UOP UNICRACKING TECHNOLOGY UPDATE

MAXIMIZING DIESEL IN EXISTING ASSETS

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INTRODUCTION

Although gasoline and crude demand have declined due to the global economic crisis and the impact of high prices earlier in 2008, distillate demand has remained relatively strong. The worldwide distillate demand over the next ten years is expected to increase by over 5 million barrels per day. Consumption of low-sulfur, high-quality diesel is projected to grow at a faster rate than both fuel oil and gasoline over the next 10 years. Of particular interest, distillate demand in the Americas is expected to increase by over one million barrels per day during that period. In addition to the transportation demand growth the price differential between gasoline and diesel is also expected to increase. As a result, refiners are asking, “How can I shift refinery production to meet the need for more high-quality diesel fuel?” To address this need, refiners are searching for cost effective solutions to successfully increase diesel yields from existing refinery processes. The key challenge is to identify the optimal path from the options available, such as changes in cutpoints, changes in operating conditions, yield selectivity enhancements via catalyst changes, minor to major investments, and implementing technology advancements. This paper will explore the possible opportunities to increase diesel production from an existing gasoline FCC-based refinery. This paper will also explore options to shift a refinery with a maximum naphtha hydrocracking unit to increased diesel production while retaining flexibility to produce both naphtha and diesel. Evaluating project cost and product requirements requires in depth knowledge of refinery wide technologies with both catalyst and process design, and their application to new challenges. UOP is uniquely suited to this task, deriving knowledge from over 100 refinery catalysts and over 70 process technologies installed worldwide for almost 100 years.

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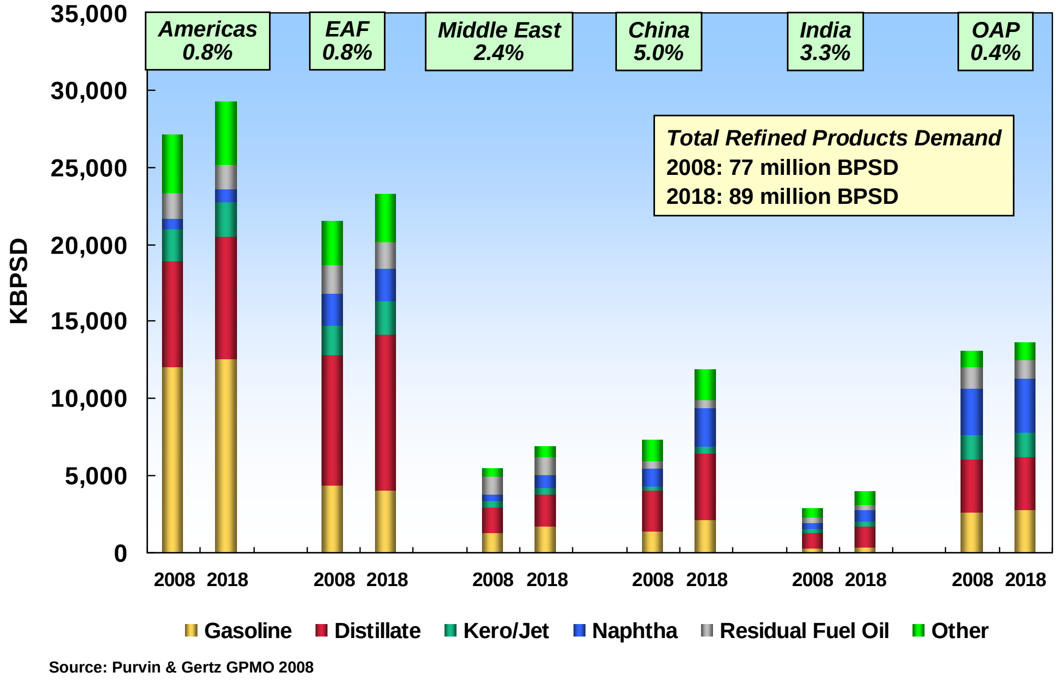
MARKET SITUATION

Refined Products Demand

Not surprisingly, most market projections show growth of refined products demand varies geographically (Figure 1[1]). The growth rates tend to be slowest in the highly-developed economies such as North America, Europe, and the developed countries in Asia. However, strong economic development in China, India and the Middle East is expected to help total refined products demand grow nearly 12 million barrels per day, a 1.4% average rate, over the next 10 years. Distillate demand is expected to experience an annual growth rate of 2.0% during this time frame, while gasoline demand is forecast to increase at 0.7% per year. These growth rates equate to ~5 million barrels per day (MMBPD) distillate demand versus ~1.6 MMBPD of gasoline demand over the ten year period. It is worth noting that worldwide demand for diesel has exceeded the gasoline demand since 2000 and this trend is projected to continue through 2018.[1]

Figure 1: Worldwide Refined Products Demand

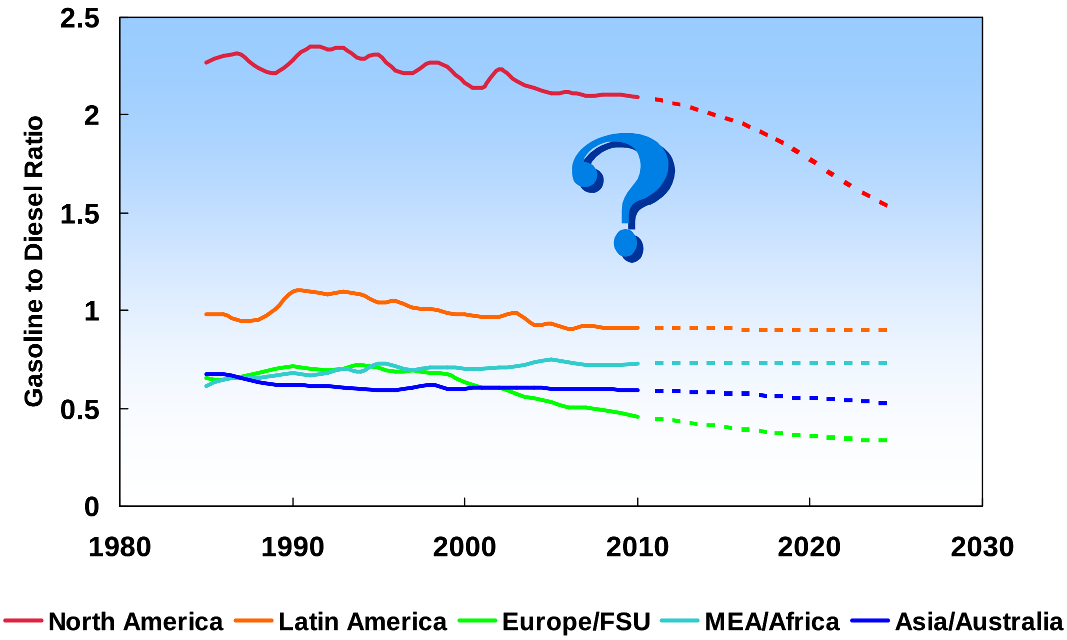


The pattern of refined fuels demand in the Americas has been shifting toward diesel in recent years as demonstrated by the gasoline to diesel demand ratio (G:D) in Figure 2. The expectation is that this will continue to shift beyond 2010 and at a much faster pace. One driving force for increased diesel demand is the continued evolution of advanced diesel engine technology. Diesel engines have progressed considerably since the noisy, smoky, unreliable engines that U.S. drivers were exposed to in the early 1980s. Today's diesel drivetrains are not only efficient; they are clean, and provide high performance. Turbo charger innovation from industry leaders like

Honeywell makes the turbo diesel the world's most efficient internal combustion engine. Consequently, demand for diesel-powered vehicles is favored by fuel economy standards since diesel engines are 15 to 30% more efficient than gasoline-powered engines. Recent implementation of more aggressive Corporate Average Fuel Economy (CAFE) regulations in the U.S. may accelerate penetration of diesel-powered vehicles.

