# Exhibit A

# Designing a crude unit heat exchanger network

**Preheat train design for heavy Canadian crudes can be very challenging, requiring an approach not normally required with other crudes**

TONY BARLETTA and STEVE WHITE *Process Consulting Services*
KRISHNAN CHUNANGAD *Lummus Technology Heat Transfer*

A well-designed crude and vacuum unit (CDU/VDU) heat exchanger network is essential to meet product yield, product quality, unit reliability and crude processing flexibility objectives when processing heavy crudes. Preheat trains conceived with the wrong flow scheme or those with multiple parallel paths that are complex to operate rarely have the flexibility needed to handle a range of crude blends or even the variability of many heavy Canadian crudes. Standard shell and tube exchangers designed with low velocity are prone to rapid and heavy fouling.

It is becoming ever more important to temper crude train design that has been developed from composite curves, optimal energy targets and pinch points with crude unit experience and know-how. Practical concerns include operability, reliability, exchanger type and minimal fouling design. Real-world experience using flexible preheat networks, good exchanger design practices and proven exchanger technology is proving to be more important than theory. This article covers practical considerations when designing CDU/VDU preheat networks for heavy crude processing.

## Heavy crude challenges

The desalter is an integral part of the crude unit, and unit reliability is directly related to desalter performance. Desalting is becoming increasingly important as crudes get heavier and contain more contaminants that increase the difficulty to desalt. Poorly performing desalters with a high desalted crude salt content are dramatically increasing unit corrosion and wreaking havoc on unit reliability.

With heavy crude processing — particularly with some heavy Canadian crudes — it is becoming more important to have the flexibility to operate the desalter at an optimum temperature. The optimum desalter temperature is no longer a single, fixed design target; it is an operating variable that must be adjusted to maintain peak desalter performance. In heavy Canadian crude processing, the optimum temperature can change by 15-25°C, depending on the crude or crude blend, to avoid massive asphaltene precipitation. The ability to change the desalter temperature by 15-25°C must be part of the preheat train's design objectives. This requirement must be identified, since a preheat train designed with normal methods will not provide the massive amount of swing heat that will need to be shifted to/from the cold crude train.

> **The ability to change the desalter temperature by 15-25°C must be part of the preheat train's design objectives**

Many heavy Canadian crudes have a high asphaltene and solids content and considerably higher fouling potential compared with other crudes. Blending these crudes with paraffinic diluents or other paraffinic crudes can precipitate asphaltenes in the preheat train or desalter. Special exchanger design considerations are required to reduce fouling.

Refiners have noticed a variable composition with some heavy Canadian crudes. Some of these crudes, such as Western Canadian Select (WCS), are blends of other heavy crudes. As blend ratios change, so does the composition. Some heavy Canadian crudes are distillate laden, while others contain more gas oil. It is becoming apparent that refiners with preheat trains flexible enough to handle variable product yields will benefit most from processing these crudes.

## Current network design practice

CDU/VDU preheat train designs are relying more and more on theoretical constructs such as pinch analysis without sufficiently considering realities such as fouling tendency and system operating flexibility required for heavy crude processing. Advances in computer speed and easy-to-use targeting programs have made pinch analysis a prerequisite for network design. While pinch technology can be a very useful tool, a preheat network cannot be designed for a single theoretical optimum point, nor can it ignore the practical realities of running today's ever more challenging crudes.

The preheat train is part of an integrated system and needs to have the flexibility to process

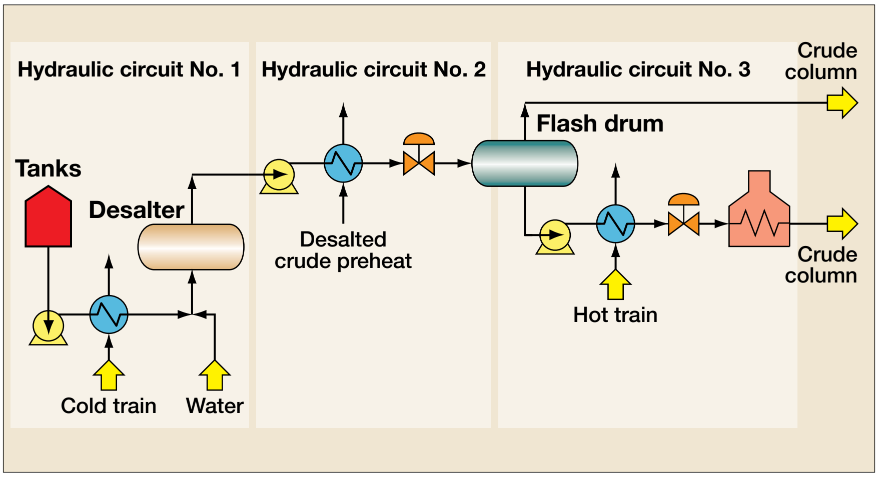


**Figure 1** Simplified preheat train

varying crude blends while meeting seasonal or economic product yield targets. These days, few refiners have the luxury of running one crude or even a consistent crude blend. Increasingly, refiners are processing larger quantities of opportunity or heavy crudes to remain profitable.

To make matters worse, outmoded design approaches that rely on exchanger experts and vendors to design around an allowable pressure drop, without sufficient understanding of the integrated system, continue to be used. Today, most projects use system engineers to develop P&IDs, with hydraulic calculations for each circuit setting hydraulic allowances for exchangers, control valves, strainers and other equipment. In many cases, system engineers do not do the process modelling and therefore do not have a thorough understanding of the variability of all potential operating scenarios that are required of the exchanger network.

This approach then uses in-house specialists or vendors to design the exchangers, with a major focus on allowable pressure drop. While this approach may be efficient from an execution standpoint, it is a prescription for poor performance. Reliable, low fouling exchangers should be the goal of preheat train design, with pressure drop simply a factor that the hydraulic system needs to handle.

Crude unit exchanger networks must operate reliably for four to six years. Proprietary exchanger technologies with helical baffle designs, such as the HelixChanger heat exchanger, have proven essential in reducing fouling when designed at high velocity. Yet, many recent designs have not taken advantage of the benefits of this technology because of the perceived added exchanger cost. It is not surprising, then, that many crude heater inlet temperatures degrade by 25-40°C within the first few months of operation.

## A more effective approach

Exchanger networks must have the flexibility to meet critical objectives such as desalter temperature in addition to satisfying column heat balances that may be variable as a result of changes in crude composition. Process engineers must first identify the need for and degree of flexibility required for specific crudes or crude blends and make that flexibility requirement part of the preheat train design. There must be more interaction and communication between process and systems engineers to assure flexibility is incorporated into designs.

Secondly, strict adherence to "allowable pressure drop" as the main design criterion must be tempered so that low-velocity, high-fouling designs can be replaced with high-velocity, low-fouling designs. Larger acceptance of the benefits of reduced fouling that a properly designed exchanger can bring is needed.

Finally, energy-targeted methodology can only be part of the answer. Computer programs for network design solve equations developed around a design methodology. The solutions to the equations must be tempered or augmented with practical crude unit know-how. Without this know-how, it is unlikely that an optimal and reliable design will be achieved. Four critical considerations necessary for preheat train design are the exchanger network design philosophy, process flow scheme, exchanger design guidelines and exchanger type. Attention to these key considerations will result in a more robust design.

## CDU/VDU preheat train design philosophy

Compared with other crudes, heavy Canadian crude processing requires more flexibility in the preheat train to adjust the desalter temperature in order to avoid asphaltene precipitation. Distillation column heat removal requirements require more flexibility because of seasonal diluent flow rates and variable crude compositions. The amount of required flexibility should be quantified as an objective of the preheat train design.

Multiple parallel crude trains are rarely optimal. While they may appear to be beneficial on paper, they should be avoided because they are difficult to operate and they generally have little flexibility to handle the required product rate variability and the large cold train preheat duty swings required for good desalting of heavy Canadian crude.

In the preheat train (see Figure 1), crude is heated in the cold train from the tanks to the desalter, in the desalted crude train from the desalter to the preflash drum or column, and in the flashed crude train from the preflash drum/tower to the heater. The cold train duty must have enough flexibility to meet the optimum desalter temperature.

Desalter temperature is a critical operating variable, especially with the heavier, nasty crudes from Venezuela, Canada and other regions. Desalters remove contaminants that play a major role in

CDU/VDU run length as well as downstream unit reliability. A high desalted crude chloride content increases crude unit corrosion and, in some cases, can reduce the downstream hydrotreater and coker run length, as well as increase maintenance costs. In the short run, it is possible to have poor desalter performance and be profitable; however, unscheduled outages and/or loss of containment can cause major profit losses and possibly much worse.

The cold train heats the crude from the storage tanks to the desalter through seasonal changes in raw crude temperatures. For example, Canadian crude oil pipeline temperatures vary seasonally from 20-40°C, with the optimum desalter temperature varying from 120-140°C, depending on the crude blend. The amount of cold train duty that needs to be shifted to meet the wide range of desalter temperatures, while also handling the variable raw crude temperature, is very large. This is a major challenge because of the large amount of swing heat that must be moved before and after the desalter.

Identifying services that allow heat adjustments upstream and downstream of the desalter is critical. Typically, the crude column kerosene pumparound, vacuum gas oil product, diesel product and sometimes vacuum bottoms when it is being run down to storage at low temperatures are good candidates. Exchanger services that provide swing heat should have flow-controlled bypasses so that adjustments can be made as needed. Some Canadian crude blends have large middle distillate product yields, whereas others produce high percentages of VGO. Column heat removal must be sufficient to deal with these variations while meeting desalter and product rundown temperatures. Preheat system flexibility is essential.

Low-fouling exchanger design should be an objective, while the outdated practice of designing for allowable pressure, which leads to low velocity and high fouling, should be discarded. Old rules-of-thumb that require the dirtier service on the tube side for ease of cleaning no longer apply. For example, placing vacuum residue on the tube side will result in poor exchanger design with a high pressure drop and high fouling. Placing vacuum residue on the high-velocity shell side of the HelixChanger heat exchanger will provide a higher heat transfer coefficient, less surface area, lower fouling and less cleaning.

## CDU/VDU process flow scheme

Selecting the right process flow scheme for a crude unit can have a large impact on preheat train design optimisation and unit reliability. Unfortunately, there is no computer program that determines the optimum flow scheme. It is determined from experience and thoughtful evaluation of distillation column heat and material balance requirements dictated by crude blends and their variability. Other factors, such as the mitigation of a high-risk, high-corrosion surface area and crude tower stability, are also important.

Three areas in which the designer positively influences the preheat train are: energy recovery from the top of the crude tower, the number of crude tower pumparounds and their location, and the number of vacuum column product draws. Selecting the right flow scheme, in many cases, can significantly reduce exchanger surface area requirements. In other instances, selecting the wrong flow scheme for the sake of network optimisation can destroy unit reliability and profitability. Refiners processing opportunity crudes have learned this the hard way. Many have experienced short run lengths or periodically must reduce the crude charge rate to clean rapidly fouling exchangers. Others have had extremely high corrosion rates in the crude overhead system, causing unscheduled outages. Clearly, the flow scheme matters.

Many heavy Canadian crudes contain large portions of naphtha used as diluent. In these cases, it is necessary to recover some low-level heat in the crude column overhead, where raw crude is heated with overhead vapour. However, the crude overhead exchanger is a high-fouling and often severe corrosion service. Since this is a high-risk exchanger, the design should maximise heat recovery with minimal surface area.

When crude overhead exchangers are used, viscous crude should be routed through the shell side to minimise the surface area. This is rarely done, because many designers still believe raw crude should always be in the tubes for ease of cleaning. However, it is nearly impossible to get a reasonable heat transfer coefficient with the highly viscous crude on the tube side. In fact, the flow regime is often laminar, resulting in large surface area requirements with a high pressure drop. Shell-side design can be further improved by using helical baffles to minimise dead areas and maximise the conversion of pressure drop to heat transfer. To keep the exchanger clean, it is important to target velocities of 1.5-2.4 m/s on the shell side of the exchanger.

When crude is put on the shell side, the exchanger must be mounted vertically so that the crude overhead can be water washed effectively to minimise corrosion. Crude overhead exchanger corrosion is one of the most common causes of unscheduled outages due to tube failures. Good desalting and an effective water wash system are essential for crude overhead corrosion control.

Horizontal exchangers, with crude routed through the tubes and crude overhead condensing on the shell, have a proven track record of high fouling and are virtually assured of high corrosion rates when processing heavy crudes. It is simply not possible to thoroughly water wash the shell side of conventional exchanger bundles, with inherent "dead" areas that are nearly impossible to reach with water wash. It is also very difficult to effectively water wash the crude overhead stream when it is on the tube side of a horizontal exchanger. However, a vertical exchanger with crude overhead condensing on the

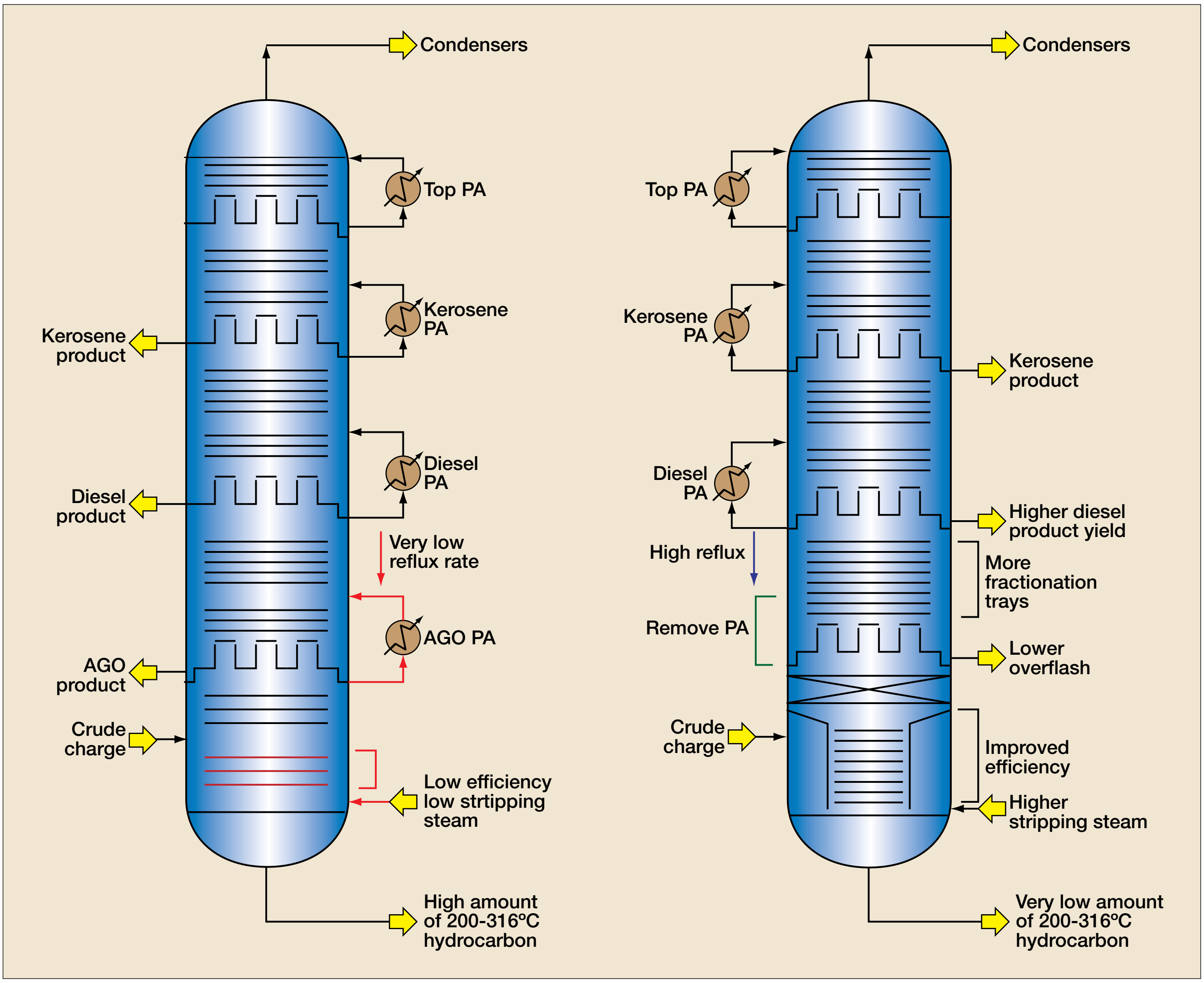


**Figure 2** Crude tower pumparounds

tube side has no dead areas and can be effectively water washed.

