CHANGING REFINERY CONFIGURATION FOR HEAVY AND SYNTHETIC CRUDE PROCESSING

Gary R. Brierley, Visnja A. Gembicki and Tim M. Cowan
UOP LLC
Des Plaines, Illinois, USA

INTRODUCTION

Reduced availability of light conventional crudes in the future will create demand for new crude sources that will necessitate refinery configuration changes. The production of heavy crudes, synthetic crudes, and bitumen blends is growing, and the supply of bitumen-derived crudes is expected to reach almost three million barrels per day by the year 2015[1]. A plethora of synthetic crudes and bitumen blends have become available, all of which pose different challenges for today's refiners. Some crudes are both higher in contaminant levels and have a composition that makes them more difficult to upgrade. Coupled with the demand for increased production of ultra-clean diesel and gasoline, innovative refinery configuration changes will be needed to accommodate these new feedstocks. The potential processing schemes under consideration range from simple hydrotreating for contaminant removal, to hydrocracking and fluid catalytic cracking for conversion of gas oil to high-quality transportation fuels. It is the integration of these process technologies, however, that offers the greatest economic potential. This paper focuses on the processing of heavy and synthetic crude blends using innovative process integration across several technology platforms to produce clean fuels.

MARKET SITUATION

World oil demand is projected to continue increasing, at a rate of about 1.5% per year, with increased growth of transportation fuels coupled with a relatively flat heavy oil demand. The Energy Information Administration recently predicted that the demand for crude oil in the United States will increase at an average rate of 1.1% through to the year 2030[2]. Most of the 400,000-barrel annual increase in crude consumption in the United States will be used for transportation fuels, with gasoline representing about 45% of total petroleum consumption. The demand for distillate fuels is growing at a faster rate than the demand for gasoline. These changes in demand

© 2006 UOP LLC. All rights reserved.

have been accompanied by well-known ultra-low-sulfur regulations for diesel and gasoline, forcing a significant capital investment through the end of decade.

The production of light and medium crudes from the Western Canadian sedimentary basin is dropping by about 20% every five years. Given the increasing demand for oil, and declining production of conventional crudes in both the United States and Canada, the Canadian oil sands will become a key source of future crude supply. The volume of oil in place in the various deposits is estimated at 1.7 trillion barrels, of which 174 billion barrels is recoverable with existing technology. This places the size of the established reserves second only to Saudi Arabia. As recovery technologies improve, the size of those recoverable reserves could increase significantly. The proximity of the source, security of supply, and competitive pricing will drive the refinery investment needed to accommodate these crudes.

Today, the level of production has reached one million barrels per day, and it is expected to increase to almost three million barrels per day by 2015. Oil sands crudes are expected to represent more than 75% of the crude produced in Western Canada. While most of the imports into the United States are in PADDs II and IV, further pipeline expansions will increase penetration in PADD II and the Pacific Northwest (Northern PADD V). New pipeline systems are expected in the future, reaching Texas (PADD III) and a new sea port in British Columbia. From this new port, marine shipments to both California (Southern PADD V) and the Far East are expected.

As will be shown later, the composition and contaminant levels of bitumen-derived crudes does not make them an easy replacement for conventional crudes, especially since most existing refineries have limited capacity to accept poorer quality feedstocks. These crudes are fundamentally different, so refiners need to understand them and also be prepared for the changes needed to process them.

Bitumen-derived Crudes

The term “synthetic crude” has never been strictly defined, but it has come to mean a blend of naphtha, distillate, and gas oil range materials, with no resid (1050°F+, 565°C+ material). Canadian synthetic crudes first became available in 1967 when Suncor (then Great Canadian Oil Sands) started to market a blend produced by hydrotreating the naphtha, distillate, and gas oil generated in a delayed coking unit. The light, sweet synthetic crude marketed by Suncor today is called Suncor Oil Sands Blend A (OSA). Syncrude Canada Ltd. started production in 1978, marketing a fully-hydrotreated blend utilizing fluidized-bed coking technology as the primary upgrading step. Today, this product is referred to as Syncrude Sweet Blend (SSB). Husky Oil started up a heavy conventional crude upgrader in 1990 using a combination of ebullated-bed hydroprocessing and delayed coking technologies. Their sweet synthetic crude is traded as Husky Sweet Blend (HSB). The Athabasca Oils Sands Project (AOSP) started producing a sweet synthetic crude in 2003 called Premium Albian Synthetic (PAS) using ebullated-bed hydroprocessing technology. There are also small volumes of two synthetic crudes produced at the Consumers’ Co-op refinery called NSA and NSB.

The quality of the kerosene and diesel in these synthetic crude blends has been a major concern in the past. Bitumen is itself a very aromatic feed, and the choice of primary upgrading

technology has an effect on the final distillate quality. Husky's HSB and AOSP's PAS crudes are produced using an ebullated-bed resid hydrocracking technology, and hence have full-range diesel cetane numbers above 40. Suncor's OSA crude is produced using delayed coking, giving the full-range diesel a cetane number very close to, or just below 40. Syncrude's SSB crude is produced using the more-severe fluidized-bed coking technology, and the diesel has a cetane number of about 33. The kerosene cut of SSB has a smoke point of just 13 mm. Starting in June of 2006, Syncrude will start to produce Syncrude Sweet Premium (SSP), where the distillate has been further upgraded to give a full-range diesel cetane number of 40, and a kerosene smoke point of 19 mm.

Table 1 compares the basic composition and quality of Syncrude SSB against Brent crude[3]. The SSB crude has lower sulfur and no resid (as shipped), it contains significantly less naphtha-range material, and more distillate and VGO. Note that due to pipeline contamination, synthetic crudes like SSB can have some resid component when actually received in the refinery.

Table 1 – Comparison of Syncrude SSB and Brent Crudes

	Brent	***SSB Produced***	***SSB Received****
Gravity, API	**38.6**	**31.8**	**33.5**
Sulphur, wt%	**0.29**	**0.1**	**0.2**
RVP, psi	**8.2**	**4.6**	**N/A**
Yield, vol%			
C_4-	**2.9**	**3.4**	**N/A**
C_5- 350°F	**28.6**	**15**	**21**
350 - 650°F	**29.6**	**44**	**40.5**
650 - 350°F	**29.8**	**37.6**	**31.5**
1050°F plus	**9.1**	**0**	**3**
Properties			
Kerosene smoke pt, mm 350 - 650°F	**25**	**13**	**---**
Cetane	**50**	**30**	**---**
Pour	**-5**	**-55**	**---**

While sweet synthetic blends make up the majority of the synthetic crudes on the market, some sour synthetic blends are also available. Suncor markets a range of sour synthetic blends, each tailored to meet specific refinery processing capabilities. Suncor OSE crude is a blend of hydrotreated coker naphtha with non-hydrotreated coker distillate and coker heavy gas oil. Suncor's OSV crude is a blend of hydrotreated coker naphtha with straight-run distillate and straight-run VGO. There are several other sour blends available (OSH, OCC, etc), each with its own processing characteristics. While these sour crude blends still contain no resid fraction, they are generally sold to medium and heavy sour crude refineries. Note that AOSP markets a heavy sour blend called Albian Heavy Synthetic (AHS) which is a blend of their sweet PAS crude with

unconverted oil from their ebullated-bed resid hydrocracking unit. Since this crude does have a resid component, it is not really a synthetic crude as it has been defined here, but neither is it a bitumen blend, like those described below.