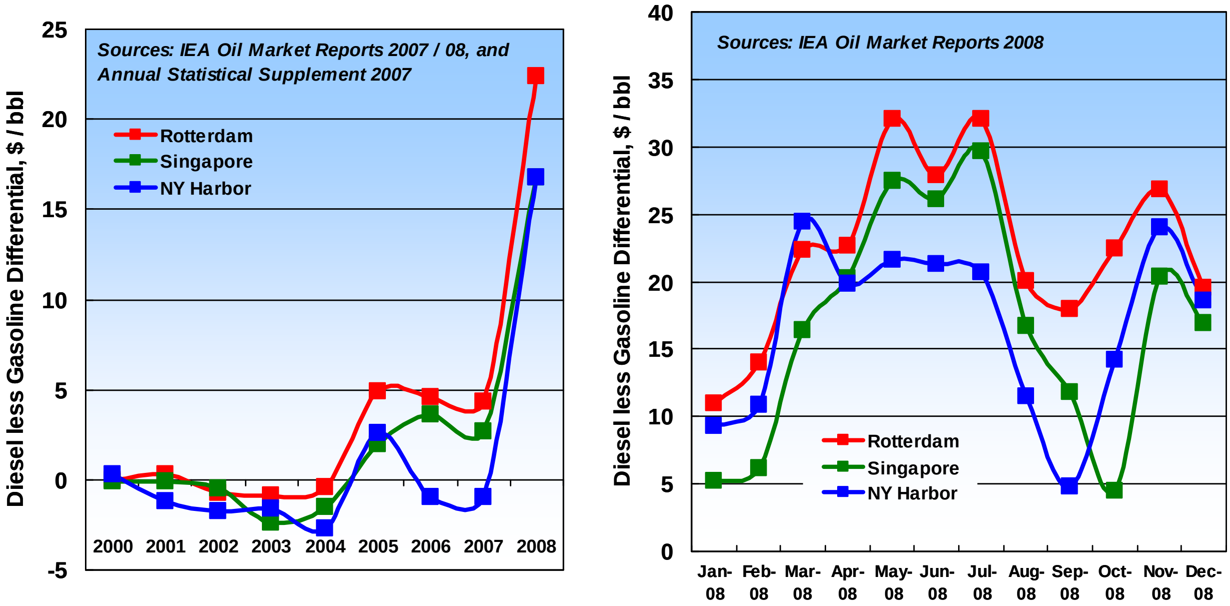
The increase in the production of diesel fuel by U.S. refiners is also a result of globalization, being driven by countries experiencing strong economic development. China, India and nations of the Middle East are building their economies based on trucks, trains and other modes of transportation that require diesel. As these countries increase their industrial capacity, diesel demand will continue to increase. Many of these countries also utilize diesel power generation stations to provide power since their electricity requirements are growing faster than electrical generation supply. Economic growth has also increased living standards in these countries, thus enabling development of a middle class that can afford cars, which in turn further increases demand for transportation fuel. Although, some of these countries, such as China tend to favor gasoline-fueled cars, other developing markets are still favoring diesel-fueled vehicles.

Figure 2: Shifting Gasoline-to-Diesel Demand



Recent regulations such as the Renewable Fuels Standard, aimed at increasing the amount of renewable components, such as ethanol, in the U.S. gasoline pool have created a mismatch between refining capabilities and product demand. Refiners are faced with an oversupply of high-octane gasoline blending components, thus depressing gasoline margins. At the same time, global demand for diesel has continued to grow, but it is not easy to force a refinery configured to maximize gasoline yield to significantly increase diesel yield from existing equipment. Consequently, the supply of diesel to the marketplace has remained relatively tight compared to gasoline, thus supporting healthier margins for diesel fuel production. This has resulted in a significant jump in diesel-gasoline differentials as shown in Figure 3. Changes in the pricing spread between gasoline and diesel have resulted in a re-examination of how best to shift refinery G:D ratios to meet the market requirements while maximizing refinery profitability.

Figure 3: 2008 Diesel-to-Gasoline Differentials

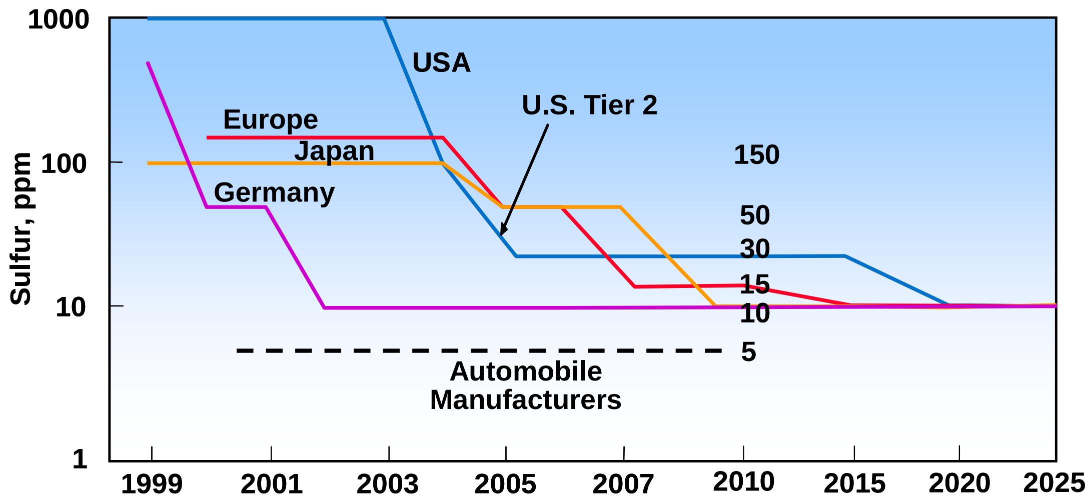


Environmental Regulations

Motor fuel specifications have changed significantly over the past 10 to 15 years and are continuing to evolve. The World Wide Fuel Charter Initiative is helping to set advanced emission control requirements, and thus drive fuel qualities. Sulfur and aromatics contents are being reduced in most developed countries and the trends are spreading to other regions. The Clean Air Initiative for Asian Cities (CAI-Asia) is developing a road map for cleaner fuels and vehicles in Asia[2]. The most notable changes govern the sulfur content of both gasoline and diesel fuel.

Tier II regulations in the U.S. have driven gasoline sulfur down to < 30 ppm. Europe has reduced sulfur to <15 ppm. Japan already has very low sulfur levels in its gasoline while other countries are moving in the same direction, albeit at a less aggressive pace. The evolution of gasoline sulfur specifications is shown in Figure 4. By the end of the decade, 80% of the world's gasoline consumption will be ultra-low sulfur (< 50 ppm).

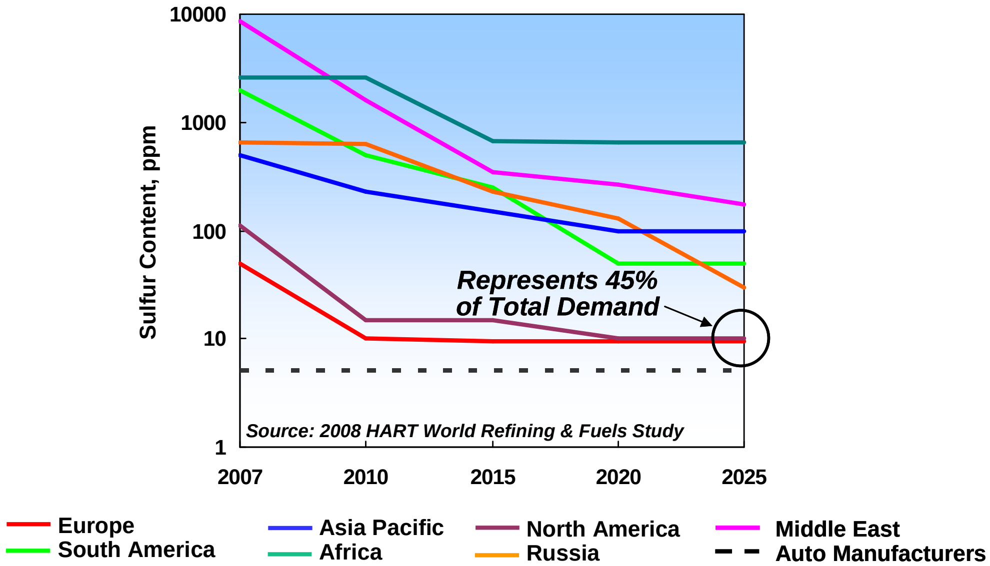
Figure 4: Worldwide Changing Gasoline Sulfur Standards



Source: AM-02-36, NPRA 2002 Annual Meeting &
Hart Energy World Refining and Fuels Service 2006-2025 (2008 Edition)

Diesel fuel sulfur content is being reduced at a similar pace to gasoline with Germany mandating maximum sulfur levels of 10 ppm in January 2003, the U.S. mandating 15 ppm in 2006, Japan planning to go to 10 ppm, and other Asian countries are following a similar trend. Several other European countries are voluntarily switching to 10 ppm sulfur in diesel ahead of this year's deadline (Figure 5).

