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Virtual reality improving training at refining and petrochemical facilities

American Fuel & Petrochemical Manufacturers

The operator of an 800-ton crane at ExxonMobil's Baton Rouge, Louisiana polypropylene project construction site lowers a new 150-feet-tall reactor into place. The maneuver requires that the operator understands the physics of the lift, as well as ensuring the rigging is installed properly, the swing is stabilized and bystanders are safely out of the way.

Installing two reactors, with a combined weight of 1.1 MM lbs, requires precision and a steady hand at the crane controls. That is why the company is using virtual reality (VR) to train its crane operators before the heavy lifting begins. ExxonMobil is using VR training at the more than $500-MM polypropylene project to improve work performance and safety, while also reducing training time.

"We're hiring a lot of people, so it's imperative we increase competency quickly. One way is through virtual reality," said Keitt Wannamaker, project lead for the ExxonMobil polyolefins plant. "We have found that the VR training saves time, improves project reliability and, in some cases, is more cost-effective than traditional training methods (FIG. 1)."

VR allows workers to become familiar with the operations of the new plant before it is completed, and ExxonMobil is hoping to expand the use of VR as it gears up for a major expansion of its facilities along the Gulf Coast.

Training the next generation. The safety performance at U.S. refineries and petrochemical facilities is better than ever and continues to improve, thanks in part to a range of technologies, such as drones and systems that monitor facilities digitally rather than manually. Injury and incident rates at refineries and petrochemical facilities have dropped during the past 30 years and are now five-times lower than the total recordable rates of the entire manufacturing sector.

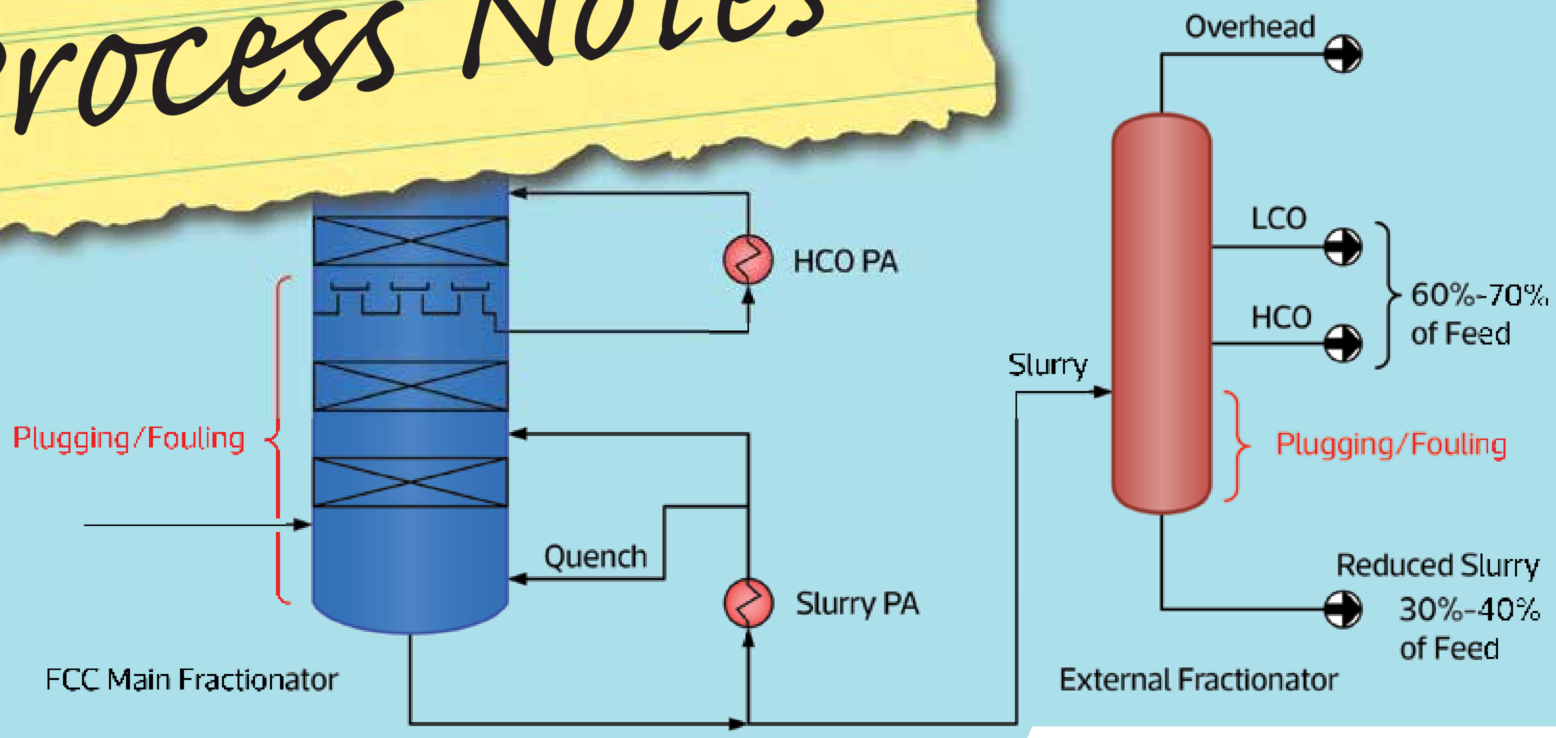
However, such good news also presents a new challenge: training a new generation of workers who have little first-hand experience with safety incidents. As their older colleagues retire, the transfer of institutional knowledge becomes more challenging without direct experience. VR and augmented reality (AR) can help meet this need.

"Within the next 10 years, some companies will be losing 40%–50% of their workforce," said Christopher McAulay, an operations trainer with Sinclair's refinery in Casper, Wyoming. "We have a bunch of people with three to six years of experience, and we want them to be ready if, for example, we are putting something online they have never seen before."

VR can help shorten the learning curve. "As humans, our original way of learning is by contextually experiencing it," says Tyler Gates, Managing Principal of Brightline Interactive, a VR development company that got its start nearly 16 years ago building training simulations for the U.S. Department of Defense. "We are spatial beings. VR helps people better understand what it is like to actually be in a certain real-life scenario—an experience that the brain remembers like a lived experience—

See VIRTUAL REALITY, page 3

Process Notes



Process to minimize FCC slurry product

Equipment Design Matters

Many attractive projects fail to meet expectations at startup. Disappointing performance often results from bad simulation practices and/or poor equipment design rather than faulty execution. Refineries are currently considering FCC revamps to increase olefins for more alky unit feed, maximize LCO product recovery, and minimize slurry product by producing HCO for hydrocracker feed. These changes raise fractionator operating temperature. Higher temperatures require better process and equipment designs to avoid fouling and coke formation, which lead to poor reliability and potentially to an unscheduled shutdown.

While getting the simulation right is important, process equipment design is equally critical to a project's success. Consider a project to minimize FCC main fractionator bottoms product (Slurry, DCO, CSO, etc.). As outlined in the top figure, an external fractionator can recover substantial quantities of LCO and HCO from the FCC slurry product, reducing slurry volume by 60% - 70%.

Upgrading a significant quantity of low-value slurry to LCO and HCO provides a powerful economic incentive to execute a recovery project, but poor reliability can destroy project value. Good process design is important. For example, proper quench and pumparound system control is essential. However, ultimate results are driven by equipment design rather than the theory of a process model.

In both the main and external fractionators, liquid distributors must be designed for practical flow rates and to handle solids. Unsophisticated distributor design creates uneven liquid distribution that reduces fractionation efficiency and LCO recovery against the endpoint specification. The main fractionator slurry pumparound and quench distributors must eliminate hot spots in the grid and bottoms liquid pool, respectively, to prevent coke formation. The picture below illustrates the result when equipment design is left to low-cost vendor solutions.

Finally, the bottom product from the external fractionator (reduced slurry) will be nasty. Stripping trays must be specially designed to work in this extremely fouling service, and bottoms pumps must be compatible with very low API material containing solids.

Equipment design matters. Don't miss performance goals by applying generic equipment design to specialized problems.

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VIRTUAL REALITY, continued from page 1

operate in that environment, fail safely and learn from their decisions."

Enhancing training with VR. Since early 2019, Brightline has been working with the American Fuel & Petrochemical Manufacturers (AFPM) to develop a VR simulation that will supplement training for employees at refining and petrochemical facilities. The complex, 130-task simulation will help ensure that employees are thoroughly trained in starting a fired heater, a key facility operation for which hands-on, in-the-field training is difficult due to the potential consequences of inaccurate execution. AFPM spearheaded the project to provide shared resources for its member companies, which comprise virtually all U.S. refining and petrochemical capacity.

"As AFPM develops these emerging training technologies and measures their effectiveness, our member representatives can take the results back to their companies, show the value of VR and potentially expand its use," said Daniel Forest, Manager of safety programs at AFPM.

The simulation begins in a classroom setting, which includes a tutorial that acclimates trainees to the VR environment, then covers the basics of key VR actions used in the simulation, such as the proper way to turn valves or press buttons. Trainees can choose between two learning scenarios: a guided simulation that walks the operator through the procedure, providing prompts and assistance; or an unguided module that allows the individual to fail safely and learn from their mistakes within the VR environment.

"When you look at millennials and Gen Z and at how they learn, this VR and immersive learning component adds another style of learning, which this new workforce entering the market needs," said Russell Klinegardner, Chief Operating Officer of Houston Area Safety Council (HASC), which is also beginning to incorporate VR simulations into training for contractors for work at fuel and petrochemical facilities.

A more connected workforce. In addition to programs like those being developed by AFPM and HASC, refining and petrochemical companies are also studying technologies that connect workers and improve communications and collaboration.

For example, Flint Hills Resources is testing connected lens technology, which if adopted, would allow an engineer in Wichita, Kansas, to see exactly what a counterpart in Minnesota is doing and offer advice.

"We're looking at different wearable devices to have a more connected workforce," said Bjorn Olson, Flint Hills' Technical Training Lead.

With connected lens technology, workers conducting highly complex tasks can consult experts in real time regardless of location and distance. This bypasses the logistical challenges that once precluded experts from being onsite in situations where their experience is most needed.

U.S. refining and petrochemical facilities are embracing these and other steady advances in VR and AR technologies to continue to improve safety, benefit employees and remain dynamic in the fast-paced energy marketplace. ●

FIG. 1. An employee interacts with a digital refinery during a Flint Hills Resources training exercise. Training with virtual reality can lead to higher recall accuracy.

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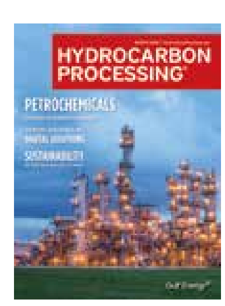


Advanced analytics drive IIoT success

J. ZINSLI, Seeq

Refineries must mitigate risk, anticipate maintenance, optimize operations and minimize operational expenses. To achieve these goals, plant personnel rely heavily on data to drive decisions.

The excitement around the Industrial Intranet/Internet of Things (IIoT) is its ability to deliver this data at lower cost and in greater volumes than ever before. This is accomplished when IIoT implementations take advantage of advancements in the areas of wired and wireless sensors, networking and data storage technologies.