A top pumparound can be added to further reduce the amount of high-risk surface area in the crude overhead system. This is especially important with heavy Canadian crude processing. Without a top pumparound all of the reflux for the top tray must be condensed in the crude overhead exchangers. With a top pumparound to supply the reflux the crude overhead exchangers will only condense the product. To be effective, the top pumparound return temperature must be high enough to avoid sublimation of amine salts and water condensation in the top of the crude tower.

Crude column pumparound and product streams can be drawn from the same location or from different locations in the column. For example, some designers will draw diesel product and diesel pumparound from different locations. While this provides some benefits in draw temperature, it can adversely affect fractionation. Low liquid rates on fractionation trays can ultimately lead to product draws that dry out at certain conditions, resulting in unstable operation. When this occurs, as it frequently does, the benefits of split draw are diminished. Crude units designed to process a wide range or variable crude blends should draw product and pumparound from the same location in the column.

Atmospheric gas oil (AGO) pumparounds (see Figure 2) are only warranted when the crude blend is light enough to generate high lift in the crude tower and then provide sufficient reflux between diesel and AGO product for good fractionation. If an AGO pumparound is used with heavy crude, the diesel/AGO product fractionation is poor, resulting in excessive diesel boiling range material in the AGO product. However, this is often overlooked in favour of the high draw temperature associated with AGO pumparounds.

Most vacuum towers are designed with light (LVGO) and heavy vacuum gas oil (HVGO) products, which sets the amount of heat available at a given temperature level. Two-product vacuum towers produce draw temperatures of approximately 145°C and 270°C for LVGO and HVGO streams, respectively. Most, if not all, of the low-level LVGO pumparound heat is lost to air or cooling water because there are not many heat sinks for the low draw temperature. HVGO product heat can be recovered into crude, waste heat steam generation or to reboil light ends towers. The required HVGO pumparound rate

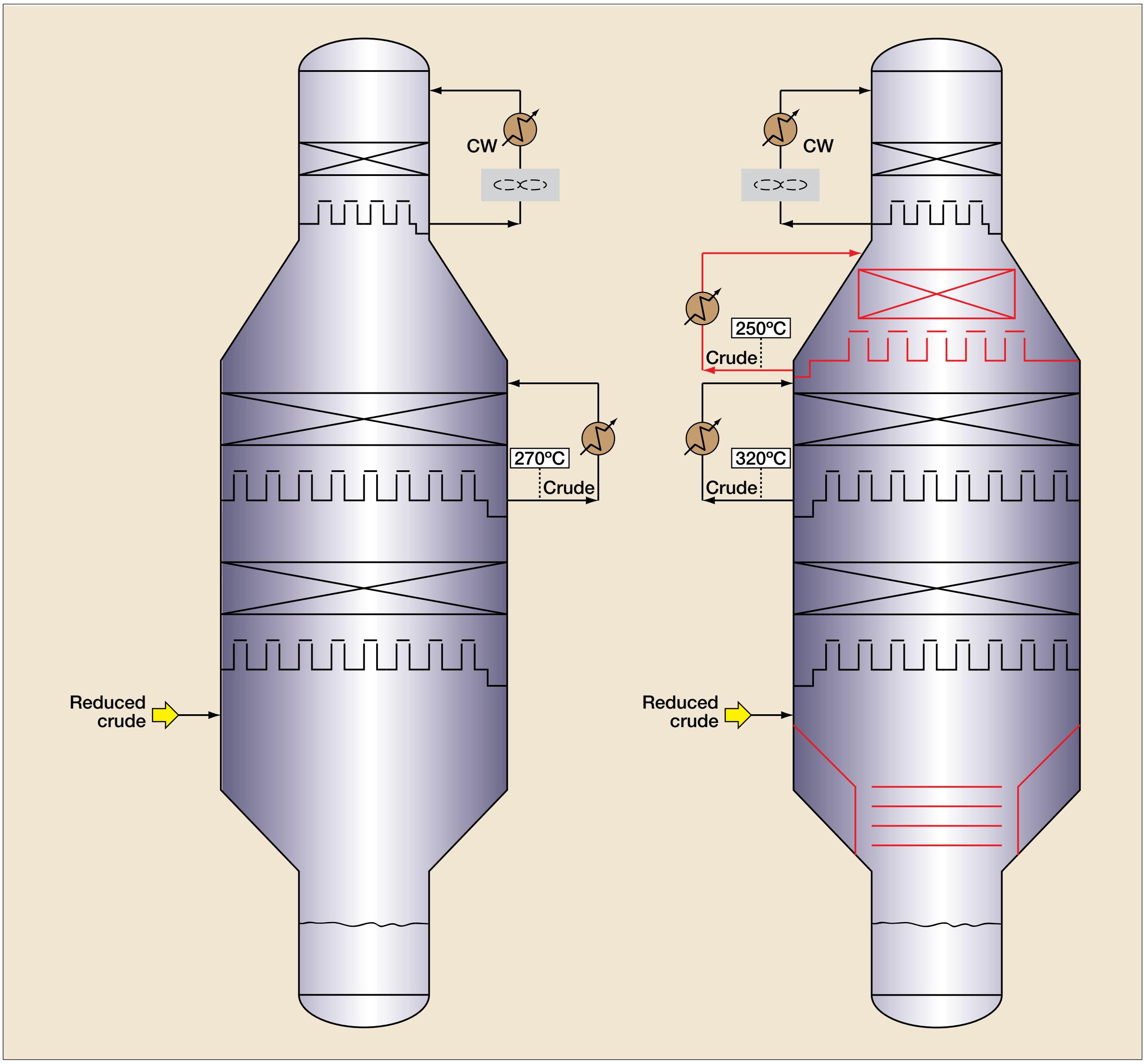


**Figure 3** Vacuum tower MVGO pumparound

and exchanger surface area are typically very high with two product vacuum towers due to a relatively low temperature and high duty.

Adding medium vacuum gas oil (MVGO) product produces three temperature levels (see Figure 3), minimises heat loss to air and water, maximises the heat recovered into crude preheat, and reduces the overall surface area. MVGO and HVGO pumparound streams are approximately 250°C and 320°C, respectively, depending on the product split between MVGO and HVGO. The higher HVGO draw temperature reduces the number of exchanger shells and surface area compared to only an HVGO pumparound.

Figure 4 shows a fully optimised vacuum tower producing diesel, LVGO, MVGO and HVGO product streams. This maximises the production of high-value diesel boiling range material from the CDU/VDU and optimises both the MVGO and HVGO pumparound draw temperature for a given amount of recoverable heat. Drawing LVGO product from the bottom of the fractionation bed further increases the MVGO draw temperature, reducing the capital and operating costs to recover it.

## Low-fouling design

Fouling is a layer that accumulates on the inside and outside of the tubes, reducing heat transfer. The higher the fouling resistance, the lower the heat transfer. The fouling resistance can be between 50-85% of the total resistance for a heavily fouled exchanger. To compensate for high fouling, more area is needed; however, adding more area can be counterproductive because it generally results in lower velocity and higher fouling.

Crude preheat exchangers can be susceptible to very high fouling. Fouling factors as high as 0.01 hr-m$^2$-°C/Kcal have been back-calculated from operating data. Exchanger design and selection are important and can have a significant impact on fouling. Low velocity designs result in high fouling, even for light crudes. A

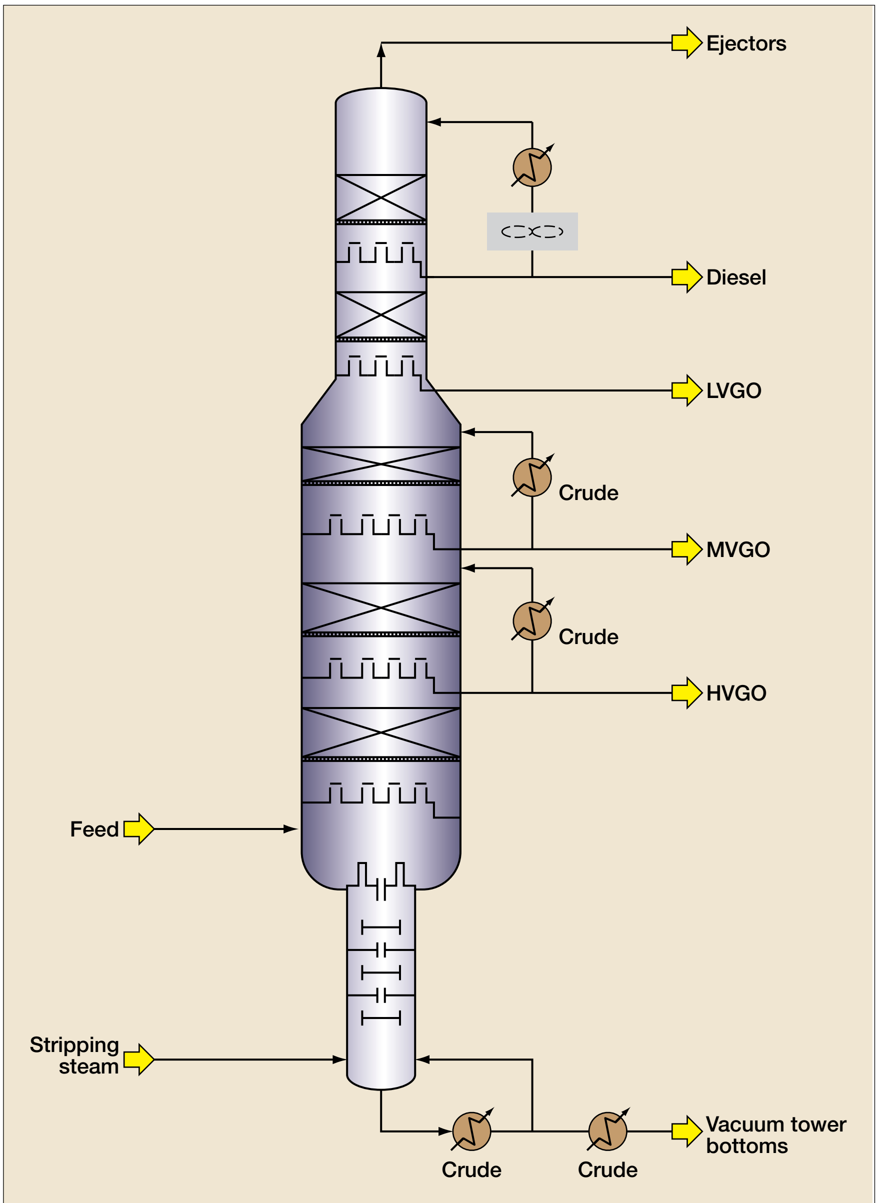


**Figure 4** Optimised four product vacuum tower

properly designed exchanger with high tube- and shell-side velocities will minimise fouling. Certain heavy crude oils are incompatible when mixed together, causing asphaltenes to precipitate. These crude oils are highly unstable, so it is very important to design the exchangers for high velocity.

## Exchanger design guidelines

The designer cannot control the crude fouling tendency, only the exchanger design and exchanger type. For new designs, exchangers can be designed with high velocity and reasonably low fouling factors, which results in a minimal excess surface area. However, for revamps, it is not always possible to rectify all low-velocity designs and realistic fouling factors must be determined from actual plant data so that future performance can be predicted.

## Velocity

Low tube velocities result in high fouling. To minimise fouling, velocities are ideally kept above 2.4 m/s and sometimes higher on the tube side and between 1.2-2.4 m/s on the shell side. High shell-side velocities are achievable with advanced bundle designs, such as that of the HelixChanger heat exchanger, whereas a high shell-side velocity is not practical with standard segmental baffles.

For a new design, when crude is placed on the tube side, a two-pass exchanger with 1in tubes should be used. The number of tubes needed to obtain 2.4 m/s sets the shell's inside diameter. The length of the exchanger or number of shells is adjusted to meet surface area requirements. Increasing the shell's inside diameter and the number of tubes to meet the surface area requirements reduces the tube- and shell-side velocities and increases fouling. Designers will sometimes enlarge the shell's inside diameter to reduce the number of shells to reduce costs. However, this design results in lower velocity, more fouling and higher lifecycle costs that are greater than the original savings.

For a new design, a 1in tube with two passes minimises the pressure drop. A typical two-pass crude exchanger with crude on the tube side at 2.4 m/s will have less than 0.7 $kg/cm^2$ pressure drop per shell. One-inch tubes are preferred over 0.75in tubes because the pressure drop per metre of tube is lower at the same velocity.

For grassroots crude units, a low-fouling design can be incorporated into the pump head specifications. In revamps, exchanger velocities are often limited by existing pump size, pipe flange ratings and exchanger design pressure. Pump system hydraulics must be evaluated carefully for each circuit to determine opportunities to increase velocity and reduce fouling. A low fouling design is not always possible in a revamp because of existing constraints.

