TOPIC PAPER #16

REFINING AND MANUFACTURING

On July 18, 2007, The National Petroleum Council (NPC) in approving its report, *Facing the Hard Truths about Energy,* also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the Task Groups and their Subgroups. These Topic Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached Topic Paper is one of 38 such working document used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix E of the final NPC report provides a complete list of the 38 Topic Papers and an abstract for each. The printed final report volume contains a CD that includes pdf files of all papers. These papers also can be viewed and downloaded from the report section of the NPC website (www.npc.org).

NATIONAL PETROLEUM COUNCIL

REFINING & MANUFACTURING SUBGROUP OF THE SUPPLY TASK GROUP OF THE NPC COMMITTEE ON GLOBAL OIL AND GAS

TEAM LEADER

David L. Whikehart
Optimization LP Manager
Marathon Oil Corporation

MEMBERS

Alison A. Keane
Environmental Protection Specialist
Office of Policy, Economics and Innovation
U.S. Environmental Protection Agency

Philip Stephenson
Vice Chairman
The Rompetrol Group NV

Michael E. Leister
Fuels Technology Manager
Marathon Oil Corporation

Thomas H. White
Policy Analyst
Office of Oil and Gas Analysis
U.S. Department of Energy

David A. Sexton
Vice President
Strategy and Portfolio
Shell Oil Products U.S.

James R. Wilkins
Refining HES Manager
Marathon Oil Corporation

Refining and Manufacturing Cross Cutting Team Report

Team Leader: David Whikehart
Date Submitted: March 21, 2007

I. Executive Summary

This report attempts to answer a few key framing questions that were developed at the start of this project concerning refining capacity projections over the next 25 years. Specifically, the framing questions included;

- What new refining capacity will be built over the next 25 years to process the projected the crude oil demands?
- Where will the new capacity be located?
- What new technologies need to be developed to increase the capacity to process unconventional oil?
- What policy or regulatory barriers exist today that inhibits the development of new refining capacity?

A survey of 10 studies comprising 18 scenarios contained 27 direct or inferred refining capacity projections. The primary integrated studies from the IEA and EIA provided the context for assessing the range of refining capacity data from the other studies. Based on the IEA and EIA reference scenarios, the world refining industry must experience significant growth (32 MM BPD) over the next 25 years to meet the projected primary oil demand. The various studies and scenarios referenced in this paper provide a variety of projections based on different assumptions. However, all of the cases with a projection for 2015 (11 data points) show primary oil demand exceeding the projected 2015 refining capacity, even with an assumption that all of the announced capacity expansion projects in the latest Oil & Gas Journal Worldwide Construction survey are executed.

The location of the new capacity in most cases follows current trends. Based on the IEA and EIA data, growing oil demand in the United States will continue to outpace the increase in refining capacity, requiring increased imports of finished products.

Europe, the Middle East, and Africa will grow refining capacity above their oil demand, allowing for the export of finished products. Asia is projected to move from a balanced oil demand/refining capacity scenario to an imbalanced system similar to the United States where product imports are needed to bridge the supply gap.

The increase in unconventional oil production, primarily from Canada, should not require any new technology development for the refining industry. Existing residual oil conversion technologies including coking and solvent deasphalting should be sufficient to process the heavy oil into finished products. The complexity of refineries that will make investments to process the heavy crude will increase, however, due to the need for this residual oil conversion capacity as well as the need for additional hydrogen supply and hydrotreating processing capacity.

There are significant environmental regulatory barriers to refining capacity investments in the United States. Regulations from the Clean Air Act, New Source Review, and the National Ambient Air Quality Standards all place heavy cost burdens and uncertainty on refinery capacity expansion investments. Permitting issues seem to be the most onerous, given the fragmented design of the process and an appeals procedure that can significantly extend the time require to receive permit approval.

II. Overview of Methodology

This report is primarily based on a survey of publicly available data on refining capacity and configuration projections, world oil demands, regulatory requirements, and technical requirements. This report also contains observations and insights by the members of this subgroup based on their personal knowledge and expertise.

The main body of this report starts with an analysis of the IEA World Energy Outlook 2006 report which includes projections for refining investments in the Reference Scenario. There was enough data in the IEA report to derive the capacity impact of the investments by region. Dave Whikehart of Marathon Petroleum Company provided this analysis. Capacity projection data from other reports and studies (including the EIA and Oil and Gas Journal) were then layered onto the base IEA data to chart a range of projections from which key observations were developed. Tom White of the US Department of Energy provided the analysis of the EIA data.

A European perspective on the potential increase of refining capacity was provided by Philip Stephenson of Rompetrol.

A critical issue that was identified early in this development of the framing questions involves the impact of unconventional oil on refinery configurations and the potential need to install new conversion technology. This issue was addressed by in a paper written by David Sexton of Shell and incorporated into this report. Additional work concerning the impact of processing unconventional oil on the energy intensity of refineries was added by Tom White to complete the picture.

An assessment of the environmentally driven regulatory issues associated with expanding existing refining capacity in the US was addressed in a paper by Alison Keane of the US EPA. A second paper focused on permitting issues was authored by Jim Wilkins of Marathon Petroleum Company. Together, these papers provide a sense for the regulatory barriers to increasing U.S. refining capacity.

The impact of “boutique” transportation fuels was also raised as an infrastructure issue. Mike Leister on Marathon authored a paper on these specialty fuels and their impact on the supply chain.

A brief summary on the impact of blending of biofuels and synfuels into hydrocarbon based transportation fuels completes this paper. This summary was written by David Whikehart and was based mostly on Marathon’s experience as an ethanol blender for over 15 years.

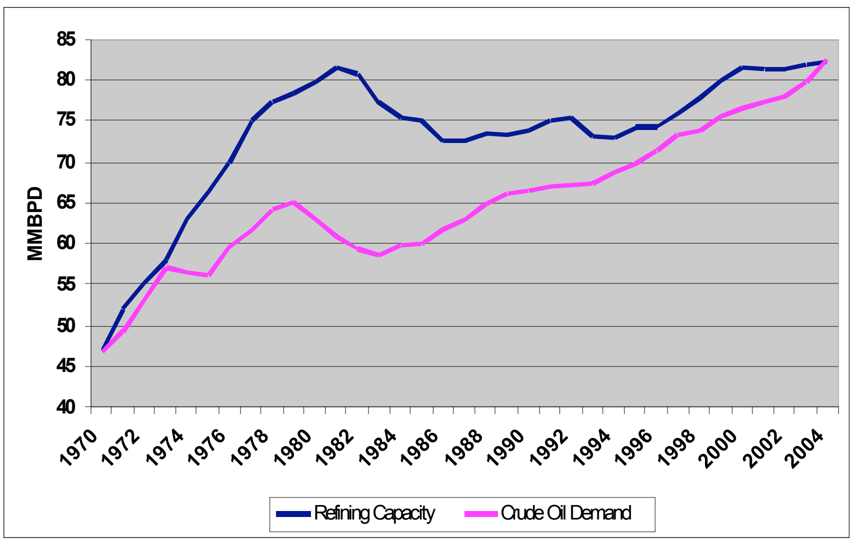
At the end of each report section there is a table that summarizes the observations and implications for that section. The reference source of the observation/implication is also listed.

A final section contains potential policy options for use in the NPC report integration process. The policy options make use of the Economics/Environment/Security triangle as a reference point.

III. Background

Refining capacity has experienced significant change over the past 35 years. The rapid increase in capacity in the 1970's coupled with the oil price shock in 1979 lead to overcapacity, poor margins, and rationalization of the industry. The number of refineries in the United States fell from over 300 to 150 while the average capacity per refinery steadily increased. Figure 1 shows the trends of refining capacity and crude oil demand. The overcapacity experienced by the industry has been slowly reduced over time until the last few years, when the gap appears to have closed.

Figure 1



In the United States, refining capacity has not kept up with oil demand, resulting in increased finished product and blendstock imports. More than 30 years have passed since the last new refinery was built in the U.S.; however, many refineries have increased capacity through the expansion of existing facilities.

Atmospheric distillation is the most basic refinery process and is the unit that is most commonly used to identify the capacity of a refinery. This paper will use the term "refining capacity" to mean the atmospheric distillation capacity.

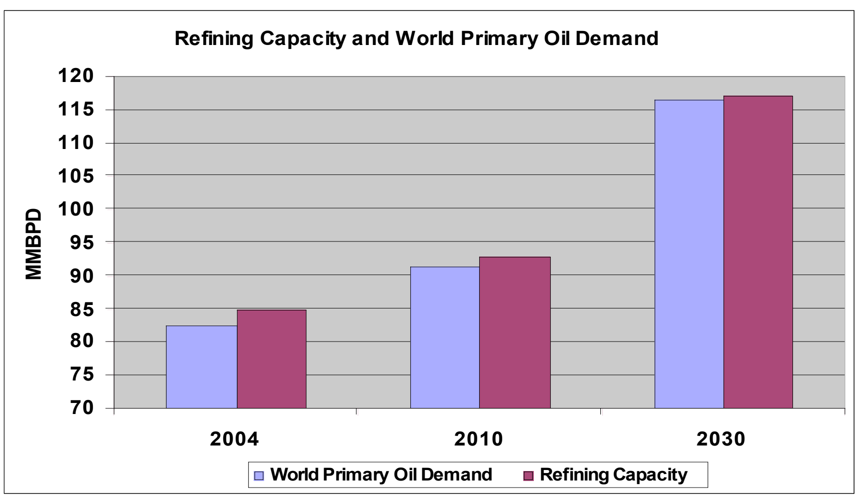
IV. Refining Investment and Capacity Projections

1) IEA and EIA

IEA WEO 2006 Reference Scenario Assumptions

The International Energy Agency World Energy Outlook 2006 makes some assumptions in its Reference Scenario that impact refining industry capacity investments through 2030. First, the study assumes that there will be no new government policies introduced that will impact energy supply and demand. This assumption is critical in that no new barriers to constructing refining capacity will be considered in the Reference Scenario. Second, the study assumes that market prices will be high enough to stimulate sufficient investment in new supply infrastructure to enable all of the projected demand to be met. The assumption of no new barriers to installing refining capacity coupled with sufficient economic drivers allow for the projected demand for refining capacity to track with the study's World Primary Oil Demand projections, as shown in Figure 2.

