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Troubleshooting Hydrotreater Performance: Part I

A comprehensive review of operating parameters and performance issues affecting ULSD hydrotreater

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A systematic approach to troubleshooting hydrotreater performance provides a methodology for unexpected problems. Hydrotreaters are looked upon in refinery operations as relatively reliable units. Nonetheless, there are unexpected performance issues that occur periodically. For these instances, a methodology has been developed. Various parameters affecting hydrotreater operation are examined in order to resolve the problem, or at least identify what the problem is so that it won't happen again.

The key parameters of feed properties and operating conditions are usually the source of most hydrotreating performance issues, followed by the impact of start-up procedures on unit performance. This is why it is important to maintain good records during startup loading and sulfiding. Record keeping allows for a review and identification of any irregularities during the start-up procedure. Suggested test runs also tend to be valuable in isolating the source of a problem and developing a solution.

Impact of feed contaminants on catalyst performance

Many of the feeds currently processed in refining facilities were not on the market 20 years ago. Contaminants in these feeds may not have been expected, including their effect on catalyst performance.

The onset of a performance problem coincides when the operator begins to see less than expected results expected from the hydrotreater. It has been ART's experience that the first course of action by the refining community is to attribute the problem to catalyst performance. Nonetheless, the facility's catalyst vendor should be contacted to help assist in solving the hydrotreater's performance issues.

The catalyst vendor typically has a very broad base of experience in hydrotreaing, more so normally than the staff on the given hydrotreater at the refinery. The first step would be to examine the certificate of analysis of the catalyst shipped to the refinery and ensure that all the parameters are within specification. In some cases, a pilot plant activity test should be in order to confirm the catalyst's performance prior to loading into the unit. At this stage, most of the catalyst parameters and activity are within specification, so the refiner can proceed on to the next troubleshooting step of examining whether the feed and operating conditions are as expected.

Actual feed properties should be compared with expected properties, including feed API or density, feed boiling range (especially the tail end!) and feed composition, such as percent cracked stock (visbreaker gasoil, LCO, coker gasoil, etc.), as well as olefins content or Bromine Number of the feed composition, and feed contaminants, including:

- Nitrogen
- Sulfur
- Conradson carbon residue (Concarbon) and microcarbon residue (MCR), especially in VGOs or heavier feeds
- Poisons (Ni, V, Fe, Na, Si, As, etc.)
- Asphaltenes (an indication of entrainment of residual oils in heavier feedstocks).

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The expected feed properties are those properties listed in the "Invitiation to Bid" (ITB) that the refiner sent to the vendors. For example, did the refiner note feed poisons such as Ni and V in the ITB? Those feed properties are a key component in the performance estimate.

The previously noted feed boiling range is a very important parameter, particularly in ULSD where the kinetics for making 10 ppm (or less) diesel is very strongly dependent on the most difficult sulfurs to remove. Those sulfurs tend to be the ones that are in the highest boiling range (i.e., at the tail end of the feed). Therefore, if the tail end range is greater than expected, it will have a significant impact on the performance of a ULSD hydrotreater.

ART would normally suggest a simulated distillation of the feed instead of just a D86 distillation. Simulated distillation of the feed provides a much better indication of a "tail" if it indeed exists. It only takes a few percentage points increase at the tail end to make a huge difference in unit performance.

Feed composition is another important parameter. For example, the percentage of each component in cracked stock (e.g., visbroken gasoil, LCO, coker gasoil, etc.) and the component's properties need to be determined. In addition, olefins in the feed are easy to convert, but they do release a significant amount of heat, which can impact unit performance. They also consume a significant amount of hydrogen, which will impact hydrogen partial pressure, particularly at the bottom of the reactor.

SOR Activity Evaluation

In one refinery evaluation (40 days onstream) that began with a two-week start of run (SOR), the WABT temperature was actually 20-25 °F higher than expected using feed provided by the refiner. Loading and sulfiding went according to plan and the analytical and activity testing on samples from the lots met expectations. However, the expected SOR temperature should have been closer to 640 °F while the actual SOR temperature required to produce 10 ppm sulfur diesel was actually in the 660-665 °F range. Temperature was then reduced to the 610-575 °F range for about 10 days to produce 300 ppm sulfur diesel. Thereafter, operating severity had to be increased to a WABT in the 680-710 °F range to achieve 10 ppm sulfur diesel. This higher severity relative to the WABTs observed during SOR coincided with the degree of catalyst deactivation rate associated with the feed.

Table 1. Feed Properties Case Study: Expected vs Actual.