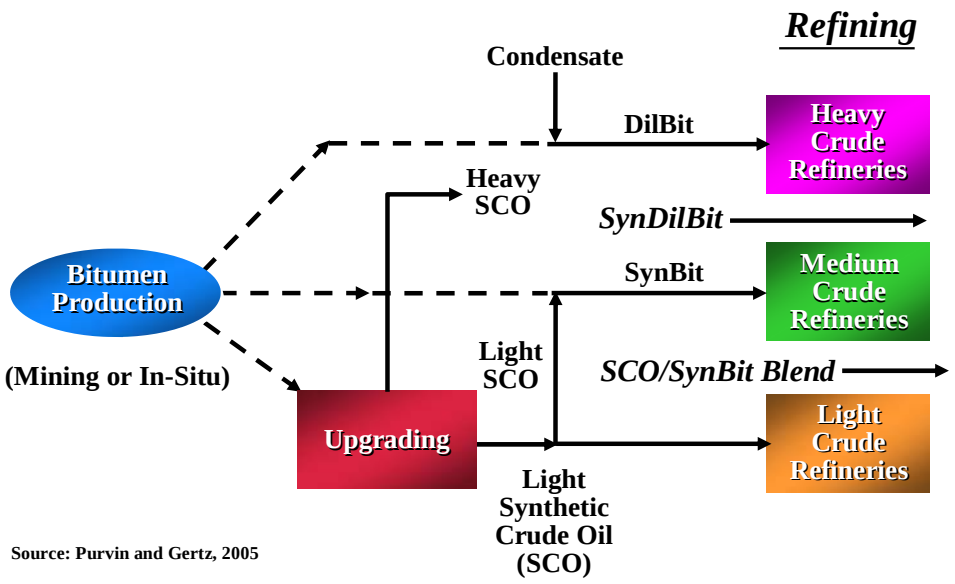
Together, the various synthetic crudes make up the majority of the bitumen-derived crudes on the market today. However, over 400 KB/D of bitumen are produced and shipped to market without having been upgraded. The bitumen must be diluted with a lighter hydrocarbon stream to meet the specifications required for shipping in pipelines. DilBits are blends of bitumen and condensate, typically natural gas condensate. They normally contain 25 – 30 lv% condensate and 70 – 75 lv% bitumen. The most common streams are Cold Lake Blend (CLB), Bow River (BRH), and various Lloyd blends (LLB, LLK, WCB). Since the majority of condensate is C_5 to C_{12} material, and the majority of bitumen is C_{30}+ boiling range material, these crudes have become known as "dumbbell crudes." There is a lot of material boiling at each end of the boiling point curve, but little in the middle.

Natural gas condensate is in short supply in Northern Alberta where the bitumen is produced. Condensate sells at a significant premium to light sweet crudes for this reason, and some condensate is actually being shipped by rail back to Alberta from the United States. To address the shortage of diluent, and the problem with dumbbell crudes, producers have started to market SynBits, blends of sweet synthetic crude (typically OSA) and bitumen. SynBits have a more continuous boiling point curve than DilBits, with a significant portion of distillate-range material in the blend. However, since the synthetic crude diluent has a much lower API gravity than condensate, more diluent is needed, so SynBits are typically 50 lv% synthetic crude and 50 lv% bitumen. The most common SynBits on the market today are Christina Lake Blend (CSB) and MacKay Heavy (MKH), both of which are blends of bitumen produced by Steam Assisted Gravity Drainage (SAGD) and OSA crudes.

SynDilBits are actually blends of condensate, hydrotreated synthetic crude, and bitumen. They typically contain about 65 lv% bitumen, with the remaining volume split between the two diluent streams. The most common of these streams are Wabasca Heavy (WH) and Western Canadian Select (WCS).

Light sweet synthetic crudes, heavy sour synthetic crudes, DilBits, SynBits, and SynDilBits all target different refineries. Figure 1[4] on the next page summarizes how bitumen is upgraded, or blended with other streams to make various types of crude blends. Light sweet synthetic crudes are usually sold to light crude refineries, while heavy sour synthetic crudes and DilBits are normally processed in heavy crude refineries. SynBits and SynDilBits are usually sold to medium crude refineries, or blended with additional synthetic crude for processing in a light crude refinery.

Figure 1 – Disposition of Bitumen-derived Crudes

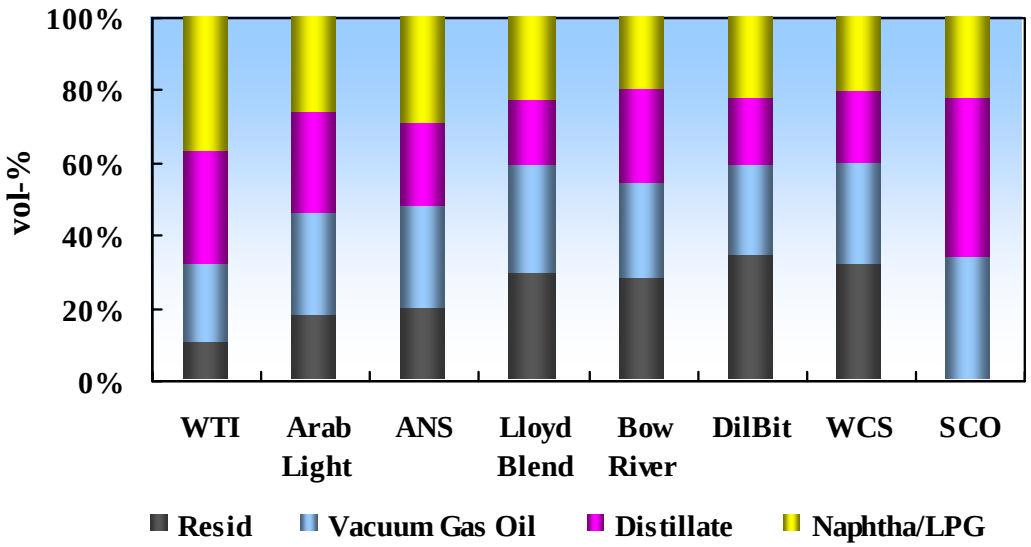


WCS is a somewhat unique SynDilBit in that it has a proprietary formula developed by EnCana, Talisman, Canadian Natural Resources Limited (CNRL), and Petro-Canada. They wanted to reduce the large number of heavy crudes being marketed from Western Canada, and achieve consistency in the heavy crude blends being shipped from Canada. Each batch contains specified amounts of the following crudes; LLW, LLC, CLB, CSB, MKH, and BR[6]. As such, each batch contains condensate, hydrotreated synthetic crude (OSA), heavy conventional crude, medium conventional crude, Cold Lake bitumen, and Athabasca bitumen. Each batch is blended to meet the following specifications; API gravity of 19 - 22°, carbon residue of 7 – 9 wt%, sulfur of 2.8 – 3.2 wt%, and a total acid number (TAN) of 0.7 – 1.0 mg KOH/g.

WCS may well become the new marker heavy crude from Western Canada, and efforts are being made to have it traded on the New York Commodities Exchange. Production of WCS started in January of 2005, with shipments currently at 250 KB/D, but expected to increase to more than 500 KB/D by 2008.

Each synthetic crude and bitumen blend has its own unique processing characteristics. The compositions of three conventional light crudes, two heavy conventional crudes, two bitumen blends, and one synthetic crude are compared and contrasted in Figure 2. Compared to the marker West Texas Intermediate (WTI) crude, a typical synthetic crude has no resid, 50% more VGO, 50% more distillate, and only half the naphtha. DilBits and WCS have about three times the volume of resid material than WTI, 50% more VGO, but only half the distillate range material, and half the naphtha.

Figure 2 – Crude Composition



PROCESSING IMPLICATIONS

The processing implications to the refinery will be a function of the type of bitumen-derived crude imported. First and foremost, refiners used to processing WTI will have a three-fold increase in the amount of resid coming to the refinery if they replace WTI with WCS. Beyond the implications to the crude and vacuum unit, extra resid conversion capacity will certainly be required. Refineries already seem to be anticipating this need. There is about 200 KB/D of incremental delayed coking capacity in various stages of planning in PADD II, PADD IV, and northern PADD V[1]. The addition of coking capacity can bring a new set of issues to these refiners. Not only must the refinery deal with the coke disposal issue, they must deal with the cracked products a coker generates. Coker naphtha typically has a high sulfur and nitrogen content, but is also rich in olefins and diolefins. Coker naphtha cannot simply be added to the straight-run feed to the naphtha hydrotreater protecting the catalytic reforming unit. The coker distillate is also high in sulfur and nitrogen, and has a very low cetane number due to its high aromatic content. The heavy gas oil produced in a coker from bitumen has a particularly high aromatic content, and therefore makes a poor FCC feedstock. Each of these streams will also contain differing levels of silica from the antifoam agent used in the coke drums which can poison the catalyst in downstream hydroprocessing units. Coupled with the high VGO component of all synthetic crudes and bitumen blends, there is a twofold impact on the FCC unit. Higher throughputs are required to process the additional VGO, and the feedstock is poor quality.

