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Combine power options with clean fuels projects

A build-own-operate project structure involving refinery upgrade results in increased product yield and power production

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A mid-size U.S. refiner initiated an extensive study to examine the processing and economic benefits of a bottom-of-the-barrel upgrade as compared to its current operations. The project financing is based on a build-own-operate integrated project structure involving a refinery upgrade which results in an increased refinery product yield and produces an opportunity fuel for use in a cogeneration unit power plant.

A project company is formed by several equity partners. The equity partners usually include the refiner, the project developer, a local power company and other interested investment groups. These equity investors provide the leverage to finance an off-balance sheet refinery upgrade. In this case, the project company can receive revenue from

- a processing fee from the refinery,
- sale of power and steam to the refinery, and
- sale of power to the grid.

Deregulation of the electric power industry has made this concept far more viable.

This project upgrade typically consists of the addition of a delayed coker and a circulating fluidized bed (CFB) cogeneration unit, and other units as necessary, to a refiner's current configuration and allows the refiner to process less-expensive heavy sour crudes. Petroleum coke formed in the coking process is burned to generate steam and electricity in the CFB. The net incremental conversion of vacuum residue and crude-cost savings provide substantial additional revenue to the refiner.

The existing refinery configuration. The refinery currently processes a range of light Canadian crudes and has a configuration as depicted in Fig. 1. The vacuum distillation unit (VDU) produces light and heavy vacuum gas oil (VGO) which feeds the fluid catalytic cracker (FCC). The VDU also produces several grades of asphalt. The refinery has no bottom-of-the barrel conversion capabilities and is limited to a relatively light crude slate containing no more asphalt than necessary to meet the local asphalt demand.

The diesel sidecut from the crude distillation unit (CDU) is desulfurized along with FCC light cycle oil (LCO) in a diesel hydrotreater (DHT). The kerosene/jet fuel sidecut from the CDU is desulfurized in a kerosene hydrotreater (KHT). The virgin naphtha is desulfurized in a naphtha hydrotreater (NHT).

The hydrotreated naphtha is split. The heavy naphtha is reformed in the catalytic reformer unit (CRU). The light naphtha is stabilized in a saturate gas plant (SGP) and then isomerized in an isomerization unit (ISOM). The SGP also recovers light ends from the NHT, CRU and ISOM, and produces propane- and butane-rich streams. The CRU produces sufficient hydrogen to support the refinery's hydrogen demands.

The FCC unit produces light ends, gasoline, light cycle oil and decant oil. The unsaturate gas plant (UGP) recovers light ends from the FCC and stabilizes the FCC gasoline. The UGP butenes are alkylated with the SGP butanes in the sulfuric acid alkylation unit (ALKY). The UGP propenes are polymerized in the catalytic polymerization unit (POLY) or sold as chemical-grade propane. High-sulfur decant oil is sold as carbon-black feedstock and used as refinery fuel oil to the extent limited by permitted SO_x emission levels. The permitted SO_x emissions from the FCC require the addition of some FCC $DESO_X$ catalyst.

The base project upgrade. The base project upgrade, originally evaluated in early 1998, centers around a new delayed coker and a new CFB, and is depicted in Fig. 2. The inclusion of the delayed coker allows the refiner to process heavier, less expensive Canadian crudes as well as lighter crudes. The lighter crudes will be processed to meet the local asphalt demand. The majority of the time, however, less-expensive heavy Canadian crudes can be processed and the incremental vacuum residue will be processed in the delayed coker.

The delayed coker upgrades this substantial volume of residue and decant oil to valuable intermediates.

