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AM-14-35 Optimizing Naphtha Complexes in the Tight Oil Boom

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OPTIMIZING NAPHTHA COMPLEXES IN THE TIGHT OIL BOOM

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INTRODUCTION

The shale crude boom is upon us as evidenced by the increased activity in exploration, drilling, transportation, processing, and even public opinion. This is particularly true in North America, where success has been greatest due to advances in crude extraction techniques and recovery methods. North American shale crudes and Canadian tar sands continue to displace waterborne imports, declining from ~50% in 2010 to ~33% in 2013. These domestic crudes offer lower cost raw materials but also present some new technical and logistical challenges. Refiners today face ever increasing demands to optimize current assets and operating expenses in order to maximize profitability. This paper attempts to explore some of the opportunities and challenges associated with shale crudes, aka tight shale oil. One example explored here within illustrates an increase in product value of approximately \$6/ BBL and \$300M/ year increase in profitability.

Tight shale crude is typically characterized as light, sweet and is contrasted by the heavy, sour Canadian bitumen tar sands. These crudes have very different yield patterns for refined products, as well as contaminant levels, impacting the refiners' processing units and product slate. Tight oil crudes typically have higher light and heavy naphtha yields, presenting increasing challenges to the Naphtha Complex, typically consisting of Naphtha Hydrotreating (NHT), Light Naphtha Isomerization and UOP CCRTM Platforming units. The lower VGO and vacuum residue yields, directionally decreases coker, FCC and alkylation rates, decreasing their contribution to the gasoline pool. Conversely, light naphtha, isomerate and reformate octane-barrels increase in the gasoline pool and play an increasing role in gasoline production and overall profitability. This occurs at a time when the North American market is generally octane long and utilizations are down. However,

opportunity is created with exports to adjacent octane short markets, coupled with lower energy and raw material costs facilitated by the shale boom.

The critical step in increasing profitability is to properly define objectives and constraints. Each refinery has a unique configuration, set of processing objectives, equipment limitations, and budget constraints; therefore, there is no universal solution to maximize profitability. Solutions for refiners located in the U.S. PADD II and III regions that can access and sell products more readily may differ from inland refiners who incur higher product transportation costs. Recall that much of the North American shale is being transported by rail, and not the more conventional pipeline.

A linear program (LP) study was used to evaluate the refinery-wide impact when switching to a lighter tight oil feed slate. Specific attention is devoted to the Naphtha Complex and the impact on the gasoline pool. When determining the crude slate, optimizing current unit design capacities, coupled with demand and transport costs, are key factors for maximizing profitability. This paper will discuss solutions for optimizing the Naphtha Complex which includes technology and catalyst options.

A best solution exists for every situation and every purse. However, determining which solution provides the greatest value, meets the overall processing objectives, and stays within the available budget requires technical expertise and optimization that examines the entire system and leverages the technologies available. Several examples included in this paper demonstrate the benefits.

MARKET OVERVIEW

The US supply of domestic natural gas liquids (NGL's) and crude was drastically impacted by improvements in hydraulic fracturing technology. The supply of natural gas was first impacted, resulting in a price decrease which presented refiners with a lower cost fuel and feedstock for hydrogen. Access to lower priced natural gas improved profitability compared to other regions in the world. Figure 1 shows the relative advantage of competitive natural gas prices available to U.S. refiners as compared to other regions of the world.





Source: Bloomberg, November 2012

The second major application of hydraulic fracturing technology was to recover liquid hydrocarbons from existing shale plays which were previously uneconomical. Shale plays such as Bakken in North Dakota, Eagle Ford in Texas, and other developing areas of the U.S including the Utica field in the Northeast as well the Monterey field in California have been known for decades. The location of these resources is illustrated in Figure 2.





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Production of tight shale oil from these fields has increased rapidly such that North Dakota is now the second largest producer of crude oil in the U.S. (U.S. EIA data). When taken in total, tight shale oil production has led to the largest annual increase in U.S. crude oil production in history (Wall Street Journal, January 18, 2013, "U.S. Oil-Production Rise Is Fastest Ever"). In fact, the daily U.S. crude production increased by nearly 800,000 barrels per day in 2012 to reach a total production of 6.4 million barrels per day. At present, the U.S. EIA estimates production will increase to 7.9 million barrels per day in 2014 as shown in Figure 3. The Bakken field alone has increased production from 125,000 barrels per day five years ago to producing nearly 750,000 barrels per day. Longer-term, forecasts call for U.S. tight shale crude production to add between 2 (OPEC 2012 World Oil Outlook) and 6 million barrels per day. The recently issued BP World Energy Outlook estimated U.S. tight shale oil production could add as much as 5 MMBPD by 2030.



Figure 3: U.S. Short Term Tight shale oil Impact on Oil Production

Shift in US Crude Runs

Price discounts have resulted as the development of takeaway capacity lagged the rapid production increases. Much of the incremental crude production is routed through the Cushing, OK oil storage hub, contributing to record inventories, creating a situation where the WTI benchmark price has flipped from a small premium versus Brent crude to discounts ranging from almost \$30/barrel at one point in 2011 to approximately \$15-\$20/barrel in January 2013. Although this discount is forecast to

close to perhaps \$5-\$6/bbl as new takeaway capacity is added, this factor is a major driver of the improved U.S. refinery profitability and high run rates.

In response to the discounted crude supply many U.S. refiners have chosen to make investments in crude logistics to gain access to these crudes. Shareholder and investment community presentations by Marathon, Tesoro, Valero, and Phillips 66 note investments in rail unloading facilities, tank cars, and refinery fractionation improvements aimed at enabling increased throughput of these crudes. PBF recently completed the first phase of their rail unloading facility at Delaware City, while BP has made similar statements regarding transport of tight shale oil to their Cherry Point, WA refinery.



Figure 4: U.S. Shale Oil Projections by Field

Source: Citi Investment Research and Analysis, "Resurging North American Crude Production and the Death of the Peak Oil Hypothesis", February 15, 2012

Equally of interest to refiners is the quality of this crude, as it is typically quite light (~40-45°API gravity), and contains very low quantities of sulfur. A comparison of published assay data indicates these crudes contain a high quantity of naphtha-range material and low quantities of vacuum residuum, and have important differences relative to imported light sweet crudes such as Bonny Light that are available to U.S. refiners. As a result, U.S. refiners are displacing / reducing imports of these internationally priced foreign light sweet crudes with the domestically produced materials. This has contributed to altering the trade flows for these grades. Another consequence of the availability and processing of favorably-priced light crude coupled with low natural gas prices and a sophisticated refining infrastructure has enabled significant exports of refined products to other gasoline and octane short markets.