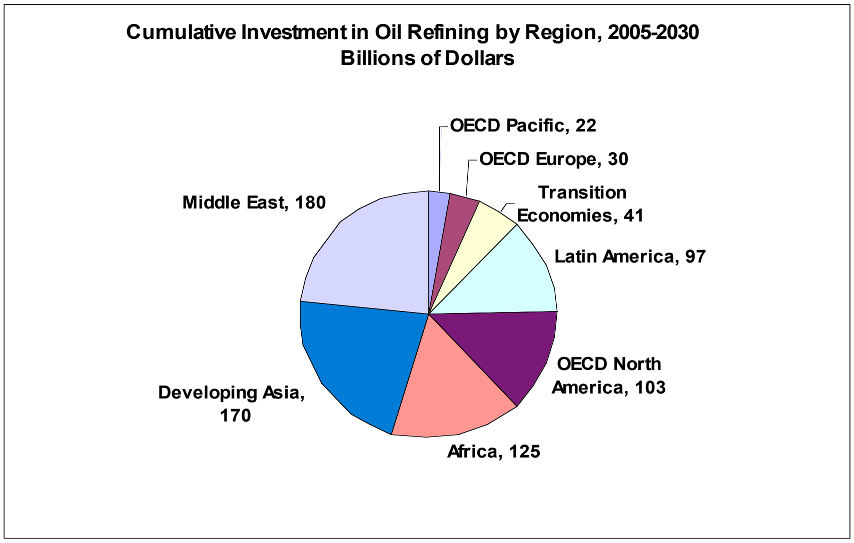
Figure 2



Refining Investment

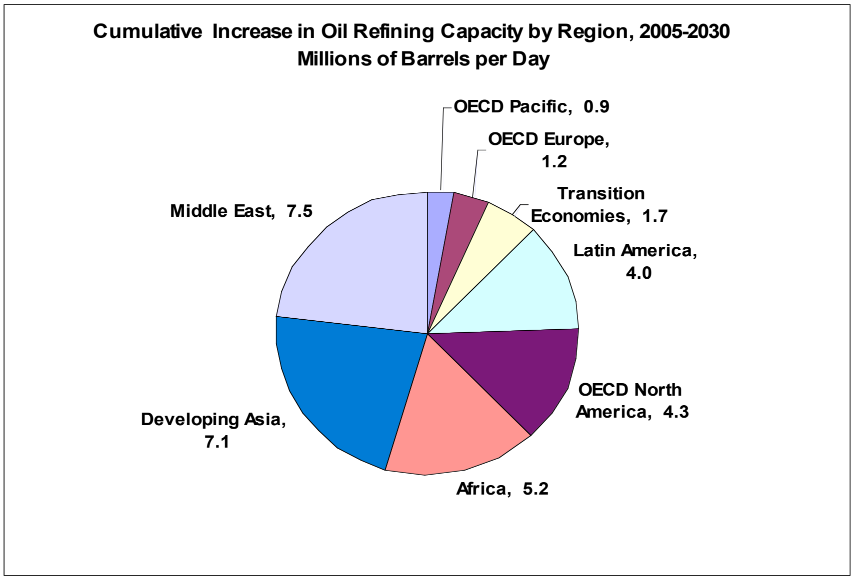
The Reference Scenario contains cumulative investment estimates in energy infrastructure by fuel type for 2005-2030 (in year 2005 dollars). The oil portion of the estimate is $4.3 trillion with 18%, or $774 billion, in refining investments. These investments include distillation and conversion capacity, as well as fuel quality enhancement for environmental needs. Figure 3 illustrates the cumulative refining investments by region.

Figure 3



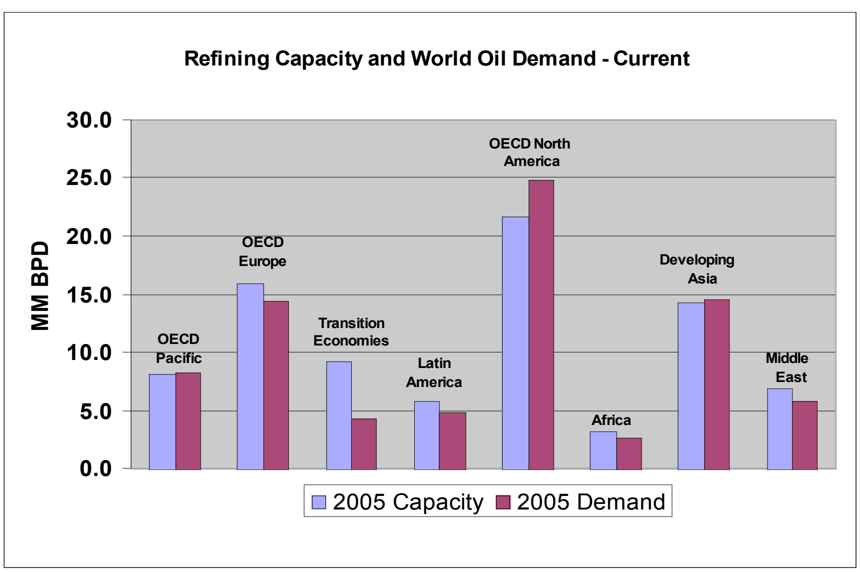
A simple calculation that divides the projected increase in refining capacity over the same time frame (32 million BPD) into the total investment of $774 billion yields an average investment cost of about $24,100 per BPD. While this simplistic approach mixes all types of investments (distillation, conversion, product quality, new construction, expansions); it does provide a means to convert investment dollars to refining capacity. Using this average capacity investment cost approach, the cumulative increase in refining capacity by region was calculated and is shown in Figure 4.

Figure 4



The IEA WEO 2006 also contains a regional breakdown of primary oil demand that can be compared to the regional refining capacity data to provide more insight into the import/export picture for refined products. Figure 5 illustrates the refining capacity/oil demand scenario in 2005. North America shows a significant deficiency in refining capacity relative to oil demand, while Europe, Transition Economies, Latin America, and the Middle East all show refining capacity in excess of their oil demand. The Pacific, Africa, and Developing Asia regions are essentially balanced.

Figure 5



A comparison of the calculated cumulative refining capacity increase through 2030 with the IEA's projected oil demand in 2030 is illustrated in Figure 6. The projection shows that the gap between refining capacity and oil demand in North America will increase, most likely resulting in increased product imports. Using this approach, Developing Asia is projected to become significantly deficient in refining capacity relative to oil demand. The remaining regions are projected to build refining capacity in excess of oil demand, providing the products needed to close the demand gaps in North America and Asia.

Figure 6

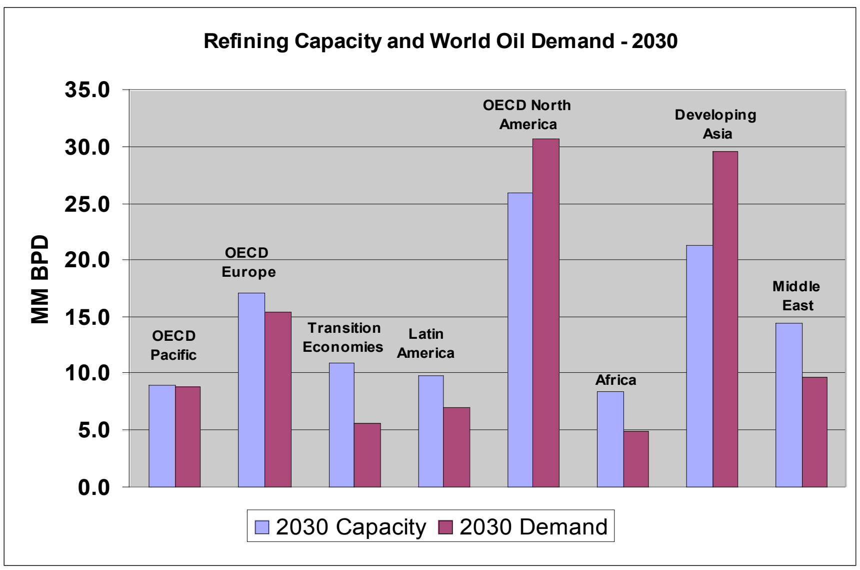
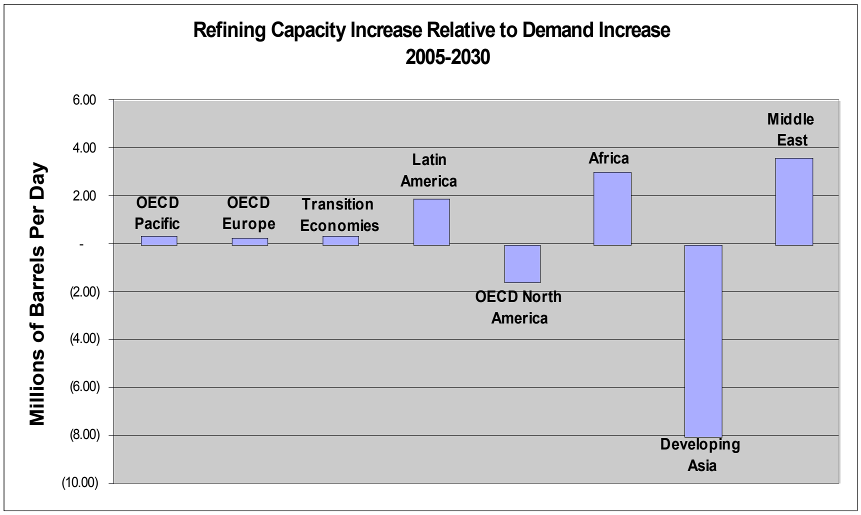


Figure 7 was developed to simplify the comparison between Figure 5 and Figure 6. In Figure 7, the projected deficiency in refining capacity for Asia stands out as does the positioning of the Middle East, Africa, and Latin America as potentially increasing their supply of products to North America and Asia to meet projected oil demands.

Figure 7

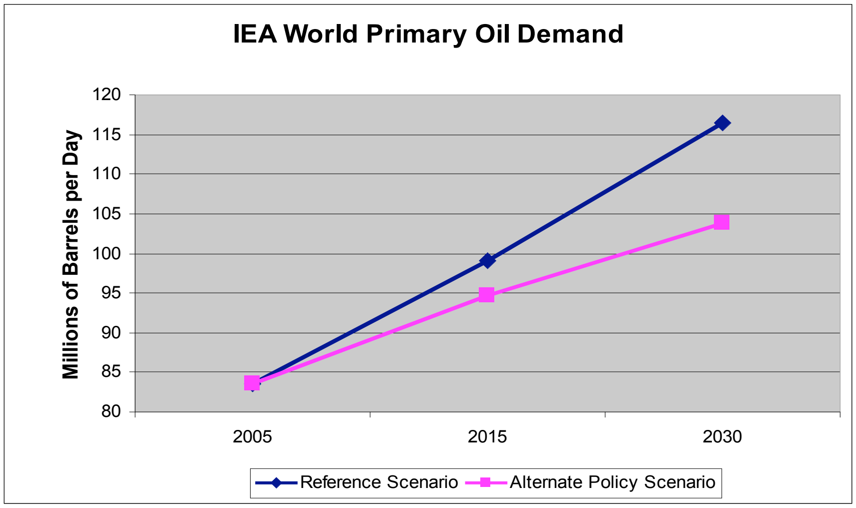


IEA WEO 2006 Alternative Policy Scenario Assumptions

The International Energy Agency World Energy Outlook 2006 makes some assumptions in its Alternative Policy Scenario (APS) that impact refining industry capacity investments through 2030. The study assumes that countries adopt policies that they are currently considering that enhance energy security and/or address climate change. For the United States, these policies include EPACT 2005, state-based renewable portfolio standards, and Corporate Average Fuel Economy reform. The APS also excludes technology that has not yet been commercially demonstrated. This includes carbon capture and storage, second generation biofuels, and plug-in hybrids.

The APS projects that the world primary oil demand in 2030 will be 103 million BPD, or about 13 million BPD less than the Reference Scenario. This will require about 40% less refining distillation capacity to be constructed to meet the 2030 demands. Figure 8 compares the world primary oil demand for both scenarios.

Figure 8

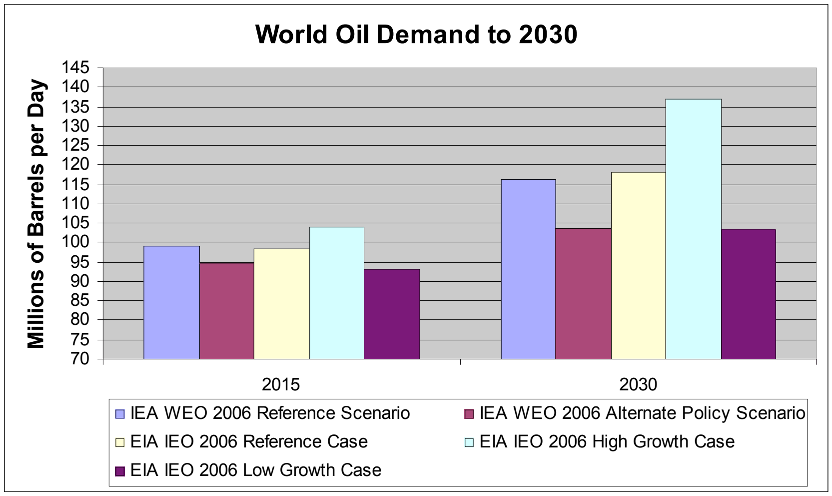


The total investment in refining capacity in the APS was calculated by adjusting the $771 billion cumulative refining investment through 2030 by the 40% reduction in capacity demand. This results in the refining investment of $458 billion, a reduction of $312 billion.