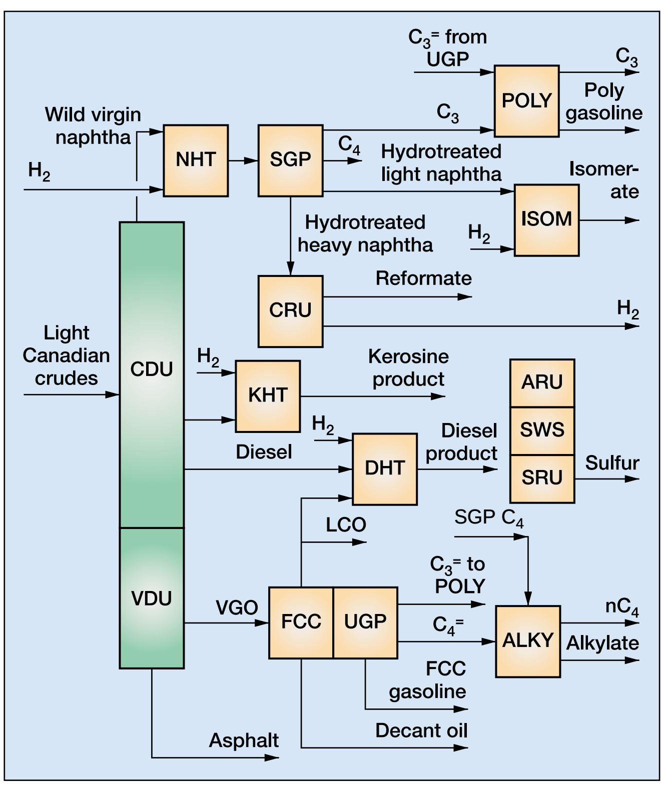

Fig. 1. Block flow diagram—existing refinery configuration.

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These intermediates are processed further to produce salable motor fuels. The product mix remains substantially the same as in the existing refinery configuration, but the crude cost is greatly reduced.

The incremental unsaturate light ends produced in the delayed coker are to be processed in the revamped UGP. The coker naphtha produced in the delayed coker unit is to be upgraded to isomerate and reformate with further processing in the NHT, ISOM and CRU. The NHT may require a revamp to process the coker naphtha in addition to the wild-virgin naphtha. The light coker gas oil (LCGO) is to be upgraded to diesel product in the DHT. The DHT will require a revamp to process the LCGO and increased amounts of LCO in addition to the virgin diesel. The heavy coker gas oil (HCGO) is to be upgraded to FCC feed. A new, high-pressure gas oil hydrotreater (GHT) is included to upgrade this stream. The new GHT and revamps to the NHT and DHT consume quantities of hydrogen in excess of the production in the existing CRU. A new hydrogen plant (H_2P) is included to supply the new GHT and balance the rest of the refinery hydrogen requirements.

In addition to the vacuum residue, a large portion of the FCC decant oil produced will be charged to the coker. As the decant oil is highly refractory in nature, its conversion in the coker is lower than for the vacuum residue. The unconverted decant oil present in the HCGO will also be hydroprocessed in the GHT, thus improving its ability to be further converted in the FCC. A small decant-oil purge is expected to avoid an accumulation.

A new amine regeneration unit (ARU) is included to accommodate the incremental sour gases produced and revamps to the existing sour water stripper (SWS) and sulfur recovery unit (SRU) are planned.

Impact of clean fuels legislation on the base project upgrade. The clean fuels regulations proposed by the USEPA in 1999 imposed an additional level of complexity and capital expense to the upgrade. The proposed reductions in diesel sulfur are to be dealt with as part of the planned DHT revamp. MTBE phaseout and the proposed reductions in gasoline sulfur proved to be much more complicated in an FCC refinery. The impacts to the base project upgrade are depicted in Fig. 3.

The proposed reductions in gasoline sulfur require reductions in FCC gasoline sulfur as the great majority of sulfur in gasoline originates in the FCC. With the intention of minimizing the capital cost, an FCC gasoline hydrotreater (FGH) was added to the scheme at first. The licensed process unit is available from several licensors. A preliminary technology review was conducted for study purposes only.

When a rigorous evaluation of FCC emissions was performed for environmental permitting, it was discovered that the SO_x emissions from the FCC regenerator would be substantially higher for the project upgrade compared with the existing refinery operation. Therefore, prohibitive quantities of $DESO_x$ catalyst would be required to reduce these emissions to below the permitted limits. The main reason for this problem is that the vacuum gas oils from the heavy Canadian crudes have lower aniline points and higher sulfur than the light Canadian crudes and tend to deposit more coke containing more sulfur on the FCC catalyst. To mitigate these emissions, an FCC flue gas scrubber (FGS) was added to the scheme.

