Prospectus for 2007 Multi-Client Strategic Report:

Future Refinery Operations to Meet Fuel Supply Security and Environmental Requirements

Increasing Production of Ultra-clean Fuels and Petrochemicals, On-site Manufacture of Green Fuels, Refinery Energy Efficiency Improvements to Reduce GHG Emissions, and Integrated Gasification Combined Cycle

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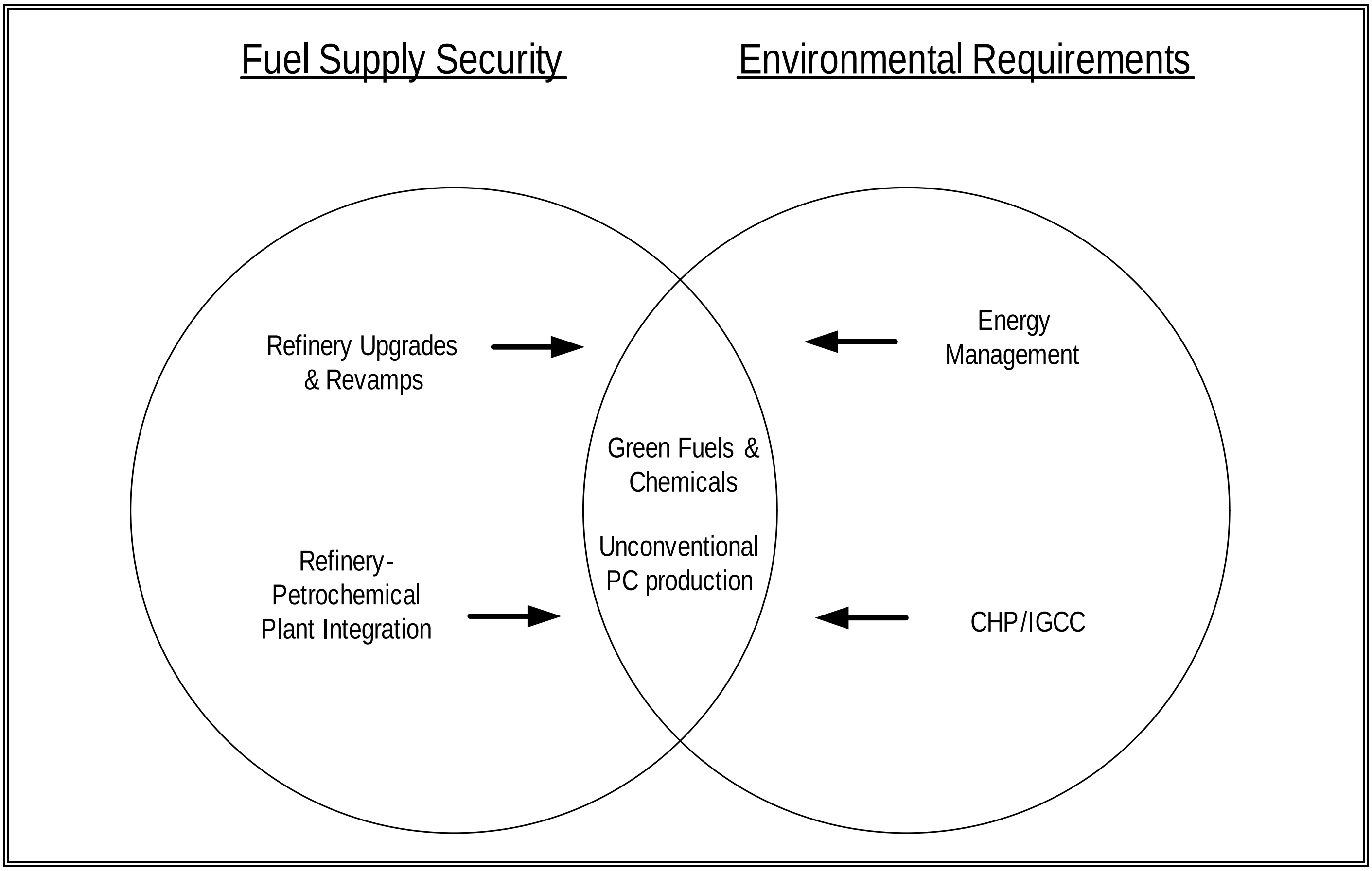
INTRODUCTION

The issues of energy security and tightening environmental requirements facing the refining industry are not limited to the US. Refiners in other Organization for Economic Cooperation and Development (OECD) nations, as well as developing regions in Asia and Latin America, are in a similar situation in the wake of record oil prices, diesel supply shortages, biofuels mandates, and the rising threat of global warming. In addition, Middle Eastern oil producers—which are expanding their downstream capacities in the hope of capturing rising global fuel demand—find the future to be rather cloudy due to uncertainties regarding future oil consumption.

The following diagram best delineates the two primary objectives refiners must meet in their future operations in the near and intermediate terms: fuel supply security and compliance with environmental requirements. Achieving these objectives can be reached via six options, including refinery upgrades and revamps, refinery-petrochemical plant integration, non-traditional petrochemicals production, production of green fuels and chemicals in refineries, energy management, and cogeneration of heat and power.



Report Scope and Focus

PART I

Upgrades and Revamps to Produce High Volumes of Ultra-Clean Fuels

Mandates for ultra-low-sulfur motor gasoline and diesel and surging fuel demand in the world, especially in China and India, have forced global refiners to undertake unprecedented construction work in terms of upgrades, new unit additions and, in some cases, grassroots refineries.

