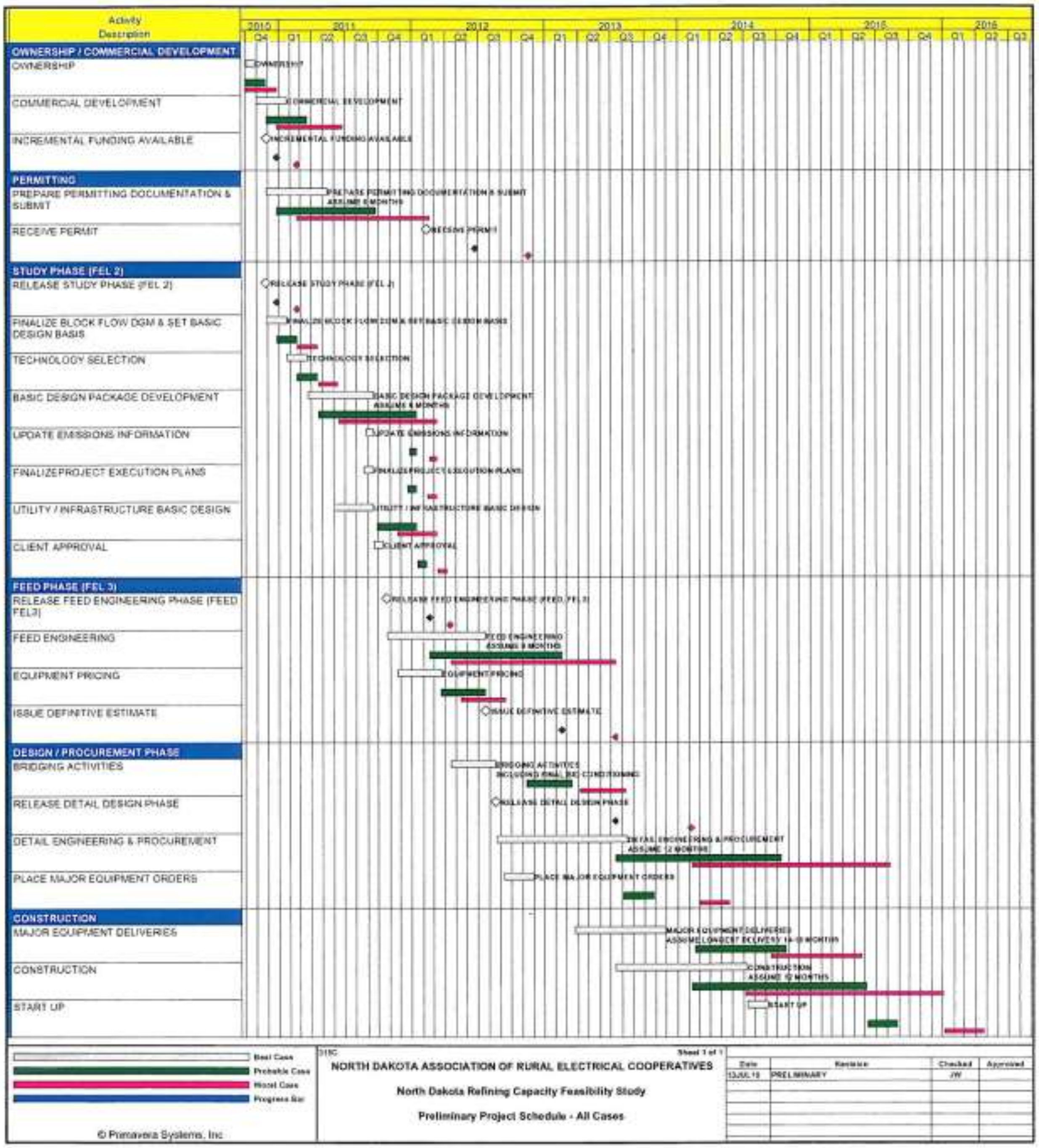
Preliminary project milestone schedule has been developed for three scenarios – best, probable, and worst as shown in the attached Gantt chart. The study team believes that the overall project schedule will not be much difference between the two cases under consideration. The overall project duration, including permit application and pre-commissioning/initial start up, could range from about four (4) years in the best case to about six (6) years in the worst case. It would be about fifty-nine (59) months for the probable case with Q4 2010 start and Q3 2015 completion. Major assumptions/considerations are as follows:

A standard “stage gate” process is assumed between the various phases.

The client should consider overlapping the stages (bridging) to save schedule. This would provide the shortest overall duration for all scenarios.

In the best case scenario, it has been assumed that the same contractor will perform the work from the study through the detail design phase.

To minimize the duration of the detail design phase, serious consideration should be given to getting AFE (Approved for Expenditure) monies appropriated for the Feed Phase to purchase all long lead equipment and other equipment requiring vendor engineering such as pumps, exchangers, etc. Recent experience has shown vendors’ engineering groups are slow to provide the necessary drawings to support an accelerated project engineering schedule.



Activity Description
2010
2011
2012
2013
2014
2015
2016
OWNERSHIP / COMMERCIAL DEVELOPMENT
OWNERSHIP
COMMERCIAL DEVELOPMENT
INCREMENTAL FUNDING AVAILABLE
PERMITTING
PREPARE PERMITTING DOCUMENTATION & SUBMIT
ASSUME 6 MONTHS
RECEIVE PERMIT
STUDY PHASE (FEL 2)
RELEASE STUDY PHASE (FEL 2)
FINALIZE BLOCK FLOW DGM & SET BASIC DESIGN BASIS
TECHNOLOGY SELECTION
BASIC DESIGN PACKAGE DEVELOPMENT
ASSUME 6 MONTHS
UPDATE EMISSIONS INFORMATION
FINALIZEPROJECT EXECUTION PLANS
UTILITY / INFRASTRUCTURE BASIC DESIGN
CLIENT APPROVAL
FEED PHASE (FEL 3)
RELEASE FEED ENGINEERING PHASE (FEED FEL3)
FEED ENGINEERING
ASSUME 9 MONTHS
EQUIPMENT PRICING
ISSUE DEFINITIVE ESTIMATE
DESIGN / PROCUREMENT PHASE
BRIDGING ACTIVITIES
INCLUDING FINAL BID CONDITIONING
RELEASE DETAIL DESIGN PHASE
DETAIL ENGINEERING & PROCUREMENT
ASSUME 12 MONTHS
PLACE MAJOR EQUIPMENT ORDERS
CONSTRUCTION
MAJOR EQUIPMENT DELIVERIES
CONSTRUCTION
ASSUME 18 MONTHS
START UP
Best Case
Probable Case
Worst Case
Progress Bar
© Primavera Systems, Inc
Sheet 1 of 1
NORTH DAKOTA ASSOCIATION OF RURAL ELECTRICAL COOPERATIVES
North Dakota Refining Capacity Feasibility Study
Preliminary Project Schedule - All Cases
Date
Revision
Checked
Approved
PRELIMINARY
JW

CASH FLOW ASSUMPTIONS

PRICING

The pricing used for the cash flow analysis was based on the Phase I market analysis and updated to incorporate price forecasts published by Purvin & Gertz in May of 2010 for the Chicago market, with adjustments for transportation to/from the North Dakota location. Crude pricing used local crude location and quality differentials for the first 20,000 B/D of North Dakota (ND) Sweet crude but also added additional costs in the early years of the 34,000 B/D refinery operation as additional location costs were assumed to be incurred to import larger volumes of ND Sweet crude from greater distances. The discussion explaining our forecast methodologies and assumptions are provided in the Phase I report. The changes from the original forecast to the current one are not substantial in magnitude.

Product import pricing assumed Chicago spot pricing plus transportation (such as for diesel imports) while product export pricing assumed Chicago spot pricing less transportation (such as for gasoline exports). A sampling of the prices used in the analysis is shown in the next table for 2010 through 2030.

NORTH DAKOTA REFINERY STUDY
Pricing (Current $/B)

	2010	2015	2020	2025	2030
Crude					
WTI, Cushing	79.71	92.22	107.52	132.19	155.54
ND Sweet, Delivered (20 KBPD)	73.10	84.37	104.28	128.78	151.85
ND Sweet, Delivered (34 KBPD)	73.10	86.83	104.31	129.09	152.19
Other Feedstock					
Ethanol, Delivered	83.64	120.82	138.34	164.66	189.53
Products					
LPG	49.88	57.36	67.97	85.01	101.07
Naphtha	80.10	90.43	106.13	131.06	154.34
Gasoline	91.23	100.03	118.72	143.73	168.32
Kerosene/Jet	89.84	108.67	124.21	152.33	179.07
ULSD	93.41	112.06	130.27	159.19	186.83
Fuel Oil (1%)	63.49	66.99	79.25	99.77	118.99

TAXES AND DEPRECIATION

The tax rates used for the cash flow analysis included a property tax rate of roughly 2% of economic value (which was included in the refinery fixed costs as 0.25% of replacement cost), a 35% federal income tax rate and a 6.4% state income tax rate. The property tax was assumed to be waived for the first five years of operation. A five-year tax holiday was assumed for the state income tax although this had very little effect on the results due to the impact of depreciation on the taxable income during that time. The depreciation was calculated assuming a double declining balance per the 10 year MACRS (Modified Accelerated Cost Recovery System) method assuming loss carry forward. Sales tax exemptions on purchased materials were not considered at this stage of the analysis due to a lack of detail on specific equipment items. In addition, it can be reasonably be expected that a majority of the larger equipment items will be manufactured in other parts of the country by companies with the requisite experience.

CASH FLOW RESULTS AND SENSITIVITY ANALYSIS

A cash flow analysis was performed on the two refinery configurations using the above assumptions on crude charge, product yields, and capital and operating costs, incorporating a base five-year construction period with a project startup on January 1, 2016. We have assumed a 95% on-stream factor each year, which allows for distributed turnarounds for scheduled maintenance of key process units. The base case cash flow models are shown in Tables 1 and 2 at the end of this section.

The annual cash flows started with revenues for the products, based on the cross multiplication of sales volumes and prices for each product. The cost of feedstocks (crude and ethanol in the 20K case, crude only in the 34,000 B/D case) were deducted to get gross margin. We also deducted variable costs to get what we call Contribution Margin. After that, fixed costs were subtracted to get EBITDA, or Earnings Before Interest, Taxes, Depreciation and Amortization.

Annual depreciation charges were calculated per the MACRS system, and taxable income was determined by subtracting depreciation from the EBITDA. If the depreciation charge was larger than the EBITDA, then no income tax was charged and the difference was accumulated in a loss carryforward account. Once the annual EBITDA exceeded the depreciation and the loss carryforward was used up, then the project began to pay both state and federal income taxes. For the first five years of the project's operation, regardless if there was positive taxable income, the tax exemption at the state level reduced the project's obligations.

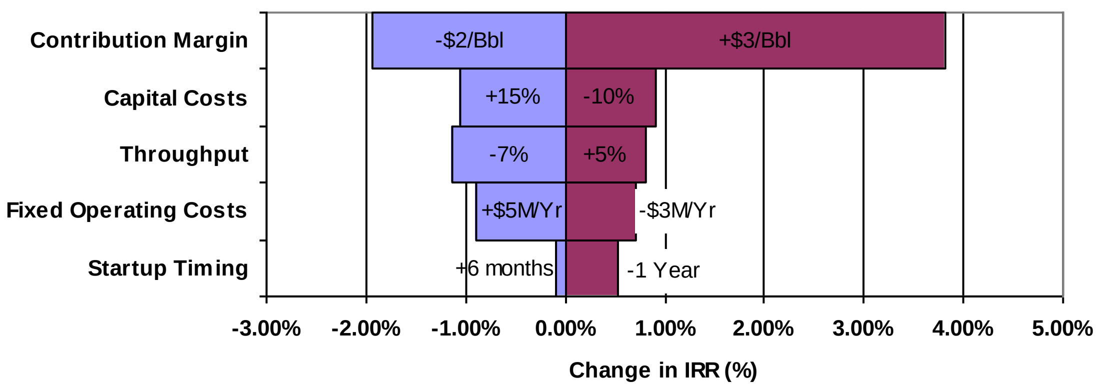
A sensitivity analysis was also performed to determine the impact on the project return for changes in throughput, capital costs, contribution margin, fixed operating costs and project schedule. The results for the cash flow and sensitivity analysis are shown in the next table.

NORTH DAKOTA REFINERY STUDY Cash Flow Sensitivity Analysis (%IRR)	20 KBPD Refinery		34 KBPD Refinery	
	Real	Nominal	Real	Nominal
Base Case	1.6%	3.7%	7.0%	9.2%
Throughput + 5%	2.4%	4.5%	7.7%	9.9%
Throughput - 7%	0.5%	2.5%	5.8%	8.0%
Capital Costs + 15%	0.6%	2.6%	5.5%	7.7%
Capital Costs - 10%	2.5%	4.6%	8.0%	10.3%
Contribution Margin + $3/Bbl	5.3%	7.5%	10.8%	13.1%
Contribution Margin - $2/Bbl	-0.3%	1.7%	3.7%	5.8%
Fixed Operating Costs + $5M/Yr	0.7%	2.8%	6.3%	8.5%
Fixed Operating Costs - $3M/Yr	2.3%	4.4%	7.3%	9.5%
Early Start-up (1 yr)	2.0%	4.2%	7.4%	9.7%
Late Start-up (6 mos)	1.5%	3.6%	6.9%	9.1%

For the 20,000 B/D refinery the calculated real IRR (assuming no inflation) for the base case conditions was 1.58% while the nominal IRR was 3.67%. The 34,000 B/D refinery base case results showed a real IRR of 6.96% with a nominal IRR of 9.19%, indicating that investment in additional capital to upgrade the produced naphtha to finished gasoline is not economic. Assuming a required 15% nominal return, which represents a more typical minimum return for a refining investment, the NPV for the 20,000 B/D refinery was calculated to be -$244.4 million while the NPV for the 34,000 B/D refinery was estimated at -$156.7 million.

The sensitivity analysis was performed for both refineries assuming a 15% increase and a 10% decrease in most of the variables considered with the results for both the real and nominal IRR shown in the table above. For the project schedule sensitivity an increase of 6 months and a decrease of 1 year to the project schedule were used for the analysis based on the project schedules provided by Mustang Engineering and discussed in the project schedule section. The throughput increase was capped at 5% based on using a maximum 1.0 stream factor and the throughput decrease was limited to 7% for a minimum 0.88 stream factor. The nominal IRR sensitivity results for the 20,000 B/D refinery project are presented as a tornado chart in Figure IV-1 below.

FIGURE IV-1
20 KBPD REFINERY IRR SENSITIVITY TORNADO CHART

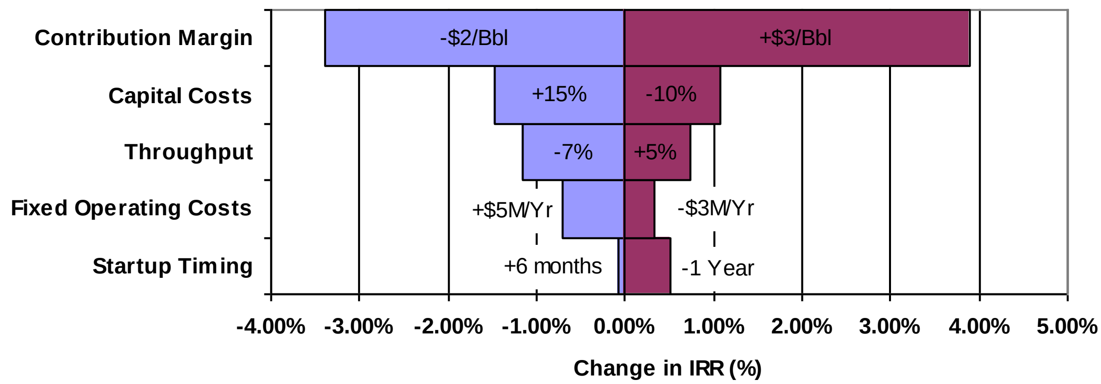


The largest sensitivity impact to the 20,000 B/D refinery project IRR was a change in contribution margin. Increasing the contribution margin $3/Bbl (about 15%) increased the nominal IRR 3.82% to 7.49% while decreasing the contribution margin $2/Bbl (about 10%) decreased the nominal IRR 1.95% to 1.72%. This indicated that the project return is most dependent on the refining margins realized by the project.

The next largest factor in the realized project return was the capital cost. An increase of 15% in capital costs reduced the nominal IRR by 1.05% to 2.62% while a 10% decrease in capital costs increased the nominal IRR by 0.91% to 4.58%. It should be noted that the capital cost changes were made independent of the fixed costs. Assuming that a change in capital costs resulted in a like change in fixed costs, the nominal IRR for a 15% increase in capital/fixed costs was 1.51% while the nominal IRR for a 10% decrease in capital/fixed costs was 5.59%.

The other sensitivity variables considered included changes in fixed costs (independent of capital costs), changes in throughput and variations in project schedule. These sensitivities resulted in a range of nominal IRR between 2.79% and 4.48% compared to the base IRR of 3.67%. The nominal IRR sensitivity results for the 34,000 B/D refinery project are presented as a tornado chart in Figure IV-2 below.

FIGURE IV-2
34 KBPD REFINERY IRR SENSITIVITY TORNADO CHART



The largest sensitivity impact to the 34,000 B/D refinery project IRR was also a change in contribution margin. Increasing the contribution margin +$3/Bbl (about 15%) increased the nominal IRR 3.91% to 13.10% while decreasing the contribution margin -$2/Bbl (about 10%) decreased the nominal IRR 3.38% to 5.81%. This again indicated that the project return is most dependent on the refining margins realized by the project.

The second largest factor in the realized project return was again the capital cost. An increase of 15% in capital costs reduced the nominal IRR by 1.48% to 7.71% while a 10% decrease in capital costs increased the nominal IRR by 1.08% to 10.27%. The capital cost changes were again made independent of the fixed costs. Assuming that a change in capital costs resulted in a like change in fixed costs, the nominal IRR for a 15% increase in capital/fixed costs was 6.80% while the nominal IRR for a 10% decrease in capital/fixed costs was 10.98%.

The other sensitivity variables considered included changes in fixed costs (independent of capital costs), changes in throughput and variations in project schedule. These sensitivities resulted in a range of nominal IRR between 8.04% and 9.92% compared to the base IRR of 9.19%.

NORTH DAKOTA REFINERY STUDY
Margin and Capital Cost Sensitivity for Nominal 15% IRR

	Capital Costs			Contribution Margin		
	% Reduction	Real	Nominal	$/bbl Incr.	Real	Nominal
20 KBPD Refinery	-64.9%	12.6%	15.0%	+$ 11.4	12.6%	15.0%
34 KBPD Refinery	-33.7%	12.6%	15.0%	+$ 4.7	12.6%	15.0%

The two largest sensitivity variables were also analyzed for each refinery case to determine the magnitude of change that would be required to yield a 15% minimum nominal IRR for the project assuming all other variables stay at the base conditions. The results are shown in the table above. For the 20,000 B/D refinery case, a 65% reduction in capital costs (independent of fixed costs) or a $11.43/bbl contribution margin increase would be required to yield a 15% nominal project IRR. For the 34,000 B/D refinery case, a 34% reduction in capital costs (independent of fixed costs) or a $4.71/bbl increase in contribution margin would be required to yield a 15% nominal project IRR.

RISK ANALYSIS

The next level of sensitivity analysis performed was a Monte Carlo-type multi-variable risk analysis. The analysis was performed using an industry standard Excel add-in package called @RISK. The cash flow models for each refinery base case were modified to incorporate probability distributions for the key sensitivity parameters, For throughput, contribution margin, fixed costs and capital costs, a triangular distribution was employed, based on the ranges used in the sensitivity analyses described previously. For the schedule start-up dates, a discrete distribution was used. The Monte Carlo simulator was set up to run 10,000 iterations for each refinery base case. The analysis produced a wider range of IRR than the sensitivity analysis because multiple parameters are favorable or unfavorable at the same time. The results from the Monte Carlo analyses are shown in the table below and in the graphs that follow.

NORTH DAKOTA REFINERY STUDY
Results of Monte Carlo Risk Analysis

	20,000 B/D Case		34,000 B/D Case	
	Real	**Nominal**	**Real**	**Nominal**
Minimum IRR %	(1.7)	(0.5)	2.2	4.3
Mean IRR %	2.0	4.1	7.2	9.4
Maximum IRR %	6.4	8.6	12.2	14.7
Standard Deviation, %	1.4	1.4	1.6	1.6

The mean IRR results from the risk analysis are very close to the base case IRR's. The range of results shows that even with all of the main parameters in a favorable mode, the 20,000 B/D refinery still does not achieve a return that would be attractive to a traditional investor, with a maximum return of 6.4 % real or 8.6% nominal. The likelihood of all of the variables meeting peak conditions over the life of the project is very remote.

Figures IV-3 and IV-4 show the distribution of results for the 20,000 B/D refinery in real and nominal IRR, respectively.

FIGURE IV-3
ND REFINERY STUDY RISK ANALYSIS: 20 MBPD CASE

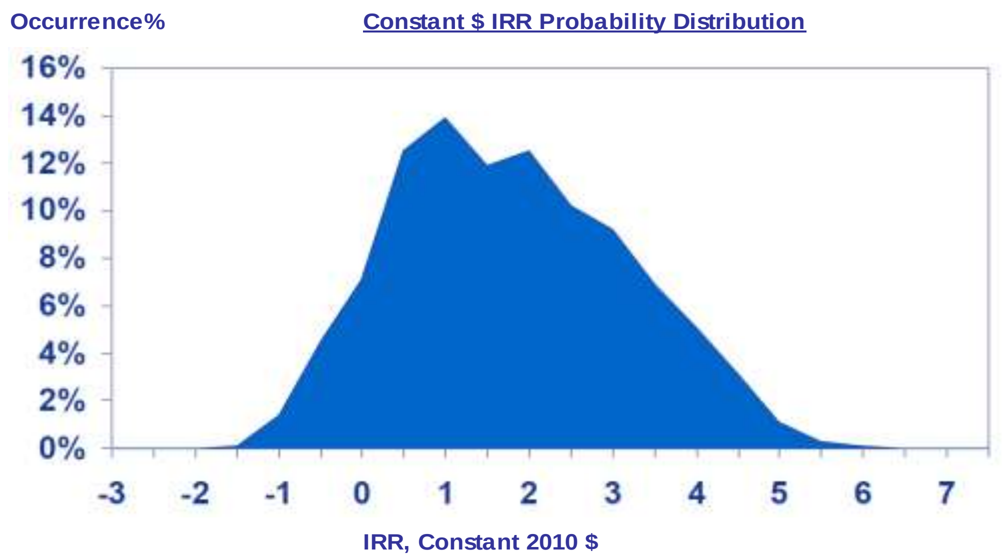
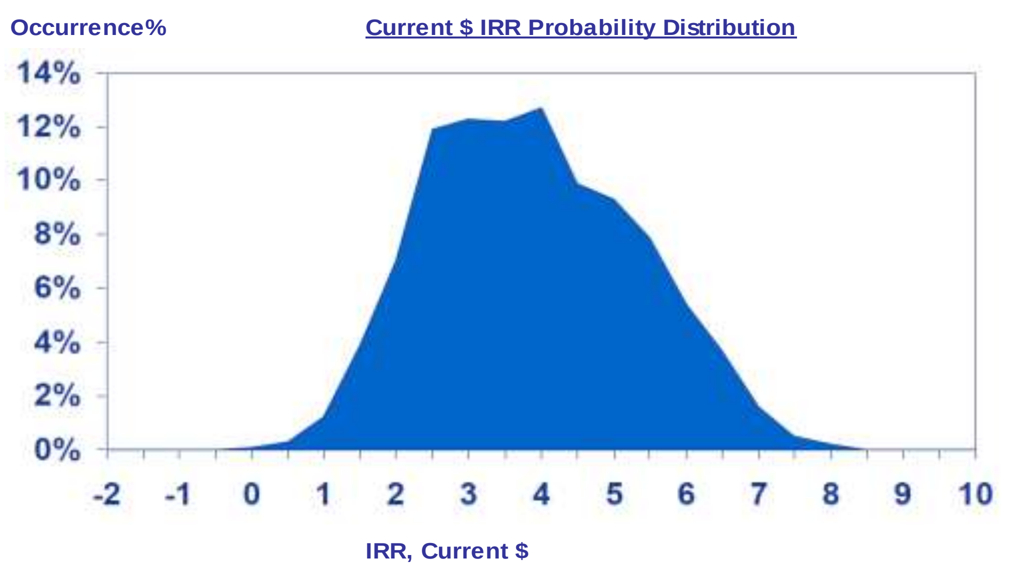


FIGURE IV-4
ND REFINERY STUDY RISK ANALYSIS: 20 MBPD CASE



For the 34,000 B/D case, the maximum IRR's are borderline attractive at 12.2% real and 14.7% nominal. Again, there is only a very small likelihood that these results could be achieved consistently over the life of the project. At the other end of the distribution, there is a very small probability that the return will only be 2.2% real or 4.3% nominal. Figures IV-5 and IV-6 show the distribution of the Monte Carlo analysis for the 34,000 B/D refinery case in real and nominal IRR, respectively.

FIGURE IV-5
ND REFINERY STUDY RISK ANALYSIS: 34 MBPD CASE

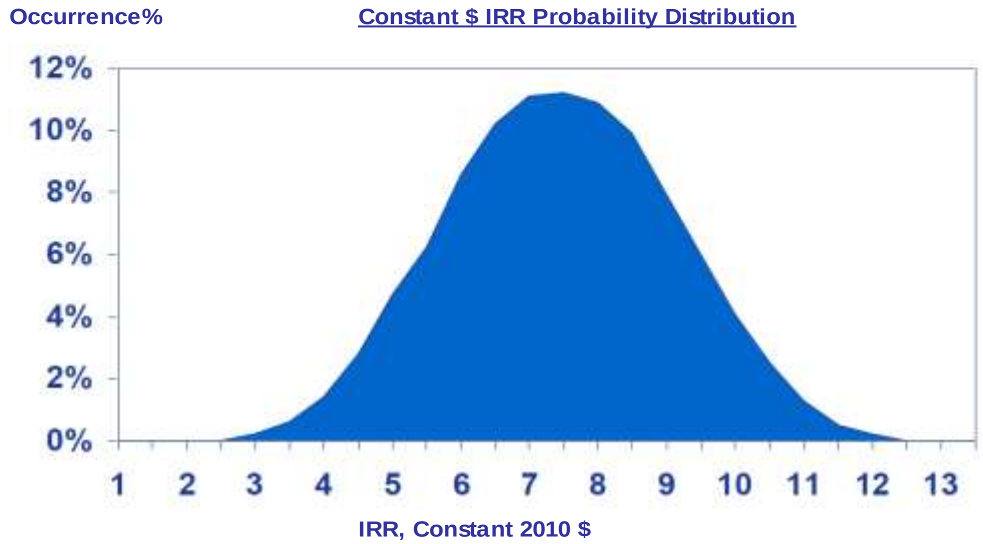
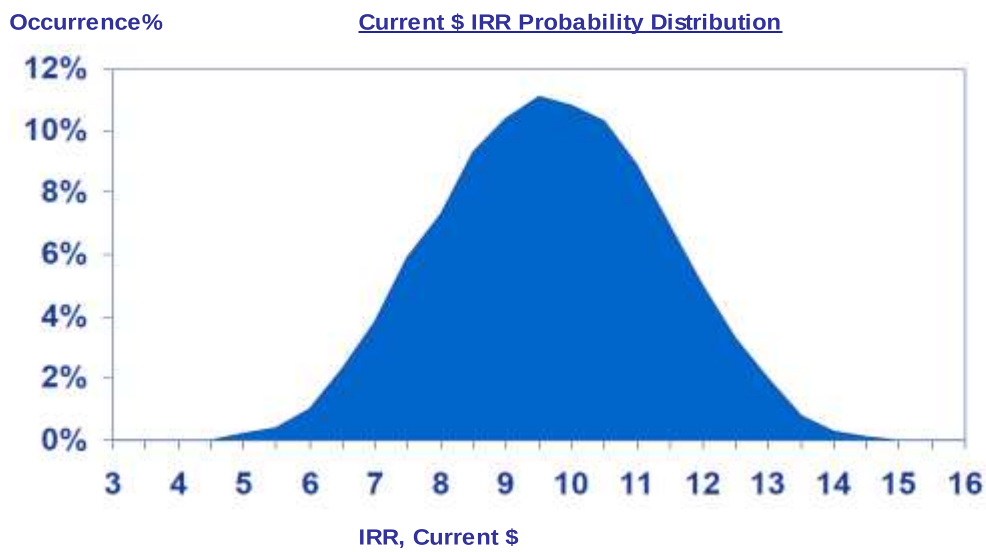


FIGURE IV-6
ND REFINERY STUDY RISK ANALYSIS: 34 MBPD CASE



The end result of the risk analysis is that the basic profitability of the two refinery cases is not robust, particularly for the smaller refinery. There is a very small chance that the larger facility could achieve a reasonable rate of return under optimal conditions over the life of the project.