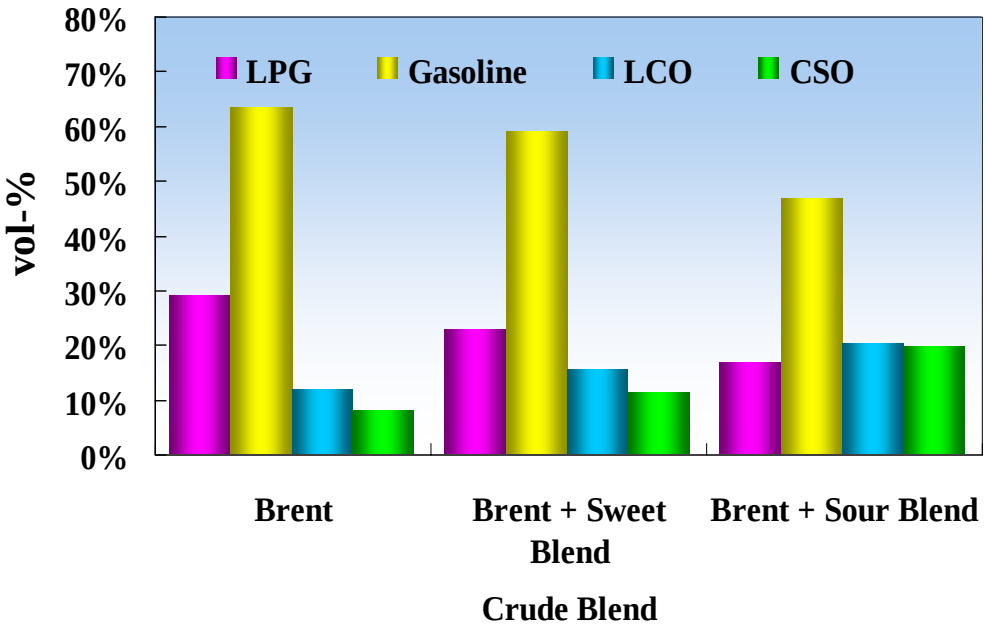
Refiners used to processing the VGO from a sweet conventional crude, like Western Canadian Mixed Sweet (MSW) crude, will see a significant shift in their FCC yield pattern if they start to process VGO from most bitumen-derived crudes. Table 2 shows commercial data from a Canadian refinery, and the impact of switching their FCC feed from a VGO from 100% MSW crude, to a VGO from SSB crude[3]. Conversion in the FCC unit dropped by more than 20% as the yields of LCO and decant oil tripled.

Table 2 – FCC Yield Impact of Processing Synthetic VGO

	Western Canadian	*Synthetic Crude*
Yield, vol% FF		
Propylene	**11.7**	**6.2**
Butylene	**14.0**	**6.9**
Gasoline	**61.1**	**51.3**
LCO	**9.6**	**27.6**
Decant	**2.7**	**9.3**
C_3 + Liquid Yield	**116**	**110**
Properties		
Gasoline		
RON	**91.9**	**96.5**
MON	**80.9**	**84.3**

Most refiners will not see such a drastic change, as they will most likely replace only a portion of their current crude diet with synthetic crudes or bitumen blends. The impact will be closer to that shown in Figure 3. This graph shows the FCC yields for the VGOs from three crude blends; 100% Brent crude, 75% Brent plus 25% of a sweet synthetic blend, like Syncrude SSB, and 75% Brent plus 25% of a sour synthetic blend, like Suncor OSE. As the sweet synthetic and the sour synthetic blends are added to the FCC feed, the yields of LPG and gasoline drop off, while the yields of light cycle oil and slurry oil increase. This has been one of the historical problems refiners have experienced while trying to process synthetics. The loss of FCC conversion has adversely affected the value of the synthetic blends. This adverse impact increases dramatically as the percentage of synthetic crude in the diet increases. All the VGO-range material in OSE crude is coker heavy gas oil. This underscores the impact coker gas oil has on FCC performance, so if a refiner is also adding a new coker to convert the surplus resid in a bitumen blend like WCS, the overall impact on FCC yields could be even more pronounced.

Figure 3 – Impact of 25% Synthetic on FCC Yields



Most aspects of the refinery operation will be affected by the shift to synthetic crudes or bitumen blends. If a refiner decides to import a sweet synthetic crude like SSB, their reformer feed will become richer. With more naphthenes in the reformer feed, hydrogen production will increase. They will, however, have limitations blending distillate fuels. Depending on the other crudes being processed, the refinery could be limited to just 20% SSB in their crude diet if running for maximum jet production (smoke point limit), or about 35% if running for maximum diesel production (cetane number limit). These limits will be relaxed when Syncrude starts producing SSP in June of 2006. There are also fewer distillate blending constraints with other sweet synthetics like OSA, HSB, or PAS. The production of ULSD is more difficult than indicated by the low sulfur level of the distillate cuts of the crude. The sulfur and nitrogen species left in the kerosene and diesel cuts are the most refractory, difficult-to-treat species that could not be removed in the upgrader's relatively high-pressure hydrotreaters. FCC conversion and gasoline yield will drop significantly when using any of the currently-available synthetic crudes, and the production of lube base stock may be impossible due to the aromatic nature of the synthetic VGO. The large percentage of VGO-range material in these crudes may result in the FCC unit capacity becoming a bottleneck. Since synthetic crudes contain no resid, they can be used to increase refinery throughput without having to increase resid conversion capacity.

If a refiner chooses to process one of the sour synthetic crudes, all of the benefits and limitations discussed above for a sweet synthetic crude still apply, but much more severe hydrotreating will be required at the refinery to produce ULSD or acceptable-quality FCC feed. The sulfur and nitrogen content of these crudes is very high compared to a conventional light sweet crude. Additional sulfur plant capacity may be required. The TAN number of these crudes may also become an issue. Crudes with straight-run VGO components from bitumen, like OSV, have higher TAN numbers. Metallurgy upgrades may be required to handle these crudes. Sour synthetic crudes produced from coker products are more aromatic in nature, but the TAN numbers are much lower.

DilBits have both a high resid content and a high sulfur content. They are relatively low in distillate content, and high in VGO content. Significant resid conversion capacity and hydrotreating capacity would have to be added to a light sweet crude refinery to process a DilBit. The FCC unit will again be limited by the large volume of the FCC feed. Although better quality than a coker-derived VGO, the straight-run VGO from bitumen is still very aromatic, and makes a poor FCC feed. The TAN number of these crudes can be high, depending on the source of the bitumen. For example, Athabasca bitumens are reported to have higher TAN numbers. The large volume of condensate in the blend may pose a problem for some refiners. All the light naphtha may not be able to be blended into the gasoline pool without exceeding RVP specifications. As already mentioned, some refiners are already shipping the condensate back to Alberta by rail, both to alleviate any light ends constraint, but also to realize the higher netbacks for condensate. Depending on the gasoline to diesel (G/D) ratio of the refinery involved, there may be insufficient material for the distillate pool.

SynBits generally have a lower resid content than DilBits, but more distillate and VGO-range material. Since the majority of the distillate comes from a sweet synthetic crude, with the remainder from bitumen, the distillate quality is only marginal. Some hydrotreating will be required to achieve a 40 cetane number in the full-range diesel. The VGO is still a poor-quality FCC feed due to the high aromatic content. The TAN number will be lower than that found in a DilBit since about half the feed has already been severely hydrotreated. The sulfur content of a SynBit is also much lower than that of a DilBit.

REQUIRED PROCESS MODIFICATIONS

Changes will be needed in a refinery to accommodate the processing of bitumen-derived crude blends. The addition of resid conversion capacity, of which coking is the most common, to convert the large volume of resid present in a DilBit, SynBit, or SynDilBit like WCS, is almost a given. As mentioned previously, there are several new coking projects being considered for that portion of the refining market currently able to access bitumen-derived crudes via pipelines. The heavy gas oil produced in the coker, coupled with the large volume of low-quality VGO in these crudes, overwhelms FCC units designed for VGO from light sweet crudes. These VGO streams can be upgraded to premium-quality FCC feeds with hydrotreating or hydrocracking. To avoid any regret capital, one must first have a basic understanding of FCC chemistry, and how that chemistry is affected by the addition of bitumen-derived feeds to the FCC unit.

The aromatic nature of bitumen-derived VGOs makes them poor FCC feedstocks. The quality of three bitumen-derived VGOs are compared to the VGO from an Arab Light crude in Table 3. The bitumen-derived fractions have lower API gravities and lower hydrogen contents, consistent with higher levels of sulfur, nitrogen, and aromatics. A brief overview of the chemistry of aromatic conversion in an FCC unit is useful to give more insight into reasons why these feedstocks are more difficult to process.