Countries around the world continue to revise their fuel standards. The future will see the cleanest, highest-performance transportation fuels in most developed regions of the world. Although it is not apparent in current figures, fuel-exporting regions such as the Middle East and Latin America will be forced to tailor product quality to match higher regional customer specifications. Greater economic and political ties with Western Europe will compel countries in the CIS and Central and Eastern Europe to comply with Western European fuel standards. Some analysts project that the Pacific Rim and Middle East will adopt 50-80% of the US clean fuels regulations in the near future. The following table illustrates the projections for sulfur and aromatics contents of gasoline and on-road diesel for the period of 2005-2010.

Nation	Gasoline		On-Road Diesel	
	Sulfur, ppm	Aromatics, vol%	Sulfur, ppm	Aromatics, vol%
US	15-30	<50	15	15-36 wt%
Canada	10-30	<25	15	30
Latin America	400 overall; as low as 30 in some areas	25-45	2K overall; as low as 10-50 in some areas	30-35
Western Europe	10	35	10	10
Central/Eastern Europe	50-1,000	35-42	50	—
Middle East/Africa	50	25	50-5,000	—
Asia-Pacific	10-150	30-45	10-350	10-35

Our Report focuses on the latest technologies—particularly in hydrotreating, hydrocracking, benzene reduction, sulfur plant, and hydrogen production—to perform upgrades and revamps for increasing production of ultra-clean mogas and diesel.

Hydrotreating

According to various industry-wide surveys, global hydrotreating (HT) capacity will expand by 500K bpd/y or more in the coming years, after solid growth in 2004-2006. Asian HT capacity rose by 400K bpd/y during the period, and 450K b/d of European HT capacity was added in 2005 alone followed by around 200K b/d in 2006. Tightening fuel specification encouraged refiners in these two regions to expand during the period.

To meet ultra-low-sulfur diesel (ULSD) requirements, many refiners have chosen to revamp their existing hydrotreaters. The choice of revamps over the installation of new units has been prompted by the introduction of more active catalysts and the design of more efficient reactor internals. Of course the predominant factor is the lower investment cost of revamps. An example of this benefit is illustrated by the economic data provided by Mustang Engineers and Constructors concerning 17 ULSD projects in the US in which the company was involved. Of these projects, three were grassroots facilities with investment costs of $2.2-3.8K/bpd while the 14 revamps had capital costs ranging from $100/bpd to $1.4K/bpd. If only a new reactor was added and small changes were made to the reactor loop piping and equipment, the cost of the revamp was $300-600/bpd.

With the supply of light sweet crudes dwindling, the current trend in hydroprocessing is the treatment of heavy sour feeds that contain compounds such as sulfur, nitrogen, aromatics, iron, and other undesirable components. These compounds pose significant problems with catalyst poisoning; however, developments are keeping pace with increased demand. Many refiners are now introducing LCO into their ULSD units, and feeds such as these are typically high in heavy metals. The addition of metal traps upstream from the hydroprocessing unit has resolved most of these problems. To prevent any organic nitrogen poisoning, many refinery configurations employ a pretreating unit using Ni-Mo-based catalysts upstream of the hydrocracker for maximum hydrogenation and denitrogenation.

Although taking a back-seat to ULSD projects, revamping hydrotreaters around the FCCU is another important focus. Half of all FCCUs incorporate pretreaters to meet their gasoline sulfur requirements and improvements to these make up the majority of ULSG-oriented revamps.

Five of the most common approaches to revamping hydrotreaters for clean fuels production (in order of increasing capital costs) are to upgrade feedstock and integrate processes, implement a higher-activity catalyst, replace reactor internals for increased efficiency, add reactor capacity, and increase H_2 partial pressure by installing an amine scrubber or PSA. Refiners also have the option to implement advanced process control (APC) and simulations to optimize operation. This Report devotes a complete section on evaluating revamp options, including the latest developments in hydrotreating catalysts. Recommendations are made to what option offering the best return on investment.

Hydrocracking

Hydrocracking (HC) capacity is projected to rise by an average of 250K bpd/y in 2007-2012. Strengthening diesel demand in Asia is one driver, but the main source of growth will be Europe, which is expected to be the major contributor to 2007's global addition of 400K b/d of HC capacity. FSU countries are looking to monetize on the European diesel market, providing 230K bpd/y of the incremental HC capacity in 2008-2012. US refiners are set to switch their collective focus from 2006's trend of producing cleaner fuels to the expansion of hydrocracking, coking, and distillation capacity over the next several years, as concerns over ULSD supplies persist.

Hydrocracking process licensers and catalyst manufacturers now focus on cost-effective technology to broaden the range of feeds, shift product distribution, improve product quality, reduce hydrogen consumption, and increase energy efficiency. Hydrocracking catalysts have been receiving at least as much attention as the processes. It is apparent that the rate of commercialization of new catalysts has accelerated recently, thanks to a better understanding of the process chemistry and the advent of sophisticated tools. Improvements in catalyst performance have allowed refiners to process lower-quality feeds and still enhance product quality. Catalysts designed for upgrading LCO in a hydrocracker can now produce diesel that contains 5 ppm sulfur or less with a 15-point increase in cetane index.

The development in the high-activity, acid cracking-based formulations of hydrocracking catalysts has added flexibility in the operation of the hydroprocessing units. This acid cracking ability is inherent in an amorphous silica-alumina or highly acidic zeolite carrier. Combinations of both types of carriers are available. Typically, there has been a trade-off between catalyst activity and stability. New formulations that employ amorphous silica-alumina supports and dealuminated Y-zeolites are available and offer high activity with high stability. In addition, these designs allow for lower operating pressures, increased run length, and increased diesel yields. New geometrical shapes of carriers provide higher void fractions and increased diffusion, thereby lowering pressure drop across the bed. One of the most important objectives with increased performance is the elimination of non-active zones within the bed.