Feed Composition	Expected	Actual
Vol % LCO	20	34
LCO Properties		
D2887 EP, °F (°C)	724 (384)	794 (423)_
Sulfur, wt%	0.51	0.7
API Gravity	25.6	19.2
Nitrogen, ppm	393	790
Hard Sulfur, ppm	1227	4034

As can be seen in **Table 1** listing six feed properties, there was a significant difference in the actual feed properties relative to the expected feed properties initially supplied by the refiner in the ITB. For example, the actual nitrogen content was twice as high as the expected nitrogen content. This higher nitrogen content is a key parameter in desulfurization kinetics and acts as an inhibitor for removing the hard sulfur, which may explain why the hard sulfur component was about three times as high as the expected values.

These observed changes in the six feed properties easily accounted for the previously noted 20-25 °F (11 °C) higher WABTs required to make 10 ppm sulfur in diesel. Also, the refiner had a lot of LCO in storage at the beginning of the run, which they wanted to process quickly, resulting in 40-60% LCO being processed very early in the run. This high LCO content would also cause significant coking on a freshly sulfided catalyst and result in some irreversible activity loss.

Key Operating Parameters

In reviewing the impact of key operating parameters, comparing actual operating parameters to what was expected in the ITB include:

- Feedrate/LHSV
- Make up H_2 rate, availability and purity
- Recycle rate and purity (i.e., gas rate parameters significantly impacting unit H_2 partial pressure)
- H_2S concentration in treatgas
- Operating temperature profile.

In another case comparing actual vs expected conditions, the WABT for a low sulfur diesel operation was about 35 °F higher than expected. The performance estimate in the proposal was actually based on 2.0 vol% H_2S in the recycle gas In actual operation, the H_2S in the recycle was 8-10 vol% and H_2 purity between 60-65 vol%, significantly lower than the ITB.

In reviewing the impact of H_2S, there was a 15-20 °F activity debit when increasing H_2S from 0 to 4.75%, followed by another 15 °F debit when H_2S is increased to 9.5%, which is within the range that the refiner was actually operating. The H_2S in the treat gas therefore accounts for the 35 °F activity loss at SOR. This will exist for as long as level of H_2S is present.

Another ULSD case focuses on the much of the refining industry's tendency to "over-convert," as was typical during the 2006/2007 time frame when refiners were producing the first full cycle of 10 ppm sulfur in diesel. The tendency to over-convert was to ensure that sulfur in diesel met specifications. So in many cases, refiners targeted a sulfur ppm value lower than what was listed in the ITBs. For example, sulfur conversion values below 10 ppm (e.g., Product S: 13% < 8 ppm and 2% < 5 ppm) were produced between SOR to Day 216, yielding a relatively modest deactivation rate of 1.1 °F/mo, which was well within the estimation for achieving a two year cycle length.

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For some reason after Day 216, the refiner significantly increased severity, so that 65% of product sulfur was less than 8 ppm and 20% was less than 5 ppm. The deactivation rate jumped to 5.6 °F/mo, putting the unit on a course where meeting the two-year cycle length was not feasible. Several operating reports were issued to the refiner during this time frame strongly recommending a reduction in severity. Reduced severity and product sulfur control closer to 10 ppm lowered WABT by about 14 °F and deactivation rate was stabilized, allowing the refiner to meet their targeted cycle length. This clearly demonstrates how over-conversion can be very detrimental to deactivation rate.

Loading and Sulfiding Guidelines

Sulfiding and loading procedures and processes should then be targeted if feed properties and operating conditions meet expectations.

Catalyst wetting with feed is important for best in-situ sulfiding performance, preferably at maximum liquid rate for good flow distribution. Catalyst is dry when it is loaded, so an exotherm will develop when oil is first passed over the dry catalyst (i.e., heat of absorption). Complete catalyst wetting allows this heat of absorption to essentially pass through the unit before beginning the sulfiding process. This provides better control by avoiding the addition of the exortherm from the sulfiding process on top of the exortherm from the prior heat of absorption (from catalyst wetting).

Also, the catalyst should never be left for extended periods in hydrogen at temperatures and pressures greater than 450 °F and 435 psig, respectively, as there is a potential to reduce the metals (i.e., Ni, Co and Mo). The Ni or Co will go into the metallic state while the Mo will form MoO_2. These resulting materials will not sulfide, so the operator will have essentially lost a significant portion of the active metals in the catalyst. Temperature should be reduced if there is a need to shutdown or put the startup on hold for any given length of time due to mechanical issues. This helps avoid possible metals reduction and/or coking and subsequent catalyst deactivation. Therefore, the exotherm should be controlled to less than 30 °F.