Shell-side velocity is limited by the bundle's inside diameter, and baffle geometry and spacing. For example, velocities much higher than 0.62 m/s are not practical in a segmental baffled exchanger. To increase shell-side velocity, baffle spacing and cut must be reduced. A higher pressure drop generally increases flow in the leakage and bypass areas of the bundle. Poorly matched baffle spacing and cuts can also lead to large eddies and "dead" zones.

Advanced baffle designs such as that used in the Lummus Technology HelixChanger design use quadrant-shaped baffles at an angle to create a helical flow pattern through the bundle. This flow pattern reduces dead areas and results in a lower pressure drop for the same velocity compared with a segmental baffled exchanger. The benefit is that the shell-side velocity can be designed for 1.5-2.48 m/s. Crude preheat exchangers designed with high velocity on both the shell and tube side of a HelixChanger have demonstrated extremely low fouling in heavy crude service.

**Is the pressure drop really lower?**

Fouling begins as soon as an exchanger starts up and continues until the terminal velocity is reached. After the terminal velocity is reached, fouling continues but at a much slower rate. Low-velocity exchangers foul rapidly, sometimes reaching the asymptotic fouling level within the first 6-12 months of operation. However, most crude units are being operated for four to six years between planned turnarounds. A fouled pressure drop is significantly higher than a clean pressure drop for low-velocity exchangers. It is not uncommon for the fouled pressure drop to be two to three times higher than the clean pressure drop.

An exchanger designed for high velocity results in a higher initial clean pressure drop. However, a high-velocity exchanger's fouled pressure drop is less than 1.5 times the clean pressure drop. So, does designing a low velocity really result in less pressure drop?

This is especially true for crude preheat trains with multiple exchangers in series. Designing for high velocity will appear to add to pumping costs at first; however, this is not necessarily true after factoring in the significantly higher fouled pressure drop of the low-velocity design. The problem is that there is no way to calculate fouled pressure drop. Most designers do not get feedback from their designs and they do not go to the field to measure pressure drop. If they did, they would appreciate the differences in fouled pressure drop between a low-velocity and high-velocity design.

It is slowly becoming accepted that a high-velocity (high shear stress) design is the main variable needed to produce a low-fouling design; however, there is still reluctance to specify exchangers this way because of a higher initial pressure drop and corresponding higher pumping costs. What is not normally factored in is the fuel costs of a low-velocity, high-fouling design, not to mention the higher maintenance costs associated with more frequent cleanings.

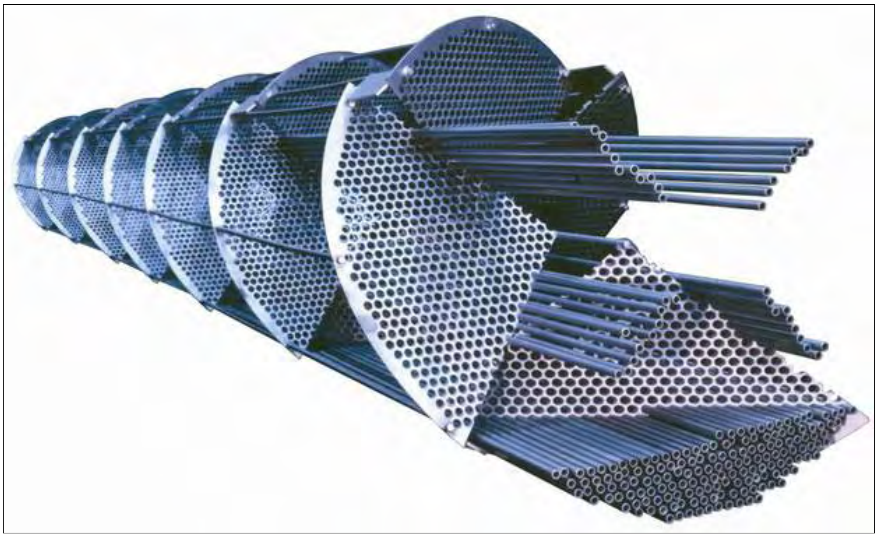

**Figure 5** HelixChanger tube bundle in fabrication *Courtesy: Lummus Technology Heat Transfer*

**HelixChanger heat exchanger advantage**

The inherent deficiencies of conventional segmental baffle shell-and-tube exchangers are widely understood. The key deficiencies are:

- The shell-side region is compartmentalised. Pressure energy is wasted in expansions, contractions and turnarounds in multiple bends rather than in generating heat transfer. The pressure gradient across the baffles drives a significant amount of flow through the tube-to-baffle and shell-to-baffle clearances that escapes heat transfer. The result is inefficient conversion of shell-side pressure drop to heat transfer
- The flow leakage streams distort the temperature profile, reducing the effective mean temperature difference (MTD) for heat transfer
- The perpendicular baffles encourage dead spots or recirculation zones where fouling or corrosion could occur.

The HelixChanger design removes most of the above deficiencies. Quadrant-shaped baffle segments, arranged at an angle to the tube axis in a sequential pattern, guide the shell-side fluid in a helical path through the tube bundle. Figure 5 shows a tube bundle in fabrication. The baffle segments serve as guide vanes without any compartmentalisation, and the flow traverses on both sides of the baffles. The helical flow path through the bundle provides the necessary characteristics to reduce flow dispersion and generate near plug-flow conditions, resulting in high thermal effectiveness. It ensures a certain amount of cross-flow to the tubes to achieve high heat transfer coefficients. Uniform flow velocities are achieved through the tube bundle, and the smooth helical flow eliminates unnecessary pressure losses in the exchanger. There is also negligible dead volume in the helical shell space.

**Reduced fouling characteristics**

The design offers reduced fouling characteristics for the following reasons:

- There are few dead spaces within the helical shell space
- The helical flow velocities achieved are significantly higher (1.5-3 times higher) than the average cross-flow velocities achieved in equivalent segmental baffle designs. Thus, the shear forces acting on the tube wall are significantly higher in the HelixChanger designs
- Uniform flow velocities through

**Figure 6** HelixChanger bundle after two years of operation in hot crude vs hot resid service

the tube-bundle are achieved due to the relatively constant helical flow area. This also translates into more uniform tube-wall temperatures.

## Conclusion

Preheat train design for heavy Canadian crudes can be very challenging. Different requirements such as the need to vary desalter temperature dictate a different approach not normally required with other crudes. A well-conceived design, with the flexibility to handle the variable composition of diluents being used to transport the crude in pipelines, is also required. Designing for high velocity and using advanced exchanger technology has proven that low-fouling designs are possible (see Figure 6).

HELIXCHANGER is a mark of Lummus Technology Heat Transfer.

**Tony Barletta** is a Chemical Engineer with Process Consulting Services, Inc, in Houston, Texas. His primary responsibilities are conceptual process design and process design packages for large capital revamps.
*Email: tbarletta@revamps.com*
**Steve White** is a Chemical Engineer with Process Consulting Services, Inc, in Houston, Texas. He has more than 30 years of process design experience for refinery revamps and grassroots units. *Email: swhite@revamps.com*
**Kris Chunangad** is Director of Heat Exchangers at Lummus Technology Heat Transfer, a CB&I company in Bloomfield, New Jersey. He has more than 18 years of experience in the design and development of advanced heat exchanger equipment, as well as their specialised application in the oil and gas, refining, petrochemical and chemical industries.
*Email: kchunangad@cbi.com*

## Exhibit B

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# Special Report: Refiners processing heavy crudes can experience crude distillation problems

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Refiners will process increasingly heavier crude slates during the next 10 years. A majority will originate from the Orinoco oil belt bitumen upgraders in Venezuela and the Athabasca tar sands region of northern Alberta.

Even blended with lighter crudes, these lower-gravity blends will require crude-unit process flow scheme and equipment design changes to meet profitability objectives.

This article addresses crude distillation unit (CDU) problem areas and identifies specific sections requiring investment to maintain profitability throughout a 4-5 year run length for refiners processing heavy crudes.

Some heavy crudes are blends of 6-8° API bitumens combined with hydrotreated lighter products from bitumen upgraders.

The blended lighter products that help produce synthetic crudes generally distill in the atmospheric column leaving a very heavy 6-8° API feed to the vacuum unit. CDUs must operate at increased severity to maintain product cut points and qualities.

Heavy crudes are more difficult for the CDU to process. Historically, refiners processing heavier crudes have had problems maintaining:

- Crude charge rate.
- Product yield and quality.
- Unit reliability.

### CDU processing difficulties

Table 1 shows some specific problems refiners face when processing heavy crude blends.

**COMMON PROCESSING PROBLEMS** Table 1

High crude-side pressure drop
Desalter upsets and poor desalting
Rapid crude-column condenser corrosion
Crude column naphtha-jet fuel section fouling
Low diesel product yield
Vacuum heater coking
Vacuum column coking
Vacuum column fouling (top section)
High vacuum-column operating pressure
Low HUGO product draw temperature
Low HUGO product yield
High metals feed to the cat feed hydrotreater
General corrosion problems

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Heavy crudes have higher viscosities, some have higher salt content, several have high naphthenic acid content, and they are all more difficult to distill than lighter crude blends. Some upgrader crudes also have lower thermal stability than conventional crudes and higher fouling tendencies due to the increased likelihood of asphaltene precipitation.

Processing difficulties can result from flow schemes and equipment designs that may have worked well with light crudes, but are not compatible with the heavy crude characteristics. Revamps to process heavy crudes must carefully consider the flow scheme and equipment design in order to maintain crude charge rate, product yield and quality, and unit reliability.

Crude blends with gravities <22° API require sufficient cold exchanger train preheat to achieve efficient desalting, which typically requires a desalter temperature between 270° and 300° F.

The desalter must separate the emulsion into low-salt crude and oil-free water.

With a heavier crude feed, the desalter temperature can decrease by 30° to 40° F., if no additional surface area is added to the cold exchanger train. The desalted crude's salt content can increase dramatically if the temperature is too low. Many heavy crudes such as Zuata or Merey can have high salt contents depending on production field operations; therefore, good desalter performance is critical. Poor cold exchanger train designs often cause low desalter temperatures, poor salt removal, and periodic upsets that send large quantities of brine to the atmospheric heater and column.

High chlorides to the atmospheric heater generate large quantities of hydrochloric acid (HCl). Severe fouling in the crude column's top, rapid fouling and corrosion in the atmospheric condenser system, and severe overhead line corrosion often reduce crude runs and unit reliability.

Most heavy crudes have higher viscosities, a condition that makes increasing or maintaining crude charge rate a challenge.

Higher viscosity reduces the crude charge-pump developed head, increases exchanger network pressure drop, and lowers heat-transfer coefficients throughout the cold preheat train. Crude charge rate, atmospheric column heat removal, and desalter temperature are all adversely affected.

Many heavy crudes contain more vacuum gas oils. Refiners, therefore, often increase the atmospheric tower bottom (ATB) product cut point to stay within the vacuum column diameter limits. As ATB cut point increases, however, vacuum unit feed gets heavier resulting in higher vacuum tower bottoms (VTB) yield.

Increasing the vacuum heater outlet temperature can sometimes offset a higher ATB cut point. But many refiners have existing heater design problems that prevent a higher outlet temperature without shortening heater run length. Refiners, therefore, must optimize ATB product cut point to maximize heavy vacuum gas oil (HVGO).

An optimized ATB cut point is about 700° F. for heavy Venezuelan Merey, BCF-17, and Zuata crudes, assuming no downstream equipment limits.

Most refiners and designers adjust ATB cut point vs. crude heater outlet temperature only.

Other parameters are, however, more effective in adjusting ATB cut point: minimized atmospheric column flash-zone pressure, minimized percent overflash, and optimized ATB stripping efficiency.

This maximizes diesel recovery and reduces vacuum ejector condensable load, which permits lower vacuum column operating pressure and helps maintain HVGO product cut point.

Maintaining HVGO cut point is a significant challenge with heavier crude blends. Most refiners lose 40° F. or more in HVGO product cut point when switching to a heavy crude diet. Maintaining cut point requires a combination of lower operating pressure, higher heater outlet temperature, reduced flash-zone pressure, lower flash-zone oil partial pressure (more heater coil steam), and improved VTB stripping. The right combination will be specific to each unit.

The combination of operating variables needed to maintain or increase HVGO cut point is more severe and can lead to rapid vacuum heater or column coking if the equipment is not carefully designed.

Heavy crudes have much higher microcarbon residue (MCR), asphaltenes, and metals. As mandated refinery gasoline and diesel pool sulfur specifications take effect, minimizing cat feed hydrotreater (CFHT) feed contaminants becomes more important.

In some cases, vanadium in the CFHT feed has increased from less than 1 ppm to 5-10 ppm with heavy Venezuelan crudes.[1]

High feed-stream contaminants can reduce run length to less than half the planned turnaround interval.

Optimizing the atmospheric column flash-zone and wash section, and the vacuum unit design can reduce CFHT feed vanadium by 30-40%.

### Heavy crude properties

True boiling point (TBP) distillation curve, contaminants (MCR, asphaltenes, and metals) distribution, viscosity, salt content, and total acid number (TAN) increase CDU operating severity and make heavy crudes inherently more difficult to process.

Venezuelan heavy crudes include Merey, BCF-17, Zuata, BCF-22, and Laguna Blend 22. US refiners are also processing large volumes of Mexican Maya crude. Heavy Canadian crudes include Cold Lake blend, Lloydminster (LLB), and tar sands blends.

Only a few refiners can process these crudes neat.

Other refiners that increase their heavy crude percentage also face many of the same processing challenges.

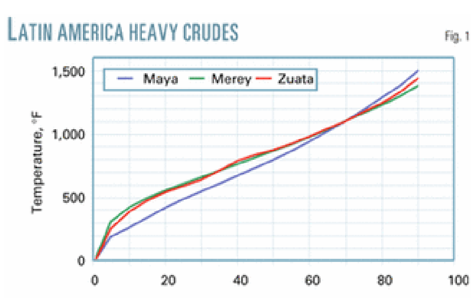
### TBP distillation

Accurate crude TBP curves are essential when CDUs are revamped to process heavy crude feeds. Figs. 1 and 2 show TBP curves for selected heavy Venezuelan and Canadian crudes.

TBP curves are typically generated from ASTM D2892 and D5236 tests. Some refiners now use high-temperature simulated distillation (HTSD) to characterize the whole crude. Significant differences between the two methods become more pronounced as crude API gravity decreases.[2]

We found that HTSD curves provide the best characterization of product yields in the 650+° F. portion of the distillation curve.