The driving forces for these innovations are declining costs and increased connectivity options, which are enabling plants to measure far more parameters of interest, many of which were too expensive to monitor with older solutions.

Accessing date and deriving results. Most of these sensors will be connected to a plant's existing regulatory control or asset management system. Wired sensors with 4-20mA outputs require spare inputs on these systems, but many newer sensors and instruments will use fieldbus digital communications, simplifying wiring and lowering costs.

Wireless sensors can be connected to a plant's control, asset management or other host system via a gateway. The sensors connect to a gateway that is hardwired to the host, usually via an Ethernet connection, eliminating the need for additional input points.

Access to this data by engineers and plant management may be enabled worldwide to anyone with intranet or internet connectivity and proper security credentials. The proliferation of high-speed Wi-Fi and cellular networks has made this type of connectivity ubiquitous and reliable.

However, collecting, storing and disseminating data is just the starting point for IIoT implementations because process and reliability engineers, collectively subject matter experts (SMEs), must analyze this data and derive results to provide operational guidance.

This is best done using advanced analytics software to connect to the myriad of data sources. The right software can be a very effective tool in the hands of SMEs, enabling them to create and share insights. The following example shows how advanced analytics software can be used in refineries and petrochemical plants to improve operations.

Advanced modeling techniques. Process engineers are actively engaged in monitoring product quality and yields, and they must closely observe operating conditions. Many process units can produce different grades of products when parameters are adjusted. For example, increasing reforming severity can result in low liquid volume yield but high-octane product, and there are times when these types of operations will be necessary to meet product specifications.

To anticipate how much an operational target must be adjusted, an SME is often asked to create a model for the process. Carrying this reformer example further, it is possible (but unlikely) that one model for reformate yield can encompass a wide array of inputs.

In most cases, the most accurate models will instead be based on narrower subsets of data. For example, the SME will likely create a low- and a high-severity model, and use each model as needed to meet current operational goals.

Advanced analytics software empowers SMEs to create multiple models, and then combine them into one model representative of operations at any point in time. While SMEs will generate these models and use them to understand specific situations, such as how the catalyst may be degrading over time, others in the organization can also benefit from their detailed efforts.

Because this new model will be of interest to multiple employees within an organization, collaboration and knowledge sharing is required. For instance, operations planning personnel need to understand these models so they can provide appropriate guidance to meet product requirements, or to evaluate the plant's capability to make new products.

Comparing models. Models, such as the one shown in **FIG. 1,** are created by an SME and then shared with others across the organization to achieve various goals.

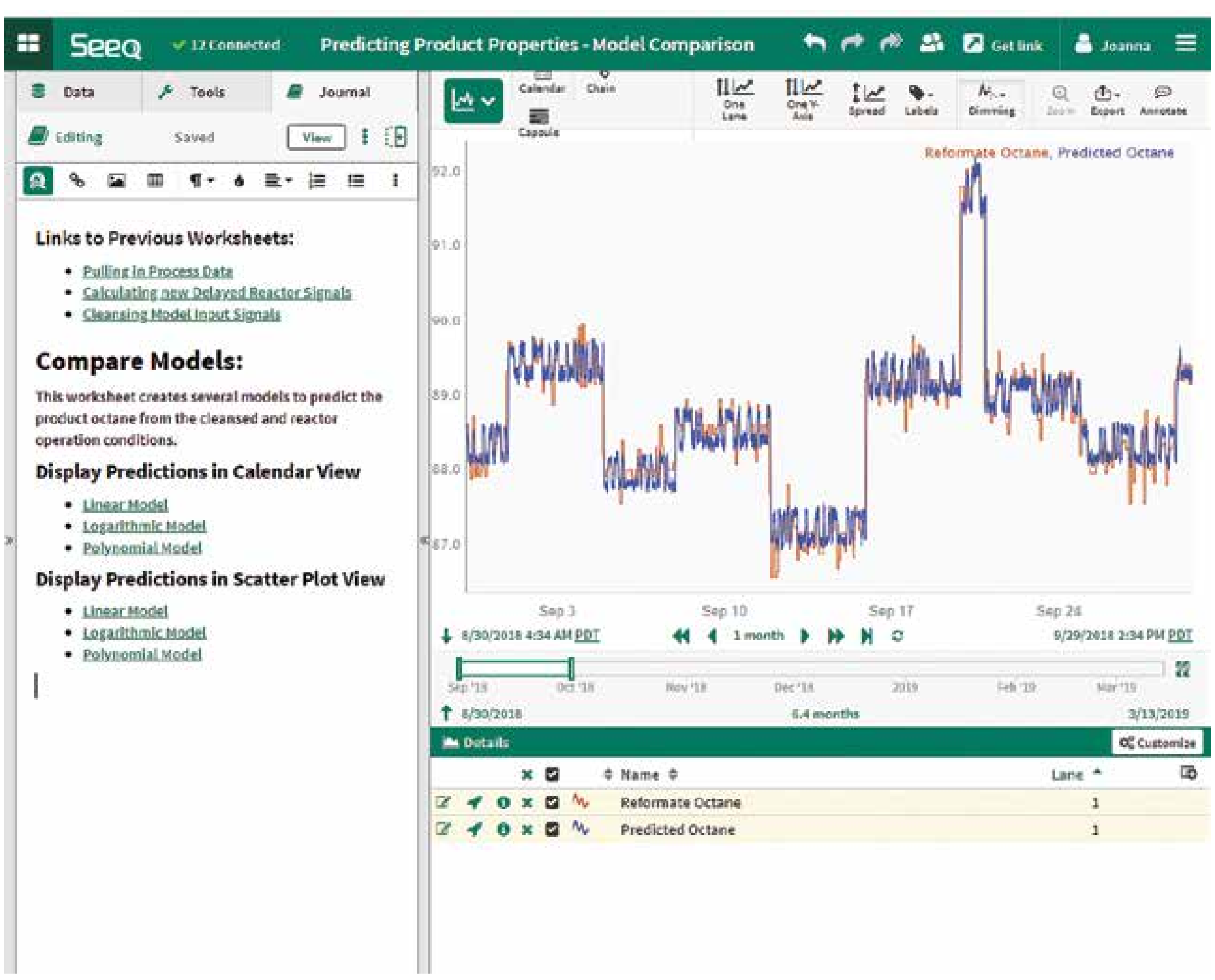


FIG. 1. This model was created by an SME and then shared with others across the organization to achieve various goals.

Using advanced analytics software with sharing functionality built in allows others within the organization to access the models developed by SMEs, supporting data-driven decisions across the enterprise.

Advanced analytics software can also be used to reduce operating expenses. Most process plants have a planning engineer or other individual responsible for communicating intermediate or utility requirements to service providers on a routine basis. These are often referred to as nominations and can be applied to electricity, natural gas, hydrogen or other utilities, or to intermediates purchased by the plant from a third-party provider, such as an electric utility.

These nominations are used by service providers to plan and adjust their operations. For example, a natural gas utility needs to plan pipeline operations to supply required amounts of natural gas. Commercial contracts typically require a process plant to consume some percentage of the nomination, with a penalty charged for either over or under consumption.

To minimize operating costs in environments where production and thus utilities consumption varies widely, planning engineers must combine their knowledge of planned operations in the short term with current and historic actual consumption.

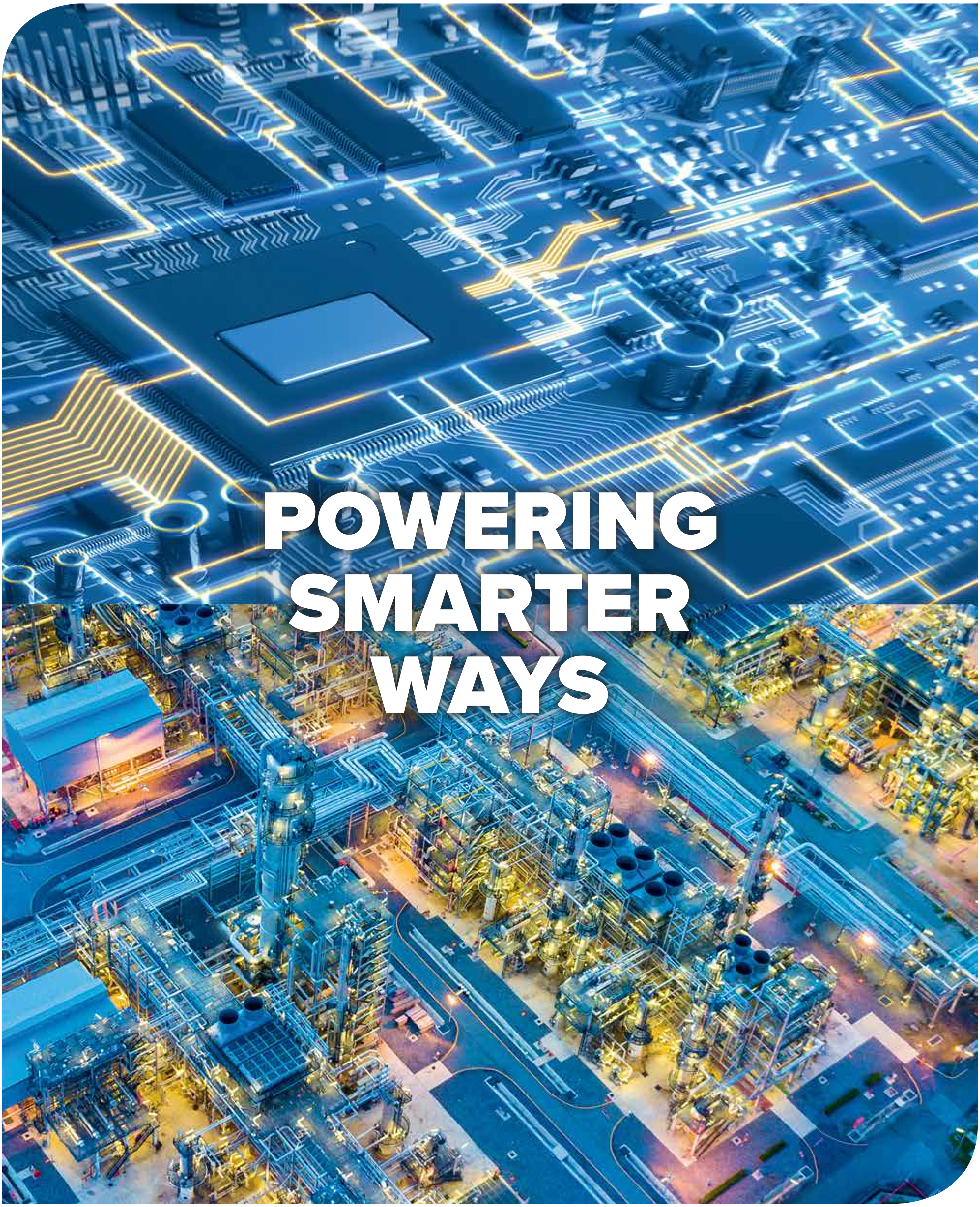
This can be done by using advanced analytics software to create a model for intermediate consumption, using process historian data from past operations. Data variables may include flowrates, temperatures and other process parameters from many units. Much like the reformer model in **FIG. 1,** multiple models must often be combined to more closely represent operations and provide accurate results.