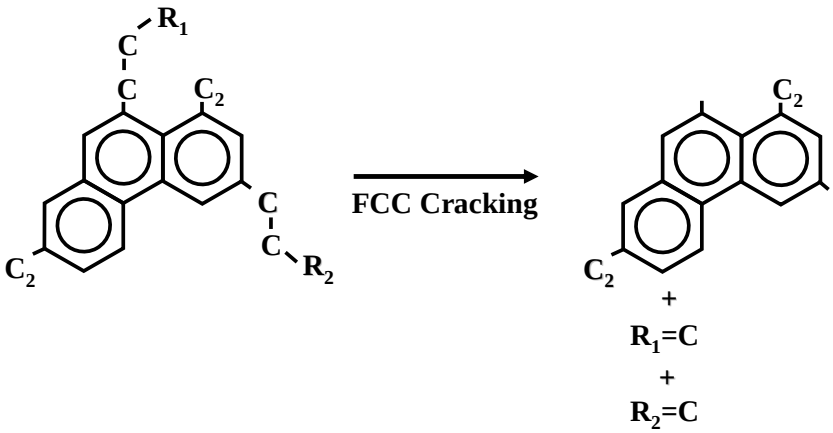
Table 3 – Bitumen-derived VGO Quality

Property	*Lt. Arabian VGO*	*Cold Lake VGO*	*Athabasca VGO*	*Coker HGO*
Gravity, °API	**22.7**	**16.3**	**14.2**	**11.4**
Sulfur, wt-%	**2.10**	**3.10**	**3.77**	**4.99**
Nitrogen, wppm	**820**	**1380**	**1854**	**4032**
Hydrogen, wt-%	**12.47**	**11.38**	**10.80**	**10.43**
Carbon Residue, wt-%	**0.50**	**0.67**	**0.50**	**0.35**
Total Aromatics, vol-%	**58**	**60**	**69**	**76**
Sim Dist D-2887, °F				
IBP / 5wt-%	**382/609**	**597/647**	**621/693**	**457/605**
10	**701**	**671**	**719**	**649**
30	**777**	**734**	**779**	**719**
50	**834**	**795**	**831**	**764**
70	**895**	**856**	**878**	**812**
90/95	**981/1020**	**942/980**	**947/972**	**878/905**
EBP	**1100**	**1054**	**1032**	**955**

Figure 4 illustrates how a three-ring aromatic compound with several alkyl side chains reacts in an FCC unit. Methyl and ethyl groups will tend to stay attached to the aromatic compounds. Alkyl side chains with a carbon number of three or greater will cleave off close to the aromatic ring. The removed alkyl side chains will initially become olefins, and may crack again into smaller components depending on the length of the chain. Paraffinic compounds with a carbon number of five or less tend not to crack. Paraffinic compounds with a carbon number of six crack slowly, and paraffinic compounds with a carbon number of seven or more will crack fairly quickly.

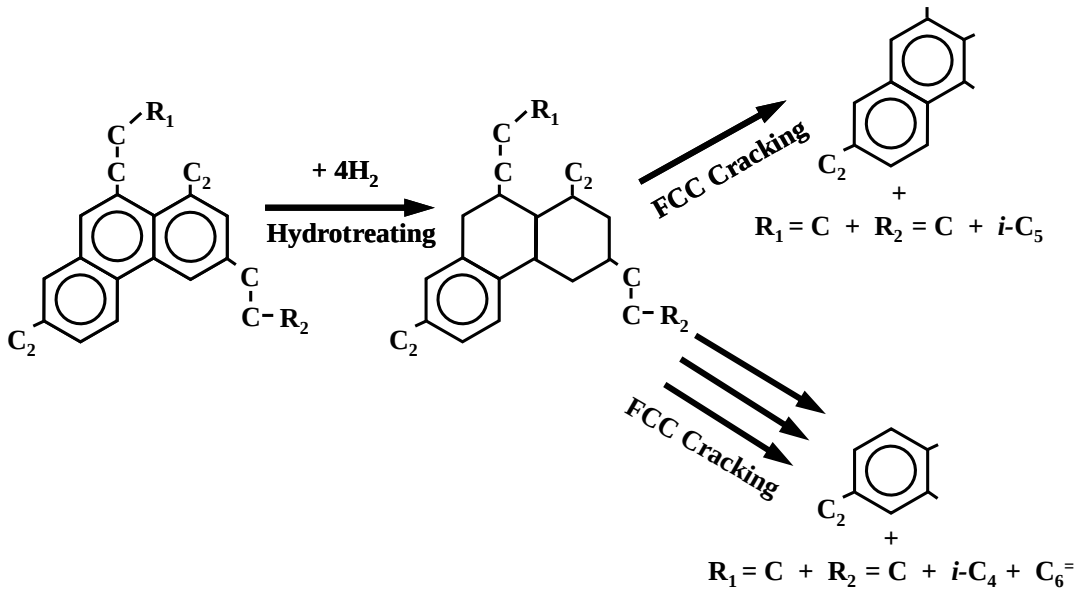
FCC cracking will not open the aromatic ring structures. Depending on the number of short alkyl side chains remaining, the compound in Figure 4 could end up in the FCC light cycle oil product, but would most likely be produced as part of the heavy cycle oil pool or the decant oil.

Figure 4 – FCC Conversion of Multi-ring Aromatic Compounds



If that same three-ring aromatic compound was partially saturated in an FCC feed pretreater before being fed to the FCC unit, the resulting products would be significantly different (Figure 5). Notice it takes only four moles of hydrogen to saturate two of the three aromatic rings. Saturated ring structures crack open far more easily in an FCC unit than aromatic ring structures. While some of the compounds would follow the upper path and partially dehydrogenate back to a two-ring aromatic compound, the majority of these partially saturated ring structures would follow the lower pathway. The longer alkyl side chains would first be cleaved off as before. The saturated rings would then crack open, leaving a single-ring aromatic structure and other paraffinic and iso-paraffinic molecules.

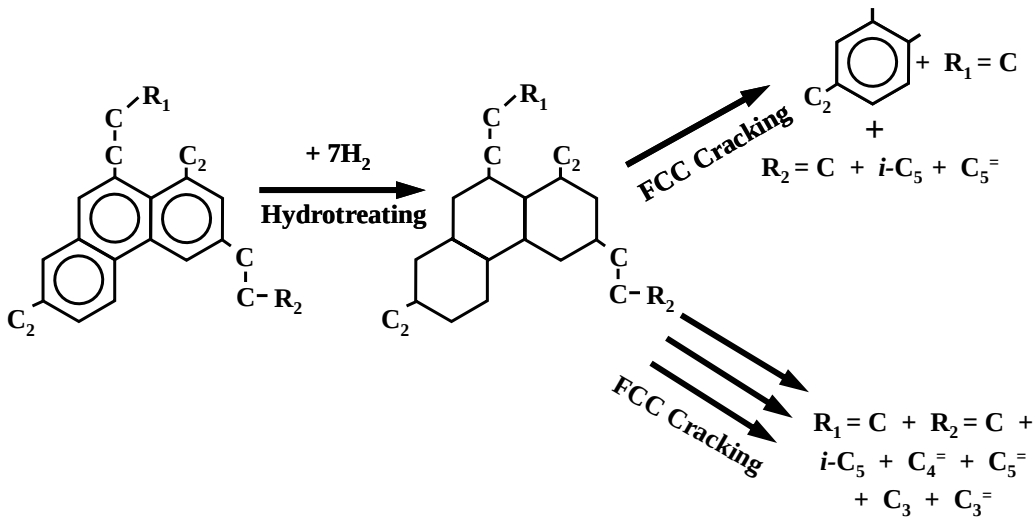
Figure 5 – FCC Conversion of Partially-saturated Aromatic Compounds



The single-ring aromatic structures created in this way are almost never benzene. The structures formed will usually be toluene and xylenes, and thus have high octane number. The iso-paraffins created will continue to crack to lighter compounds as dictated by the carbon number.

If that same three-ring aromatic compound was now fully saturated in an FCC feed pretreater before being fed to the FCC unit, the resultant products would again be significantly different (Figure 6). It would take seven moles of hydrogen to fully saturate the three-ring structure. As before, some of the structures would partially dehydrogenate back to a single-ring aromatic structure, generating several paraffinic molecules. The majority of these saturated ring structures would crack open completely, generating numerous normal paraffins, iso-paraffins, and olefins. Again, the paraffins would continue to crack to lighter compounds, depending upon their carbon number. Normal and iso-paraffinic molecules have much lower octane numbers than aromatic compounds with the same carbon number. By fully saturating the initial compound in the FCC feed pretreater, the gasoline yield would be reduced in favor of a slightly higher LPG and gas yield, and the octane number of the gasoline created would be lower.