Half the sulfur should be consumed during the low temperature sulfiding step. Consumption less than that is an indication there may be some problems with bypassing or maldistribution. The oil used for sulfiding should be straight run (SR) so that there are no olefins or other material that could lead to coking. The SR should preferably have a final boiling point (FBP) of less than 670°F, while the final temperature should be in the 600-650°F range, typically depending on the unit's capability. For example, naphtha hydrotreating units can approach 650 °F. To avoid high levels of coking at SOR and irreversible loss of catalyst activity, use of cracked stocks should be avoided for at least three days after sulfiding completion, and then gradually introduced.

In another diesel ULSD unit case study (200 days onstream: 4.0 LHSV, 600 psig, 850 SCFB H_2/Oil ratio), problems during sulfiding lead to the catalyst having to be dumped, regenerated and loaded back into the unit and sulfided properly. The actual SOR temperature was about 35-40°F higher than the expected 660 °F SOR temperature, with a significant deactivation rate (i.e., about 40 °F activity loss) over the course of 200 days. This could not be explained by feed and operating conditions, which were in the expected range. The catalyst lot analysis was favorable and loading densities were also consistent with expectations. However, problems during sulfiding included premature H_2S breakthrough during the low temperature sulfiding phase and it was observed that only about 1/3 of the sulfur was consumed.

There was also a mishap and the feed rate decreased resulting in a large exotherm with 610°F inlet temperature and outlet reaching 662°F. The final temperature hold was too short. Instead of holding for several hours, the final high temperature hold was less than 30 minutes, essentially reaching EOR after only 200 days. The catalyst was dumped at this point, as previously noted, and sent to a local regenerator for ex-situ regeneration. The same catalyst was then loaded back into the unit and sulfided properly. Proper sulfiding resulted in a significantly improved second cycle with a much lower deactivation rate allowing closer to 470 days on stream. Even though the properly sulfided catalyst in this second cycle was regenerated, it closely met expected WABTs at SOR.

Temperature Response

Engineers should focus on temperature response if there are no operational issues with loading and sulfiding. If the reactor temperature response is unusually low the problem may be due to recombination (particularly with naphtha hydrotreating), hydrogen starvation, feed bypassing the catalyst and equilibrium limited reactions (e.g., polynuclear aromatic [PNA] hydrogenation).

To determine the occurrence of hydrogen starvation, H_2 requirements should be calculated and compared to available H_2. Feed bypassing the catalyst may be occurring due to a leaking feed/effluent heat exchanger or feed going to a bypass line. Most reactors have a feed line that bypasses the reactor, which is why it should be determined if a valve is not cracked, allowing raw feed into the separator and mixing with finished product. A leaking feed/effluent heat exchanger also puts raw feed into the finished product.

In some cases, if aromatic ring saturation is the end result, equilibrium can start controlling the reaction as opposed to the kinetics, especially at EOR and higher temperatures, in which case there will be a relatively low temperature response.

Mercaptan Recombination

Problems with mercaptan formation, particularly with naphtha hydrotreating at very low sulfur levels, occur due to the recombination reaction between olefins and H_2S. Even though H_2 partial pressure may be relatively high, there is always an equilibrium between the paraffin and the olefin. While the select hydrotreating catalyst in use may be a good hydrogenation catalyst, all hydrogenation catalysts are also good dehydrogenation catalyst Cont. page 4

as well! This is why there will always exist an equilibrium of partial pressure olefins, which can lead to mercaptan formation (depending on H_2S concentration). The reaction is favored by:

- High temperature and low, relatively constant H_2 pressure (i.e., EOR conditions at bottom of naphtha hydrotreating reactor). As cycle continues and catalyst slowly deactivates, the olefins concentration increases with increasing temperature, generating measurable quantities of mercaptans
- High H_2S concentrations will also favor mercaptan formation if sulfur concentration in feed is relatively high
- Processing cracked feedstocks (e.g., VB/coker naphtha) negatively impacts H_2 partial pressure at the bottom of the reactor because these cracked materials consume excess hydrogen while also generating relatively large exotherms in saturating the olefins, essentially, reducing e hydrogen pressure and increase temperature at reactor outlet.

In a mercaptan recombination case study where SR naphtha was processed at 8.0 LHSV, 410 psig and 400 scfb H_2/oil ratio, 0.5 ppm sulfur target was not met because reactor temperature was set higher than the proposed SOR temperature of 600 °F.

At this point, it should be mentioned that in most cases, the refiner doesn't operate the naphtha hydrotreater in the same mode as the FCC pretreater or ULSD units, where there is daily feed and product analysis and temperature is constantly controlled to maintain product sulfur target levels. In many cases, the refiner will select and maintain a naphtha hydrotreater temperature where they estimate a product sulfur specification of less than 0.5 ppm can be met.