We reviewed several comprehensive test runs on crude units processing heavy crudes and compared synthesized whole crude TBP curves generated from product stream HTSDs, whole crude HTSDs, and crude assay TBP curves generated from ASTM

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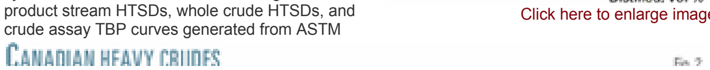

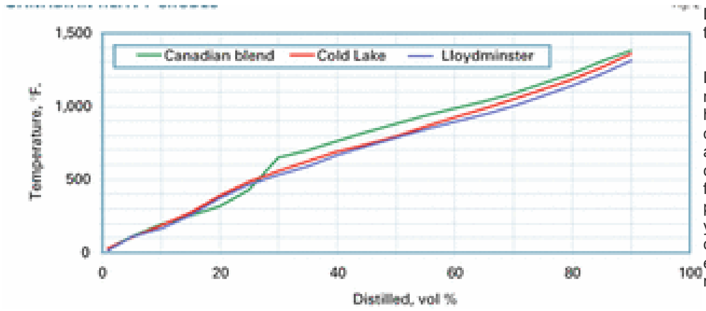

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D2892 and D5236 tests.

During a CDU revamp to process heavy crude, the designer must accurately characterize crude feed; otherwise, predicted product yields, operating conditions, and equipment design may be flawed.

Inaccurate feed characterization of crude's heavy end has resulted in poor revamp yields and coked vacuum column wash beds.

### Whole crude properties

Table 2 shows vanadium, viscosity, and salt content for some heavy crudes. Fig. 3 shows the vanadium distribution curve for Maya crude.

Some vanadium compounds begin to vaporize at 925-950° F. TBP temperatures; therefore, HVGO vanadium will rise as cut point increases.[3]

Improved HVGO fractionation lowers vanadium for the same TBP cut point.[4] A properly designed vacuum unit can reduce HVGO vanadium content by 30-50%.

**CRUDE BULK PROPERTIES** Table 2

| Crude type | Vanadium, ppmw | Viscosity at 100° F., cst | Salt content, lb/1,000 bbl of crude |
|---|---|---|---|
| Maya | 291 | 95 | 6 |
| Merey | 295 | 461 | 40-60 |
| Zuata | 260 | 328 | 61 |
| Cold Lake | 124 | 75 | 20 |
| Lloydminster (LLB) | 100 | 70 | 42 |
| Canadian blend | 155 | 80 | 40 |

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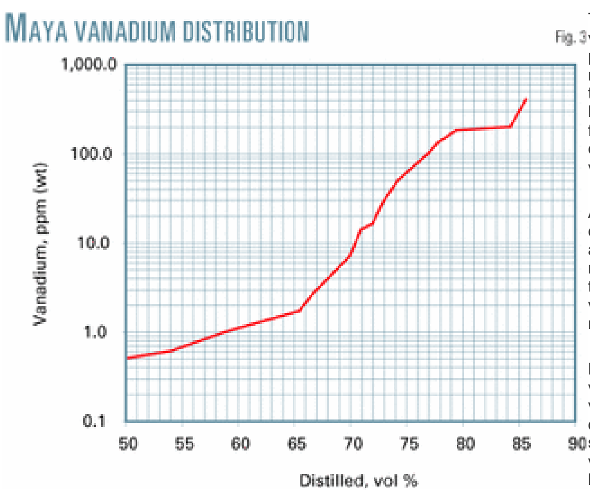

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Table 3 shows how CFHT feed vanadium content can increase for a poorly designed CDU heavy crude revamp. High ATB entrainment into the atmospheric gas oil (AGO) and high entrainment and poor fractionation in the vacuum unit caused the high CFHT feed vanadium content.

ATB and VTB produced from Maya crude will have nearly 550 ppm (wt) and 900 ppm (wt) vanadium, respectively. Operators must therefore eliminate all crude and vacuum column entrainment to minimize CFHT feed contaminants.

Because heavy crudes have more vacuum gas oils, vacuum column vapor velocities increase. Poorly distributed vapor entering the wash section creates high localized velocities that exceed the maximum limit for effective VTB deentrainment.

Some refiners have seen HVGO MCR and vanadium levels greater than 1 wt % and 10 ppm (wt), respectively, when processing 22° API gravity crudes.

Well designed flash-zone vapor horn and internals reduce entrainment; both are critical to minimize CFHT feed contaminants.[5]

**CFHT FEED STREAM VANADIUM** Table 3

| Stream | Design vanadium, ppmw | Actual vanadium, ppmw |
|---|---|---|
| AGO | 1.0 | 8.0 |
| LVGO | 0.4 | 0.4 |
| HVGO | 5.0 | 8.0 |

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Some heavy crudes require metallurgical upgrades to higher-alloy materials due to high naphthenic acid (Table 4), high sulfur, and high crude-column overhead system chloride levels (Fig. 4). Crudes with a total acid number (TAN) of 2.4 will produce an HVGO TAN of 3.5 or greater.[6 7]

**WHOLE TAN NUMBER** Table 4

| Crude type | Gravity, °API | TAN |
|---|---|---|
| Maya | 22 | 0.4 |
| BCF | 17 | 2.5 |
| Merey | 16 | 1.2 |
| Zuata | 16 | 2.4 |
| Cold Lake | 20 | 1.0 |
| Lloydminster (LLB) | 19 | 0.7 |
| Canadian blend | 19 | 2.3 |

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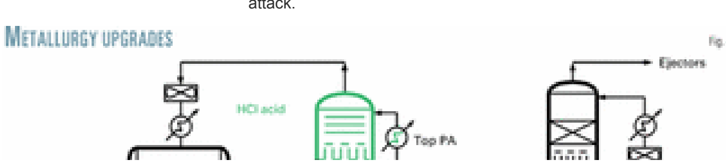
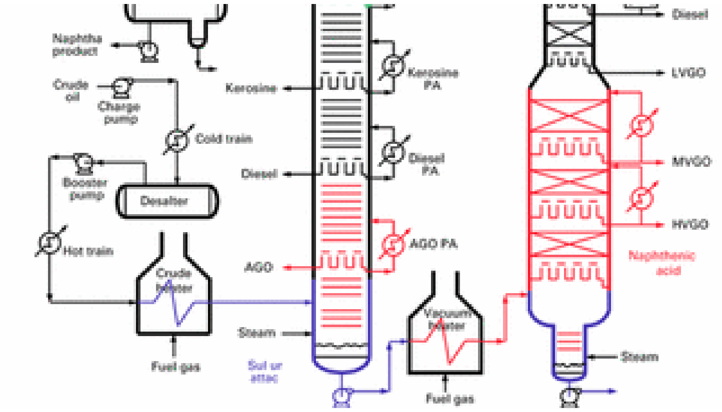
Metallurgy upgrades are needed for gas oil circuits that operate between 500° and 650° F. Piping and column internal components such as beams, packing supports, and tower attachments commonly use 317L. Some refiners use 904 stainless steel in the vacuum column for cladding and internals because it has a high molybdenum content, thus making it resistant to naphthenic acid attack.

Processing tar sands crudes creates some unique challenges. These crudes





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can have high sediment and clay contents and some blends also have high viscosity.

Desalter operations are more difficult and there is an increased likelihood of stable emulsion formation. If desalter performance deteriorates, the corrosion rate in the atmospheric column overhead system may increase and cause reliability problems.

### Maintaining crude charge rate

Revamp process flow schemes must account for the inherent crude hydraulics and preheat dilemma associated with processing heavy crudes while maintaining unit reliability.

Higher-viscosity heavy crudes reduce the crude-charge-pump developed head and can also increase exchanger fouling.

Circumventing hydraulic limits to achieve a desired crude feed rate can be expensive; therefore, a revamp must consider crude hydraulics early in the process to ensure there is sufficient capital to achieve processing objectives.

Crude charge hydraulics are not generally evaluated thoroughly enough until late in detailed engineering when they can result in scope growth, additional expenditure, or scope rationalization.

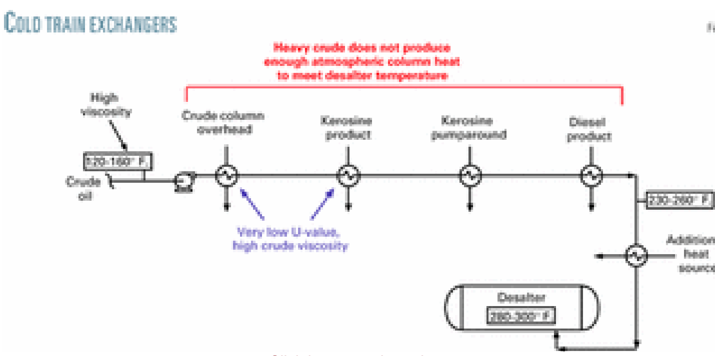
Crude charge rate will often decrease if preheat train modifications are not made. With heavy crudes, cold-exchanger-train heat transfer decreases because there is less heat available from the atmospheric column pumparounds and products.

These exchangers also have lower heat-transfer coefficients due to higher crude viscosity. Additional cold-train-exchanger surface area is needed to meet desalter temperatures necessary for efficient desalting.

To lower the cold-train pressure drop at the expense of crude velocity, refiners commonly install new exchangers parallel to existing exchangers or reduce the exchanger bundle tube passes on existing exchangers.

This approach causes increased exchanger fouling, which decreases heat-transfer coefficients and increases pressure drop.

For example, cold-train exchangers processing 100% Merey or BCF-17 operate in the laminar flow regime and have service heat-transfer coefficients as low as 12 btu/hr-sq ft-°F.



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An alternate approach is adding exchangers in series with existing exchangers (Fig. 5), which minimizes fouling and increases pressure drop. Heavy crude revamps typically require larger charge pump motors and impellers and sometimes pump replacement.

New exchanger bundles are typically designed for higher maximum allowable working pressure (MAWP) to meet cold-train charge hydraulics. Designers must also evaluate pipe flange and exchanger pressure ratings for the higher head pumps. Several heavy-crude revamp designs included very little pressure drop available on the desalter pressure-control valve and crude-heater-pass balancing valves for start-of-run operation.

When exchangers are clean, design crude-charge rates were possible; however, as the exchangers foul, pressure drop increased and crude rate was reduced.

In some designs, the operator had to open exchanger bypasses to meet design charge rates when the exchangers fouled. This generally allows a higher crude rate, but it also lowers the temperature at the desalter, reduces atmospheric-column heat removal, raises atmospheric-column operating pressure, and increases product-rundown temperatures.

When revamping a preheat train to process heavy crude, the designer must use accurate viscosities, allow sufficient pressure drop allowance for fouling, and correct pump head-flow and efficiency curves for viscosity effects.

### Product yield, quality

Many heavy crude blends contain less total atmospheric-plus-vacuum-column distillates and more ATB and VTB; therefore, high recovery of these distillates is important.

A well-designed crude unit can recover more distillates than inadequate process and equipment designs. In one case, for the same heavy crude a poorly designed flow scheme and equipment flaws yielded 20 vol % atmospheric distillates and 80 vol % ATB, whereas a proper design yielded about 33 vol % atmospheric distillate and 67 vol % ATB.

Processing heavier crudes can lower diesel product recovery, increase diesel boiling-range material in the CFHT feed, reduce HVGO recovery, increase CFHT contaminants, and increase <1,000° F. boiling-range material in the coker feed.

Higher heater temperature, lower atmospheric and vacuum-column operating pressures, lower atmospheric column overflash,[8] improved wash-section efficiency, and better ATB-VTB stripping are needed[9] to maintain product yield and quality.

Table 5 shows operating changes needed to maintain atmospheric and vacuum column ATB and VTB cut points.

**OPERATING CHANGES TO PROCESS HEAVY CRUDES** Table 5

| Variable | Atmospheric column | Vacuum column |
|---|---|---|
| Temperature | Higher | Higher |
| Pressure | Lower | Lower |
| Flash-zone oil partial pressure | Lower | Lower |
| Residue stripping efficiency | Higher | Higher |

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Heavy crudes are difficult to vaporize in the crude heater alone. Diesel product cut point may vary 30° to 80° F. due to low diesel-AGO internal reflux, high column pressure, low pumparound-heat removal, high overflash rates, and ineffective stripping section performance.

Low diesel recovery causes a high feed rate to the CFHT or FCC and may limit refinery crude rate when these units are operating at maximum capacity.

Because heavy crudes contain vanadium compounds that distill in the HVGO-product boiling range, increasing HVGO-product cut point will increase metals. The rate of increase is directly related to the process and equipment design.

Efficient VTB stripping lowers HVGO vanadium; yet most vacuum units are designed without VTB stripping. The few units that include a stripping section have tray efficiencies less than 10-15% due to poor tray design. These stripping sections can require higher steam rates, which increase condenser and ejector system capital and operating costs.

### Reliability

Unit reliability means the unit can meet a targeted run length without significant deterioration in charge rate, product yield, or product quality. Poor reliability results in unscheduled shutdowns, significantly lower product yields and quality, or reduced unit charge rates.

Heavy crudes diminish unit reliability due to chronic heater coking,[10] condenser corrosion, crude-column tray fouling, or poor desalter operations.

Correcting these deficiencies requires capital investment; otherwise, realistic run lengths may only be 1-2 years vs. 4-5 years that many refiners target. Refiners must always balance revamp capital investment against run length.

Heavy crude viscosity can cause poor desalter performance. As desalter temperature drops, oil-water separation becomes problematic and the desalted-crude salt content increases. Some refiners processing heavy crudes have had to switch from series to parallel desalter operation to eliminate oil-water separation problems.

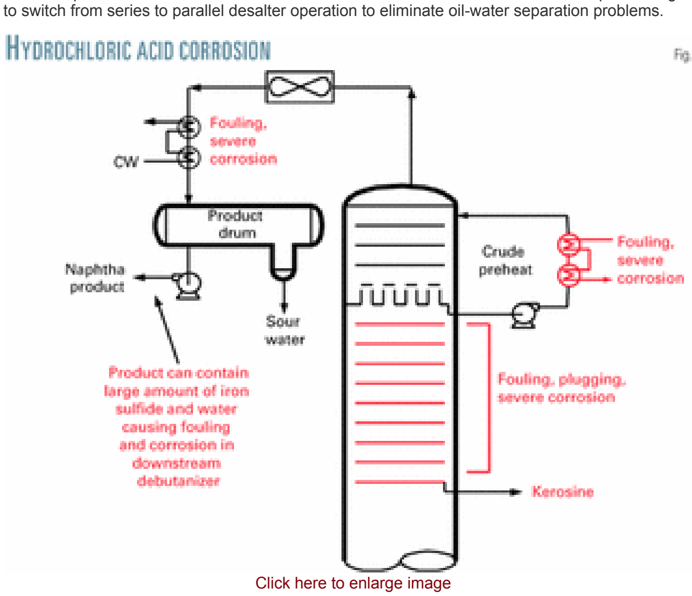


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Fig. 6 Single-stage desalting removes 90-95% of crude salt; desalted crudes may have salt contents of 3-6 lb/1,000 bbl. This high chloride content results in fouling and corrosion in the crude-column overhead condenser and an increased likelihood of column tray fouling (Fig. 6).