A nuance here is that while the model is based on historical data, it must be applied to current and expected future data to provide an appropriate look ahead to anticipated operations. Traditional tools would require manually copying and pasting both historical and planned data into a spreadsheet as part of this analysis. By using advanced analytics software connected to various data sources, an SME can skip these data access steps to quickly and simply view historical and planned data.

Another advantage of creating the model with advanced analytics software is the highly visual nature of reviewing the results and determining when to retrain or adjust the model. While this kind of activity can be carried out with traditional tools, model refinement is more complicated with those approaches and can lead to lagging when adjusting for error.

Depending on the size of these lagging corrections and the accuracy of the traditional models, these lagging nomination errors can cost operators millions of dollars annually. Advanced analytics software improves the quality and timeliness of models, allowing plant personnel to more accurately predict utility requirements. ●

JOANNA ZINSLI is a Principal Analytics Engineer at Seeq Corporation. She enjoys helping engineers across verticals discover value in their process data and simplify their routine workflows using Seeq. She received her BS degree in chemical engineering from the University of Arizona, and then began her career as a process engineer in petroleum refining with Valero Energy Corporation. After supporting several units, she transitioned to refinery economics as an optimization engineer. Just prior to joining Seeq, she managed the refinery's planning and economics team.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Not all built-in cybersecurity is equal: 13 questions for your automation vendors

R. BERGMAN and **S. GALPIN,** Bedrock Automation

If any of today's large vendors of automation systems offer cybersecurity protection, odds are good that it has been bolted on after the fact. Cybersecurity was not an issue when these systems were originally designed, so swapping them out now would be a major challenge for both the vendor and the end user. However, those systems are due for update eventually, and legacy vendors are now striving to build in as much security as they can.

Ideally, that protection would be built-in starting at the semiconductor level, making the device responsible for its own security. The system would no longer be dependent on an external, bolted-on network of firewalls, intrusion detection devices, etc., to parse out whether incoming signals can be trusted. It would be an entirely new level of depth to the defense. While elite hackers can bypass firewalls, breaking properly implemented strong cryptography is not a practical possibility. The attacker would face a whole new set of barriers that exist on many signal paths, not just one. The controller essentially would have an immune system.

Built-in security fundamentals. Built-in security is based on what is known as a public key infrastructure (PKI), the base elements of which are simple. All trusted parties have unique certificates that identify them. The certificates also include data that defines each party's system roles and privileges. Certificates are issued and managed by a certificate authority (CA). PKI mechanisms allow all members of the trust web to recognize other members and exclude imposters.

In the case of a controller module in an industrial control system (ICS), this security makes it possible to know that the actor is an engineer with permission to change the user programming or an operator with permission to change a setpoint. If the actor has the proper PKI credentials, the controller allows the action. If not, the controller blocks it.

How cybersecurity is built into a control system. Designing security into a control system begins at the silicon level. Secure computing requires a tamperproof startup process. The first code the processor executes cannot be encrypted. Protecting this code with signatures or checksums doesn't help because if it can be tampered with, the checks come too late. This initial code must be built into the microprocessor chip. Later phases can use code that is signed and encrypted, but this again requires special silicon features to protect the secret keys. Intrinsic security rests on a foundation laid at the silicon level, where a system is only as secure as its component supply chain.

A controls vendor that manufactures its own chips, such as Bedrock Automation (FIG. 1), is likely to have greater visibility into and control over its silicon than automation vendors that source most, if not all, of their components from a third party, and often offshore.

Additionally, the manufacturing process itself must be secure. The origin and lot number of every part, from microprocessors to resistors, on every circuit board must be tracked in a database and assigned. Each board must have a unique serial number.

All boards must be tested using special test fixtures and software and assembled at a secure facility, where each module is loaded with production software and a unique package of cryptographic certificates and PKI keys bound to immutable features of its silicon. These key packages are generated by a special high-security computing system and loaded directly into the modules by a secure automated process. Each module now has its full cryptographic identity. It cannot be cloned or counterfeited. The module next goes through a first heat-soak test. If all goes well, it is sealed into its tamper-resistant metal case and put through a final heat-soak test.

Key questions. Over the next several years, more and more companies will be claiming to offer some degree of built-in cybersecurity. Although they will be guided somewhat by standards, such as ISASecure (IEC 62443), each will likely interpret such standards differently and integrate them into their operations at different levels and degrees. As you evaluate your next programmable logic controller (PLC), remote terminal unit (RTU), distributed control system (DCS) or other industrial control system claiming to have built-in cybersecurity, here are some questions you can ask to ensure you are getting maximum protection.

1. Is there an embedded PKI to manage encryption and authentication of messages based on a known third-party root of trust?
2. Does the authentication support Transport Layer Security (TLS) 1.2?
3. Is encryption compliant with NIST SP800-57, Suite B?
4. Does the system have secure boot?
5. Does security extend to sub-components as well as to the device itself?
6. Is there anti-tamper protection at the component level?
7. Are the modules all-metal, anti-tamper, sealed and FIPS 140-2 compliant?
8. Does the system use a pin-less I/O backplane?
9. Is the system firmware secure and protected?
10. Are open communications protocols such as OPC UA and MQTT secure and protected?
11. Does the system have a secure component supply chain?
12. Does the system have the built-in bandwidth to support high-performance hardware accelerators without disrupting performance?
13. Is the security included in the basic cost of the control system?

For a truly intrinsically secure control system, the answers to all these questions must be, "Yes."

FIG. 1. Bedrock Automation's OSA industrial controls and power supplies have an embedded PKI that manages authentication and encryption using the same cybersecurity technology that protects military and aerospace applications.

Profitable and sustainable refinery and petrochemical integration

S. N. MAITI, SNC-Lavalin Inc.

The impact of fossil fuel usage on the environment has become widely accepted and our global society has begun to focus on alternative fuels. The aim of the UN sustainable development goal (SDG #7) is to ensure universal access to reliable, affordable and clean modern energy by 2030, with increased sustainability through the increased share of renewable energy in the global energy mix. A similar objective is outlined in the EU Energy Roadmap 2050, which aims to create a competitive low-carbon energy system.

Conversely, the demand growth of traditional transportation fuels like gasoline, diesel, etc., is declining due to several factors, such as higher efficiency vehicle engines, fuel substitution [liquefied natural gas (LNG), compressed natural gas (CNG), hydrogen (H_2), biofuels], the growth of the electric vehicles segment, strict environmental regulations, circularity of economy, etc.

This puts tremendous pressure on refiners, which face lower sales and profit margins, and forces them to utilize or innovate alternative options for sustainability. In contrast, the market demand for petrochemicals, such as ethylene, propylene and aromatics, continues to rise due to key driving factors: global population growth and economic upliftment in developing countries like India and China. It is predicted that by 2040, the global average demand growth rate for refined products will be less than 1%, whereas the petrochemical demand growth will increase steadily at ~ 4% (IHS Markit report 2018).

Integrated facilities. Standalone refining and petrochemical facilities are facing market pressure due to crude price volatility and swings in global products demands and specifications. Feed availability, flexibility in feedstock, domestic or global market-based products demands, economies of scale and capital investment efficiency are key drivers in placing the focus on refinery and petrochemical integration. An integrated complex enables refineries to better accommodate future shifts in product patterns and demand that will see a greater focus on chemicals than on transportation fuels.

Today, petrochemicals are driving the majority of investments in the hydrocarbon processing industry (HPI) worldwide. Two major problems in the HPI are decarbonization and singularity. Decarbonization of electricity is less difficult than that of refining and petrochemicals due to the number of products produced. A linear production model that generates waste materials through single use (singularity) will move to a circularity by reusing those waste products so that they never leave the value chain and may not produce much emissions.

Balancing risks and rewards. Building and operating a grassroots facility is a complex undertaking, but the economics associated with modifying or revamping a few units in an existing plant can be even more challenging. So, how does a company considering such an investment plan to properly balance project risks and the potential rewards of retrofitting current production assets to integrate with new petrochemicals units?

Integration is more complex than just the sum of its parts. Controlling as many of the variables as possible in the integration process to maximize system efficiency and profitability is essential. Several integration scenarios exist in an existing refinery: installation of a steam cracker to produce ethylene, propylene and other derivatives; an aromatics complex to produce BTXs; a gasification unit to produce chemicals through the syngas route; and petrochemicals through the recovery of propylene from fluid catalytic cracking (FCC)/coker units. The former three are very capital-intensive compared to the last one.

Deciding whether and where integration is appropriate requires careful consideration. Many factors will critically impact the investment, including the availability of internal feedstocks (propane, propylene, butane or naphtha, etc.); the synergies of utility streams (water, steam, power, hydrogen, etc.); complexity of configuration; the proximity of both plants; market demand and competition; and the ability to leverage staffing for maintenance, operation, management and logistics benefits, among others. The integrated complex should provide optimum molecule management for better return on investment (ROI).

SNC-Lavalin is working with its customers in the oil and gas industry to plan for the necessary changes to respond to these challenges. Our approach is underpinned by a detailed modelling exercise using linear programming (LP) tools that incorporate all the above

See SNC-LAVALIN, page 18

Cooling effluent streams can keep refiners out of regulatory hot water

M. CAPRA, Aggreko Process Services

A maximum temperature of 34°C (93°F) is generally the mandatory limit established by many local regulations for the disposal of wastewaters into rivers or seas. This temperature limit also ensures proper biomass activity for biological oxygen demand (BOD) load reduction.

Failure to comply with the required wastewater streams temperature limits can expose a plant site to simple warnings from local authorities, from requiring a formal commitment to modify the process by a set date, to more serious and costly consequences, such as complete closure of the activity generating the BOD and/or thermal pollution.

Beyond compliance, plant profitability objectives often dictate additional and temporary cooling of waste streams below the regulated levels.

Regardless of whether the immediate goal revolves around compliance or profitability (or both), high ambient temperatures can limit cooling efficiency of existing heat transfer equipment, mandating an alternative cooling solution that provides fast relief to meet the stated objectives, as in the case of this desalter cooling example. Such projects typically can be implemented on short schedules of just days or weeks.

FIG. 1. Biological wastewater treatment.

Cooling desalter effluent water. Crude oil desalting is generally performed after pre-heating the oil at 140°C (284°F). Efficient salts extraction prevents chlorides and other salts being introduced into the crude distillation unit (CDU); the limitation of top condenser corrosion is one of the many targets for this operation. Desalting is performed by injecting and extracting a stream of water.

In a coastal refinery, the desalter was the major contributor to thermal and BOD loads in the wastewater stream. A flowrate of 200 m^3/hr at a variable temperature between 55°C (131°F) and 73°C (163°F) had to be cooled down to 34°C (93°F) with biological treatment (**FIG. 1**) prior to disposal to the sea. Due to the plant's compact design, the only option was to cool the accumulated oily process water in a large storage tank.

An application performing 9 MW of refrigeration had been implemented utilizing basket filters, plate heat exchangers resistant to corrosion (titanium plates), and plate gaps ensuring free flow of the water-oil mixture contaminated with dissolved and non-dissolved salts. Summer temperatures and non-availability of cooling water compounded the challenge. As the maximum air wet bulb temperature was rarely above 24°C (75°F), the most logical choice was to deploy a combination of compact mobile cooling towers in a closed loop with titanium plate heat exchangers.