EIA International Energy Outlook 2006

The EIA International Energy Outlook does not explicitly model refinery capacity investments. However, it is useful to compare world oil demand between the EIA and IEA projections to gain some insights on the range of refining capacity needed to meet the demands of the various scenarios. Figure 9 compares the IEA Reference and Alternative Scenarios to the EIA Reference, High Growth, and Low Growth Cases. The EIA Reference Case and the IEA Reference Scenario are essentially the same in both 2015 and 2030. However, the EIA High and Low Growth Cases bracket the range of oil demand (and the inferred refining capacity) in both 2015 and 2030. The difference in the High and Low Growth Cases results in a range of about 11 MM BPD in 2015 and 34 MM BPD in 2030.

Figure 9



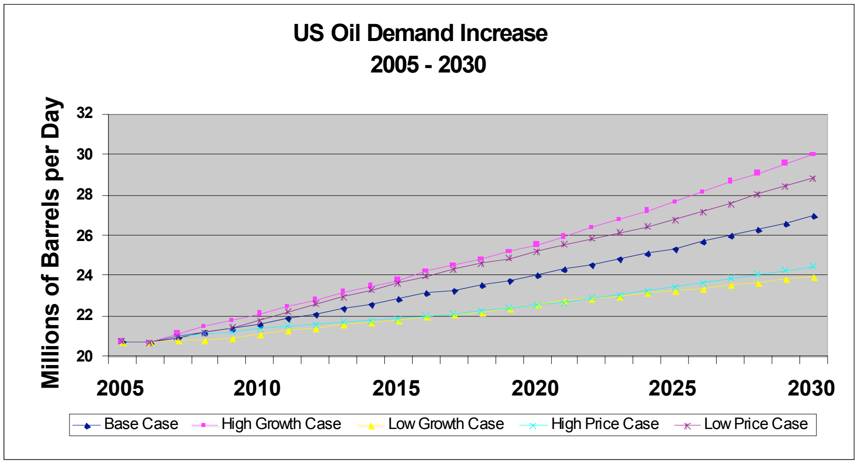
The EIA IEO 2006 projections do not consider the potential impact of proposed legislation, regulations, and standards. Further, the potential impact of existing legislation for which there is no identified implementation mechanism is also not considered in the projections.

EIA Annual Energy Outlook 2006

Projections concerning the U.S. oil demand, refining capacity, and inputs to refinery distillation units are presented in the U.S. Energy Information Administrations Annual Energy Outlook 2006 (AEO 2006). The AEO 2006 contains projections based on Federal, State, and local laws and regulations in effect on or before October 31, 2005. The AEO projections encompass five scenarios with a range of assumptions concerning future economic growth rates and oil prices. These five scenarios are the reference case, high and low economic growth scenarios, and high and low oil prices scenarios.

U.S. primary oil demand in 2030 for these five scenarios ranges from 24 to 30 million barrels per day, a growth of 3.3 to 9.3 million barrels per day relative to 2005. This range of increases results in annual growth rates ranging from 0.6% to 1.5% over the 25 year period. Figure 10 illustrates the U.S. oil demand increase.

Figure 10



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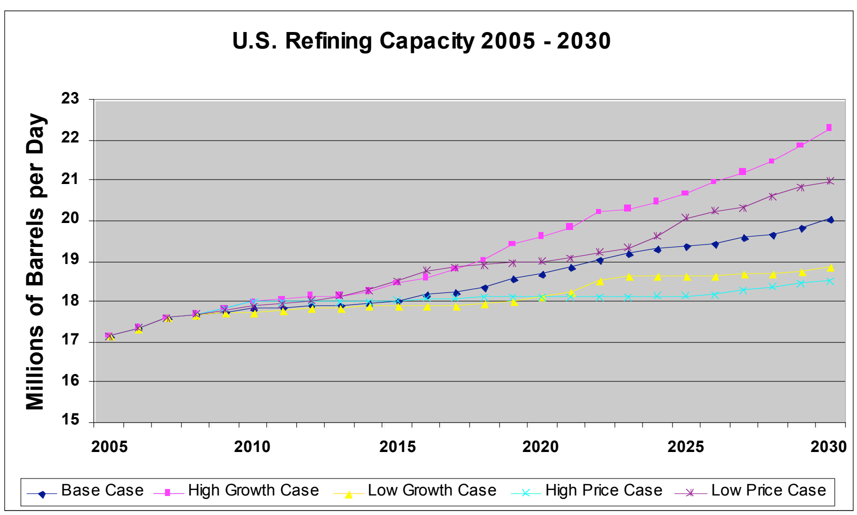
U.S. distillation capacity is projected to grow by 1.2 to 5.0 million barrels per day to a total of 18.8 to 22.3 million barrels per day depending on the scenario from 2005 to 2030 as shown in Figure 11.

Figure 11



The EIA report also projects the inputs to the distillation towers at the U.S. refineries. The value of this projection lies in a derivative calculation where the capacity utilization can determined. Higher capacity utilizations, if achievable, leave less flexibility for the U.S. refineries to respond to unplanned refinery outages such as those experienced as a result of the 2005 hurricanes. Lower capacity utilizations might imply that refining margins are relatively poor and not covering operating costs. The distillation tower input projection is shown in Figure 12 and the calculated capacity utilization is shown in Figure 13.

Figure 12

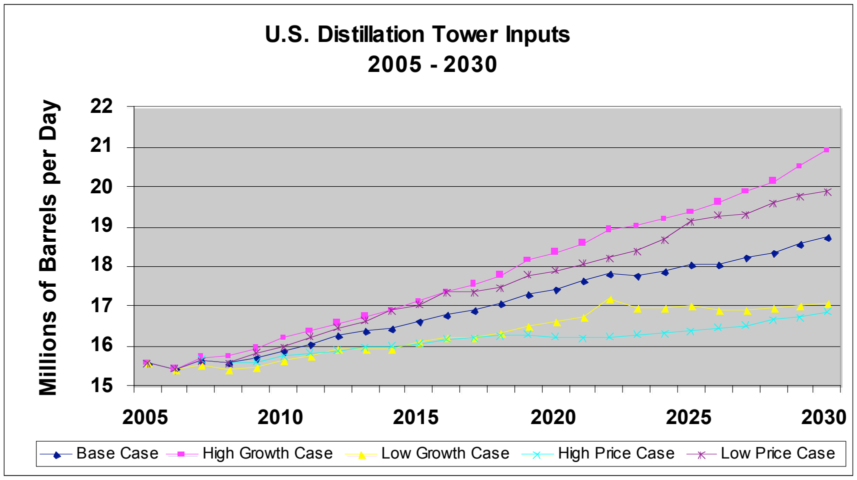
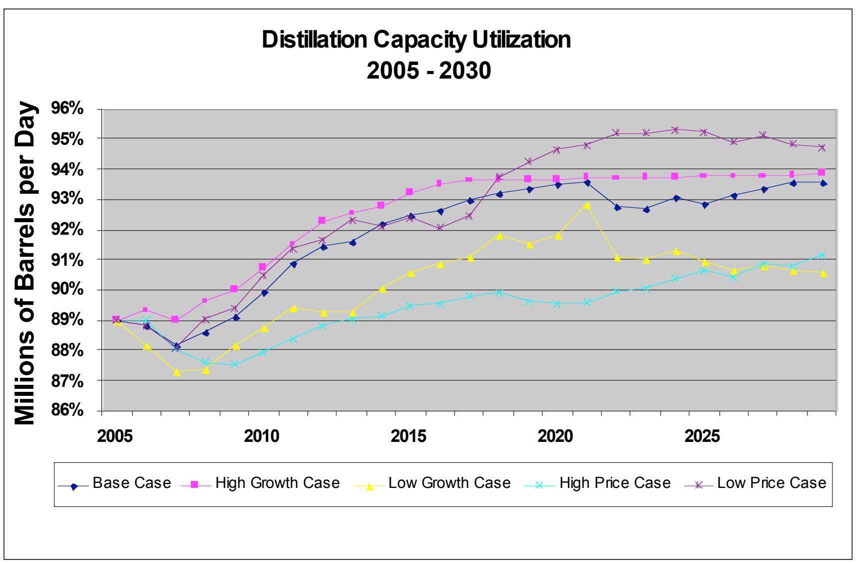
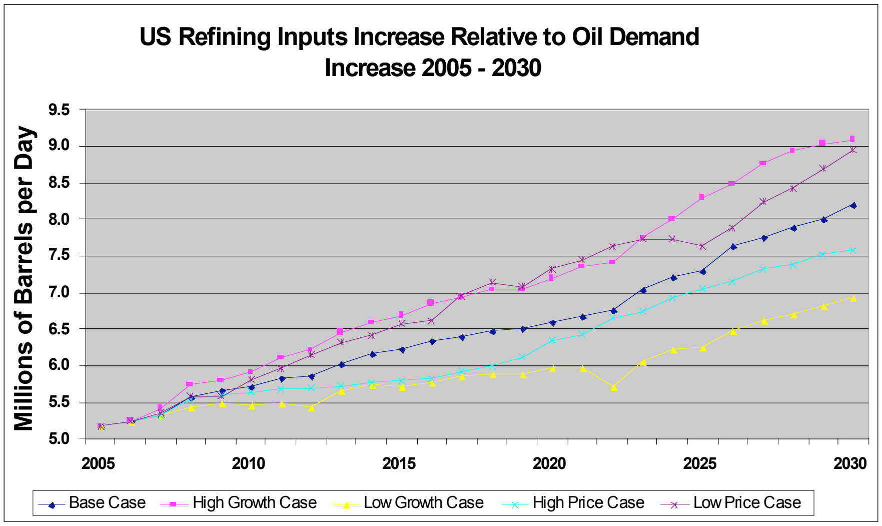


Figure 13



The difference between the inputs to the distillation towers and the oil demand yields the shortfall of supply that must be imported as finished products. Figure 14 illustrates this calculated difference and shows the gap between refining throughput and imports growing by between 2 and 4 million barrels per day to a total of between 7 and 9 million barrels per day by 2030. This represents between 35% and 70% increase in 2030 over 2005.

Figure 14



Observations and Implications

Reference	Observations	Implications
IEA WEO 2006 Reference Scenario	Assume no new barriers to installing refining capacity and sufficient economic drivers for refining capacity investments.	Refining capacity should track with primary oil demand projections.
IEA WEO 2006 Reference Scenario	Cumulative refining investments from 2005 through 2030 will total $774 billion (in 2005 dollars) with the refining capacity increasing by 32 million barrels per day.	A simple calculation that divides the projected increase in refining capacity by the invested dollars yields an average investment cost of $24,100 per barrel per day of capacity.
IEA WEO 2006 Reference Scenario	Refining capacity investments in the U.S. and Asia will not keep pace with their respective regional oil demand increases.	Increased imports of finished products and blendstocks into the U.S. and Asia.
IEA WEO 2006 Reference Scenario	Refining capacity investments in Latin America, Africa, and the Middle East will outpace their respective regional oil demand increases.	Increased export of finished products and blendstocks from Latin America, Africa, and the Middle East.