### Revamp process design

Crude-unit process flow schemes should focus on crude properties, processing objectives, and design fundamentals. Heavy oil is inherently more difficult to vaporize because there is less light material in the feed.

Crude-unit designs must optimize ATB cut point to balance overall unit performance because it influences crude and vacuum column operations. The relationship between ATB and VTB cut points are complex and refiners must evaluate the columns and ancillary equipment as a single system.[11]

With a lower ATB cut point, there is less atmospheric flash-zone vapor available to provide pumparound and product heat to the cold exchanger crude preheat train. As diesel and AGO materials shift to the vacuum tower, less high-temperature heat is available for crude preheat.

Diesel and AGO pumparound and product temperatures are about 550° F. and 625° F., respectively. LVGO draw temperature is only about 330° F.; therefore diesel and AGO product yielded in the vacuum column provides little or no preheat. A lower HVGO product draw temperature can also result due to a lighter HVGO product.

Maximizing diesel recovery is important when crude rate is limited by CFHT or FCC unit capacity. This requires optimum atmospheric column diesel-AGO fractionation, ATB stripping, and AGO product stripping.

Good diesel-AGO product fractionation requires adequate reflux rate (liquid-vapor ratio), 8-10 trays, and good tray efficiency. Most atmospheric columns wider than 16 ft in diameter will use four-pass trays. These large-diameter towers have low weir loadings (gpm/in. weir) and the tray efficiencies can be low. Low reflux and tray efficiency dramatically reduce diesel yield.

An AGO pumparound increases crude preheat; however, if the ATB cut point is only 700° F., there is not enough vapor from the atmospheric column flash zone to provide sufficient internal reflux in the diesel-AGO fractionation section to allow heat removal from an AGO pumparound.

Operating with an AGO pumparound should be based on crude TBP distillation, acceptable diesel-AGO fractionation, and ATB cut point target, not standard design practices.

The vacuum-unit design depends on the HVGO product cut point target, vacuum heater design, crude vanadium distribution, and other detailed equipment design issues. HVGO product cut points are typically less than 975° F. when crudes with gravities less than 24° API are being processed.

A dry vacuum unit design uses no steam in the heater and does not have a stripping section. Maintaining cut point is difficult even with a well-designed unit using coil steam, but a dry vacuum unit simply cannot operate reliably at cut points greater than about 950° F. when processing Merey, Zuata, or BCF-17 crudes.

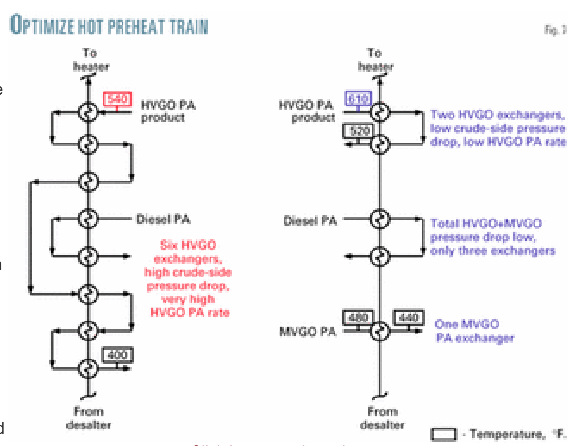
A heater without coil steam must operate at only 760-770° F. to avoid rapid coking from heavy crudes. HVGO product TBP cut points >1,000° F. require a heater outlet temperature of 795-800° F., low flash-zone oil partial pressure, and good VTB stripping.

Heavy crude increases total LVGO and HVGO pumparound duty requirements because more VGOs are yielded. A two-product vacuum column will have a high HVGO pumparound duty at a relatively low temperature of about 480-540° F. Increasing vacuum unit heat input requires more surface area and more HVGO pumparound capacity to remove the added heat.

Increasing HVGO pumparound duty typically requires increasing the number of exchangers in series because the log mean temperature difference is so low.

One refiner used six exchangers in series in the hot preheat train. Exchanger network design must address the increased pressure drop caused by additional exchangers.

This refiner can alternatively include an extra pumparound. A portion of the HVGO pumparound heat shifts to an MVGO pumparound. This increases the HVGO pumparound temperature to >600° F. and reduces the hot train preheat exchangers from six to three (Fig. 7).

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When crude hydraulics are tight, a third pumparound can help alleviate crude bottlenecks. It can also reduce the required HVGO pumparound circulation rate to stay within existing pump and piping limits. A third vacuum-unit pumparound often results in the lowest overall cost solution (Fig. 8).

## Revamp equipment design

Maximizing heavy oil vaporization, minimizing product contaminants,[12] and maintaining an acceptable run length requires fundamentally sound equipment design.

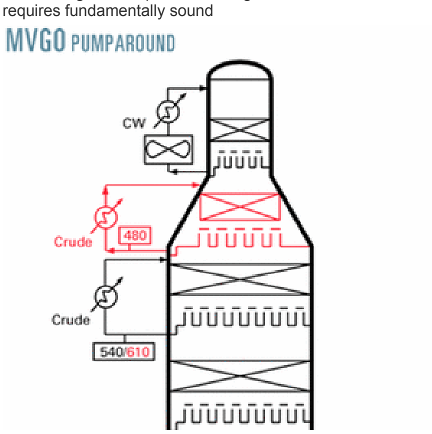


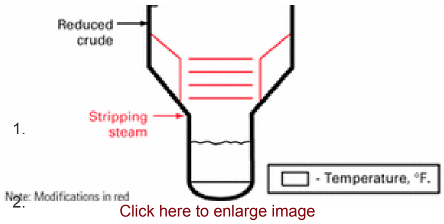

Fig. 8

Vacuum heater, ATB and VTB stripping, and atmospheric and vacuum wash section designs influence unit performance.[13 14]

Refinery vacuum heaters need to operate at outlet temperatures between 790° and 800° F. while meeting run-length targets.[15]

Maximized ATB stripping efficiency requires adequate stripping steam, maximum trays, and maximum tray efficiency. VTB stripping and vacuum heater coil steam should balance with column operating pressure.

Atmospheric and vacuum column flash-zone vapor horn and wash sections should eliminate entrainment

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and the vacuum column needs to fractionate HVGO product to reduce the TBP curve 95%-EP tail. F

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## The authors

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Steve White is a chemical engineer for Process Consulting Services Inc., Houston. He has more than 25 years' experience in process design of refinery revamps and grassroots units including crude and vacuum, FCC, hydrotreater, alkylation, butamer, reformers, and others. White previously worked as refinery technology manager for Jacobs Engineering Group Inc. and as technical service engineer for UOP LLC and Atlantic Richfield Co. He holds a BS in chemical engineering from Rice University and is a registered professional engineer in Texas.

Tony Barletta is a chemical engineer for Process Consulting Services Inc., Houston. His primary responsibilities are conceptual process design and process design packages for large capital revamps. Barletta previously worked as a production planner and process specialist for BP Oil Co.'s Alliance refinery and as a process engineer for Hess Oil Virgin Islands Corp. He holds a BS in chemical engineering from Lehigh University.

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HYDROCARBON
PROCESSING



# Innovative solutions for processing shale oils

07.01.2013 | **Sandu, C.**, Baker Hughes, Sugar Land, Texas; **Wright, B.**, Baker Hughes, Sugar Land, Texas

**New monitoring protocols can provide advance warning of any negative aspects of shale oil processing, thus enabling the refiner to take corrective measures early.**

**Keywords:** [shale oil] [paraffin] [waxes] [asphaltene]

The refining of shale oil (also known as tight oil) extracted through fracturing from fields such as Eagle Ford, Utica and Bakken has become prevalent in many areas of the US. Although these oils are appealing as refinery feedstocks due to their availability and low cost, processing can be more difficult.

The quality of the shale oils is highly variable. These oils can be high in solids with high melting point waxes. The light paraffinic nature of shale oils can lead to asphaltene destabilization when blended with heavier crudes. These compositional factors have resulted in cold preheat train fouling, desalter upsets, and fouling of hot preheat exchangers and furnaces. Problems in transportation and storage, finished-product quality, as well as refinery corrosion, have also been reported. Operational issues have led to cases of reduced throughput and crude unit shutdowns. The problems encountered with shale oil processing and possible prediction and control strategies will be presented.

## NEW RESOURCES

The production of shale gas and oils has increased rapidly due to significant advancements in drilling technology and hydraulic fracturing. Coupling chemical treatments to the mechanical drilling capabilities has enabled increased production efficiency.

In September 2012, shale oil production was reported to be nearly 1 million bpd (1 MMbpd). The most prolific production locations are in North Dakota (Bakken), Texas (Eagle Ford), Ohio, Pennsylvania (Marcellus and Utica), Colorado, Kansas, Nebraska and Wyoming (Niobrara). Other locations identified for probable shale oil production are in New Mexico, Oklahoma and Utah. By 2020, production will be at least 10 MMbpd, based on expanded drilling activity, as shown in **Fig. 1.**[1] The predictions are largely dependent on the volatility of oil prices, technical advancements, capital expenditure, infrastructure needs, and challenges associated with the processing of these abundant resources.

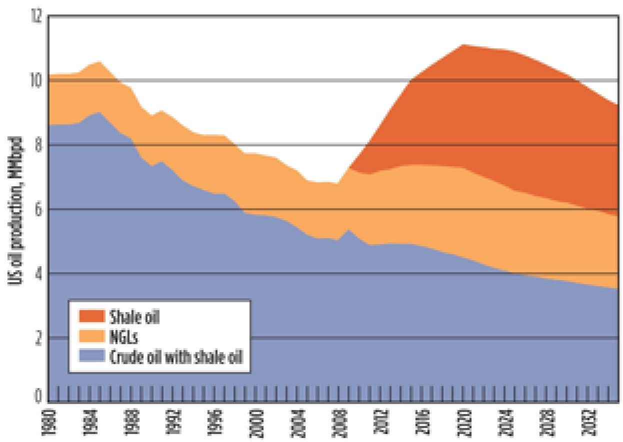


**Fig. 1.** Forecast prediction of US oil production. Source: EIA.

The properties of shale oils are significantly different than typical crude oils. As a result, a series of challenges needs to be solved to ensure uninterrupted transportation and refining of shale oils. The main challenges encountered with these feed streams will be discussed, including issues in storage, transportation, refining and finished fuel quality.

## PHYSICAL AND CHEMICAL CHARACTERISTICS

Unlike most crude oils, shale oils are light, sweet oils, with a high paraffinic content and low acidity. They also have minimal asphaltenic content phase and varying contents of filterable solids, hydrogen sulfide ($H_2S$) and mercaptans. **Table 1** is a comparison of the oil characteristics typical for shale oil, and it includes data for Eagle Ford and Bakken shale oils.[2] There are significant differences in the sulfur content and the filterable solids loading. In addition, the streams from a shale oil production region can have significant variability, as shown in **Fig. 2.** These were shale oil samples from one field, with colors ranging from pale amber to black.

**TABLE 1. Eagle Ford and Bakken shale oil property comparison**

| Parameter | Eagle Ford | Bakken |
|---|---|---|
| API | 52 | 40.8 |
| TAN, g KOH/g | < 0.05 | 0.09 |
| Sulfur, wt% | < 0.2 | 0.304 |
| Asphaltene, wt% | 0.1 | 0.41 |
| Resin, wt% | 1.6 | 4.95 |
| Filterable solids, PTB | 225 | 76 |

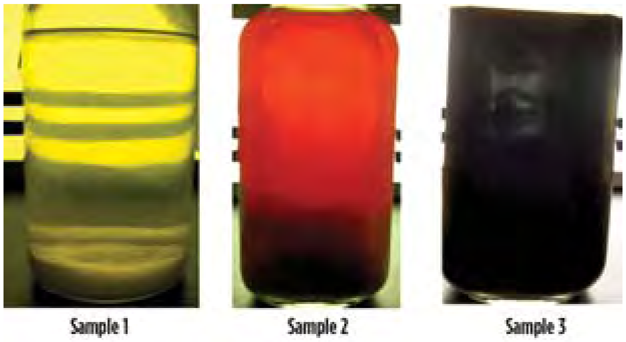


**Fig. 2.** Color variation of Eagle Ford shale oil.



Solids loading of samples from a single producing region can be highly variable and associated with the stage of fracturing and production from which the oil is produced. **Table 2** shows typical analytical results on the three shale oil samples from **Fig. 1.** Filterable solids ranged from 176 pounds per thousand barrels (PTB) to 295 PTB.

**TABLE 2. Physical properties of Eagle Ford shale oil samples**

| Parameter | Yellow | Red | Black |
|---|---|---|---|
| API | 55 | 44.6 | 52.3 |
| TAN, g KOH/g | < 0.05 | 0.07 | < 0.05 |
| Sulfur, wt% | < 0.2 | < 0.2 | < 0.2 |
| Na, ppm | 1 | 1.6 | 1.6 |
| K, ppm | 0.3 | 0.4 | 0.5 |
| Mg, ppm | 3.4 | 2.9 | 3 |
| Ca, ppm | 2.6 | 2.8 | 3.8 |
| Asphaltenes, wt% | 0 | 0 | 0.1 |
| Resin, wt% | 0.5 | 3.2 | 1.6 |
| Filterable solids, PTB | 176 | 295 | 225 |

**Paraffin.** The paraffin content of shale oil is one of the main properties that contributes to downstream problems from transportation and storage to refinery processing. Analyses of one batch of shale oil revealed paraffin chains containing well over 50 carbons. Similar paraffin analyses have been observed from multiple shale oils. To understand fouling due to wax deposition, a carbon-chain profile analysis should be performed to document the molecular-weight distribution (MWD) and the melting points of the waxes in the system. **Fig. 3** illustrates the characterization of waxes from Eagle Ford and Bakken oil samples. Some samples of Eagle Ford shale oil contain over 70 carbon paraffins.

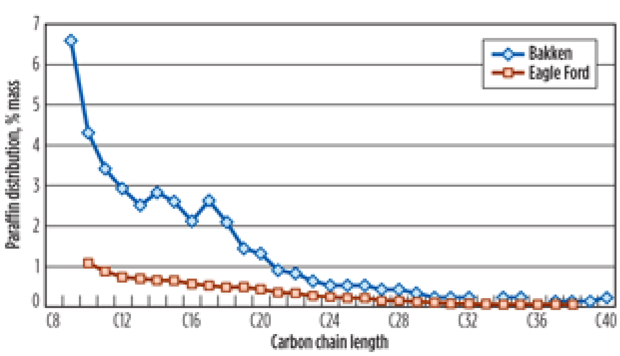

**Fig. 3.** Paraffin chain distribution for Bakken and Eagle Ford shale oils.

Due to their paraffinic nature, mixing shale oil with asphaltenic oil leads to destabilization of the asphaltene cores. Asphaltenes are polar compounds that influence emulsion stability. Once the asphaltenes destabilize, they can agglomerate, leading to larger macro-molecules. On hot surfaces, agglomerated asphaltenes easily crack or dehydrogenate and gradually form coke-like deposits.