Figure 5: Diesel Sulfur Indicative Trends



Currently, ~65% of the world road diesel is refined to low and ultra-low sulfur diesel standards. This percentage is projected to rise to approximately 75% by 2015.[3]

DIESEL PRODUCTION OPTIONS

Refiners generally have some flexibility to shift yields of gasoline, jet, and diesel to meet market demand, but there are practical limits to this flexibility dictated by the refinery configuration. The objective of our study was to investigate several of the more promising options. The refinery configuration is based on a defined crude slate and the refinery operation was assumed to be focused on producing transportation fuels with the primary emphasis on maximizing gasoline. The shifting to heavier crudes to increase diesel was not considered as an option for this study. Shifting to a heavier crude slate is certainly an option worth considering, but was defined to be outside the scope of this work.

For the purpose of this study, we evaluated optimizing feed stocks to different processing units as well as existing assets operating flexibility for three refinery case scenarios. In summary, the three refinery base case scenarios considered were:

Scenario 1. FCC based refinery,
Scenario 2. FCC with a Cat Feed Hydrotreating unit (CFH), and
Scenario 3. FCC refinery with a Hydrocracking unit (HCU).

As you shift from gasoline to diesel production hydrogen availability becomes increasingly important. The additional hydrogen is necessary because the gasoline refinery requires hydrogen only for treating where as the CFH and HCU units require hydrogen for both conversion and treating. Hydrogen is also needed to meet critical diesel specifications such as cetane and polyaromatics content in much of the world. The markets that are being accessed dictate the product slate required and process unit flexibility that is necessary. In this study, different stages of process unit flexibility have been considered, we have assumed that up to 15% additional throughput in each major process unit can be accommodated without investment, and the stages are defined below. A sensitivity analysis is presented at the end of the paper, evaluating the major process unit capacities constrained from 60 to 110% from the base cases.

- *Operational.* In this approach, conventional cutpoint changes and similar strategies were allowed, but no catalyst was changed.
- *Minimal Investment.* For this option feed and product cutpoint changes and shifts of feedstocks to other processes were allowed. Also included was a change in FCC catalyst to a more LCO selective catalyst.
- *Moderate Investment.* For this option additional feed changes were allowed from the minimal investment stage, as well as catalyst changes and moderate capital investments.

The three different FCC-based refinery scenarios were evaluated over these different stages for shifting toward maximum diesel production. A summary of these different operating scenarios and changes are discussed further in the following sections as well as the recommendations from this work.

UNDERSTANDING THE IMPACT OF SHIFTING TO DIESEL PRODUCTION

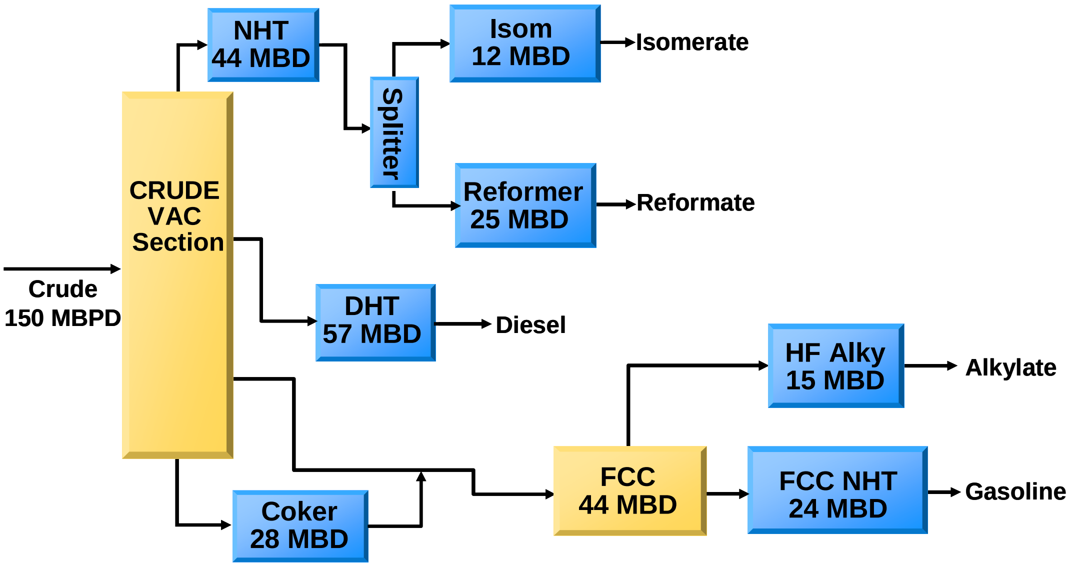
Changes in the pricing spread between gasoline and diesel have resulted in a re-examination of how best to shift refinery G:D ratios to meet the market requirements while maximizing refinery profitability. To help frame the options and provide guidance for evaluating product slate properties as well as the affect of shifting feeds and operations of process units, a refinery linear program (LP) model was developed for three refinery configuration scenarios. The LP model was used to evaluate how best to optimize the existing assets with a new diesel-focused product slate. At the same time, it was assumed that the Renewable Fuel Standard (RFS) increased the level of ethanol into the gasoline pool from 6 to 10 lv-%.

The LP was based on a crude mix consisting of 150,000 BPD of a mixture of Arab medium, Western Canadian Select (WCS), and West Texas Intermediate (WTI) crudes. A summary of the price basis used in this study is provided in Table 1. The LP was configured such that there was no buying or selling of intermediates in the cases except for the FCC clarified slurry oil (CSO). The transportation fuel specifications are based on typical U.S. summer requirements including ultra low sulfur diesel (ULSD) and gasoline. The gasoline product mix is made up of conventional regular, conventional oxygenated, and RFG regular gasoline. No premium gasoline was produced. Both of the oxygenated grades use 10 lv-% ethanol resulting in 6 lv-% ethanol in the pool for each of the base cases. The amount of gasoline production can vary in the cases, but the grade mix (i.e. quality) was fixed to have a manageable matrix of cases. The gasoline benzene and sulfur were tracked and controlled. Management of the light and heavy naphtha cutpoints, coupled with an isomerization unit, UOP Penex™ Process and low benzene reformer, UOP CCR Platforming™ Process were arranged to control benzene. FCC naphtha sulfur was managed using a FCC naphtha selective hydrotreating unit, the UOP SelectFining™ Process.

Scenario 1. FCC Based Refinery

The Scenario 1 FCC based refinery configuration, shown in Figure 6, consists of a delayed coking unit, an FCC unit with a naphtha hydrotreating unit, an UOP HF alkylation unit, a distillate hydrotreating unit, and a catalytic reforming unit. After hydrotreating, the naphtha is split for routing to an isomerization unit and reforming unit. Hydrogen for this scenario was supplied from the Platforming process.

Figure 6 – Scenario 1 Refinery Flowscheme



The refinery base case was established with the FCC in a maximum gasoline operating mode. This case was used to establish the operating unit capacities and provide the basis for assessing constraints in the other cases. The pricing set used in the cases is provided in Table 1.

Table 1 – Pricing Basis for LP

Purchases	
West Texas Intermediate	35%
Arab Medium	50%
Western Canadian Select	15%
Blend Price*	$75.27/Bbl
	% of crude price
Ethanol	123%
Normal butane	88%
Isobutane	92%
Natural Gas, $/MT	575%
Major Product Sales:	***% of crude price***
Propane	74%
Butane	85%
Non-RFG Regular Gasolines	122%
RFG Regular Gasoline	125%
Ultra Low Sulfur Diesel (Gasoline Valued Price)	116%
Ultra Low Sulfur Diesel (Distillate Valued Price)	142%
FCC Clarified Slurry Oil	86%
Petroleum Coke, $/MT	20%
Sulfur, $/MT	71%

*Purvin & Gertz 3Q08 forecast, blend of 80% 2007 and 20% 2008 actual prices

The base case for this scenario has been labeled the Base Gasoline Case and used the ultra low sulfur diesel (ULSD) Gasoline Valued Pricing to set the refinery optimization. The result of this base case is a gasoline to diesel ratio of 1.62.