A number of US refineries have taken advantage of the current price discounts associated with the increased production of tight shale crude and have begun processing these materials; predominantly

Bakken and Eagle Ford, in their facilities as a part of their crude acquisition strategy. However, as these fields mature and technology for economic extraction of these crudes develops further, the percentage of shale derived crudes being processed in US refineries will continue to rise and impact operations more significantly. One offsetting trend to this is the reduction of imports of heavy sour crudes from Mexico, and waterborne imports from the Middle East and Western Africa. These imports could be in part displaced by heavy Canadian crudes if logistics solutions are implemented. Refiners in the U.S. that have the conversion complexity and assets to simultaneously upgrade the light sweet and heavy sour materials into valuable transportation fuels will benefit.

IMPACT OF HYDRAULIC FRACKING WITH CRUDES

The massive increase in shale gas and shale crude has been primarily due to the refinement of horizontal drilling and hydraulic fracturing (aka- 'fracking'). U.S. refiners are processing higher percentages of domestic tight oil crudes due to these improvements. With increased fracking, hydraulic additives and/or total dissolved solids (TDS) are potential contamination issues which must be managed. Total dissolved solids (TDS) from fracking can vary from <5,000 ppm to >100,000 ppm and levels as high as >400,000 ppm have been reported.

Information for this section was obtained from the U.S. Department of Energy, National Energy Technology Laboratory, "Modern Shale Gas Development in the Unites States: A Primer", April 2009. The following definitions are for terms that are used throughout this paper.

- Conventional reservoirs: Wells produced from sands and carbonates (limestones and dolomites) that contain the gas in interconnected pore spaces that allow flow to the wellbore. Much like a kitchen sponge, the gas in the pores can move from one pore to another through smaller pore- throats that create permeable flow through the reservoir.
- Unconventional reservoirs Tight Oil: Wells produced from a low permeability (tight) formation such as tight sands and carbonates, coal, and shale. Because of the low permeability of these formations, it is typically necessary to stimulate the reservoir to create additional permeability. Hydraulic fracturing of a reservoir is the preferred method.

Hydraulic Fracturing

Fracturing fluids consist primarily of water but various additives are also used. Compositions are proprietary information and concentration levels can vary from company and site. HCl, however, is typically the largest additive used in a fracturing fluid. Exhibit 35 shows an approximate composition of a fracking fluid used for a Fayetteville Shale horizontal well. The ~15% HCl with ~85% water, results in an acid concentration of ~0.123 lv% HCl, corresponding to a pH of ~4.



The following table shows common hydraulic additives and other common uses. The complete list can be found in Exhibit 36: Fracking Fluid Additives, Main Compounds, and Common Uses.

Category	Purpose	Chemical
Acid	To create pathways in limestone for gas and oil. To clean perforations of mud and cement before fluid injection.	HCI(3% to 28%), Acetic Acid
Clay Stabilizers	Stabilizes Clay in well.	Salts, potassium, chloride, tetramethyl ammonium chloride
Gelling Agent	Increases fluid viscosity, more proppant transported into fractures	Guar gum, Naphthalene
Proppant	Holds fractures open	Sand, ceramic beads
Surfactant	Reduces surface tension, increasing recovery	Methanol, isopropanol

After fracking, the fracture fluid begins to flow back through the well casing to the well head. The time to recover the majority of fracking fluid varies from several hours to a couple of weeks. The total dissolved solids and minerals are inherent from that shale play and can vary. The longer the contact time with the hydraulic fluid, the solids and minerals can increase.

Consequently, it is important for the refiner to recognize the possibility of increased metals, minerals, TDS and solvents in the crude. Since metals are typically catalyst poisons in refining process units, refiners should monitor metals on catalyst, taking samples on a regular basis. Equally important is to employ the correct metals traps before reaching catalysts used in refining. High TDS can be problematic in the crude column and solvents, such as methanol and isopropanol may be converted to water and possibly deactivate water sensitive catalyst.

Source: www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf

TIGHT OIL CRUDE YIELDS SHIFT TOWARD LIGHTER HYDROCARBONS

The crude assay reflects the yield pattern and is key information for determining the refinery products. Shown below in Figure 5 is a plot of wt.% yield of LPG, naphtha, kerosene, diesel, vacuum gas oil and vacuum residue for several crudes with varying API's. The tight oil crudes, Bakken, Eagle Ford, and Utica, are typically lighter crudes, higher API, and have predominantly higher LPG, naphtha with less heavy VGO and vacuum residue material. Conversely, Western Canadian Select (WCS) is a blend of oil sands, managed by the Canadian Natural Resources, Cenovus Energy, Suncor Energy, and Talisman Energy, blended to targeted specifications. WCS is typically blended to a sulfur level of ~3.5 wt.%, API of ~20°-21° and with ~5-6 lv% pentanes to increase flow properties. Even with ~5 lv% pentanes, the WCS is still a very viscous crude with a kinematic viscosity of about 130 cSt vs. ~63 cSt for Maya and ~1-2 cSt for the tight oil crudes. Transporting WCS crudes can be challenging, with rail cars typically requiring steam tracing.



Figure 5: Crude Yields, wt.%

Source: Haverly Systems Inc.: H/CAMS -Haverly Systems Crude Assay Management System

Crude API's can be used to approximate key properties

A crude API can be used to approximate key properties, such as yields, contaminants and paraffin concentration. In Figure 5, there is a general trend of increasing lighter hydrocarbons with increasing API. For example, the Eagle Ford tight oil crude with an API of 55.6° has a higher naphtha yield than the Bakken tight oil with an API of 42.3°.

Contaminant levels also trend with the crude API. Figures 6-9 show sulfur, nitrogen, wax and naphtha paraffin concentrations vs. API. For the lighter crudes, API's \sim 50° or higher, the crude sulfur is \sim <0.1 wt.% and increases to \geq ~3.0 wt. % for the lower API crudes such as for the Western Canadian Select. Nitrogen levels also show a similar trend.

 Table 1: General Trends between Tight Oil and Western Canadian Select Crudes

Crude	Tight Oil	Western Canadian Select
API	~50°	~20°
Sulfur	Low	High
Nitrogen	Low	High
Wax	High	Low
Naphtha (200°-350°F/ 93°C-177°C)	High	Low

Tight Oil crudes: Bakken, Utica and Eagle Ford





The higher API crudes typically have a higher paraffin concentration, resulting in a higher wax level. Shown in Figure 8 are the crude wax concentrations vs. API. The WCS crude, API of ~20°, has a lower wax concentration vs. Eagle Ford, 2 wt.% vs. ~10 wt.%, respectively. The higher paraffin concentration with the higher API crudes is also consistent in the naphtha range, 200° F-350°F (93°C-177°C).