Besides discussions on state-of-the-art hydrocracking catalysts, this Report also expands on the latest catalyst advances and potential future innovations. In addition to catalysts, revamp opportunities in the areas of reactor internals, process reconfigurations, process integration schemes, process control and simulation methods, and others will be explored in detail.

Benzene Reduction

Low benzene limits (<1 vol%) for gasoline in the US, Europe, and Japan have prompted refiners to seek ways to reduce the benzene content of reformate since it contributes about 65% of the pool total (versus 25% from FCCU naphtha, 5% from light straight run or condensate, and 5% from coker naphtha).

Besides the traditional benzene reduction options as indicated below, the Report reviews new and novel concepts to satisfy revamp requirements according to the overall refinery scheme, the desired level of benzene in the pool, the benzene-producing tendency of the reformer, and the investment and operating costs involved.

- Select the appropriate crude
- Eliminate benzene precursors from the reformer feed
- Lower the reformer temperature
- Lower the reformer pressure to the compressor limit
- Lower the reformer severity
- Remove benzene from the reformate via post-fractionation or extraction
- Hydrogenate the reformate

Sulfur Recovery

Currently, the refining industry is expanding its hydrotreating capacity and increasing the volume of sour crudes it treats. As a result of the additional sulfur waste gases that are produced, increased sulfur recovery capacity is required. Stricter regulations, too, are driving refineries to remove higher percentages of sulfur, which demands more investment. Also, sulfur from vent gases, previously sent to the incinerator, may now have to be recovered to meet emissions targets. These gases are collected from the sulfur pit, the sulfur storage tank and the truck loading rack. At present, there are at least 130 sulfur recovery, Claus sulfur degasser and tail gas treating refinery-specific sulfur projects with a combined capacity 30K mt/d in various phases in various phases of construction around the world.

There are at least four revamp and expansion options for the modified Claus process: expansion via oxygen enrichment, revamp to sub-dew point operation, revamp using direct oxidation, and revamp combining selective oxidation and reduction. Also, revamp advances in tail gas treating and acid gas removal are presented.

The Report identifies numerous revamp opportunities and explains why rigorous feasibility studies and optimization techniques must be done to arrive at the appropriate solution. Degasification processes and alternative sulfur recovery techniques, i.e., biological conversion, often present strong cases for revamp attention as well. Also, improved internals for any number of vessels can greatly increase mass transfer and overall process efficiency. This particular upgrade could entail replacing the quench tower, reactor, absorber trays/packing, or any combination thereof. Finally, pumps, boilers and additional heat exchange equipment demand detailed analysis when considering a SRU revamp.

Hydrogen Production

There are at least 79 active construction projects for hydrogen production, recovery, and purification in refineries and location dedicated for refinery customers around the world. When all these projects come to fruition over the next several years, in excess of 4.3MM Nm^3/h of production capacity will be added to the current levels.

The demand for H_2 is increasing rapidly due to several factors, namely clean fuels legislation mandating desulfurization, the rising consumption of heavier and dirtier crudes, and sizeable growth in the petrochemicals sector. Catalytic reforming is the major source of H_2. Unfortunately, H_2 production from catalytic reformers in the US is expected to decline because of recent EPA legislation cutting benzene content in gasoline. In addition, Europe's reduced gasoline production in favor of diesel has greatly diminished the naphtha-reforming unit's role in H_2 production. As refineries adjust their operations to meet the 10-ppm-sulfur standard in 2008, there is a greater demand for H_2 due to the increased severity of hydroprocessing units. These two factors are leaving European refineries in an H_2 deficit. Even with hydroprocessing catalyst improvements, it is crucial for refineries to invest in increased H_2 production, especially if they are processing heavy sour feeds.

Several options are available to refiners for meeting their growing H_2 needs. Hydrogen can be obtained as a byproduct from naphtha catalytic reformers, purchased from third-party sources, or produced via on-purpose technologies. The most common on-purpose method is steam reforming, which can handle a variety of feedstocks including natural gas, LPG, naphtha, and various refinery offgas (ROG) streams. Hydrogen can be recovered from ROG streams within the refinery. Those streams exiting naphtha catalytic reformers, high-pressure hydroprocessing units, toluene hydrodealkylation units, and FCC units consist of 10-95% H_2. Despite this opportunity, only about 25% of the refinery's H_2 supply can be recovered from vent, purge, and fuel streams; consequently, there will be a need to increase H_2 production capacity or to depend more heavily on "over the fence" H_2. Other options are autothermal reforming (ATR) and gasification. Gasification uses pure O_2 and has a high operating cost, despite the fact that it can process low-value, bottom-of-the-barrel feeds. A final production option, which has been established and proven commercially, is the methanol-to-hydrogen process.

The revamp of existing H_2 plant equipment is considered to be the cheapest way to add 10-50% capacity, as most of the operating units have built-in overcapacity due to variations in equipment performance and feedstock sources. However, there are several important constraints involved in such revamps. These limitations are minimum H_2 product pressure, H_2 purity, process cooling duty, plot space availability, available down-time for revamps, utilization of export steam, other utility availability, safety, and pollutant emissions. Nowadays, H_2 production is under strict scrutiny because of its byproduct carbon dioxide (CO_2)—about 10 tons generated per ton of H_2. In addition, the debottlenecking and expansion of existing H_2 plants depends on reformer limitations such as the tube metal temperature, burner heat release, catalyst bed pressure drop, induced-draft/forced-draft fan capacity, and PSA capacity.