Operational Change Case:

- **Distillate pricing**. In this case, the refinery operations were optimized based on the Distillate Valued ULSD pricing while also targeting a gasoline pool ethanol content of 10 lv-%. Crude unit swing cuts were free to move based on economics. The re-optimization of diesel to preferred processing routes shows that a larger DHT unit is required. The net result of the optimization is a decrease in the G:D ratio from 1.62 to 1.34 (going more towards diesel product) and an increase in overall Refinery margin of ~$1.2MM/D or $7.95/Bbl of crude higher than the base gasoline case due to the increased value of the ultra low sulfur diesel product. Table 2 presents some of the changes to the process unit feed rates as well as the shift in refinery products for the different cases within the Scenario 1 based refinery case.

Minimal Investment Change Case:

- **FCC Fractionator Cutpoint Adjustment.** The FCC unit main column operation was adjusted to maximize the overall LCO volume at the expense of naphtha and bottoms. The gasoline endpoint was reduced to the minimum diesel flash and the LCO end point was maximized to the diesel final boiling point limit. It was assumed that the operational shifts in the main column can be accommodated with existing equipment and therefore no investment would be required. This operational condition shift alone significantly reduces overall G:D ratio with a marginal reduction in clarified slurry oil (CSO). The refinery margin was increased slightly ~$53M/D over the above distillate pricing case. This was due to the reduction in CSO and the much higher production of diesel represented by the reduction in the G:D ratio to 1.17. Again the DHT unit capacity increased from the prior case, 23% over the base rate, requiring some capital investment. The CCR Platforming process operation adjusted to increase hydrogen production resulting in the refiner being long on octane.
- **Catalyst Optimization**. Starting with the same main column operational shifts highlighted under the FCC Fractionator Cutpoint Adjustment case above, distillate production from the FCC unit was further enhanced through the use of a FCC catalyst targeted for maximum distillate production. The main shifts associated with these catalyst systems are a shift of CSO (primary) and naphtha (secondary) to LCO. The refinery margin increases approximately $43M/D over the prior case. A further reduction in the G:D to 1.15 is obtained. As with the prior cases the DHT capacity would need to be increased.

Moderate Investment Change Case:

- **Full Distillate**. This case represents a shift in FCC operation to low severity maximum distillate operation. This case incorporates all of the operational and catalytic effects cited in the previous cases but also includes a ~40°F reduction in reactor operating temperature. The reduction in unit operating severity results in LCO volume gain, however, with a slightly greater volumetric increase in CSO. Although this case achieves the lowest G:D ratio (1.04) of all cases simulated under Refinery Scenario 1, the increase in CSO yield reduces overall refinery margin by ~$89M/D, relative to the previous case. The G:D reduction in this case is accomplished from reducing gasoline yield at a higher rate relative to the increase in ULSD. The associated economics indicate that lowering FCC severity for maximizing distillate is not attractive. A potential alternative for managing CSO volume at reduced severity would be to implement CSO or, preferably, HCO recycle within the FCC unit. This would require installation of recycle facilities and also dictates that the impact of the recycle stream on unit coke and gas yields be factored into overall unit throughput and economics. Recycling of CSO or HCO will typically yield slightly better economics than the case simulated in this study, however, it still will not be an attractive option for maximizing distillate relative to the cutpoint and/or catalyst change options highlighted above.

Table 2 – Scenario 1 FCC Based Refinery

Case Titles	***Base Gasoline***	***Distillate Pricing***	***Fractionator Cutpoint Adjustment***	***Catalyst Optimization***	***Full Distillate***
G:D Ratio	1.62	1.34	1.17	1.15	1.04
Refinery Margin, $/Bbl of crude	Base	2.03x	2.08x	2.12x	2.04x
Ethanol Level, vol-%	6	10	10	10	10
FCC, MBPD	Base	-6%	-6%	-6%	-6%
DHT, MBPD	Base	14%	23%	25%	27%
Sulfur Plant, MTPD	Base	2%	10%	13%	14%
EEC* Δ, $MM	Base	-	$2.7	$3.5	$4.2

**Inside process battery limits only, U.S. Gulf Coast labor and erection, no special design standards.*

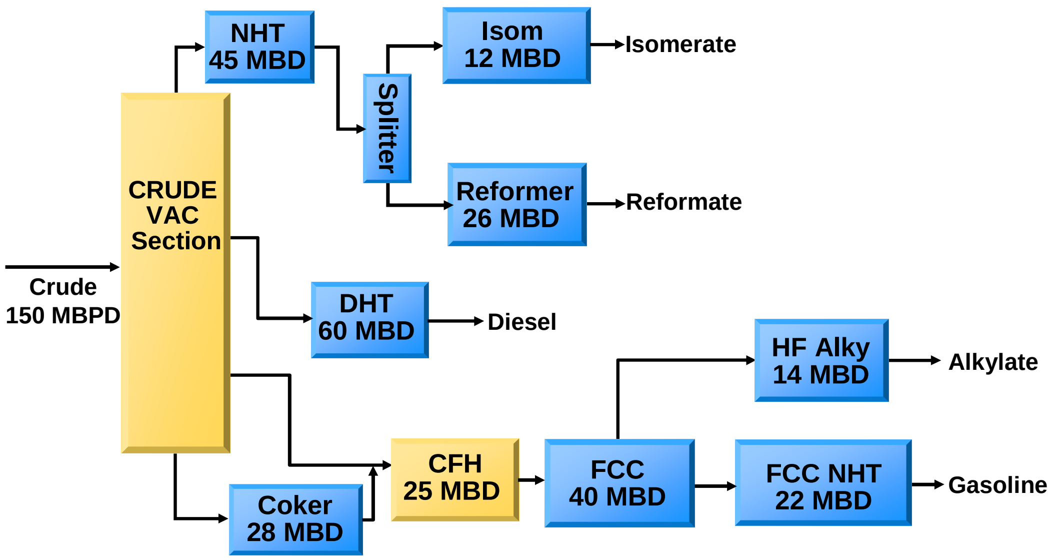
Scenario 1 Summary

A FCC-only gasoline focused refinery configuration is constrained in the amount of distillate that can be economically produced using existing assets and conventional methods. The traditional "max distillate" FCC operation shifts reactor temperature and/or catalyst activity to reduce unit conversion thereby increasing LCO production. Unfortunately, reducing reactor temperature and/or catalyst activity are not selective to LCO production alone and result in sizable quantities of CSO (or FCC bottoms) to be produced. This option will generally be economically unattractive for producing ULSD due to the swell in CSO volume and corresponding volume loss of high valued products across the FCC plant. Economics favored reduction of the FCC feedrate in all the cases consistent with shifting crude unit cutpoints to maximize distillate volume to the DHT. The simple payback (after tax) for all of Scenario 1 cases is less than a month both when the capital expenses are only incurred if the capacities are greater than 15% over the base as well as if we assume that the unit is already constrained and any increase would require capital.

Scenario 2. FCC with Cat Feed Hydrotreating Based Refinery

This refinery configuration, also defined as Scenario 2 incorporates a Cat Feed Hydrotreating unit (CFH) with the FCC unit as shown in Figure 7. To address the additional hydrogen requirements associated with the CFH, a hydrogen plant was also included. The CFH feed rate was allowed to vary between 25 to 30 MBPD. The hydrogen plant was natural gas based and the capacity was allowed to float in order to satisfy the incremental hydrogen requirements in all cases. Feed streams to the FCC were adjusted slightly with the addition of the CFH. All of the heavy atmospheric gas oil (HAGO) was routed to the FCC unit and all of the coker gasoil was routed to the CFH. The other gas oil streams were optimized based on economics between the FCC and CFH units in each of the cases.

Figure 7 - Scenario 2 Refinery Flowscheme



The Scenario 2 base case configuration has been labeled Base Gasoline Case 2 and the ULSD Gasoline Valued Pricing was used to set the refinery LP optimization. The result of this base case is a gasoline to diesel ratio of 1.53.

Operational Change Case:

- The cases investigated in this scenario were not identical to those covered in Scenario 1, but instead started from the assumption that the changes made to the FCC unit in the Catalyst Optimization case were completed already. Making these changes results in the requirement of minimal investment and this initial case is described in the Minimal Investment Change Case section.

Minimal Investment Change Case:

- **Distillate FCC and Distillate Favored Pricing**. As was done in Scenario 1, the crude unit operation was free to shift to a diesel focused operating refinery, the gasoline mix was required to produce a 10 lv-% ethanol pool from the refinery, and the FCC operation was shifted as described in the Catalyst Optimization case within the Scenario 1 refinery description. The refinery optimization reflected the move from Gasoline Valued ULSD to Distillate Valued pricing from Table 1. The CFH rate was increased to the maximum constrained level in the optimized LP configuration. The DHT and hydrogen plants increased substantially from the base case, as well. The result of these changes decreased the G:D ratio from 1.53 to 1.10 while increasing the refinery margin by $9.29/Bbl of crude. This represents an increase of over double the base case, and is mainly due to the increased value of the ultra low sulfur diesel product. Table 3 presents some of the changes to the process unit feed rates and refinery products for the different cases simulated within the Scenario 2 refinery configuration.