Figure 9: Naphtha (200°F-350°F) Paraffin wt.% vs. Crude API



Source: Haverly Systems Inc.: H/CAMS - Individual crude assays and compositions can vary.

General Refinery Trends using Crude API's

Crude API's can be used to provide general refinery trends and a directional impact on products. The following summary shows general refinery trends with increasing crude API, resulting in decreasing contaminants and increasing paraffinicity.

General Trends for Tight Oils (high API, ~50°+)

- Lower Sulfur, Nitrogen contaminants
 - Lower H₂ demand for hydrotreating and hydrocracking units
- Lower Vacuum Residue Yield
 - Lower VGO, Coker and FCC rates
 - Lower FCC rates, lower $C_3^{=}/C_4^{=}$ to Alkylation Unit, less alkylate
 - Less FCC naphtha, Alkylate in Gasoline Pool
- Higher Paraffin Concentration
 - Diesel Cut: Higher cetane number with poorer cold flow properties
 - \circ Naphtha Cut: Leaner reformer feed, lower ${C_5}^+$ and H_2 yields
- Higher Light and Heavy Naphtha Yields
 - Larger increase in light naphtha; Isomerization feed rates increase
 - Increase in feedrate to Platforming Unit (fixed bed or CCR)
 - Higher quantity of Isomerate and Reformate in Gasoline Pool

REFINING IMPACT OF PROCESSING TIGHT SHALE OIL

A refinery linear program (LP) was developed to evaluate the impact when changing the crude slate from a conventional mix of waterborne imports to newer domestic crudes, i.e. tight oil and Western Canadian Select. The refinery configuration modeled includes a Coker, VGO hydtroteater, FCC, HF Alkylation, Naphtha Hydrotreater, Isomerization and CCR Platforming unit. (See Schematic 1). The LP was based on the 2013 configuration used in the 2013 AFPM paper from Houvie, "Solutions for FCC Refiners in the Shale Oil Era", AM-13-06, and assumes a crude processing capacity of 150,000 BPD with of a mixture of Arab Medium, Maya, and WTI crudes. The LP includes dynamic process submodels of UOP licensed technologies.

Basis

The price basis used in this study is provided in Table 2. The transportation fuel specifications are based on typical U.S. requirements including ultra low sulfur diesel (ULSD) with a target cetane of 45 and gasoline (R+M)/2 = 89 at a 9 psig RVP. The West Texas Intermediate (WTI) crude price was used as the benchmark with crude purchases and products being compared on a relative basis. Table 3 shows the crude properties used in the study.

Crude Purchase Price- Relative				
West Texas Intermediate	Base			
Maya	92%			
Arab Medium	99%			
Bakken	97%			
Eagle Ford	97%			
Western Canadian Select	79%			
Major Products, % of WT	I			
Ultra Low Sulfur Diesel	121%			
RBOB Gasoline	117%			
Naphtha	84%			
Butane	55%			
Propane	50%			
Bunker Fuel Oil	69%			

Table 2: LP Study Pricing Basis

Table	3:	Crude	Pro	perties
I GOIC	••	Ciuuv	110	

		Western Canadian					
	Units	Select	Maya	Arab Med	WTI	Bakken	Eagle Ford
API Gravity	API	20.3	21.4	30.8	39.1	42.3	46.5
Sulfur	WT%	3.3	3.5	2.6	0.3	0.1	0.1
Neut or TAN No.	mgKOH/g	0.8	0.1	0.3		0.0	0.1
Nitrogen	ppm	2,770	3,573	1,210	1,000	500	41
Hydrogen	WT%	11.4	12.1	12.7	13.3	13.8	14.3
Ramsbottom Carbon	WT%	9.0	11.2	5.6		0.8	0.0
Iron	ppm	8	5	4		2	1
Vanadium	ppm	118	286	34		0	0
Nickel	ppm	49	53	10		1	0

Source: H/CAMS



Schematic 1: LP Model Configuration

Case Studies

Several case studies were run to show the impact of changing crudes. The total crude rate was kept constant at 150 MBPD. The base case crude consisted of 75 MBPD of Arab Medium, 39 MBPD of West Texas Intermediate and 36 MBPD of Maya. In case 1, the crude was changed to 113 MBPD of Bakken and 37 MBPD of Western Canadian Select. In case 2, the crude was 113 MBPD of Eagle Ford and 37 MBPD of WCS. The lighter Eagle Ford crude resulted in a higher crude blend API of 46.2°. Shown below is a summary of the cases.

		Base	Case 1	Case 2
Gasoline	(R+M)/2	89	89	89
Diesel	Cetane	45	45	45
Crudes	API	31.3	37.1	46.2
Arab Med	MBPD	75	0	0
WTI	MBPD	39	0	0
Мауа	MBPD	36	0	0
Bakken	MBPD	0	113	0
Eagle Ford	MBPD	0	0	113
WCS	MBPD	0	37	37
Total	MBPD	150	150	150
\$/BBL		Base	(-\$5.36)	(-\$5.36)

Case 1: Replacing crudes with Bakken/WCS

The first case evaluated the impact of changing to a lighter, less expensive crude blend of 75% Bakken and 25% WCS. The cost of the crude blend was reduced by \$5.36/bbl, and the API increased from 31.3°API to 37.3°API. The lighter crude resulted in a higher percentage of LPG, LSR, with similar kerosene, diesel, but lower atmospheric residue cuts. Shown below is the percentage change of the Bakken/WCS blend relative to the base.



Figure 10: Case 1- Percent Crude Yield Change relative to Base Case

The refinery impact of the crude change is quantified in Table 5. Figure 10 can be used to predict a relative change to process units. For example, an increase in the light naphtha, C_5 - C_6 , will increase the rate to the the isomerization unit. Isomerization unit capacity increased from 13.5 MBPD to >19 MBPD with marginal increases in the NHT and CCR Platforming unit. The reduction in vacuum residue will decrease flow rates to the coker and FCC units while decreasing the alkylation capacity.

The gasoline blending pool is shown in Figure 11. With the lighter crudes (Case 1), the amount of FCC naphtha decreases with an increase in isomerate; the net delta is an increase in the gasoline pool from 84.6 MBPD to 86.4 MBPD. Case 1 product value increase is \$5.80/bbl, generating a product value increase of >\$300 million/year.