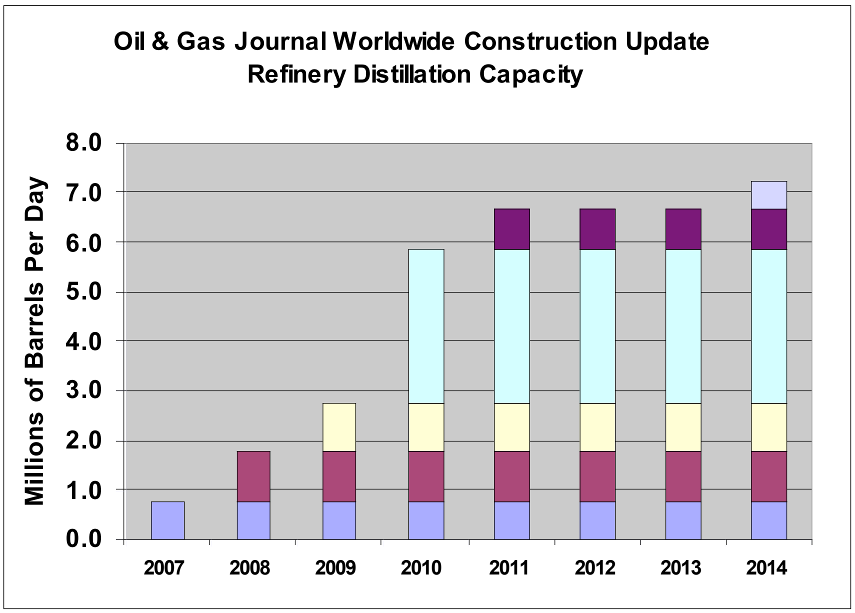
IEA WEO 2006 Reference Scenario	Refining capacity investments in the Pacific, European, and Transition regions will keep pace with their respective regional oil demand increases.	The Pacific, European, and Transition regions will each internally balance the supply and demand of finished products.
IEA WEO 2006 Alternative Policy Scenario	The APS will require about 40% less refining distillation capacity to meet the increase in primary oil demand in 2030.	Total investment in refining capacity will be reduced by about $312 million relative to the Reference Scenario.
EIA IEO 2006	The High and Low Growth Cases bracket the range of primary oil demand increase (and the inferred refining capacity increase) at 11 MM BPD in 2015 and 34 MM BPD in 2030.	Significant differences in projected refining capacity may increase investment risk and uncertainty.
EIA AEO 2006 Low Price Case	U.S. distillation capacity utilization exceeds 95%.	Higher capacity utilization may be difficult to achieve and leaves less flexibility for U.S. refineries to respond to unplanned outages and supply disruptions.
EIA AEO 2006 High Price Case	U.S. distillation capacity utilization less than 90%.	Lower capacity utilization might imply relatively poor margins that do not cover operating costs.
EIA AEO 2006	U.S. refinery distillation tower inputs are not projected to keep pace with oil demand in any of the case projections.	Imports of finished products and blendstocks are projected to increase by about 35% (2 MM BPD) in the Low Growth Case and by about 70% (4 MM BPD) in the High Growth Case.

2) The Oil &Gas Journal

Oil & Gas Journal Worldwide Construction Update

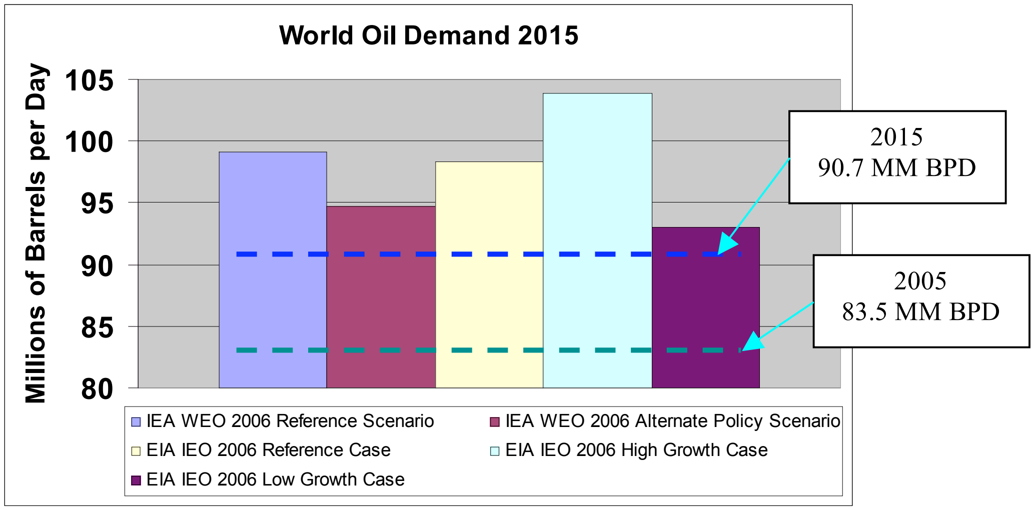
The Oil & Gas Journal published their latest construction update in November, 2006. The crude distillation projects by year of planned completion are illustrated in Figure 15.

Figure 15



The total cumulative increase in refining distillation capacity is projected to be 7.2 million barrels per day by 2015 if all of the projects are completed. This includes projects that are reported as in planning phase, in the engineering phase, and in the construction phase. Figure 16 compares the O&GJ survey results to the IEA and EIA oil demand projections.

Figure 16



Additional capacity may be added by "capacity creep" that routinely occurs without formal announcements. The increase due to creep is usually referenced in the industry at about 0.5% per year. A 0.5% annual growth rate through creep would deliver about 5 million barrels per day of additional distillation capacity by 2015. The combination of the O&GJ announced projects with the potential creep would yield just enough capacity to supply the IEA Alternate Policy Scenario demand.

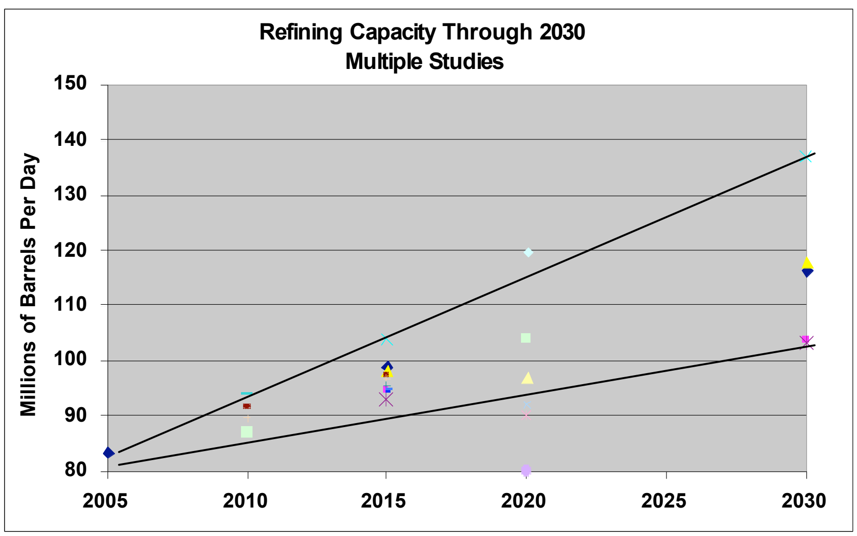
Observations and Implications

Reference	Observation	Implications
Oil & Gas Journal Worldwide Construction Update 2006	The cumulative increase in refining capacity is projected to be 7.2 MM BPD by 2015 if all projects in the survey are completed.	Refining capacity will be well short of EIA and IEA oil demand projections for 2015. The shortfall ranges from about 3 MM BPD (EIA Low Growth Case) to about 13 MM BPD (EIA High Growth Case).
	Refinery capacity creep of 0.5% per year could deliver another 5 MM BPD of distillation capacity by 2015.	The combination of the O&GJ announced projects with 0.5% creep would supply enough capacity to cover the IEA Alternate Policy Scenario Case.

3) Multiple Studies

The literature search for existing studies conducted for this paper found 10 studies (including the IEA and EIA reports) comprised of 18 scenarios and a total of 27 data points. The 2005 bases for these data points were not consistent, so the capacity/oil demand addition over time relative to each study's 2005 basis was used to allow for the comparison of the data. All of the refining capacity/oil demand projections were "anchored" to a 2005 capacity of 83.5 million barrels per day to allow for meaningful graphic display of the data. Neither refinery capacity utilization nor stream day/calendar day capacity offsets were considered in the studies, which may have lead to some of the inconsistency of the 2005 capacity basis. Figure 17 shows the data from these 10 studies.

Figure 17



A cone that encloses most of the projections was added to illustrate the divergence over time of the data points. In 2030, the boundary points are set by the EIA High Growth Case at about 137 million barrels per day and by the EIA Low Growth Case/IEA Alternative Policy Scenario at about 103 million barrels per day. Interestingly, most of the other projections fit inside the cone, with a few outliers in 2020. The divergence of the data points over time reflect the increasing variability of the assumptions in the projection models assumptions and imply increased risk of associated with refining investment returns.

The sources of the data points were not included in this report. The goal of this graph was to show the dispersion and divergence of multiple studies over the study time horizon rather than call out and question any individual study, scenario, or data point assumption.

Observations and Implications

Reference	Observations	Implications
10 studies comprised of 18 scenarios	27 data points that directly or indirectly project refining capacity were plotted resulting in a cone that diverges over time. In 2030, the cone diverges to extreme points that are 34 MM BPD apart.	The divergence of the refining capacity projections over time reflect the increasing variability in model assumptions and imply increased risk associated with refining investment returns.

V. European View

The Refining Cross Cutting Team included Philip Stephenson from Rompetrol as a member and he was able to provide a European perspective on refining capacity expansion projections. These projections were based on data obtained from CERA; however, all of the analyses and conclusions reflect Rompetrol views only.

Increased Oil Demand/New Refining Capacity

European oil demand will grow marginally compared to the rest of the world, as conservation measures are implemented. Europe's oil demand of 17 million barrels per day today will grow to slightly over 18 million barrels per day through 2020. In contrast, world demand will grow from 88 million barrels per day to over 107 million barrels per day (reflecting largely China, India and other "Big Emerging Markets" demand).

In Europe, by far the largest and fastest growing product component will be distillates, including highway diesel. Distillate demand represents more than one third

(6.6 million barrels per day) of the current total oil demand of 17 million barrels per day. Distillate demand is projected to grow to 8 million barrels per day of the 18 million barrels per day total oil demand by 2020 (e.g., approaching one half of the product demand mix).

Refining capacity in Europe will be added to meet this demand, but the growth will be slower than the rest of the world (in line with slower demand growth) and more concentrated on residual conversion capacity. European primary distillation capacity will grow by less than one million barrels per day (from 16.6 million barrels per day today to 17.4 million barrels per day m bpd in 2020). This is marginal compared to world primary distillation capacity which will grow 20% plus in the same period (from 87 million barrels per day to 107 million barrels per day). However, residual conversion capacity will grow by almost 1.5 million barrels per day from 4.5 million barrels per day today to 5.9 million barrels per day in 2020. This compares favorably with overall world growth in the same period where residual conversion capacity is projected to increase from 26.8 million barrels per day in 2007 to 38 million barrels per day in 2020. The disproportionate increase in residual conversion capacity will be driven by the production of heavier, more sour crude oils, increased environmental regulations concerning sulfur content of finished products, and better projected financial returns over the long term for more complex refiners.