Moderate Investment Change Case:

- **CFH shift to HC**. One option for further increasing diesel production in an FCC-based refinery with a CFH, is to adapt the CFH to a partial conversion hydrocracking (HC) operation. This enables greater lift than the standard CFH operation to produce more distillates. In order to model this operation, the FCC operation was kept constant based on the previous case, while the yields were modified to account for the change in feed quality and reduction in feed rate reflecting the higher CFH lift. The CFH shift from minimal conversion (17%) to a more moderate level of conversion (40%) required replacing part of the hydrotreating Albemarle KF-848 catalyst with UOP Unicracking™ catalyst DHC-32 and required additional recycle gas capacity. The DHT and hydrogen plant increased from the above case but not as dramatically as the delta from the base case to the minimal investment operating case. There is a further increase in the refinery margin, ~$99M/D over the prior case, as well as a further reduction in the G:D to 1.03. The main reason for the increased refinery margin was due to the greatly increased ULSD yield and lower FCC CSO and coke production due to the FCC feed rate reduction.

Table 3 – Scenario 2 FCC with FCC Feed Hydrotreating Unit Refinery

Case Titles	***Base Gasoline 2***	***Distillate FCC and Distillate Favored Pricing***	***CFH shift to HC***
G:D Ratio	1.53	1.1	1.03
Refinery Margin, $/Bbl of crude	Base	2.14x	2.22x
Ethanol Level, vol-%	6	10	10
FCC, MBPD	Base	-9%	-26%
DHT, MBPD	Base	23%	27%
CFH, MBPD	Base	20%	20%
Sulfur Plant, MTPD	Base	7%	6%
Hydrogen Plant, MTPD	Base	2.92x	3.37x
EEC** Δ, $MM	Base	$21.6*	$29.1*

**over ~70% of this EEC increase is attributed to the almost 3 times larger hydrogen plant.*
***Inside process battery limits only, U.S. Gulf Coast labor and erection, no special design standards.*

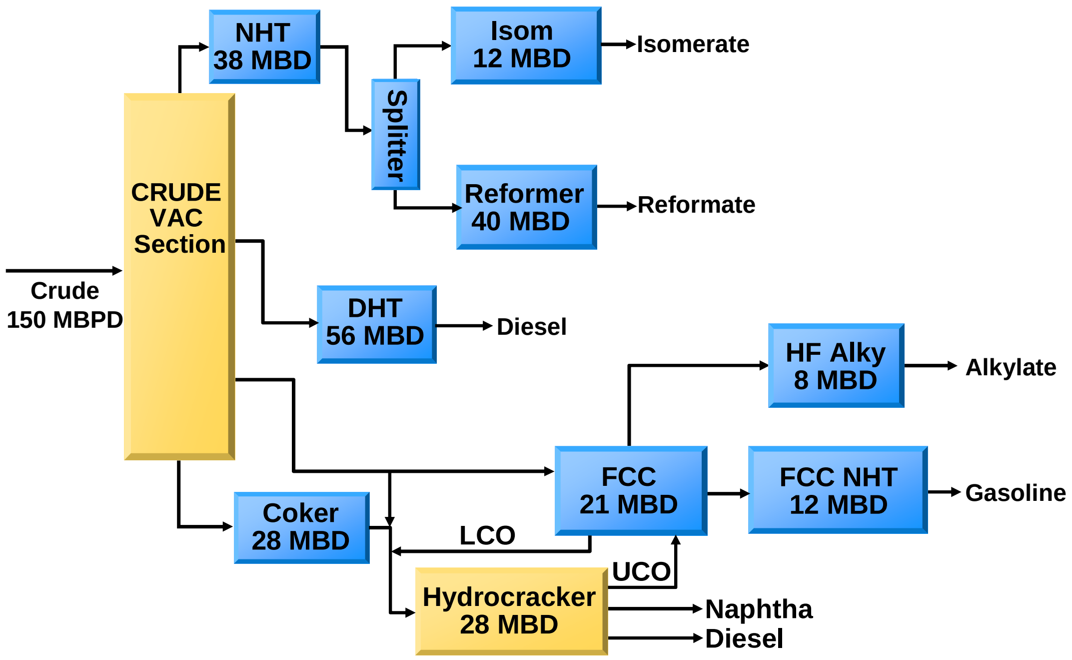
Scenario 2 Summary

An FCC-based refinery which also incorporates Cat Feed Hydrotreating unit can increase distillate production (and improve the G:D ratio) by converting the existing CFH to partial conversion hydrocracking operation. The CFH for the study was designed for 500 ppm sulfur feed to the FCC Unit for a CFH catalyst life of 2 years. In the moderate investment scenario, part of the hydrotreating catalyst was replaced with a distillate selective hydrocracking catalyst to facilitate a moderate increase in conversion without sacrificing significant catalyst life. The conversion level in this case was increased from 17% to 40% in the hydrocracking mode. The CFH unit will typically require additional recycle gas capacity to manage the increased heat release and modifications to the fractionation to recover the additional distillate. The simple payback (after tax) for the two cases in Scenario 2 is less than two months when the capital expenses are only incurred if the capacities are greater than 15% over the base. However, when we assume that the units are already constrained and any increase would require capital, the simple payback (after tax) for both cases increases to less than 2 months for the minimal investment case and less than 3 for the moderate investment case.

Scenario 3. FCC and Hydrocracking Based Refinery

Scenario 3 represents a complex refinery configuration consisting of both FCC and hydrocracking units as shown in Figure 8. This is the same configuration as Scenario 1 with the addition of a hydrogen plant and a hydrocracking unit (HCU). The HCU was added in parallel to the FCC unit. The base HCU operation is operated in a naphtha production mode. The feed streams to the HCU for naphtha production consisted of all of the Coker gasoil, HAGO and the FCC LCO. The light and heavy VGO were split between the FCC and HCU units and the unconverted oil (UCO) from the HCU was routed to the FCC. The FCC operations were maintained for gasoline production, but the yields were shifted to account for the change in feed quality.

Figure 8 - Scenario 3 Refinery Flowscheme



The Scenario 3 base case configuration has been labeled Base Gasoline 3 and the ULSD Gasoline Valued Pricing was used to set the refinery LP optimization. The result of this base case is a gasoline to diesel ratio of 1.65.

Operational Change Case:

- As was the case in Scenario 2, the cases investigated in this scenario were not identical to those covered in Scenario 1, but instead started from the assumption that the changes made to the FCC unit in the Catalyst Optimization case were completed already. Making these changes results in the requirement of minimal investment and this initial case is described in the Minimal Investment Change Cases section.

Minimal Investment Change Cases (All below cases have Distillate FCC & Distillate Favored Pricing):

- **Naphtha Feed & HCU Operation**. As described in Scenario 1, the crude unit operation was adjusted to focus on increased distillate production. At the same time, the gasoline pool was also adjusted to target an ethanol content of 10 lv-%, and the FCC operation was shifted as described in the Catalyst Optimization case within the Scenario 1 refinery description. The refinery optimization reflected the move from Gasoline Valued ULSD to Distillate Valued pricing from Table 1. The HCU feed and operations were left consistent with the base case. The DHT and hydrogen plant increased slightly from the base case. The result of these changes was to only slightly increase diesel production, thus reducing the G:D ratio from 1.65 to 1.62 while increasing refinery margin to $7.49/Bbl of crude above the Base Gasoline case. This is mainly due to the increased value of the ultra low sulfur diesel product in this case. Table 4 presents some of the changes to the process unit feed rates and refinery products for the different cases simulated within the Scenario 3 refinery configuration.