Figure 11: Gasoline Pool Blending



Base Case and Case 1

Table 5: Case 1 Economic Summary

		Base	Case 1
Gasoline	MBPD	84.6	86.4
Diesel	MBPD	55.3	52.7
G/D		1.5	1.6
Products - Crude	\$/BBL	Base	+\$5.8

\$300+ million/yr product value increase

Case 2: Replacing base crude with EagleFord/WCS; Process Unit unconstrained

In case 2, Bakken was replaced with the lighter Eagle Ford crude, increasing the blend API from 37.1° to 46.2° . Shown below is a comparison of crude yields between the two cases. The LPG was similar, but the Eagle Ford crude light naphtha and heavy naphtha yields were higher with lower atmospheric residue. The process unit capacities were unconstrained; Isomerization unit rate increased 78% from ~13.4 MBPD (Base Case) to ~23.8 MBPD and the CCR Platformer rate increased 35% from ~29.0 MBPD (Base Case) to ~39.4 MBPD. Schematic 2 highlights the units in which the capacity changed by more than 15% from the base case. Since there was a large decrease in the atmospheric residue (1050°F+/566°C), there was a rate decrease in the coker, FCC and HF Alkylation units.

Although there was a substantial increase in the capacity for the Naphtha Complex (NHT, isomerization and CCR Reformer), Base Case 84,962 BPD to 98,296 BPD, there was a decrease in the gasoline pool from 84.6 MBPD to 83.6 MBPD due to the lower FCC naphtha and Alkylate. Case 2 summary is included in Table 7.

Figure 12: Case 2 Percent Crude Yield Change



Table 6: Case 2 Economic Summary

		Base	Case 1	Case 2
Gasoline	MBPD	84.6	86.4	83.2
Diesel	MBPD	55.3	52.7	51.1
G/D		1.5	1.6	1.6
Products - Crude	\$/BBL	Base	+\$5.8	\$2.76
Prod Value	\$MM/yr	Base	~300	~151



Schematic 2: Case 2 Eagle Ford/WCS Capacity change from Base Case



Naphtha Complex increases ~15%

There was a substantial increase in the isomerization rate with the lighter Eagle Ford crude, 78%, going from 13.4 MBPD (Base Case) to ~23.8 MBPD (Case 2), which may be unachievable without a major revamp. In case 2a, the naphtha complex was constrained to maximum unit flow rates similar to Case 1. The Isomerization rate was limited to 19.1 MBPD (42% capacity increase), NHT to 49.2 MBPD, and the CCR Reformer to 30.0 MBPD (3% capacity increase). With these constraints, ~13.0 MBPD of excess isomerate was sold as naphtha, reducing the overall product value to \$0.81/bbl.

Case 2b: Eagle Ford/ WCS, Naphtha Complex constrained to Case 1 rates; Naphtha Complex increases ~15% Naphtha sold at distressed price, ~50% of original product value To simulate inland refiners and/or difficulty selling excess naphtha, the product value of naphtha was reduced to 50% of the base price. The reduced price of naphtha resulted in a negative product value of -\$2.65/bbl.

		Base	Case 1	Case 2	Case 2a	Case 2b
Naphtha Complex						Lower Naptha
Capacity			uncor	nstrained	Constrained to case 1	Price
Crude		Arab Med/WTI/Maya	Bakken/WCS	Eagle Ford/WCS	Eagle Ford/WCS	Eagle Ford/WCS
API	Deg	Base	37.1	46.2	46.2	46.2
Gasoline	MBPD	84.6	86.4	83.2	72.2	72.2
Diesel	MBPD	55.3	52.7	51.1	51.1	51.1
G/D		1.53	1.64	1.63	1.41	1.41
Naphtha Sold	MBPD				13.0	13.0
Prod-Crude	\$/bbl	Base	5.82	2.76	0.81	-2.65
VGO	BPD	55,298	74%	50%	50%	
Coker	BPD	27,589	60%	43%	43%	
FCC	BPD	41,869	93%	65%	65%	
Alkylation	BPD	12,988	90%	62%	62%	
VGO, coker, FCC,						
Alkylation	%	Base	79%	55%	55%	55%
Naphtha Complex						
NHT	BPD	42,513	116%	149%	116%	116%
Isomerization	BPD	13,418	143%	177%	143%	143%
CCR Reformer	BPD	29,031	103%	135%	103%	103%
Total	BPD	84,962	115%	148%	115%	115%
Naphtha Complex	BPD	84,962	98,296	126,304	98,296	98,296

 Table 7: Case Summaries

Naphtha Complex Feed Quality Change with Tight Oil Crudes

10 0

Arab Med/WTI/Maya

Processing tight oil crudes increases the paraffinicity of the reformer naphtha. With a leaner CCR Platforming unit feed, there is a decrease in C_5^+ and H_2 yields. Shown in Figure 13 and Table 8 is a summay of the naphtha product qualities.



Figure 13: CCR Platforming Unit Feed Quality



Bakken/WCS

Eagle Ford/WCS

		Base	Case 1	Case 2	Case 2a	Case 2b
Naphtha Complex				•		Lower Naptha
Capacity			uncor	nstrained	Constrained to case 1	Price
Crude		Arab Med/WTI/Maya	Bakken/WCS	Eagle Ford/WCS	Eagle Ford/WCS	Eagle Ford/WCS
API		Base	37.1	46.2	46.2	46.2
Prod-Crude	\$/bbl	Base	5.82	2.76	0.81	-2.65
CCR Reformer						
Paraffins	LV%	63.1	60.2	74.8	74.8	74.8
N+2A	LV%	47.8	47.3	34	34	34
Products						
RONC		99.8	102.0	101.3	101.6	101.6
Yield						
LPG	lv%	5.4	6.6	9.3	9.4	9.4
Reformate	lv%	80.8	78.5	75.2	74.9	74.9
LPG	BPD	1,591	1,961	3,621	2,907	2,907
Reformate	BPD	23,460	23,558	29,569	26,141	26,141
Isomerate RONC- BBLS		80.6	80.6	80.6	80.6	80.6
		13,615	19,407	24,151	19,128	19,128
Isomerate (RONC-BBLS/Day)	мм	1.1	1.6	1.9	1.5	1.5
Reformate (RONC- BBLS)/Day	MM	2.3	2.4	3.0	2.7	2.7

Table 8: Naphtha Complex Feed Quality

Overall Case Summary

Figure 14: Product Value minus Crude Value



Table 9: Case Summaries

Case	Conditions	Driver
Base	More expensive crude	Highest Diesel
1	Cheapercrude	More Gasoline
2	Crude lighter, less diesel, alkylate	Less Gasoline Less Diesel
2a	Same as Case 2, but Naphtha Complex Capacity constrained	Naphtha sold
2b	Same as 2b, but lower naphtha price	Naphtha sold at distressed pride

UOP's key LP findings when processing tight oils (Higher API's):

- Lower crude price is the key economic driver
- Increasing API, increasing light Naphtha (C₅/C₆)
- Diesel Production decreases
- Isomerate and Reformate octane-bbls increase in gasoline pool.
- Gasoline pool barrels can decrease if decrease in FCC naphtha plus Alkylate is greater than increase in Isomerate and Reformate in pool.
- If excess light naphtha is sold, price differential (crude naphtha) is key to profitability.
- Balancing the light tight oil Crudes with a Heavy Western Canadian Select is important to maximize current assets.
- Optimizing Naphtha Complex key to profitability

OPTIMIZING THE NAPHTHA COMPLEX



Figure 15: Naphtha Complex

Shown above is a block flow diagram of a Naphtha Complex: Naphtha Hydrotreater, Naphtha Splitter, Isomerization unit and CCR Platforming unit From the previous case evaluations, the flow rate to the Naphtha Complex typically increases as the crude becomes lighter. The Isomerate and Reformate blendstocks are a larger percentage of the overall gasoline pool; consequently, optimizing these assests is key to maximizing profitabilty.