<u>The Report analyzes many options currently available for expansion and de-bottlenecking</u>:

- Comprehensive H_2 PINCH analysis
- Installation of an adiabatic pre-reformer or a post-reformer
- Addition of LTS units to existing plants, or retrofitting of an HTS unit to an MTS unit
- Modification of the PSA unit in order to improve H_2 recovery
- Reducing the purge gas pressure
- Performing an adsorbent change-out, or utilizing additional adsorbent vessels
- Addition of an upstream CO_2 removal system or revamp of the existing unit
- Selection of optimized catalysts and adsorbents
- New membrane systems made of novel polymeric and ceramic materials.

Refinery-Petrochemical Integration

The petrochemical business has been a key and consistent contributor to the bottom line of refiners, which can generate valuable bulk chemicals for the downstream markets. Significant profit margins from petrochemical sales have also been the incentive for many oil companies in Asia and the Middle East to include petrochemical production in their new refineries via integration. For instance, high-severity FCCUs for increased production of light olefins are planned for refining/PC facilities in India, the Philippines and Saudi Arabia. Also, the startup of several olefin metathesis units is expected in East Asia and the Middle East.

Refinery-petrochemicals integration refers to the co-location and coupling of refining and petrochemicals processing operations within a single facility. Because an integrated facility has more control over its petrochemicals feedstock cost, it can more readily maintain its margins for petrochemicals products. Shared infrastructure and services reduce both capital and operating costs for the integrated plant: lower shipping and storage costs for exchanged feedstocks are an important part of this synergy. Environmental emissions are lower for integrated operations than for separate operations, since materials that would be disposed of or combusted in a singular facility are more likely to be converted into marketable products in a dual-purpose plant. Other benefits are that fuels specifications can be met more economically, and any residue from such an operation may be converted into coke or electricity, avoiding the production of fuel oil. Cogeneration of electricity may be more economical for a large, integrated operation because it has greater volumes of low-value streams than either a refinery or a petrochemicals plant.

Refineries and petrochemicals operations have a history of exchanging product streams in ways that are advantageous to both sides. These exchanges support refining needs to meet stricter specifications for clean fuels and improve yields of both fuels and petrochemicals. As discussed in the Report, integration can potentially address the following issues:

- Adapting to seasonal variations in gasoline blending requirements, e.g., for RVP and VOC, which affect the disposition of certain blendstocks toward use in an ethylene plant.
- Dealing with off-spec gasoline sulfur content, reducing the distillation index and benzene content of gasoline, and meeting ULSD specifications.
- Utilizing an excess of C_4 materials in the US due to the ban on MTBE. One option here is to send unbranched C_4 to an ethylene plant and use the branched components as alkylation feed.
- Increasing the production of propylene from FCCUs to meet growing demand for the olefin.
- Sending AGO and LVGO to an ethylene plant from a refinery that is short on capacity for gas oil conversion (i.e., FCC or hydrocracking), leaving only the HVGO to be processed in the refining operation.

Exchange opportunities like those mentioned above provide added incentives for actual integration of refining and petrochemicals production. Moreover, an integrated facility will have not only the flexibility to shift the production balance between fuels and petrochemicals so as to take advantage of the varying economic cycles of the refining and petrochemicals businesses, but also the ability to benefit from the higher demand growth and return for petrochemicals versus refined fuels.

Our discussion of refinery-petrochemical integration is concerned with developments in and implementation of process technologies that support integrated production of fuels and petrochemicals. These technologies are grouped and discussed according to the functionalities that they provide:

- integration of hydrocracking and steam cracking for coproduction of ULSD and petrochemicals,
- catalytic cracking with flexible selectivity for fuels and petrochemicals,
- catalytic cracking for selectively converting heavy feeds to olefins,
- olefin conversion processes (e.g., metathesis) for upgrading lower-value olefins from steam-cracked and/or catalytically-cracked streams,
- catalytic reforming processes that provide flexibility in the conversion of naphtha to gasoline blendstocks or aromatics, and
- on-purpose processes for converting light hydrocarbons to aromatics.

Non-traditional Petrochemical Production

There exist processes for producing olefins, propylene in particular, that use either natural gas or a light paraffin such as propane as feedstock, and the Report discusses them separately because interest in them largely depends upon a having a feed that is relatively inexpensive, has no other local use and possibly may not be disposed of without violating regulations on flaring and venting. However, we do point out cases where one of these processes may be integrated with a more conventional refining or petrochemical process.

- Olefin Production from Natural Gas - MTO and MTP. Natural gas can be converted to methanol by using commercially available technologies for the production of syngas. There are several processes by which this methanol can then be used to produce olefins. If the products are primarily propylene and ethylene with little C_5+, the process is referred to as methanol-to-olefins (MTO). A similar process that yields propylene and gasoline is called methanol-to-propylene (MTP).
- Olefin Production by Dehydrogenation of Paraffins. Processes of this nature create olefins by removing hydrogen from a paraffin feedstock (C_3 or C_4). Dehydrogenation operates at a high temperature and uses a catalyst (chromia/alumina or platinum/alumina) that provides efficient conversion and high selectivity towards the desired product. Regeneration is required because of coke formation on the dehydrogenation catalyst. Propane dehydrogenation (PDH) provides propylene with a yield of 85 wt% and small amounts of hydrogen and ethylene byproducts. These can be used as fuel for the PDH process.