Location of New Refining Capacity in Europe

New capacities in Europe will be added primarily through restart and revamp of Central and Eastern Europe facilities along with expansion and debottlenecking of existing capacity in Western Europe. We know of no completely new "greenfield" facility under consideration anywhere in the region.

Political and environmental factors in European countries may inhibit the construction of new capacity ("Not In My Back Yard" perspective). This needs to be balanced by security factors that may drive an EU energy policy towards conservation and energy independence. The resulting bureaucratic push will most likely be for diversified sources of power production (return to nuclear power), diversified supply of hydrocarbons (mix of FSU, Mideast, N and W Africa), lowered consumption (also to reduce greenhouse gas emissions), diversified transit routes, and the possible expansion of refining capacity. Economic factors will drive refiners to (re)build more complex, flexible and therefore profitable refining capacity

European Policy or Regulatory Barriers

In Western Europe, interest groups oppose and can prevent (or at least substantially delay) the installation or expansion of refining capacities

In developing Central and Eastern Europe, grass roots environmental lobbies are not (yet) powerful or skilled in using political/legal tactics against new capacities. However, foreign investors may take on more risk due to political and regulatory uncertainty.

Observations and Implications

Reference	Observations	Implications
Rompetrol	Oil demand will grow in Europe by about 1 MM BPD through 2020.	European refining capacity will expand to meet the increased oil demand.
Rompetrol	Financial returns will be better for complex refineries that increase residual oil conversion capacity.	European refineries will invest a disproportionate share of funds in residual conversion capacity relative to crude distillation capacity.
Rompetrol	New refining capacity in Central and Eastern Europe will be added by restarting and revamping existing facilities. New refining capacity in Western Europe will be added through expansion and debottlenecking of operating facilities.	No new greenfield refineries are expected to be constructed in Europe.
Rompetrol	Western Europe has a well developed democratic political process.	Interest groups oppose and can delay/prevent the installation of new refining capacity.
Rompetrol	Central and Eastern Europe.has an emerging democratic political process.	Elevated country risk in refining investments.

VI. Impact of Unconventional Oil on Refinery Configurations

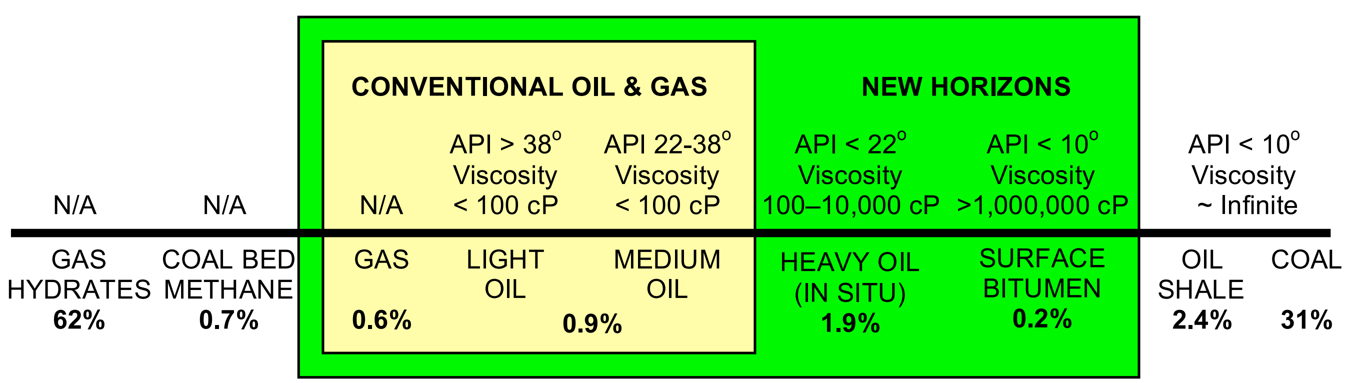
Background

This portion of the Refining Cross Cutting Team paper was written by David Sexton of Shell. Mr. Sexton used the combined knowledge of his colleagues as the resource for most of his paper. As a result, references to existing studies that can be found in the public domain are limited.

Feedstocks or primary resources which are not intensively exploited today will be referred to as unconventional fossil fuels in this paper. Unconventional feedstocks are not easily categorized, but they tend to fall within two broad groups, those that are basically variants of natural gas or petroleum, and those that are truly separate resources with unique chemistries like oil shale and methane hydrates. For this paper, only the processing of unconventional petroleum (heavy viscous oil and bitumen/oil sands) from the first group and oil shale from the second were considered.

Conventional oil, conventional gas, and conventionally produced heavy oil make up about 2% of the world's probable hydrocarbon resources. Surface bitumen, in-situ bitumen and extra heavy viscous oil together are estimated to be as big as the conventional resource base at approximately 2%, and oil shale could add that much again at about 2.4% or world resources.

World Hydrocarbon Resources



The easiest new hydrocarbon targets are those that are closest to what is already known and routinely processed today. Heavy viscous oil (HVO) fits this description. For clarity heavy viscous oil should not be confused with conventional heavy oils like Maya, and Arab Heavy that are below 20 API but produced by conventional methods or steam flooding and processed at heavy conversion refineries. The cutoff is fuzzy, but HVO and bitumen are generally about API 12 and heavier. Bitumen is extra heavy viscous oil that is not mobile at reservoir conditions. It may be in-situ (produced by thermal methods like steam) or close to the surface where it can be mined. Both HVO and bitumen are hydrogen deficient; they are generally sour and contain lots of metals and other contaminants.

Bitumen/Oil Sand (API <10°) is bitumen mixed with clay, sand and water. It basically forms a gritty sludge. Oil sand comprises an estimated 0.2% of world hydrocarbon resources. The processing of mined oil sand requires crushing of oil rich sand, hot water extraction of the hydrocarbons, and centrifuge separation to collect the bitumen. The separated bitumen is then cracked into lighter liquid products. This is done by thermal processes like coking or by hydrogen addition processes like LC-fining (a high temperature and pressure hydrocracking process not commonly used in refineries).

In-situ Bitumen and HVO are produced by thermal methods (cyclic steam or steam assisted gravity drainage) and do not require the sand crushing. Otherwise processing is pretty much the same as that described above. Approximately one trillion barrels of recoverable HVO and bitumen are estimated to exist, but they are difficult and expensive to produce, transport and refine. Although in some cases a reservoir is sufficiently warm to pump HVO, bitumen (whether surface or in-situ) and HVO generally cannot be pumped.

Some bitumen is diluted with lighter hydrocarbons to make it transportable and shipped directly to conventional complex heavy refineries. However, most of it (over 65%) is converted to syncrude by the processes described above and then shipped to refineries that still need substantial Nelson complexity to add the hydrogen required to make acceptable diesel, jet and gasoline.

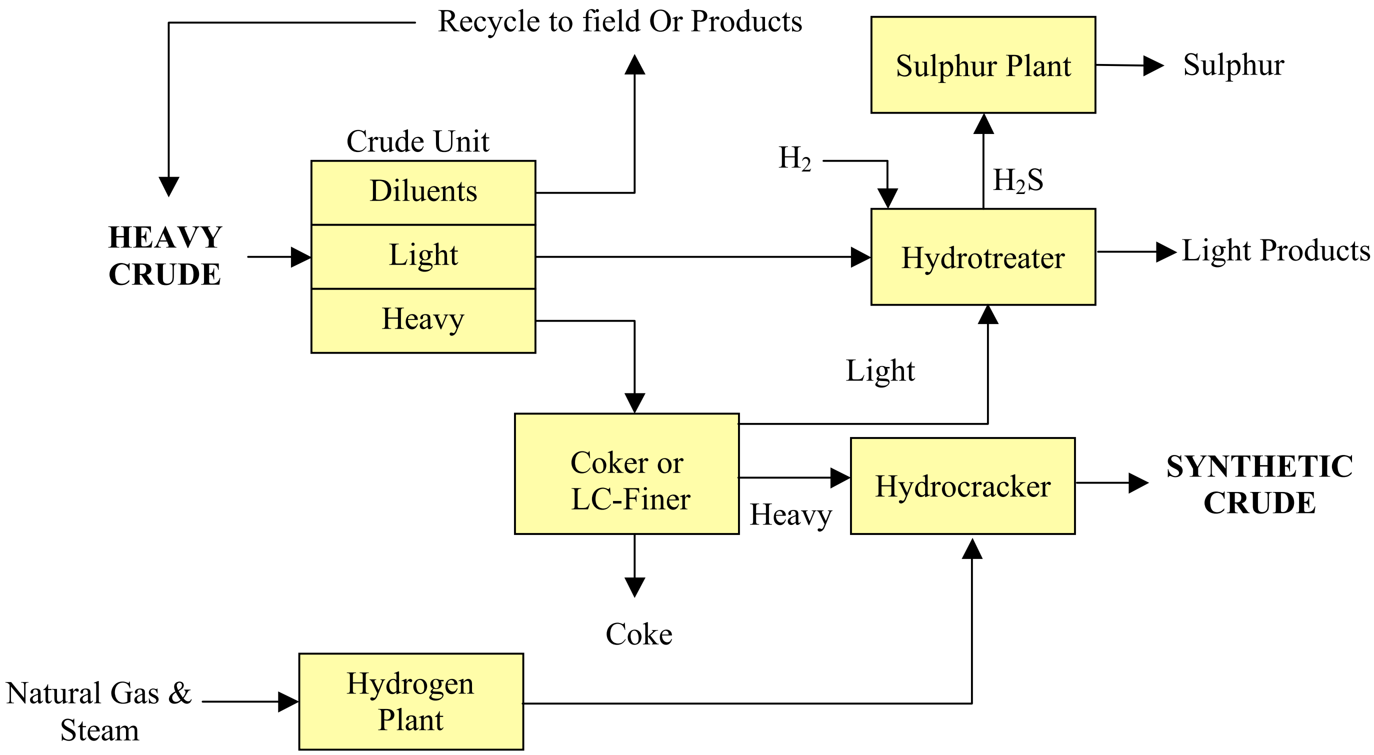
Hence, refineries designed to process these unconventional oils will require the capacity to cost effectively generate significantly more hydrogen than refineries processing conventional light to medium oils today, and they will be at the extreme high end on the continuum of Nelson's complexity factors.

Oil Shale is essentially rock and an oily substance called kerogen. Oil shale constitutes about 2.4% of world hydrocarbon resources. The US is estimated to have over 1.5 trillion barrels alone. For oil shale, extraction and processing are so closely interlinked as to be essentially one process. In-situ extraction of hydrocarbons from oil shale requires a slow heating process that works something like a low-temperature delayed coker. Volatile organics are then extracted through thermal fractures in the reservoir and processed by conventional means. Only a few formations are sufficiently concentrated with hydrocarbons to justify the effort. Other processes have mined, crushed, and retorted (like pyrolysis) oil shale to produce a synthetic oil that is subsequently processed in a conventional refinery to produce finished fuels.

Impact on Refinery Configurations

Globally there is insufficient heavy oil refining capacity, and the refining of heavy crude is capital intensive. Heavy refining capacity costs more than twice that for conventional oil.

An integrated approach to production, transportation, and refining of unconventional oils will be required, especially for HVO and Bitumen. Onsite conversion/upgrading at the wellhead is likely to become more prevalent. HVO and bitumen give much more vacuum residues than lighter oils. These residues are responsible for the highly viscous nature of the oils. The residues must be converted to lighter fractions either on-site or at a refinery using thermal or catalytic processes. The schematic below provides a simplified flow diagram for the conversion of heavy crude to a synthetic crude, which may be further processed by conventional means.



The principal role of the crude unit is to fractionate the heavy crude into different components according to boiling point and molecular weight, but water and salts must be removed first. Use of well-known thermal processes like coking (shown above) will continue to grow. Use of solvent deasphalting processes that separate vacuum residues into a heavy pitch containing most of the metal contaminates and a deasphalted oil will grow as well. Deasphalted oil still needs cracking and hydrogen addition to produce fuel products.