Figure 6 – FCC Conversion of Fully-saturated Aromatic Compounds



In general, the FCC cracking of saturated and aromatic ring structures can be summarized by Table 4 below. Cracking of multi-ring aromatics produces high cycle oil yields but low gas, LPG and gasoline yields. The gasoline produced would consist mainly of paraffins and olefins. FCC cracking of single-ring aromatic compounds produces low gas, LPG and cycle oil yields, but a high gasoline yield. The gasoline produced is mostly aromatic, and therefore has a high octane number. FCC cracking of saturated ring structures produces a low yield of cycle oil, a reasonably high gasoline yield, but a higher yield of gas and LPG than cracking of single-ring aromatics. The gasoline produced would again consist mainly of paraffins and olefins, and would therefore have a lower octane number.

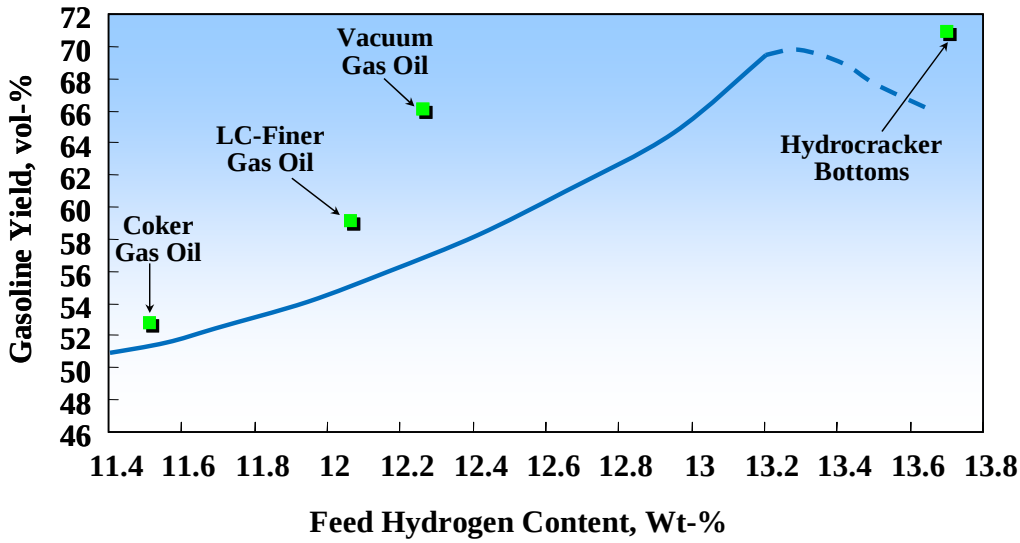
Table 4 – FCC Cracking of Aromatic Rings (Summary)

Multi-ring Aromatics	■ **High cycle oil yield** ■ **Low gasoline yield** ■ **Gasoline mostly paraffins and olefins** ■ **Low gas yield**
Mono-ring Aromatics	■ **High gasoline yield** ■ **Gasoline mostly aromatic (high octane)** ■ **Low gas yield**
Naphthenes	■ **Reasonably high gasoline yield** ■ **Gasoline mostly paraffins and olefins (lower octane)** ■ **Higher gas yield**

From this, it can be concluded that if the refiner's objective is maximum gasoline yield from his FCC unit, the feed pretreater conditions should be set to ensure that all the multi-ring aromatic compounds are saturated down to single-ring aromatics. Hydrogen addition beyond this point would only serve to lower gasoline yield and gasoline octane. Higher conversions would, of course, be achieved, but product value would not be maximized. If a refiner were trying to use his FCC unit to produce olefins for alky feed or MTBE or other chemical production, obviously a higher feed hydrogen level would increase the production of olefins.

The curve shown in Figure 7 illustrates the FCC gasoline yield as a function of the feed hydrogen content. VGOs from more aromatic crudes are near the bottom left-hand end of the curve, while VGOs from more paraffinic crudes would be located near the top right-hand end of the curve. The trend shows that gasoline yield increases with increasing feed hydrogen. Gasoline yield will not continue to rise, however, as the feed hydrogen content is increased. At some point, the gasoline yield will drop off, as the conversion to gas and LPG continues to increase. Overall, conversion will continue to increase, but the gasoline yield will drop. This drop off is not a detriment if the refiner is trying to make olefins for alky feed or petrochemical feedstock with the FCC unit, but it is detrimental if the FCC unit is designed to achieve the maximum gasoline yield. This yield response is represented by the dashed portion of the curve, although the exact inflection point is a function of the feedstock and other variables.

Figure 7 – FCC Gasoline Yield Controlled by Feed Hydrogen Content



Yui et al[5] took several intermediate VGO streams derived from Athabasca bitumen, hydrotreated them at a constant severity, and then processed them in an FCC pilot plant to determine product yields and qualities. The gasoline yield data from that study is also shown in Figure 7. Note that the hydrotreated coker gas oil had a hydrogen content of 11.5wt%, and gave a gasoline yield just above the UOP curve. The gas oil produced in the ebullated-bed resid hydrocracking unit had a higher hydrogen content after hydrotreating, and generated a gasoline yield above the curve, while the hydrotreated VGO distilled directly from bitumen produced a gasoline yield well above the curve. There is a valid reason as to why these bitumen-derived VGO streams all generated FCC gasoline yields above the standard UOP curve. One of the characteristics of these VGOs is the very low paraffin content. Some bitumen derived coker VGO samples analyzed at UOP have actually been shown to contain no paraffins of any kind. All the molecules were aromatics, naphthenes, or sulfur species which were almost all aromatic compounds. Without the paraffins to crack to gas and LPG, bitumen-derived VGOs can produce very high gasoline yields, if the hydrogen content is raised to the appropriate level.

Many people believe that the unconverted oil from a hydrocracker is the best FCC feedstock available. The Yui study obtained a sample of hydrocracker bottoms from a Canadian refinery when they were processing 100% synthetic heavy gas oil in their hydrocracker. It is clear that very high conversions and gasoline yields can be achieved by first hydrocracking the bitumen-derived heavy gas oil streams. Since the data points fall to the right of the conventional crude curve, it suggests that hydrocracker bottoms are less efficient gasoline feedstocks than conventional crudes. The important question becomes, "Is the extra hydroprocessing severity required to raise the hydrogen content from about 12.3 wt% all the way to 13.7 wt% worth an extra five or six percent in FCC gasoline yield?" UOP would suggest that hydrogen is most effectively used to increase the hydrogen content to the 12.3 to 12.5 wt% range. Beyond this level, more and more naphthenes and paraffins would be created in the FCC feed, decreasing the gasoline yield and increasing the LPG and gas yield. Since LPG has a high value to many refiners as alky feed or chemical plant feedstock, the most economic hydrogen content will be different for each application, and must be carefully determined.

Table 5 – Required FCC Feed Pre-treat Severity

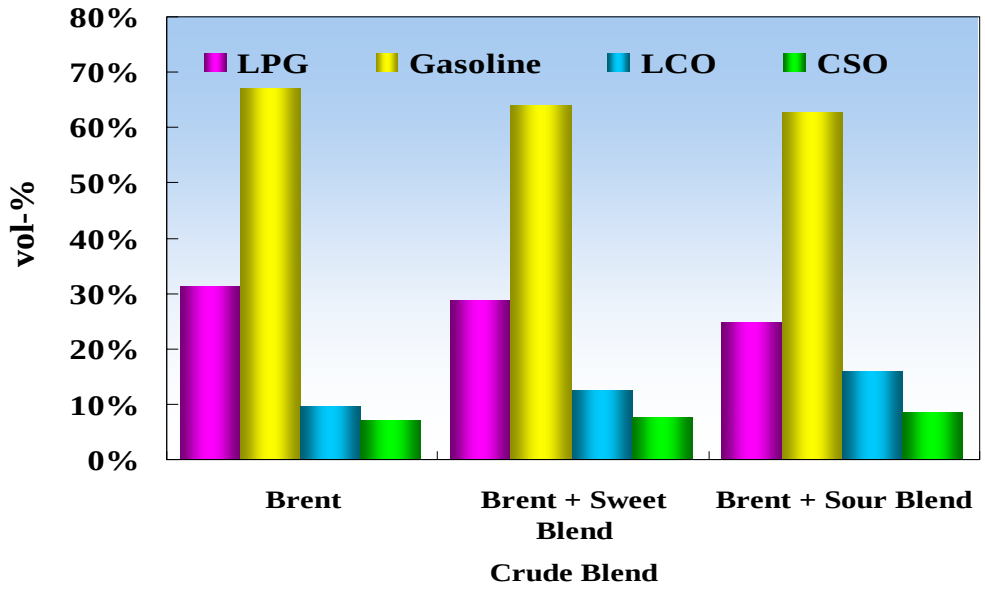
Source of VGO or HGO	*12.0% Hydrogen*	*12.5% Hydrogen*
Vacuum Column	**1400 psig** **1.6 LHSV**	**1600 psig** **0.9 LHSV**
Ebullated-bed Processing	**1600 psig** **1.2 LHSV**	**1800 psig** **0.8 LHSV**
Delayed Coker	**1700 psig** **1.2 LHSV**	**1900 psig** **0.8 LHSV**
Fluidized-bed Coker	**1900 psig** **0.8 LHSV**	**2100 psig** **0.7 LHSV**

Recognizing that the optimum hydrogen content for bitumen-derived heavy gas oil streams may be between 12.0 and 12.5 wt%, UOP has estimated a rough set of operating conditions necessary using UOP's Unionfining™ process technology to increase the hydrogen content of each of the raw feeds to those levels. As might have been expected, the vacuum heavy gas oil would require the least severe conditions, where heavy gas oil product from the fluidized-bed coking unit would require the most severe conditions. These pressure and liquid hourly space velocity combinations are thought to be close to the economic optimum, but the same results can be achieved at lower pressure if the space velocity is lowered sufficiently.