Since the wastewater effluent temperature required regular monitoring, remote monitoring of the heat exchanger's pressure drop and temperature completed the temporary solution design. The operational feedback alerted staff when periodic backflushing of the exchangers became necessary.

The automated monitoring also provided control of the cooling water make-up and blow-down, as well as the biocide injection to avoid the legionella risk. Utilizing this supplemental cooling strategy, the refinery managed to comply with all local authorities' environmental inspections for four consecutive summers. Further, as no oil spillage occurred, the engineered solution also achieved compliance with internal environmental rules.

Because each refinery presents unique situations, the choice of equipment selected to perform a supplemental cooling role plays a critical role. Engineered applications achieve the most energetically-convenient solution while deploying large, temporary refrigeration.

Additionally, energy optimization, mitigation of operational issues and achievement of operational goals require automatic controls implementation that allow full monitoring of all operating variables, as well as the cold wastewater temperature.

Temporary cooling applied to wastewater may not always reveal clear and computable added values. However, the difference between achieving process enhancements and the cost of non-compliance with local environmental regulations, which may lead to the shutdown of wastewater treatment and consequent termination of site operations, clearly highlights the prioritization of evaluation criteria. ●

MASSIMO CAPRA is the Manager of Aggreko Process Services in Europe, supporting Russia and the Middle East's refining and petrochemical sectors. He has 35 years of experience in the refining and chemical process industries as a process and project engineering manager for companies that include AGIP, Foster Wheeler Italiana, Tecnimont and Aramco Overseas Company, and as a freelance consultant. He worked as a Process Technologist and Team Leader at OPCW, conducting more than 150 process inspections in chemical facilities. Capra earned an MS degree in chemical engineering from Politecnico di Torino (IT), a PGC in project management from the University of Wales (UK), an MBA from Robert Kennedy College (CH), a 6 Sigma Black Belt from BMGI (USA) and an ISO9001 Lead Assessor certification from SGS (NL).

FROM ASIA TO THE U.S., FUEL PRICES PUMMELED BY CORONAVIRUS FALLOUT

Prices and profit margins for motor and aviation fuels globally are under pressure from a severe loss of demand as more countries enforce lockdowns and planes are grounded, forcing more refineries to reduce output.

U.S. ultra-low sulfur diesel (ULSD) was the latest product refined from crude oil to take a hit in its cash market last week after refiners boosted production in a bid to flee poorer margins for other products more affected by coronavirus fallout.

Refining margins for gasoline and jet fuel have tanked because of decreased demand for transportation fuels, as the disease outbreak has forced businesses to close and governments to push residents to avoid travel and public places.

In Asia, profit margins for jet fuel turned negative for the first time in more than a decade as global airlines canceled flights. Emirates and Singapore Airlines were the latest carriers to announce huge cuts in their passenger flights, and European jet fuel prices last week plummeted to a near 17-year low.

For most of last week, U.S. diesel margins held up relatively well, as both trucking and farming, two sectors that rely on diesel, continued operating.

But refiners' moves to divert production capacity previously devoted to other fuels to diesel is starting to cause oversupply in some regions.

Underscoring falling demand, Colonial Pipeline Co said it would cut volumes on its primary lines delivering gasoline and diesel fuel to the U.S. East Coast from the Gulf Coast.

Refiners around the world have already started cutting output or are considering such measures as the coronavirus curbs travel and driving.

EXXON'S BATON ROUGE REFINERY CUTS PRODUCTION DUE TO LOW DEMAND

Exxon Mobil Corp cut production at its 502,500-bpd Baton Rouge, Louisiana refinery as poor demand has pushed up inventories and filled storage tanks.

The number of contract workers at the Baton Rouge refinery was cut by 1,800 people on Friday as Exxon begun informing service companies of planned spending cuts. Industry sources confirmed that the refinery's production was cut to about 440,000 bpd on Saturday.

Exxon spokesman Jeremy Eikenberry said the spending cuts will be announced when final decisions are made. "We are notifying contractors and vendors of our intended reductions, and they may be adjusting their staffing and budgets accordingly," Eikenberry said.

The number of contract workers at the refinery averages 2,000 and increases when major overhauls are underway. Contract workers are employed by the third-party service companies that Exxon has been informing of its spending plans.

Social distancing and working from home to prevent the further spread of the coronavirus in the U.S. have reduced demand for motor fuel across the country. At least three refineries in California have cut production, as well. LyondellBasell Industries sent home about 500 contract workers from its Houston refinery last week.

Exxon's Baton Rouge refinery restored full production on March 9 after it was shut by a February 12 fire. The Baton Rouge refinery is the second-largest in Louisiana and Exxon's second-largest in the U.S. ●

Digitalizing the downstream supply chain

TIM HOFFMEISTER, Implico Group

One thing that all successful downstream operations have in common is multi-way collaboration along the supply chain. Here, digitalization provides all involved parties with significant benefits, such as higher transparency, deeper knowledge and better interaction between business partners. The key to this is data, and the logic behind it is simple: the more information a company has, the better its decision-making becomes. This is equally valid for tank terminals, refineries, service station networks and their business partners (**FIG. 1**).

Dare to innovate. Traditionally, oil and gas firms tend to play it safe and stick to proven processes and procedures. Considering the value and sensitivity of the traded products, the motto, "Never change a running system" seems logical. However, technology is evolving at supersonic speed, rewarding those who are brave enough to innovate with all-new options and opportunities. These first-movers are gaining more and more market share.

New approaches in central areas like stock keeping, data processing, contract management or data communication are key to success. In these fields, digitalization promotes safety, transparency, accuracy and efficiency.

Digitalize your assets. At the heart of this development lies the desire of companies to make their assets digital. The list of technologies that help them master this challenge is long: The Internet of Things (IoT) gives components a voice and enables them to communicate directly with a receiver. Big Data facilitates new ways to gather, process, access and exchange vast amounts of information. Cloud technologies render high-end IT solutions and services more flexible and scalable than ever before. Artificial intelligence (AI) enables machines to learn and make intelligent decisions on their own. Smart terminal management systems shift fully automated work steps to the background, freeing resources for employees to focus on their unique strengths as humans, such as working creatively and providing personalized customer service. The last-mentioned idea also points out another strong merit of digitalization—if done right, it supports rather than rivals the work of human personnel.

Invest in the future. Naturally, digitalization does not come for free. It requires certain investments, not only financially but also time- and effort-wise. However, given the fundamental importance of digitalization in today's oil and gas industry, these investments can hardly be enough or too much. After all, every dollar and every hour that a company spends on digitalization is a direct investment in its future. However, spending alone is not enough. Here, the challenge is to make intelligent investments in the right areas, avoiding the usual traps. In the mid-to-long term, there is no alternative to it. To gain a competitive edge and keep it, a downstream company must digitalize its processes, methods and assets.

Additionally, we are talking about an on-going investment. Digitalization goes full circle; there is no defined end to it. Once a company has begun its digital transformation journey and seen the first benefits, it will stay on track and continuously optimize its business. With this in mind, the decision to become digital should also not be based on short-lived variables like the current oil price or the prospect of a quick win. History has shown that there will always be ups and downs; digitalization helps companies to make the most of either state. ●

FIG. 1. The more information a company has, the better its decision-making becomes, and this is equally valid for tank terminals, refineries, service station networks and their business partners.

UOP E6: EFFICIENCY METRICS TO ACCELERATE INTEGRATION

Honeywell UOP E6 provides a framework to evaluate potential investments in petrochemicals integration.

Today's future-forward refiners are evaluating the costs and benefits of integrating fuels and petrochemicals. The UOP E6 methodology provides critical insights into an investment's profitability and enables long-term competitive positioning.

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Honeywell UOP

OPTIMIZED INTEGRATION PLANS DELIVER IMPROVED ECONOMICS

Petrochemical integration enables a significant increase in value compared to producing only fuels. Using the E6 framework, UOP helps refiners develop an integration strategy that will deliver an optimum economic solution and investment plan.

To get a better idea of an optimized integration, consider this case study based on a typical FCC-centric refinery focused on producing Tier 3-compliant fuels.

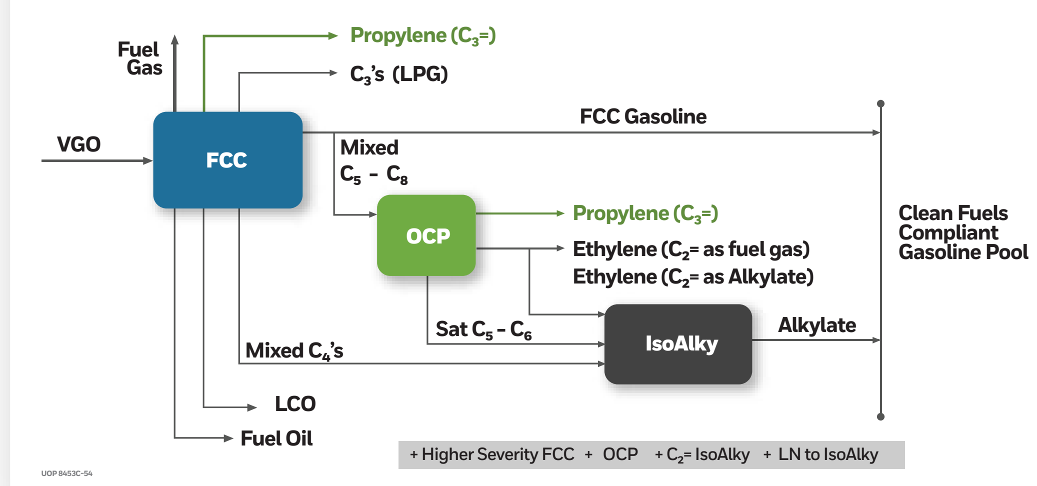
The integration is carried out in three consecutive steps:

Step 1: Increase FCC unit severity for greater propylene production within the optimum economic range.

Step 2: Add olefins cracking process (OCP) to more efficiently crack C4-C6 olefins into propylene, extending the economic range of propylene production.

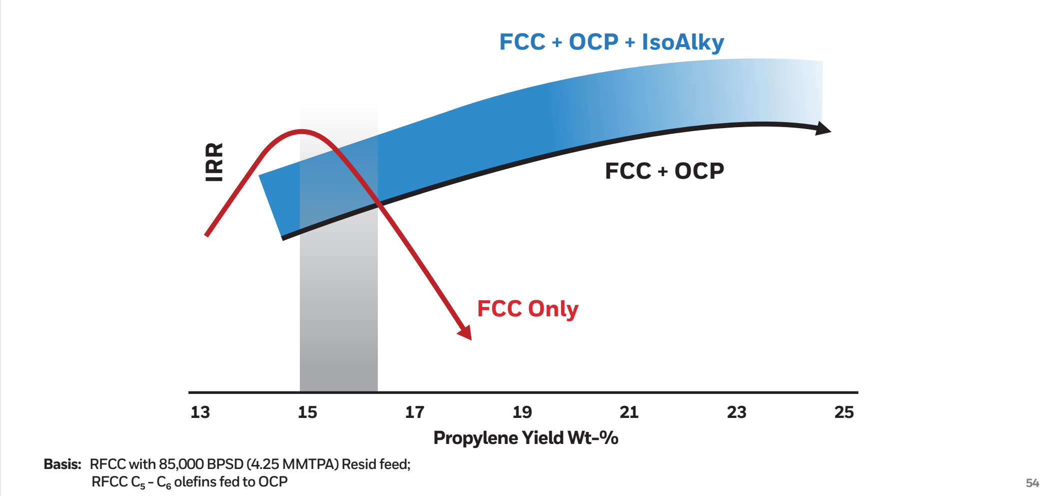
Step 3: Add ISOALKY Technology both to increase the production of high-value alkylate and to better monetize light naphtha.