- **Distillate HCU Operation with Naphtha Feed**. The feed routing and the FCC operation were left constant with the previous case. The HCU operating mode and therefore yields were shifted to maximize distillate production. The DHT decreased in size from the prior case, although the hydrogen plant and HCU did increase. For this case the refinery margin increased by ~$184M/D over the Naphtha HCU operation. This was due to the reduction in CSO and coke make and the much higher production of diesel represented by the reduction in the G:D ratio to 0.90.
- **Distillate Feed & HCU Operation case**. This is the same configuration and operation as in the above case, except that, LCO was removed from the HCU feed and routed directly to the DHT with the intent of increasing overall refinery ULSD production. However, contrary to the desired effect, HCU rates decreased. The reason is that constraints on the gasoline pool qualities, specifically RVP and VOC, controlled the relative HCU and FCC feed rates. Adjusting FCC and HCU unit feed rates allowed the balance of high RVP HCU light naphtha product with the lower RVP alkylate and FCC naphtha. HCU light naphtha yield increased for the new case and so, high HCU rates were not maintained as desired, the FCC feed became heavier and overall yields slumped. Although this option did result in a slight G:D ratio improvement, the overall effect with reduced HCU rate and poorer FCC yields resulted in a refinery margin **decrease** of ~$21M/D from the prior case.

Moderate Investment Change Cases:

- **Distillate Feed & HCU Operation with Distillate Catalyst**. This is the same configuration and operation as in the previous case, with the main change being the replacement of the original naphtha selective catalyst to a distillate selective catalyst. This change resulted in the removal of the HCU light naphtha yield problem. The more selective distillate operation provided an improvement over all the previous cases. The margin improved ~$29M/D over the prior naphtha catalyst case with distillate feed, and ~$8M/D above the naphtha feed with distillate HCU operation. This case had the lowest G:D of 0.81, and highest overall ULSD production of all of the cases that were simulated.

Table 4 – Scenario 3 FCC and Hydrocracking Units Refinery

Case Titles	*Base Gasoline 3*	*Distillate FCC and Distillate Favored Pricing 3*	*Dist HCU with Naphtha Feed*	*Dist HCU with Distillate Feed*	*Dist HCU & Feed with Dist Catalyst*
HCU Catalyst	Base	Base	Base	Base	Distillate
G:D Ratio	1.65	1.62	0.90	0.88	0.81
Refinery Margin, $/Bbl of crude	Base	1.75x	1.87x	1.86x	1.88x
Ethanol Level, vol-%	6	10	10	10	10
FCC, MBPD	Base	17%	-23%	-24%	-28%
DHT, MBPD	Base	5%	5%	13%	8%
HCU, MBPD	Base	-9%	12%	-4%	10%
Sulfur Plant, MTPD	Base	1%	6%	4%	6%
Hydrogen Plant, MTPD	Base	1.14x	1.50x	1.25x	1.60x
EEC[*] Δ, $MM	Base	$2.7	$6.5	$2.1	$10

[*]*Inside process battery limits only, U.S. Gulf Coast labor and erection, no special design standards.*

Scenario 3 Summary

The FCC and HCU based refinery has several options to maximize distillate production depending upon the type of hydrocracking unit that exists in the refinery. The HCU offers flexibility to maximize distillate production in various ways that can be as simple as changing the product fractionator to draw distillate product to changing the hydrocracking catalyst to one that is more distillate selective. The extent of the changes that can be implemented will depend on the unit flow scheme, unit design conditions and product quality objectives. Such changes to the unit require a detailed study to evaluate the existing unit design flexibility, available heat exchange network and fractionation train.

For the Scenario 3 refinery defined above, the HCU is assumed to be a Single Stage hydrocracking unit designed for maximizing naphtha production. The operating pressure was assumed to be 1500 psig. One of the consequences of modifying the HCU operation to shift from maximum naphtha mode to distillate mode is a reduction in hydrocracking severity, which in turn reduces hydrogen consumption and heat release. This relaxation of the operating window permits the use of lower activity distillate selective catalyst within the constraints of the heat exchange flexibility. Not surprisingly, shifting the product slate from naphtha to distillate has significant impact on the product fractionator, which must be addressed. In this study, naphtha selective Unicracking catalyst HC-24, was changed to Unicracking catalyst HC-150, an intermediate distillate selective hydrocracking catalyst. As shown in Table 4, a significant improvement in G:D ratio can be achieved by changing the Unicracking catalyst. The simple payback (after tax) for all of Scenario 3 cases is less than 1 ½ months both when the capital expenses are only incurred if the capacities are greater than 15% over the base as well as if we assume that the unit is already constrained and any increase would require capital.

SENSITIVITY CASES

Several sensitivity cases were run for the above Scenarios using the LP model. Three different sensitivities were evaluated: unit rate limit sensitivity, hydrogen limit sensitivity and ULSD to gasoline price differential sensitivity. The results of the sensitivity analysis are provided in the following sections.

(Note that additional operating costs for new catalyst are not included in the refinery margin results indicated.)

Unit Rate Limit Sensitivity

In reality, a refiner will have constraints on the amount of additional capacity which can be accommodated within existing assets. Sensitivities were evaluated to provide an indication of the impact this constraint has on the economics of diesel maximization. For each of the three refineries, the beginning base gasoline mode was considered the "as built" refinery that defined the unit capacities. For this sensitivity work, it was assumed that these unit rates could only vary from about 60% to 110% around the base rate except for the H_2 Plant and CFH. The H_2 Plant remained open for this evaluation, but is addressed in a subsequent section. The CFH rate was constrained to about 62 to 75% of the gasoline mode FCC unit rate. New rate limited base cases were defined by re-running the Distillate Pricing modes with these unit rate limits setting the base case for analysis to compare with a similarly rate limited case that included the various improvement options discussed above. Results are shown in Tables 5 – 7.

Table 5 – Rate Constrained Scenario 1 FCC Refinery

Rate Constrained Cases	***Distillate Pricing Rate Limited (Base)***	***Catalyst Optimization***	***Relative Open Rate Delta Result***
Margin, M$/Day	Base	+26	+96
G:D	1.44	1.46	
Rates, % of Max			
DHT	100	100	
FCC	85	91	
Sulfur Plant	92	100	

The 100% of maximum rates for the DHT and Sulfur Plant represented in Table 5 refer to the rates reaching 110% of the gasoline mode base unit capacity. The margin improvement for the constrained FCC refinery is reduced by about four-fold relative to the open rate situation due to DHT and Sulfur Plant limits. Only a slight shift to the full Catalyst Optimization mode was possible which had generated most of the benefit from improved FCC yields.

Table 6 – Rate Constrained Scenario 2 FCC & CFH Refinery

Rate Constrained Cases	***Distillate FCC & Pricing Rate Limited (Base)***	***CFH shift to HC***	***Relative Open Rate Delta Result***
Margin, M$/Day	Base	+6	+99
G:D	1.37	1.37	
Rates, % of Max			
DHT	**100**	**100**	
FCC	91	91	
CFH	**Min**	**Min**	
Sulfur Plant	93	93	
Hydrogen Plant, MTD (open)	39	39	

The margin improvement for the constrained Scenario 2 refinery is reduced by an order of magnitude relative to the open rate situation due to CFH and DHT limits. Only a slight shift to the partial conversion hydrocracking mode was possible generating some modest yield upgrade. However, these gains were essentially inconsequential since very little movement was possible due to the hydrotreating limits.

Table 7 – Rate Constrained Scenario 3 FCC & Hydrocracking Refinery

Rate Constrained Cases	***Distillate FCC & Pricing 3 Rate Limited (Base)***	***Dist HCU & Feed with Dist Catalyst***	***Relative Open Rate Delta Result***
Margin, M$/Day	Base	+198**	+193**
G:D	1.61	0.82	
Rates, % of Max			
DHT	95	98	
FCC	**100**	68	
SelectFining Unit	78	**Min**	
HCU	86	98	
Sulfur Plant	93	97	
Hydrogen Plant, MTD (open)	57	86	

** *(Each individual constrained case refinery margin was lower than the respective individual unconstrained case refinery margin. The items indicated are delta margins where there was greater economic suppression between the base points than between the improved points.)*

The constrained Scenario 3 refinery margin improvement was less affected by the imposition of unit rate limitations. This results because most of the capacity difference is involved with the finished products off the HCU. There is not a great impact at the DHT and supporting units. The constrained Base Distillate Case had a naphtha focused HCU operation with distillate pricing and so, economics favored a maximum FCC rate. The constrained, all distillate, HCU favored maximizing the HCU rates at the expense of the FCC as indicated by the minimum SelectFining Process rate.

H_2 Limit Sensitivity

All H_2 was provided by the catalytic reforming unit for the Scenario 1 refinery configuration, so there was no H_2 Plant sensitivity for this refinery Scenario. Notably, many of the higher margin cases indicated octane give-away in the gasoline pool consistent with a H_2 operation at the reformer.