As indicated in the schematic, the diluent stream from onsite upgrading can be sent back to the field and used to dilute heavy crude for transportation to a remote location for conversion. The diluent would otherwise be used in finished products such as gasoline. Upgrading in the field avoids the cost of transporting the diluent back to the field from a refinery location. The most common diluent is condensate, which is becoming scarcer as gas fields decline. This is forcing a shift to the use of syncrude as the diluent.

Refineries of the future will require additional hydrogen production since heavy oil processing demands about ten times the hydrogen used for conventional light oil.

Better methods are needed to captures and sequester CO_2 associated with hydrogen generation for refining.

To upgrade liquid or solid residue streams (like petroleum coke from a delayed coker), future refineries may employ more gasification technology to manufacture syngas (carbon monoxide and hydrogen), which may be put to a number of uses. Although, hydrogen for upgrading is usually produced by steam methane reforming, natural gas is becoming scarcer and more expensive. Future refineries will increasingly need technologies like gasification to provide hydrogen for upgrading disadvantaged unconventional oils. The syngas can also be used directly for power generation or "shifted" to make more hydrogen. If shifted; the carbon monoxide becomes carbon dioxide that can be captured for enhanced oil recovery. Lastly the syngas could be converted to liquid fuels using Fisher-Tropsch technology.

Energy Intensity and Carbon Emissions Due To Unconventional Oil Processing

Carbon emissions from petroleum refineries are the result of combustion, venting, or fugitive sources. The majority of carbon emissions are the result of combustion emissions in boilers, process heaters, turbines, catalytic and thermal oxidizers, and coke kilns, and venting emissions from catalytic cracking, catalytic reforming and catalytic regeneration, flexi and delayed coking, and hydrogen plant steam methane reforming. As supplies of conventional (lighter and less sour) crude oils declines and unconventional (heavy and/or synthetic) crude oils are expected to fill a larger portion of refinery feedstocks used to produce products, especially with the significant expected growth in world petroleum demand. Because petroleum products are expected to continue to meet increasingly more stringent environmental requirements to reduce criteria pollutants (VOC, NOx, particulate emissions) the processing of these heavier more sour unconventional crude oil will require more severe processing and increased energy intensity. Since the primary source of carbon emissions in refineries is from combustion of fuels for crude processing, carbon emission from refineries tracks closely with refinery energy consumption. Estimates for U.S. refinery energy consumption are available from the EIA's AEO. Based on EIA's AEO 2006, petroleum refinery energy consumption per barrel of refinery inputs is expected to grow by approximately 7.0 percent from 2007 to 2030 This expected growth in energy consumption can be attributed to the more severe processing and the need for more hydrogen to refine both conventional and unconventional crude oil into refined products. Refined product quality specifications are also expected to increase due to requirements from the U.S. Clean Air Act to produce cleaner fuels.

Observations and Implications

Reference	Observations	Implications
Shell	Globally there is insufficient heavy oil refining capacity. Heavy oil refining capacity costs twice that for conventional oil.	Significant price discounts for Canadian crude exist in the market to signal the increased demand for logistics and processing investments.
Shell	Bitumen diluted with lighter hydrocarbons (Dil-Bit) and syncrude (Syn-Bit) require complex refineries for conversion to transportation fuels.	Refining investments in heavy oil conversion, including coking and solvent deasphalting as well as hydrogen production and hydroprocessing will be required to process the Canadian oil sand material.
Shell	Petroleum coke produced from unconventional oil processing in oil refineries require disposition.	Refineries might invest in syngas production to extract hydrogen and generate power.
EIA AEO 2006	Unconventional oil requires increased unit energy consumption to be converted to transportation fuels in more complex refineries.	The energy intensity of the U.S. refining industry is projected to increase by 7% through 2030.

VII. U.S. Regulatory Barriers to Capacity Expansion

New Refining Capacity Location Issues

There are numerous factors to be considered when assessing where new refining capacity will be located, including political, security, environmental and economic factors – many of these factors overlap, particularly where regulations, policy and perception inhibit the locating of new or expanded refining capacity. Both existing and proposed regulations increase the cost of doing business and public perception often either directly or indirectly restrains expanding existing refineries or locating new refineries.

For example, Chemical Facility Security Act legislation has been introduced in the 107th, 108th, and 109th Congress and is expected to be reintroduced again in the 110th Congress. Provisions range from requiring designated facilities to submit to Department of Homeland Security (DHS) vulnerability assessments and plans for increasing facility security and responding in the event of an emergency to requiring the use of "safer" technologies in security plans for high-risk facilities. Some require the regulations to be issued by the Environmental Protection Agency (EPA), while others direct the DHS to establish regulatory requirements. Petroleum refineries are included in the definition of "chemical facility" under these proposed bills. Given the view that these facilities are or could be a prime target for terrorism or other forms of violence and should be more heavily regulated by government in the area of security, it makes it all the more difficult not only to site new refining capacity due to the public's perception that these facilities are dangerous, but to expand existing refinery capacity. In addition, the economic costs of doing business may increase significantly with any new governmental requirements.

Under current environmental regulations, refineries are already under heavy scrutiny both from a government and community standpoint. This not only adds to the cost of doing business, but impacts decisions on where new or expanded refining capacity may be located. According to the Federal Trade Commission, "[N]ew environmental regulations have required substantial investments in refineries, and a gallon of environmentally mandated gasoline costs more to produce than a gallon of regular gasoline." Since the Clean Air Act's massive 1990 rewrite, the refining sector has had to spend a much as $4 billion each year on regulatory compliance at existing refineries. These investments, which by now total nearly $50 billion, maintain existing capacity but do nothing to increase it."

These regulations and the costs imposed are primarily based on air emissions from petroleum refineries. Based on the National Emissions Inventory (NEI), petroleum refineries, in 1999, emitted over one million tons of air pollutants. The pollutants emitted in the greatest quantities by petroleum refineries are sulfur oxides (SOx), nitrogen oxides (NOx), and carbon monoxide (CO). Along with hazardous air pollutants and volatile organic compounds, emissions of these criteria air pollutants are regulated by EPA under the Clean Air Act (CAA). Given EPA's stringent requirements in this regard, and the fact that all CAA permitting must go through a public review process, siting and permitting issues are a factor impacting where new refineries are sited or current refinery capacity is increased. Again, the cost of doing business under these environmental regulations and the public perception that these businesses are "dirty" or "unhealthy" inhibits new refining capacity. Refineries sited in areas that are in non-attainment for any one of the criteria and hazardous air pollutants will face even tougher governmental and public scrutiny and tougher emission control standards (i.e. more regulatory cost) than those sited in areas under attainment.

Other environmental regulations impact costs associated with the actual process of refining petroleum as well as the transportation and marketing of the final product. Refining capacity has historically been sited close to the source in EPA Regions 4, 6, 9 and 10. EPA sets Fuel Specification Standards that require particular gasoline blends for certain geographic areas, as well as variations on those blends. EPA issued standards in 1973 that called for a gradual phase down of lead to reduce the health risks from lead emissions from gasoline. Beginning in 1989, EPA required gasoline to meet volatility standards (in two phases) to decrease evaporative emissions of gasoline in the summer months. Upon passage of the 1990 CAA amendments, EPA began monitoring the winter oxygenated fuels program implemented by the states to help control emissions of carbon monoxide. It also established the reformulated gasoline program, which is designed to reduce emissions of smog-forming and toxic pollutants. EPA also set requirements for gasoline to be treated with detergents and deposit control additives. More recently, EPA implemented standards for low sulfur gasoline and low sulfur diesel. The ability to meet these standards in various geographic locations may impact whether or not and where new refining capacity is located

Policy and Regulatory Barriers

The most significant regulatory barrier that may inhibit the development of new refining capacity is New Source Review (NSR), under the CAA, which is a preconstruction permitting program, established to ensure that air quality is not significantly degraded from the addition of new and modified factories, industrial boilers and power plants. In areas that are in non-attainment with EPA air quality standards for criteria air pollutants, NSR assures that new emissions do not slow progress toward cleaner air. In areas that are in attainment with current air quality standards, NSR assures that new emissions do not significantly worsen air quality. NSR mandates certain technology requirements on any large new or modified industrial source and that advances in pollution control occur concurrently with industrial expansion. NSR requires stationary sources of air pollution get permits before they start construction. There are three types of NSR permits and a source may have to meet one or more of these permitting requirements: Prevention of Significant Deterioration (PSD) permits which are required for new major sources or a major source making a major modification in an attainment area; Nonattainment NSR permits which are required for new major sources or major sources making a major modification in a nonattainment area; and Minor source permits. The permit specifies what construction is allowed, what emission limits must be met, and often how the emission sources must be operated Thus, depending on where new capacity is located or existing capacity are expanded, significant regulatory burdens will be imposed through mandated permitting requirements, such as pollution control technology or operational restrictions.

Another CAA regulation that may impose a barrier to expanded refining capacity is the National Emission Standards for Hazardous Air Pollutants (NESHAPS). Refineries, as major sources under the CAA, are subject to two NESHAP standards. First the "National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries," requires maximum achievable control technology (MACT) controls for emissions of air toxics from storage tanks, equipment leaks, process vents, and wastewater collection and treatment systems. New or modified sources face tighter standards then existing sources. The second, the "National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units," requires MACT on these specific units, which were not included in the original NESHAP for refineries. Again, new or modified sources have more stringent requirements for these units than existing facilities imposing a significant hurdle to expanding or building new refining capacity.

Refineries are also subject to the National Ambient Air Quality Standards, which regulate ozone. The CAA requires EPA to set National Ambient Air Quality Standards (NAAQS) for ground-level ozone and five other criteria pollutants, including NOx, SOx and Particulate Matter (PM). The new 8-hour ozone standard imposes specific provisions on states with areas in non-attainment. EPA works with partners at state, local, and tribal levels to meet these standards. Each state must develop a plan describing how it will attain and maintain the NAAQS. This plan is called the State Implementation Plan (SIP). In general, the SIP is a collection of programs (monitoring, modeling, emission inventories, control strategies, etc) and documents (policies and rules) that the state uses to attain and maintain the NAAQS. These programs and regulations directly impact the industry in each state and local area, again depending on the areas' attainment or non-attainment status. In order to get SIP credits to meet their NAAQS requirements, state will impose specific requirements on industry. In the case of refineries, which are a source of NOx and Sox, states may mandate pollution control requirements as well as operation control mandates more stringent than current federal government regulations. In other words, the states can go above and beyond federal regulatory requirements, imposing additional requirements and additional costs.

Permitting Experience

U.S. petroleum refineries are required to obtain several regulatory permits in conjunction with major expansion projects to ensure the protection of air quality, water quality, and in some rare cases proper management of solid and hazardous wastes. This discussion will focus on the complexities and potential delays associated with the air quality permit process since it has been attributed to the lack of the new refining capacity within the United States.