IMPACT OF FEDERAL REGULATIONS

Petroleum refiners in the U.S. have to adhere to a plethora of federal regulations covering many aspects of refinery operations and product quality. As noted in the schedule previously, there is a long interval of time set aside early in the process for permitting, much of which is set by federal regulations, as well as by state and local regulations. These will not be discussed in this section. The focus here is on the product markets which are heavily influenced by regulations, both existing and anticipated.

The key areas of regulation that will impact any new refinery project in the U.S., not just North Dakota, are the Renewable Fuel Standard (RFS), tighter CAFÉ standards, reduced benzene in gasoline requirements, and albeit preliminary in definition, climate change initiatives. We'll examine them individually, and point out where the refinery analysis was potentially impacted.

CAFE STANDARDS / RFS

The Energy Independence and Security Act (EISA) was signed into law by President Bush in December of 2007. EISA calls for efficiency improvements in all sectors of the economy (including transportation) through a series of mandates and research programs. Two sections of the law are expected to have the greatest impact on the refined product markets. These are the increase in corporate average fuel economy (CAFE) standards for new light duty vehicles and a significant increase in the Renewable Fuels Standard (RFS) volumes previously passed into law in 2005. Other sections in EISA have the potential to affect the refining industry, but these are thought to be less significant than the CAFE standards and RFS.

CAFE Standards

EISA called for a gradual increase in new light duty vehicle fuel efficiency requirements up to 35 miles per gallon (MPG) on average by the 2020 model year. Light duty vehicles are defined as passenger cars and light trucks up to 8,500 lbs gross vehicle weight. The new CAFE requirement is stated as an annual average of all the new vehicles sold by an automaker. This is a very significant change from the previous requirements of 27.5 for cars and 22.5 for light trucks.

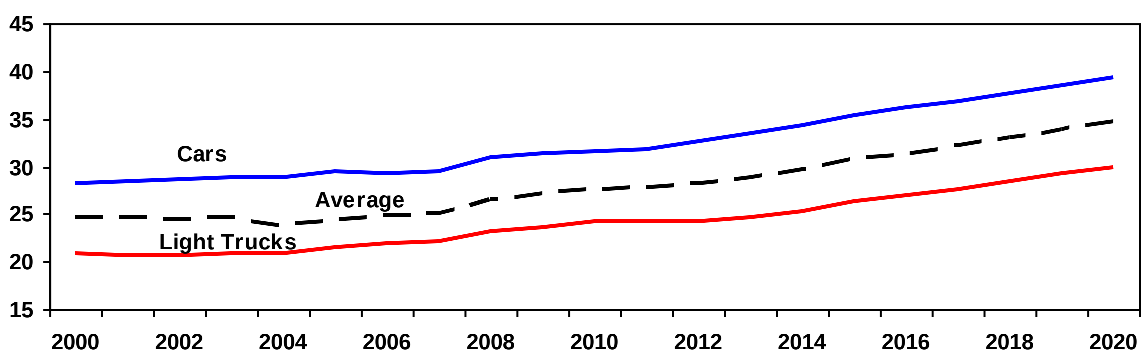
On May 19, 2009, President Obama announced a new program to develop new national vehicle standards aimed at reducing greenhouse gas (GHG) emissions and increasing fuel economy at an accelerated rate. The nation-wide program was developed jointly by the U.S. Environmental Protection Agency (EPA) and the National Highway Traffic Safety Administration (NHTSA) on behalf of the U.S. Department of Transportation (DOT) rather than through

Congressional action. The NHTSA and EPA intend to propose two separate sets of standards, each under their respective statutory authorities.

In 2008, NHTSA proposed Corporate Average Fuel Efficiency (CAFE) standards for model year 2011 through 2015 vehicles under the authority of the EISA. However, responding to a Presidential Memorandum of January 26, 2009 from President Obama, NHTSA issued CAFE standards limited to model year 2011 vehicles while reviewing appropriate CAFE standards for 2012 and later model years. The EPA, under the authority of the Clean Air Act (CAA), is proposing a national carbon dioxide (CO_2) emissions standard that would target an average maximum of 250 grams of CO_2-equivalent (CO_2e) per mile in model year 2016. The standards would take effect beginning in model year 2012 with a linear phase-in of the emissions standards. EPA and NHTSA have determined that if the automotive industry were to achieve the target level of CO_2 emissions through fuel economy improvements alone, this would equate to achieving a level of 35.5 miles per gallon for all new passenger car and light-duty trucks sold in the U.S.

The proposed new vehicle standards would accelerate the new vehicle CAFE standards of 35.5 miles per gallon from the 2020 model year established under EISA to the 2016 model year under the current proposal. The proposed regulations were used as the basis for the assumptions used to model the efficiency of the future vehicle fleet. Increasing the average CAFE requirement from about 25 MPG currently to 35 MPG by 2016 will be challenging for all automakers, but in our view this is achievable given existing technology. Our forecast of new vehicle MPG is slightly lower than the 35.5 MPG-equivalent considering that some manufacturers would continue to pay civil penalties rather than achieving the required CAFE levels and the ability to use CAFE credits for alternative fuel vehicles (mostly E-85) through 2020. Figure IV-7 shows our assumptions for new vehicle efficiency.

FIGURE IV-7
NEW VEHICLE EFFICIENCY RATING
(Miles Per Gallon)



Embedded in the assumptions for average new vehicle efficiency are views on market shares for gasoline-electric (hybrid) vehicles and diesel-powered vehicles. Hybrid car market share is expected to continue strong growth as automakers will likely offer additional models now that CAFE requirements have increased. Diesel car market share is also expected to improve some, but high pump prices relative to gasoline and higher vehicle acquisition costs will likely keep market share below 5%. In the light truck category, however, we expect that automakers will expand offerings of diesel models as a way to meet the new CAFE standards and maintain needed load-carrying and towing performance in this lucrative market segment. It is assumed that diesel-powered light trucks will be marketed primarily to commercial pick-up truck users.

Our forecast of new conventional-powertrain car efficiency changes results in an EPA-based average new car fuel efficiency in the year 2015 of about 35 MPG and 40 in 2020 versus about 29 currently. New truck CAFE efficiencies are expected to gain from 22 MPG currently to 30 MPG by 2015. When translated to the fleet calculation, the CAFE efficiencies yield about a 23.5 fleet MPG average in 2020 versus about 19.5 currently. It is important to note that these efficiencies are based on our use of conventional gasoline without ethanol. Gasoline blends containing ethanol will have a slightly lower efficiency. The lower efficiency of gasoline-ethanol blends is taken into account in our declining gasoline demand outlook, which was presented in the Phase I report.

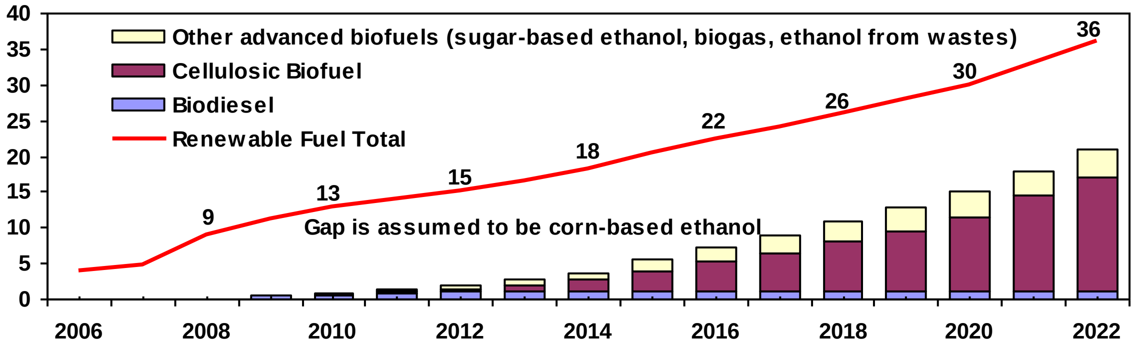
Renewable Fuels Standard

EISA increases the Renewable Fuels Standard volumes previously enacted into law in 2005. The law calls for a total of 36 billion gallons per year (BGY) of renewable fuel by 2022. This includes corn ethanol, cellulosic ethanol, biodiesel, butanol, sugar-based ethanol, biogas and any other fuel that has 50% reduction in lifecycle greenhouse gas emissions. In February 2010, the EPA issued the RFS2 regulation that changed 2010 requirements and allowed technologies that have a lower reduction in greenhouse gas lifecycle emissions.

The cellulosic ethanol requirement is quite aggressive. The product is first required in 2010, despite the fact that no commercial cellulosic ethanol plants existed in 2009. By 2015, 3 BGY of cellulosic ethanol is required, increasing to 16 BGY by 2022. Several new small-scale demonstration cellulosic ethanol plants are being designed and built with hopes of improving the technologies that have been tested in laboratories. These plants are not expected to startup until 2010 and later. The EPA administrator is given authority under EISA to lower the overall requirement if cellulosic ethanol does not develop into a commercially viable technology. RFS2 lowered the 2010 cellulosic ethanol requirements to 6.5 million gallons from 100 million gallons.

In addition to cellulosic biofuel, EISA also calls for specific volumes of other advanced biofuels to be produced and blended into the fuel supply. These include butanol, ethanol from wastes, sugar-based ethanol, and biogas. A requirement to use biodiesel is also included in the Act beginning in 2009 and continuing through 2012. RFS2 regulations combined the 2009-2010 biodiesel requirement into one for 2010. We have assumed that the biodiesel requirement will continue through the end of our forecast period at the same level. Although there is no specific requirement for corn-based ethanol, it is expected to supply a significant portion of the gap between the total RFS requirement and the advanced biofuel requirement (cellulosic, biodiesel, and other advanced biofuels). Figure IV-8 illustrates the renewable fuels requirements.

FIGURE IV-8
RENEWABLE FUELS REQUIREMENTS IN EISA
(Billion Gallons per Year)



Total renewable fuels volumes increase from near current levels to 36 BGY and the new advanced biofuels phase in over the period with corn-based ethanol assumed to remain at 15 BGY. Note that cellulosic biofuel and biomass-based diesel are both types of the advanced biofuels category and that there is a volume of “undifferentiated” advanced biofuels.

By definition, a renewable biofuel must have a 20% reduction in lifecycle greenhouse gases (GHG) compared to the traditional petroleum fuel it replaces (2005 baseline). Existing biofuels plants and those under construction by December 2007 are grandfathered for this GHG requirement. Similarly, the comparable cellulosic biofuel GHG lifecycle reduction requirement is 60%, while the biomass-based biodiesel and “undifferentiated” biofuels categories must have a 50% GHG lifecycle reduction. The RFS2 is referred to as “nested” since there is a progression from higher GHG lifecycle reduction fuel types to lower (shown in the above table as moving from left to right). The potential impact on a new refinery might be that some credits may need to be purchased to meet the various tiers of compliance within the RFS regs. Again, increased use of bio-fuels reduces the need for refinery-based product, as reflected in our forecasts.

A related issue to the RFS2 standard is the issue of the ethanol blend wall. Over the next five years, the ethanol content in the total U.S. gasoline will approach, then theoretically exceed 10% based on the RFS2 mandated volumes and projected gasoline demand. The EPA is considering a partial waiver that would allow higher “mid-level” grades of gasoline to be sold, such as E15 or E20. The current thinking is that the EPA will issue a waiver for late model vehicles, probably 2000 model year and newer allowing them to fuel with up to 15% ethanol (E15). Older vehicles, boats and small engines will most likely not be approved for this new fuel. Therefore, a new fuel grade would be required in the market. There is a major concern amongst refining companies that the E15 grade products could be unintentionally be used in non-approved engines by consumers. However, in our analysis, we have assumed that the gasoline produced in the 20,000 B/D case will contain 15% ethanol.

BENZENE REDUCTION PROGRAM

In February 2007, the EPA finalized rule-making activities intended to reduce emissions of hazardous air pollutants from motor vehicles. The regulations require more stringent control of hydrocarbon exhaust emissions at low temperatures, reduced evaporative emissions from portable fuel containers, and lower benzene content in gasoline.

The gasoline benzene controls require that refiners and importers meet an annual average maximum benzene content of 0.62% (volume) on all gasoline (both conventional and reformulated). California gasoline is excluded from the program. A nationwide credit banking and trading system is to be established, but no supplier will be allowed to exceed a maximum physical average of 1.3%. The new benzene restriction will come into effect on January 1, 2011. At that time, the toxic emissions control programs applying to both RFG and conventional gasoline will be replaced by the new benzene controls.

The EPA has estimated that the current average benzene content of U.S. gasoline is about 1.0%, but it varies widely among refiners. The cost of compliance with the new standards will also vary widely, depending on each facility's configuration, feedstocks and operation. The technologies generally used to reduce benzene include prefractionation of reformer feed to eliminate benzene precursors, isomerization of light naphthas to saturate benzene, extraction of benzene from reformate, and saturation of benzene in streams such as FCC naphtha. In our analysis, we have assumed that any small refiner advantages will have expired and that the refinery will have to produce gasoline with 0.62 percent benzene or less to be in compliance.

CLIMATE CHANGE INITIATIVES

The U.S. signed the Kyoto Protocol on November 12, 1998, but the treaty was not ratified by the U.S. Congress. The treaty called for the U.S. to implement a 7.0 percent reduction in greenhouse gas emissions from 1990 levels between 2008 and 2012. The U.S. has not ratified the Kyoto Protocol, but the Bush administration proposed a program of voluntary steps to increase energy efficiency. The EISA legislation can also be viewed as climate change legislation as its vehicle efficiency and biofuels mandates were based on a greenhouse gas reduction from the transportation sector.

With the election of Barack Obama and the Democrat-led Congress, new efforts are being made to advance climate change policies. There are two different approaches being taken. The EPA is advancing a regulatory agenda where GHG would be regulated under existing Clean Air Act (CAA) law. Separate from this, the Congress is working on comprehensive climate change legislation that would regulate GHG emissions, most likely through a cap and trade scheme.

On April 17, 2009 the U.S. Environmental Protection Agency (EPA) issued an endangerment finding, ruling that global warming poses a "public health concern." This puts in place the legal requirements needed to begin to control GHG emissions through the CAA without Congressional action. The EPA has also issued proposed regulations that would make it difficult to expand refineries without providing offsets in GHG emissions and put in place a comprehensive GHG reporting system.

There are a myriad of issues with regulating GHG through the CAA. It appears that essentially no party really wishes to regulate climate change through the CAA – including environmentalists, the Administration, auto manufactures or refiners. Most policy watchers view the move by the EPA as a way to put pressure on Congress to enact a new climate change law and to increase the U.S. climate change credentials internationally.

In July of 2009, the House passed the Waxman-Markey bill (H.R. 2454: American Clean Energy and Security Act of 2009), which seeks to limit greenhouse gas emissions. The U.S. Congress is set to take up the climate change legislation again in 2010 although this may get pushed to 2011 due to mid-term elections, healthcare legislation and financial industry reform bills.

The Waxman-Markey proposal includes the framework of a market-based cap-and-trade program to reduce global warming pollution from electric utilities, oil companies, large industrial sources and other emission sources greater than 25,000 tons per year of CO_2e emissions. The federal cap-and-trade proposal would establish 2005 as the base emissions period and require regulated entities to reduce emissions by 3% in 2012, 20% by 2020, 42% by 2030 and by 83% by 2050.

Broadly, the bill sets a cap on emissions to achieve these GHG reduction targets. This cap is provided for with carbon allowances which are limited each year at a generally declining rate. The government would either provide allowances for free (mostly in early years) or through an auction. The concept is that allowances are provided for free to sectors and segments of the economy that are most likely to be impacted by this legislation (climate change cost), but political factors must be expected as well.

The climate change bills are massive pieces of legislation and would have a broad and significant reach on the U.S. economy. In addition to the GHG cap and trade provisions, the bills call for major advancements in energy efficiency in all sectors, new power system standards, renewable targets, carbon capture and storage, and “green” job formation.

To a large extent, the petroleum sector does not directly interact with other energy sectors in the U.S. Most large industrial consumers and power generators have moved away from oil to coal or natural gas due to better pricing and widespread availability. At the same time, there is relatively limited scope for a major shift away from petroleum-based fuels to other energy sources in the transportation sector – beyond the RFS standards included here. As such, the oil sector is largely isolated, at least as far as the GHG impact amongst the different energy sources.

Regarding petroleum regulation under the proposed cap and trade schemes, the biggest impact will be at the refinery-level and at the end-use consumer. The H.R. bill would regulate the GHG emissions from the refinery (process-related emissions) and the fuel consumption (combustion of the fuel by end-users) at the refinery. U.S. refineries account for roughly 6% of total U.S. emissions. Under the H.R. 2454 bill, refiners would receive 2% of the allowances. Further, as written, the refinery would need to have allowances for all fuel sales as well, with some exceptions. Two key exceptions would be for fuels that are exported or for petrochemical feedstocks that are not later emitted through combustion. It may be that naphtha exported to Canada would fall into one of these categories.

Essentially, the refinery would need to collect allowances for each ton of refinery fuel consumed and for each ton of product sold. These allowances would be surrendered to the EPA the following year with some ability to bank (build an inventory for later years) or borrow (from inventory). At this stage in the project analysis, it is too early to try and predict the financial impact from these yet-to-be finalized regulations.

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V. REFINERY ANALYSIS

ISBL PROCESS DESCRIPTIONS

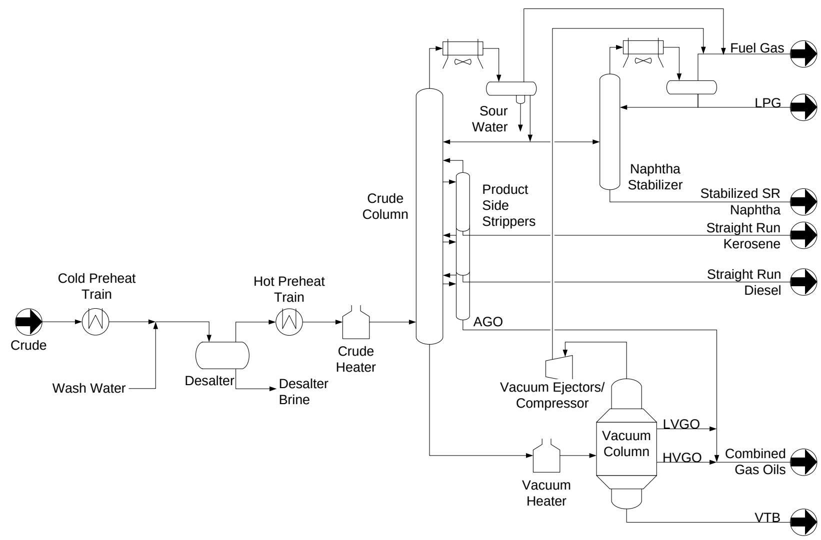


FIGURE 5-1
Crude and Vacuum Unit

CRUDE AND VACUUM UNIT (FIGURE 5-1)

The function of the Crude Distillation Unit is to provide primary separation of the crude oil for subsequent processing by downstream units. Crude oil is pumped to the battery limits and preheated by exchange with hot products. The crude oil feed continues through a desalter to remove entrained inorganic salts followed by further heat exchange, before being routed to a charge heater. The heated feed is separated in an atmospheric distillation column to yield liquid product streams – naphtha, kerosene, diesel, and atmospheric gas oil. Atmospheric residuum is withdrawn from the bottom and sent through another heater to the Vacuum Distillation Unit. Condensed stripping steam is recovered in the crude column overhead system and is sent to the sour water collection system.

The function of the Vacuum Distillation Unit is to separate atmospheric residuum into vacuum gas oil for feed to the Hydrocracker unit and vacuum residuum for sale as fuel oil. The feed material is partially vaporized in a charge heater before being distilled under vacuum conditions to prevent excessive thermal decomposition. Light and heavy vacuum gas oils are produced as liquid products. Vacuum residuum is the remaining liquid fraction that is withdrawn from the bottom of the column. Condensed ejector steam is recovered in the column overhead system and is sent to the sour water collection system.

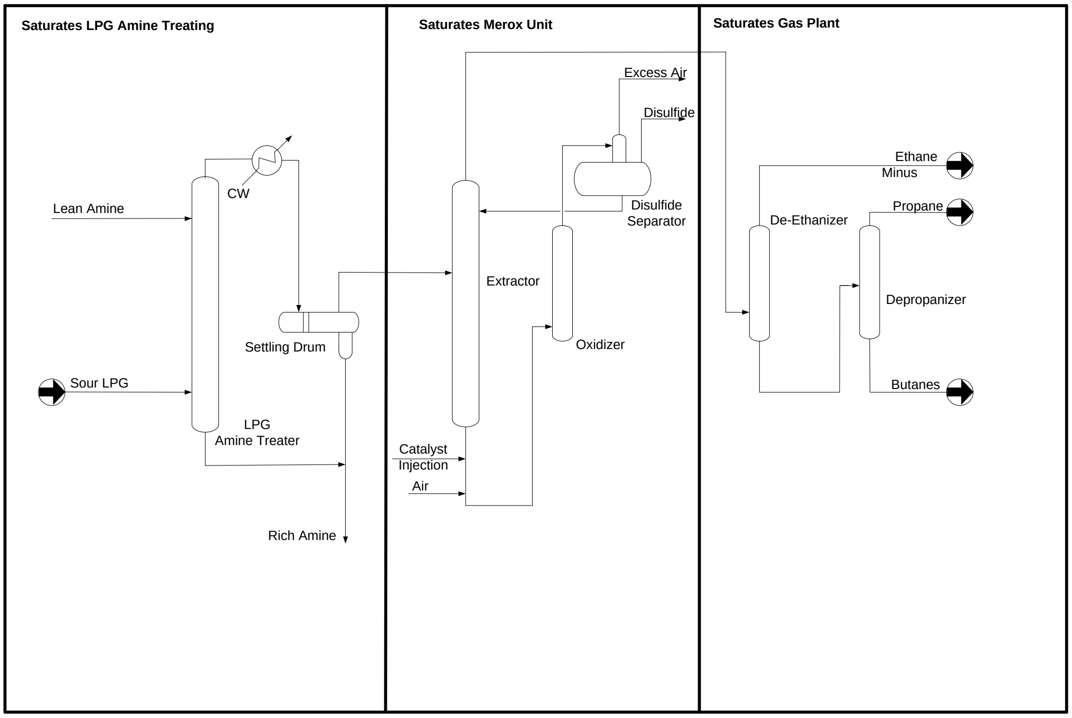


FIGURE 5-2
Gas Plant

GAS PLANT (FIGURE 5-2)

Light ends are produced as byproducts from several refinery process units. These light ends are routed to the Gas Plant, where propane and butanes are recovered as finished products. Ethane and lighter hydrocarbons are treated to produce a gas stream suitable for use as refinery fuel. These fractionation objectives are achieved in two distillation columns operating in series: the De-ethanizer and the Depropanizer. The Gas Plant includes an amine contactor and a Merox caustic treater to remove sulfur compounds from various sour gas and LPG streams. The H_2S-rich amine is sent to the Amine Regeneration Unit for regeneration and returned to the Gas Plant as lean amine. Other sulfur, including sulfur in the form of mercaptans, leaves the refinery as a solute in the spent caustic from the Merox caustic treater.

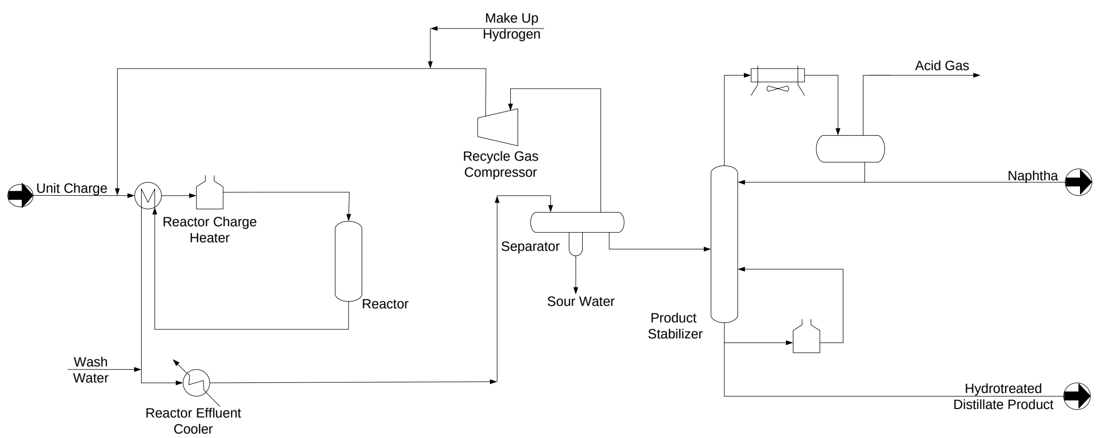


FIGURE 5-3
Distillate Hydrotreater Unit

DISTILLATE HYDROTREATER UNIT (FIGURE 5-3)

The Distillate Hydrotreater treats distillate streams such as kerosene and diesel to remove contaminants such as sulfur and nitrogen using fixed bed catalytic reactors. The mixed distillate streams fed to the Distillate Hydrotreater are mixed with recycle and make-up hydrogen, heated by exchange with reactor effluent and a charge heater, and passed over the catalyst beds. The hydrogen reacts with the sulfur and nitrogen contaminants to produce H_2S and ammonia. Some of this H_2S and ammonia is absorbed in a water wash section, and the resulting sour water product is sent to the sour water collection system. Light ends from the hydrotreater reactors are separated from the hydrotreated distillate in a stabilizer column. Depending on market demands, a fractionator system may be warranted to further separate the distillate into the finished kerosene and diesel products.

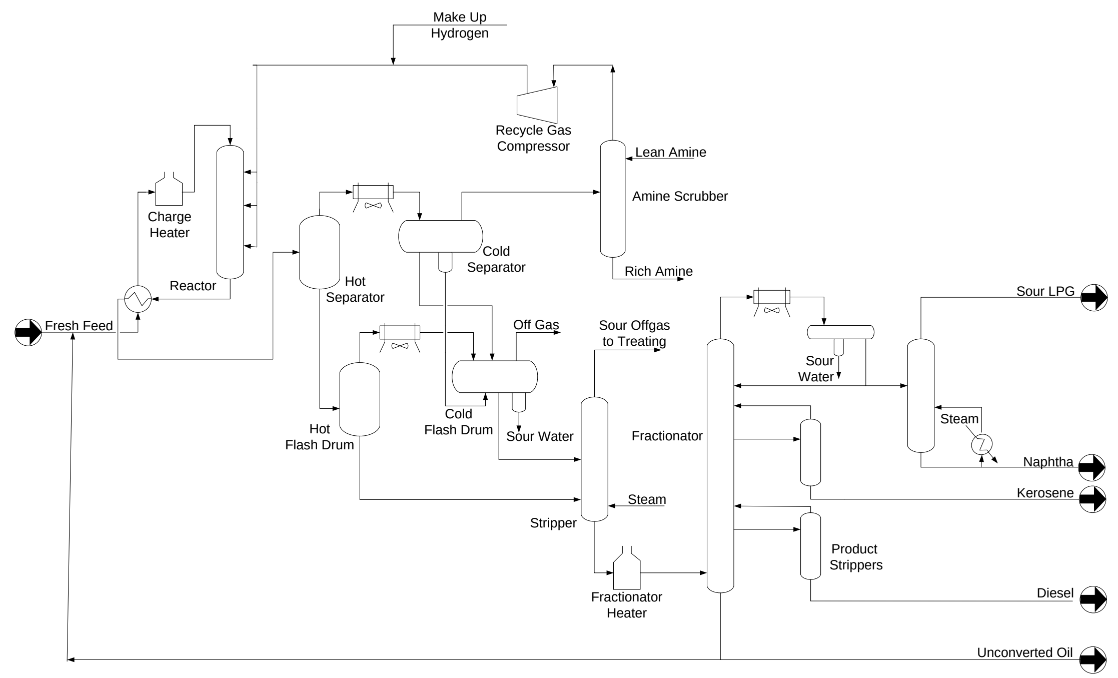


FIGURE 5-4
Hydrocracker Unit

HYDROCRACKER UNIT (FIGURE 5-4)

The Hydrocracker Unit hydrotreats and cracks gas oil feedstock to produce naphtha, jet fuel, and diesel. The hydrocracker will be designed to accommodate the seasonal variations in the diesel fuel cold flow properties. The liquid feeds (fresh feed and the unconverted oil recycled from the fractionator) are mixed with recycled and make-up hydrogen, heated, and routed through a series of fixed-bed catalytic reactors where hydrotreating and hydrocracking reactions occur under conditions of high pressure and high temperature. In the hydrotreating reactions, hydrogen combines with sulfur and nitrogen to produce H_2S and ammonia, which can be then be removed. In the hydrocracking reactions, heavy hydrocarbons are converted to lighter materials via the addition of hydrogen. Each reactor vessel is preceded by a process heater. Reactor effluent is cooled by heat exchanged with the feed and then washed with water and scrubbed in an amine contactor to remove H_2S and ammonia. The scrubbed gas is compressed and recycled to the reactor section. Condensed stripping steam and wash water are sent to the Sour Water Collection System. Amine rich with H_2S is sent to the Amine Regeneration Unit. The hydrocarbon liquid effluent from the reactors is sent to a fractionation section where the various product streams are separated. Products from the fractionators include fuel gas, light ends, light and heavy naphtha, kerosene, diesel, and fractionator bottoms. Most of the fractionator bottoms are recycled to the reactor section. A small stream is continuously purged to avoid exchanger fouling in the reactor loop.