Interest in both of these technologies may be further heightened by rising concerns over the environmental and economic impacts of the flaring and venting of gases from natural gas and petroleum operations. Globally, gas flaring contributes 400MM mt/y of CO_2 to the atmosphere, and the amount of gas vented and burned at oil facilities has a potential market value of $69B/y. Russia is one of the foremost countries in terms of volumes of gases flared or vented to the atmosphere (and followed by Nigeria, Iran, Iraq, Kazakhstan, Algeria, Angola, Libya, Qatar, Saudi Arabia, and China.) Russian crude production yields 55B m^3/y of gases, 36% of which is flared. Under a recent law, this share must be reduced to 5% by 2011. In support of a GHG emissions cutback and to provide more feed for energy and petrochemicals use, Russia's Sibur is planning to send flare gas to a PDH/PP complex that it will build at Tobolsk by 2010. A similar complex is planned for construction at Orenburg, Russia.

PART II

Production of Clean Fuels and Chemicals from Bio-feedstocks in Petroleum Refineries

In the name of energy security and concerns over global warming, many countries around the world have moved to promote increased use of biofuels through government mandates and tax incentives. The US's Renewable Fuel Standard (RFS), a part of the Energy Policy Act of 2005, aims to double the nation's use of ethanol and biodiesel from 4B gal/y (261K b/d) in 2006 to 7.5B gal/y (489.2K b/d) in 2012. Furthermore, the latest energy bill passed in Dec. 2007 calls for 36B gal/y (2.35MM b/d) of ethanol by 2022, with 21B gal/y (1.37MM b/d) coming from cellulosic sources. Canada may enact a 5% biofuel blending mandate by 2010. Brazil has a 23% ethanol mandate, made a voluntary 2% biodiesel blending directive mandatory in Jan. 2008, and plans to boost the biodiesel requirement to 5% in 2010, 2011, or 2013, depending on output. Argentina will legislate a 5% biofuel mandate by Jan. 1, 2010.

The European Union's Biofuel Directive 2003/30/EC mandated a minimum proportion of biofuels at 2% of energy content by Dec. 31, 2005, which will rise to 5.75% by Dec. 31, 2010. The European Commission's Strategic Energy Review, which was unveiled on Jan. 10, 2007, proposes a 20% share of renewable fuels in energy output by 2020, as well as a 20% reduction of primary energy consumption based on 1990 levels. Meanwhile, France will incorporate a 5.75% biofuel spec in 2008, Germany mandated a 4.4% biodiesel blend in 2007, and Spain will blend 5.83% biofuels by 2010.

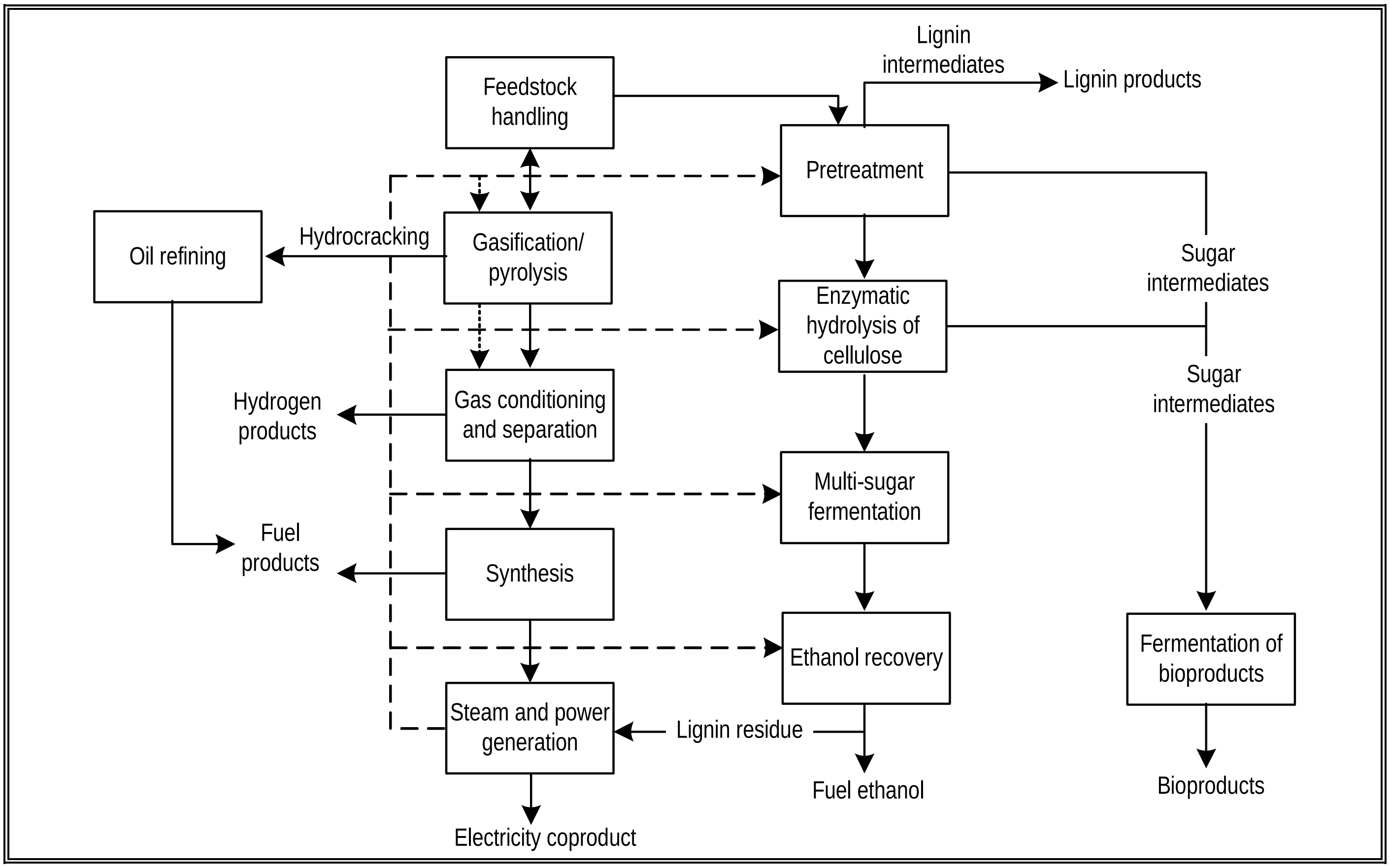
Biofuels have also been established in Asia. China has seen ethanol use legislated in the past several years. Japan hopes that half of its gasoline consumption will comprise E3 ethanol-blended gasoline and plans to replace its entire gasoline pool with E10 by 2030. Also, the country allowed 5% biodiesel blending beginning in 2007. The Indian government mandated that refiners blend gasoline with 5% ethanol in 2003, and Australia is seeking to establish a 2% biofuels blending mandate in 2010. In Southeast Asia, Thailand currently promotes the use of E10, Malaysia will require 5.75% biodiesel-blended fuel for general consumption in 2010, and Indonesia will mandate a 10% biodiesel fuel mix in 2010.