Several shale oil production locations have high $H_2S$ loading. To ensure worker safety, scavengers are often used to reduce $H_2S$ concentrations. The scavengers are often amine-based products-—methyl triazine, for instance—that are converted into mono-ethanolamine (MEA) in the crude distillation unit (CDU). Unfortunately, these amines contribute to corrosion problems in the CDU. Once MEA forms, it rapidly reacts with chlorine to form chloride salts. These salts lose solubility in the hydrocarbon phase and become solids at the processing temperatures of the atmospheric CD towers and form deposits on the trays or overhead system. The deposits are hygroscopic, and, once water is absorbed, the deposits become very corrosive. These physical properties are responsible for the problems that are being experienced by refineries handling shale oils.

## Extraction and production

The challenges associated with the production of shale oils are a function of their compositional complexities and the varied geological formations where they are found. These oils are light, but they are very waxy and reside in oil-wet formations. These properties create some of the main difficulties associated with shale oil extraction. Such problems include scale formation, salt deposition, paraffin wax deposits, destabilized asphaltenes, corrosion and bacteria growth. Multi-component chemical additives are added to the stimulation fluid to control these problems.

Shale oils are characterized by low-asphaltenic content, low-sulfur content and a significant MWD of the paraffinic wax content. Paraffin carbon chains of C10 to C60 have been found, with some shale oils containing carbon chains up to C72. To control deposition and plugging in formations due to paraffins, the dispersants are commonly used. In upstream applications, these paraffin dispersants are applied as part of multifunctional additive packages where asphaltene stability and corrosion control are also addressed simultaneously.

Scale deposits of calcite, carbonates and silicates must be controlled during production or plugging problems arise. A wide range of scale additives is available. These additives can be highly effective when selected appropriately. Depending on the nature of the well and the operational conditions, a specific chemistry is recommended or blends of products are used to address scale deposition.

## Storage and transportation

Another challenge encountered with shale oil is the transportation infrastructure. Rapid distribution of shale oils to the refineries is necessary to maintain consistent plant throughput. Some pipelines are in use, and additional pipelines are being constructed to provide consistent supply. During the interim, barges and railcars are being used, along with a significant expansion in trucking to bring the various shale oils to the refineries. Eagle Ford production is estimated to increase by a factor of 6—from 350,000 bpd to nearly 2 MMbpd by 2017; more reliable infrastructures are needed to distribute this oil to multiple locations. Similar expansion is estimated for Bakken and other shale oil production fields.

The paraffin content of the shale oils is impacting all transportation systems. Wax deposits have been found to coat the walls of railroad tank cars, barges and trucks. Waxy deposits in pipelines regularly require pigging to maintain full throughput. Bakken shale oil is typically transported in railcar, although pipeline expansion projects are in progress to accommodate the long-term need. These railcars require regular steaming and cleaning for reuse. Similar deposits are being encountered in trucks being used for shale oil transportation. The wax deposits also create problems in transferring the shale oils to refinery tankage. **Fig. 4** shows samples of deposited wax collected from pigged pipelines in shale oil service.

**Fig. 4.** Waxy deposits removed from shale oil pipelines.



Multiple chemical and mechanical solutions are used to mitigate these deposit problems. A combination of chemical-additive treatment solutions involving paraffin dispersants and flow drag-reducer technologies has proven to be effective in pipeline applications. Wax dispersants and wash solvents have been used to clean transportation tanks and refinery storage vessels. In the case of pipeline fouling management, a combination of these technologies, coupled with frequent pigging, are the main means to mitigate wax deposition. Preventive fouling control programs have been developed to manage the wax deposition occurring in storage tanks. By injecting the proper chemical treatment to control wax buildup in storage tanks, the production field and refinery can handle and transfer larger quantities of oil without significant plugging issues.

One other problem encountered in storing and transporting shale oils is the concentrations of light ends that accumulate in the vapor spaces, requiring increased safety and relief systems. Shipping Bakken crude via barges was challenged by the increased levels of volatile organic compounds (VOCs). Vapor-control systems should be used to ensure a safe environment.

Due to the paraffinic nature of shale oils and their lack of heavy bottoms, most refineries mix crude oil with the shale oil. Unfortunately, the shale oils have low aromatic content, so mixing with conventional crude oil often leads to asphaltene destabilization. If blended oils are transported, the deposits can consist of waxes and precipitated asphaltenes. Dispersants specifically designed for both hydrocarbon types can control deposit formation during transportation. Until a proper transportation infrastructure is built, significant variation of shale oil shipments and potential for contamination are still possible. Refineries are already experiencing the impact of the quality variation of shale oil feeds, and of processing challenges.

## REFINERY IMPACTS

Due to the variation in solids loading and their paraffinic nature, processing shale oils in refinery operations offers several challenges. Problems can be found from the tank farm to the desalter, preheat exchangers and furnace, and increased corrosion in the CDU. In the refinery tank farm, entrained solids can agglomerate and rapidly settle, adding to the sludge layer in the tank bottoms. Waxes crystalize and settle or coat the tank walls, thus reducing storage capacity. Waxes will stabilize emulsions and suspend solids in the storage tanks, leading to slugs of sludge entering the CDU. Waxes will also coat the transfer piping, resulting in increased pressure drop and hydraulic restrictions.

Mixing asphaltenic crude with paraffinic shale oils leads to asphaltene destabilization that contributes to stable emulsions and sludge formation. To control these problems, wax-crystal modifiers or paraffin dispersants can be applied successfully. Wax-crystal modifiers must be added when the shale oil is still hot from the formation. When the paraffins begin to leave the liquid phase, wax modifiers are ineffective, and paraffin dispersants are required to control deposition.

Desalter operations may suffer from issues related to the shale oil properties. Solids loading can be highly variable, leading to large shifts in solids removal performance. Sludge layers from the tank farm may cause severe upsets, including growth of stable emulsion bands and intermittent increases of oil in the brine water. Agglomerated asphaltenes can enter from storage tanks or can flocculate in the desalter rag layer, leading to oil slugs in the effluent brine.

Solutions include using tank farm additives to control the formation of sludge layers, along with specially designed asphaltene dispersants and aggressive desalter treatments to ensure optimum operation. Pretreatment, coupled with high-performance desalter programs, have provided the best overall desalter performance and desalted crude quality; multiple treatment options for both areas can ensure maximum performance. **Fig. 5** is an example of applying a tank pretreatment. A crude-oil tank treatment program was initiated that broke waxy emulsions in tankage, enabling improved water resolution of the raw crude oil and minimizing sludge and solids entering the desalter. This program provided significant improvement of solids released into the desalter brine water compared to previous operations. Prior to initiating the pretreatment program, solids in the brine averaged 29 PTB, and the emulsion band control was sporadic. After the tank pretreatment program started, the desalter emulsion band could be controlled with the emulsion breaker program, and solids removal to the brine water increased by a factor of 8 to an average of 218 PTB.

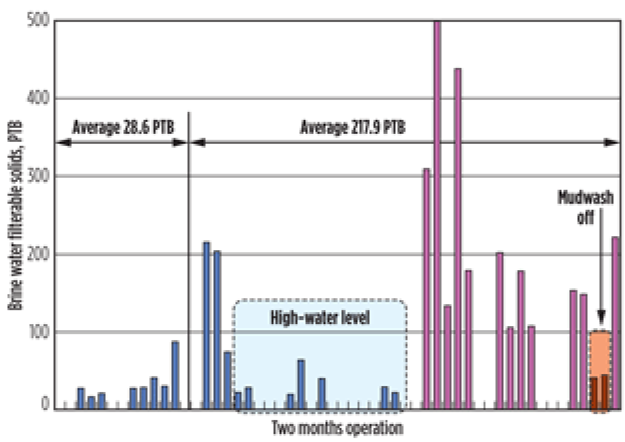


**Fig. 5.** Tank pretreatment impact on desalter filterable solids.

Preheat exchanger fouling has been observed in the cold train before the desalters and in the hot train after the desalters. Cold train fouling results from the deposition of insoluble paraffinic hydrocarbons, coupled with agglomerated inorganic solids. Solutions to cold train exchanger fouling include the addition of wax dispersants and other oil management best practices to ensure consistent solids loading with minimum sludge processing.[a] Crude oil management can include additives to stabilize asphaltenes and surfactants that resolve emulsions and improve water separation.[a] These practices also include proactive asphaltene stability testing to ensure that the crude blends to be processed retain an acceptable compatibility level.

Hot train fouling occurs from destabilized asphaltenes that agglomerate and form deposits. These materials entrain inorganics, such as iron sulfide and sediments from production formations, into the deposit matrix. Some deposits, including high molecular-weight paraffins, become complex with the asphaltene aggregates. Mixing shale oils with asphaltenic crude oils results in rapid asphaltene agglomeration. Rapid hot train exchanger fouling has been seen in units running crude blends with asphaltene concentrations of 1% or less. **Table 3** shows the analysis from a hot exchanger deposit that had to be shut down for cleaning after only a short time online. This hydrogen-to-carbon ratio is consistent with asphaltenic deposits.

**TABLE 3.** Hot train exchanger deposit analyses of shale oil with asphaltenic crudes in wt%

| Sample | C | H | N | O | Cl | Fe | S | H/C atomic ratio | Ash | Summary |
|---|---|---|---|---|---|---|---|---|---|---|
| Exchanger 1-crude side | 82 | 8 | 1 | 2 | 1 | | 6 | 1.16 | 1 | Asphaltenes |
| Exchanger 2-crude side | 78 | 7 | 1 | 4 | 1 | 1 | 8 | 1.07 | 3 | Asphaltenes |
| Exchanger 3-crude side | 81 | 8 | 1 | 2 | 1 | | 7 | 1.18 | 3 | Asphaltenes |

Feed analyses of the shale oil and crude blend being processed revealed poor stability of the asphaltenes. Asphaltene stability tests are used to measure the ability of a crude oil blend to hold asphaltenes in solution.[3, a] The method utilizes light scattering, coupled with automatic titration, to force asphaltene destabilization and agglomeration.

As titration begins, the oil becomes less opaque and the light intensity increases. When the destabilization point is reached and the asphaltenes rapidly agglomerate and flocculate, the fluid opacity suddenly increases. Inflection points on the curve show where asphaltenes become unstable: farther to the right indicates higher stability asphaltenes, while inflection points farther to the left suggest unstable asphaltenes. **Fig. 6** shows asphaltene stability results for several crude blends, along with a test on Eagle Ford shale oil. An inflection point was not achieved for the shale oil because it has no asphaltenes to flocculate. Typical crude oils are shown, with asphaltene stability index (ASI) results around 120. When the shale oil was blended with the typical crude oils at a ratio of 80/20, the measured asphaltene stability result was less than 30, indicating rapid and uncontrollable destabilization of the asphaltenes.

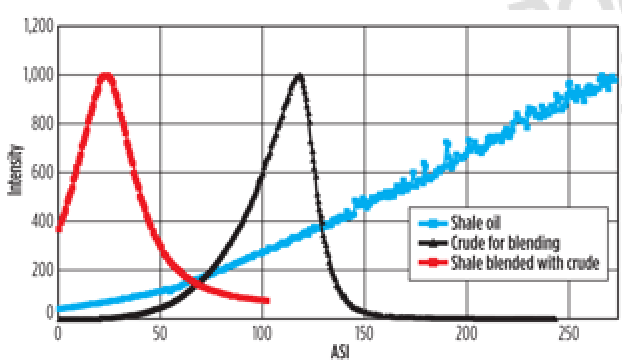


**Fig. 6.** Asphaltene stability index testing of shale oil and shale oil/crude blends.

If the asphaltenes in the crude blend were not being rapidly destabilized, the asphaltene stability would have been well above 120. This data shows that mixing certain crude oils with shale oil can result in rapid asphaltene deposition. New technology can provide the capability to rapidly perform asphaltene stability measurements onsite with a high degree of accuracy.[4, a]

Hot-train exchanger fouling can be controlled through antifoulant additives designed to control the agglomeration and deposition of asphaltenes and entrained inorganic solids. Another fouling control strategy is to do regular analysis of the stability of the asphaltenes in the crude oil blend under consideration for processing. This information can guide operations to minimize fouling problems.

CDU atmospheric furnace fouling has also been observed at several refineries processing shale oils, especially those processing a blend of asphaltenic crude and shale oils. In some cases, the fouling rate was so severe that the crude unit had to be shut down for furnace pigging. CDU furnace operations with conventional crude oils experience little to no fouling, and these furnaces can easily run for 5 to 6 years between turnarounds. **Fig. 7** shows the rate of fouling in a unit processing a mixture of shale oil with crude vs. the rate of fouling with more typical crude feeds.

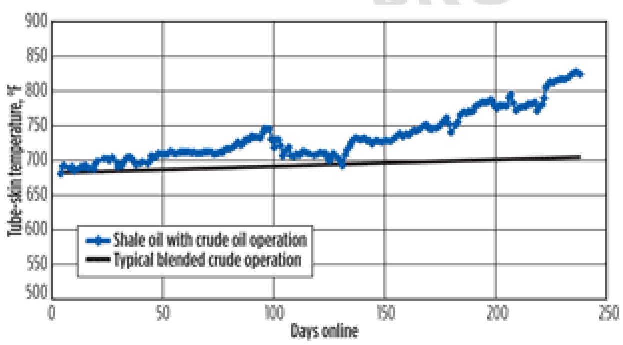


**Fig. 7.** Atmospheric furnace skin temperature trends.

Depending on the asphaltene stability of the shale oil/crude oil blend, the furnace skin temperatures can climb by 0.5°F/day to 2°F/day vs. more typical operations of 0.1°F or less. To control furnace fouling when processing shale oils blended with various crude oils, constant monitoring of the asphaltene destabilization potential is required. Setting a minimum limit on the ASI ensures that the majority of the asphaltenes stay in solution. This limit should be developed for each unit, based on correlations between the rate of furnace fouling being experienced and the stability index. Using appropriate antifoulant additives can control agglomeration of asphaltenes and disperse offending materials into the bulk oil phase.