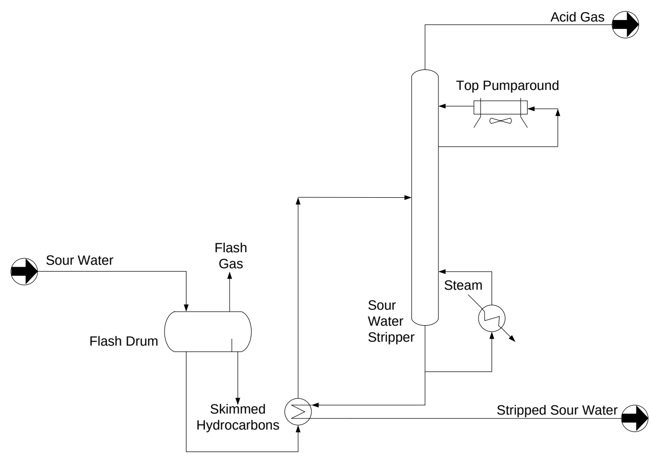


FIGURE 5-5
Sour Water Stripper Unit

SOUR WATER STRIPPER UNIT (FIGURE 5-5)

In the Sour Water Stripper Unit, aqueous streams containing H_2S, other organic sulfur compounds, ammonia, and oil, are collected from various process units and combined in a feed surge tank. Liquid hydrocarbons are decanted from the water and returned to the recovered oil tank. The sour water is heated and charged to a stripper tower where H_2S and ammonia are removed in the overhead vapors and cooled by air or cooling water. Condensed water reflux is returned to the stripper tower. The non-condensable acid gas is routed to the Sulfur Recovery Unit. The stripped water is reused at the crude desalter. Any remaining stripped water is routed to the water treatment plant.

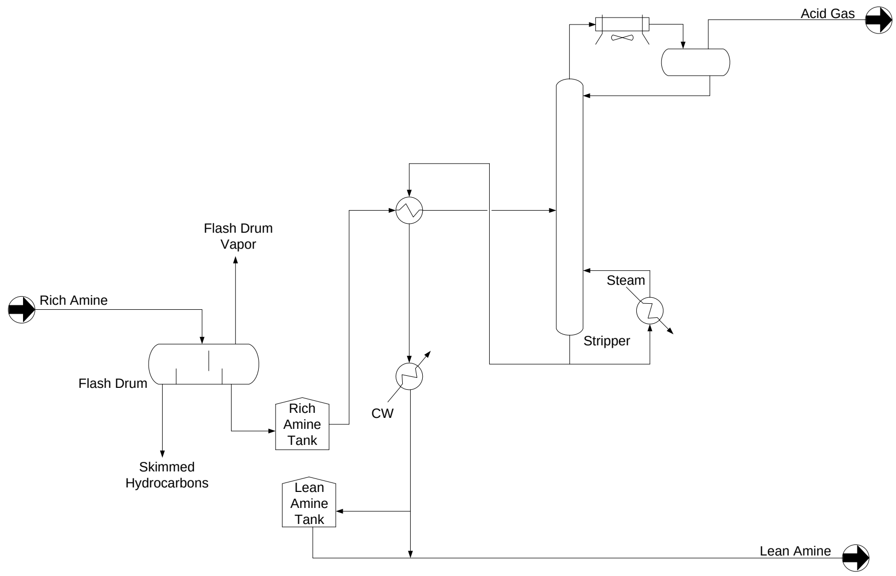


FIGURE 5-6
Amine Regeneration Unit

AMINE REGENERATION UNIT (FIGURE 5-6)

The Amine Regeneration Unit is used for regeneration of the amine solution used in amine contactors in various refinery process units. The Amine Regenerator is a liquid stripper column with a steam-heated reboiler. Mixed rich amine solutions are fed to the column yielding an overhead acid gas product that is routed to the Sulfur Recovery Unit as feed. The stripped amine bottoms liquid is cooled and filtered and then recycled back to a storage tank as lean amine for re-use in amine contactors.

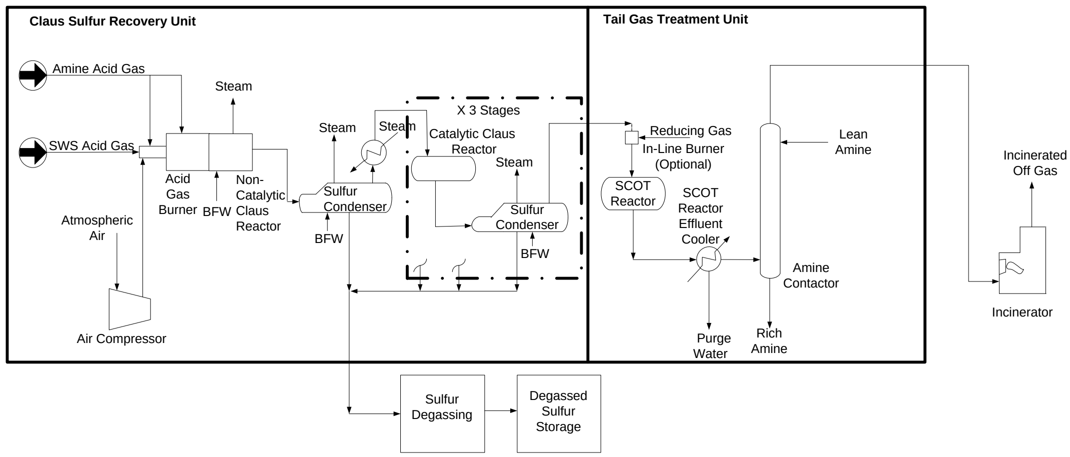


FIGURE 5-7
Sulfur Recovery Unit

SULFUR RECOVERY UNIT (FIGURE 5-7)

Sulfur is recovered from the acid gas streams from the refinery's Sour Water Stripper Unit and Amine Regeneration Unit. The Sulfur Recovery Unit will include a Claus reactor train, a tail gas treater, and a thermal oxidizer. The three-stage Claus reactor train together with the thermal reactor will convert approximately 97 percent of the H_2S in the acid gas feed to elemental sulfur. Each of the three reactor stages is followed by a condenser that cools, condenses, and removes the elemental sulfur. The molten sulfur flows through seal legs to a molten sulfur sump. The vapor from the last sulfur condenser then flows to the tail gas treater. The tail gas treater will recover additional sulfur compounds from the Claus reactor tail gas and recycle them back to the inlet of the Claus reactors. Overall, the Claus reactors and tail gas treater combination will convert more than 99.9 percent of the H_2S in the sulfur plant feed to elemental sulfur. In the tail gas treater, effluent from the Claus reactor train is combined with hydrogen or natural gas before passing through a reducing reactor and a catalytic hydrogenation reactor in series. The gas exiting the catalytic hydrogenation reactor is then routed to an amine absorber column to scrub H_2S from the gas. The overhead stream from the amine absorber column is routed to a thermal oxidizer for safe disposal of unrecovered sulfur compounds. The rich amine solution is sent to the Amine Regeneration Unit. In the Claus sulfur sumps, residual H_2S is removed from the molten sulfur through a degassing process before the sulfur is pumped into storage tanks.

HYDROGEN PLANT (FIGURE 5-8)

The Hydrogen Plant produces high-pressure, high-purity hydrogen to supply the Distillate Hydrotreater and the Hydrocracker units. Natural gas feedstock is preheated and then hydrotreated to convert sulfur contaminants to H_2S. The feed then flows through zinc oxide beds which removes the H_2S. The desulfurized feed is mixed with superheated process steam and fed to the catalyst tubes of the reformer furnace. The outlet process gas contains primarily hydrogen, carbon monoxide (CO), and carbon dioxide (CO_2). The overall reaction is endothermic, requiring heat supplied by the furnace. The vent gas from the PSA system meets most of the furnace fuel demand, supplemented by refinery fuel gas. Medium-pressure steam is a byproduct of the Hydrogen Plant, produced from the waste heat steam generator. The reformer exit process gas is cooled and then fed to the shift converter, which converts CO to hydrogen and CO_2. The gas is further cooled and sent to the PSA purification system. High-purity hydrogen is sent to the Distillate Hydrotreater and the Hydrocracker units. The PSA offgas is collected in the vent drum and used as fuel for the reformer furnace.

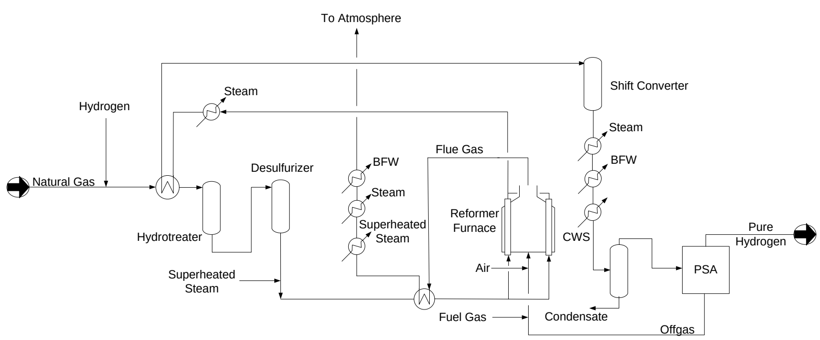


FIGURE 5-8
Hydrogen Plant

UTILITY BALANCES

A preliminary utility summary is presented in Table 5-1. Major utilities needed to support the refinery operation include electricity, fuel, steam, condensate, boiler feed water, fresh water, cooling water, and compressed air. The rates were derived by factoring off the design rates of similar facilities.

TABLE 5 - 1

Preliminary Utility Summary - New Refinery Feasibility Study

Normal + Intermittent Utilities Requirements

Unit	Power Operating	Power Connected	HP 600# consumed (gen)	MP 300# consumed (gen)	LP 50# consumed (gen)	BFW	Well Water	Strppd SWS Water		Condensate consumed (gen) Hot	Condensate consumed (gen) Cold	Sour Water to SWS		Desalter Brine	Other Loss	Stm Gen Blow Down	Cooling Water	Cooling Water Duty	Fired Fuel
								Non-phenolic	Phenolic			Non-phenolic	Phenolic						
	kW	kW	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	gpm	MM Btu/hr	MM Btu/hr
Crude and Vac Unit	1,479	3,203	0	17,757	(17,784)	18,674	0	7,172	17,547	(8,465)	0	(12,132)	0	(21,878)	0	(889)	1,318	15	97
Saturates De-ethanizer	1	3	0	0	1,069	0	0	0	0	(1,069)	0	0	0	0	0	0	93	1	0
Saturates LPG Merox	14	34	0	0	58	0	0	0	0	(58)	0	0	0	0	0	0	10	0.1	0
Saturates C3/C4 Splitter	5	15	0	0	1,817	0	0	0	0	(1,817)	0	0	0	0	0	0	132	2	0
Distillate Hydrotreater Unit	1,071	2,078	0	6,426	(9,471)	7,162	0	0	0	818	0	0	(4,610)	0	0	(325)	238	3	16
Hydrocracker Rxn Section	1,114	1,943	(5,376)	8,000	(229)	22,283	0	0	0	0	(21,913)	0	0	0	(2,000)	(765)	131	2	13
Hydrocracker Frac Section	563	1,089	0	4,576	(1,733)	0	0	0	0	9,906	0	0	(12,749)	0	0	0	237	4	52
H2 Plant	204	373	0	(13,438)	0	40,447	0	0	0	0	0	0	0	0	0	(1,926)	53	0.5	129
Amine Regeneration Unit	111	270	0	0	4,923	0	0	0	0	(4,923)	0	0	0	0	0	0	42	1	0
Sour Water Stripper Unit	54	86	0	0	8,421	0	0	0	0	(8,421)	0			0	0	0	0	0	0
SRU/TGTU Unit	161	212	(2,408)	0	(2)	3,611	0	0	0	(1,085)	0	0	(188)	0	(44)	(72)	91	1	1
Flare System	6	15	0	424	0	0	0	0	0	0	0	0	0	0	(424)	0	0	0	2
Flare Gas Recovery	142	168	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	0
Sulfur Loading Facilities																			
Tank Farm	343	770	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Utility Boilers	19	300	(17,783)			18,672										(889)			25
BFW Deaerators	38	100			6,280					(6,280)									
Other Utilities Systems	1,177	1,767	0	0	8,475	0	51,641	0	0	(8,475)	0	0	0	0	(51,641)	0	0	0	0
Steam Letdown 600# to 300#			25,568	(25,568)															
Steam Letdown 300# to 50#				1,822	(1,822)														
Steam Letdown 50# to atmos					0										0				
Waste Water Treatment Plant	251	625										0	0						
Marine Terminal Allowance	0	0																	
Admin / Whhs Buildings	150	450																	
Total	6,904	13,499	0	0	0	110,849	51,641	7,172	17,547	(29,868)	(21,913)	(12,132)	(17,547)	(21,878)	(54,108)	(4,867)	2,397	28	335

Steam Boilers:

Normal	17,783	lb/hr
Design	2 x 30,000	lb/hr

Well Water Requirement	#/Hr	GPM
CT Evaporation Loss	34,427	69
CT BD & Windage Loss	17,214	34
Steam Generation BD	4,867 *	10 *
Desalter Brine	21,878 *	44 *
Excess Strp'd SWS Water	4,960 *	10 *
H2O Consumed in H2 Plants	25,084 *	50 *
	-	-
Total continuous WW req'd	108,430	217
*** Total BFW Makeup Req'd**	56,789	114

Refinery Fuel Balance	M.W.	LHV BTU/SCF	#/Hr	MMBTU/Hr
Refinery Fuel Gas Produced	8.55	587	2,964	77
H2 Plant PSA Offgas (Est'd)				113
Propane To Vaporizer	44.10	2315	2,161	43
IC4 to Vaporizer		19437 BTU/#	0	0
Excess NC4 to Vaporizer		19494 BTU/#	0	0
NG for fuel (Excl. H2 Plant Fd)	16.70	922.00	2.6 MMSCFD	102
Total Refinery Fuel Supply				335
Natural Gas to H2 Plant			8.4 MMSCFD	
Total Natural Gas Import			11.0 MMSCFD	

OSBL SYSTEM CONCEPTUAL DESIGN

AIR QUALITY

Flue gas will be continuously discharged from process fired heaters, tail gas incinerator, and utility boilers. Emissions from the flare will be minimized with the inclusion in the project design of a flare-gas recovery system. The quantity of major air pollutants, along with the methods and devices to reduce emissions, are discussed later in this section.

ELECTRICITY

Power is assumed to be imported. No on-site generator is included in the utility summary.

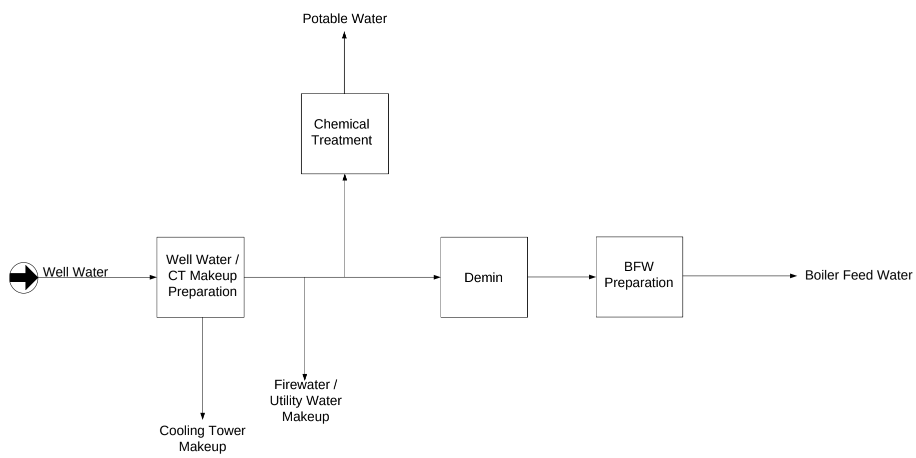


FIGURE 5-9
Water

WATER (FIGURE 5-9)

Fresh water supply is assumed to be well water. It is required for make-up to boiler feed water, cooling tower, wash water, potable water, and firewater systems. To minimize water consumption, air coolers usage will be maximized.

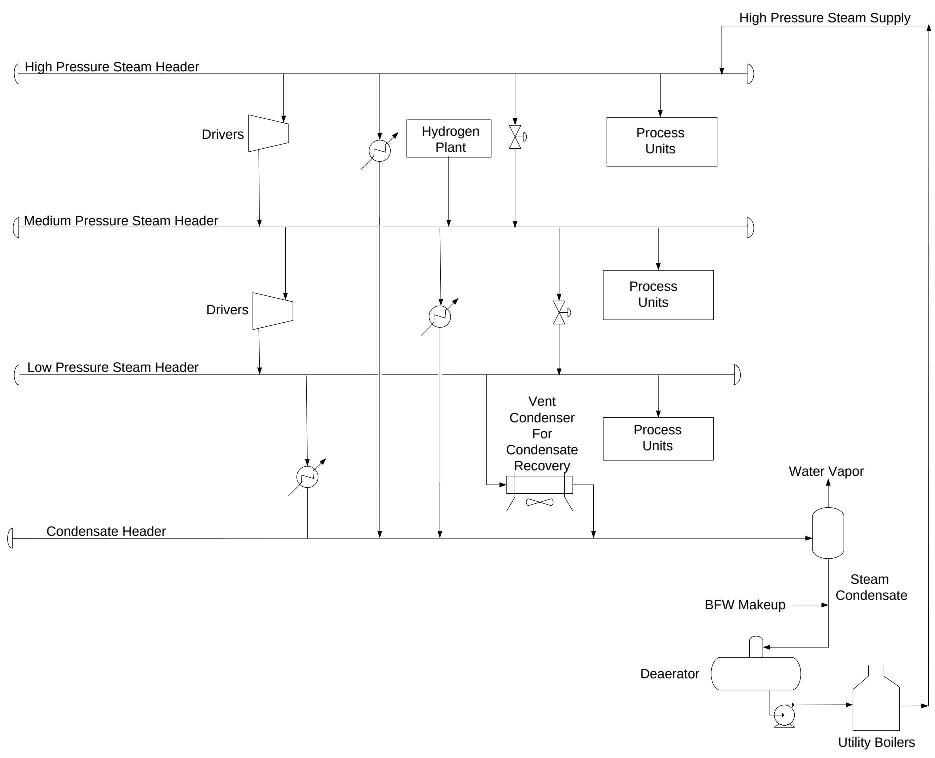


FIGURE 5-10
Steam

STEAM (FIGURE 5-10)

The steam system consists of high pressure (600 psig), medium pressure (300 psig), and low pressure (50 psig). High-pressure steam is generated in utility boilers. Medium and low pressure steam is produced via waste heat recovery in the process units; steam turbine drivers; and from pressure letdowns. Most of the steam condensate is recovered and deaerated before going to the boilers. A generous design factor is included in the basis for the utility boilers to cover the refinery start-up and shutdown cases.

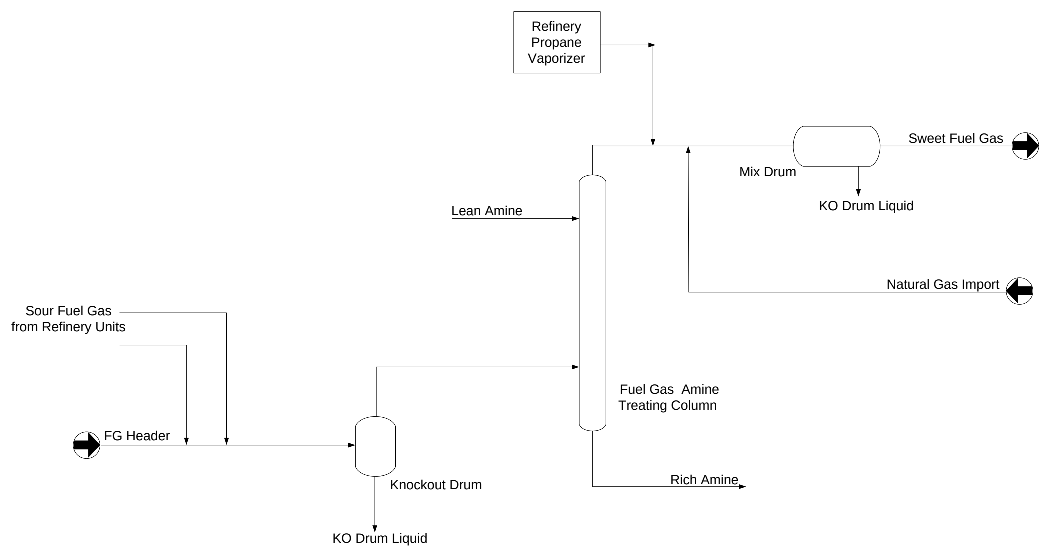


FIGURE 5-11
Fuel

FUEL (FIGURE 5-11)

Plant fuel includes fuel gas (mainly methane and ethane), LPG (propane), and imported natural gas. Sour fuel gas produced in process units will be scrubbed using amine to remove H_2S before going to the various refinery fired heaters via the refinery fuel gas mixing drum. In the current scheme, the refinery exports fuel oil. Based on future refinery economics, it may be desirable to specify burners capable of dual-fuel firing, especially for the utility boilers.

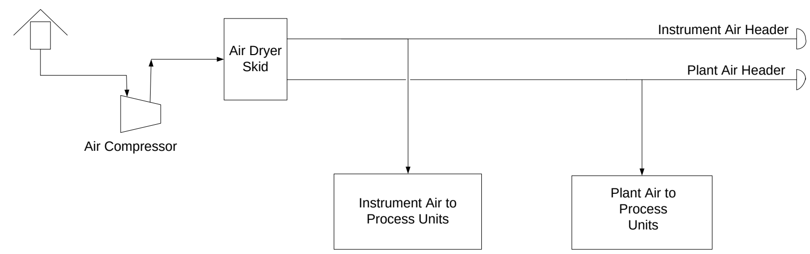


FIGURE 5-12
Air

AIR (FIGURE 5-12)

An instrument air system will be provided to supply compressed dry air for instrument uses. A design factor is included in the equipment basis to cover the intermittent utility air requirement. Because of the refinery location, utility air is dried to minimize freezing concerns.

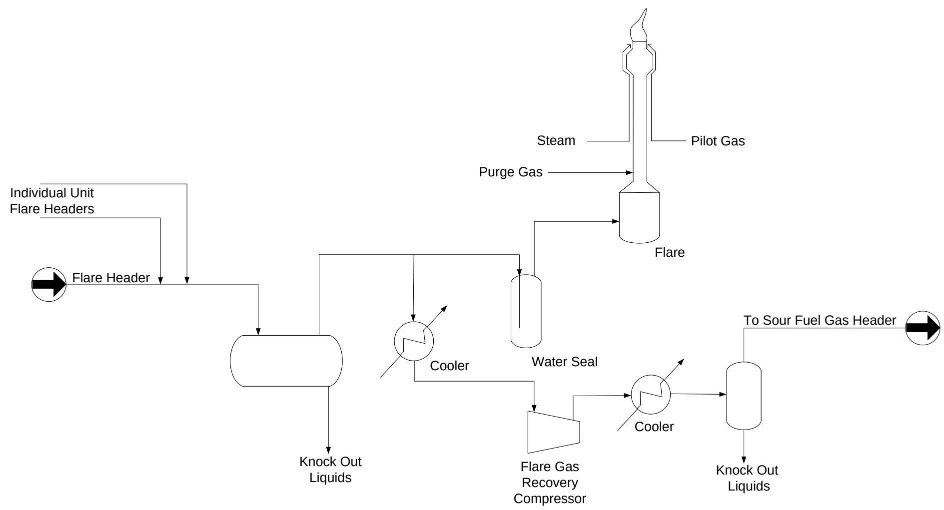


FIGURE 5-13
Flare

FLARE (FIGURE 5-13)

The refinery will have a pressure relief system that would contain non-routine hydrocarbon releases. In the event of process upset or sudden shutdown, the system will accept discharges from pressure relief devices and emergency depressurizing equipment throughout the refinery. The relief vapors will be combusted at the elevated flare and the combustion products safely discharged to the atmosphere.

Refinery fuel gas is purged up the flare stack to prevent air infiltration and is ignited at the top by a continuous pilot flame. Steam will be supplied to the flare tip to ensure smokeless operation. A knock-out drum and pumps will be provided to remove liquid from the stream before entering the flare stack. To minimize emissions, a flare gas recovery system is included in the design. Hydrocarbon vapor is compressed and routed to the sour fuel gas system rather than combusted at the flare tip.

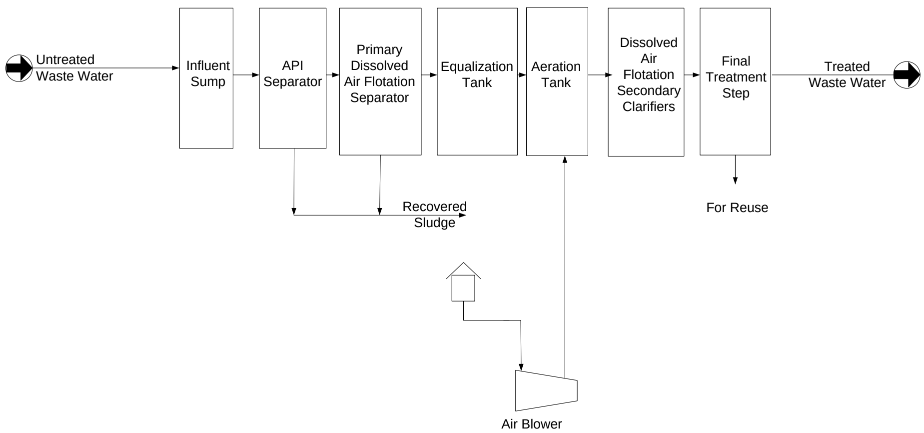


FIGURE 5-14
Waste Water

WASTE WATER (FIGURE 5-14)

The wastewater treatment plant (WWTP) is designed, in conjunction with the overall water balance, to minimize water consumption and to maximize water recycle and reuse. In general, the dissolved solids content of the various process water discharge streams is used as a guide to assess its suitability for use as makeup water to other processes. For example, stripped sour water, having low dissolved solids content, will be used as makeup water to the desalter in the Crude Unit. A preliminary design basis for the WWTP is shown in Table 5-2.

TABLE 5 - 2

Preliminary Waste Water Production Summary

Waste Water Sources	Cont./ Intrmttnt C / I	Rate Basis Design Load	Rate Basis Load Unit	Est. Flow Rate LB/Hr	Est. Flow Rate GPM	Remarks
Refinery						
Crude Unit Desalter Brine	C	5	LV% of Oil	21,878	44	With 500 - 1500wppm of insoluble floatable oil
From Sour Water Stripper	C			4,960	10	Excess stripped SWS water
Cooling Tower Blowdown	C	3	Cycles	17,064	34	Based on concentration cycle of 3 and evaporation rate of 2.3 %.
BFW blowdown	C	5%	Stm Make	4,867	10	
Tank Water Draw (Allowance)	I			37,500	75	Assume 4" nozzle in full crude tank full open draining to closed drain system
Closed and Open Drain System (Allowance)	I			37,500	75	Assume one unit max pumping from ISBL sump to WWTP any given time
Spent Caustic from Merox, Penex, etc.						Assume this is trucked out of refinery
Stormwater processing (Allowance)	I			47,622	95	Note 1
Continuous Feed to WWTP Total				**48,769**	**98**	
Continuous + Intermittent to WWTP Total				**171,391**	**343**	

NOTES:
1. The first 1 inch of rainwater in process area will be processed in WWTP, working off the volume in one week.
Stormwater after the first 1 inch in process area and outside process area will be collected in the check pond and released to the natural waterways after the refinery determines the water is clean.
Process area ~ 700' x 2200' (includes future process areas)

Segregating clean storm water from the oily process wastewater is essential to minimizing the contaminated wastewater requiring treatment. The first one inch of rainwater in process/paved areas is assumed to be contaminated and will be collected in tanks. An allowance in the WWTP design is included to work off this water within one week. Storm water after the first one inch inside process/paved areas and outside process areas is collected in an impoundment basin for testing. Clean storm water could be recycled as makeup water or discharged through a permitted outfall.