Utility Efficiency: Leverage the right technologies to create value



With OCP and ISOALKY Technology, the economic optimum is moved from 15 to 25 wt% propylene production. Each step builds on the previous to increase the economic quality of the investment. This integration provides higher-value uplift for discounted streams, while targeting the highest-value fuel blend product (alkylate) and one of the highest PetChem products (propylene). The ultimate balance of fuels and petrochemicals will be unique for each project.

Emissions: Avoid excessive FCC severity to reduce C0₂ footprint



Compare the internal rate of return (IRR) for each integration. FCC+OCP+ISOALKY Technology delivers more value.

PetChem integration can be a complex and capital-intensive problem. Optimization, not maximization, is the key. Our experts and the UOP E6 framework are helping refiners develop strategic, bankable investment plans for integration.

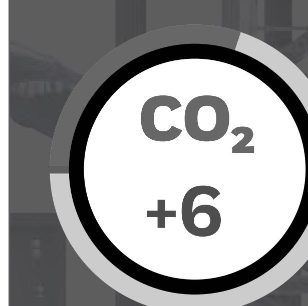
TWELVE QUESTIONS TO SMARTER INVESTMENTS

The UOP E6 framework benchmarks performance in 6 critical areas. Ask yourself these 12 questions to help plan a path to sustainable, profitable integration.

1. Are you selling any products at a discount?
2. What streams do you want to create more of or avoid?

3. How constrained is your steam methane reformer?
4. Do you ever need to shift your operations based on hydrogen availability?

5. What are your fuel gas, power, and steam costs/drivers?
6. Do you have infrastructure constraints that impact any of these?



7. What is your carbon tax rate?
8. How are you performing against existing emission permits?

Let's talk about the efficiency of your investments.

Future refining opportunities and FCC catalyst challenges

M. SCHMALFELD, BASF

The AFPM Annual Meeting brings together leaders from across the refining industry who drive the safe, profitable and efficient use of crude oil and natural gas in North America. The public's expectations for sustainability and new regulatory changes have led the global market to become more dynamic today; this is expected to continue to change as the transportation fuel segment is projected to reach its peak demand in the coming years. The world grapples with the challenges of meeting the needs of a growing population, improving living standards and an increasing global awareness that change is needed to sustainably meet the global demand for energy and chemicals.

Our industry's visionary leadership must work together to inspire new thinking and plans for change in the coming decades. Leadership should, at the same time, hold a practical view on the near-term refinery operational needs to ensure focus remains on "sweating the assets," making yield improvements and meeting sustainability goals. The best processes and catalysts must be utilized to achieve maximum economic value for the refinery and its customers.

Meeting the pace of change. Two topics are considered here: (1) emerging changes in the energy and refining market, and (2) the need to take a very pragmatic near-term approach to meet the pace of change in the fluid catalytic cracking unit (FCCU), which highlights the need for catalyst innovation to achieve the vision of future FCC operation. In **FIG. 1,** the key drivers for FCC catalyst innovation, the expected implications for catalyst development and the target features of future FCC catalyst are presented.

Let us first consider the broad potential changes in the market. Energy and petrochemical producers are now more focused on sustainability and the circular economy (an economic system aimed at eliminating waste and continual use of resources with a regenerative design). A circular economic model is the future for how the world will expect energy and product delivery and recovery. Increasingly, the public judges sustainability progress achieved in the energy and petrochemical industry when they look at how to invest, when to implement innovative energy solutions and when to establish new energy distribution and storage systems.

Change is being driven by countries and governments that decide to eliminate fossil-fueled vehicles or certain types of vehicle engines in cities, and question whether to utilize nuclear power. Increasingly, regulations are requiring cleaner processes and tighter environmental standards for the energy and transport industries. After more than 70 years of a refining industry focus on fuels supply, suppliers now explore the most effective crude for chemicals processes, as fuels will no longer be the only driver for how the FCCU is operated. Roughly 70% of propylene output from refineries is utilized as feedstock for the petrochemicals industry—this is the starting point for value-adding chains to produce polypropylene, acrylonitrile, propylene glycols, cumene, butyraldehyde, acrolein and other products.

Additionally, renewable power generation options (solar, wind, tidal, etc.) require new concepts for storage. Energy storage options are moving beyond the storage tanks used for crude oil, natural gas and fuels to new storage concepts, such as geothermal heat sinks, water reservoirs with associated power generation potential, advance batteries, renewable biomass (algae, massive reforestation for CO_2 capture, etc.) and hydrogen storage systems.

Transitioning objectives. The transition will take time, and our near-term energy requirements will be met by the refining and natural gas industries. The longer-term focus must consider new approaches as the market shifts away from transport fuel as the primary output of a refinery and toward petrochemicals as a major objective. New challenges from regulatory bodies are being implemented to make the world more sustainable. This presents challenges for the refining industry. The circular economy focus is already starting to drive new feedstocks into the refining segment, such as various recycled biomass feedstocks and recycled plastics. Despite these new energy market drivers, refineries will remain vital to meeting the world's energy and petrochemical needs in the coming decades. FCC is the main conversion process in a typical refinery, and FCC innovations are driving the many integrated petrochemical refinery plants. The FCCU will remain a major conversion workhorse in the coming decades.

To be pragmatic, the refinery of today will in most cases be required in the coming decades to generate the transportation fuels required by our customers. However, there is a shift in the refinery focus away from fuels to integrating petrochemicals requirements into FCCU yield targets. For new refineries, the petrochemical requirements can become most of the unit yield focus. The catalyst utilized in the FCCU plays a significant role in establishing the FCCU performance and contributes significantly to the refinery operation. Looking at the future, goals set and challenges faced by the refining world will continue to drive catalyst innovation. Main emerging trends and market needs that shape FCC catalyst developments include the significant increases in need for crude feed flexibility to utilize both tight oil and opportunity crudes, the growing petrochemical demand, circular economy and the tightening environment regulations. Catalyst development is the key enabler for the future of FCC, which makes it a challenging yet stimulating field of research. ●

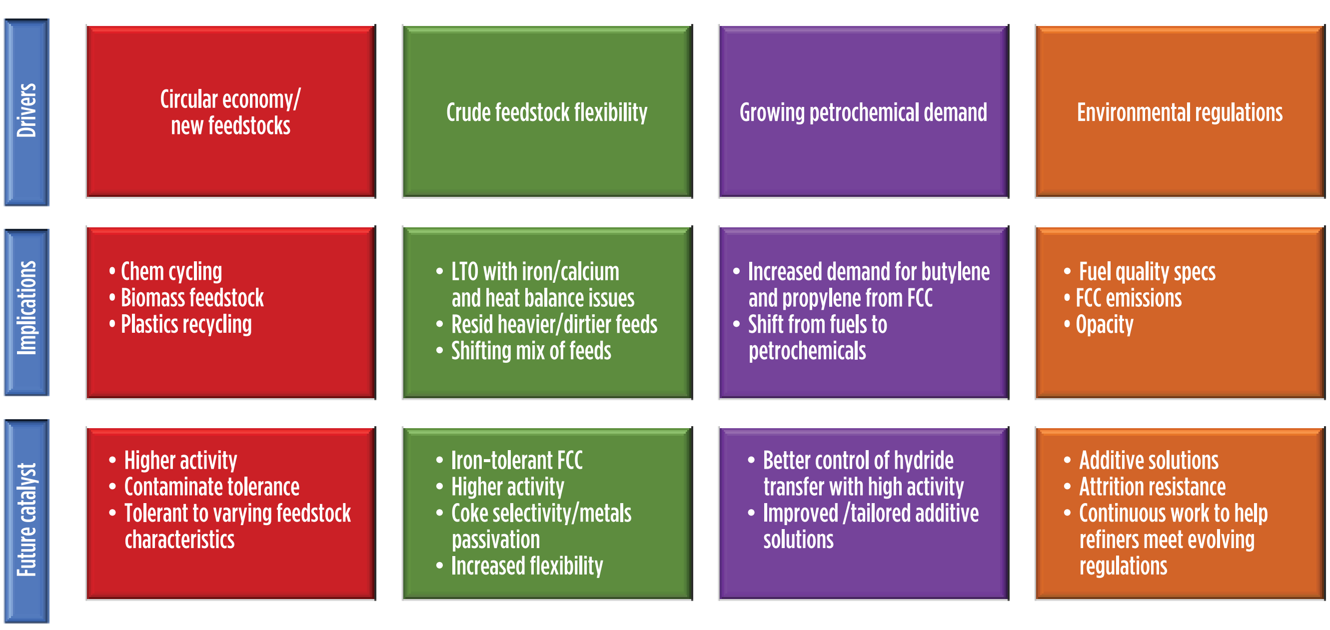


FIG. 1. Future FCC Catalyst Drivers

MARK SCHMALFELD is the BASF Corporation Global Marketing Manager for Refining Catalyst. He has more than 25 year of diverse experience in the catalyst industry. His leadership has supported everything from lab prototyping to marketing of new catalyst technologies supporting FCC catalysts, automotive catalysts, specialty zeolites and adsorbents. Schmalfeld has a chemical engineering degree from Purdue University and a MBA from University of Florida.

AS TOTAL U.S. CRUDE OIL IMPORTS HAVE FALLEN, IMPORTS FROM CANADA HAVE INCREASED

In 2005, U.S. refineries relied heavily on foreign crude oil, importing a record volume of more than 10.1 MMbpd. About 60% of the imported crude oil came from four countries: Canada, Mexico, Saudi Arabia and Venezuela, and each was responsible for between 12% and 16% of total U.S. crude oil imports that year. By 2019, U.S. crude oil import trading patterns had changed significantly. In total, U.S. crude oil imports have fallen sharply, but imports from Canada have risen steadily to 3.8 MMbpd, more than twice the imports from Canada in 2005. U.S. crude oil imports from Canada accounted for 56% of all U.S. crude oil imports in 2019, according to the U.S. Energy Information Administration's (EIA) Petroleum Supply Monthly.

U.S. imports of crude oil remained relatively high through 2007 until the economic downturn in 2008–2009 led to lower demand for petroleum products. However, since 2010, crude oil imports did not grow along with the U.S. economy because of increasing domestic crude oil production. As a result, by 2019, total U.S. crude oil imports were down to 6.8 MMbpd, or about one-third less than 2005 volumes.