From a strategic point of view, refiners should not try to compete with biofuels producers, but rather try to use renewable feedstocks in traditional petroleum refining processes and make products that are compatible with conventional hydrocarbon fuels. Bio-feedstocks include vegetable oils and animal fats, cellulosic materials, starches, and sugars. The first generation of fuels derived from bio-feeds are ethanol made from corn and sugar cane by fermentation, and biodiesel produced from fatty acids via transesterification with methanol. Subsequent generations of fuels and chemicals may be produced in one or more of the following ways, which are attracting the interest of companies associated with petroleum refining:

- hydrogenation of fats and vegetable oils in a diesel hydrotreater to produce a green diesel that can be blended with conventional diesel,
- catalytic cracking of fats and oils to produce a green gasoline that can be blended with conventional gasoline obtained from VGO cracking,
- production of synthesis gas from biomass followed by conversion to Fischer-Tropsch hydrocarbons,
- thermal depolymerization of animal fats and hydrocarbon feedstocks,
- catalytic decomposition of cellulosic materials, and
- pyrolysis or hydrothermal upgrading of biomass to provide liquids that are suitable for co-processing with conventional crudes.

The implementation of these processing techniques in petroleum refineries can result in a competitive advantage for both refiners and society at large. First, the processes provide refineries with alternative feeds that are renewable and lower in cost than petroleum. Second, they can reduce the costs of producing fuels and chemicals from bio-feeds by utilizing the existing production and distribution systems for petroleum-based products and avoiding the establishment of parallel systems. Third, they offer refiners a way to compete with non-refining processors of bio-feeds. Last, but not least, they provide a production base for fuels and chemicals that is less threatened by changes in government policies toward fossil feeds and renewables.

Specific goals and challenges exist for petroleum refiners thinking of using bio-feeds. One is to produce bio-based fuels that have higher energy densities than ethanol and biodiesel and are compatible with petroleum-based products and their distribution systems. Another is to use biomass feedstocks that are otherwise waste materials or are not also sources of food for humans and animals. Yet a third option is to make the maximum use of existing refinery operations. The following diagram shows one example of integration of conventional oil refining and bio-refining.



This Report describes the efforts by various companies associated with petroleum refining to develop technologies for meeting the above challenges. It also covers relevant research and patent activities by other organizations. The section concludes with an assessment of the current status of technology developments and their likely directions.

Refinery Energy Management to Abate GHG Emissions

Several issues in recent years have pushed the task of energy management to the top of oil refiners' priority lists. Oil prices are at an all-time high, and CO_2 emissions have increased by 20% in the last 10 years. Many countries around the globe have adopted emissions limitations, such as the Kyoto Protocol, that might require refiners to reduce greenhouse gas (GHG) production in the future through drastic improvements in refinery energy efficiency. Unfortunately, more stringent standards for refined products and the increasing use of opportunity crudes—high-TAN and heavy or sour crudes—often consume a larger quantity of fuel, thereby increasing emissions.

The European Commission (EC) issued a proposal on Jan. 31, 2007 to slash CO_2 emissions from fuel usage, production, refining, and transport by 10% (or 500MM mt) over the period of 2011-2020 in an effort to adhere to its Kyoto Protocol requirements. In the US, the energy legislation signed into law on Dec. 19, 2007 provides the Environmental Protection Agency (EPA) with $3.5MM in fiscal 2008 to create a registry that will be used by refineries and other industrial plants to report emissions of greenhouse gases. The bill mandates that the EPA develop the system within nine months and establish a final rule on GHG reporting within 18 months. The law will call for emissions reporting at "appropriate thresholds in all sectors of the economy" as determined by the EPA, meaning that both upstream and downstream energy ventures will be required to report emissions of CO_2 and other greenhouse pollutants. Presently, only electric utilities are required to report GHG emissions, although some other plants voluntarily track and disclose their emissions activities to the EPA. The rule is likely a preliminary step in establishing a national carbon cap-and-trade program.

For refiners around the world, the call to fight global warming via GHG emissions reductions will require strategic changes to existing operations. These changes include a combination of energy efficiency improvements, fuel switches, crude substitutions, utilization of refinery-CO_2 LP models (particularly those focusing on FCC regeneration; steam reforming for H_2 production; and fuel for steam, process heating, and electricity generation), IGCC schemes, CO_2 capture and storage strategies, and carbon trading programs. However, refiners must also cope with the fact that worldwide action to battle climate change will inevitably reduce demand for refined products, which are produced almost entirely from fossil fuels.