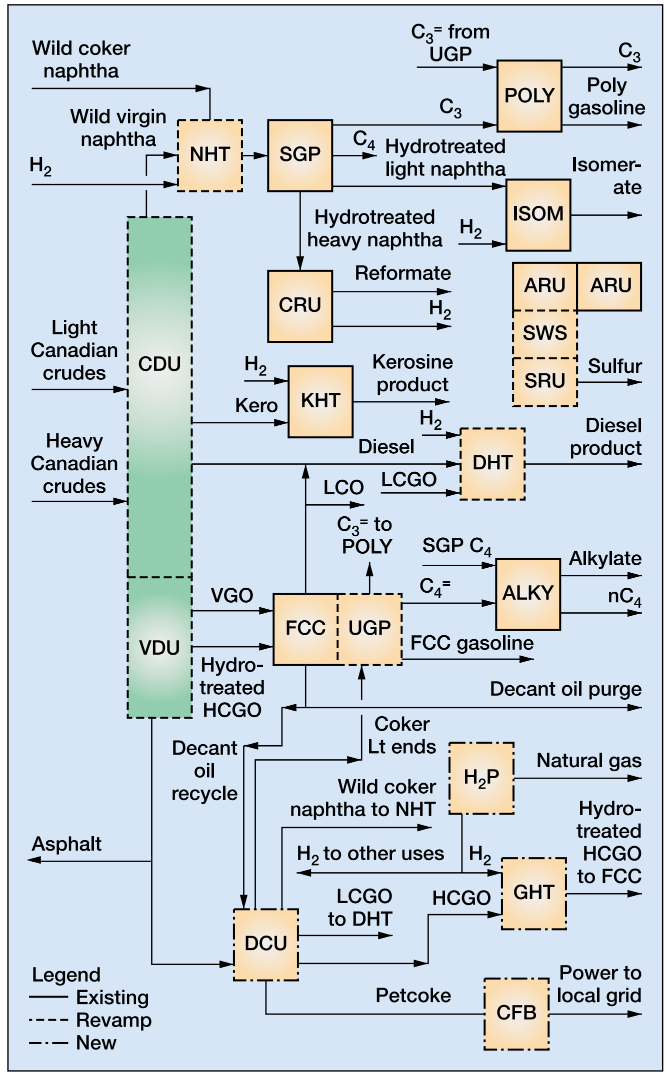

Fig. 2. Block flow diagram—base project upgrade.

At this point, the base project upgrade contained three new units to remove sulfur. The GHT provided a yield benefit by upgrading HCGO to FCC feed. The FGH and FGS provided no benefit other than environmental compliance for sulfur control. In some cases, FCC gasoline hydrotreating impacted the refinery economics due to yield and/or octane losses. It was at this point in the study that the decision was made to evaluate an alternate scheme to improve the yield benefit associated with this capital investment.

Alternate project upgrade. The alternate project upgrade includes a new delayed coker and a new CFB, as was the case for the base project upgrade. A new high-pressure FCC feed hydrotreater (FFH) is included to process all the HCGO and VGO to produce a quality FCC feed. The changes to the configuration due to the alternate project upgrade are depicted in Fig. 4.

The FFH, available as a licensed process or an open-art unit, desulfurizes and upgrades the FCC feed to a level where the sulfur in the FCC gasoline directly from the FCC would be at an acceptable level. The FGH is eliminated. The possible loss of octane-barrels is also avoided. In addition, FCC regenerator emissions would be within current and future permissible levels eliminating the need for a FGS.

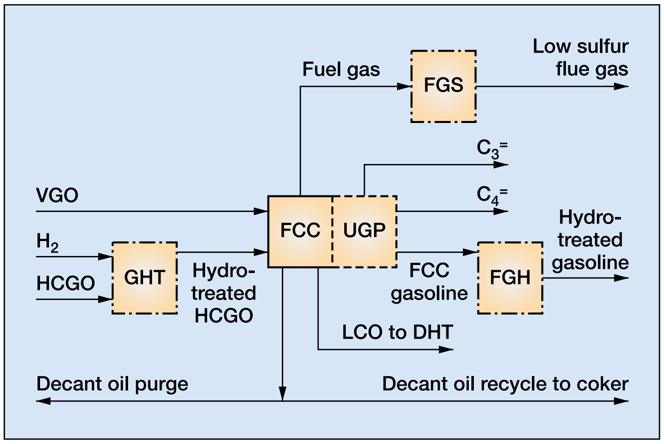

Fig. 3. Block flow diagam—base project upgrade with gasoline hydrotreater.