The WWTP facilities include wastewater collection, primary treatment, secondary treatment, final treatment, sludge treatment and sludge dewatering. Primary treatment is used to remove free oil and suspended solids prior to the secondary treatment. Secondary biological treatment is used to remove dissolved organic materials. Final treatment may include denitrification filters or a polishing filtration system. Belt filter presses are used to reduce water content in primary and secondary sewage sludges prior to offsite transfer or disposal.

TANK FARM

The Tank Farm will consist of above-ground cylindrical storage tanks for hydrocarbons, specialty chemicals, and water and pressurized storage vessels (i.e. spheres). The hydrocarbon storage tanks and pressurized vessels are used for storing crude oil, intermediates, and finished products. Internal floating roof tanks are used for volatile services, while fixed cone roof tanks are used for low-volatility petroleum liquids. The pressurized vessels are used for storing high vapor pressure materials such as propane and butanes. Table 5-3 contains a preliminary tank list for the refinery.

TABLE 5 - 3

PRELIMINARY TANK LIST

Description	Notes 20,22 Vap Press at Stg Temp psia	Note 22 Stg Temp °F	Base Tank Type: Fixed Roof Type	Floating Roof Type	Vapor Recov	Qnty	Diameter ft	Tank Height or Length ft	Heel + Free board ft	From LLL to HLL ft	Total Nominal Volume of Storage Barrels	Total Working Volume Of Storage Barrels	Rate BPD	Days Cap Rqrd days	Days Invtry days	Insulated	Hting Rqrd	Epoxy Lined		Turnovers per year
Refinery Feeds																				
Crude	6	90	-	Double Deck	No	2	130	48	9	39	226,965	184,409	34,000	5	5.4	No	No	Yes	Epoxy line floor and bottom 8' of the shell (corrosion b/c of water)	67
Total Refinery Feeds						**2**					**226,965**	**184,409**	**34,000**		**5.4**					
Refinery Products																				
Mixed LPG	130	90	Sphere	-	-	2	46			46	18,156	18,156	2,000	4	9.1	No	No	No		
Naphtha	~14	90	Cone	Pipe Pontoon	N	3	75	48	9	39	113,314	92,068	15,000	6	6.1	No	No	No		59
Jet Rundown	~0.04	90	Cone	-	N	1	45	48	9	39	13,598	11,048	1,500	6	7.4	No	No	No		50
ULSK / Jet Export	~0.04	90	Cone	-	N	2	45	48	9	39	27,195	22,096	1,500	13	14.7	No	No	No		25
Diesel Rundown	<0.01	90	Cone	-	N	1	100	48	9	39	67,149	54,559	16,000	3	3.4	No	No	No		107
ULS Diesel Export	<0.01	90	Cone	-	N	3	70	48	9	39	98,709	80,201	16,000	5	5.0	No	No	No		73
Fuel Oil	~0.02	150	Cone	-	N	2	40	48	9	39	21,488	17,459	2,000	8	8.7	Yes	Yes	No		42
Total Refinery Products						**14**					**359,610**	**295,587**	**36,500**		**8.1**					
Intermediate Products																				
SR Disillates (To DHDS)	~0.04	90	Cone	N2 Pad	N	2	65	48	9	39	56,741	46,102	11,300	3	4.1	No	No	No	Note 27	89
AGO / VGO (To HC)	~0.02	150	Cone	N2 Pad	N	2	55	48	9	39	40,625	33,008	9,500	3	3.5	Yes	Yes	No	Note 27	105
Total Refinery Intermediate Products						**4**					**97,366**	**79,110**	**22,800**		**3.5**					
Support Systems Tanks																				
Slop	~12	90	-	Annular Pont	N	2	80	48	9	39	85,951	69,835	34,000	2	2.1	Yes	Yes	Yes		50
Stormwater Surge (Note 24)	~12	90	-	Annular Pont	N	2	60	48	9	39	48,347	39,282	22,859		1.7	Yes	Yes	Yes	1" rain in process area + allowance	24
Caustic (Fresh)	0.7	90	Cone	-	N	1	20	40	4	36	2,238	2,014	1,786		1.1	Yes	Yes	No	Note 14	30
Amine (Lean)	0.7	90	Cone	N2 Pad	N	1	55	48	5	43	20,313	18,197	2,400	7	7.58	Yes	Yes	No	Note 27	12
Fire Water + well water hold up	0.7	90	Cone	-	N	2	300	48	5	43	1,208,687	1,082,782	840,000		1.29	Yes	Yes	Yes	Note 12	1
BFW Make-Up	0.7	90	Cone	-	N	2	90	48	5	43	108,782	97,450	15,000		6.50	Yes	Yes	Yes		56
Potable Water	0.7	90	Cone	-	N	1	35	40	3	37	6,855	6,341	5,000		1.27	Yes	Yes	Yes	Assumed only	288
Molten Sulfur	-	280	Cone	-	Y	2	30	40	3	37	10,072	9,317	653	10	14.27	Yes	Yes	No		26
Total Support Systems Tanks						**13**					**1,491,246**	**1,325,219**								

NOTES:
1) Consider taller tanks. An economical height for a floating roof tank for capacities up to 200,000 barrels is generally 8 feet higher than for a fixed roof tank of the same capacity. This is due to the higher unit cost of the floating roof in comparison to shell costs. For capacities over 200,000 t the economical height is generally 56 to 64 ft. The maximum allowable tank height is governed by the maximum allowable soil loading. Soil borings are required to predict maximum allowable soil loading.
6) Excludes tankage required by waste water treatment plant.
10) Basis for heating: A) All water tanks to be heated and insulated. B) All hydrocarbon tanks with pour point <90 to be heated and insulated. C) May need to consider external steam heaters with forced circulation for VGO and VTB.
11) Basis for epoxy liner: All water services and only water portion of HC services to be epoxy lined.
12) Well water is stored in same tank as fire water. Total storage = 11,000 gpm for 8 hours + 5 mmgalpd x 6 days
14) 25°Ba Caustic assumed diluted in unit. A 25,000 gal tank car is 595 bbl so assume working tankage of 3 tank cars.
18) Pipe pontoons are fabricated from aluminum.
20) Tank Contents vapor pressures are approximate and conservatively estimated. These should be re-verified in the next phase of engineering.
22) Vapor pressure of tanks with a variation in HC content and composition is set at ~12 psia to assume the lightest of the product/intermediate streams in the refinery.
22) The storage temperature of 90°F corresponds to the maximum ambient temperature in the summer time. Any product streams which run down to the tanks cool down to the ambient temperature.
23) Throughput is calculated by dividing the product rate by the number of tanks. It is an average throughput for the tanks in a given service.
24) Stormwater after the first 1 inch inside process area and outside of process areas is collected in the check pond and released to the natural waterways after the refinery determines the water is clean.
27) Tank padded to keep oxygen out of the feedstream to process unit.

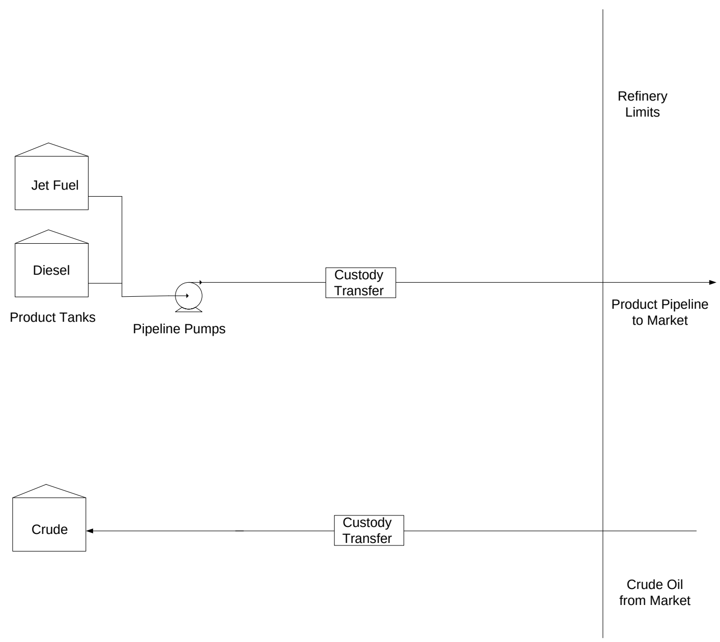


FIGURE 5-15
Product Loading - Pipeline

PRODUCT LOADING (FIGURES 15 &16)

The crude oil supply is by pipeline. Jet and diesel products will be shipped via pipelines. Naphtha will be shipped to the Canadian market by rail. LPG and fuel oil will be shipped offsite by rail cars. The refinery will also include a rail car loading rack for molten sulfur product. Liquid product loading racks will be designed for complete capture and maximum recovery of displaced hydrocarbon vapors using vacuum-regenerated, carbon adsorption-based vapor recovery technology. Provisions are included in the plot plan for a separate truck loading terminal to support local markets.

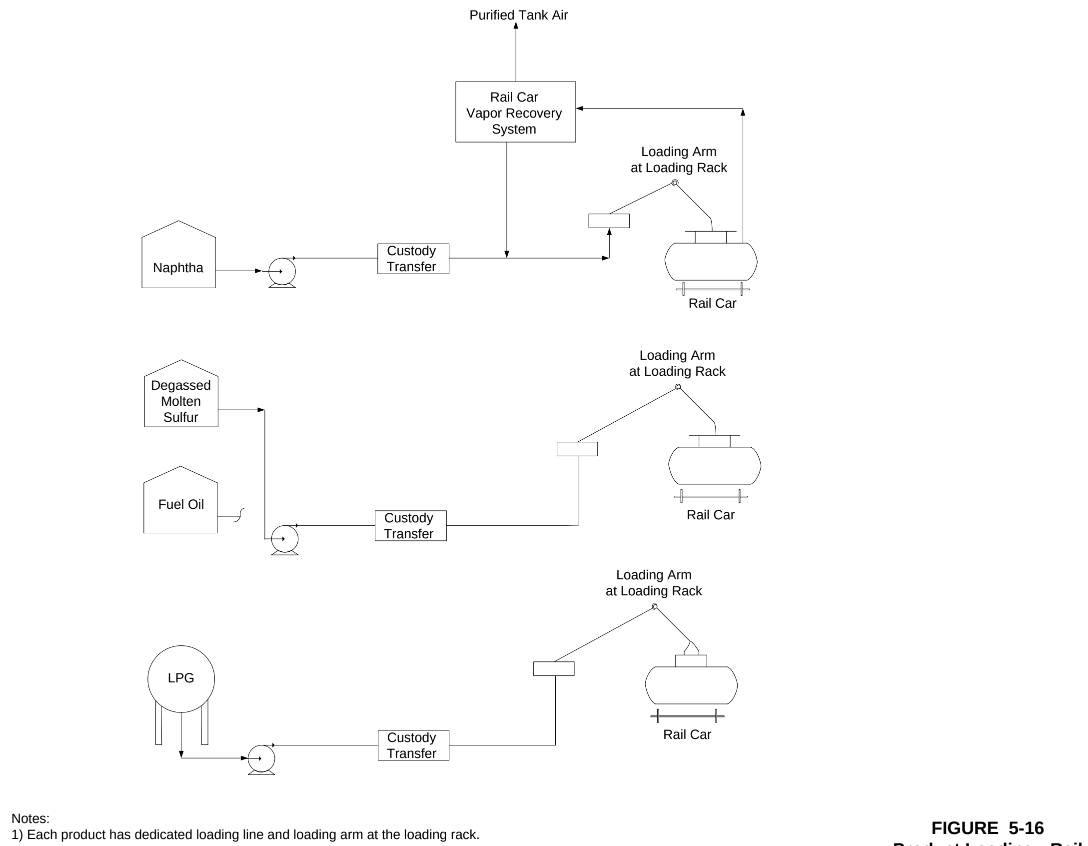


FIGURE 5-16
Product Loading - Rail

EMERGENCY EQUIPMENT

The refinery will have two diesel-powered emergency firewater pumps. The pumps will supply firewater in the event that the main water supply system is inoperative, so they are expected to be operated infrequently, with much of the operation being routine testing. The engines will fire diesel fuel with sulfur content of no more than 15 parts per million by weight (wppm).

EMISSIONS ANALYSIS

ESTIMATES

Table 5-4 presents a preliminary summary of pollutant emission rates from all emission sources at the refinery. Annual emissions are calculated assuming the hourly emission rate for 8,760 hours per year. All equipment will be designed to meet US Environmental Protection Agency air emissions standards. Calculation methodologies and assumptions are discussed in Section below.

Table 5 – 4
Preliminary Summary of Potential Emissions

Pollutant	Heaters, Thermal Oxidizer, and Flare	Tanks	Product Loading	WTP	Cooling Tower	Equipment Leak	Emergency Equipment	Total(tpy)
Carbon Monoxide (CO)	99.1						0.4	99.5
Nitrogen Oxides (NOx)	80.4						0.8	81.2
PM-10	16.6				0.1		0.0	16.7
Sulfur Dioxide (SO_2)	23.0						0.0	23.0
VOC	13.5	1.6	0.1	6.9	0.6	11.4	0.0	54.1
Hydrogen Sulfide (H_2S)	1.3					0.4		1.7

SOURCES

Emissions of pollutants from process heaters are calculated as the product of the design heat input capacity, expressed in MMBtu/hr, and an emission factor, expressed in lb/MMBtu heat input. Assumed emission control technologies include low-NOx burners, amine treating of refinery gas, low sulfur fuel, and good combustion control.

The recommended emission control technology for the flare is a flare gas recovery system. Emissions for the flare stack are based on the fired duty from continuous pilot operation and stack purge gas. Emission factors for some pollutants are different than process heaters due to burner design and level of combustion control.

Emissions of SO_2 and H_2S from the thermal oxidizer in the Sulfur Recovery Plant are based on 99.97% sulfur recovery. Emission factor for other pollutants are similar to process heaters and flare.

Emissions from organic liquid storage tanks are calculated using U.S. EPA's "TANKS 4.09" software, which uses the emission factor equations from AP-42 Chapter 7. To address H_2S emissions from the sulfur tanks, the recommended control technology is to degas the sulfur to maximum 15 wppm H_2S prior to storage.

For the naphtha rail loading racks, a vacuum-regenerated, carbon adsorption-based vapor recovery system is included to comply with a VOC emission limit of 1.25 lb VOC/million gallons of product loaded.

Emissions from the wastewater treatment plant are calculated using U.S. EPA's "WATER9" software.

Emissions from the cooling tower will include particulate matter, due to the dissolved solids content of aerosol drift from the tower, and VOC from evaporation of organic compounds that may be present in cooling water due to leaks in indirect contact heat exchangers. Continuous monitoring will be used to detect any such leaks, so as to provide for timely repair.

Emissions of VOC and H_2S from equipment leaks are calculated using the "EPA Correlation Approach" in the U.S. EPA document, *Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017). Annual emissions are based on the conservative assumption that 0.3 percent of valves and connectors in gas/vapor service and light liquid service are leakers, and 99.7 percent are non-leakers. For all other component types, 1 percent are assumed to be leakers and 99 percent non-leakers. Each leaking component, regardless of type and service, was conservatively assumed to be emitting at 10,000 vppm concentration. Ninety-nine percent of compressors, 30 percent of pumps in light hydrocarbon service, and one percent of all other component types were conservatively assumed to be emitting at an equivalent concentration equal to that at which they would be considered leakers. All remaining components were assumed to be emitting at the default zero emission rate.

Emissions of pollutants from internal combustion engines are calculated by multiplying the kilowatts (kW) and emission factors, in grams per kW-hour (g/kWh). Each internal combustion engine is proposed to operate the equivalent of 100 hours per year.

SITE PLAN – CONCEPTUAL DESIGN

PRELIMINARY LAYOUT

A conceptual plot plan for the refinery is included below. The location is assumed to be adjacent to a highway and a rail line is nearby for local and regional product transportation.

OVERALL LAND REQUIREMENTS

Approximately 200 acres are required for the project providing they are obtained in a continuous arrangement. Right-of-way for rail spur to the refinery is not included.

FUTURE EXPANSION

The conceptual plot on 200 acres allows for 30% future development of process, utility, and storage facilities.

BUFFER ZONES

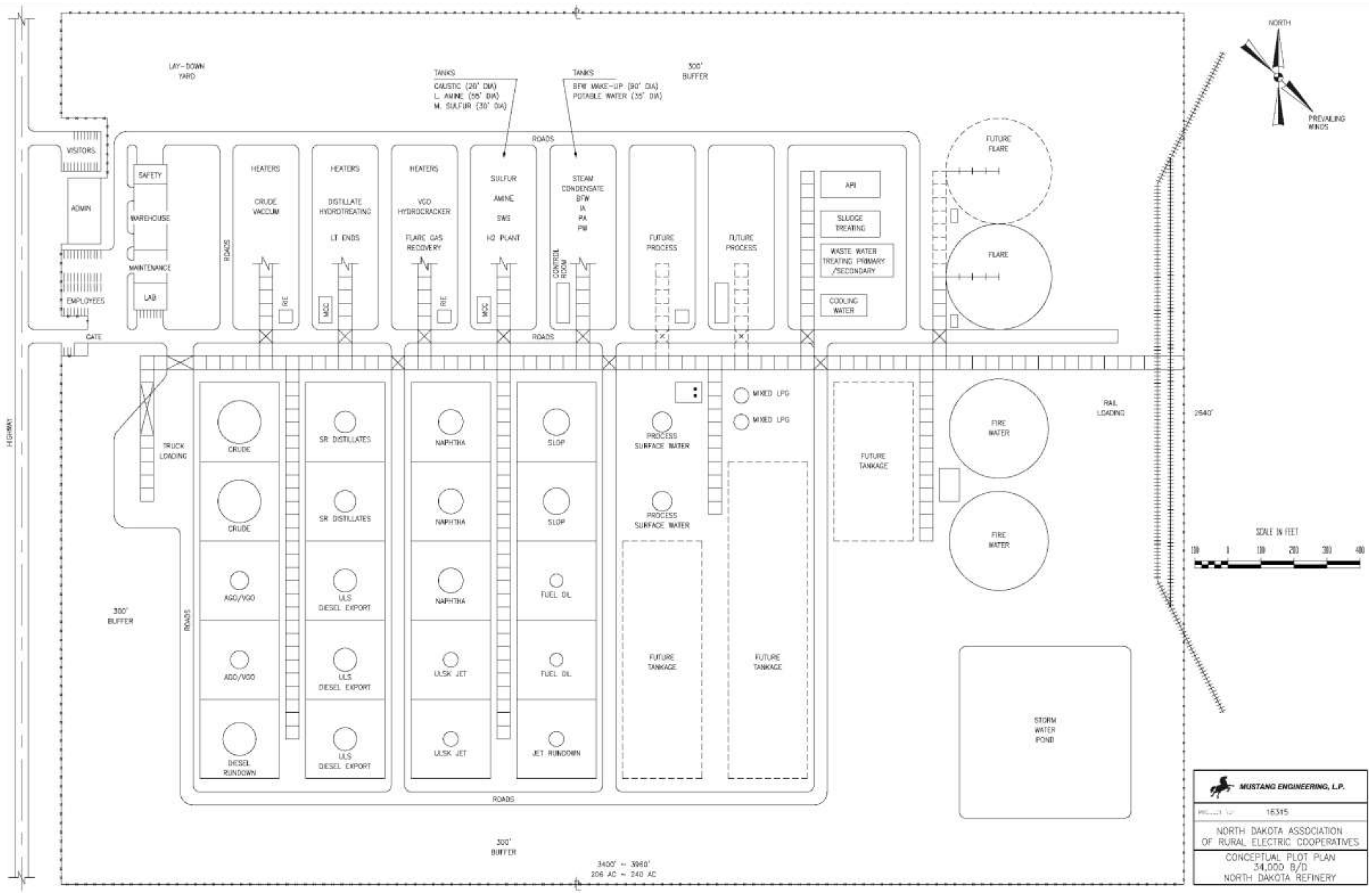
There are allowances for 300-foot buffer zones along the frontage road and adjacent properties.

ROADS

Fifty feet is provided between units and tankage limits for 20-foot wide roads with five-foot shoulders and ten-foot storm water ditches.

CODE AND STANDARD SPACING

The spacing between and within process units is based on Industrial Risk Insurers (IRI) oil and chemical plant spacing. Heaters are located at the north end of the process areas upwind of the equipment.



LAY-DOWN YARD
TANKS
CAUSTIC (20' DIA)
L. AMINE (55' DIA)
M. SULFUR (30' DIA)
TANKS
BFW MAKE-UP (90' DIA)
POTABLE WATER (35' DIA)
300' BUFFER
NORTH
PREVAILING WINDS
ROADS
VISITORS
ADMIN
SAFETY
WAREHOUSE
MAINTENANCE
LAB
EMPLOYEES
GATE
HEATERS
CRUDE VACCUM
HEATERS
DISTILLATE HYDROTREATING
LT ENDS
HEATERS
VGO HYDROCRACKER
FLARE GAS RECOVERY
SULFUR
AMINE
SWS
H2 PLANT
STEAM CONDENSATE
BFW
IA
PA
PW
CONTROL ROOM
FUTURE PROCESS
FUTURE PROCESS
API
SLUDGE TREATING
WASTE WATER TREATING PRIMARY /SECONDARY
COOLING WATER
FUTURE FLARE
FLARE
RIE
MCC
HIGHWAY
TRUCK LOADING
CRUDE
CRUDE
AGO/VGO
AGO/VGO
DIESEL RUNDOWN
SR DISTILLATES
SR DISTILLATES
ULS DIESEL EXPORT
ULS DIESEL EXPORT
ULS DIESEL EXPORT
NAPHTHA
NAPHTHA
NAPHTHA
ULSK JET
ULSK JET
SLOP
SLOP
FUEL OIL
FUEL OIL
JET RUNDOWN
MIXED LPG
MIXED LPG
PROCESS SURFACE WATER
PROCESS SURFACE WATER
FUTURE TANKAGE
FUTURE TANKAGE
FUTURE TANKAGE
FIRE WATER
FIRE WATER
RAIL LOADING
2640'
SCALE IN FEET
100 0 100 200 300 400
STORM WATER POND
300' BUFFER
300' BUFFER
3400' ~ 3960'
206 AC ~ 240 AC
MUSTANG ENGINEERING, L.P.
16315
NORTH DAKOTA ASSOCIATION OF RURAL ELECTRIC COOPERATIVES
CONCEPTUAL PLOT PLAN
34,000 B/D
NORTH DAKOTA REFINERY

VI. SITE SELECTION CRITERIA

Site selection is a fundamental decision for a project. Transportation costs have a direct influence on the revenues generated by a refinery. In the financial risk analysis of this project, improvement of the contribution margin, which is directly related to revenues, had the largest potential for improving the project return. The products from the most feasible refinery are limited to primarily naphtha and diesel fuel. The transportation options for naphtha are limited at this time to a specific pipeline and rail road options. The market for naphtha is also limited to Western Canada. The other primary product is diesel fuel with its market being North Dakota. Optimization of the refinery location relative to these products and the existing crude transportation infrastructure should be a primary consideration.

This refinery will require a relatively large skilled labor force. Labor costs make up over 50% of the total operating cost. Locating the refinery in a place that can attract and maintain the required skilled labor at a competitive labor cost is another important consideration.

The availability of fuel and electricity are also primary considerations. This study assumes that electricity and natural gas will be imported. The costs for these utilities are a primary expense and are directly related to the contribution margin so obtaining these at competitive rates is fundamental to the success of a project. Capital cost reduction has the second largest potential for improving the project returns according to the risk analysis. Therefore, the cost for providing the infrastructure for these utilities is an important consideration.

Another fundamental requirement is the availability of water at a competitive unit cost and economic capital cost. This study assumes that water will be obtained from a well. Water is a natural resource and will likely have competing interests, along with federal and state regulations that will place limitations on the resource.

The availability and cost of the land required for the facility is another important consideration. In addition, the proximity to national parks, communities, natural resources, population centers, and other industries are items that must to be carefully considered. These considerations will become apparent during the zoning and permitting process if not considered during the site selection process. These issues should be thoroughly explored prior to selecting a site.

As well as items that directly affect the cost of operating the refinery and/or may be a significant capital cost, there are a variety of other considerations that should be evaluated such as ongoing technical and mechanical support, and other goods and services required by routine facility operations.

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VII. BENEFITS TO NORTH DAKOTA

The state of North Dakota would benefit from increased economic activity, due to both direct and secondary effects associated with the construction and ongoing operation of a new refinery.

The effects of additional refinery capacity on upstream components of the petroleum industry in North Dakota are limited to the extent there is a reduction in crude oil discounts and as result there is an increase in production revenue. In the Phase I market analysis it was determined that a 50,000 BPD refinery's impact on crude pricing would be approximately a $4 per barrel increase in the netback price of crude oil from start-up in 2015 until 2020 The 20,000 BPD case would have a $4 per barrel increase starting in 2017 ending in 2020. In both cases the benefit would disappear due to additional pipeline capacity and the elimination of rail transportation discounts estimated to occur in 2020. The benefit to North Dakota from the 34,000 BPD refinery would be for a period of 3-5 years. This period of increased crude netback prices would positively contribute to increases in severance taxes and royalty payments which are based on gross revenues of the crude producer. There will also be some economic activity associated with transportation of crude to the new refinery. Depending on the location of the refinery, part of the benefit from increased crude netback prices may be reduced to cover the cost for transportation of the crude to the refinery.

New refinery capacity would result in additional direct employment in petroleum processing plus addition secondary jobs to support the new business. The 34,000 BPD refinery option presented in this study would provide employment for an estimated 75 operations personnel with an average salary of $80,000 and 80 maintenance positions with an average salary of $75,000. In addition, 55 professional and administrative jobs with an average salary of $85,000 would be created. The personal income from these jobs is estimated to be about $16.6 million per year. In addition to these direct positions, there would be an associated volume of new business activity. This activity will result from new business required to provide goods and services to the refinery plus increased economic activity resulting from the spending of this new personal income.

The 34,000 BPD refinery will introduce an additional 16,000 BPD of diesel fuel into the local market and reduce diesel fuel transfers into the state. This new local production will require adjustment in the existing distribution infrastructure and provide new opportunities for the marketing of diesel fuel.

Additional diesel fuel supply in North Dakota could reduce the rack price for diesel. In addition, because of incremental local production of diesel fuel originating in North Dakota, there is potential for fuel supply disruptions to be reduced. These benefits must be balanced against the impact to existing refiners who would face challenges from additional product supply in the region..

During construction of the refinery an estimated $220-250 million of the capital cost could be paid for labor and some local fabrication work. This money will cover workers' salary, a portion of which will go for state taxes and another portion will be spent in the local communities for subsistence of the labor force during the 3-year construction period.

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VIII. PROJECT INCENTIVES AND BARRIERS

This section of the report is intended to outline ideas that may increase the economic return of a project. The sensitivity analysis performed in Phase II of this study identified the contribution margin and the capital cost as the two variables with the largest potential impact on project returns.

The largest opportunity for reducing capital cost would be to expand an existing refinery instead of building a "grass roots" facility which was the basis of this study. An existing refinery may be able to reduce investment in the outside battery limit (OSBL) and infrastructure expenditures by fully utilizing and/or expanding existing facilities rather than by building new equipment.

Another option that should be explored to reduce capital costs would be to evaluate extensive modular construction opportunities due to the relatively small size of this refinery. However, this type of construction would likely take place in another location where the expertise exists, reducing the work done in ND and the economic benefits. Exploring the potential for obtaining, relocating and installing existing process equipment as an alternative to purchasing new equipment may reduce capital costs and improve the overall schedule

The study was based on a generic North Dakota location. Based on the selection criteria the next phase of project development would consider more specific site advantages and disadvantage including logistical costs. By selecting a specific location, the contribution margin may change due to optimization of logistical cost.

The financial analysis was done assuming that the sponsor would invest its own capital to pay for the construction of the refinery. The returns from the study are based on this equity finance model. Sponsors generally set return on investment guidelines that must be met before they will invest their capital in a project. Depending on the sponsor's cost of capital and other strategic objectives, a project must meet a minimum level of return on investment. An investment that has a higher internal rate of return (IRR) than the minimum level of return will add value to the company.

If the sponsor were able to borrow money at a lower interest rate than the cost of equity then the cost to finance a project would be less and may show a higher IRR on the equity portion of the project. Opportunities for debt financing of the project should be explored in an effort to improve the project return on investment. Due to the potential benefits to North Dakota, the potential to finance part of this project through one of the North Dakota trust funds could be an option.