Shale oils often contain high concentrations of $H_2S$ that require treatment with scavengers due to safety purposes. Amine-based scavengers often decompose as the crude oil is preheated through the hot preheat train and furnace, forming amine fragments. MEA, one of the most commonly used amines, readily forms an amine-chloride salt in the atmospheric tower. These salts deposit in the upper sections. Often, under-deposit corrosion is the major cause of failures in process systems because CDU tower under-salt corrosion rates can be 10 to 100 times faster than a general acidic attack. Mitigation strategies include controlling chloride to minimize the chloride traffic in the tower top and overhead, increasing the overhead operating temperature so that the salts move further downstream in the overhead system, and acidifying the desalter brine water to increase removal of amines into the water phase.

## Finished fuels

The quality of the finished fuels from refining shale oils has changed significantly. As the shale oils have higher light-ends content, one benefit is increased production of naphtha for gasoline, and stable diesel and jet distillates. These increased volumes can boost refinery margins. However, due to the chemical nature of these shale oil feeds, several challenges can be encountered. The streams are more paraffinic—thus, they suffer from poor pour and cloud-point properties. In addition, shale oils are lower in sulfur content, so the need for lubricity additives is anticipated. Effective additives can be used to improve all distillate stream properties. Conductivity can also be off-spec; a combination of lubricity/conductivity improvers can raise the quality of the distillate. To optimize chemical treatment program, testing on specific product streams is required and suitable product selection should be customized. **Table 4** summarizes the main issues identified for different distillate cuts that a refiner can experience as well as chemical and mechanical solutions that can mitigate these challenges.

**TABLE 4.** Possible problems and solutions for finished fuels from shale-oil processing

| Distillate | Challenge | Solutions |
|---|---|---|
| Light ends ($C_1$–$C_4$) | Copper strip corrosion | Corrosion inhibitors |
| Naphtha | Water shedding, corrosion | Corrosion inhibitors, microbial control |
| Jet fuel | Lubricity, conductivity, water shedding, stability | Various lubricity additives, filtration devices, dry solid systems, microbial control |
| Diesel | Lubricity, conductivity, stability, water shedding | Various lubricity additives, de-hazers, microbial control |
| Residual fuel oil | Asphaltene instability, gum deposits | Blending and compatibility monitoring |
| | | Asphaltene stabilizers |
| | | Paraffin dispersants |

Preparing to process shale oils. The risks that shale oils present can be successfully managed. The first step is to identify the onset of all concerns. To be prepared for processing shale oils, monitoring protocols can provide advance warning of any negative aspects of shale oil processing and the impacts on product quality, thus enabling the refiner to take corrective measures early. **HP**

## ACKNOWLEDGMENT

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## NOTES

[a] CRUDE OIL MANAGEMENT, ASIT and FIELD ASIT SERVICES are trademarks of Baker Hughes Incorporated.

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**The authors**

**Bruce Wright,** a Baker Hughes senior technical support engineer for downstream chemicals, is based in Sugar Land, Texas, and specializes in the hydrocarbon processing industries. With more than 30 years of industry experience, he is involved in technical support and troubleshooting of refinery fouling problems. Mr. Wright has experience as a product development research scientist and also in environmental, health and safety compliance. He is an inventor or co-inventor on eight US patents and has published nine technical papers. Mr. Wright is a 1977 graduate of the Rensselaer Polytechnic Institute with a BS degree in chemical engineering. He also holds an MBA degree from the University of Houston. Mr. Wright is a registered professional engineer in the state of Texas, and is a member of the American Institute of Chemical Engineers.

**Dr. Corina Sandu,** a Baker Hughes R&D manager for downstream chemicals, is responsible for leading a team of scientists who are researching and developing upgraded and novel technologies to increase refinery industry processing performance. She is located in Sugar Land, Texas. Dr. Sandu holds a PhD in materials chemistry from the University of Houston, and a post-doctorate from Rice University. She is a member of the American Chemical Society and the Society of Petroleum Engineers. Dr. Sandu has authored and co-authored 24 publications in peer-reviewed journals and holds five patents.

**Charles Harry**
*07.19.2013*

The addition of mbp needs or usage would be useful relative to Fig.1 in regards to why there is an ongoing large increase in shale oil production followed by it gradual decline.

**Peter LoGiudice**
*07.10.2013*

Excellent well thoughtout overview-Thanks

**Joseph**
*07.03.2013*

What will be the typical Calorific Value of Shale oil in Kcal/ Kg? C/H2 Ratio
Any estimation of Metal Contents like Vanadium, Na, Si etc

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# Exhibit D

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# PHILLIPS 66
# 2012 SUMMARY ANNUAL REPORT

Headquartered in Houston, Phillips 66 is an energy manufacturing company with segment-leading Refining and Marketing (R&M), Midstream and Chemicals businesses. The company has approximately 13,500 employees worldwide. Phillips 66's R&M operations include 15 refineries with a net crude oil capacity of 2.2 million barrels per day, 10,000 owned or supplied branded marketing outlets, and 15,000 miles of pipeline systems. Phillips 66's Midstream segment includes its 50 percent interest in DCP Midstream, LLC, one of the largest natural gas gatherers and processors in the United States, with 7.2 billion cubic feet per day of gross natural gas processing capacity. Phillips 66's Chemicals business is conducted through its 50 percent interest in Chevron Phillips Chemical Company LLC, one of the world's top producers of olefins and polyolefins with more than 30 billion pounds of net annual chemicals processing capacity across its product lines.

2012
Summary Annual Report

# TOGETHER WE ARE PHILLIPS 66

## Company At-A-Glance

### HIGH-PERFORMING BUSINESSES CREATE STRENGTH THROUGH DIVERSITY

Last May, Phillips 66 emerged as an independent energy company positioned for success. Built on a strong heritage, Phillips 66 is steadfastly rooted in values of safety, honor and commitment, and is dedicated to the company vision of providing energy and improving lives.

At Phillips 66, we have three main businesses: refining, transporting and marketing petroleum products; gathering and processing natural gas and natural gas liquids; and manufacturing petrochemicals, polymers and plastics. Our 13,500 highly motivated and experienced employees work together to help shape the energy revolution. At our core, we are an energy manufacturing company, and we are excited about the future.

## TIMELINE OF HISTORY

**1875**

Conoco begins as Continental Oil and Transportation Co., one of the first petroleum marketers in the West.


**1917**

Brothers Frank and L.E. Phillips establish Phillips Petroleum Company in Bartlesville, Okla.

**1933**

Phillips invents high-octane aviation fuel, which went on to boost Allied airplanes and support victory in WWII.

**1949**

Phillips forms new subsidiary, Phillips Chemical Company. Phillips leads refining industry in installing electrostatic precipitators to reduce air emissions.

**1981**

DuPont acquires Conoco. It was the largest merger in U.S. history at the time.

REFINING AND MARKETING

MIDSTREAM

CHEMICALS

2000

Phillips and Duke Energy combine midstream businesses, creating today's DCP Midstream. Phillips and Chevron combine chemicals and plastics operations, creating Chevron Phillips Chemical Company.

2001

Phillips acquires Tosco Corporation, one of the largest U.S. refiners and marketers at the time.

2002

Conoco and Phillips merge, creating the sixth-largest publicly traded oil company in the world and third largest in the United States.

2011

ConocoPhillips announces plans to spin off its downstream operations into independently traded Phillips 66.

2012

Phillips 66 begins regular way trading on the New York Stock Exchange on May 1, 2012, under the ticker symbol PSX.

# TO OUR **SHAREHOLDERS**

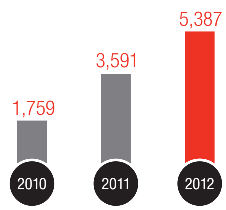
On May 1, 2012, we launched Phillips 66 as a new energy manufacturing company. Formed through the repositioning, or spin-off, of ConocoPhillips' downstream operations, we have the enthusiasm of a new company and the expertise that comes from more than 135 years of history. We have a passion for operating excellence, an exceptional workforce and an asset portfolio with significant growth potential. Together we are taking a classic in a new direction and capturing the opportunities of the energy revolution.

Greg C. Garland
Chairman, President and Chief Executive Officer

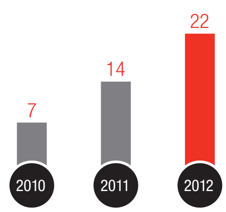
We manufacture and transport energy products that people around the world use every day. We convert raw materials into products such as gasoline, diesel, jet fuel and lubricants; process natural gas and natural gas liquids (NGL) for powering businesses, heating homes, cooking and electricity; and produce petrochemicals and plastics found in cars, electronics and other everyday goods.

The Phillips 66 leadership team was pleased with our performance during 2012, which included four months of operations with ConocoPhillips and the remainder of the year operating as Phillips 66. We set a clear strategy and executed well in a strong margin environment, resulting in a 50 percent increase in adjusted earnings. Our adjusted earnings for 2012 were $5.4 billion, and our return on capital employed (ROCE) improved from 14 percent to 22 percent. We also demonstrated our commitment to returning capital to shareholders through more than $600 million of dividends and share repurchases. The market recognized these results with a total shareholder return of 64 percent.

**ADJUSTED EARNINGS**
($ in millions)




**RETURN ON CAPITAL EMPLOYED**
(percent)




## Who We Are

Each of our businesses is a leader in its industry. Our Refining and Marketing (R&M) business refines crude oil and markets petroleum products both in the United States and internationally. Our Midstream segment includes our 50 percent ownership of DCP Midstream, a joint venture with Spectra Energy, as well as other midstream operations. This segment gathers and processes clean-burning natural gas, and participates in the growing NGL value chain, including gathering, processing, separating and storing NGL. Our segment that generates the highest ROCE is Chemicals, comprising our 50 percent investment in Chevron Phillips Chemical Company (CPChem), a joint venture with Chevron, which manufactures petrochemicals, polymers and plastics globally.

We have strong U.S. manufacturing operations with a global reach. More than 80 percent of our assets are in the United States, many located near shale plays. Internationally, CPChem's operations in the Middle East, which mainly serve markets in Asia, also benefit from proximity to low-cost feedstocks.

Our 13,500 dedicated, talented employees are the lifeblood of our operations, and we are proud of their daily commitment to excellence. This was particularly evident in their efforts to successfully launch Phillips 66 as a publicly traded company. Our employees' skills and determination resulted in a flawless repositioning.

At Phillips 66, we are committed to safe, reliable, efficient and environmentally responsible operations. This commitment is part of who we are and what we do. It is critical that we protect the people who work in our facilities and the communities in which we operate. Safety and operating excellence are our highest priority and are important drivers of our financial results.

## Equipped for the Energy Revolution

Over the last decade, the energy industry has seen a dramatic transformation. New technologies have made a century's worth of oil and gas resources available from shale thousands of feet underground. These developments are allowing the United States to reduce imports of foreign oil and become a more attractive market for domestic manufacturers. U.S. refiners and petrochemical manufacturers have a competitive advantage, as lower-cost feedstocks become more available. The development of shale oil and gas also increases demand for infrastructure and logistics that are needed to transport, process, fractionate and store these natural resources.

With assets situated primarily in the United States and a portfolio spanning the downstream value chain, Phillips 66 is uniquely positioned to capture the opportunities presented by the shale oil and gas revolution. Our strategy is aimed at capitalizing on these market developments across our businesses.

## Our Strategy

Our approach optimizes allocation of capital between reinvestment in our businesses and distributions to our shareholders. Our growth initiatives are focused primarily around expanding midstream and chemicals capacity. We acquired a one-third ownership interest in DCP Midstream's Sand Hills and Southern Hills NGL pipelines, representing a total estimated investment of $800 million. In 2012, DCP Midstream completed the first phase of the Sand Hills Pipeline, which transports NGL shipments from the Eagle Ford field into market hubs in Mont Belvieu, Texas. Between 2013 and 2015, DCP Midstream expects to bring $6 billion of major projects online in the liquids-rich shale plays. As we announced in December, we intend to form a master limited partnership (MLP) to support growth opportunities in transportation and midstream and create value for our shareholders. Subject to market conditions and final approval by our board of directors, we anticipate selling a minority interest in the MLP in an initial public offering in the second half of 2013.

CPChem has several major growth projects under way. On the U.S. Gulf Coast, CPChem is adding NGL fractionation capacity at its facility in Old Ocean, Texas. In 2012, CPChem began constructing the world's largest 1-hexene plant at its Cedar Bayou Complex in Baytown, Texas. The plant will utilize CPChem's proprietary technology to produce 1-hexene, a value-adding component used to manufacture plastics, and is expected to be complete in the first half of 2014. Additionally, CPChem is evaluating development of a $5 billion petrochemicals project, including a world-scale ethane cracker at Cedar Bayou and two ethylene derivative facilities in Old Ocean. The final investment decision for this project is expected in 2013, with startup anticipated in 2017.

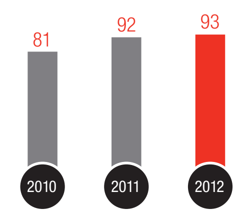
In addition to investing in attractive growth opportunities, we also understand the importance of capital efficiency. Our focus on improving ROCE in Refining is core to our strategy. Over the long term, we intend to capture a 400 basis point ROCE improvement over mid-cycle margins in Refining by lowering our feedstock cost, improving clean product yield, expanding refined-product export capability and reducing controllable costs. Lowering crude costs, by processing more advantaged crudes, is our single largest driver to improve Refining returns. We have a substantial team focused on sourcing and securing more advantaged crudes for our refineries, and we expect over the next several years to replace 500,000 barrels per day of higher-cost crudes with increasingly advantaged crudes.

We have a tradition of being a shareholder-friendly company, and returning capital to shareholders remains a priority for Phillips 66. Dividends also reflect our confidence in earnings stability and reinforce our financial discipline. Our intent is to increase the dividend annually, in line with growth in mid-cycle earnings. In 2012, we paid two quarterly dividends and announced two 25 percent dividend increases. We also began repurchasing common stock as part of a $2 billion repurchase program approved by our board of directors. These capital distributions have a foundation in our strong operating cash flow, which exceeded $4 billion again in 2012.

We have highly experienced leaders, and we are building a high-performing workforce. Throughout the company, we promote collaboration and inclusiveness, advancing business continuity at all levels of the organization and developing an engaged, motivated workforce.