The open unit rate Scenario 2 refinery cases were re-examined in comparison to the same cases with a constrained H_2 Plant with results shown in Table 8. As indicated, the imposition of the H_2 Plant limit essentially reduces the improvement potential by about a third. The limited cases ran at the minimum CFH rate in full partial conversion hydrocracking mode at the maximum allowed H_2 Plant operation.

Table 8 – Hydrogen Limit Sensitivity Constrained Scenario 2 FCC & CFH Refinery

Margin Improvement move to HC Mode	***Delta $M/Day***
All Open Unit Rates	+99
Above with Limited H_2 Plant	+67

The Scenario 3 refinery inherently had more flexibility particularly since the starting condition was a naphtha based HCU with relatively high H_2 uptake in comparison to distillate operation at lower H_2 uptake. The H_2 sensitivity was examined with unit rate constraints in place as shown in Table 9. As indicated, the imposition of the H_2 Plant limit essentially removes about 30% of the potential improvement value by limiting the degree to which the maximum distillate mode HCU improvements can be exploited.

Table 9 – H_2 Limit Sensitivity Constrained Scenario 3 FCC & Hydrocracking Refinery

Margin Improvement for Max Distillate HCU with Distillate Catalyst	***Delta $M/Day***
Limited Unit Rates, except H_2 Plant	**+198**
Above with Limited H_2 Plant	**+141**

Price Sensitivity

Sensitivity to price was examined by re-running the various cases over a range of ULSD to gasoline differentials and plotting these results against delta margin per barrel of crude. This was done for all three refinery Scenarios and used the Base Distillate case specific to each Scenario as the anchor point for the refinery delta margin calculation, i.e.

Refinery Upgrade, $/bbl Crude = Delta Refinery Margin $/Day / 150,000 BPD Crude
Delta Refinery Margin = Improved Case Margin $/Day – Base Distillate Case Margin $/Day

Figure 9 shows the price sensitivity for Scenario 1 options with open unit capacities. The low severity FCC operation requires the highest differential to generate a positive incentive due to the large amount of clarified slurry oil produced for that option. The naphtha recut shows intermediate incentive except at low differentials where gasoline is more strongly favored. The

LCO catalyst optimized case indicates the highest incentives even at low differentials due to the reduction in CSO yield. Across all cases shown, the most significant (>10%) throughput increases occur at the DHT (+30%), and Sulfur Plant (+15%).

Figure 9 - Scenario 1 FCC – Margin Upgrade vs. ULSD-Mogas Differential

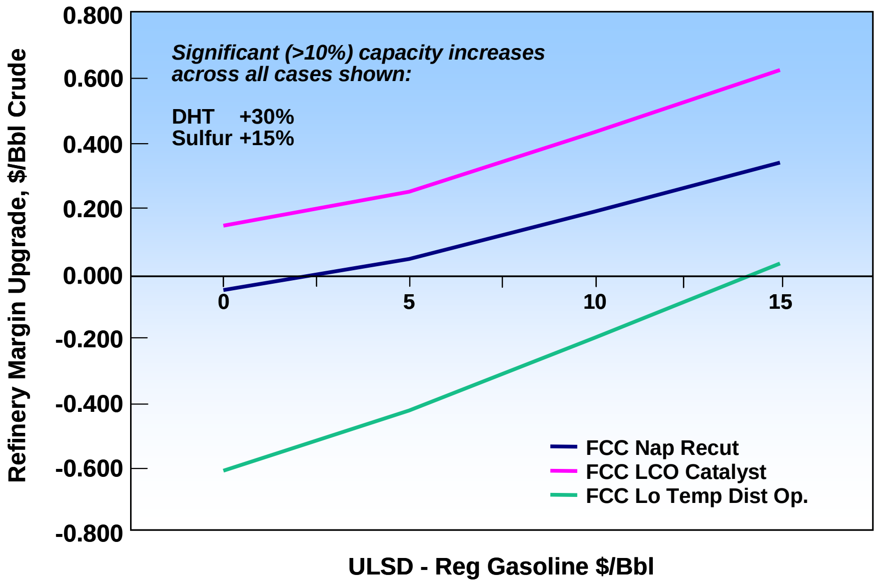


Figure 10 shows the incentive for the combined FCC options with the imposition of unit capacity constraints. As before, there is some overall positive incentive indicated even at low differentials due to CSO reduction. However, little improvement potential is possible due to the DHT and Sulfur Plant limits, and so, the value slope is essentially flat.

Figure 10 - Scenario 1 FCC – Margin Upgrade vs. ULSD-Mogas Differential

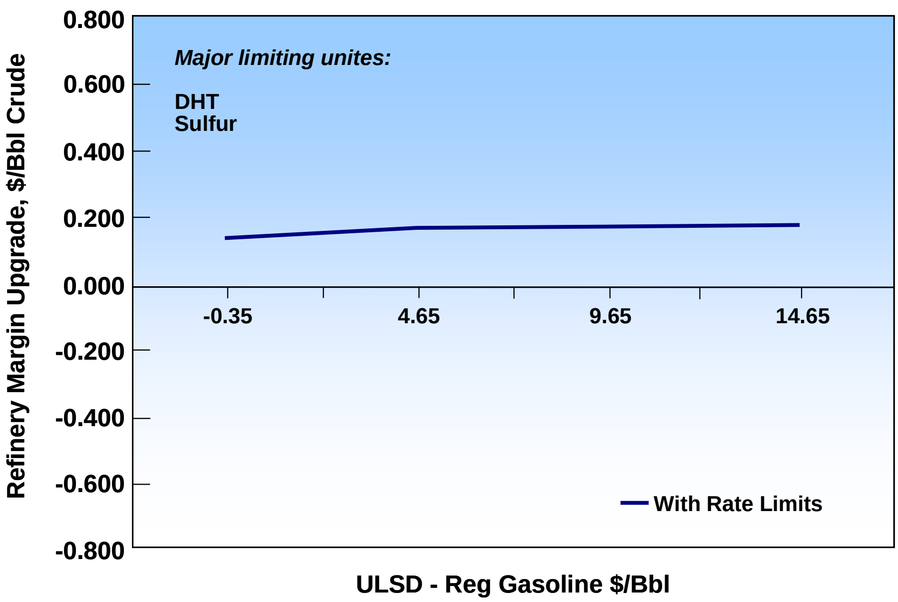


Figure 11 shows the price sensitivity results for the Scenario 2 refinery in partial conversion hydrocracking mode with all open unit capacities (except the CFH that was limited to 30 MBPD max). Greater incentives are shown relative to the FCC cases due to more degrees of freedom with the CFH partial conversion hydrocracking mode. Similar to the FCC cases, positive incentives are indicated at low differentials due mostly to slurry oil reduction. Across all cases, the most significant (>10%) unit throughput increases occur at the DHT (+25%), CFH (+20%), and H_2 Plant (+350%). Price sensitivities for the Scenario 2 refinery with the imposition of unit capacity constraints are not shown, since, as indicated above, improvement potential is very low once DHT limits are in place.