It has been our experience that the refiner will then not "bother" looking at daily product analytical data until they encounter an operational issue with the naphtha reformer. They will then begin to review the analytical data to perform the required temperature adjustment. Therefore, this is not an uncommon scenario that the refiner selects a temperature and just sets it there.

In this case, the refiner further increased temperature when the 0.5 ppm sulfur target was not being met, resulting in even higher sulfur levels (i.e., from about 0.6 ppm S to 1.2 ppm S between 610 and 630 °F, respectively). This indicated to ART that the unit was encountering recombination reactions and a reduction in inlet temperature to the proposed 600 °F or below was recommended. Sulfur levels then decreased well below 0.5 ppm while also eliminating recombination reactions and mercaptans generation.

Future Case Studies

The next issue of *Refinery Operations* will further examine the effects of H_2 availability, liquid maldistribution, radial temperature spreads, feed rate response, flow rate tests and feed contaminant effects on hydrotreater performance as summarized from the Spring 2011 ART Webinar on "Troubleshooting Hydrotreater Performance." ■

The Author

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INDUSTRY NEWS

IEA Cautious About Future of Refining Industry

Given sluggish economic recovery, soaring oil prices, new plant additions and tight margins, the future of global refining is still in the shadow of uncertainty and the outlook remains bearish throughout 2011. On top of that, the global refining industry is experiencing growing pains as it undergoes rationalization and consolidation. Refineries are being shut down and put up for sale as refining capacity eclipses falling post-recession demand.

The International Energy Agency (IEA) says global oil demand will be lower than previously expected in 2011, as high oil prices pressure the global economy. Moreover, the recent unrest in the Middle East and the knock-on effects of the tsunami and nuclear disaster in Japan all have the potential to slow down, if not derail, global economic recovery.

The global refining industry has now endured more than two years in a difficult operating landscape, but in spite of plant closures reducing production by around 1.6 million bpd and a partial resurgence in oil demand – there are little signs of a sustained margins recovery.

The IEA projects global refining output to rebound to 75.3 million bpd when the seasonal refinery maintenance peaks this month (June). At the moment, the IEA estimates global refinery throughput to have dropped to a seasonal low of 73.5 million bpd (in March) due to spring maintenance. ■

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PetroChina Will Continue Buying Refineries

PetroChina Co Ltd , Asia's largest oil and gas producer, plans to produce half its oil and gas from outside China and double its trading volumes by 2015, but isn't looking to make major foreign acquisitions, its chairman recently said.

China's top state-owned energy firms have been aggressively expanding on the international stage as they look to not only secure energy supplies to feed the country's rapid growth, but to reduce their reliance on a market where profits are crimped by state-set controls on fuel prices.

PetroChina aims to produce 400 million tonnes of oil equivalent by 2015, with half coming from existing overseas projects, Chairman Jiang Jiemin told a news conference.

The company was able to achieve its 200 million tonnes overseas production target without making more acquisitions, Jiang said.

PetroChina has been flexing its muscles across the world, expanding its international trading network and buying refineries over the past few years, a departure from the days when its state-owned parent, China National Petroleum Corp, led the overseas expansion.

Outside of China, PetroChina will focus on Central Asia, the Middle East, Africa, South America and the Asia-Pacific region for cooperation in both upstream and downstream businesses in the next five years, Jiang said. ■

China Agrees to Invest in Cuban Oil Refinery

The *Associated Press* reported on June 7 that Cuba and China have signed a series of economic accords that include the expansion of an oil refinery in Cienfuegos. Officials say the refinery agreement is a joint plan by Cuban-Venezuelan oil company Cuven Petrol SA and China's Technip Itali SA. They also plan a liquid natural gas project. Precise details are not available. The accords were signed during a visit by Chinese Vice President Xi Jinping, who is widely expected to be the nation's next leader. China is Cuba's No. 2 commercial partner after Venezuela.

A June 5 report from the *Ghana News Agency* (GNA) says that the management of New Alpha Refinery-Ghana, a South African based company with a subsidiary in Ghana is undertaking feasibility studies to establish a tank farm and second refinery in Ghana. The refinery will be located in the Western Region in addition to the establishment of a power-generation plant using gas turbines. Mr. Merlyn Julie, Executive Chairman of New Alpha Refinery Ghana, speaking to the GNA in Accra, said management was equipping itself to train personnel for the oil and gas industry. "We envisage providing jobs for about 4,800 to 5,000 people," he added.