Naphtha Complex Overview

Hyrotreated feed from the NHT is sent to the Naphtha splitter; the lighter C_5/C_6 paraffins are sent to the isomerization unit and the heavier C_7 ⁺ to the CCR Platforming unit. Controlling the gasoline pool benzene level is a key specification, impacting the Naphtha Complex design. The naphtha splitter is designed for benzene control, splitting the benzene precursors (methycyclopentane (MCP), cyclohexane (CH), benzene (BZ)) either to the Isomerization or CCR Platforming Unit. When benzene production is targeted, benzene precursors are sent to the reformer unit. If minimum benzene is targeted, then the benzene precursors would be sent to the isomerization unit, which is excellent for benzene saturation and conversion to high octane C6 paraffins.

Removing the C6 components from the Platforming unit feed has many advantages. First, a higher C_7 feed rate can be achieved to the CCR Platforming unit. Second, since C_6 components are among the hardest to reform, the CCR Platforming unit severity is reduced. Third, the benzene concentration of the reformate product is greatly reduced.

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Processing the C_5 and C_6 components in an isomerization unit allows the refiner to recover lost octane due to benzene reduction. Since isomerate is free of aromatics and olefins, it is an ideal blending component for gasoline allowing refiners to reduce their gasoline benzene, total aromatics and olefin content while improving the octane of the C_5 and C_6 fraction.

Naphtha Hydrotreater (NHT)

Crude Straight Run Naphtha (SRN), FCC naphtha, Hydrocracker and/or Coker naphthas are common feedstocks to the NHT. Tight oil crudes have low contaminants while Canadian bitumen crudes and coker naphthas have substantial amounts of sulfur and nitrogen. The level of contaminants will impact the design, performance, yields and catalyst selection.

Shown below is a plot of naphtha $(200^{\circ}\text{F}-350^{\circ}\text{F}/93^{\circ}\text{C}-177^{\circ}\text{C})$ and vacuum residue $(1050+^{\circ}\text{F}/566^{\circ}\text{C})$ nitrogen and sulfur. Vacuum residue can be processed in a coker unit, producing naphtha which is further hydrotreated in the NHT unit. Common process concerns are metals, olefins, sulfur, nitrogen and silicon from antifoam used in coker drums. The higher level of contaminants and additional coker naphtha to the NHT result in more severe operating conditions, impacting reactor pressure, LHSV and H₂ consumption. Therefore, attention to the NHT and operating conditions should be reevaluated when processing the heavier bitumen crudes.



Figure 16: Naphtha and Vacuum Residue N Figur

Figure 17: Naphtha and Vacuum Residue S

Show below is a process flow schematic of a NHT unit.



Schematic 3: NHT Flow Diagram

NHT Process Flow

The naphtha feed is pumped and mixed with hydrogen-rich recycle gas, preheated by exchange against reactor effluent and then heated to reaction temperature by the fired charge heater before passing to the reactor. Heat integration is provided to minimize fired heater and product condenser utilities.

In the reactor, the sulfur and nitrogen impurities contained in the feed are converted to hydrogen sulfide (H_2S) and ammonia (NH_4) over the hydrotreating catalyst. Olefins and diolefins present in the feed are hydrogenated to the corresponding paraffins. The hydrogenation reaction is exothermic and is relatively small for straight run naphtha, but increases with coker naphtha. The NHT operating conditions should be evaluated when processing heavy vacuum residues, i.e. Canadian

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bitumens, since directionally there would be a higher heat of reaction with an increased amount of coker naphtha.

The reactor configuration is downflow to ensure maximum utilization of catalyst. Scale and debris are removed by skimming the upper layer of catalyst during a unit turnaround.

The reactor effluent, containing hydrotreated naphtha, hydrogen-rich gas, hydrogen sulfide and ammonia, is cooled by exchange against the combined feed and is then mixed with wash water, injected from the condensate injection tank. The product separator contains a coalescer to ensure good separation. The separator vapor passes to the recycle gas compressor suction drum and then to the recycle gas compressor. Make-up hydrogen is introduced at the suction of the recycle gas compressor or upstream of the product condenser.

The net bottoms from the column are heat exchanged with the stripper feed and sent to the naphtha splitter column. The overhead vapors from the splitter column are totally condensed in the splitter condenser and pass to the splitter overhead receiver. The net overhead C_5/C_6 light naphtha is sent to the Isomerization unit, while the column bottoms are reboiled by the splitter reboiler. The heavy C_7^+ naphtha net bottoms is heat exchanged with the separator liquid and then sent to the CCR Platforming unit.

Optimizing the NHT Unit - Catalyst Improvements

Catalyst improvements have allowed refiners to increase feed rate and/or reduce utilities. UOP has introduced two new catalysts, HYT-1118 for straight run, low nitrogen feeds and HYT-1119 for cracked stocks and high nitrogen feeds. Table 10 is a comparison of catalyst properties.





Product	S-120	HYT-1118	S-125	HYT-1119
Туре	CoMo	СоМо	NiMo	NiMo
Density (Sock/Dense) kg/m3	730/810	551/633	642/752	593/682
Shape	Cylinder	Quadralobe	Quadralobe	Quadralobe

HYT-1118 Catalyst for straight run, low N naphtha

HYT-1118 catalyst is UOP's latest generation cobalt molybdenum hydrotreating catalyst, building upon the proven performance of UOP's S-120 catalyst. HYT-1118 catalyst provides the benefits of higher hydrodesulfurization (HDS) and hydrodenitrification (HDN) activity while being more than 30% less dense than the previous generation S-120 catalyst.