The purpose of this Report is to offer refiners a complete view of energy management in their operations through the following:

- keeping up to date on recent political activity related to energy management and emissions in the refining sector;
- analyzing and evaluating steam, heat, power, and hydrogen systems to minimize energy losses and fuel consumption during generation and distribution;
- presenting alternative approaches to conducting an energy management program in an industrial setting;
- conducting unit-by-unit analyses of major refinery processing equipment, highlighting energy use, general improvements, and technological developments to be implemented in the future;
- scrutinizing commercial energy management programs offered by major oil and consulting companies;
- examining commercial software and hardware packages offered for energy management; and
- discussing recommended energy efficiency improvements in the short- and long-term with various investment requirements.

Many refiners believe that the "low-hanging fruit" of energy efficiency improvements were previously picked during similar market conditions in the early 1990s. This idea is blatantly false and a great deal of energy savings with little or no capital investment required is available to any refinery operator.

To truly manage energy in a refinery setting it is not only necessary to explore improvements on a site-wide basis, but also to focus on individual processing units' contribution to energy performance. In a typical refinery, the major energy consumers include crude distillation, reforming, hydrotreating, catalytic cracking, vacuum distillation, and alkylation. Operations like thermal cracking, hydrocracking, isomerization, etc. require less energy but cannot be ignored. The following table demonstrates energy-saving opportunities in various refinery units.

Process	Energy consumption per unit of feedstock		Energy efficiency index*	Estimated potential savings, $MM/y
	Target standard of net energy consumption, MJ/mt (K Btu/bbl)	Specific net energy consumption, MJ/mt (K Btu/bbl)		
Atmospheric distillation	800 (103.4)	1,095.5 (141.7)	137%	4.7
Vacuum distillation	450 (58.1)	630.9 (81.6)	140%	1.2
Fluidized catalytic cracking	1,300 (168.1)	1,508.7 (195.1)	116%	0.5
Straight-run hydrotreating	900 (116.4)	1,471.8 (190.3)	162%	0.3
Middle distillate hydrotreating	800 (103.5)	1,130.4 (146.2)	141%	0.3
Catalytic reforming	2,800 (362.1)	3,232.2 (418)	115%	0.5
Alkylation	6,000 (775.9)	11,595.6 (1499)	193%	1.1
Visbreaking	1,200 (155.1)	1,325.2 (171.4)	110%	0.4

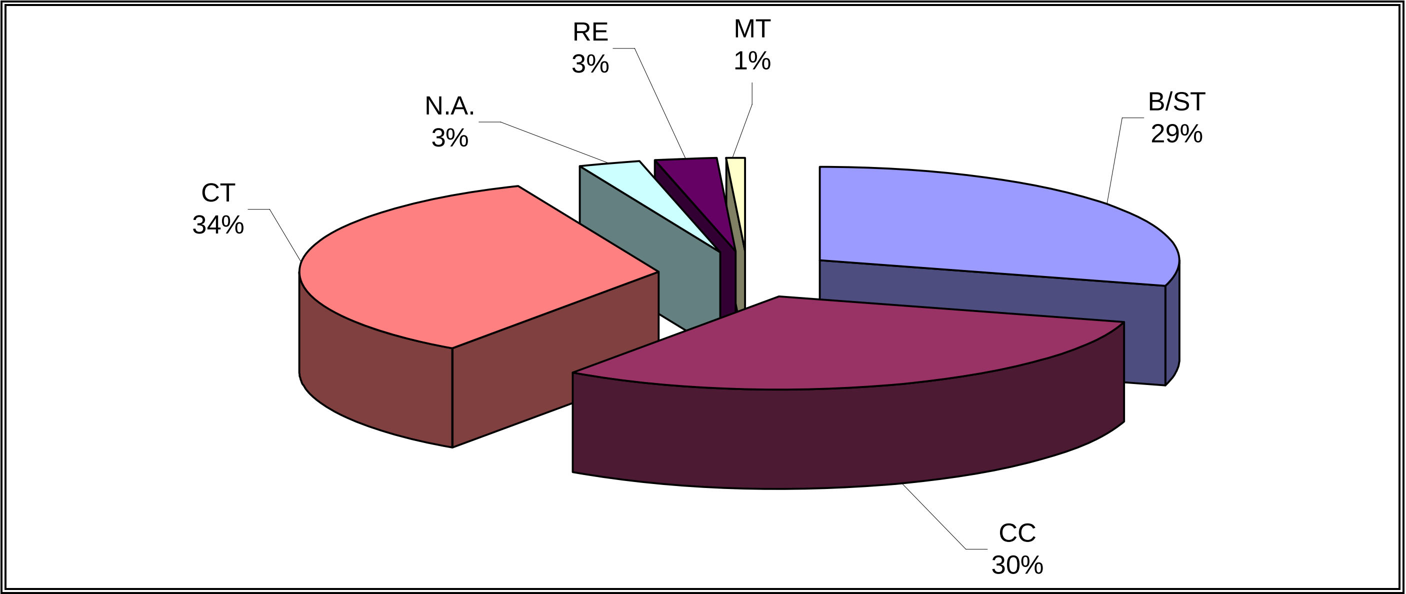
*The energy efficiency index represents the specific net energy consumption as a percentage of the target standard energy consumption

The study also devotes a separate section to commercially available energy management programs from various companies. Furthermore, case studies are presented and critically analyzed to support the implementation of such programs. Overall, this Report will serve as roadmap, reference source and guide to energy management in a refinery setting. The information presented will help refinery operators (1) identify inefficient use of energy and primary savings opportunities, (2) evaluate alternative options for improvement, (3) select and implement commercial energy management systems, and (4) plan for the future to sustain and improve energy efficiency.