North Dakota Refining Capacity Feasibility Study - Phase I Final Report

North Dakota Association of Rural Electric Cooperatives

April 23, 2010

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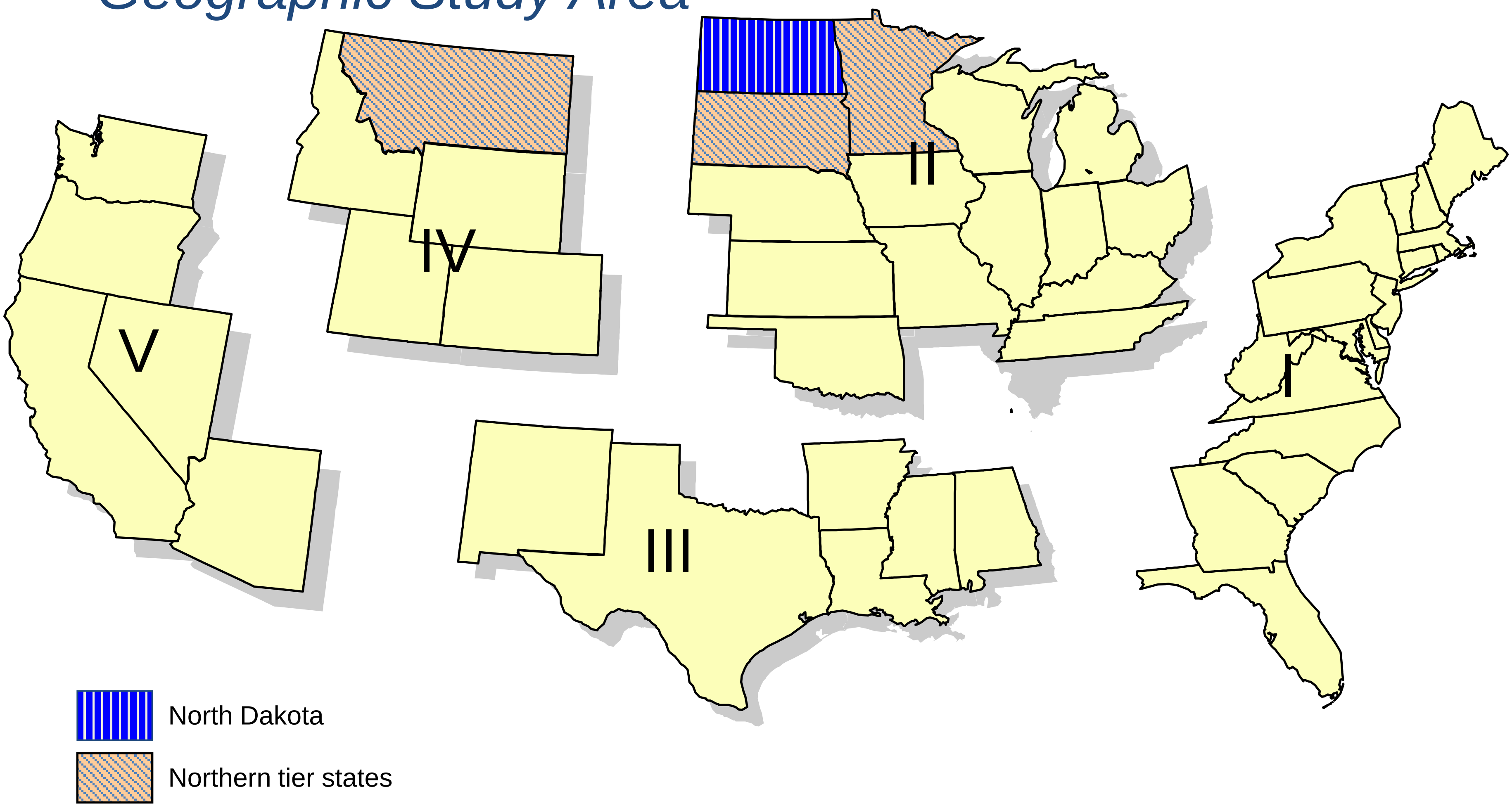
About this Report

This report was prepared by the Consultants under a contract with NDAREC, which received federal grant funds for the study.

This document and the analysis, opinions and conclusions expressed in this report reflect the reasonable efforts of the Consultants and NDAREC using information available at the time of the oil refinery study and within the resources and timeframe available for this study. Those reviewing this document or other documents related to the oil refinery study should recognize the *limitations of the study and understand that any predictions about the future are inherently uncertain due to events or combinations of events, including, without limitation, the actions of government or other entities or individuals. Neither the Consultants, nor NDAREC, or any of their employees, agents, task force members, advisory committee members, or any other representatives of these parties, make any express or implied warranties regarding the information, analysis, opinions, or conclusions contained in this document or other documents related to the oil refinery study, nor do they assume any legal liability or responsibility of any kind for the accuracy, completeness or usefulness of this document or the oil refinery study. No information contained in this document nor any other information released in conjunction with the oil refinery study shall be used in connection with any proxy, proxy statement or solicitation, prospectus, securities statement or similar document without the written consent of Consultants and NDAREC. Although this is a document available for use by the public, there are no intended third party beneficiaries of the agreement between Consultants and NDAREC for the performance of the oil refinery study.*

Light Refined Product Market Analysis

Geographic Study Area



PADD II Light Refined Product Balance

PADD II LIGHT REFINED PRODUCTS BALANCE, 2008
(Thousand Barrels per Day)

	Gasoline	Total Diesel	Jet / Kero
Supply			
Production	1,937	987	209
Imports	1	5	0
Net Receipts	593	249	74
Adjustments	21	0	0
Total	2,552	1,241	283
Disposition			
Demand	2,544	1,222	275
Exports	19	12	9
Stock Change	-13	7	-2
Total	2,550	1,241	282

Note: (1) Source: DOE Petroleum Supply Annual 2008

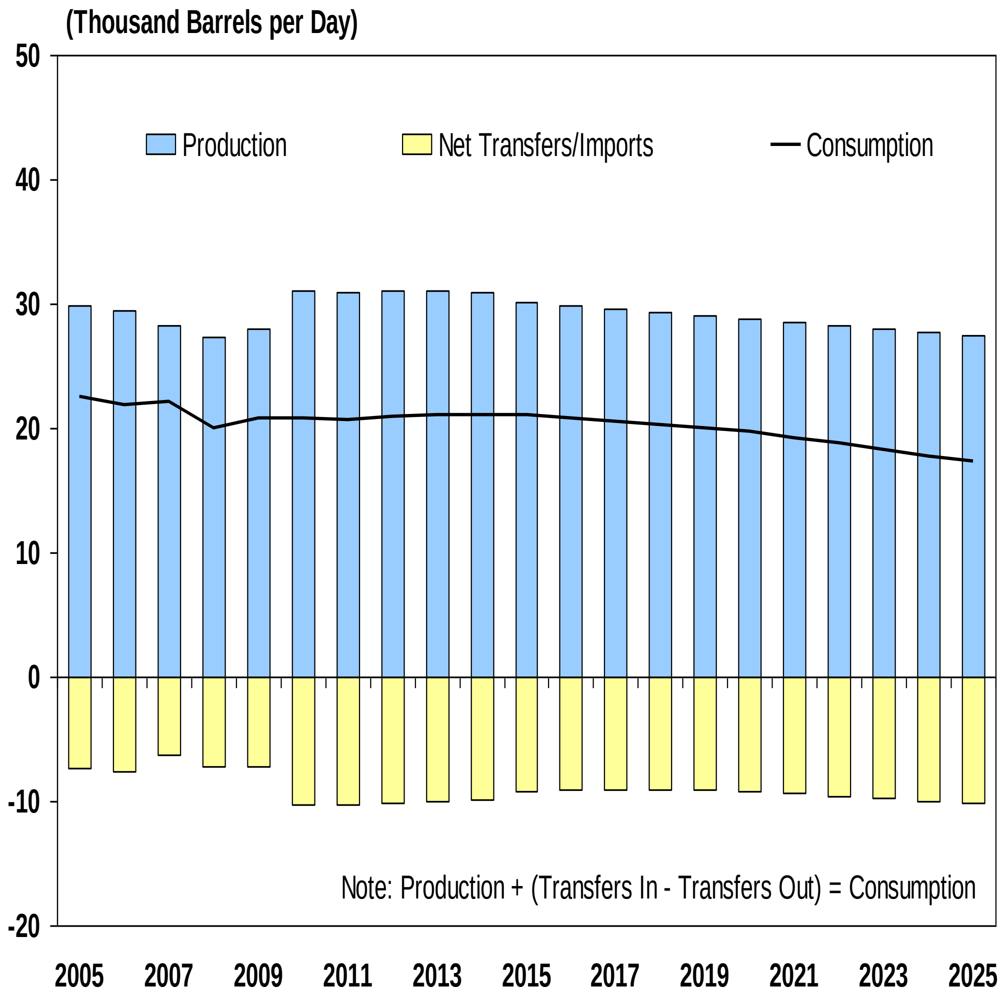
- PADD II is large proportion of overall US demand.
- PADD II depends on supply of products from other regions, primarily PADD III.

PADD II Gasoline and Diesel Outlook

- *PADD II gasoline demand begins to decline by 2015*
- *Reflects mandated vehicle efficiency improvements*
- *Reflects ethanol growth*
- *This trend mirrors overall U.S. demand projections*

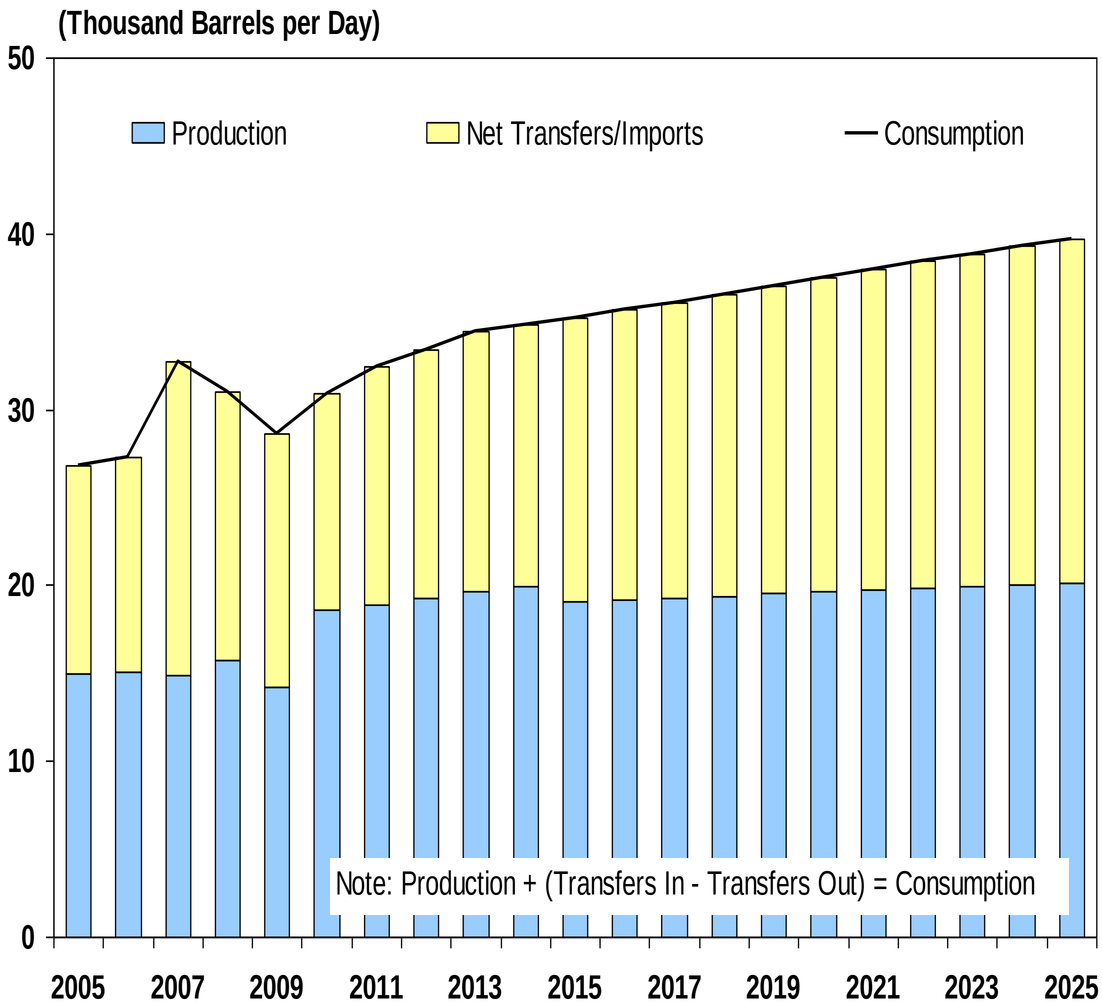
- PADD II diesel demand is projected to grow in line with underlying economic growth.
- Consistent with Energy Information Administration (EIA) and U.S. Department of Energy (DOE) trends

North Dakota Gasoline Balance



- North Dakota's demand for light refined products represent a small fraction of the overall PADD II total.
- North Dakota is a conventional gasoline market with some ethanol blending.
- The market balances on net transfers out of the state.
- Excludes ethanol

North Dakota Diesel Balance

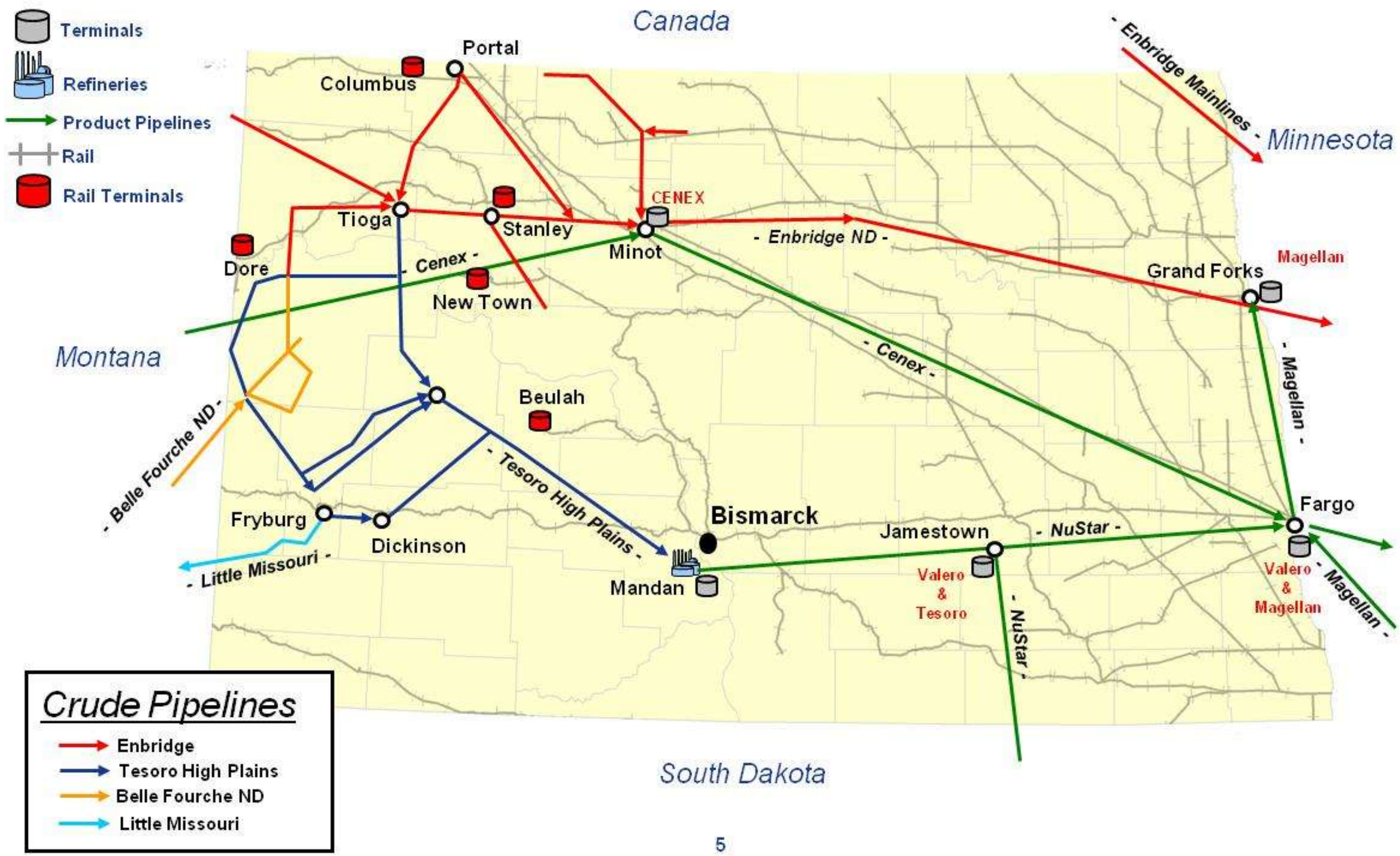


- The diesel market relies on increasing net transfers into North Dakota.
- Relative consumption of gasoline to diesel is lower than both the overall U.S. and PADD II markets because of the diesel consumption in the agriculture sector.

PADD II Transfers

- Product transfers are essential to North Dakota's refined product balance
- Some product movement is structural due to common ownership of pipeline refining and pipeline assets.
  - From Montana via Cenex
  - From South PADDII via NuStar
  - From Minnesota via Magellan
  - From Mandan to Minnesota via Nustar

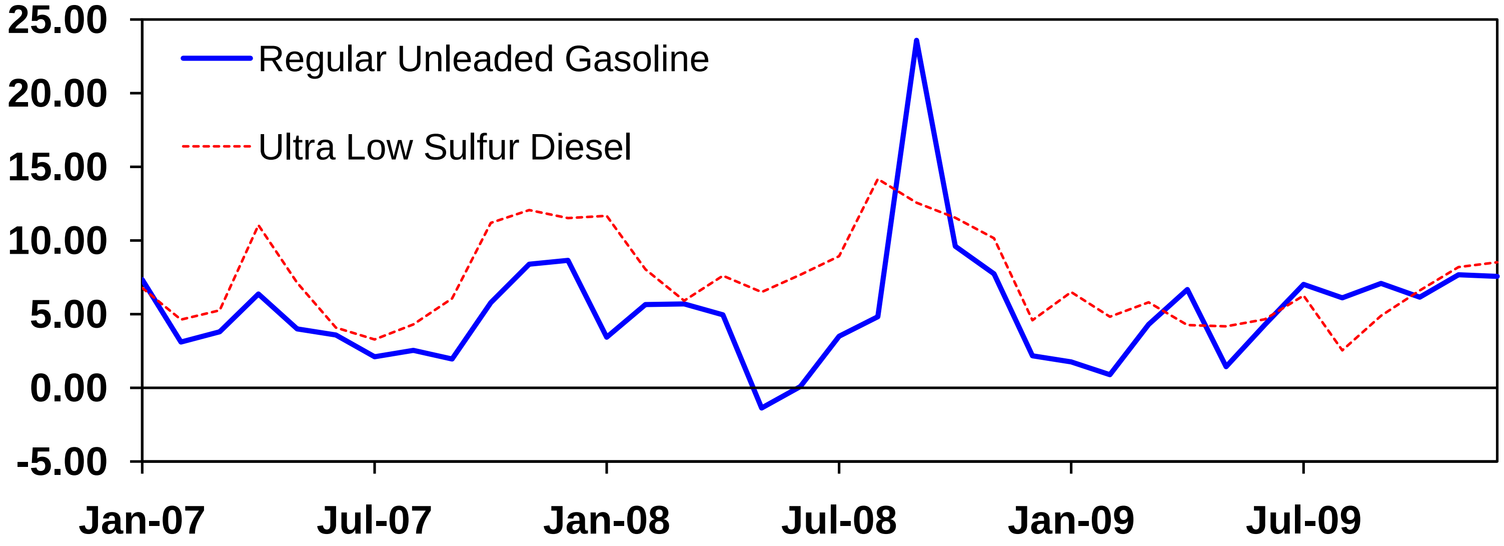
PADD II Transfers



North Dakota Product Pricing

- Due to dependence on transfers, product pricing in Minneapolis is related to U.S. Gulf Coast prices by transportation costs.
- Northern tier markets exhibit higher prices relative to Minneapolis.
- Prices approximate volumetric averages for North Dakota.

Unbranded North Dakota Average Rack - Minneapolis Rack (U.S. Cents per Gallon)

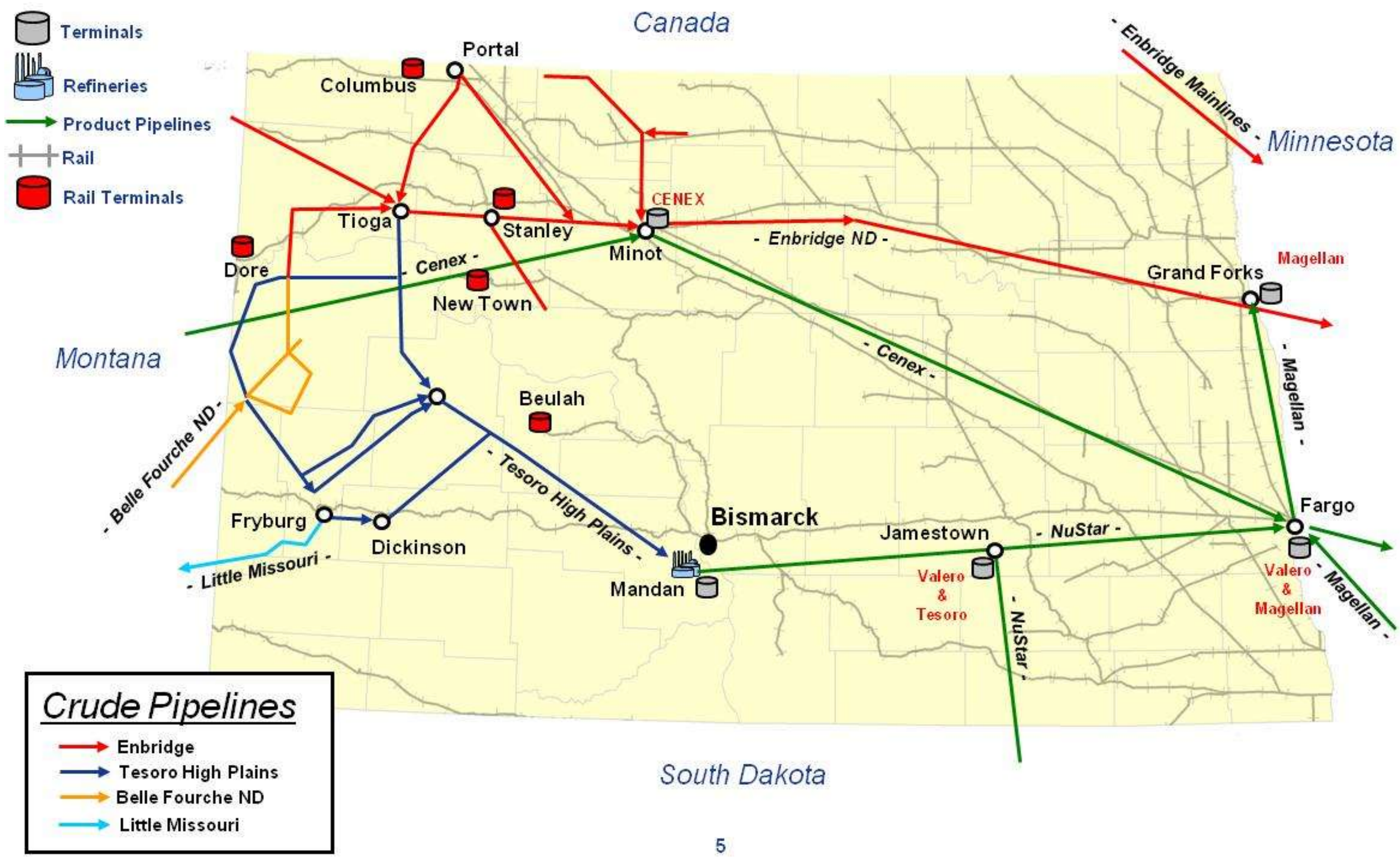


NGL and Fuel Oil Market Analysis

Propane, Butane, Residual Fuel

- *NGL demand is higher than supply.*
  - *Propane demand in the Upper Midwest (North and South Dakota, Minnesota and Wisconsin) is 78,000 B/D*
  - *Production is 17,700 B/D*
  - *Imports from Canada and inter-PADD transfers complete the balance.*
  - *Butane market in the Upper Midwest also relies on Canadian imports and inter-PADD transfers*
  - *Overall demand for residual fuel in PADD II is lowest of all PADD regions.*
  - *North Dakota's demand is less than 1,000 B/D*
  - *Additional production will lead to increased transfers from ND.*

Infrastructure Analysis



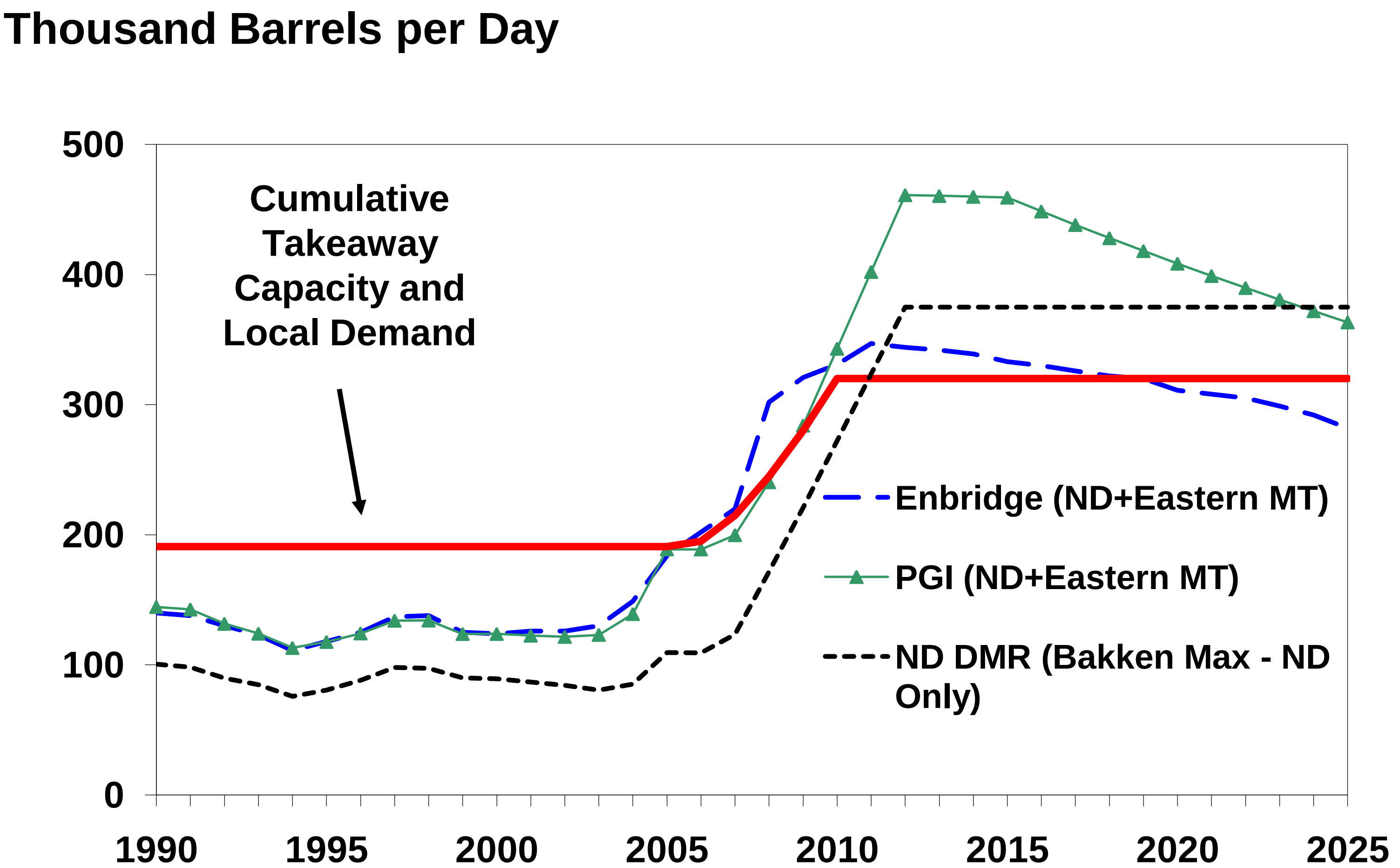
Infrastructure Analysis

- Facilities
  - Crude gathering and trunk lines
  - Refined product pipelines
  - Terminals
  - Rail facilities
- Recent and Potential Projects
  - ENDPL Phase 6
  - Bridger/Butte debottleneck
  - EOG unit train
  - Enbridge Portal reversal
  - Bridger Four Bears