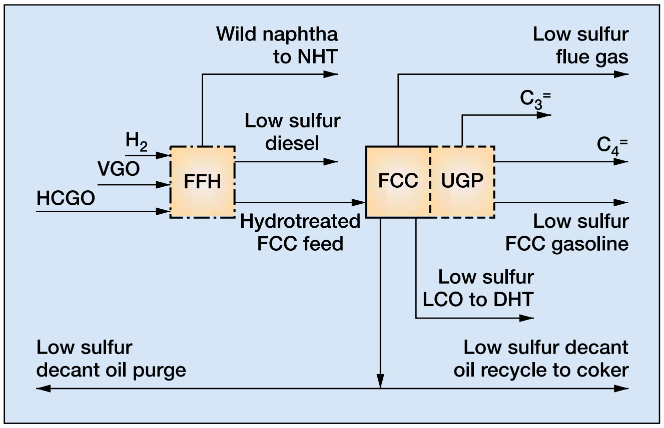

Fig. 4. Block flow diagram—alternate project upgrade with FCC feed hydrotreater.

Because of the increased capacity of the FFH, a substantial liquid yield benefit is realized, as compared to the smaller GHT. The high-quality hydrotreated FCC feed results in a higher conversion in the FCC, producing increased quantities of olefins and FCC gasoline and less LCO and decant oil.

Another advantage to the alternate project upgrade is the simplicity of the scheme. One new unit replaces three new units. Also, FFH is a well-established and proven process with many units in service. The technical risk of this scheme is substantially less as compared to the base scheme. In addition to producing low-sulfur gasoline, the FCC also produces low-sulfur LCO and decant oil products. The low-sulfur LCO can be upgraded to diesel with less difficulty in the revamped DHT. Less decant oil with improved properties allows for a smaller decant oil recycle through the coker and a good chance a purge will not be required. Any decant oil purge that may be required has a low-sulfur content and can be used as refinery fuel oil within the permitted SO_x emissions limits.

One impact of the alternate project upgrade is the substantial increase in hydrogen demand requiring a larger new H_2P. A larger new ARU will also be required and the revamps to SWS and SRU are more extensive.

New unit capital cost analysis. Table 1 presents a comparison of recent budgetary capital costs of the new process units for the base and alternate project upgrades. A capital-cost comparison for the revamped process units is outside the present scope of this study. However, a qualitative assessment indicates the revamped units for the base project upgrade would necessitate a higher capital investment than the alternate project upgrade to satisfy the requirements of the upgrade.

Table 1. New unit capital costs production

Base project upgrade	Alternate project upgrade
Delayed coker	Delayed coker
CFB cogeneration unit	CFB cogeneration unit
Gas oil hydrotreater	FCC feed hydrotreater
FCC gasoline hydrotreater	Hydrogen plant
FCC flue gas scrubber	Amine regeneration unit
Hydrogen plant	
Amine regeneration unit	
Base MM USD	Base less 11.0 MM USD

Table 2. Margins and operating costs

Base project upgrade	Alternate project upgrade
Production margin	
Base MM USD/YR	Base plus 6.1 MM USD/YR
Utilities/Catalyst/Chemicals cost	
Base MM USD/YR	Base plus 1.9 MM USD/YR
Net revenue	
Base MM USD/YR	Base plus 4.2 MM USD/YR

Table 3. Operator requirements

Base project upgrade	Alternate project upgrade
Base operators per shift	Base less 2 operators per shift

Production margin and utilities/catalyst/chemicals cost analysis. Table 2 presents a comparison of the production margins and utilities, catalyst and chemicals costs for the base and alternate project upgrades.

Operator requirements analysis. Table 3 presents a comparison of the operator requirements for the base and alternate project upgrades.

Discussion of results. The comparisons presented indicate the alternate project upgrade is favored with respect to several aspects. The lower, new, unit capital cost coupled with the expected, lower, revamped unit capital cost make the project easier to finance and reduce the processing fee charged to the refiner. The simpler arrangement has several yield incentives so the increased production margin more than offsets the increase in utility/catalyst/chemicals costs. Proven technology minimizes any potential technical risk associated with the upgrade and provides a long-term solution to the clean fuels problem faced by this refiner. A thorough analysis of the upgraded refinery, including environmental concerns, was the key in determining the proper configuration to maximize profits and produce a clean fuels product slate for years to come. ■

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