Combined Heat and Power: Integrated Gasification Combined Cycle

The basic need for clean, cost-effective, efficient power is present in every refinery operation throughout the world. However, oil refiners have traditionally been skeptical about constructing power plants onsite due to their limited electricity requirements (usually about 60 MW for a stand-alone refinery) and the capital intensity of such projects. Besides the legislative requirements of capping CO_2 emissions, the recent trend toward liberalization of the electricity market, combined with an increasing need to dispose of refinery waste streams, has led many to reconsider their options. Combined Heat and Power (CHP), or cogeneration, has emerged as an efficient way to meet these increasing demands while maintaining superior environmental performance. An estimated 27% improvement in efficiency will be realized simply by switching to cogeneration from stand-alone power generation. Traditional CHP methods primarily include combined-cycle power plants, reciprocating engines, microturbines, or combined boiler/steam turbine configurations.

A survey of all US refinery-related CHP facilities was conducted based on both the fuel type and the prime mover. As can be seen in the following diagram, combustion turbines (CT) made up the largest demographic with 33% of the CHP plants, combined-cycle (CC) and boiler/steam turbine (B/ST) plants followed closely with 30% and 29% respectively. The remaining 7% of US cogeneration plants utilized reciprocating engines (RE—3%) and microturbines (MT—1%) with information for the remaining 3% being unavailable.



Despite these factors, CHP installations have decreased in recent years; however, the contemporary trend to limit and cap emissions (NO_X, CO_2, etc.) has once again jump-started the research and development effort for cogeneration technology. Cogeneration is widely viewed as an effective option to improve efficiency and meet environmental standards in the future for large-scale industrial plants.

In the refining sector, one rapidly-emerging cogeneration option is Integrated Gasification Combined Cycle (IGCC). This technology capitalizes on both the market trends listed above and the constant drive to improve efficiency and integration within the refinery. Furthermore, hydrogen supply is considered to be an increasingly important issue in hydrocarbon processing. Many processing units throughout a typical oil refinery use large volumes of H_2, which can become a great financial burden. Refiners can take advantage of these situations by integrating large, efficient gasification plants into their facilities to cheaply generate their own power and steam, as well as a significant supply of hydrogen gas.

Gasification converts a range of carbonaceous feedstocks into clean syngas for the production of hydrogen, steam, chemicals, and electricity. Currently, coal accounts for 49% of this feedstock, petroleum provides 37%, and the remaining 14% is derived from a combination of natural gas, petroleum coke (petcoke), and biomass/waste. In the next few years, the majority of new gasification projects will continue to involve the use of coal as the primary feedstock. However, the processing of petroleum refinery residues, petcoke, and waste streams will have an added significance in a GHG-constrained world.

The syngas from a gasifier can be sent to a CO shift reactor for H_2 and chemicals production or be routed to combined-cycle turbines as part of an IGCC plant for power generation. IGCC is considered to be the most efficient conversion method of processing solid feeds to yield electricity. Several IGCC operations around the world are associated with refinery applications to process low-value residues and petcoke for the production of power, steam, and H_2. The addition of an IGCC complex in an existing refinery also offers a more cost-effective approach to reducing emissions than other abatement technologies. The actual reductions that can be achieved through the implementation of IGCC include a 40% decrease of total onsite CO_2 emissions and an 80% reduction of SO_X, NO_X, CO, and particulate emissions.

Currently, carbon capture and sequestration (e.g., for enhanced oil recovery in nearby declining oil fields) is a key selling point for IGCC projects. High CO_2 concentrations in gasification product streams provide the needed economy of scale, and the benefits could be magnified if combined with the gasification of biomass in the future. Recently, the US EPA supported the advancement of refinery gasification by reclassifying certain solid petroleum waste materials to promote the recycling of these materials via gasification.[i] Furthermore, the US Dept. of Energy (DOE) has continued its involvement in gasification-based clean-coal projects (in conjunction with the FutureGen Alliance) to promote carbon capture in fossil fuel-based power production. This project was originally supported by the Energy Policy Act of 2005, which authorized $1.65B for clean-coal projects, including $800MM specifically for IGCC. (The DOE's contribution was estimated in Jan. 2008 to be closer to $1.1B due to inflation and other factors.[ii]) The 2005 Act also allotted $300MM in tax credits for gasification projects not directly associated with power generation. Government involvement in the development of gasification and clean-coal processes will hasten the progress and availability of these breakthrough technologies.

Overall, gasification is a technology with a great deal of potential for the future. Throughout the world today, hundreds of gasification units are used both in and out of refinery settings. Several new opportunities in the US and China will look to expand the use of readily-available coal as a feedstock to create power, steam, and chemicals. In other areas, such as the Canadian oilsand fields, gasification is finding new applications by utilizing bottom-of-the-barrel residuals to help reduce emissions, close the hydrogen gap, and increase overall plant efficiency.

<u>This Report analyzes the growing importance of gasification technology in the hydrocarbon industry with a focus on integrated gasification combined cycle (IGCC) for combined heat and power generation.</u> It also includes detailed studies of the latest gasification and IGCC technology advances by major licensers. Finally, a look at the future of gasification and IGCC is discussed considering the introduction of advanced gas and hydrogen turbines and membrane technologies that will lead to both improved efficiency and environmental performance in this area.

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