HYT-1119 Catalyst for cracked stocks and high N feed

UOP's HYT-1119 is a robust catalyst designed for use in naphtha hydrotreating applications to remove sulfur and nitrogen compounds with cracked stocks and high nitrogen feeds. HYT-1119 has high stability due to high pore diameter and pore volume, resulting in long catalyst life. In addition, standard regeneration methods can be used to minimize catalyst life-cycle costs.

Shown below are the features and benefits of HYT-1119:

- Improved metals distribution
- 20% higher surface area for higher Silicon pickup
- No Phosphorus for increased stability & higher Silicon pickup
- Lower aromatic saturation
- Reduced loaded density for lower fill cost
- Higher HDS and HDN activity

Example of the benefits of HYT-1119 Catalyst

In the previous case evaluations, the base NHT feed rate was 42,513 BPD and increased to 49,174 BPD with the Bakken/WCS crude and further to 63,185 BPD with the Eagle Ford/WCS crude. The following shows the economic advantage of the higher activity and lower fill cost of HYT-1119 catalyst. For case 2, over \$1.36 million dollars could be saved over the cycle life of the catalyst. In addition, the longer catalyst life can provide additional benefits and cost saving benefits by extending shutdowns between skimming, replacing and/or regenerating.

		Base	Case 1	Case 2
Feed Rate	MBPD	42,513	49,174	63,185
Catalyst		HYT-1119*		
HDS Activity	°C	5.6	5.6	5.6
Fuel Savings	MBTU/hr	4.1	4.75	6.1
Refinery Fuel Gas	\$/MBTU	3.6	3.6	3.6
5 yr Fuel Gas Savings	\$1,000	646	749	962
Approximate lower				
fill cost	\$1,000	200	300	400
Total Savings/5 yr	\$1,000	846	1,049	1,362

Table 11	: Economic	Benefits	with HVT	-1119	Catalyst
I abit II	. Economic	DUIUIUS	WILLI II I I	-111/	Catalyst

Cycle length can be extended

Isomerization

Light naphtha, C_5 - C_6 , from the Naphtha Splitter overhead is sent to the Isomerization unit. UOP offers several isomerization designs in which the product RONC can range from ~82 to ~92.

- UOP Par-IsomTM Process design: ~82-85 RONC
- UOP PenexTM Process design: HOT Penex Hydrogen Once Through ~82-85 RONC
- UOP PenexTM design with Recycle: ~87-92 RONC

ParIsom Unit with PI- 242 or PI-244 Catalyst



Figure 18: ParIsom Flow Scheme

The Par-Isom unit uses PI-242 or PI-244 (lower Pt) catalyst, while the Penex Unit uses a chlorided alumina type catalyst. The PI-242/244 catalyst is robust to water and sulfur upsets and does not require a high chloride concentration; consequently, driers and caustic scrubbing for chloride removal are not required, reducing CAPEX. Both processes can produce 82 to 85 RONC without a liquid recycle.

UOP PI-242 and UOP PI-244 Par-Isom catalyst features and benefits:

• UOP's PI-242 or PI-244 offer an alternative to chlorided alumina catalyst with nearly equivalent selectivity and activity along with tolerance to contaminants such as sulfur and water.

Fully regenerable and long life

• Use of UOP Par-Isom catalyst can reduce the required catalyst volume from 10% to up to 50% compared to competitive products, thus reducing the fill cost. For new units, UOP Par-Isom catalyst can reduce catalyst and Pt fill cost by 58% and 63% respectively, along with reduction in CAPEX and OPEX.

Penex Process with I-122, I-82 I-84 chlorided alumina catalyts

Figure 19: Penex Process Flow Scheme



Table 12: Isomerization Catalyst Properties

Catalyst	Pt Content (wt%)	Feed Cyclics
I-82 catalyst	0.24	High-level
I-84 catalyst	0.18	Mid-level
I-122 catalyst	0.12	Very low level

A benefit of the Penex low coking tendency is that the unit could be designed for "Hydrogen Once Through" (HOT). In the HOT Penex process, recycle gas is not required, thus eliminating the need for a product condenser, product separator, stabilizer feed/bottoms exchanger and recycle gas compressor. The lower equipment and utility costs significantly lower capital expenditures (CAPEX) and operating expenditures (OPEX), and is the current standard design for Penex units. The product RONC is 83 - 85 RONC for a single hydrocarbon pass.

Penex Hydrocarbon Recycle Options

Paraffin isomerization is an equilibrium limited process; consequently, unconverted normal paraffins and other low octane isomers are present in the reactor effluent isomerate at near equilibrium conditions. The product octane can be increased to 87 - 92 RONC by separating these unconverted low octane components from the reactor effluent and recycling them back to the reactors for further isomerization. This separation and recycle can be accomplished via fractionation or selective adsorptive separation. The optimal selection of recycle scheme will depend on the refiner's requirements, feedstock and other site specific factors.

De-Isopentanizer (DIP) / Penex/Super De-Isohexanizer (DIH)

In UOP's DIP/Penex/Super DIH configuration, the fractionation scheme is designed to recycle low octane C_5 and C6 components to the Penex reactors to achieve the maximum conversion level and therefore the highest product octane number.

This scheme utilizes an upstream DIP column and a Super DIH column located downstream of the Penex reactor. The upstream DIP column separates iC_5 from the overhead. Unconverted C_5 's, normal hexane (nC₆), and methyl pentanes (MP) are recycled for higher octane. The Super DIH column products consists of C₆ side-cut, C₇⁺ product and iC₅ from the DIP overhead.

UOP has recently designed several DIP/Penex/Super DIH units for refiners to produce 91-91.5 RONC isomerate product. A simplified process flow of DIP/Penex/Super DIH unit is shown below.



Figure 20: DIP/Penex/Super DIH

UOP I-82 and UOP I-84 Penex Catalysts

I-82 catalyst is the highest activity, light paraffin isomerization catalyst commercially available. The catalyst is an amorphous, chloride alumina catalyst containing platinum and is a robust product for maximizing isomerate octane-barrels. I-82 is optimized for the UOP Penex process and is particularly suited for feedstocks that contain a high concentration of benzene and C_6 + cyclic hydrocarbons. The catalyst selectively converts normal butane, pentane and hexane to higher octane branched hydrocarbons. In addition, I-82 saturates benzene and is designed to operate over a wide range of reaction conditions and feedstocks.

I-84 catalyst is an extension of I-82 catalyst, but with lower platinum concentration and is suited for feedstocks which have a moderate levels of benzene and C_6 + cyclic hydrocarbons.

Gasoline Pool improvements with I-82 catalyst example

The following example shows the benefits of operating with I-82 catalyst and the impact on the gasoline pool. The base performance is with I-84 catalyst (25% less Pt than I-82) with a feed with a moderate X factor of 15 wt.% and with 2 wt.% benzene. "X" factor is variable used to define feed quality and PIN (Paraffin Isomerization Number) is used to define the product.