Figure 11 - Scenario 2 FCC & CFH– Margin Upgrade vs. ULSD-Mogas Differential

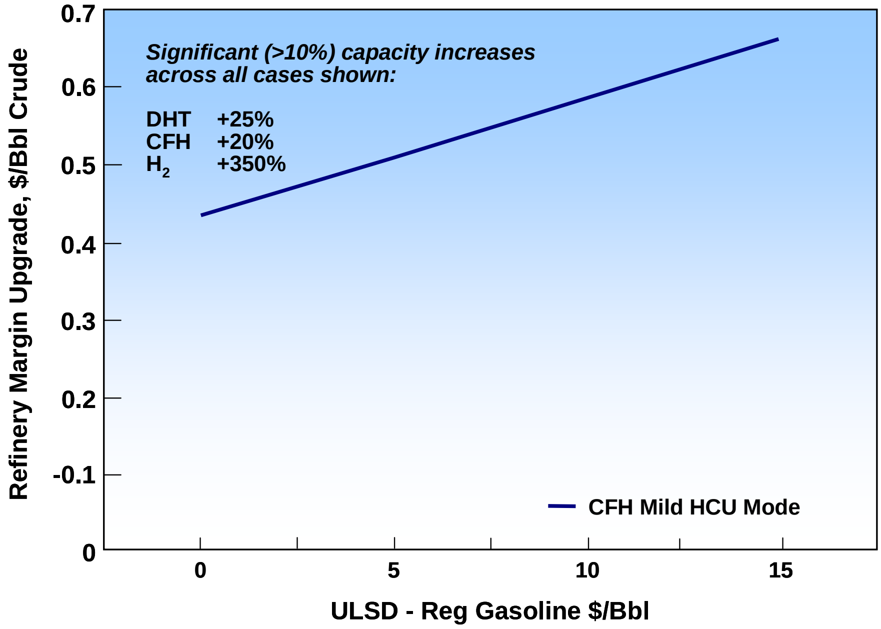


Figure 12 shows the price sensitivity results for the Scenario 3 refinery options with open unit capacities. All these modes produce large amounts of distillate, and, as a result, incentives are negative at the lower differentials that favor gasoline and rise sharply as differentials improve toward favoring ULSD production. The relative value of the options vary (cross) at different ends of the scale in proportion to the favored product and its production rate. Notably, in this analysis, at the high ULSD differential, the distillate HCU operation with distillate feed (i.e. routing LCO away from the HCU and direct to the DHT) did not perform comparatively well even though much higher distillate yield might be expected. This occurred since HCU light naphtha yield was much higher in this mode and to balance gasoline volatiles (RVP, VOC), the high HCU rate could not be maintained over the FCC. Across all cases, the most significant unit throughput increases (>10%) occurred at the DHT (+15%), HCU (+20%), FCC/Alky (+15%), and H_2 Plant (+15%).

Figure 12 - Scenario 3 FCC & HCU– Margin Upgrade vs. ULSD-Mogas Differential

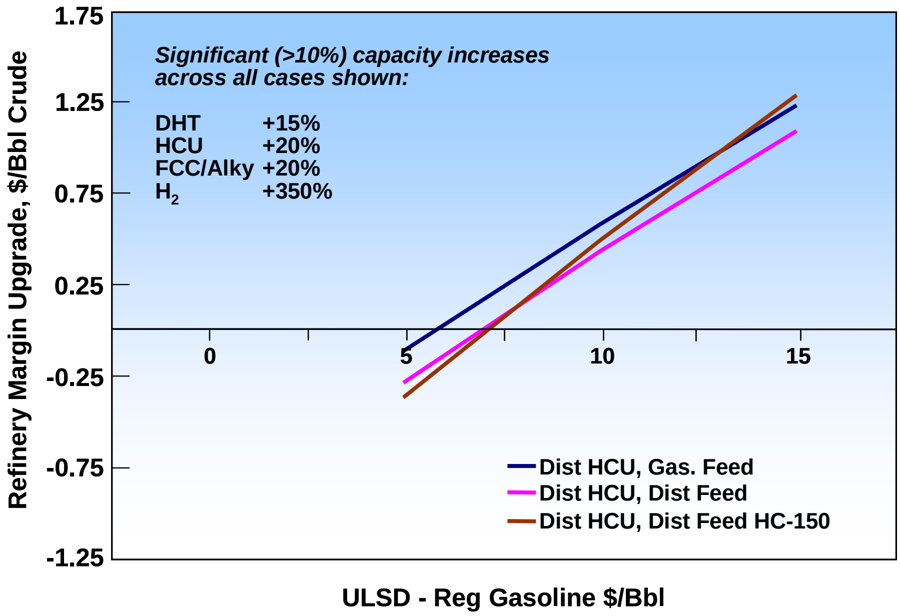
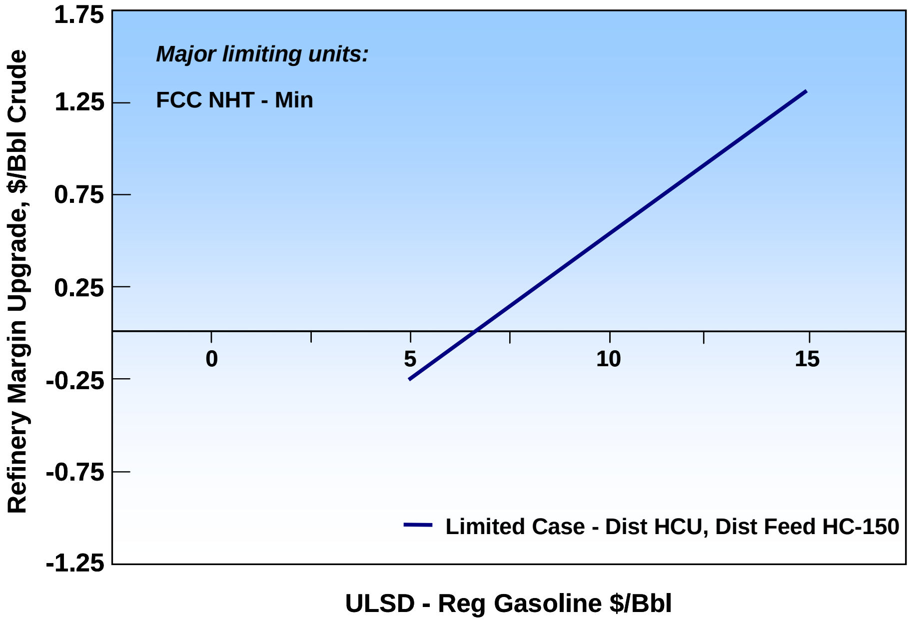


Figure 13 shows the results for the Scenario 3 refinery with limited unit capacities (except H_2). Since the open rate HCU price sensitivity results above clustered fairly close together, only the max distillate HCU with distillate catalyst case is shown below for comparison. Results are fairly close to the open unit rate results since the HCU produces finished products with less impact on supporting units. Primarily the minimum SelectFining Unit rate was limiting as feed favored the HCU over the FCC.

Figure 13 - Scenario 3 FCC & HCU – Margin Upgrade vs. ULSD-Mogas Differential



CONCLUSION

Addressing the question of how best to optimize the balance between gasoline and diesel production and feedstock shifts depends on the refinery configuration, gasoline and diesel markets, other blending considerations (such as whether blending ethanol), hydrogen availability, equipment constraints, and the ability to invest. The challenge for a refiner is how to choose and implement a solution that provides the best value. In many, but necessarily not all cases, this will often be the low-cost solution. Solutions will be refinery-specific and will be determined by the current refinery configuration, the type of processing units present, external blending requirements (i.e. ethanol), and access to markets that allow trading of intermediate streams.

A refiner's first step in meeting the optimization of gasoline and diesel production requirements is to review the current yield pattern of each unit and analyze any feed shifts and operations that can be accomplished without major changes. Next, the refiner should determine what the operating window and roles are for the existing assets in light of the market requirements. These steps may involve considering the impact from alternative crudes that can be processed, future refinery revamps or expansions, and any changes in FCC unit operation that alters existing product mix. Once these preliminary steps are complete, the refiner needs to evaluate a number of solutions and determine if one solution offers better economics and flexibility than another. UOP can help evaluate the affect on the product slate based on the improvements that can be achieved for unit designs and constraints to maximize the return on investment, across the total refinery.

As shown in this paper, the process units that typically require the largest increases in capacity to shift toward diesel include the distillate hydrotreating unit, cat feed hydrotreating unit, H_2 Plant and Sulfur Plant. For the distillate and cat feed hydrotreating units, UOP is uniquely positioned to assist refiners with further analyses and solutions as a leading hydrotreating technology licensor with a full scope of state-of-the-art hydrotreating catalysts via its alliance with Albemarle, the Hydroprocessing Alliance. UOP can also assist with optimized solutions for increased H_2 capacity via state-of-the-art H_2 management studies and its positions as the leading supplier of PSA units for high purity hydrogen production.

The complex refinery with FCC and hydrocracking units, typically have significant potential to shift toward diesel production with attractive economics and minimal investment. UOP is well positioned to assist refiners with further analyses and solutions as a leading hydrocracking licensor with a full scope of state-of-the-art hydrocracking catalysts for all applications.

Fully integrated and optimized solutions that drive toward minimum investment cost and project timing, ensuring maximum project profitability are critical in meeting these challenges and taking advantage of the opportunities they present. Operational improvements, revamps of existing equipment, major expansions, as well as grass-roots refinery projects all need to be evaluated, requiring in depth knowledge of refinery wide technologies, and the ability to integrate catalyst applications into the process design. A licensor that can offer refiners a full portfolio of process technology, adsorbents and catalysts, specialized equipment, engineering and technical services, as well as operational support services can assist in maximizing the ability of the refiner to meet their individual market demands.

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