Crude Production

- *Crude oil production is decreasing in most producing regions in the US, except in the Williston Basin.*
- *North Dakota production benefits from recent technology advancements.*
  - *Horizontal drilling*
  - *Multi-stage fracturing*
- *Crude from the Williston Basin will serve markets in North Dakota as well as other refining centers.*
  - *Pipeline capabilities must keep pace with production.*
  - *Rail transportation can supplement takeaway capacity.*

Production – Williston Basin



Crude Supply and Pricing Analysis

Bakken Light Sweet Crude Oil

LIGHT SWEET CRUDE ASSAY COMPARISON

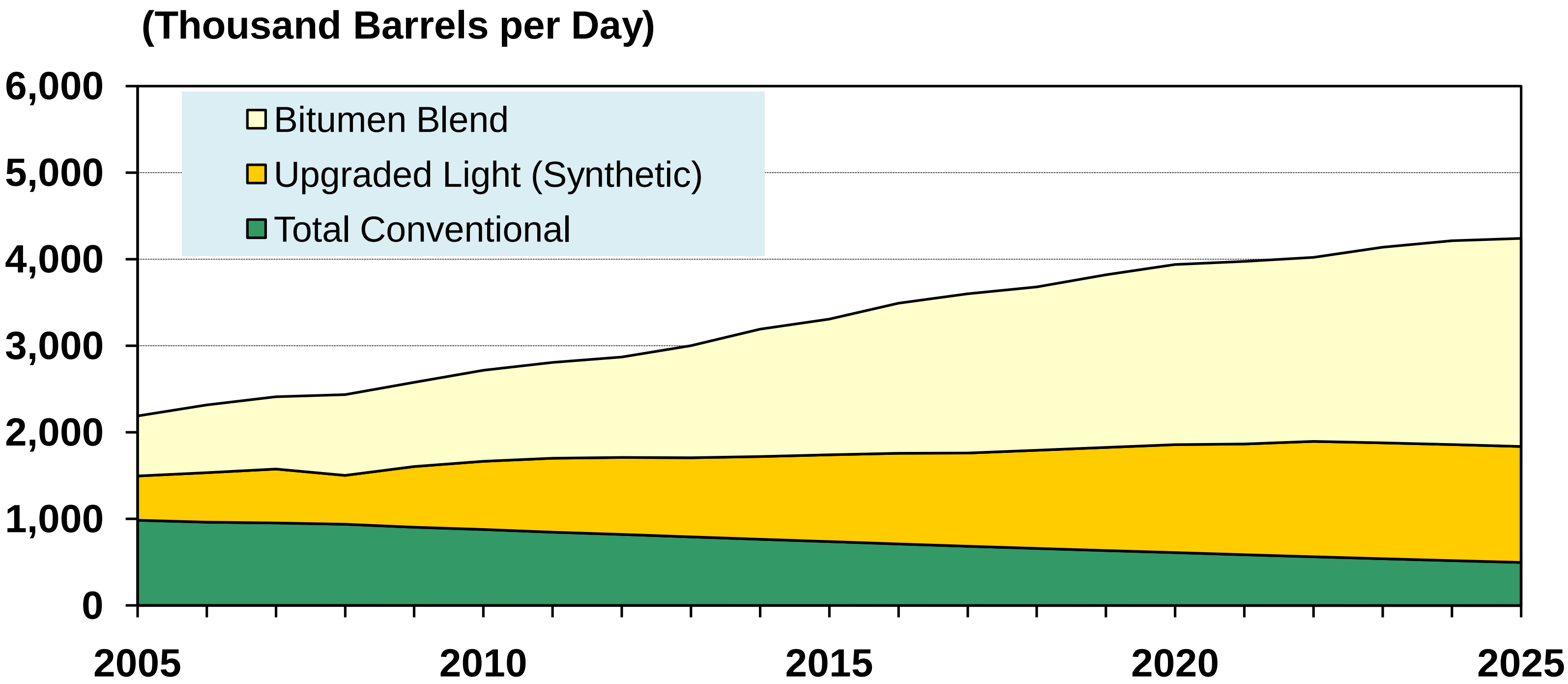
		Bakken [1]	WTI	LLS
API Gravity	Degrees	> 41	40.0	35.8
Sulfur	Weight %	< 0.2	0.33	0.36
Distillation Yield:	Volume %			
Light Ends	C1-C4	3	1.5	1.8
Naphtha	C5-330 °F	30	29.8	17.2
Kerosene	330-450 °F	15	14.9	14.6
Diesel	450-680 °F	25	23.5	33.8
Vacuum Gas Oil	680-1000 °F	22	22.7	25.1
Vacuum Residue	1000+ °F	5	7.5	7.6
Total		100	100.0	100.0
Selected Properties:				
Light Naphtha Octane	(R+M)/2	n/a	69	71
Diesel Cetane		> 50	50	49
VGO Characterization (K-Factor)		~ 12	12.2	12.0

Note: (1) Properties are approximate, based on available assay information.

- Bakken crude is expected to price relative to WTI
- Quality and transportation adjustments will determine the netback price.
- Williston Basin crude is estimated have a higher refining value.

Next Best Crude Source

- Synthetic crude oil from Alberta is a potential alternative source of crude.



Market Modeling

Approach and Methodology

- *Separate crude and product market models*
  - *Yearly forecasts for production, supply and demand*
  - *Logistics structure to balance markets*
  - *Includes, actual transportation costs; public tariffs, truck and rail costs*
- *Competitive economic markets – a basic premise*
- *Provide a rational basis for estimating price impact of large changes in crude and product markets*
- *Models are balanced using linear programming methods*
- *Results validated using historical prices in North Dakota*

Market Modeling

Modeling Premise

- *Phase 1 Analysis – Evaluation of incremental addition of refinery capacity relative to a reference case of no capacity increase.*
  - *Process light sweet Bakken crude*
  - *Capacity cases: 100,000 (base), 50,000, and 20,000 B/D*
  - *Maximize finished gasoline, jet and diesel fuel.*
  - *Maximize light product yield consistent with demand forecasts.*
  - *Employ proven commercial technologies.*

Intake and Yield Results

REFINERY INTAKE/YIELD (1)
BAKKEN LIGHT SWEET

	Volume Percent
Crude	100.0
Total Intake	100.0
Light Ends	7.8
Gasoline	44.1
Jet/Kerosene	5.0
Low Sulfur/ULS Diesel	42.7
1% Sulfur RFO	4.0
3% Sulfur RFO	0.9
Total Yield	104.5
Sulfur (Tonnes)	0.02

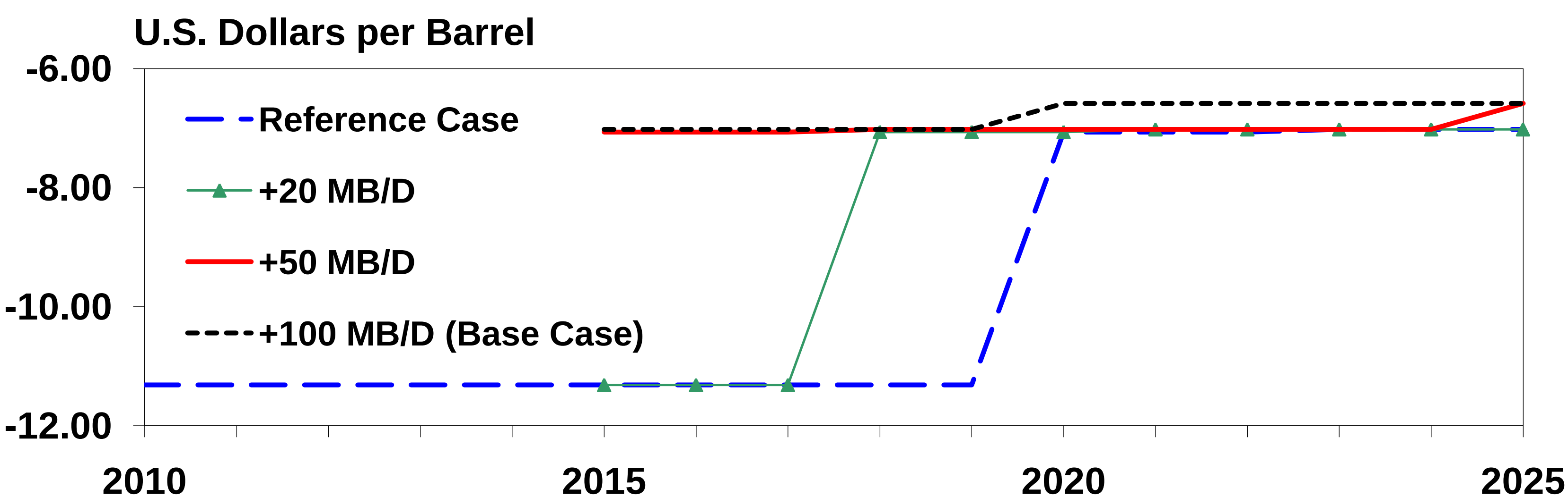
Note: (1) VGO hydrocracking configuration.

- *Uses a vacuum gas oil (VGO) hydrocracking configuration with no bottoms conversion.*
- *Produces high yield of diesel relative to gasoline.*
- *Fuel oil yield is low.*

Crude Supply and Pricing Analysis

ND Sweet (field) Minus WTI, Cushing

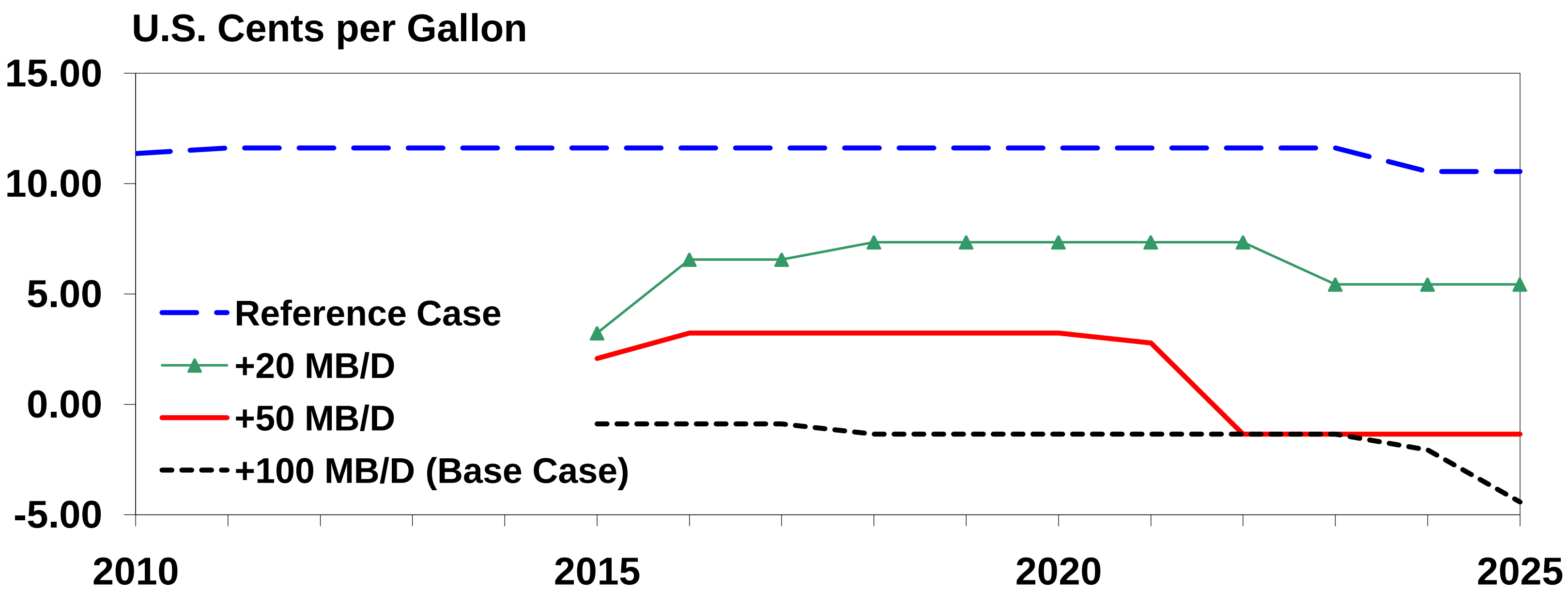
- *Additional refining capacity will strengthen crude prices in the state.*
- *Prices are indicative of field prices in North Dakota*
- *Actual costs will vary pending specific locations of the refining capacity.*



Crude Supply and Pricing Analysis

Gasoline Differentials: ND Minus Gulf Coast

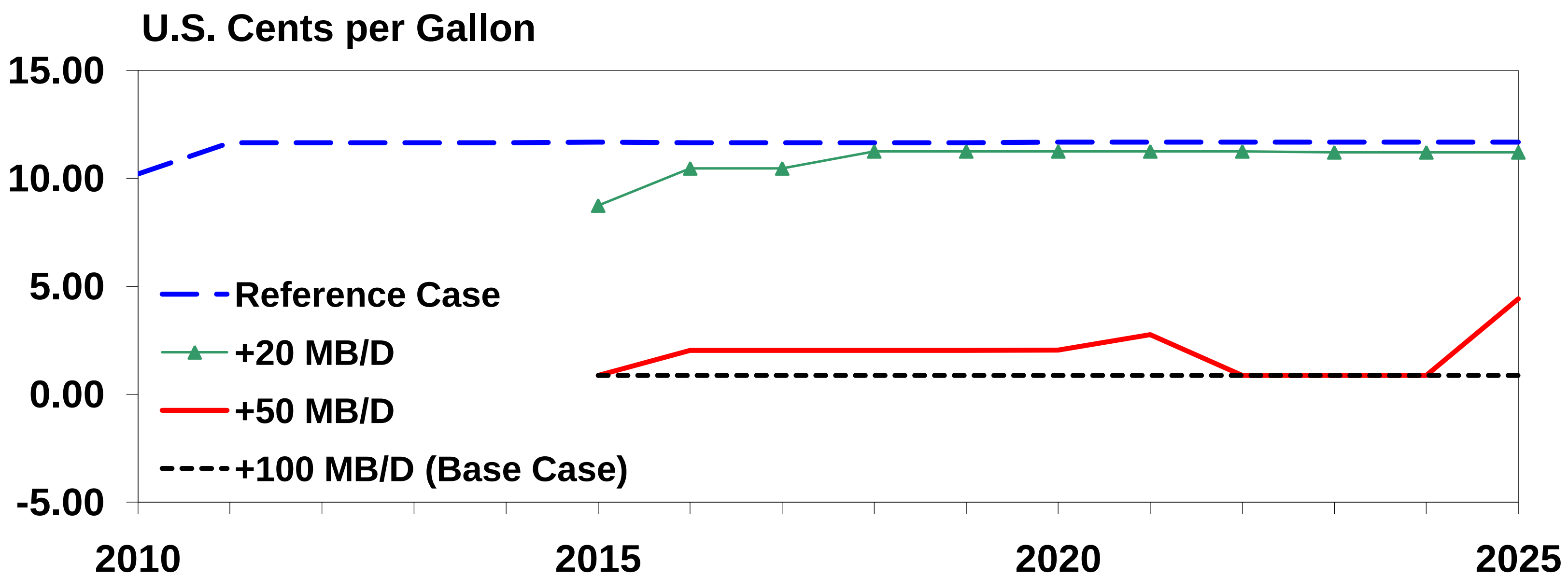
- *Provides indicative prices at a generic location in North Dakota*
- *Additional refining capacity will weaken product pricing*
- *Impact varies with refinery capacity*



Crude Supply and Pricing Analysis

Diesel Differentials: ND Minus Gulf Coast

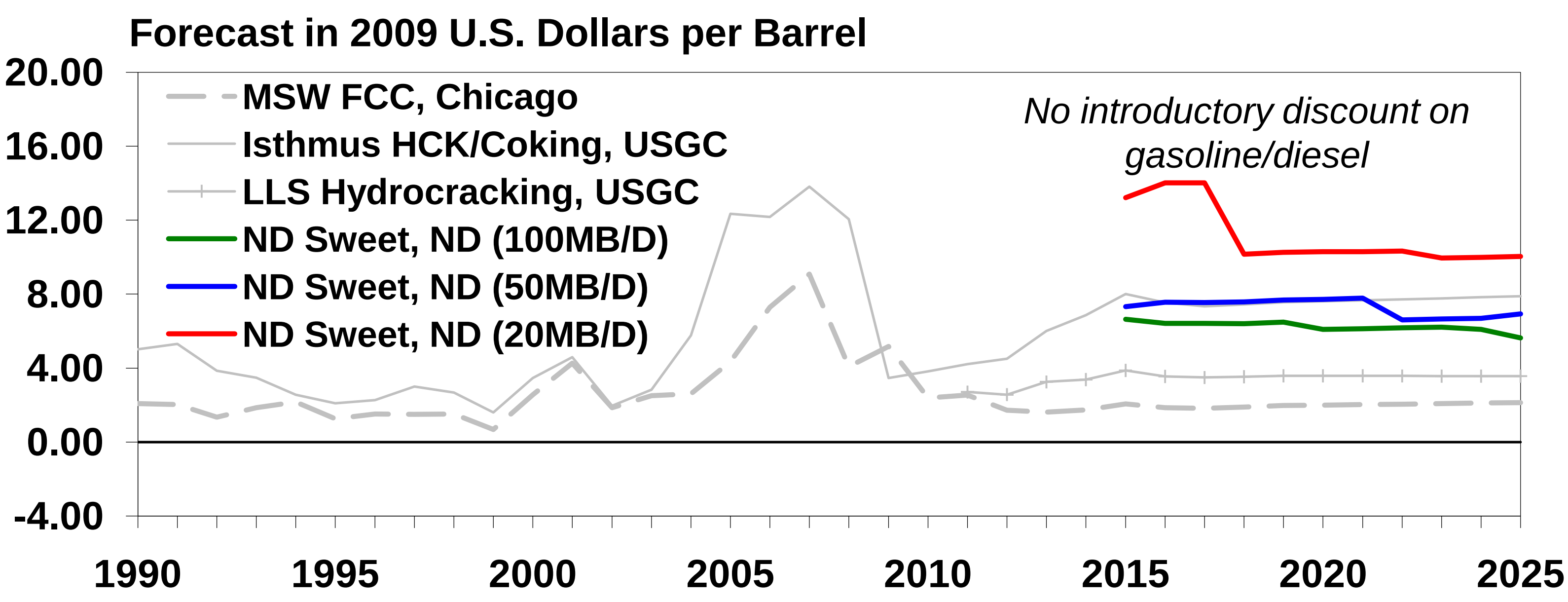
- *Provides indicative prices at a generic location in North Dakota*
- *Additional refining capacity will weaken product pricing*
- *Small impact from 20,000 B/D case*



Refining Margin Analysis

Variable Cost Refining Margin

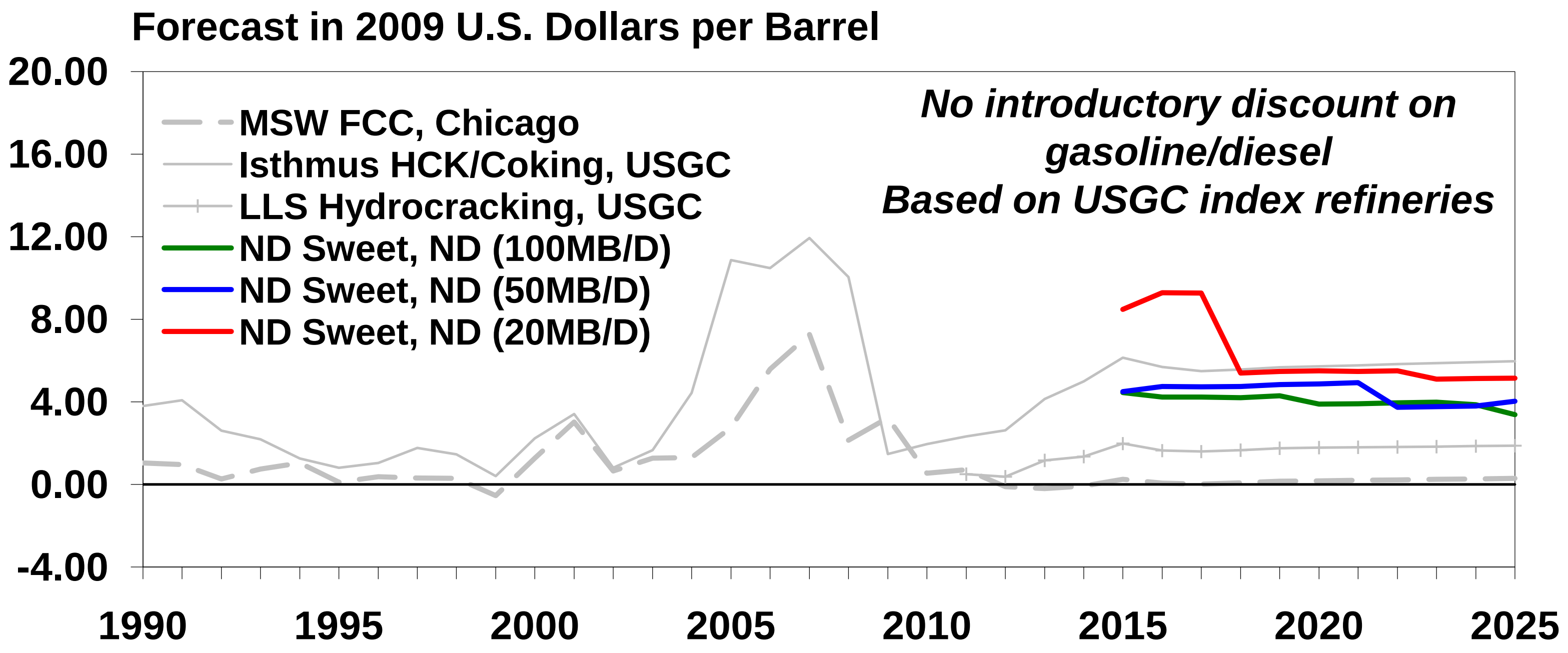
- *Variable cost refining margin is gross revenue less crude costs and variable costs – no fixed operating costs or capital recovery.*
- *Variable cost margins are strongly positive in all cases, highest for the 20,000 B/D case.*



Refining Margin Analysis

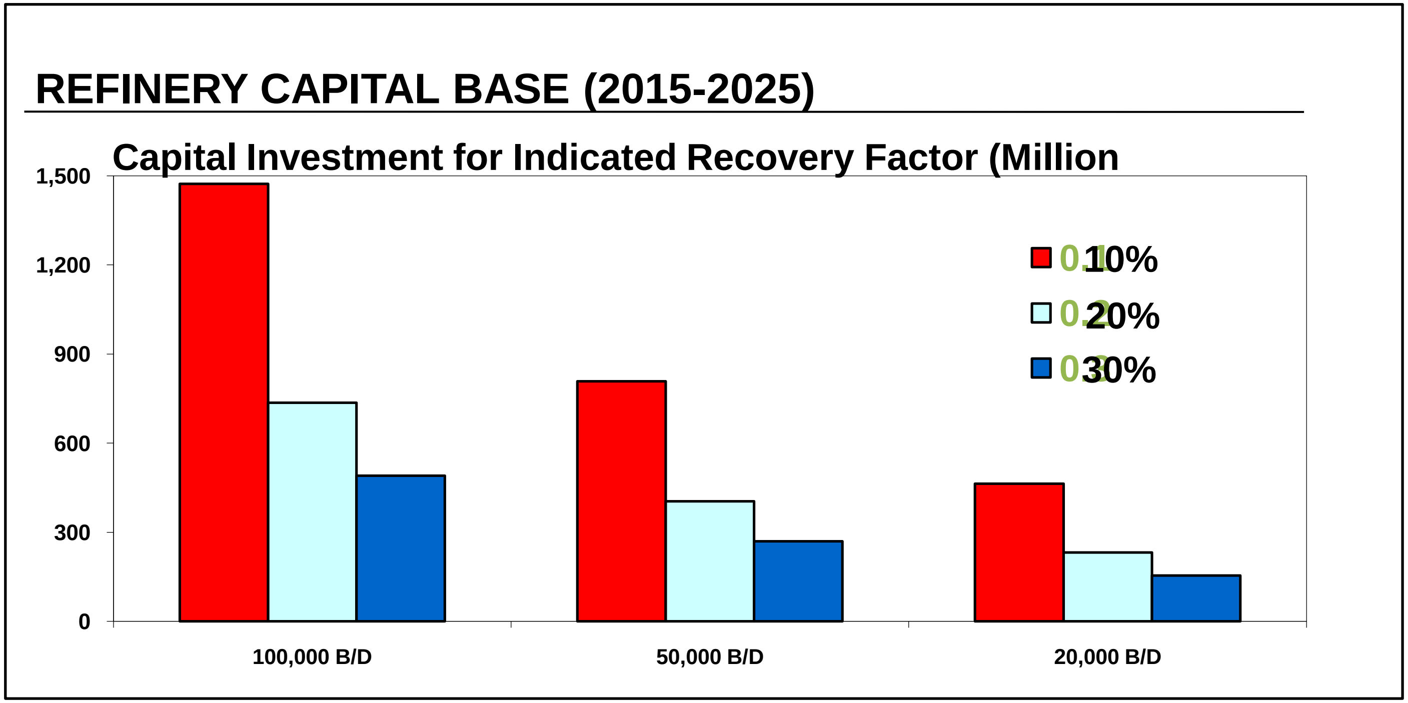
Net Refining Margin

- *Net refining margins are variable refining margin less fixed costs - no capital recovery.*
- *Net refining margins are forecast to be positive in all cases.*



Capital Recovery Estimate

- *The net refining margin is the source of cash for capital recovery*
- *The capital recovery factor is a simplified measure of project economics based on projected cash flows*
- *Excludes depreciation, taxes and other company-specific costs.*



Capital Recovery Analysis

- *The simple ND CRF's have been compared to the implied capital for a USGC refinery of comparable configuration.*
- *None of the refinery capacity additions appear to achieve adequate capital recovery to support traditional project finance.*
- *The ND vs. USGC location factor is expected to be a disadvantage.*

CAPITAL INVESTMENT (2015-2025)
USGC INDEX REFINERY vs. NORTH DAKOTA
(2009 Billion Dollars)

	North Dakota Project		
(Thousand B/D) :	**+100**	**+50**	**+20**
Capital supported at CRF of:			
10%	1.47	0.81	0.46
20%	0.74	0.40	0.23
30%	0.49	0.27	0.15
U.S. Gulf Coast Index Refinery Capital	1.73	1.02	0.52

Competitive Analysis

Project Sponsor

Pro's	Con's
Possible opportunity for non-traditional project finance.	Marginal (or poor) economics for traditional project finance.
	May require introductory price discount to gain market share

Competitive Analysis

Crude Producer

Pro's	Con's
100,000 b/d size shows initial (higher) and sustained (lower) price increase	Price differential is not a permanent change in the market as additional pipeline infrastructure is built and production levels fall
20,000 and 50,000 b/d cases support an increase in crude price into years 2020 and 2018 respectively	.
Diversification of marketing options.	

Competitive Analysis

Crude Pipelines

Pro's	Con's
Project opportunity for short run pipeline to serve new grassroots refinery	Crude availability is reduced, potentially deterring certain incremental pipeline expansion projects
Project opportunity to upgrade existing infrastructure.	

Competitive Analysis

Refined Product Pipelines

Pro's	Con's
Increased refined product availability results in pipeline infrastructure projects for upgrades and new systems	May require projects to reach new markets that result in lower prices
Potential exists for increased utilization of existing assets to transport incremental product	Specific location of refinery may disadvantage certain operators.

Competitive Analysis

Wholesale Marketers

Pro's	Con's
Alternative supply would be available if grassroots refinery is constructed, resulting in additional competition.	Specific location of refinery may disadvantage certain operators.
Lower wholesale prices	

Competitive Analysis

Existing Refiners

Pro's	Con's
Possible project opportunity for expansion of regional refineries.	Upward pressure on crude prices and downward pressure product pricing will result in reduce refinery margins.
	Commercial and logistical impacts on current business patterns.

Competitive Analysis

State of North Dakota

Pro's	Con's
Additional skilled jobs supporting incremental refining capacity within the state.	
Increase in tax revenue	
Additional refining capacity will foster related business expansions or relocations	

Competitive Analysis

North Dakota Consumers

Pro's	**Con's**
Additional local supply of refined products reduces risk of product supply constraints	
Potential for reduced product prices.	