Major refinery expansion projects typically result in criteria pollutant emission increases in excess of the significance levels specified in the new source review ("NSR") regulation. As a result, these expansion projects must be permitted either under the prevention of signification deterioration ("PSD") or the Non-Attainment program of the NSR regulation. In recent years, petroleum refineries have submitted several PSD and Non-Attainment permit applications to collectively increase refining capacity in excess of 1.4 million barrels per calendar day as summarized below:

Refining Company	Refinery Location	Proposed Crude Capacity Increase (BPCD)	Submittal Date of Permit Application	Permit Approval Date by Agency	Total Duration of Permit Process (days)
British Petroleum	Whiting, IN	260,000	August 1, 2006	Still Pending	230^{+}
ConocoPhillips Company	Wood River, IL	94,000	May 15, 2006	Still Pending	308^{+}
Valero Energy Corporation	Port Arthur, TX	105,000	January 31, 2006	Still Pending	412^{+}
Valero Energy Corporation	St. Charles, LA	160,000	December 21, 2005	Still Pending	453^{+}
Marathon Petroleum Company, LLC	Garyville, LA	180,000	April 25, 2006	December 27, 2006	246
Motiva Enterprises, LLC	Port Arthur, TX	325,000	January 25, 2006	November 20, 2006	299
Flint Hills Resources	Pine Bend, MN	50,000	October 11, 2005	June 21, 2006	253
Arizona Clean Fuels Yuma LLC	Tacna, AZ	150,000	December 22, 1999	April 14, 2005	1,940
ConocoPhillips Company	Borger, TX	54,000	June 28, 2004	April 8, 2005	284
Citgo Petroleum Corporation	Lake Charles, LA	105,000	Not Available	Not Available	Not Available
Total		1,483,000			

The approval of theses air quality permits has taken anywhere from eight months to five years. The refining expansion projects facing extended permit approval periods could be delayed, scaled back, or even abandoned due to an inability to execute them within the desired time frames.

Several problematic aspects exist with the current system for reviewing and processing air permit applications, particularly with regards to the implementation of the NSR regulation, as noted below:

- Permitting authorities are not mandated to review and process a PSD application within a specific time frame. Although § 165(c) of the Clean Air Act provides for final action on a PSD permit application within one year after filing of a complete permit application, nothing in current law prevents permitting agencies reviewing an application for months before reaching a decision regarding completeness;

- Permitting authorities have a chronic shortage of personnel with experience and expertise able to review PSD permit applications including those associated with petroleum refineries. The lack of experienced permit writers often leads to inconsistent and time consuming reviews. Moving the responsibility for EPA oversight of State-administered NSR programs to a headquarters office, established specifically for oversight of NSR permitting decisions relating to new refining capacity, would greatly diminish the arbitrary and capricious decision making that can occur across geographic regions within the current system

- Permitting authorities must make control technology decisions upon all available information at the time of permit issuance (i.e. Best Available Control Technology under the PSD program or Lowest Achievable Emission Rate under the Non-attainment NSR program). In some cases, as a result of this provision, some refining companies must address or agree to install new pollution control technologies which were not commercially available at the time of filing the permit application. This provision has caused some lengthy delays in the permitting of refining capacity projects. The stipulation that the administrative record be frozen at some date earlier in the permitting process, such as the date that the complete application is filed, would greatly reduce the uncertainty that necessarily results from the current policy; and

- Permitting authorities, like the U.S. EPA and some delegated States, have administrative appeals provisions that are disadvantageous to permit applicants. For example, the EPA and some State rules stipulate a PSD permit be automatically and indefinitely stayed upon the filing of a petition for review by a concerned citizen or environmental group. It can take several months if not years to dismiss an environmental appeal petition, even if that petition has no merit. During this time period, the Permittee is prohibited to begin construction of the project for which has already taken one to two years, or more, for permit issuance

In recent years, the Bush Administration has identified the need to lessen the permitting hurdles for significant refinery expansion projects through several legislative activities. In particular, subtitle H of Title III of the Energy Policy Act of 2005 (42 U.S.C. 15951 *et seq*.) aims to improve coordination of Federal and state regulatory reviews for new refineries through "permitting cooperative agreements" between EPA and state permitting authorities. Subsequent legislative attempts identified even more specific and tangible streamlining, such as the Refinery Permit Process Schedule Act of 2006, which never became law, proposed several improvements to the Energy Policy Act as noted below:

- Broadens the scope to cover both new and expanding refineries;
- Maintains the statutory provisions for providing federal financial and non-financial assistance to States processing refinery permit applications;
- Provides for appointment of a Federal coordinator for all Federal authorizations required by the new or expanding refinery;
- Mandates that all Federal and State agencies responsible for Federally required permits and approvals cooperate with the Federal coordinator;
- Mandates that all Federal and State agencies responsible for Federally required permits and approvals enter into an agreement regarding expeditious completion of all reviews;

- Establishes specific deadlines for agencies that are parties to the required agreements; and
- Establish a consolidated record for all administrative appeals of Federal and State permits and approvals.

A proposed bill with similar language would help eliminate some of the inconsistencies and time disparities that exist in obtaining air quality permits for significant U.S. refining capacity projects.

Observations and Implications

Reference	Observations	Implications
Chemical Facility Security Act	New security regulations for refineries to be issued by the Department of Homeland Security and Environmental Protection Agency.	The public may misperceive an increase in security risk associated with refineries making it more difficult to site capacity expansions.
Federal Trade Commission	The Clean Air Act of 1990 has required the refining industry to spend over $50 billion to meet more stringent fuel and emissions.	This significant investment maintained existing capacity and did not contribute to capacity expansion.
Clean Air Act (CAA)	Some refineries are located in areas that are in non-attainment for criteria air pollutants.	These refineries will face more stringent emission control standards and more difficult public review process for capacity expansions.
National Emissions Standards for Hazardous Air Pollutants (NESHAPS)	Refineries are considered major sources and must comply with industry specific standards.	Maximum Achievable Control Technology must be installed to control emissions from storage tanks, equipment, process vents, wastewater systems, Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.
National Ambient Air Quality Standards (NAAQS)	Each state must develop their own plan to attain and maintain compliance with standards covering ground level ozone, five criteria pollutants, and	States may mandate emission control requirements as well as operational control mandates more stringent than federal government regulations.

	particulate matter.	
New Source Review (NSR)	Preconstruction permitting program established to ensure that air quality is not significantly degraded from the addition of new and modified facilities.	NSR permits can impose significant regulatory burdens including the installation of pollution control technologies and operational restrictions.
New Source Review (NSR)	NSR permit applications for 1.4 MM BPD of new U.S. refining capacity have been submitted since 1999. The approval timeframe (for the 800 MBPD of capacity approved) ranged from 8 months to 5 years. Over 600 MBPD of capacity is still pending permit approval.	The capacity expansion projects still in the permitting process risk delay, scope reduction, or abandonment due to the inability to execute the projects in the desired time frames.
New Source Review (NSR)	Permitting authorities are not mandated to review and process an application within a specific time frame.	Applications can take months to be considered complete before final action can commence.
New Source Review (NSR)	Permitting authorities have a chronic shortage of experienced personnel able to review refinery expansion applications.	Permit reviews can be inconsistent and time consuming.
New Source Review (NSR)	Permitting authorities must make control technology decisions upon available information at the time of permit issuance.	Refineries may have to agree to install new emissions control technology that was not commercially available at the time of filing of the permit application.
New Source Review (NSR)	Permitting authorities have administrative appeals provisions that are disadvantageous to permit applicants.	It can take months (and years) to dismiss an environmental appeal petition that has no merit.

VIII. Boutique Transportation Fuels

Boutique gasoline fuels are defined in the broadest of terms by many experts as all summer grade specialty fuels other than 9.0 RVP conventional gasoline. CARB CBG, RFG (Region 1, Region 2, and the Chicago version), 7.8 RVP, 7.0 RVP, 7.2 RVP, etc can all be considered boutique fuels. To these we could add ether bans, ethanol mandates, sulfur specifications, etc. which can even make some versions of 9.0 RVP gasoline a boutique fuel. In reality, a boutique fuel is not a specific fuel type but is a combination of a fuel plus its distribution infrastructure. For purposes of this report, a boutique fuel is defined as a fuel that is unique within its own distribution system; an island with exclusive fuel requirements.

The boutique fuel situation is mainly a summer phenomena associated with gasoline volatility. While ASTM has established vehicle/gasoline performance standards, the Federal and the State governments have placed supplemental fuel controls, mainly on gasoline RVP, in order to reduce air emissions to acceptable levels. Most of these programs are primarily concerned with ozone formation and therefore the RVP controls are in place during the summer months (VOC season), usually from June 1 to September 15 at retail locations. The main exception to this is RFG, which is a year round program, but still effectively has a lower RVP from June 1 to September 15.

In recent years, states and on occasions localities have added biofuels mandates, effectively ethanol or biodiesel per gallon requirements. The result of these mandates is a large number of different gasoline specifications which vary geographically, and a dramatic expansion of boutique fuels. Such state and local requirements are unnecessary complications for the fuel distribution system given the federal renewable fuel mandate enacted as part of EPACT05. Congress clearly intended that no geographic or per gallon requirement be placed on the use of renewable fuels so as to allow distribution and blending flexibility to minimize the cost of renewable fuel blending and distribution on consumers. State mandates preclude such day-to-day optimization, and potentially create serious resupply issues in the event of a supply disruption to either the base fuel or the mandate renewable fuel.

In spite of the concerns raised about boutique fuels and their effects on the distribution infrastructure, there have not been many comprehensive studies into this matter. EPA has issued two major and several minor papers on the topic. None of these discuss the distribution system in any serious detail and EPA only addresses federal and state SIP (State Implementation Plans for NAAQS attainment) fuels. Also, EPA failed to address the boutique fuel implications of the EPACT05 Renewable Fuel Standard (RFS) and Congress in its EPACT05 requirements for boutique fuels studies and fuel reconciliation specifically directed EPA to not address these other fuels.

EIA and GAO have also issued recent papers on boutique fuels. The EIA study was very informative and revealed their in depth understanding of fuels and the distribution system. The GAO study was written from a high level and failed to address fuel production or the distribution system in the needed depth. The most thorough recent national study was conducted by Mathpro Inc. and Stillwater Associates LLC for API. This study actually conducted detailed surveys of distribution system tankage and capabilities to handle the required gasoline fuels. This is the only study that clearly addresses boutique gasolines as the combination of a unique fuel and its distribution infrastructure.

In spite of their differences, these studies had many common findings. These include:

- The current distribution infrastructure adequately handles the current boutique fuels requirements under normal circumstances.
- Boutique fuels become a concern when there is a failure of a critical piece of the distribution infrastructure or a large upset in refinery production of the fuel in question.
- On a day to day basis, the current boutique fuels/infrastructure, once in place and optimized, likely represents the lowest production cost option and, when there are not distribution system problems, the lowest cost to the customer.
- Any reduction in the number of boutique fuels, when combined with the anti-backsliding principle, may result in the increase in stringency of the average properties of the U. S. gasoline pool. The elimination of a current boutique fuel and its replacement with a more stringent, but more commonly available fuel, results directionally in increased production costs and decreased production capability.

The Mathpro/Stillwater study which examined numbers and sizes of tanks and pipeline size and capability, concluded that the current distribution systems were capable of handling the current boutique fuels on a routine basis and were also capable of handling the likely new boutique fuels requirements of states trying to achieve attainment of the 0.080 ppm 1 hour ozone NAAQS.

Boutique fuels reduction advocates argue that simplifying the numbers of fuels should result in less volatile market reactions to supply disruptions, reducing the impact on the consumer. Even if the average refinery production costs are increased and supply is decreased due to the increased stringency, the availability of fuel to resupply the area in the event of a supply disruption will tend to offset these factors and provide a more stable market for consumers. In the case of new boutique fuels, the refinery production cost increases and supply distribution cost increases argue against new boutique fuels, or at least in favor of limiting new areas addressing environmental issues to already established boutique fuels. In this manner, supply reliability is potentially enhanced rather than degraded. The key point is that adding or reducing any new or existing fuel is a decision that requires a very detailed analysis of all of the production sources and all of the infrastructure modifications that would be required, plus the potential impact on the fuels supplied to other areas in the regional distribution system.