Domestic refineries' use of crude oil from Canada has increased in nearly every year since 2009, but imports from Saudi Arabia, Mexico and Venezuela have generally decreased. These changes in crude oil trade were driven by the relative price and refinery operational advantages for importing oil from Canada, which displaced more and more barrels from Saudi Arabia. Persistent decline in production in both Mexico and Venezuela, along with U.S. restrictions on crude oil imports from Venezuela in 2019, contributed to fewer imports from those countries.

Direct comparisons of the top three importing countries, based on EIA's monthly data from 2019, further show that the crude oil imports from Canada of 3.8 MMbpd were more than seven times greater than those from Saudi Arabia (500,000 bpd) and more than six times greater than crude oil imports from Mexico (599,000 bpd). ●

Proposed 2020-compliant VLSFO specs

A. BARSAMIAN, E. CURCIO and **D. SON,** Refinery Automation Institute LLC

Now that 2020 is here, two of the serious issues facing the shipping, refining and petrochemical industries are the safety and the price of very-low sulfur fuel oil (VLSFO).

- The safety issue comes from the lack of standardization of VLSFO composition and characteristics, which directly affects engine performance and could potentially result in the loss of propulsion and/or engine damage.
- The price of VLSFO depends on the price of blend components and profit margins. Low-viscosity VLSFO implies a greater proportion of more expensive gasoil, whereas high-viscosity VLSFO implies the use of much cheaper residues and fluid catalytic cracking (FCC) cycle oils and slurry. But what happened? Even though high-viscosity VLSFO is cheaper to produce, it can be used like the "old" high-sulfur fuel oil (HSFO) without burdening shipowners to make changes to engine performance, the use of existing lube oil or having to re-train personnel. This is valuable to shipowners (where 60% of the operating cost is fuel cost), and therefore commands a premium.

Due to the proliferation of so-called 2020-compliant "specs" and the resulting chaos in the marketplace, Refinery Automation Institute is taking the initiative to propose three VLSFO specs based on current market VLSFO availability in approximately three viscosity clusters.

The proposed three VLSFO specs (**FIG. 1**) span the 30 cSt–380 cSt viscosity range and are compliant with the existing ISO8217-2017 specs, with some additions based on the "usability and fitness for use considerations" for VLSO fuels.

The proposed specs based on current VLSFO viscosity clusters are RMV30, RMV130 and RMV380, which parallel the existing RMB 30, more or less RMD80, and RMG380— except for sulfur—and three additional tests: ASTM Spot Test, Shell P-value and SARA (aromaticity and asphaltene contents).

- The ASTM "spot" test, D4740 is an approximate indication of compatibility and stability.
- The Shell P-value is a measurement of asphaltene solubility and precipitation due to compatibility/stability issues using aromatics titration testing.
- SARA measures **S**aturates, **A**romatics, **R**esins and **A**sphaltenes. SARA indicates the asphaltene solvent power of fuel and susceptibility to paraffins catalyzing the asphaltene precipitation.
  - o Aromaticity is critical to keep asphaltenes in solution, generally a level of at least 50% is needed.
- The sulfur spec is pegged to 0.47 mass% to account for Marpol testing margins rather than the ISO 4259 methodology of 0.59 of reproducibility. This ensures 95% confidence level of always meeting the IMO 2020 spec.

ISO adopting the proposed VLSFO specs will promote stability of VLSFO pricing and performance, ensuring predictability for both shipowners and suppliers. We plan to send the proposed VLSFO specs to the ISO Technical Working Group responsible for ISO 8217-2017 and PAS.

For additional information and comments, please contact the authors at ara@refautom.com.

ISO 8217 - PROPOSED REQUIREMENTS FOR VLSFO MARINE RESIDUAL FUELS

Characteristic		Unit	Limit	Category ISO-F- RMA	RMB	RMV	RMD	RMV	RME	RMG		RMV	RMG		RMK			Test method reference
				10	30	30	80	130	180	180	380	380	500	700	380	500	700	
Kinematic viscosity at 50 °C		mm2/s a	Max	10/30	30	30	80	130	180	180	380	380	500	700	380	500	700	ISO 3104
Density at 15 °C		kg/m3	Max	920	960	960	975	975	991			991				1010		ISO 3675 or ISO 12185; see 6.1
CCAI		–	Max	850	860	860	860	860	860			870				870		see 6.2
Sulfur b		mass %	Max	Statutory requirements		0.47	Statutory requirem	0.47	Statutory requirements			0.47	Statutory requirements					ISO 8754 or ISO 14596 or ASTM D4294; see 6.3
Flash point		°C	Min	600	600	600	600	600	600			600				600		ISO 2719; see 6.4
Hydrogen sulfide		mg/kg	Max	200	200	200	200	200	200			200				200		IP 570; see 6.5
Acid number c		mg KOH/g	Max	25	25	25	25	25	25			25				25		ASTM D664; see 6.6
Total sediment – Aged (TSA only)		mass %	Max	10	10	10	10	10	10			10				10		ISO 10307-2; see 6.9
Carbon residue – Micro method		mass %	Max	25	10	10	14	14	150			180				2000		ISO 10370
Pour point (upper) d	Winter	°C	Max	0	0	0	30	30	30			30				30		ISO 3016
	Summer	°C	Max	6	6	6	30	30	30			30				30		
Water		volume %	Max	30	50	50	50	50	50			50				50		ISO 3733
Ash		mass %	Max	40	70	70	70	70	70			100				150		ISO 6245
Vanadium		mg/kg	Max	50	150	150	150	150	150			350				450		IP 501, IP 470 or ISO 14597; see 6.14
Sodium		mg/kg	Max	50	100	100	100	100	50			100				100		IP 501, IP 470; see 6.15
Aluminium plus silicon		mg/kg	Max	25	40	40	40	40	50			60				60		IP 501, IP 470 or ISO 10478; see 6.16
Spot Test		number	Max			1		1				1						ASTM D 4740
Shell P-Value		P-VAL	Min			1.5		1.5				1.5						Shell SMS 1600-83
Asphaltenes (SARA)		wt%	Max			1.0		3.2				10.0						IP 143
Aromatics (SARA)		wt%	Min			55		55				55						IP 143
Used lubricating oil (ULO): – Calcium and zinc; or – Calcium and phosphorus		mg/kg	-	Calcium > 30 and zinc > 15 or Calcium > 30 and phosphorus > 15														IP 501 or IP 470, IP 500; see 6.17

a 1 mm²/s = 1 cSt.
b The purchaser shall define the maximum sulfur content in accordance with relevant statutory limitations.
c See Annex E of ISO 8217.
d Purchasers should confirm that this pour point is suitable for the ship's intended area of operation.

FIG. 1. ISO 8217 proposed specs for VLSFO marine residual fuels.

Improving sustainability through digital transformation

C. LAU, Schneider Electric

In the last two years, we have been seeing a major shift of sentiment toward sustainability from the major oil and gas companies. More and more major oil and gas producers are acknowledging climate change and announcing sustainability strategies and ambitious sustainability goals. Part of the motivation behind these shifts can be attributed to public opinion and, more recently, investment community pressure. Recently, a major investment institution withdrew investment funds from one of the largest oil and gas companies in the world, stating that the oil and gas producer is not adequately addressing sustainability. This sends a subtle message to oil and gas companies that sustainability ought to be a critical part of their company strategies, not just a public relations marketing campaign.

To immediately and completely shun fossil fuels is unrealistic; but adopting an energy transition strategy like a gradual shift to natural gas and renewables is a pragmatic one. Fossil fuel power generation will decrease from 60% to 50% from 2020–2040 (primarily decreasing in coal sources), but natural gas and renewables are forecast to grow. The shift to gas is a major transition strategy because electrification comes from power generation; burning gas generates 50%–60% less carbon dioxide (CO_2) than coal. The electric vehicle (EV) segment is projected to grow by a few million in 2020 to about 160 MM by 2040; therefore, electrification is forecast to grow drastically.

Without committing to any particular sustainability goals set by regulations, oil and gas companies must show that they are making sustainability improvements year over year. An automation cliché rings true here: "You cannot improve what you cannot measure." Companies must measure their sustainability key performance indicators (KPIs), make them visible and show consistent improvement on these KPIs.

Seizing opportunities. A few progressive oil and gas companies are diversifying some of their investment portfolio into greener businesses, such as renewable generation, electrical distribution, EV charging infrastructure, bio fuels, etc. Others are focusing on improving operations to become more sustainable through better design, safer operations, use of renewables, electrification of processes, use of local content, local labor, development of the local economy, etc.

Other opportunities to reduce the oil and gas industry's carbon footprint include reducing methane emissions/leakage, primarily in the upstream segment. Other opportunities to reduce combustion emissions include developing carbon capture, utilization and storage options, and developing uses for natural gas in the transportation sectors. Digitalization advances offer great opportunity in improving energy efficiency by data integration, visualization and optimization, and require (in general) much less investment compared to plant and hardware capital investments.

Schneider Electric helps oil and gas companies improve sustainability through a few digital transformation strategies:

Safety is sustainability. Safety is the fundamental and most important sustainability KPI in the oil and gas industry. Industrial accidents impact human lives and cause major environmental pollutions. The license to operate and corporate branding hinge upon safe operations. Digital asset maintenance that incorporates Industrial Internet of Things (IIOT) technologies and artificial intelligence (AI) data analytics further improve asset availability and performance.

Sustainability compliance reporting. Plant-to-enterprise sustainability visibility helps manage energy, sustainability and efficiency data across an enterprise. It optimizes onsite energy resources and allows companies to easily track, forecast and visualize data to maximize a facility's efficiency.

Sustainable power sourcing. Schneider Electric helps clients to source renewable energy strategically by providing expertise to navigate the rapidly evolving renewable energy markets.

Resilience/microgrid management. Microgrid management provides optimum and reliable energy management, allowing integrated real-time control for microgrid stability, supported by advanced analytics into a comprehensive, scalable management system. Microgrid management is especially valuable for energy optimization applications that may include multiple energies sources like renewable energy, grid power, onsite power generation, battery energy storage, UPS, etc.

Improved energy efficiency. Through integrated power and process systems, and software technologies like advanced process control, real-time optimization and data analytics, operators are presented with real-time information on energy economics, instilling accountability in operations. Optimized energy management increases process efficiency by reducing the total cost of energy per unit of output (e.g., balancing demands for electricity, gas and steam consumption).

Sustainability as a service. AlphaStuxure is a joint venture between Carlyle Group and Schneider Electric to provide an energy as a service solution to help customers design, build, own, operate and maintain their energy management system with no capital outlay. Many companies are now mandating renewable energy as part of the energy source mix. ●

CONSTANTINE LAU is a Global Director of the oil and gas segment with Schneider Electric, and has more than 20 years of experience in industrial automation and software. He is responsible for oil and gas segment business strategies, sales and marketing programs. Lau has published numerous articles on advanced software topics, including advanced process control and optimization, AI systems and Fieldbus. He graduated with dual engineering degrees from the University of Texas, and an MBA from the University of Houston.