Mr. Julie said management was negotiating with the Ministry of Energy and other stakeholders as well as the landowners to fast track the proposal and conduct a technical audit to enable them to use Tema Oil Refinery (TOR) as a module for the training. "The project, which comes with import and export facilities; a tank farm and a gas turbine, will have the capacity to process 200,000 bpd. This will be more than quadruple the capacity of TOR whose output is about 45,000 bpd," he added. Mr. Julie said the company would supply neighboring countries with refined products such as gasoline and jet-fuel.

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On the need for an additional refinery, Mr. Julie said this was necessary because of Ghana's rising consumption of petroleum products of about three billion litres annually compared to TOR's capacity of 45,000 bpd, which was inadequate to keep up with the trend despite imports of refined products from Europe to augment its output. "Construction of an additional refinery is deemed more than just welcome news: it will improve local manpower capacity for the hydrocarbon industry and create jobs," Mr. Julie said.

He explained that European refineries had been operating at all time high, with nearly 30 cargoes traversing the Sub-Saharan African shores on a monthly basis, with Nigeria alone receiving about 10 of these cargoes. "Ghana's ability to export refined products to neighboring countries will be a strategic economic venture," he added. The company has initiated a feedstock agreement with Nigeria and Mali to buy feedstock (crude oil) and set up an off-take agreement in return to sell the refined products to them. According to project consultants in South Africa, all layouts and technical issues are being concluded and are confident of a successful implementation. ■

Refiners in Flooded Regions Returning to Full Operations

One U.S. refinery near the rain-swollen Mississippi River had started to return operations to normal at the end of May as flood waters receded. Exxon Mobil Corp's 504,500 bpd Baton Rouge refinery reopened its Mississippi River docks. Refinery production has been cut by at least 10% since the docks were shut on May 11.

Alon USA Energy's 80,000 bpd Krotz Springs, Louisiana, refinery, remained shut at the end of May as high water levels on the Atchafalaya River cut off crude oil shipments. Other refineries, all located along the Mississippi, continue to operate. Scores of U.S. heartland rivers from the Dakotas to Ohio have flooded following a snowy winter and heavy spring rains, feeding near-record crests on the lower Mississippi River. There are 10 refineries located along the Mississippi and Atchafalaya rivers that can process 2.4 million bpd of oil, or 13.7% of the country's refining capacity, including:

- Alon USA Energy Krotz Springs, Louisiana : 80,000 bpd
- Chalmette Refining, Chalmette, Louisiana: 192,500 bpd
- ConocoPhillips, Belle Chasse, Louisiana: 247,000 bpd
- Exxon Mobil Corp, Baton Rouge, Louisiana: 504,500 bpd
- Marathon Oil Corp, Garyville, Louisiana: 436,000 bpd
- Motiva Enterprises, Convent, Louisiana: 235,000 bpd
- Motiva Enterprises, Norco, Louisiana: 234,700 bpd
- Murphy Oil Corp, Meraux, Louisiana: 120,000 bpd
- Valero Energy Corp, Memphis, Tennessee: 180,000 bpd
- Valero Energy Corp, St. Charles, Louisiana: 185,000 bpd.

While refiners are operating at lower capacity, U.S. gasoline inventories remain high, rising almost 1.3 million barrels to about 206 million barrels, based on the U.S. Energy Information Administration's (EIA) most recent weekly data. Total U.S. gasoline inventories are just 1% percent below the prior five-year average. ■

PROCESS OPERATIONS

Advances in Vacuum Unit Technology and Operation

Vacuum distillation process has become an important chain in maximizing the upgrading of crude oil. As distillates, vacuum gas oil (VGO), lubricating oils and/or conversion feedstocks are generally produced. The residue from vacuum distillation can be used as feedstock for further upgrading, as bitumen feedstock or as fuel component. The technology of vacuum distillation has developed considerably in recent decades, such as the vacuum unit shown in **Figure 1**. The main objectives have been to maximize the recovery of valuable distillates and to reduce the energy consumption of the units. For example, the direct fuel consumption of modern and efficient vacuum units is 1.0% in intake, depending on feed quality.

At the flash zone where the heated feed is introduced in the vacuum column, the temperature should be high and the pressure as low as possible to obtain maximum distillate yield. The flash temperature is restricted to about 420 °C (788 °F). In the older type high vacuum units the required low hydrocarbon partial pressure in the flash zone could not be achieved without the use of "lifting" steam. The steam acts in a similar manner as the stripping steam of crude distillation units. This type of units is called "wet" units.