- Feed characterization: X-factor = C6 naphthenes + Bz + C7 paraffin + C7 naphthenes
- Paraffin Isomerization Number (PIN):

$$i - C5$$
 formation $_ratio = \frac{i - C5 wt \%}{i - C5 wt \% + n - C5 wt \%}$

$$22 DMB _ formation _ ratio = \frac{22 DMBwt \%}{22 DMBwt \% + 23 DMBwt \% + 2MPwt \% + 3MPwt \% + n - C6wt \%}$$

• PIN number: iC5 ratio + 22DMB ratio +23DMB ratio

Feed Conditions (Moderate): Benzene 2 wt. %; X factor 15 wt. %

Table 13: Economic Benefits with I-82 Isomerization Catalyst

		Base	Case 1	Case 2
		Arab		
		Med/WTI	Bakken/	Eagle
Crude		/Maya	WCS	Ford/WCS
Isom Feed X Factor			10	
Base Conditions with I-84				
Isomerate - Reformate	M Oct-BBLS	Base	Base	Base
Total Gasoline Pool	MBPD	84.6	86.4	83.2
Reformate RONC	RONC	99.8	102.0	101.3
Catalyst Change to I-82				
Isomerate- Reformate	M Oct-BBLS/D	8.3	12.0	13.7
Total Gasoline Pool	MBPD	84.7	86.6	83.4
Reformate RONC	RONC	99.5	101.5	100.8
Product Value inc	\$Million/yr	2.2	3.0	3.8

Low X Factor Feed (~5-15)

The yield and RONC/MONC benefits are dependent upon the X factor of the feed. The higher performance of I-82, even at a low feed X factor, improved the product value from \$2.2 million/year (Base Case) to \$3.8 million/year (Case 2). The higher isomerate RONC-BBLs allowed the CCR Platforming Unit to decrease severity and increased C_5^+ yields.

Figure 21: Product Value Increase with I-82 with varying X factor feeds.



CCR Platforming Unit

Heavy naphtha, C_7 +- C_{11} , from the Naphtha Splitter bottoms is sent to the CCR Reformer unit. The heavy naphtha is reformed to convert paraffins and naphthenes to an aromatics-rich reformate and hydrogen. Shown below is the process flow for the CCR Platforming Unit.



Figure 22: CCR Platforming Unit Process Flow

Process Flow

Hydrotreated straight-run naphtha is mixed with recycle hydrogen, then preheated by exchange with reactor effluent in the combined feed exchanger. The combined feed is raised to the reaction temperature in the charge heater and sent to the reactor section. The predominant reactions are endothermic; consequently, an interheater is used between each reactor to reheat to the reaction temperature.

Catalyst flows vertically by gravity down a reactor stack of 3 to 4 reactors. Over time, coke builds up on the catalyst and requires regeneration. Coked catalyst is continually withdrawn from the bottom of the last reactor in the stack and transferred to UOP's CycleMaxTM CCRTM regenerator for catalyst regeneration, consisting of four steps: coke burning, oxy-chlorination, drying and reduction. The first three steps of coke burning, oxychlorination and drying occur in the regeneration tower, while the fourth step, reduction, occurs in the reduction zone on top of the first reactor in the reactor stack.

The effluent from the last reactor is heat exchanged against combined feed, cooled and split into vapor and liquid products in a separator. The vapor phase is rich in hydrogen gas. This is compressed by the recycle gas compressor and split into two streams: recycle gas and hydrogen rich

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net gas. The recycle gas is recycled back to the reactors while the net gas is sent to the product recovery section.

The product recovery section consists of a recontacting and net gas compression scheme. Debutanizer receiver vapors are recycled back to the net gas compression to permit increased amounts of LPG and C_5^+ recovery. The net gas from the product recovery section flows to a Chiller System to further improve the recovery of both C_5^+ material and LPG, and then sent to a UOP PolybedTM PSA (Pressure Swing Adsorption) Unit for purification. The PSA Unit will separate the gas streams into high purity hydrogen net gas and low purity tail gas. Recovery of hydrogen and LPG are further enhanced by UOP's patented Tailgas Recycle scheme.

Unstabilized reformate from the product recovery section is fed to the Debutanizer column. Net gas from the overhead receiver is recycled to the product recovery section. The net overhead liquid from the Debutanizer is sent to the Sat Gas Plant. The Debutanizer bottoms are routed to gasoline blending.

Flue gas from the charge heater and interheaters are sent to a common convection section where high pressure steam is generated.

CCR Platforming Catalyst Options

UOP continues to develop new CCR Platforming catalysts to address customers' demands and deliver higher performance. UOP has an extensive catalyst portfolio, addressing various customers' needs for motor fuel and/or aromatics production. Figure 23 shows the evolution of UOP's CCR Reforming catalyst: R-134TM, R-234TM, R-264TM, R-254TM, R-284TM and new R-334TM catalyst.

The R-130 series catalyst was first commercialized in 1993. Features of the R-130 series catalyst are high activity (lower reactor inlet temperatures), good surface area stability and chloride retention.

Due to changes within the market, a low coke R-234 catalyst, was developed, providing an initial 20-25% lower coke make and higher C5+ yield vs. R-134 catalyst. R-234 catalyst also maintained the same excellent surface area stability and chloride retention as the R-130 series catalyst.

R-264 catalyst was developed specifically for customers who targeted to increase throughput to their unit. The R-264 is a high yield, higher density catalyst, providing an increased reactor pinning margin. For BTX (benzene/toluene/xylene) operation, the unit could be operated at higher feed rate, and coupled with the higher activity, maximum BTX is produced.

UOP also developed promoted catalyst, R-254 and R-284 catalysts, both providing significantly higher yields. There are over 10 units operating with R-254 catalyst and others with R-284 catalyst.

UOP's latest catalyst offering is R-334 catalyst, designating the first 300 series product. The R-334 catalyst is UOP's highest yield catalyst and also features long life, low coke. Table 14 shows the catalyst properties for R-234, R-254 and R-334 catalysts. It is interesting to note, the high yield R-334 catalyst does not include a promoter, obtaining the optimal performance by proprietary base and manufacturing technique.