Phase II Study– Key Tasks

- *Refinery configuration analysis*
  - *alternative process schemes and yield patterns*
- *Project development schedule*
  - *analysis of pertinent scenarios*
- *Economic analysis of key scenarios*
  - *Class V capital cost estimation including offsites and owner's costs*
  - *Operating cost generation*
  - *Project discounted cash flow analysis including working and sustaining capital requirements*
  - *Sensitivity and risk analysis- Monte Carlo simulations*
  - *Scenario screening and recommendations*
- *Refinery utility analysis*

Phase II Study– Key Tasks (cont.)

- Refinery site location and plot plan development
  - Identify siting criteria and potential locations
  - Develop preliminary site plan
- Analysis of potential refinery emissions
- Identify benefits to North Dakota
  - Jobs creation
  - Refinery support business development
  - Taxation impacts
- Analyze impacts of federal regulations on potential refinery project
- Present results to NDAREC/DOE

North Dakota Refining Capacity Feasibility Study
- Phase II Final Report

North Dakota Association of
Rural Electric Cooperatives

October 8, 2010

About this Report

This report was prepared by the Consultants under a contract with NDAREC, which received federal grant funds for the study.

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Study Team

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Introduction

Phase I -Market Analysis

- Provide a market assessment for refined petroleum product.

- Market trend analysis- historical, current, forecast.

- Analyze infrastructure, crude supply & pricing, product pricing.

- Provide a refining margin analysis and capital recovery estimate.

Phase I – Findings

Market Analysis

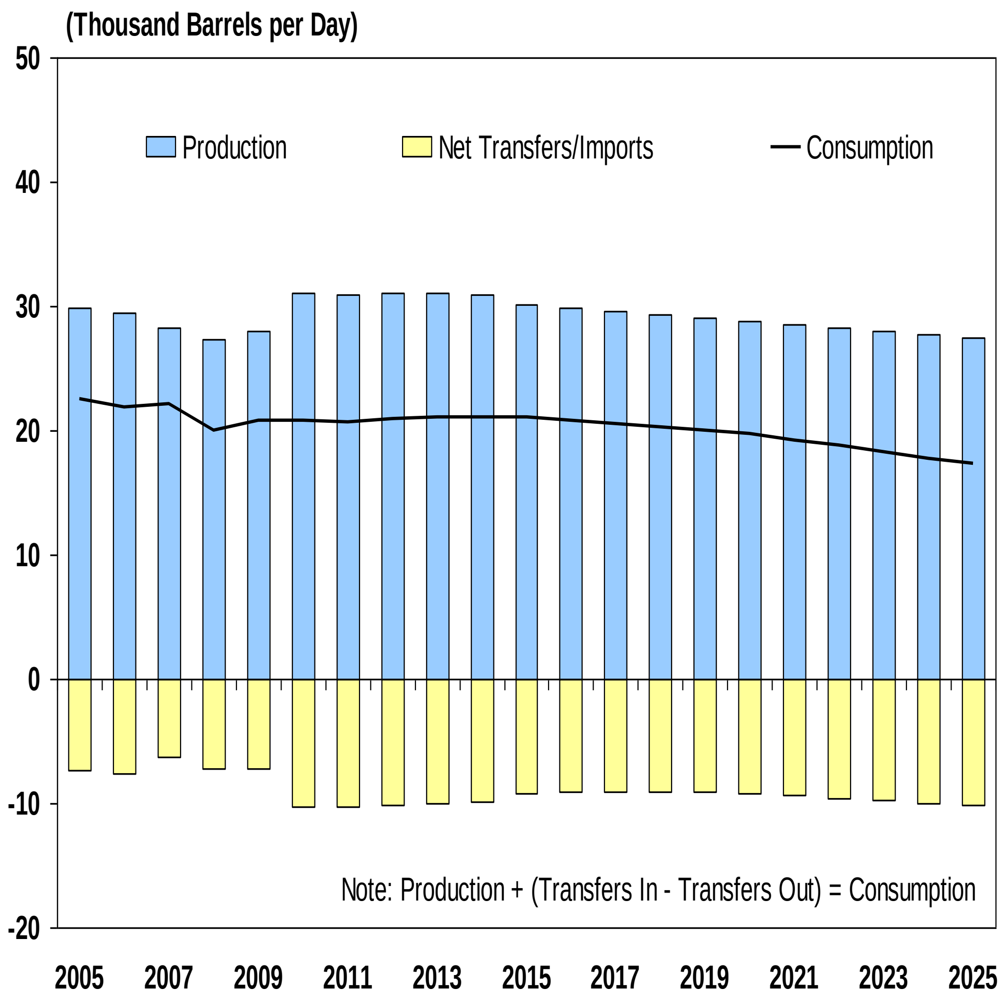
- *PADD II gasoline demand begins to decline by 2015*
- *Reflects mandated vehicle efficiency improvements*
- *Reflects ethanol growth*
- *This trend mirrors overall U.S. demand projections*

- PADD II diesel demand is projected to grow in line with underlying economic growth.
- Consistent with Energy Information Administration (EIA) and U.S. Department of Energy (DOE) trends

Economic Analysis

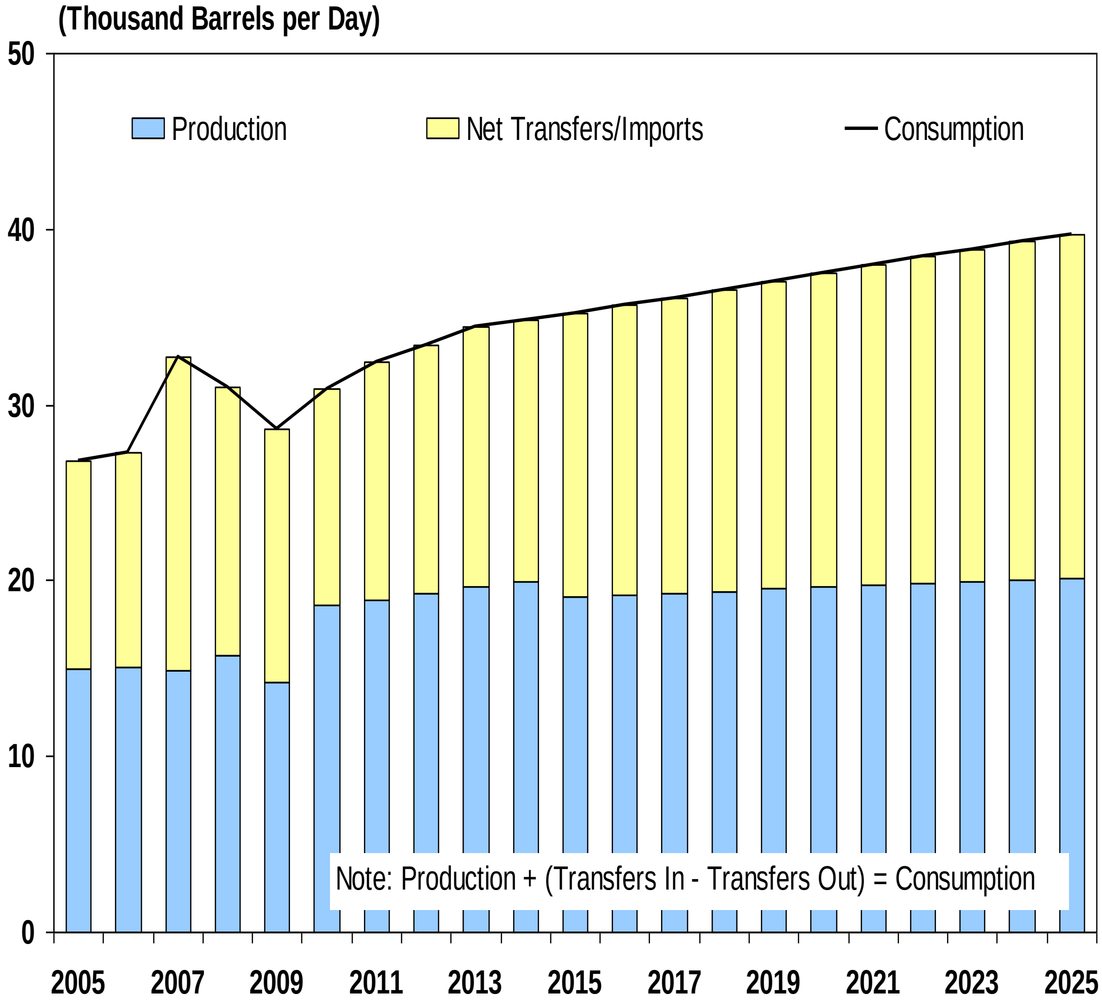
- None of the specified refining capacity additions appear to achieve adequate capital recovery to support traditional project finance.

North Dakota Gasoline Balance



- North Dakota's demand for light refined products represent a small fraction of the overall PADD II total.
- North Dakota is a conventional gasoline market with some ethanol blending.
- The market balances on net transfers out of the state.
- Excludes ethanol

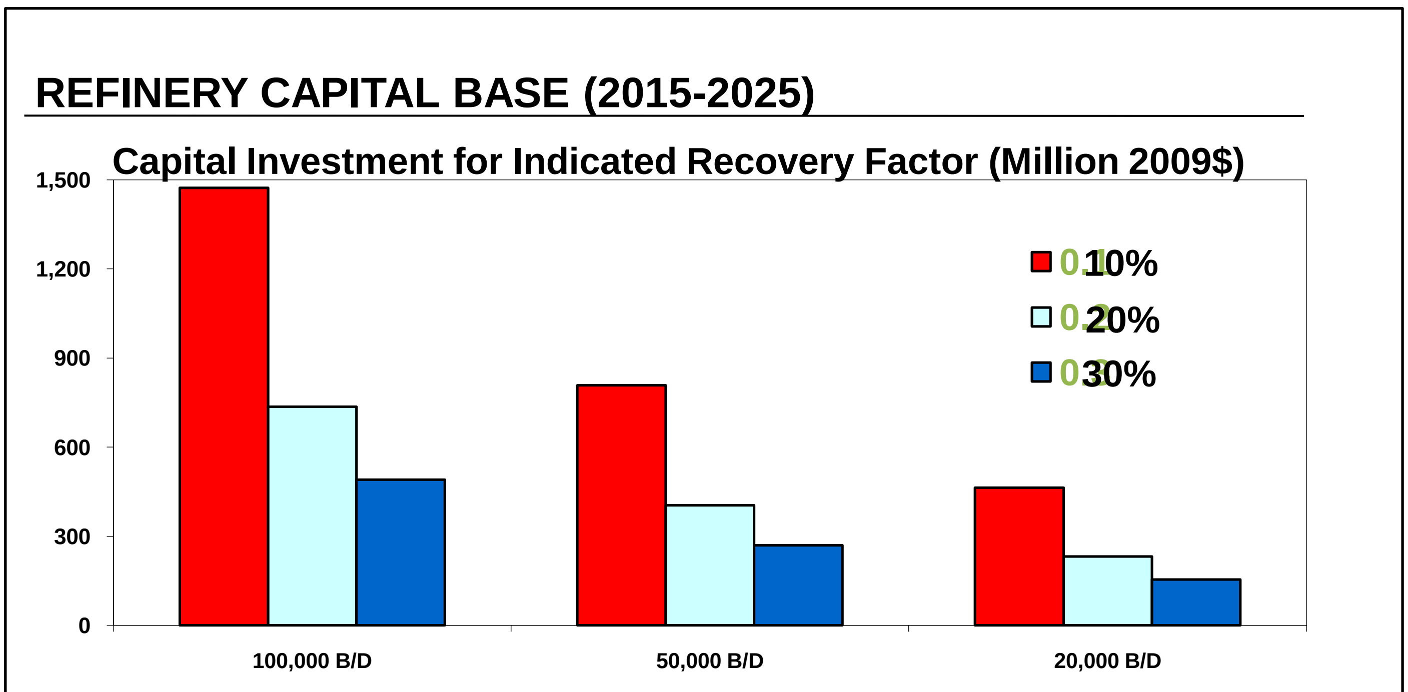
North Dakota Diesel Balance



- The diesel market relies on increasing net transfers into North Dakota.
- Relative consumption of gasoline to diesel is lower than both the overall U.S. and PADD II markets because of the diesel consumption in the agriculture sector.

Phase I Capital Recovery Estimate

- *The net refining margin is the source of cash for capital recovery*
- *The capital recovery factor is a simplified measure of project economics based on projected cash flows*
- *Excludes depreciation, taxes and other company-specific costs.*



Phase II Modifications

- *Based on the findings from Phase I the following modifications were instituted by NDAREC.*
- *Base Case*
  - *Replace the 100,000 B/D case with the 20,000 B/D case due to its lower impact in the existing market and potentially better return on investment.*
- *Alternate Case*
  - *Add a naphtha refinery case, eliminating the production of gasoline.*
    - *Gasoline supply in North Dakota exceeds demand.*
    - *Maximize diesel production based on market demand.*
    - *Existing market for naphtha in Alberta.*

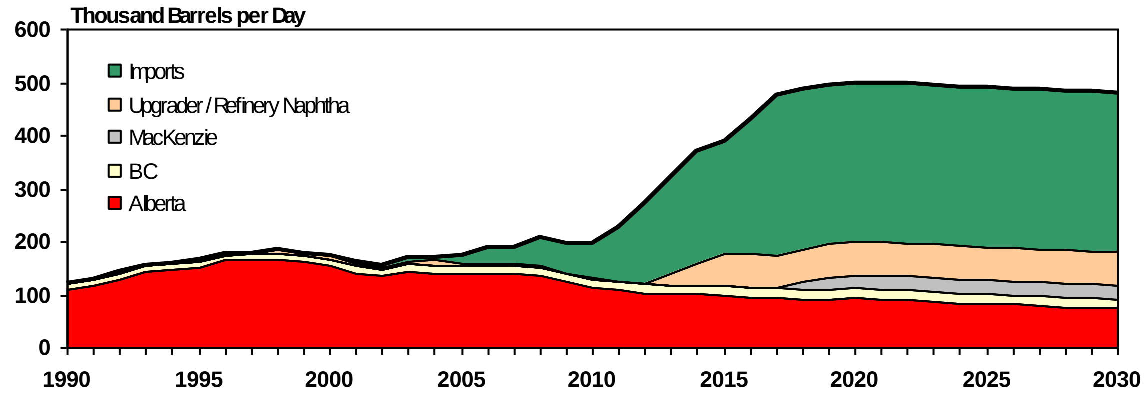
Phase II Deliverables

- Naphtha Market Analysis
- Economic Analysis
- Sensitivity and Risk Analysis
- Impact of Federal Regulations
- Project Schedules
- ISBL Process Descriptions
- Utility Balances
- Conceptual OSBL Design
- Emissions Analysis
- Preliminary Site Plan
- Site Selection Criteria
- Benefits to North Dakota
- Project Incentives and Barriers

Market Review-Canadian Naphtha/Diluent

- Naphtha is used as a diluent for pipelining Bitumen (heavy crude).
- Growth in the Canadian bitumen production has created a demand for naphtha.
- Canadian import of hydrocarbon streams such as naphtha is the most expedient short term option for increasing the supply of diluent to meet the demand created by the growth in bitumen production.

FIGURE 3
CONDENSATE AND NAPHTHA SUPPLY



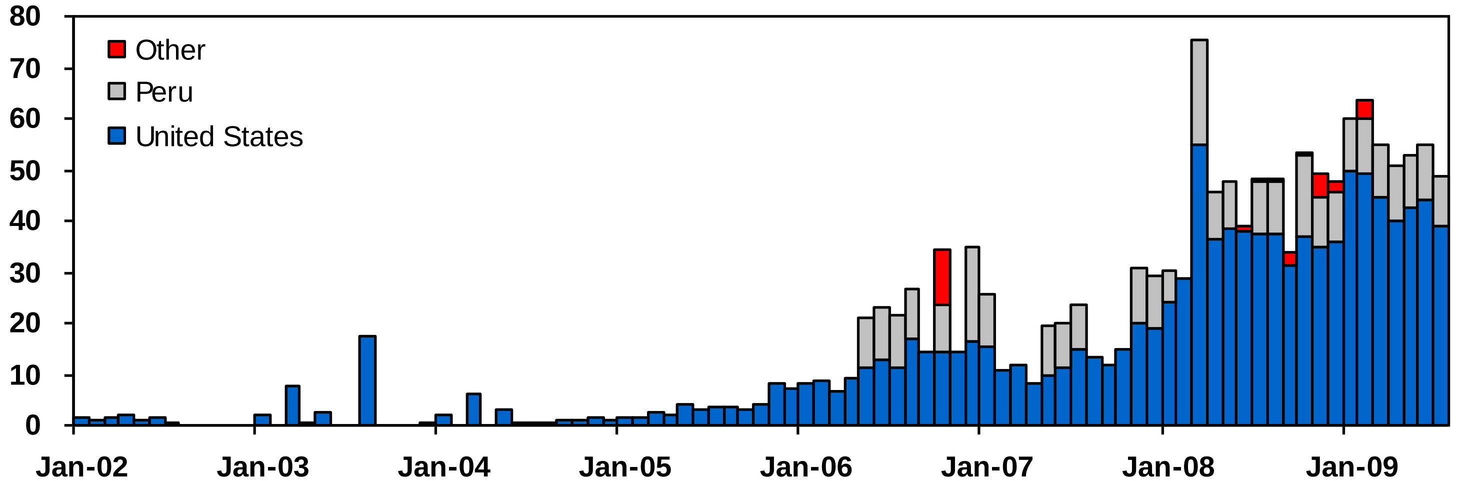
Pipeline Transportation

- Enbridge Southern Lights project allows up to 180,000 BPD of diluent components to be shipped from Chicago to Edmonton, Canada.
- The pipeline is expandable to more than 300,000 BPD.
- Currently the tariffs for uncommitted shippers are not economical compared to rail transportation.
- Currently batches cannot originate at Clearbrook.
- The study netback prices are based on rail transportation.

Rail Transportation

- Rail is currently the most expedient short term option for importing diluent into Canada.

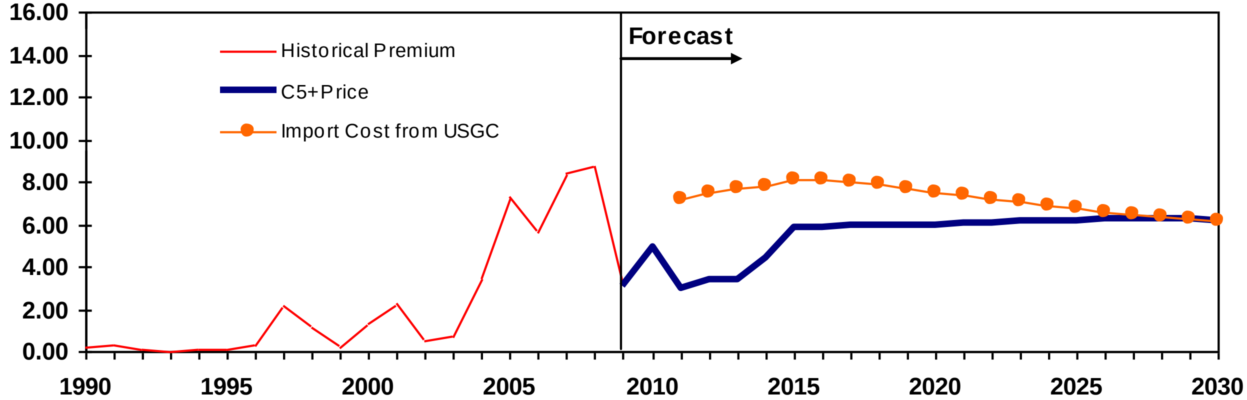
FIGURE 5
WESTERN CANADA CONDENSATE & NAPHTHA IMPORTS, BY ORIGIN
(Thousand Barrels per Day)



Condensate Naphtha Pricing

- Naphtha is co-mingled with other condensate streams which together comprise the Enbridge pooled condensate (CRW).
- The C5+ price, the price of Enbridge pooled condensate (CRW) is expected to increase through 2015 and continue an increasing slope through 2030 due to increases in the demand of diluent.

FIGURE 6
CRW PREMIUM OVER ALBERTA MSW AT EDMONTON, DILBIT CASE
(Forecast in Constant 2010 U.S. Dollars per Barrel)



LP Modeling Yields

	20 KBPD Refinery	34 KBPD Refinery
Charge and Yield		
Crude Charge		
North Dakota Sweet	20.0	33.9
Other Feedstocks		
Ethanol	0.8	0.0
Total Feedstocks	20.8	33.9
Liquid Yields		
LPG	1.3	1.1
Naphtha	0.0	15.0
Gasoline	8.7	0.0
Kerosene	1.0	1.5
Gasoil/Diesel	9.5	16.0
Fuel Oil (1% S)	1.0	2.0
Total	21.5	35.5
Other Yields		
Sulfur (ltpd)	3.6	6.2
Major Unit Capacities		
Crude	21.0	35.7
Vacuum	5.6	9.4
VGO Hydrocracker	6.2	10.6
Isomerization Unit	3.1	
Semi-Regen Reformer	5.6	
Naphtha Hydrotreating	8.7	
Kero/Diesel Hydrotreating	7.4	12.6
Bensat Unit	0.4	
Hydrogen Production (MMCFD)	7.3	20.7
Sulfur Recovery (LTD)	6.0	10.4

20KBPD

- Gasoline, jet and diesel yield is 92.3% of refinery charge.

34KBPD

- Jet and diesel yield is 51.6% of refinery charge.
- The full production of naphtha (combined light and heavy) is assumed to be sent to Canada by rail.

Capital Cost Analysis

NORTH DAKOTA REFINERY STUDY
CAPITAL COST ESTIMATE
($ millions)

	20 KBPD Refinery	34 KBPD Refinery
Direct Construction Costs		
Inside Battery Limits (ISBL)		
Crude	$ 32.5	$ 49.5
Vacuum	$ 13.8	$ 20.6
VGO Hydrocracker	$ 86.7	$ 126.7
Isomerization Unit	$ 30.5	
Semi-Regen Reformer	$ 35.6	
Naphtha Hydrotreating	$ 35.7	
Kero/Diesel Hydrotreating	$ 43.4	$ 43.0
Bensat Unit	$ 7.0	
Light Ends Recovery	$ 3.4	$ 3.8
Hydrogen Production	$ 24.7	$ 47.2
Sulfur Recovery	$ 9.4	$ 13.6
Total ISBL Costs	$ 322.8	$ 304.4
Outside Battery Limits (OSBL)[1]	$ 150.2	$ 193.0
License and Engineering Fees	$ 15.4	$ 10.3
Initial Catalyst Fills	$ 4.7	$ 5.2
Total Direct Costs	$ 493.0	$ 512.9
Indirect Construction Costs		
Owner's Costs (15% ISBL+OSBL)	$ 70.9	$ 77.5
Contingency (15% Direct+Owner's)	$ 84.6	$ 91.4
Total Indirect Costs	$ 155.5	$ 168.9
Total Capital Costs	$ 648.5	$ 700.9

[1] OSBL costs include tankage, product loading facilities, utilities, buildings and other infrastructure

- Accuracy 40%
- Location factor estimated at 1.15 versus USGC.
- Owners costs (spare parts, permitting, land, management, studies, etc.) are estimated to be 15%.
- Contingency estimated to be 15%.

Operating Cost Analysis

	20 KBPD Refinery	34 KBPD Refinery
Fixed		
Maintenance (incl. T/A + Labor)	11.6	13.3
Labor (except Maintenance)	17.6	14.8
Taxes and Insurance	3.5	3.9
Other	6.1	6.6
Total Fixed Costs	38.9	38.5
Total Fixed Costs ($/bbl Crude)	$5.33	$3.12
Variable		
Fuel	11.3	19.7
Electricity	2.2	2.3
Make-up Water	1.1	1.5
Catalyst and Chemicals	1.2	1.3
Total Variable Costs	15.8	24.7
Total Variable Costs ($/bbl Crude)	$2.16	$2.00
Total Operating Costs	54.7	63.3
Total Operating Costs ($/bbl Crude)	$7.49	$5.11

- Larger refinery has fixed cost economies of scale.
- Variable costs in the 20 KBPD case are higher per barrel due to the increased complexity.
- Operating Cost for both cases are higher per barrel than typical large USGC refineries.

Project Schedule Analysis

- Critical factors for probable case are:
  - Organization and commercial development completed during 1Q 2011
  - Funding for initial engineering (FEL) activities available by Jan. 1, 2011
  - Permitting, financing and engineering will take approximately 36 months.
  - Construction period 16 months
  - Probable case completion – 4^{th} Qtr. 2015

Cash Flow Assumptions

North Dakota Refinery Study
Pricing (Current $/B)

	2010	2015	2020	2025	2030
Crude					
WTI, Cushing	79.71	92.22	107.52	132.19	155.54
ND Sweet, Delivered (20 KBPD)	73.10	84.37	104.28	128.78	151.85
ND Sweet, Delivered (34 KBPD)	73.10	86.83	104.31	129.09	152.19
Other Feedstock					
Ethanol, Delivered	83.64	120.82	138.34	164.66	189.53
Products					
LPG	49.88	57.36	67.97	85.01	101.07
Naphtha	80.10	90.43	106.13	131.06	154.34
Gasoline	91.23	100.03	118.72	143.73	168.32
Kerosene/Jet	89.84	108.67	124.21	152.33	179.07
ULSD	93.41	112.06	130.27	159.19	186.83
Fuel Oil (1%)	63.49	66.99	79.25	99.77	118.99

- Phase 1 market analysis with updated Purvin & Gertz price forecasts from May, 2010.
- Local crude pricing, with appropriate supply cost.
- Transportation adjustments to and from North Dakota for diesel and gasoline.
- Naphtha netback based on Edmonton diluent value.