One of the latest developments in vacuum distillation has been the deep vacuum flashers, in which no steam is required. These "dry" units operate at very low flash zone pressures and low pressure drops over the column internals. For that reason the conventional reflux sections with fractionation trays have been replaced by low pressure drop spray sections. The steam consumption of the dry high-vacuum units is significantly lower than Cont. page 5

that of the "wet" units. They have become net producers of steam instead of steam consumers. Three types of high-vacuum units for long residue upgrading have been developed for commercial application:

- Feed preparation units
- Luboil high- vacuum units
- High - vacuum units for bitumen production.

These units will be discussed in the upcoming September special report sponsored by Process Consulting Services: Innovations in Crude Unit Design and Optimization. ■

Consider Importance of Role Played by Hydrocracking Catalysts in Combining Effectiveness of Thermal and Catalytic Reactions

In a recent June 1 blog posting on *Chemical Engineering Processing* by Marten Ternan, CANMAR Engineering, Inc., "Vacuum Residue Hydrocracking Catalyst for Hydrogen Addition," Ternan provides selected literature describing catalytic hydrocracking of reaction mixtures containing vacuum residue (i.e., molecules having nominal boiling points greater than 525°C [977 °F]).

The Ternan report begins by covering the fundamental objectives with residue hydrocracking noting the two essential changes required for the conversion of the large molecules present in vacuum residue. The size of the molecules must decrease and the atomic H/C ratio must increase if the products are to become useable as conventional fuel products. Although heteroatom removal reactions (hydrodesulfurization, hydrodenitrogenation, hydrodeoxygenation, and hydrodemetallization) are also necessary, by themselves they are not sufficient. Ternan notes that catalysts can have a large impact on hydrocracking processes even though considerable conversion occurs concurrently via thermal non-catalytic reactions. ■

Approaches on Evaluation and Selection of Hydrotreating Catalysts for Resid Upgrading

A paper presented at the 22nd North American Catalysis Society meeting during the first week of June by A. Marafi and E. Kam from the Petroleum Refining Department, Petroleum Research & Studies Center, and Kuwait Institute for Scientific Research (KISR), respectively, introduces atmospheric residue desulfurization (ARDS) as one of the major processes operating at refineries worldwide for upgrading petroleum residues to more valuable clean products. Due to the importance of the process, research and development related to the process and its' catalysts have gained increasing attention internationally. The presentation by Marafi and Kam address the efforts made at their facilities to develop the required testing methodology for evaluating and selection of ARDS catalysts. The study includes details on the necessary experiments, operating conditions and essential parameters required to generate the data needed for ARDS catalyst system performance. ■

Western Refining Reduces Wiring Costs, and Improves Performance with Honeywell OneWireless

At Western Refining's Gallup, New Mexico, refinery, process unit and tank operations have been upgraded using Honeywell's OneWireless technology, as per a detailed paper concerning this successful implementation to be presented by Reginald Joseph, Sr. Process Controls Engineer, Western Refining, at the June 21 Honeywell User's Group Symposium.

Briefly, this advanced wireless mesh network has proven to be a reliable, cost-effective solution for a wide range of process plant applications. Based on Western Refining's experience, wireless is a desirable alternative in applications where traditional copper wiring often brings not only

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added cost, but also high maintenance and unreliability. With wireless, plant infrastructure investments reduce immediately, and the ROI can be significant. Projects that previously could not occur now become immediately worthwhile.

For Western Refining, wireless has proven to be a desirable alternative to traditional copper wiring, which brings not only added cost, but also high maintenance and unreliability. ISA100 DSSS wireless transmitters can be used to monitor a variety of processes and assets in hazardous and remote areas, and this data can be utilized in a variety of systems.

Wireless frequency hopping spread spectrum technology also adds security and ensures that noise interference at any one frequency does not block communications or cause security concerns. A single, scalable wireless network conserves spectrum and power.

Furthermore, the wireless installation was fast, inexpensive, and easy. Operators, engineers and technicians have one system to learn, operate and maintain. Wireless allows plant personnel to react quickly to changing conditions, and gather information they need to optimize processes. Plant infrastructure investments reduce immediately, and significant ROI can be realized. I/O costs have been significantly lowered, and projects that previously could not occur now become immediately worthwhile.

According to the paper by Reginald Joseph, by 2011, Western Refining plans to install more than 100 Honeywell wireless transmitters throughout the Western Refining Gallup refinery for various process monitoring tasks, as well as non-critical control applications. Wireless instrumentation will be installed on at least six additional process units. ■

EDITORIALLY SPEAKING

New Feedstocks Sources Replacing Foreign Crudes in Spite of Processing Challenges

Global markets need extra oil as refinery demand is about to rise. According to a recent Reuters report, Fatih Birol, chief economist for the International Energy Agency (IEA), told Reuters reporters that "There is a need for more oil in the market, and we hope producing countries are reading the market signals in the way we are. We are already seeing the impact of high oil prices in the U.S. and China," he said, adding that US economic data was showing slower growth rates while inflationary pressure in China was on the rise. What may be more important for many refiners is the introduction of different types of feedstocks and the impending process and operational challenges that refiners are facing with these feedstocks.