Table 14: Catalyst Properties

Catalyst	R-234	R-254	R-334		
Shape	Sphere				
Pill Diameter	1/16 inch (1.6 mm)				
Surface Area	180 m²/g				
Density (ABD)	35 lb/ft ³ (560 kg/m ³)				
Pt Level	0.29 wt%				
Crush Strength	50+ N				
Promoter?	No Yes I		No		

MAXIMIZING PROFITABILITY WITH HIGH YIELD R-334 CATALYST

Several cases were evaluated in this paper, altering the crude blends. The following example quantifies the benefits of higher yields with R-334 catalyst for Case 2 (75% Eagle Ford/25% WCS). The feed composition and feed rate were kept constant, but the catalyst was changed from R-234 catalyst to R-334 catalyst.

The high yield R-334 catalyst reduces cracking, decreasing fuel gas, LPG and C5's. The benefits of R-334 catalyst include higher yield, but in addition, the reduced cracking reduces C5's, decreasing the reformate RVP by 0.2 psig (1.4 kilopascal). The reduction in RVP allows additional 110 BPD of C4's to be blended into the Gasoline Pool, while maintaining the 9 psig (62 kilopascals) RVP target.

		R-234	R-334	
Case		2		
Crude		Eagle Ford/WCS		
Feedrate	BPD	39,317 39,317		
Reformate	RONC	101.3	101.3	
Р	lv%	75	75	
N	lv%	16	16	
Α	lv%	9	9	
Product Yields			Delta	
H2	SCFB	1775	90	
Fuel gas	wt.%	2.57	-0.52	
C3	lv%	2.33	-0.53	
C4	lv%	2.8	-0.6	
C4 C5	lv% lv%	2.8 2.1	-0.6 -0.47	
C4 C5 C5+,	lv% lv% lv%	2.8 2.1 80.9	-0.6 -0.47 1	
C4 C5 C5+, C5+ RVP	lv% lv% lv% psi	2.8 2.1 80.9 2.1	-0.6 -0.47 1 -0.2	

Table 15: R-334 Yield Benefits

Figure 24: R-334 Catalyst Delta Yields



Table 16 summarizes the blendstocks used in the Gasoline Pool for Case 2, and Figure 24 is the delta yields (R-334 yields minus R-234 yields). The alkylate, FCC naphtha and Isomerate remain constant, with the reformate increasing 397 BPD to 29,966 BPD with an additional 110 BPD of C₄'s, increasing the Gasoline Pool by 507 BPD. The product value increase is \sim \$8.2 million/year.

Table 16: R-234 and R-334 Gasoline Pool Blend stocks

		Gasoline Pool		
		R-234 R-334 Delta		
C4	BPD	477	587	110
Reformate	BPD	29,569	29,966	397
Alklate, FCC Naphtha,				
Isomerate	BPD	53,151	53,151	
Total Gasoline Pool	BPD	83,197	83,704	507

R-334 Gasoline Pool benefit Summary:

- >500 BPD increase
- ~110 BPD C4 upgrade into pool
- ~\$8.2 million/year product value increase

SUMMARY

Processing lower cost tight oil shale crudes such as Bakken, Utica and Eagle Ford, coupled with heavy Canadian bitumens such as Western Canadian Select (WCS) provides significant margin opportunity, however presents new challenges. With higher light naphtha yields, optimizing the Naphtha Complex is a key component to profitability. This case study demonstrated that existing refinery configurations can be optimized to process a new crude diet consisting of tight oils and increase profitability. Profitability can be increased further when employing the latest high yield catalysts, such as:

- ~\$1.0 million/catalyst life can be obtained through lower fill and fuel costs benefits *with UOP HYT-1119 Hydrotreating catalyst* on a 40 MBPD NHT Unit.
- ~\$8 million/year can be obtained *with UOP R-334 Platforming Catalyst on a* 30 MBPD CCR Platforming Unit at ~101 RONC.
- ~\$4 million/year can be obtained with UOP I-82 catalyst (75% Eagle Ford/25% WCS). The higher isomerate octane-bbls allowed the CCR Platforming Unit to operate at lower severity, resulted in higher product values.

General Trends with Crude API's:

• Crude yields, properties, contaminants trend with API. The higher the API, light naphtha increases, vacuum residue decreases, contaminants decrease and paraffinicity increases. These trends are applicable within individual cuts. For example, tight oil diesel and naphtha cuts are more paraffinic, with low contaminants. WCS diesel cut is lower in paraffins, resulting in diesel with improved cold flow properties, but lower cetane.

Tight Oils (Higher API's) Trends:

- Lower Crude price key economic driver.
- Diesel Production decreases due to less upgrade of vacuum residue material. Diesel has higher cetane with poorer cold flow properties.
- Higher Light Naphtha yield, impacting Isomerization unit. NHT and CCR Platforming Unit rates also increase, but at a lower percentage.
- CCR Reformer feed paraffinicity increases. A feed paraffin increase of ~10 lv% decreases C5+ yields ~2-3 lv% (102 RONC) and increases coke make by ~20-30%.
- Isomerate and Reformate octane-bbls increase in gasoline pool; FCC naphtha and Alkylate decrease.

- Gasoline Pool barrels can decrease if the decrease in FCC naphtha plus Alkylate is greater than the increase in Isomerate and Reformate in pool.
- Processing Tight Oils can be unprofitable. A possible scenario would be if light naphtha cannot be blended into the gasoline pool (either due to process unit constraints, or gasoline pool RVP limits) resulting in excess naphtha being sold. Transportation costs and product demand impact profitability.

Canadian Bitumen Crudes (Western Canadian Select – WCS)

- Low API crudes with high contaminants and vacuum residue yield; typically diluted with pentanes (~5 lv%) to increase flow properties.
- Balancing the light tight oil crudes with a Heavy Western Canadian Select is important to maximize current assets.

UOP solutions for Optimizing a Naphtha Complex:

- *Naphtha Hydrotreating: Higher activity and lower fill cost with HYT-1119 catalyst.* For example, with a 40 MPBD NHT Unit, ~\$1.0 million/catalyst life can be obtained through lower fill and fuel costs benefits.
- *Isomerization: I-82 catalyst is a robust, high activity catalyst.* For a low X factor feed (~5-15), the higher isomerate octane-bbls allowed the CCR Platforming Unit to operate at lower severity and resulted in product values ranging from ~\$2.2 million/year (Base Case) to \$3.8 million/year (Case 2 75% Eagle Ford/25% WCS) vs. I-84.
- CCR Platforming: UOP introduces the first 300 series catalyst, R-334, with the highest commercial yields. The catalyst does not include a promoter, obtaining optimal performance utilizing a proprietary base and manufacturing technique. For a 30 MBPD CCR Platforming Unit at ~101 RONC, ~\$8.2 million/year can be obtained.

Processing light tight oil crudes with heavy Canadian bitumen presents new challenges to refiners. UOP has developed new products to meet our customers' needs, and coupled with process design, technical service solutions can assist refiners to maximize current and future assets.

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