Many refiners use the UOP K Factor to estimate the hydrogen content of an FCC feedstock. The UOP K Factor works very well when trying to distinguish between aromatic and paraffinic VGO's. However, when the FCC feed is hydrotreated, the UOP K factor-hydrogen content relationship begins to break down. Thus, if the FCC feed has been severely hydrotreated, the refiners should focus on API gravity, nitrogen content, and most importantly, hydrogen content of the FCC feed.

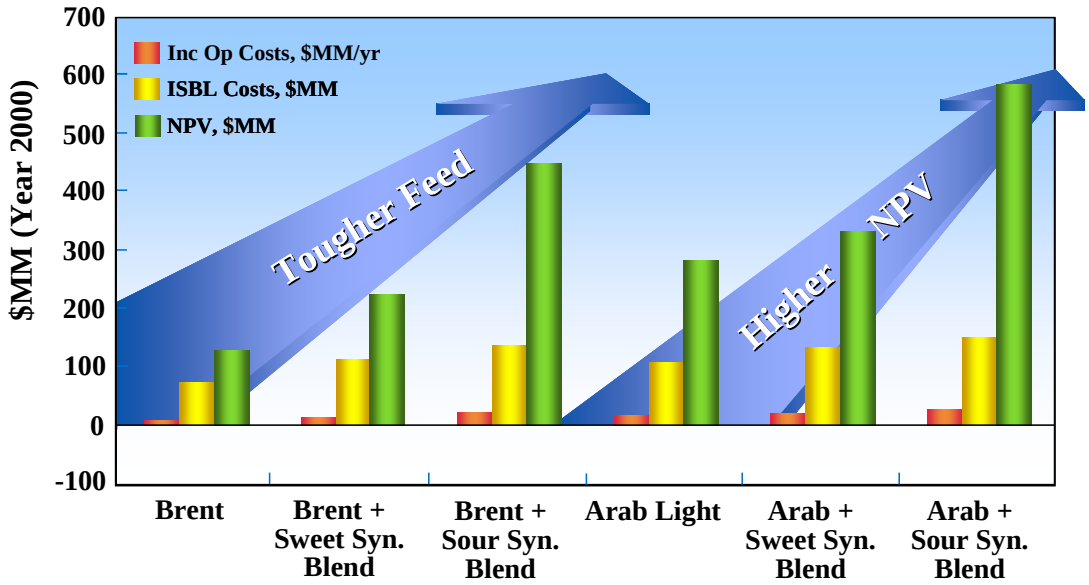
The penalty associated with the quality of the VGO from a bitumen-derived crude changes rapidly once the FCC feeds have been hydrotreated. Figure 8 summarizes the FCC yield pattern for the same Brent/synthetic VGO blends shown in Figure 3, but after the feeds had been hydrotreated to a constant sulfur content. The yield of LPG and gasoline is up in all cases, with the expected reduction in light cycle oil and slurry oil yields. The magnitude of this yield shift is not consistent between cases. There is a much greater increase in LPG and gasoline yield with synthetic VGOs in the FCC feed, especially the sour synthetic blend. When this same analysis was completed substituting the Brent crude component with the more aromatic Arab Light crude, the increases in LPG and gasoline yields were even greater, to the point that two of the three cases had gasoline yields greater than the corresponding Brent crude cases. **The most difficult to treat feeds gained the most advantage by hydrotreating.**

Figure 8 – FCC Yields on Hydrotreated VGO Feeds



In 2000, UOP completed an internal study that compared the economics of FCC feed pretreating with post-treating of FCC products. UOP studied the impact of blending 25% of two different synthetic crudes into a conventional crude diet. The FCC yield patterns discussed above were part of that study. One of the conclusions from that study was confirmation that the economics for pretreating the FCC feed improved as the quality of the raw FCC feed became worse. The incremental operating costs, capital costs, and net present values for each case are summarized in Figure 9 below. While all the capital and product prices used for this study are now six years out of date, the conclusion is still valid; the tougher the feed, the higher the NPV.

Figure 9 – FCC Feed Pre-treat Economics



The economics of FCC feed pretreating projects are driven by two factors: better yields from the FCC unit itself, and incremental conversion. Whenever a VGO-range feed is severely hydrotreated, about 10 – 15 lv% of the feed is converted to distillate and lighter products. Some of this conversion is simply a shift in the boiling point curve as sulfur and nitrogen is removed from the molecules, but some hydrocracking to lighter products does occur. Assuming the distillate and lighter products are fractionated from the hydrotreated VGO before it is fed to the FCC unit, hydrotreating the feed effectively debottlenecks the FCC unit. If a refinery has an FCC unit sized for 50 KB/D, after hydrotreating, there will only be about 43 KB/D of hydrotreated VGO left to feed to the FCC unit. This allows the refiner to acquire additional crude if the other processing units have surplus capacity, or at a minimum, it allows the refiner to purchase surplus VGO to keep the FCC unit full. In either case, it is the incremental conversion in the FCC feed pretreater that makes the economics so attractive.

UNICRACKING™ PROCESSES

As previously mentioned, all the sweet and sour synthetic crudes, as well as the bitumen blends, have a high VGO content relative to conventional crude. Hydrotreating alone can turn these low-quality VGOs into premium FCC feeds and reduce the volume of the feed available, but most refiners importing bitumen-derived crudes for the first time will still have surplus VGO that cannot be processed in their FCC unit. This problem will be made worse by the addition of the heavy gas oil generated in the coker, for those refiners choosing to process a bitumen blend. Additional VGO conversion capacity must be added. Refiners may consider an FCC expansion project, or even an entirely new FCC unit, but since they are probably going to construct a high-pressure hydrotreater to process the FCC feed, it only makes sense to consider converting the incremental VGO barrels with hydrocracking technology. Hydrocracking has the advantage in that, unlike an FCC unit, it can be used to produce both gasoline and high-quality distillate fuels.

In order to avoid increased utility cost and unnecessary quality give-away caused by excess hydrogen consumption, efficient hydrogen consumption is a critical parameter in hydroprocessing unit design and operation. With growing demand and more stringent specifications for fuels, it is recognized by industry experts that hydroprocessing technologies will be key in the future to meeting the refinery conversion capacity and quality needs. Recent advances in UOP's hydrocracking technology portfolio, such as the Advanced Partial Conversion Unicracking (APCU) process, and the other Unicracking configurations discussed below, were designed for optimal treatment of the distillate and unconverted product fractions, resulting in more efficient hydrogen utilization.