The Reuters report also noted that OPEC is considering raising oil supply targets for the first time since 2007 to prevent prices from soaring further, and sources said that the most likely outcome would be for a rise of 1.0 million bpd. But traders said that such an increase would have a soothing effect on oil prices only if it meant a rise of a million bpd above current production levels, and not just an increase above OPEC's targets set over two years ago. The 11 members bound by OPEC production targets, all except Iraq, pumped 26.23 million bpd in May, nearly 1.4 million bpd above their 24.84 million bpd target.

Total world oil demand is expected to rise from 88.21 million bpd in the current quarter to 89.91 million bpd in the third quarter and to 90.16 million bpd in the last quarter of 2011, according to the Paris based International Energy Agency's (IEA) latest figures.

Birol also said that global refinery demand will grow by 3-3.5 million bpd this summer as refiners ramp up activity to meet seasonally higher oil product demand reflecting factors including the resumption of the driving season in the United States. An ongoing drought in China is also likely lead to increased use of diesel generators, he said.

As previously noted, the introduction of different types of "unfamiliar" feedstocks is another challenging factor facing refiners. For example, the rapid increase in production of high API gravity Eagle Ford Shale crude in South Texas is low in sulfur, and is also valued because its crude oil and natural gas rich liquids can be stripped out and sold for a premium to refiners.

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However, it is a quietly held secret that this "high quality" crude is causing some challenging corrosion issues in refinery operations. To be sure, this is a relatively new feedstock and technology licensors and refiners will no doubt work closely in resolving processing challenges encountered with these crudes, as the current 61,000 bpd production of Eagle Ford Shale crude may increase to 410,000 bpd by 2015.

Resolution of these feedstock processing challenges will provide a competitive edge to certain "regional" refiners that are not otherwise competitive on a global scale. For example, NuStar Energy L.P. recently (April 2011) closed on its $41

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million acquisition of certain refining and terminal assets of the bankrupt AGE Refining, a small, low complexity 14,500 bpd refinery in San Antonio, Texas.

"This relatively small transaction is a great acquisition for our investors, employees and community," said Curt Anastasio, President and CEO of NuStar Energy L.P. and NuStar GP Holdings, LLC. "We can lock in guaranteed margins through the futures market for crude, distillates and gasoline-related products for the next three to four years. So we expect the refinery to generate attractive returns, and it is projected to be immediately accretive to our earnings and distributable cash flow."

The refinery purchases and processes crude oils and condensates from across South Texas, including the rapidly developing Eagle Ford Shale. It produces and sells various products, including jet fuels, ultra-low sulfur diesel (ULSD), naphtha, reformates, liquefied petroleum gas (LPG), specialty solvents and other highly specialized fuels, to commercial and retail customers and the U.S. military.

In addition, Valero Energy's 93,000-bpd refinery near San Antonio is processing crude oil from the Eagle Ford Shale, said Bill Klesse, chairman, president and CEO of Valero. The facility is operating 27,000 bpd of Eagle Ford crude and is expected to run 60,000 barrels per day before 2011s end. "This is replacing foreign crude," Klesse said.

Production from the Eagle Ford Shale formation in Texas could eventually reach 750,000 to 800,000 bpd, industry observers say. "The numbers get bigger every time we look," Mark Hurley, vice president of Enterprise Products Partners' oil and offshore business, said during an energy conference in New York.

Flint Hills Resources, an independent subsidiary of privately held Koch Industries Inc, said recently that it finalized a deal to receive Eagle Ford Shale crude and condensate into its facilities in Corpus Christi from Anadarko Petroleum Corp's holdings.