Cash Flow Results

- Internal Rate of Return and IRR Results
  - Real returns are discounted to 2010 dollars.
  - Nominal returns are not discounted.
  - All cash flows are on unleveraged basis.
  - 20,000 BPD Results
    - Real IRR 1.6%, Nominal IRR 3.7%
    - NPV (15% nom.), $-244.4 million
  - 34,000 BPD Results
    - Real IRR 7%, Nominal IRR 9.2%
    - NPV (15% nom.), $-156.7 million

Cash Flow Sensitivity

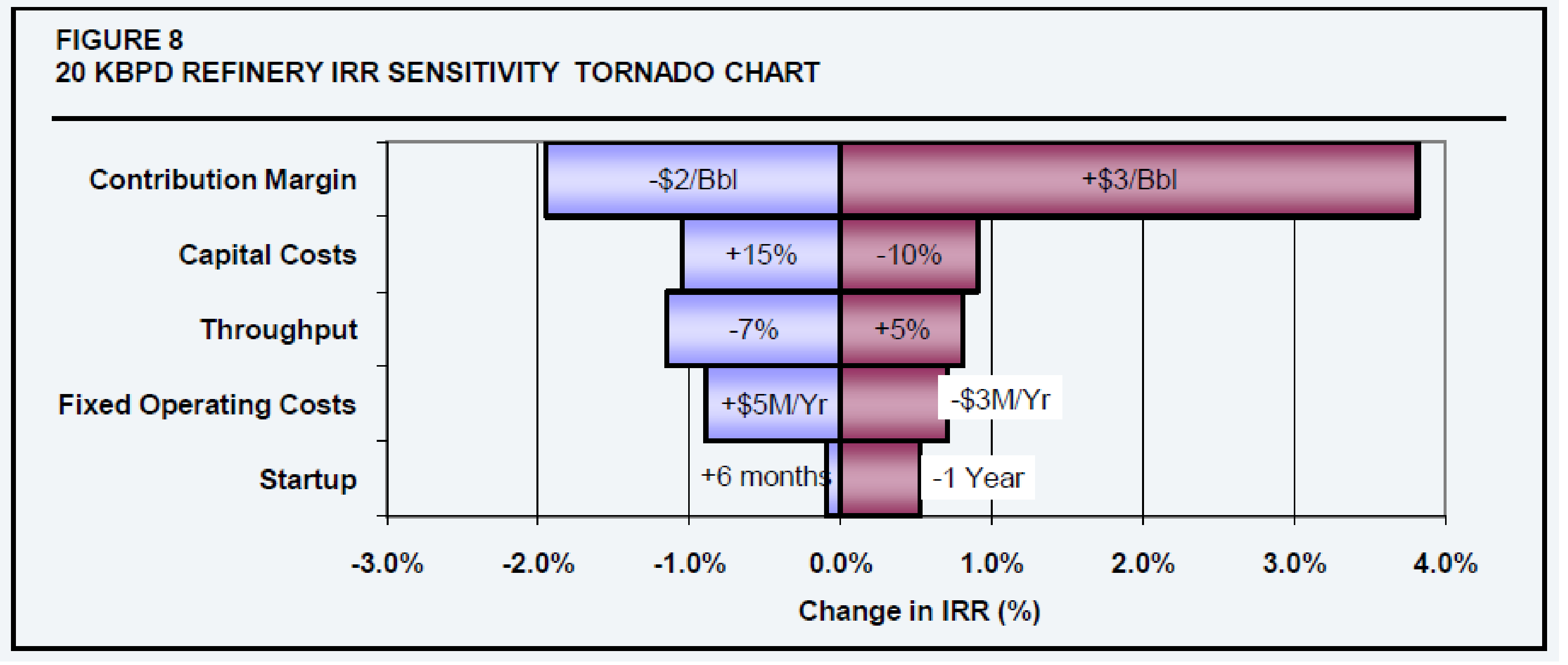
- Sensitivity Analysis Variables
  - Most variables assume 15% increase, 10% decrease
  - Schedule increase 6 months, decrease 1 year
  - Throughput increase 5%, decrease 7%
  - Contribution Margin (CM)
    - (CM) =Revenues-Cost of Goods-Variable Operating Costs

Cash Flow Sensitivity

North Dakota Refinery Study
Cash Flow Sensitivity Analysis (%IRR)

	20 KBPD Refinery		34 KBPD Refinery	
	Real	**Nominal**	**Real**	**Nominal**
Base Case	1.6%	3.7%	7.0%	9.2%
Throughput + 5%	2.4%	4.5%	7.7%	9.9%
Throughput - 7%	0.5%	2.5%	5.8%	8.0%
Capital Costs + 15%	0.6%	2.6%	5.5%	7.7%
Capital Costs - 10%	2.5%	4.6%	8.0%	10.3%
Contribution Margin + $3/Bbl	5.3%	7.5%	10.8%	13.1%
Contribution Margin - $2/Bbl	-0.3%	1.7%	3.7%	5.8%
Fixed Operating Costs + $5M/Yr	0.7%	2.8%	6.3%	8.5%
Fixed Operating Costs - $3M/Yr	2.3%	4.4%	7.3%	9.5%
Early Start-up (1 yr)	2.0%	4.2%	7.4%	9.7%
Late Start-up (6 mos)	1.5%	3.6%	6.9%	9.1%

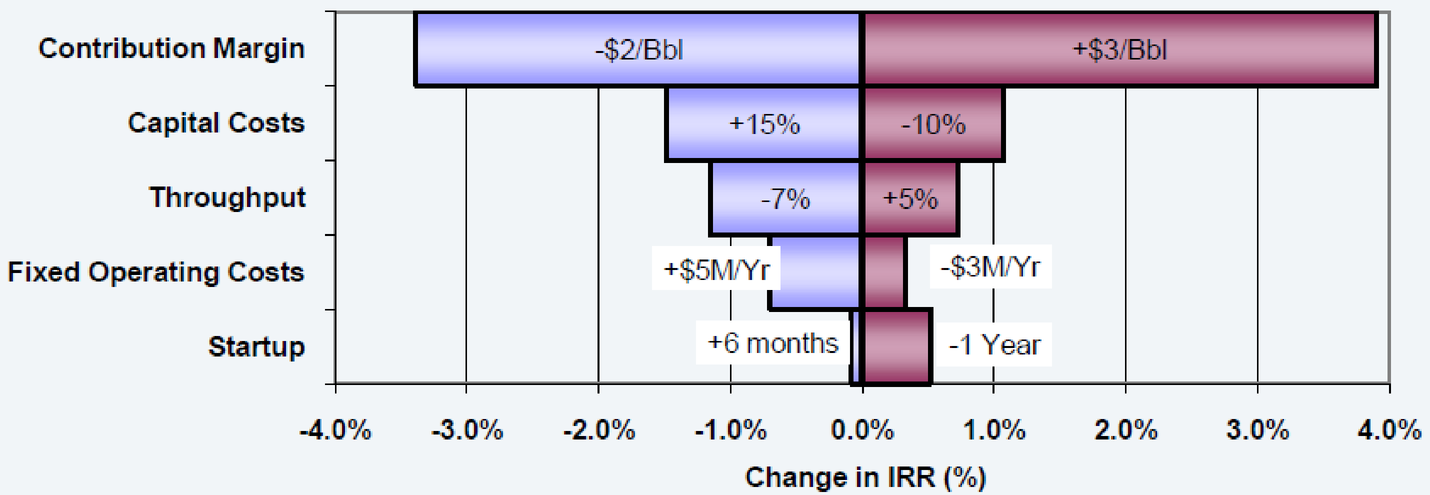
Cash Flow Sensitivity



- Contribution margin followed by capital cost has the largest impact.

Cash Flow Sensitivity

FIGURE 9
34 KBPD REFINERY IRR SENSITIVITY TORNADO CHART



- Contribution margin followed by capital cost has the largest impact.

Cash Flow Sensitivity

- What capital cost decrease or contribution margin increase will be required to yield a 15% IRR?

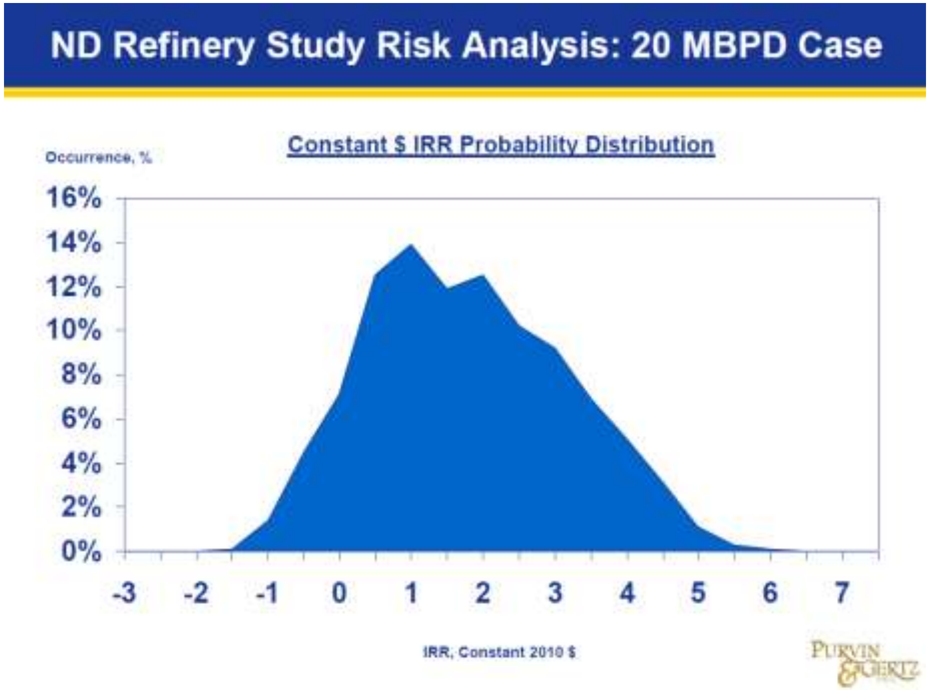
North Dakota Refinery Study
Margin and Capital Cost Sensitivity for Nominal 15% IRR

	Capital Costs			Contribution Margin		
	% Reduction	Real	Nominal	$/bbl Incr.	Real	Nominal
20 KBPD Refinery	-64.9%	12.6%	15.0%	+$ 11.4	12.6%	15.0%
34 KBPD Refinery	-33.7%	12.6%	15.0%	+$ 4.7	12.6%	15.0%

Risk Analysis

- 10,000 Iteration Monte Carlo analysis
- Triangular distribution for key variables:
  - Plant throughput
  - Contribution Margin
  - Fixed Costs
  - Capital Costs
- Discrete distribution for schedule variable
- Same ranges as in sensitivity analysis

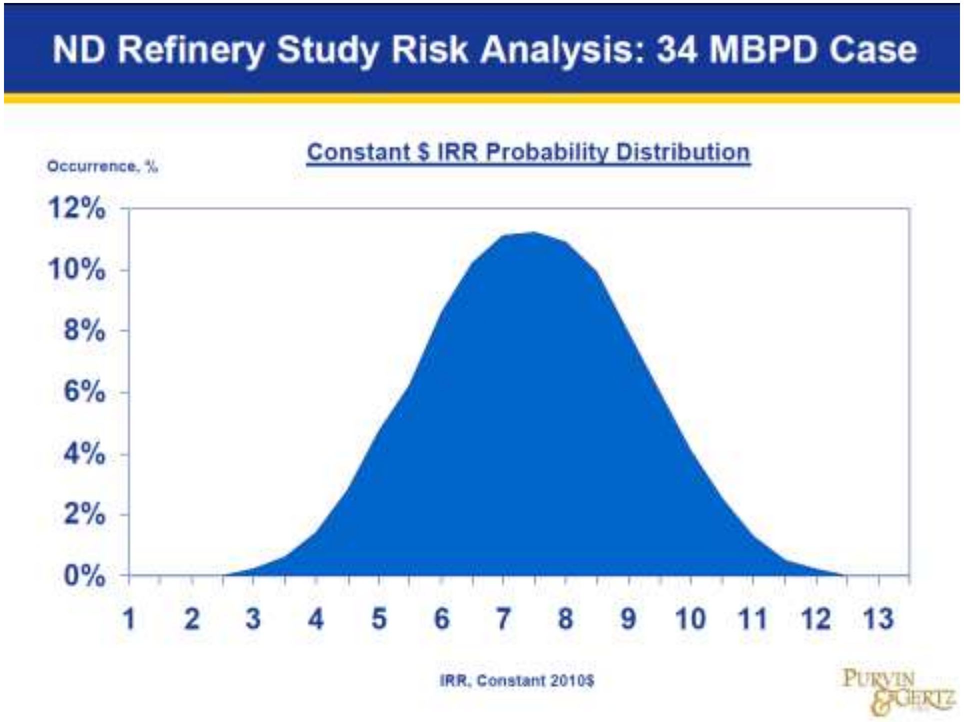
Monte Carlo Analysis



- 20 MBPD Case, Constant $ IRR
- Minimum IRR result =

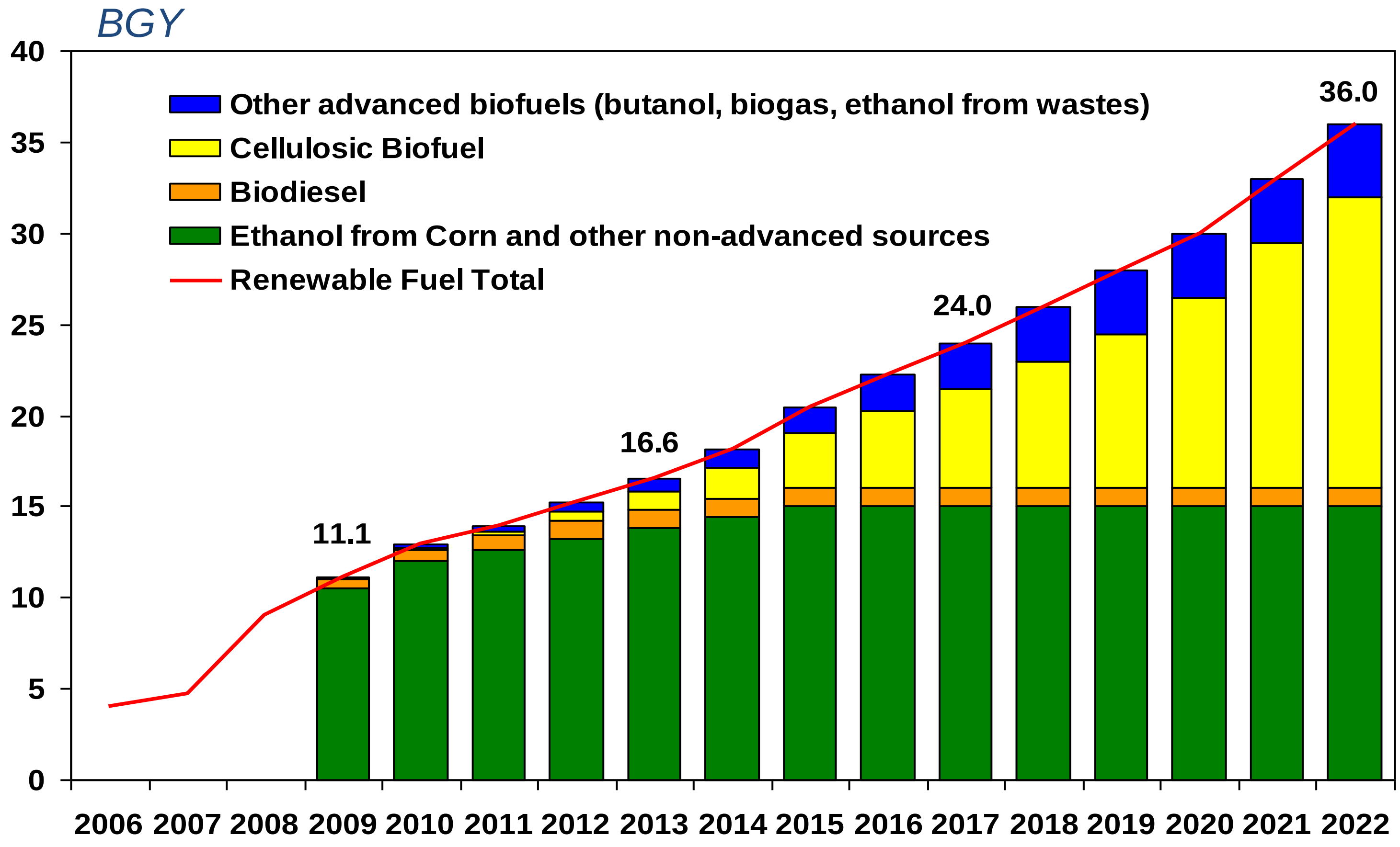
  -1.7 %
- Mean = 2.0 %
- Maximum = 6.4 %
- Std. Deviation = 1.4 %

Monte Carlo Analysis

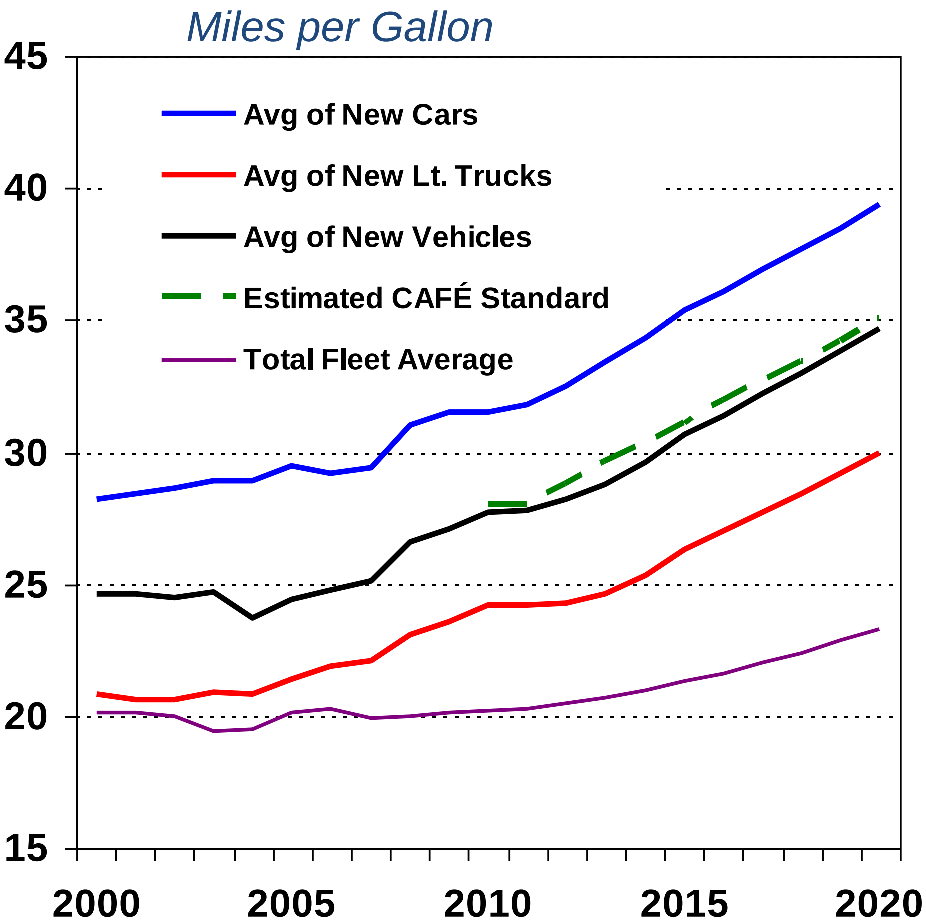


- 34 MBPD Case, Constant $ IRR
- Minimum IRR result = 2.2 %
- Mean = 7.2 %
- Maximum = 12.2 %
- Std. Deviation = 1.6 %

Renewable Fuel Standard as established by 2007 Energy Independence and Security Act (EISA)



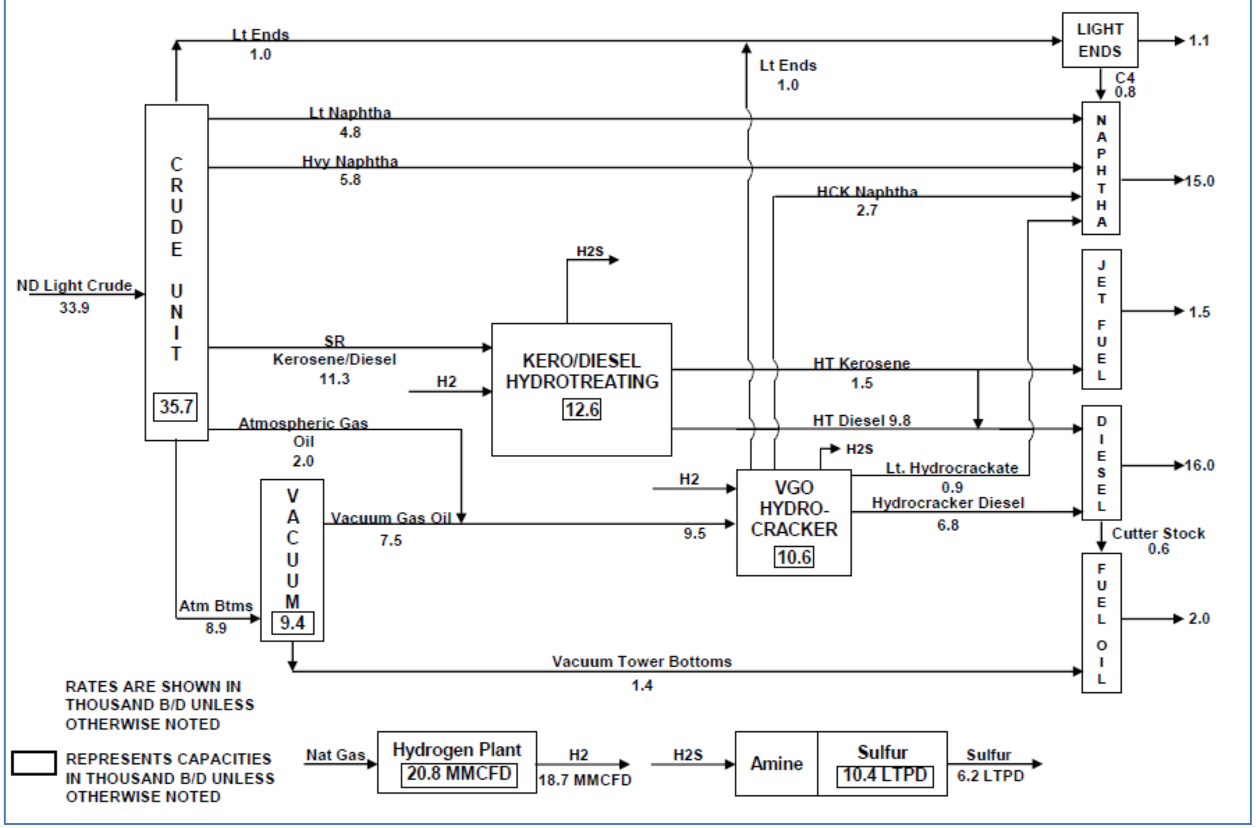
Corporate Average Fuel Economy (CAFE) requirements increase greatly



- CAFE standard establishes average fuel efficiency requirement for auto manufactured for US sale
- Applies to “light duty” vehicles up to 8,500 pounds (includes ½ ton SUVs and trucks)
- New standard includes mileage targets with concurrent greenhouse gas emissions limits.
- Standard established in 1975 but largely stagnant from mid-1980s to 2000

Refinery Configuration – 34,000 B/D

FIGURE 2
NORTH DAKOTA REFINERY SIMPLIFIED BLOCK FLOW DIAGRAM: 34,000 B/D CASE



Refinery Analysis

- Major Refinery Facilities
  - Crude and Vacuum Distillation
    - to provide primary separation of the crude oil for subsequent processing by downstream units.
    - to separate atmospheric residuum into vacuum gas oil for feed to the Hydrocracker unit and vacuum residuum for sale as fuel oil.
  - Gas Plant recovers propane and butanes as finished products from light ends.
  - The Distillate Hydrotreater Unit removes contaminants such as sulfur and nitrogen from distillate kerosene and diesel.
  - Hydrocracker Unit hydrotreats and cracks gas oil feedstock to produce naphtha, jet fuel, and diesel.

Refinery Analysis

- Support Facilities and Offsites:
  - Hydrogen Production
  - Sulfur Recovery
  - Crude Oil/Products Storage, Blending and Shipping
  - Utilities
  - Emergency Pressure Relief
  - Fire Fighting
  - Buildings

Refinery Analysis - Emissions

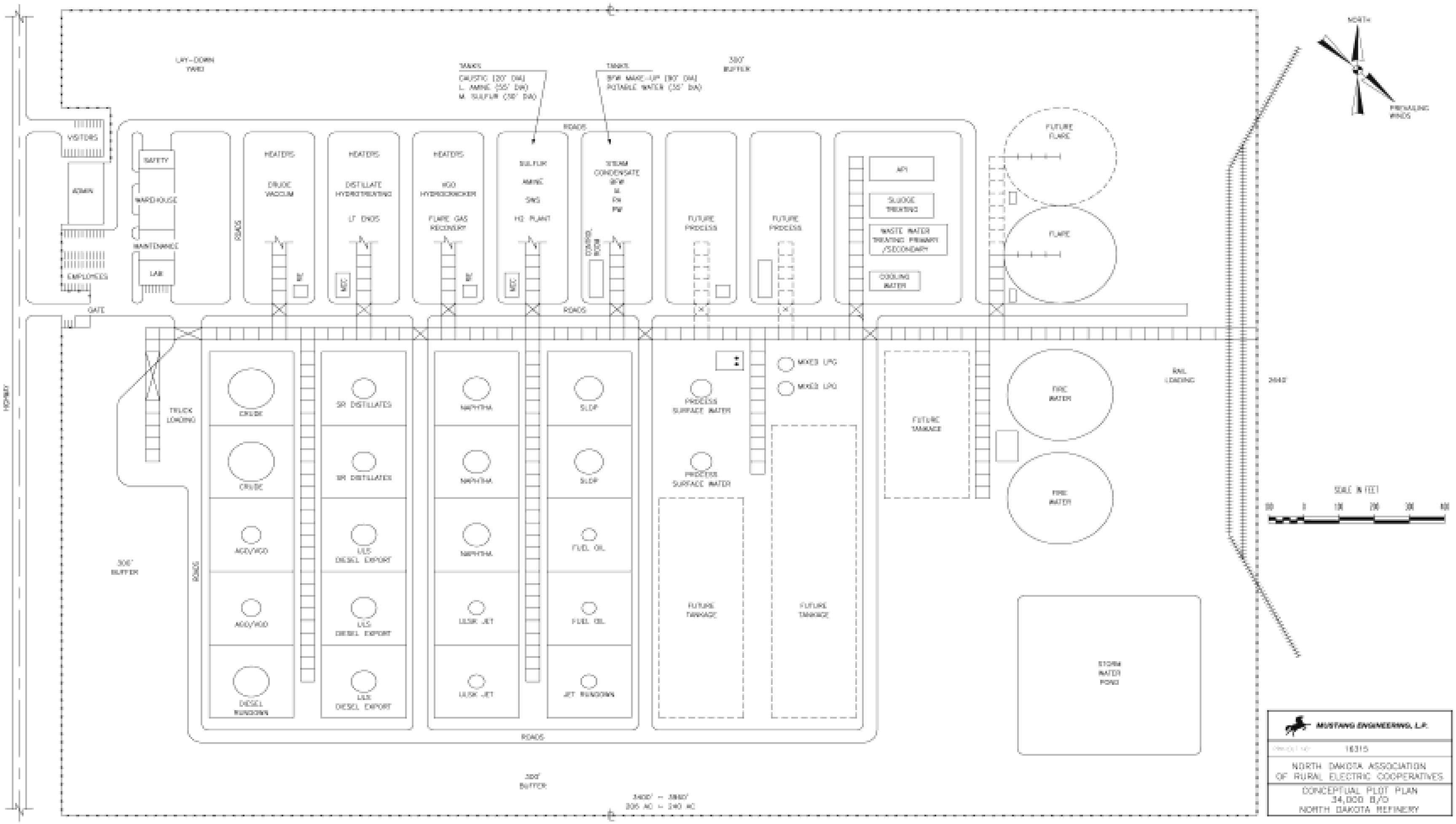
Preliminary Summary of Potential Emissions

Pollutant	Heaters, Thermal Oxidizer, and Flare	Tanks	Product Loading	WWTP	Cooling Tower	Equipment Leak	Emergency Equipment	Total (tpy)
Carbon Monoxide (CO)	99.1						0.4	99.5
Nitrogen Oxides (NOx)	80.4						0.8	81.2
PM-10	16.6				0.1		0.0	16.7
Sulfur Dioxide (SO_2)	23.0						0.0	23.0
VOC	13.5	11.6	0.1	16.9	0.6	11.4	0.0	54.1
Hydrogen Sulfide (H_2S)	1.3					0.4		1.7

Refinery Analysis

- Emissions
  - Annual emissions assume 8,760 operating hours per year.
  - All equipment will be designed to meet US Environmental Protection Agency air emissions standards.
  - Emissions are based on EPA accepted emission factors for specific equipment and state of the art control practices.
  - Emissions of SO_2 and H_2S from the thermal oxidizer in the Sulfur Recovery Plant are based on 99.97% sulfur recovery.
  - For naphtha rail loading, a vacuum-regenerated, carbon adsorption-vapor recovery system is included to comply with VOC emission limits.
  - Emissions from the cooling tower will include particulate matter and VOC's.

Refinery Site Plan



Refinery Analysis

- Site Plan – Conceptual Design
  - The location is assumed to be adjacent to a highway and rail line is nearby.
  - Approximately 200 acres are required for the project. Right-of-way for rail spur to the refinery is not included.
  - The conceptual plot on 200 acres allows for future development of process, utility, and storage facilities.
  - There are allowances for 300-foot buffer zones along the frontage road and adjacent properties.
  - The spacing between and within process units is based on Industrial Risk Insurers (IRI) oil and chemical plant guidelines.

Site Selection Criteria

Primary Considerations:

- Optimize product and crude transportation costs relative to existing infrastructure.
  - naphtha transportation to Canada is assumed to be railed with possible future pipeline options.
  - diesel fuel will be marketed primarily in North Dakota.
- Locate the refinery:
  - to attract and maintain the required skilled labor at a competitive labor cost.
  - to minimize capital and operating costs associated with the import of fuel and electricity.
  - where sufficient water is available.

Benefits to North Dakota

- New refinery capacity would provide employment to:
  - an estimated 75 operations personnel with an average salary of $80,000
  - an estimated 80 maintenance positions with an average salary of $75,000
  - an estimated 55 professional and administrative jobs with an average salary of $85,000
- The personal income from these jobs is estimated to be about $16.6 million per year.
- Increased economic activity required to provide goods and services to the refinery and would result from the spending of this new personal income.
- 16,000 BPD of diesel fuel supply into the local market would potentially reduce supply disruptions.
- Citizens of the state could realize benefits due to the lower cost diesel fuel.
- During construction of the refinery an estimated $220-250 million could be paid for labor and some local fabrication work.
- Increased crude netback prices for a period of 3-5 years may positively affect severance taxes and royalty payments.

Opportunities to Improve Project Viability

- Expand an existing refinery instead of building a "grass roots" facility.
- Evaluate use of extensive modular construction.
- Exploring the potential for obtaining, relocating and installing existing process equipment.
- Optimize return of a grassroots refinery through the site selection process to improve the contribution margin.
- Debt financing options may provide opportunities to improve the IRR.

Conclusions

- There is a market for naphtha produced in North Dakota created by the growth in bitumen production in Canada.
- The 34,000 BPD diesel and naphtha refinery produces a higher return on investment than the 20,000 BPD refinery producing gasoline and diesel.
- The 34,000 BPD naphtha refining project provides a nominal 9.2 % IRR. Further alternatives could be explored to improve the return on investment.
- The benefits to North Dakota are primarily in the areas of increased state revenues, new employment opportunities and an increased North Dakota production of diesel fuel.

Thank you!

- Questions?

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