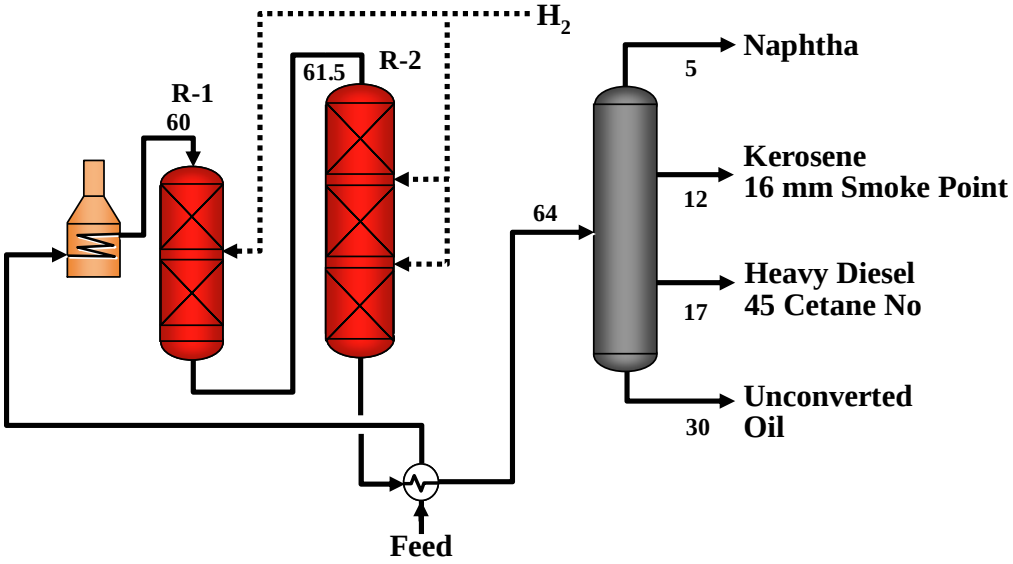
Once-Through Unicracking Unit

When most refiners think about partial-conversion hydrocracking, they think of a simple once-through Unicracking process unit. This configuration has the lowest capital cost of the various Unicracking process configurations. The unit shown in Figure 10 is sized for a fresh feed rate of 60 KB/D with an unconverted oil rate of 30 KB/D, meaning the unit is designed to give a gross conversion of 50 lv%. If the cracking reactor was loaded with a high-activity naphtha catalyst, such as UOP's HC™ 29 catalyst, the yield pattern would be very close to that shown in Figure 10. The unit would produce about 5 KB/D of naphtha, 12 KB/D of kerosene with a relatively low smoke point, and 17 KB/D of heavy diesel with a reasonable cetane number. Note that if the

kerosene and heavy diesel were combined to form a full-range diesel, the cetane number would be close to 40.

One key consideration with this simple configuration is the quality of the unconverted oil produced as FCC feed. Unconverted oil from this unit would have high hydrogen content, similar to the 13.7 wt% seen in the unconverted oil from the Canadian refinery discussed earlier. Again, if a refiner is trying to make alky feed or petrochemical feedstock with their FCC unit, this would make an excellent feed, but if the FCC unit is being run for maximum gasoline production, the hydrogen content of the unconverted oil may be too high.

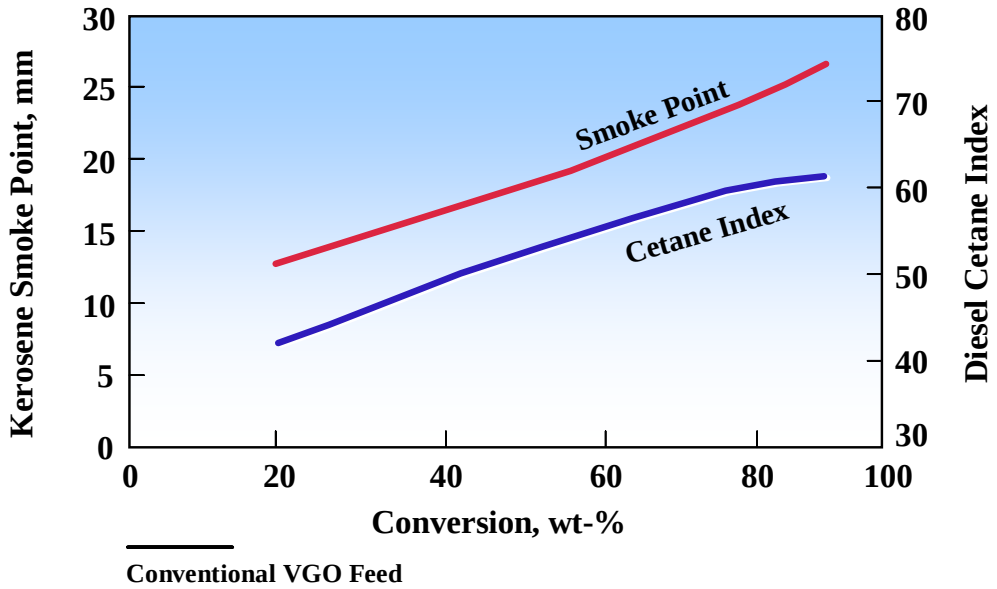
Figure 10 – Once-through Unicracking Unit



Separate-Hydrotreat Unicracking Unit

The quality of the distillate fuels produced in a low conversion once-through Unicracking unit can be poor. Figure 11 is a plot of both kerosene smoke point and diesel cetane index plotted against conversion in the Unicracking unit. While these plots are based on a VGO from conventional Arab Light crude, the message is the same for bitumen-derived VGOs. Kerosene smoke point and diesel cetane index both increase with increasing conversion. If a refiner wants to generate high-quality distillate fuels from a poor-quality VGO stream, they need to run the Unicracking unit at a high conversion level.

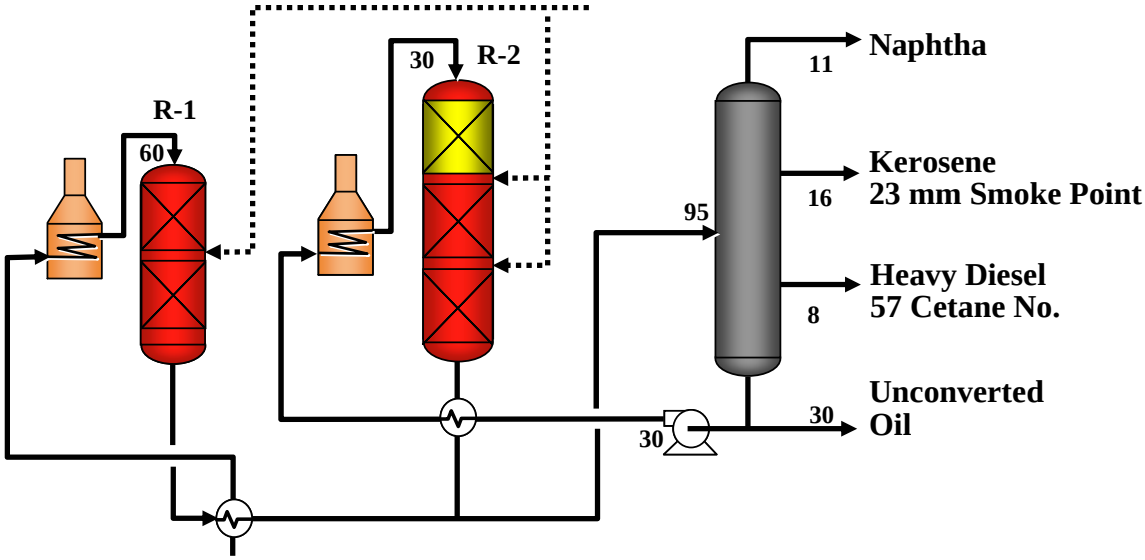
Figure 11 – Distillate Quality as a Function of Conversion



Both the distillate quality and the unconverted oil quality can be controlled by using a different Unicracking unit configuration. In UOP's separate-hydrotreat configuration shown in Figure 12, the severity in the R-1 pretreat reactor would be set to achieve the desired hydrogen content in the unconverted oil, in this example a hydrogen content of 12.5 wt%. The R-1 effluent would be routed directly to the product fractionator. About 30 KB/D of unconverted oil would be fed to the cracking reactor, this time running at 80 lv% crack-per-pass. A bed of pretreat catalyst could be added to the cracking reactor to get the organic nitrogen down to the optimum level for the cracking catalyst, about 100 wppm or less. The effluent from the cracking reactor would also be routed directly to the product fractionator.

The fractionator in the separate-hydrotreat configuration would be larger than that in the once-through configuration, but the high-pressure equipment in the cracking reactor loop would be 50% smaller, now sized for only 30 KB/D. At the high conversion level of 80 lv% crack-per-pass, the unit would generate higher yields of both naphtha and kerosene, but less heavy diesel. The quality of both distillate streams would be significantly higher than the once-through unit. Only about 3 KB/D of the 30 KB/D of unconverted oil produced in the unit would have been processed to a high hydrogen content in the cracking reactor, thereby reducing overall hydrogen consumption. The separate-hydrotreat configuration effectively allows independent control of both the unconverted oil quality and the distillate fuel quality.