While it may be true that a reduction in the current number of boutique fuels will not prevent infrastructure problems and the potential for supply disruptions, the reduction may result in replacement supply being closer at hand. However, this replacement supply still has to move through non-traditional, suboptimal distribution means, such as barging or trucking to replace pipeline movements. The arguments to decrease the number of boutique fuels, typically point to California supply disruptions and price volatility, the Midwest supply disruptions in 2000 and 2001, the frequent problems with Arizona fuel supply, the Northeastern power outage and of course the various hurricane problems in 2005 and for several recent years in Florida. However, in none of these cases has a boutique fuel been the primary cause of the supply problem and in none of these cases, except perhaps some of California's disruptions, would the elimination of the boutique fuel have significantly reduced neither the duration nor the magnitude of the supply problems. This is because serious infrastructure problems were the primary cause of these supply disruptions.

Given that the presence of a boutique fuel has the potential to significantly aggravate a supply disruption, implementing a quick and definitive waiver system can help to reduce these aggravations. In the 1999, 2000 and 2001 supply disruptions, EPA was just learning how to gather supply information, how to grant waivers and what to require after the waiver period ended. Further, EPA's waiver authority beyond RFG was in question. As a result EPA waivers were often delayed if granted, for too short a duration to maximize their impact. In recent years, EPA has improved their process for detecting supply problems and issuing waivers, particularly in the aftermath of being granted much broader and clearer waiver authority in EPACT05. If and when used effectively, such waiver authority can reduce the impact of supply disruptions and boutique fuels by temporarily removing the boutique fuel requirement. The use of waivers has reduced the impact of boutique fuels on supply disruptions in recent years. In the aftermath of the 2005 gulf hurricanes, for example, the EPA worked with industry and granted both gasoline and diesel waivers in a manner that allowed expanded production and supply. The waiver process does have some inefficiencies, however. Following the 2005 gulf hurricanes, EPACT05 only allowed EPA to grant waivers for 20 days and only allowed EPA to grant waivers for federally enforced requirements (separate waivers were needed for duplicative and identical state requirements, often delaying the benefit of the EPA waiver). The short duration of EPA waivers meant that waivers had to be issued repeatedly resulting in uncertainty at the end of each waiver period.

In attempting to resolve the political impacts of supply disruptions due to boutique fuels, legislators and regulators must understand in detail the full implications of their proposed changes. It is possible, that in attempting to mitigate a temporary, infrequent problem, that they can impose higher fuel costs to the consumer on an everyday basis. These higher costs are unlikely to significantly reduce the likelihood of an infrastructure or production problem.

The boutique fuel situation, described above, deals primarily with gasoline. However, the principles apply to all fuels and their distribution systems. With the advent of California diesel and Texas low emission diesel requirements, plus the newly created EPA diesel categories of ultra low sulfur diesel, low sulfur diesel, high sulfur diesel and heating oil, boutique diesel concerns will certainly have to be addressed in the future. The advent of state and local biodiesel mandates seriously complicates this situation.

Observations and Implications

Reference	Observations	Implications
EPA, EIA, GAO, and API Studies	Boutique fuels tend to increase resupply challenges in the event of a supply disruption.	Reducing the number of boutique fuels may improve the speed of resupply efforts in the event of a supply disruption.
EPA, EIA, GAO, and API Studies	Reducing the number of boutique fuels, coupled with fuel quality anti-backsliding would require boutique fuels to be introduced into regions that do not require them to attain air quality standards.	Increased cost of fuel supply and reduced production of fuels at the refineries.
EPA, EIA, GAO, and API Studies	The establishment of a new fuel requirement in a single state can further constrain the fuel distribution systems in many states.	The establishment of new fuel requirements approved by a central authority (DOE or EPA), preempting a state from unilaterally establishing a new fuel requirement. This preemption should include biofuel mandates.
Marathon	The boutique fuel waivers granted in previous supply disruptions were difficult to negotiate between state and federal authorities. Also, the short duration of the waivers introduced uncertainty into the resupply decision process.	EPA should be granted the authority to waive both the federal and state SIP fuel requirement. Also, the 20 day waiver limitation in EPACT05 should be lengthened to 45 or 90 days.

IX. Biofuels and Synfuels Blending

The growth of biofuels and synfuels manufacturing may have multiple impacts on refining capacity and terminal distribution system investments. This section of the report will focus on the potential reduction in the reliability of the transportation fuels supply chain by shifting the primary logistic movement away from refined product pipelines to the railroads.

Renewable Fuels Standard

With increased emphasis on "energy security," US policy does not currently support increased expansion of petroleum refining. Instead, the US is promoting "alternative fuels," and fuel blends that impact the current infrastructure.

The Renewable Fuels Association lists 111 ethanol refineries currently operating in the US, with an additional 75 refineries and eight expansions under construction. Current policy supports construction of these refineries over construction of petroleum refineries.

The Renewable Energy Standard (RFS) requires that ethanol, currently at 3% of the nation's gasoline supply, grow to 5 percent by 2012, and ethanol is projected to continue growing beyond 2012. It provides that beginning in 2013, a minimum of 250 million gallons a year of cellulosic derived ethanol be included in the RFS. It provides refiners some flexibility by creating a credit trading program that allows refiners to use renewable fuels where and when it is most efficient and cost-effective for them to do so. The law exempts small refineries (defined as facilities where the average daily crude oil throughput does not exceed 75,000 barrels per day) from the RFS program until January 1, 2011. The statute will require petroleum refineries to manufacture more gasoline blending stock to support the increase in ethanol production.

Biofuels and Synfuels Blending Issues

The blending of biofuels and synfuels into traditional hydrocarbon based transportation fuels provides both challenges and opportunities. Biofuels blending poses more challenges than synfuels blending since the actual blending occurs at the product distribution terminals rather then the refinery. Further, a disruption in the ethanol supply chain could significantly impact gasoline sales since it is difficult to switch back to a non-blended gasoline product at the retail stores without experiencing product quality and environmental compliance problems. Specifically, switching between an ethanol blended gasoline product and a non-ethanol blended product can cause entrained water to come out of phase and cause serious engine performance problems. Also, the 1 psi vapor pressure specification waiver of a 10% blend is violated if the blend in the retail tank drops below 10% ethanol during the transition.

Ethanol also has a leveraging effect on lost gasoline sales since it makes up 10% of the finished blend. Simply put, in an E10 (10% ethanol, 90% conventional gasoline) blending scenario, 9 gallons of gasoline will sit in inventory at the product distribution terminal waiting on 1 gallon of ethanol to arrive. Additionally, the product distribution terminals require significant modification in the form of ratio blending control and tankage to insure that a quality product within legal specifications is delivered to the customer.

Synfuels blending provide more opportunity since they will most likely be shipped to a refinery for blending into traditional hydrocarbon based transportation fuels. In the controlled blending environment of a refinery, the potentially high blendstock quality characteristics of synfuels may be exploited and optimized. Segregated tankage would be required to take advantage of this quality opportunity.

Reliability and Cost of the Transportation Fuels Supply Chain

The transportation fuels supply chain typically consists of two logistical movements. The primary movement is made in large, cost efficient, bulk volumes by dedicated pipelines, barges, and ships and connects the refinery to the product distribution terminal. The secondary movement is made in small, less cost efficient volumes and connects the product distribution terminal to the retail store outlets by trucks. Biofuels cannot be moved by pipeline due to ethanol's affinity to water (pipelines typically contain water since many gasoline treating processes are wet), and due to the potential trailback of biodiesel into jet fuel. The incompatibility of biofuels in the product pipeline infrastructure requires that the biofuels be moved by rail car and truck from the biorefineries to the product distribution terminals. The impact is a shift in the primary movement from large, cost efficient, bulk shipments by dedicated pipelines, barges, and ships to small, less cost efficient shipments by non-dedicated railroads and trucks. The primary movement will have increased costs and reduced reliability as a result of this shift.

Given the relative immaturity of the biofuels supply chain, it seems likely that infrastructure investments will be required in the form of tankage, rail systems, trucks, and possibly dedicated ethanol pipelines. While these challenges may be significant in scope and cost, they should bring the reliability of the biofuels supply chain up to the level of the hydrocarbon transportation fuels supply chain.

Observations and Implications

Reference	Observations	Implications
Marathon	Biofuels cannot be moved by pipeline, requiring they be shipped to product distribution terminals by rail road and truck.	The primary transportation movement for a significant portion of the transportation fuels supply chain will shift from large, cost efficient, and reliable bulk shipments by dedicated pipelines, barges, and ships to small, less cost efficient, less reliable shipments by non-dedicated rail roads and trucks.
Marathon	The ethanol supply chain appears to be the weakest link in the overall gasoline supply chain.	The weakest link in the supply chain dictates the reliability of the overall system due to the difficulty of switching between ethanol blended and non-blended products at the retail level. (9 gallons of gasoline wait on 1 gallon of ethanol)
Marathon	Synfuels have some desirable blend qualities and do not require special handling in the product distribution system.	Synfuels blending may provide blend optimization opportunities at the refinery.

X. Policy Options

Policy options were developed based on the "Key Policy Dimensions Triangle" that is anchored at the corners by Economic, Environmental, and Security dimensions.

Issue	Policy Dimensions	Policy Option
U.S. refining capacity is not projected to keep pace with oil demand, resulting in increased dependence on finished product and blendstock imports from Europe, the Middle East, and Africa.	Economy, Security	Assuming that this supply/demand gap in the U.S. product supply is not desirable, policies should be implemented to encourage domestic refining capacity development. If this supply/demand gap is determined to be desirable, policies should be implemented to encourage the expansion of product import facilities and distribution system.
Globally, there is insufficient heavy oil refining capacity and heavy oil refining capacity costs twice that for conventional oil.	Economy, Security	Assuming that enhanced security of Canadian supply to the U.S. is desirable, policies should be implemented that support and facilitate the development of transportation infrastructure and refining capacity for heavy oil processing.
Arbitrary and capricious decision making concerning New Source Review permitting can occur across geographic regions in the U.S.	Environment, Economy	Assuming that consistent permitting standards are desirable, a policy should be implemented that establishes a central authority for NSR permitting specifically for new refining capacity.

Emission control technology decisions are made before the technology is commercially available.	Environment, Economy	Assuming that the delays incurred in the permitting process as a result of changing technology requirements is not desirable, a policy should be implemented to "freeze" the record early in the permitting process to significantly reduce the uncertainty of the investment scope.
Environmental permitting poses many hurdles to refinery capacity expansion and requires streamlining.	Environment, Economy	Assuming that permit streamlining is desirable, reintroduce the Refinery Permit Process Schedule Act of 2006.
The establishment of a new fuel requirement in a single state can further constrain the fuel distribution systems in many states.	Economy, Security	The establishment of new fuel requirements approved by a central authority (DOE or EPA), preempting a state from unilaterally establishing a new fuel requirement. This preemption should include biofuel mandates.
The boutique fuel waivers granted in previous supply disruptions were difficult to negotiate between state and federal authorities. Also, the short duration of the waivers introduced uncertainty into the resupply decision process.	Economy, Environment	EPA should be granted the authority to waive both the federal and state SIP fuel requirement. Also, the 20 day waiver limitation in EPACT05 should be lengthened to 45 or 90 days.
The ethanol supply chain is not as reliable as the gasoline supply chain due in part to the difficulty in switching between	Economy, Environment	Assuming that a reliable transportation fuels supply chain is desirable, a policy should be developed that allows for the transition from

ethanol blended gasoline and non-ethanol blended gasoline.		ethanol blended gasoline to non-ethanol blended gasoline without violating the vapor pressure specification waiver.