Applied Motion introduces internationally certified stepper drive

Class I hazardous locations containing flammable gases, vapors or liquids in the air in quantities that can produce explosive or ignitable mixtures require motors certified for operation in this environment. The same is true for Zone 2 (also known as Division 2) hazardous locations in which flammable gases, vapors or liquids are unlikely to occur in normal operation but, if they do occur, will only persist for a short period of time. These explosive areas are commonly found in the oil, gas, refining, petrochemical, mining and printing industries.

Applied Motion offers the only step motor drive internationally certified for use in hazardous locations with ATEX and IECEx certification for Class I, Zone 2 locations, and UL certification for Class 1, Div. 2, Group C & D locations. Approved for use in hazardous industrial applications throughout the U.S., Canada, Europe and Middle East, the STAC6-Q-H stepper drive (FIG. 1) eliminates the hassle and costs associated with gaining regulatory compliance for specifying different drives approved for use in different locations. The global coverage offered by the stepper drive gives Applied Motion's partners operating in hazardous environments in the oil, gas and printing industries a best-in-class solution for their motion control applications.

In operation, the STAC6-Q-H stepper drive is powered by single-phase 120 VAC that generates a nominal 160 VDC internal bus. The drive provides superior performance when paired with high-quality NEMA 23, 24, 34 or 42 frame step motors. An advanced anti-resonance algorithm ensures optimal torque over a wide speed range, while microstepping to 51,200 steps/rev provides for smooth, high-resolution positioning.

An encoder feedback option is available for enhanced system accuracy using Applied Motion's proprietary Stall Detection and Stall Prevention features, which overcome limitations of open-loop step motor systems. The drive is capable of running stored programs created with Applied Motion's Q programming language and has sufficient input/output signals to connect to multiple external devices or sensors. ●

FIG. 1. Applied Motion offers a step motor drive that is internationally certified for use in hazardous locations with ATEX and IECEx certification for Class I, Zone 2 locations, and UL certification for Class 1, Div. 2, Group C & D locations.

Oil-to-chemicals: New approaches from resid and VGOs

JOHN. J. MURPHY and **CLYDE F. PAYN,** The Catalyst Group

Crude oil-to-chemicals (COTC) continues to be a powerful industry driver, and a strong trend of high interest to integrated refineries and chemicals producers. This is reinforced by many factors, most notably by forecasts that predict a slowing of transportation fuels growth approaching 2040 (with hybrids and EVs), while the growth in chemicals is expected to increase as the population and middle-class wealth continues to rise, leading to increasing demand for packaging, consumer goods and automobiles.

Numerous corporations have committed a combined $315 B to reconfigure their assets to produce more petrochemicals than transportation fuels, as revamps as well as to build new grassroots refineries during the next decade. We anticipate that another $300 B or more will also be announced in the next five years as refiners and chemical companies reassess their positions, knowing that the longer-term outlook for transportation fuels from crude oil is expected to plateau and then decline.

Integration. Considerable flexibility is being offered by petrochemical licensors, particularly in petrochemical resid and vacuum gasoil (VGO) and fluid catalytic cracking (FCC) upgrading units. These global changes include deep catalytic cracking (DCC) from Sinopec, as well as Western leaders such as TOTAL's R2R modifications, and Axens' high-severity FCC (HSFCC) with Saudi Aramco. Technology does not stand still. Advances in catalytic visbreaking may also be important in the future, when looking into advanced lower-cost alternatives and R&D pipelines.

Two main interests for producers are 1) to decrease capital intensity through scale, simplicity and location; and 2) to expand/maximize flexibility toward the use of current (heavier) feedstocks in considering the "oil-to-chemicals" approach. The idea that better utilizing assets from within an integrated refinery site means that you are most likely already dealing at 10-times the size of a world-scale petrochemical plant. Although scale counts, it is also only one of many factors. New advanced configurations will now begin to incorporate the planning of improved efficiency gains and reduced carbon dioxide (CO_2) emissions, as well. In its *2018 Outlook for Energy,* ExxonMobil forecast that by 2040, while energy efficiency gains are expected to nearly double, carbon emissions are only projected to increase by a modest 10% (**FIG. 1**). BP statistics, along with Chevron, IEA and EIA forecasts, also show similar trends.

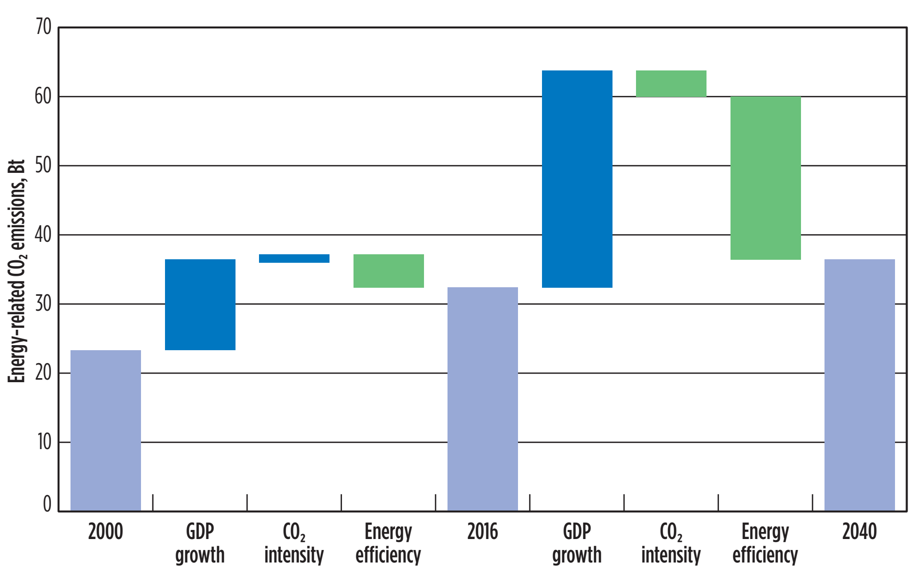


FIG. 1. Energy efficiency gains are expected to nearly double by 2040, while carbon emissions are projected to increase by a modest 10%. (ExxonMobil *2018 Outlook for Energy*).

Company	Location	Cost ($BIL)	Type	Projected Start up
China				
Zhejiang Petroleum and Chemical[2]	Zhoushan, China	$20	Greenfield	2019 (Phase 1)
Hengli Petrochemical[2]	Changxin Island, China	$11	Greenfield	2019
Shenghong Petrochemical[1, 2]	Lianyungang, China	$11.84	Greenfield	2019
Ningbo Zhongjin Petrochemical (subs Rongsheng Petrochemical)[3, 4]	Ningbo, China	$5 (est)	Revamp	2018
Saudi Aramco/NORINCO/Panjin Sincen (Huajin Aramco Petrochemical)[5]	Liaoning Province, China	$10+	Greenfield	2024
SABIC/Fuhaichuang Petrochemical[5]	Zhangzhou, China	NA	Greenfield	NA
SINOPEC/SABIC (Tianjin Petrochemical)[5]	Tianjin, China	$45 combined (est)	Revamp	Operating, pre-2017
PetroChina[6]	Dalian, China		Revamp	Operating, pre-2017
PetroChina[6]	Yunnan, China		Revamp	Operating, pre-2017
CNOOC[6]	Huizhou, China		Revamp	Operating, pre-2017
SINOPEC[6, 7]	Lianyungang, China	$2.8	Greenfield	NA
SINOPEC[6, 8]	Caofeidian, China	$4.2	Greenfield	NA
SINOPEC[6, 9]	Gulei, China	$4.26	Greenfield	2020
	Total China:	$120.1		
Other Asia				
Hengyi Group[1]	Pulau Muara Besar, Brunei	$20	Greenfield	2020
Saudi Aramco/ADNOC India Consortium[2]	Raigad, India	$44	Greenfield	2025
Petronas/Saudi Aramco (RAPID)[5]	Pengerang, Malaysia	$2.7	Greenfield	2019
ExxonMobil (Singapore Chemical Plant)[11, 12]	Jurong Island, Singapore	<$1	Revamp	2023
Pertamina Rosneft[8, 13, 14, 15]	Tuban, East Java, Indonesia	$15	Greenfield	2025
	Total Other Asia:	$82.7		
Middle East				
ADNOC[2]	Al Ruwais, UAE	$45	Revamp	2025
Saudi Aramco/SABIC[2]	Yanbu, Saudi Arabia	$30	Greenfield	2025
Saudi Aramco/Total[5]	Jubail, Saudi Arabia	$5	Greenfield	2024
KNPC/KIPIC (Al-Zour Refinery)[16]	Al Ahmadi, Kuwait	$13	Greenfield	2019
Oman Oil Company/Kuwait Petroleum International (Duqm Refinery)[17]	Oman	$15	Greenfield	NA
	Total Middle East:	$108		
Europe				
MOL Group[18]	Hungary, Croatia	$4.5	Revamp	2030
	Total Europe:	$4.5		
Total Greenfield: $215	Total Revamps: $100	Total Global: $315		

FIG. 2. Announced oil-to-chemicals investments, 2019. (TCGR, "Oil-to-chemicals II: New approaches from resid and VGOs.")

In addition to Saudi Aramco/SABIC announcements, ongoing investments in competitive COTC developments are being seen. In a more recent example, private chemical producers Hengli and Rongshengin China are back-integrating their chemical plants to add more than 9 MMtpy of paraxylene (PX) capacity by 2021. This is expected to reduce PX imports by 4 MMtpy, with plans to yield up to 45 wt% of chemicals processing heavy crudes, which will tighten medium-to-heavy crude markets while also adding a 40% surplus to distillates and gasoline markets.

One of the most difficult components has been to understand that all licensors need to prioritize their own businesses. Therefore, they will prefer greenfield investments to revamps—even if these can be accomplished at lower inside battery limits (ISBL) and outside battery limits (OSBL) costs. This is not a criticism but rather a statement of fact based on desired business focus. Moreover, one understanding is to appreciate how existing and new configurations can be tailored towards either aromatics or olefins; however, this may not be the best measure if the goal is to produce more olefins. In this regard, assuming an existing steam cracker, the revamp approach may be quite different.

Advances to heavy oil processes. For processes that convert the higher molecular weight constituents of petroleum (the heavy ends) to products that are suitable for use of feedstocks to the petrochemical section of the refinery, the assessments are broken into groups to include carbon rejection and hydrogen-addition approaches, along with process combinations and new configurations.

- Carbon rejection
- Hydrogen addition
- Combining processes and treatment of intermediates
- Configuration issues and advances
- New processes likely to be deployed during the next five years.