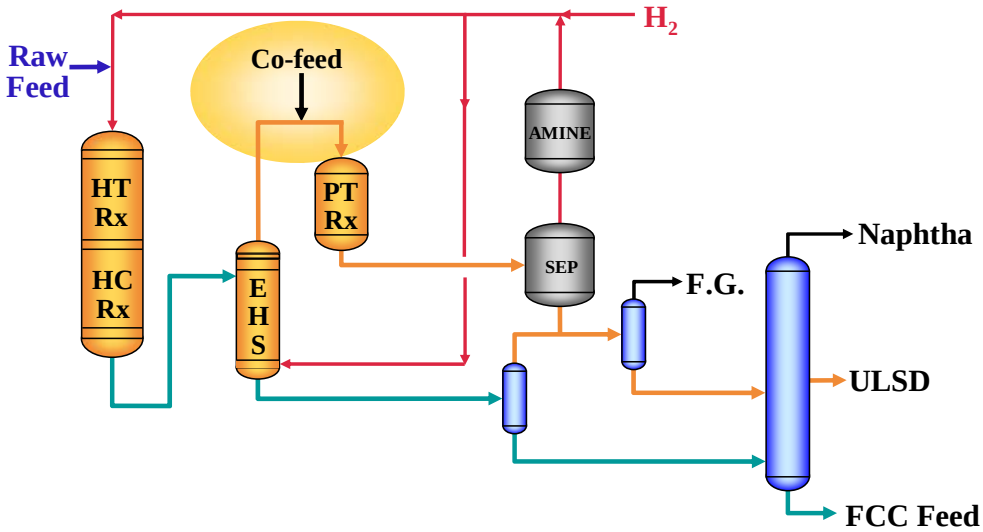
Figure 12 – Separate-Hydrotreat Unicracking Unit



Advanced Partial Conversion Unicracking (APCU) Unit

Typical once-through hydrocrackers operating at low to moderate conversion levels may not produce USLD-quality distillate. The unit pressure is often set by the need to produce low-aromatic, high-cetane diesel. This higher design pressure results in the production of unconverted oil with a high hydrogen content, and a higher overall hydrogen consumption. In the APCU unit flow scheme depicted in Figure 13, the unit is designed to produce ULSD and partially hydrotreated FCC feedstock as primary products, while operating at a significantly lower pressure. The refiner achieves two goals with the addition of this unit; increased production of ULSD, as well as improved quality of the FCC feedstock.

Figure 13 – Advanced Partial Conversion Unicracking Unit



The benefits of the APCU process compared to a conventional low-conversion hydrocracking process are reflected in more efficient use of hydrogen due to lower pressure operation, and staging of reactions in a way that minimizes over-processing and product quality giveaway. Separation of cracked products from the desulfurized FCC feed in the Enhanced Hot Separator (EHS), followed by an additional Distillate Unionfining process step, allows the distillate quality to be controlled independently of FCC feed quality. Over-treating of FCC feed is avoided and excess hydrogen consumption is minimized. The APCU process can achieve hydrogen savings of five to ten percent compared to a conventional mild hydrocracking scheme. The integration of a separate Unionfining reactor in the process enables post-treating of other refinery middle distillate streams. For refiners processing a bitumen blend following the installation of a coker, the coker diesel stream must be severely hydrotreated to meet ULSD specs. With the APCU process, that stream could be processed as a co-feed in the Distillate Unionfining reactor, using the hydrogen and heat from the Unicracking reactor, resulting in utility cost savings. The level of hydrotreating of these streams can be independently controlled to add just the right amount of hydrogen, an added benefit of APCU process.

The typical operating conditions and the resultant FCC feed quality for FCC feed pretreating, the once-through Unicracking process, the separate-hydrotreat Unicracking process, and the APCU Unicracking process are summarized in Table 6. Since the quality of the VGO from an Arab Light crude is so different from that of a WCS VGO, the operating conditions to treat both feeds are shown for comparison. Note that this comparison represents model predictions for representative feed properties and that the units are sized for typical run lengths. The table should be used as a qualitative guide to differentiate between the various processing options. This is not meant to be a substitute for a customized hydroprocessing solution.

Table 6 – Hydroprocessing Options Summary

Feed	*Unit Type*	*FCC Feed H_2, wt-%*	*FCC Feed Nitrogen, ppm*	*ULSD*	*Pressure psig*	*LHSV*	*FCC Feed %FF*	*H_2 Cons (SCFB)*
Arabian	**Unionfining Process**	**12.8**	**<1000**	**No**	**Base**	**Base**	**85**	**500**
Arabian	**Once-Through Unicracking Process**	**13.5**	**<50**	**Yes**	**Base+600**	**0.3*Base**	**50**	**1150**
WCS	**Unionfining Process**	**12.4**	**<1000**	**No**	**Base+1000**	**0.3*Base**	**80**	**1000**
WCS	**Once-Through Unicracking Process**	**13.2**	**<50**	**Yes**	**Base+1000**	**0.17* Base**	**50**	**1900**
WCS	**Separate-Hydrotreat Unicracking Process**	**12.5**	**<500**	**Yes**	**Base+1000**	**0.2*Base**	**50**	**1700**
WCS	**APCU Process**	**12.9**	**<50**	**Yes**	**Base+800**	**0.17*Base[+]**	**50**	**1800**

[+] Plus additional volume for diesel co-feed

Many refiners believe they can treat a portion of their VGO in a Unicracking unit to generate some high-quality VGO, and then blend it with lower quality VGO, like coker gas oil, to get an FCC feed with hydrogen content near the 12.5 wt% UOP believes to be close to the optimum level. While this may be true mathematically, the FCC unit in actuality is concerned only with the types of molecules being fed to it, and not the average hydrogen content. The three- and four-ring aromatics in the coker gas oil will still end up in the cycle oil or the slurry oil, and the naphthenes and paraffins in the hydrocracker bottoms will still be mostly converted to gas and LPG. Some hydrogen donor reactions will occur in the FCC unit to transfer hydrogen from the hydrogen-rich stream to the hydrogen-deficient stream, but the overall yields will still be significantly worse compared to those obtained if the entire feed stream has been hydrotreated to a hydrogen content of 12.5 wt%. Some refiners have reported significant synergies when processing Unicracking unit unconverted oil with lower-quality VGOs in their FCC unit.

EXPERIENCE AND PILOT PLANT STUDIES

UOP has been very successful in licensing technology for synthetic crude projects in Canada, the United States, and Venezuela. Our understanding of the processing issues is based on extensive pilot plant and commercial experience. UOP has completed both hydrotreating and hydrocracking pilot plant studies on numerous distillate and VGO-range feeds derived from Athabasca bitumen, Cold Lake bitumen, Lloydminster heavy conventional crudes, and Orinoco Belt heavy crudes.

UOP has licensed 22 of the 32 hydroprocessing units currently in operation, design, or construction for the upgraders in Western Canada. UOP's experience with hydrotreating, hydrocracking, FCC, coking, and reforming gives us the unique ability to look at all the units affected by import of any of these bitumen-derived crudes.

CONCLUSIONS

The supply of Canadian light and medium sweet crudes is declining. There is a vast oil sands resource in Canada which up until recently, has not been exploited to any great degree. Synthetic crudes and bitumen blends will become the dominant crudes in PADD II, PADD IV, and Northern PADD V in the next ten to fifteen years. Refiners planning to process one of the bitumen blends will have to install additional resid conversion capacity. Refiners planning to process any bitumen-based crude will have to install FCC feed pretreating capacity to maintain acceptable FCC yields. Many refiners will have to install hydrocracking capacity to convert the large volume of VGO-range barrels present in these crudes, and to meet the increasing demand for distillate fuels.

The hydrogen content of an FCC feedstock is the critical parameter to control when trying to optimize the performance of all the VGO processing units. UOP has developed novel Unicracking process flow schemes that allow the refiner to control the hydrogen content of the FCC feed independently from conversion level or distillate quality.

REFERENCES

1. Purvin & Gertz Inc., "Global Markets for Canadian Oil Sands Crudes", December, 2005
2. Energy Information Administration, "The AEO2006 Early Release", www.eia.doe.gov, January 2006
3. Halford, T.L., McIntosh, A.P., and Rassmussen, D., "A Canadian Refiner's Perspective of Synthetic Crudes", Proceedings of the 1997 NCUT Conference, Directions in Refining and Marketing of Synthetic Crude Oil (SCO) and Heavy Oil, September, 1997
4. Purvin & Gertz Inc. "Fuel Options for Oil Sands Development", September, 2004
5. Yui, S., Matsumoto, N., and Sasaki, Y., "Athabasca oil sands produce quality FCC feeds", Oil & Gas Journal, January 19, 1998 Journal
6. www.crudemonitor.ca – a website sponsored by the Canadian Association of Petroleum Producers

A Honeywell Company

UOP LLC
25 East Algonquin Road
Des Plaines, IL 60017-5017

© 2006 UOP LLC. All rights reserved.