For some refiners, global oil market and refining challenges are no doubt being tempered by these regional opportunities. ■

FACILITY UPDATES

Refinery Operational Status Updates (May/June 2011)

Country	Company	Facility	Capacity	General Comments
China: Northeast province of Liaoning. Largest PetroChina refinery	PetroChina Co. Ltd	Dalian refinery	20.5 million tonnes/yr or 410,000 bpd	Repairs to 10 million tonne/yr CDU (200 kbpd) in May 2011. Unit will be down for about one month. Half of feedstock sour crude from M.E. Current plans are to to process 3.0 to 3.3 million tonnes of Russian ESPO Blend in 2011. Facility also runs sweet Sudanese Nile Blend Crude & sweet West African crude.
India: Located at Vadinar, Gujarat in central state of Madhya Pradesh	Bharat Oman Refineries Ltd. (BORL)	Bina Refinery	6.0 million metric tonnes/yr	New Bina Refinery dedicated in May 2011 to produce Euro III & IV petroleum products. New facility also has "inbuilt" flexibility to meet Euro-V equivalent standards for petrol & diesel w/minimal investment. $2.0 billion facility has bottom upgradation facility to ensure yield maximization with flexibility to process all types of crudes.
Oman	Oman Refineries & Petrochemical Co.	Sohar	187,000 bpd	CB&I awarded FEED & proj. mgmt. services in 1st quarter 2011 for the "Expansion Project" that will increase capacity from 116 Kbpd to 187 Kbpd. Also debottlenecking existing units. Contract value @ $40 million.

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Country	Company	Facility	Capacity	General Comments
United States: Pennsylvania	Sunoco, Inc.	Philadelphia	335,000 b/d	Sunoco, Inc. on May 5 said it had traced problems at Philadelphia refinery to maintenance work it completed between 2007 & 2009. All units now operating at full rates as of May 26.
United States: Pennsylvania	Sunoco, Inc.	Marcus Hook	178,000 b/d	Sunoco on May 5 said utilization rates at all of its northeast U.S. refineries were as low as 74% in first quarter 2011.
United States: Joliet, Illinois	ExxonMobil	Joliet Refinery	238,000 bpd	Reuters news agency reports SRU failure on May 9, 2011.
United States: Aruba	Valero	Aruba Refinery	235,000 bpd	Valero reported in mid-May, 2011 that it had returned its Aruba CDU to planned rates after shutting down April 27, 2011 to repair a leak.
Canada: Alberta	Suncor Energy	Edmonton	135,000 bpd	Recently upgraded to run 100% oil sands feedstocks.
Canada: Quebec	Suncor Energy	Montreal	130,000 bpd	Recently upgraded to produce gasoline, distillates, asphalts, petrochemicals, solvents, heavy fuel oil, feedstocks for lubricants.
Canada: Ontario	Suncor Energy	Sarina	85,000 bpd	Recently completed TAR and $1.0 billion investment for low sulfur diesel and improved operational efficiency. Refinery produces kerosene, jet, diesel.
United States: Colorodo	Suncor Energy	Commerce City	93,000 bpd	Recent $445 million upgrade enables clean fuels production and oil sands processing. Products include gasoline, diesel & paving grade asphalt.
United States: Ferndale, Washington	BP	Cherry Point refinery	225,000 bpd	Restarted CDU, coker & reformer on May 24 that had been shut down since April 11 for maintenance.
United States: Pasadena, Texas (Houston ship channel)	Pasadena Refining Systems, Inc. (Petrobras subsidiary)	Pasadena refinery		The refinery's 100,000 bpd FCC unit that was originally scheduled to be restarted on May 9 was restarted on May 24.
Brazil: Rio de Janeiro state	Petrobras	Comperj	165,000 bpd	Capacity could double as per the possibility of increasing project scope included in Petrobras' 2010-2014 business plans.
Venezuela: Paraguana Complex in N.W. state of Falcon	PDVSA	Cardon	305,000 bpd	Explosion in an FCC furnace occurred on May 24, 2011. Refinery has been offline since mid-May due to power outage.
Venezuela: Paraguana Complex in N.W. state of Falcon	PDVSA	Amuay	640,000 bpd	Amuay refinery partially affected by same power outage that shut down Cardon refinery on May 11. Entire PDVSA refining network continues to encounter operational problems going into summer 2011.

CALENDAR OF EVENTS

JUNE

13-14, *The Global Catalyst Technology Forum*, Euro Petroleum Consultants, Dubrovnik, Croatia, +44 (0) 20 7357 8394, www.europetro.com.

15-16, *9th International Bottom of the Barrel Technology Conference*, Euro Petroleum Consultants, Dubrovnik, Croatia, +44 (0) 20 7357 8394, www.europetro.com.

SEPTEMBER

22-23, *Russia & CIS Refining Technology Conference & Exhibition*, Euro Petroleum Consultants, Moscow, Russia, +44 (0) 20 7357 8394, www.europetro.com.

OCTOBER

9-12, *NPRA Q&A and Technology Forum,* San Antonio, Texas, +1 292 457 0480, www.npra.org.

NOVEMBER

Nov. 29 – Dec. 1, *ERTC 16th Annual Meeting*, Barcelona, Spain, +44 (0) 207 484 9700, conf@gtforum.com, www.gtforum.com.