Highlights addressing potential deployment of technology advances, including combinations and configurations include:

- For decades, propane has been the mainstay used extensively in deasphalting heavy feedstocks, especially in the preparation of high-quality lubricating oils and feedstocks for catalytic cracking units. Future units, which may well be derived from the ROSE™ process, will use solvent systems that will allow operation at elevated temperatures relative to conventional propane deasphalting temperatures, thereby permitting easy heat exchange. Other areas of future process modification will be in the extractor tower internals, studies with higher molecular weight solvent, accurate estimation of physical properties of mixed streams, studies in combination with other processes and firming up design tools for supercritical solvent recovery configuration.
- For heavy feedstocks, which will increase in amounts in terms of hydrocracking feedstocks, reactor designs will continue to focus on online catalyst addition and withdrawal. Fixed-bed designs have suffered from (1) mechanical inadequacy when used for the heavier feedstocks, and (2) short catalyst lives (six months or less), even though large catalyst volumes are used [a liquid hourly space velocity (LHSV) typically of 0.5–1.5]. Refiners will attempt to overcome these shortcomings by innovative designs, allowing better feedstock flow and catalyst utilization or online catalyst removal.
- Catalyst development will be key in the modification of existing processes and the development of new processes to make environmentally acceptable distillable liquids. Although crude oil conversion is expected to remain the principal future source of petrochemicals, natural gas reserves are emerging, and will continue to emerge, as a major hydrocarbon resource.
- The detrimental effects of coke are a reduction of support porosity, leading to diffusional limitations and finally blocked access to active sites. Nevertheless, moving-bed or ebullated-bed processes alone—or in combination with fixed-bed reactor technology and/or also coupled with thermal processes employing suitable catalyst with metal retention capacity—represent the most efficient way of handling petroleum bottoms and other heavy hydrocarbons for upgrading.

Critical to an assessment of the oil-to-chemicals potential are the number and types of committed investments to date. A 2019 industry study (TGCR 2019) documents the announced investments declared during the last five years as oil-to-chemicals projects, along with company, location, size of project and investment. Where available and announced, **FIG. 2** includes the wt% fuel vs. chemical targets.

Project examples exist where these considerations have already been reviewed. For example, MOL Petrochemicals, Tiszaujvoros, Hungary, has decided to upgrade its 100,000-tpy facility to produce more polymer grade propylene from steam cracking and refinery feedstocks. It has chosen two steps utilizing Lummus OCT, which will generate increased propylene production, and a CDHydro Deisobutanizer, which will generate an isobutene-rich stream. These modifications are reportedly available for less than $50 MM. The MOL revamp is interesting as it intends to incorporate Innovacat swing fixed-bed technology in the refinery.

Another example is the revamp for the Polish refiner Grupa LOTOS. In 2011, it installed and made operational a new generation of DAO hydrocracking technology as part of a major resid upgrading project called the 10+ Programme. In this case, it raised refining capacity by 75%, focused on higher margin diesel fuels to increase market share and enhanced margins by $5/bbl. In this case, the two units added by Shell Global Solutions were a 45,000-bpd DAO hydrocracker using 50/50 VGO/deasphalter (DAO) straight off these units, with the added DAO unit. What is interesting using Urals feedstock is that the hydrocrackers, inclusive of both hydrodemetalation (HDM), hydrodesulfurization (HDS) and hydrodenitrogenation (HDN), were able to increase conversion from 60% to 85% with a recycle mode.

Based on the information from these examples and assuming the VDU and ADU investments are already in place, then, a solvent deasphalting (SDA) unit (KBR Rose, or Axens Hyvahl or SELEX-Asp) depending on the product slate chosen, is a considered first step at a lower approximate cost of $250 MM–$280 MM. The following issue depends on the existing HDM, HDS and HC capacity.

Takeaways. The ongoing drive for improved profitability profiles, derived by producing petrochemicals as opposed to fuels, has justified the increased pace of the oil-to-chemicals movement. Not only are demands for olefins and aromatics growing more quickly than gasoline and diesel, the profit margins for these petrochemicals are also higher, and even more so when made directly via oil-to-chemicals conversion routes.

Two oil-to-chemicals approaches—carbon out and hydrogen in—have implications across related technologies. Coking will remain a "go to" for carbon-out with any advances outsizing impacts (due to the breath of implementation, e.g., delayed coking); hydrogen supplies will need to increase or become more flexible (without additional energy/CO_2 impacts) to address the range of upgrading requirements. •

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MAJORS LOOK TO STORE JET FUEL AT SEA AS AIR TRAVEL DRASTICALLY CURBED

Major oil companies including BP and Shell are preparing to take the rare step of storing jet fuel at sea as the coronavirus outbreak disrupts airline activity globally, while refiners are shifting to diesel due to the poor margins associated with jet fuel production.

Jet fuel demand has cratered as airlines suspend flights due to the coronavirus pandemic, which globally has infected more than 350,000 people and killed more than 15,000 (as of 3/23/20), prompting travel restrictions from governments around the world, including the U.S. Market participants and refiners have had to scramble to adjust to incredibly low prices.

Storing jet fuel at sea, however, is something of a last resort. The product is sensitive to contamination and degrades more quickly than other refined fuels and especially crude oil, so after a few months, it no longer can be used for aviation, according to analysts.

Jet fuel demand averages about 8 MMbpd, but that has already dropped by about 20%, according to Robert Campbell, head of oil products at consultancy Energy Aspects.

Overall, the oil market could see a record build in supply in April that could overwhelm storage capacity within months, analysts said.

"With European kerosene (jet fuel) stocks near record levels, floating storage is one possibility for surplus jet fuel, though due to strict quality specifications, traders will be reluctant to attempt long-term storage of surplus fuel given the risk of contamination," Campbell said.

Shifting the mix. Storing refined products is more difficult than storing crude oil due to concerns about oxidation, stability and moisture content. Some U.S. refiners have decided to blend jet into the diesel pool, which is presently more profitable. A small amount of jet fuel can be dropped into diesel in crude distillation towers at a refinery, which separates raw crude oil into products with different boiling points.

Refiners can also choose to adjust their fluid catalytic cracking units (FCCUs) to yield less gasoline and more distillate. However, the move could be oversupplying the diesel market in some regions of the U.S. •

SNC-LAVALIN, continued from page 7

factors and tests them through different scenarios by way of sensitivity analysis. The objective is to assess—as rigorously as possible—whether and where integration is appropriate and, if it is, what market drivers will deliver the optimum ROI. The result is a detailed economic analysis for the overall profitability of an integrated complex.

Case study. More than 60% of U.S. refineries have one or more FCCUs, and approximately 75% of them are in the U.S. Gulf Coast (USGC) region. Half of the U.S. propylene is produced as a byproduct of FCC operation, and investment spending is going into FCC revamp to produce low-sulfur, high-octane gasoline. The majority of U.S. refineries can be integrated to petrochemicals based on current gasoline producing configuration by adding propylene recovery and other propylene-based petrochemical units, such as acrylic acid and acrylates. Several market studies show that the demand for acrylic acid and acrylates is a steadily growing market in both the U.S. and developing countries globally.

This case study illustrates the synergies of refinery-petrochemical integration through a propylene recovery unit from an FCC-based refinery. The base case is a 100,000-bpd fuel refinery to produce naphtha, diesel and IMO fuel oil using a 50/50 blend of Arabian Light and heavy crudes (FIG. 1).

The feed and product pricing are an average of 2Q and 3Q 2018, USGC. The integration cases considered in this study are:

- Case #1: Base case configuration with crude unit, DHDS, ARDS, SGP, SRU/ARU and HMU
- Case #2: Case 1 plus RFCC (23,000 bpd) with a propylene recovery unit (9,200 bpd)
- Case #3: Case 2 plus polypropylene unit (9,000 bpd)
- Case #4: Case 3 plus acrylic acid unit (1,100 tpd)
- Case #5: Case 4 plus n-butyl acrylate unit (1,800 tpd)
- Case #6: Case 4 plus 2-ethyl hexyl acrylate (2,600 tpd)

The study presents the incremental relative economics for each of the integration steps. FIG. 2 shows the economic summary of all cases.

The installation of a propylene recovery unit requires 20% more capital without giving any economic benefit. Integrating a polypropylene unit (Case #3) will enhance the rate of return (IRR), but the inclusion of an acrylic acid or an acrylates unit will be much better and will enhance the return to as high as 10%–20% (Cases #4, #5 and #6).

Uncertainty in the traditional fuel market will lead to integration. The complexity of integration projects depends on the variety of process units, whether it is revamp/expansion or new grassroots plant, and the optimal solution is highly specific to each company. The downstream technical solutions group at SNC-Lavalin provides consulting and advisory expertise to support investment, financing and strategic decisions. ●

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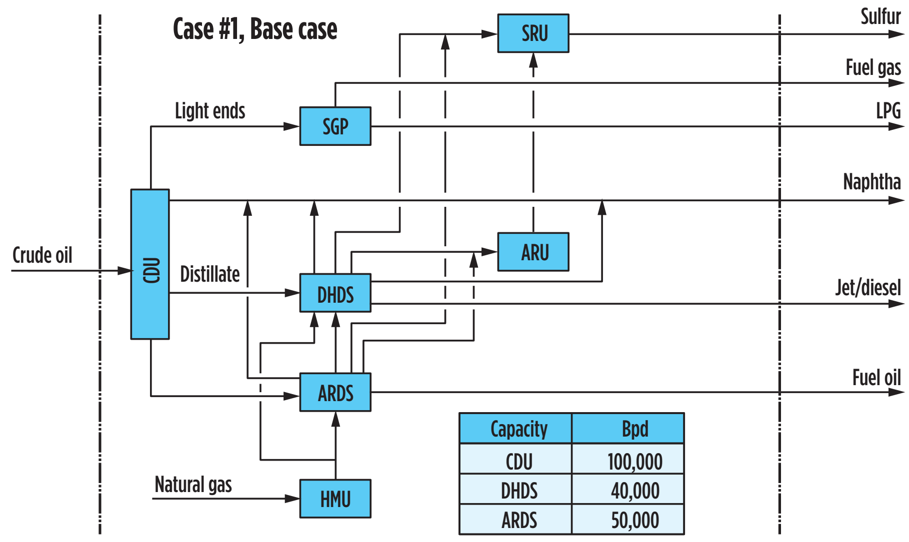

FIG. 1. Base case configuration of a simple fuel refinery.

Case no.	1	2	3	4	5	6
Relative TIC	1.00	1.20	1.39	1.52	1.63	1.62
Payback period, yrs	11.4	11.4	10.7	8.9	7.1	5.3
IRR, %	8.5	8.5	9.4	11.9	15.5	20.7

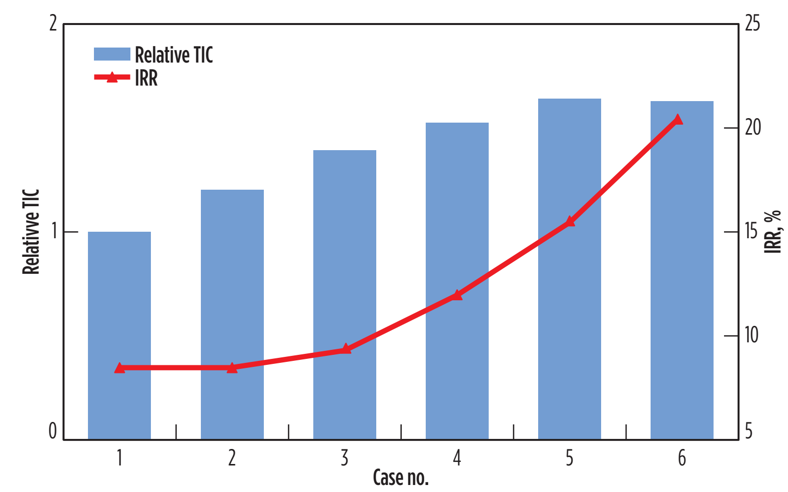

FIG. 2. Relative investment and IRR.