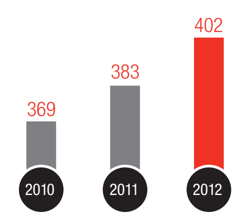
### REFINERY CAPACITY UTILIZATION

(percent)



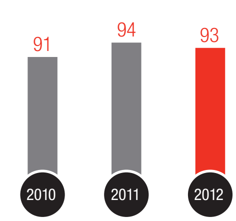

### DCP MIDSTREAM NGL PRODUCTION

(MBD)



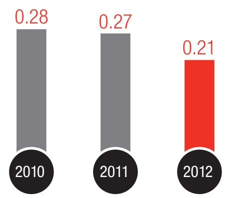

### OLEFINS AND POLYOLEFINS CAPACITY UTILIZATION

(percent)




## TOTAL RECORDABLE INJURY RATE FOR COMBINED WORKFORCE

(Incidents per 200,000 hours worked)




*Excludes DCP Midstream and CPChem.*

Several noteworthy displays of our motivated, high-performing workforce occurred last year as Hurricanes Isaac and Sandy made landfall near our refineries in Belle Chasse, La., and Linden, N.J. During the days and weeks following those storms, many Phillips 66 employees left damaged homes and went to work to get our refineries back up and running. Through collaborative teamwork, they provided support and services needed by local communities to begin recovering from the storms. The facilities also donated fuel to emergency responders and to hospitals. These efforts contributed to the restoration of the communities and exemplified our values of safety, honor and commitment, as well as the work ethic of our employees.

Our commitment to operating excellence and financial strength enables us to pursue the strategic initiatives outlined above. Across all segments, our recordable injury rates are among the best of our respective peer groups. Additionally, we have achieved a steady reduction in our domestic refining emissions over the past 10 years, resulting in a total improvement of nearly 80 percent. While these results are impressive, our work in these areas is never complete, as we continuously strive for best-in-class performance.

Our financial strength is supported by earnings diversification, disciplined capital spending, a strong balance sheet and access to capital markets. Through outstanding financial results and $1 billion of debt repayment, we improved our debt-to-capital ratio to 25 percent at the end of 2012. In 2013, equity growth and debt reduction are expected to further improve the debt-to-capital ratio to the lower end of our target range of 20 percent to 30 percent. Financial strength, coupled with sufficient cash flow and liquidity, affords us the flexibility to invest in our most valuable growth projects throughout the business cycle. Our planned 2013 capital program is $3.7 billion, including our share of capital spending by DCP Midstream, CPChem and WRB Refining which is expected to be self-funded by these joint ventures. More than half of the $3.7 billion investment is directed toward Midstream and Chemicals.

## Providing Energy, Improving Lives

The American shale revolution has the potential to give Phillips 66 and other domestic manufacturers a sustainable competitive advantage in the global marketplace. Indeed, companies that manufacture energy-intensive products are likely to become more competitive as a result of growth in low-cost energy supplies in the U.S., and many are returning to the U.S. after a 30-year phase of offshoring.

This growth in manufacturing requires people – and jobs. Including our joint ventures, Phillips 66 provides or supports nearly 100,000 American jobs. We are committed to the resurgence of American manufacturing.

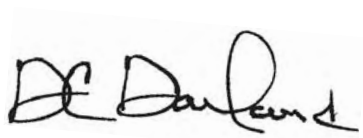
Energy companies operate in a complex environment with evolving market trends and changing regulations. Phillips 66 welcomes and encourages thoughtful involvement and discussion on energy policy. As an industry, we can do a better job communicating about our businesses – the domestic infrastructure needs, the costs of delays and policy changes, as well as the collective benefits of energy manufacturing and its positive impact on jobs and the economy. Together we can promote economic progress and energy security while improving the lives of people we serve and protecting the environments in which we operate.

Around the globe, energy products make lives better – from transportation fuel to plastics used in everyday life. At Phillips 66, we bring our own energy to work every day, and we conduct our business with safety, honor and commitment – always.

## A Promising Future

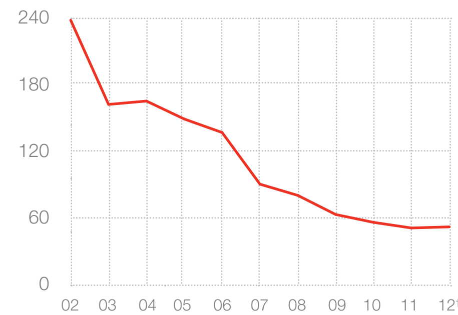
On May 1, 2012, we launched a new company, but one with a tradition of operating excellence, teamwork and financial discipline. Our ability to be a leading company in three different sectors is unique and provides distinctive investment opportunities. We garner insights and expertise from our collective businesses, which provide diverse perspectives and deeper understanding of the industries in which we operate. We believe this ultimately translates into increased value for our shareholders through diversified earnings streams and growing shareholder distributions, and for society through energy that creates jobs and economic progress.

On behalf of our board of directors, leadership team and employees, I thank you for your interest in this new company and for your ongoing support of Phillips 66.



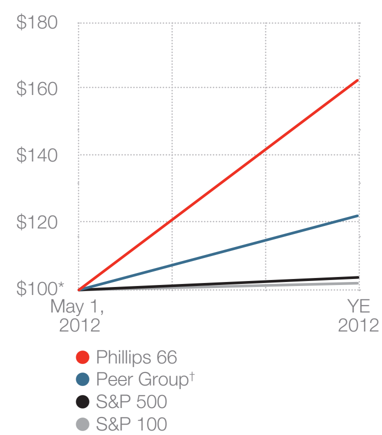
Greg C. Garland
Chairman, President and Chief Executive Officer
March 2013

**U.S. REFINING EMISSIONS***
(in Lb/MBbl)




*Includes criteria pollutant emissions (SOx, NOx and particulate matter).
†Through Q3 2012.
Excludes the Trainer and Wilhelmshaven refineries.

**CUMULATIVE TOTAL SHAREHOLDER RETURN**
($100 invested on May 1, 2012)




*Closing prices on May 1, 2012.
†Dow, Marathon Petroleum, Tesoro and Valero.

# OUR
# OPERATING SEGMENTS

From our Refining and Marketing operations to our strategic partnerships in Midstream and Chemicals, Phillips 66 offers an advantaged portfolio of assets, brands and products. Our businesses are highly competitive with strong market positions in the U.S. and across the world, placing us at the forefront of a changing energy landscape.


Ponca City Refinery / Ponca City, Okla.

# REFINING AND MARKETING

A focus on reliable operations and increasing volumes of cost-advantaged crude oil processed in the company's refineries helped our Refining and Marketing (R&M) segment capitalize on improved market conditions and achieve strong 2012 financial performance. R&M's 2012 adjusted earnings of $4.5 billion increased $1.8 billion compared with 2011. It also was a record year for R&M's safety and environmental performance.

## Upholding Operating Excellence

Operating excellence – delivering energy safely, efficiently, reliably and in an environmentally sound manner – remains a cornerstone of our strategy. In 2012, R&M employees achieved their lowest injury rate ever. In addition, our multi-year program focusing on mechanical integrity and risk reduction helped us achieve our best process safety performance on record. We continue to make progress toward reducing air emissions from our operations and have achieved a steady decline in sulfur oxide and nitrogen oxide emissions from our refineries over the last decade.

## Improving Margins

Delivering lower-cost crude oil and other feedstocks to our refineries contributed to R&M's improved financial performance in 2012. Cost-advantaged crude oils include heavy crude oil from Canada and South America, as well as light crude oil produced from shale formations, such as the Bakken in North Dakota and the Eagle Ford in Texas. By the end of 2012, we were processing approximately 170,000 barrels per day (BPD) of lower-cost shale crude oil in eight of our U.S. refineries.

Our largest advantaged crude project, the coker and refinery expansion (CORE) project at the Wood River Refinery in Illinois, performed well in its first full year of operation. Completed in 2011, the CORE project doubled the refinery's heavy crude oil gross processing capacity, improved its clean product yield by 5 percent, and increased overall production rates. The Wood River Refinery is jointly owned by Phillips 66 and Cenovus Energy, Inc., and operated by Phillips 66.

In 2012, we completed several low-capital yield improvement projects in other refineries. Additionally, we continue to maintain a rigorous focus on cost management and portfolio optimization.

**R&M OPERATING HIGHLIGHTS**

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Crude Oil Processed (MBD) | 2,064 | 2,166 | 2,156 |
| Refinery Utilization (percent) | 93 | 92 | 81 |
| Clean Product Yield (percent) | 84 | 84 | 83 |

"We're proud of what our people accomplished in 2012. Our employees' commitment to operating excellence and their teamwork to secure lower-priced crude oil for our refineries improved our financial results. We continue to keep safe, reliable operations as our top priority."

– Larry Ziemba, executive vice president,
Refining, Project Development and Procurement

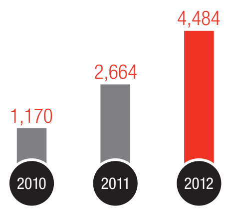
## Maximizing Value

Our Marketing, Specialties and Other organization maximizes the value of our refining business by upgrading, delivering and selling refined products, including motor fuels, lubricants, petroleum coke and other products.

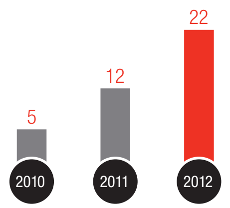
Our retail marketing business performed well in 2012, as the European fuel business captured high margins. Adjusted earnings from our U.S. fuel marketing activities remained strong. In addition, our lubricants and flow improver businesses had record earnings in 2012. We expect our Specialties businesses to continue adding value and providing stable earnings.

The Commercial organization leverages market knowledge and asset flexibility to strategically acquire feedstocks and sell refined products. In 2012, the organization played an instrumental role in securing sources of cost-advantaged feedstocks for our refineries, while identifying new markets for the export of refined products. Our Transportation business is highly integrated with our R&M assets and optimizes our operations.


### R&M ADJUSTED EARNINGS
($ in millions)




### R&M ROCE
(percent)




## R&M was recognized for strong safety and environmental performance in 2012.

- Several locations received Star status under the U.S. Occupational Safety and Health Administration's (OSHA) Voluntary Protection Program (VPP). These businesses join 17 other Phillips 66 sites with the VPP Star distinction:
  – Product storage terminal in Glenpool, Okla.
  – Product storage terminal in Tacoma, Wash.
  – Pipeline division in Casper, Wyo.
- Phillips 66 Pipeline LLC earned the American Petroleum Institute's Safety Performance Award for achieving the lowest OSHA recordable incident rates among its peer group.
- The Santa Maria refining facility in Arroyo Grande, Calif., was recognized by the American Fuels and Petrochemicals Manufacturers with a Distinguished Safety Award, the trade association's highest honor for safety performance.
- The Bayway Refinery in Linden, N.J., earned the U.S. Environmental Protection Agency's ENERGY STAR® certification, which signifies that the industrial facility performs in the top 25 percent of similar facilities nationwide for energy efficiency. Our Billings Refinery in Montana and Lake Charles Refinery in Louisiana also have earned ENERGY STAR certification.

# MIDSTREAM

DCP Midstream Processing Plant / Carthage, Texas

Our Midstream business includes DCP Midstream, LLC, our 50/50 joint venture with Spectra Energy Corp. DCP Midstream owns the general partner of DCP Midstream Partners LP, a master limited partnership which owns and operates complementary midstream assets. The DCP Midstream enterprise has an industry-leading footprint in the growing natural gas liquids (NGL) producing regions and is one of the largest natural gas gatherers and processors in the United States. DCP Midstream's NGL production represents more than 17 percent of all the NGL extracted in the United States.

In addition, Phillips 66 holds interests in three NGL fractionators and the Rockies Express (REX) natural gas pipeline. In 2012, we acquired a direct one-third ownership interest in DCP Midstream's Sand Hills and Southern Hills NGL pipelines. Including future capital expenditures, we expect to invest approximately $800 million in these two NGL pipelines.

Our Midstream adjusted earnings for 2012 were $286 million. The decrease in adjusted earnings from the previous year was related primarily to lower NGL commodity prices in 2012. Although annual earnings declined, the position of our Midstream segment in proximity to the most attractive basins provides a platform for growth and helped maintain sector-leading capital efficiency.

In 2012, DCP Midstream gathered, processed or transported 7.1 trillion British thermal units per day (BTUD) of natural gas, and produced 402,000 BPD of NGL, compared with 7.0 trillion BTUD and 383,000 BPD in 2011. DCP Midstream's assets are primarily located in the following natural gas regions of the United States: Midcontinent, Rocky Mountain, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas, Central Texas, Antrim Shale and Permian Basin.

Adding to its NGL infrastructure, DCP Midstream completed the first segment of the Sand Hills Pipeline in South Texas, which provides service for Eagle Ford NGL. The final phase of the pipeline, extending service to the Permian Basin, is expected to be in operation in the second quarter of 2013. In total, the Sand Hills Pipeline will include approximately 720 miles of pipeline and have an estimated initial capacity of 200,000 BPD. This project, along with the Southern Hills NGL pipeline, will add additional fee-based earnings to DCP Midstream's portfolio.

"Our accomplishments in 2012 are helping us transform DCP into a full value-chain midstream logistics company. We are executing on a tremendous set of growth opportunities, underpinned by a very solid foundation of well-run and strategically located assets. We're focused on operational excellence, and I'm extremely proud to report that we've had another record year in safety performance."

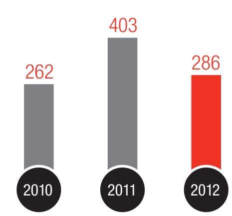
– Wouter van Kempen, president and chief executive officer of DCP Midstream, LLC, and chief executive officer of DCP Midstream Partners LP

**MIDSTREAM OPERATING HIGHLIGHTS**

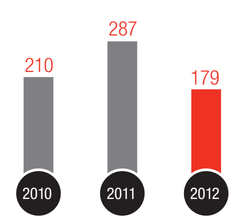
| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Natural Gas Gathered, Processed or Transported* (TBTUD) | 7.1 | 7.0 | 6.9 |
| NGL Produced* (MBD) | 402 | 383 | 369 |
| NGL Fractionated† (MBD) | 105 | 112 | 120 |

*Represents 100 percent DCP Midstream.
†Excludes DCP Midstream.

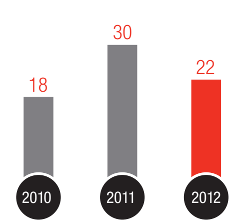
**MIDSTREAM ADJUSTED EARNINGS**
($ in millions)




**PHILLIPS 66 NET SHARE OF DCP EARNINGS**
($ in millions)




**MIDSTREAM ROCE**
(percent)




DCP Midstream has a number of other growth projects planned or under construction with anticipated startup ranging from 2013 to 2015.

Now in its 13th year of operation, DCP Midstream's workforce includes more than 3,200 employees managing over 63,000 miles of pipelines. DCP Midstream also owns or operates 62 processing plants and 12 NGL fractionators. The company is headquartered in Denver, Colo.

Outside DCP Midstream, Phillips 66's NGL position is focused on growing value from NGL production and third-party NGL suppliers, as well as our 100,000 BPD of net fractionation capacity. About 60 percent of this fractionation capacity is serving Mont Belvieu, Texas, with remaining capacity in Conway, Kan.

# CHEMICALS

Phillips 66 is the only independent downstream energy company to have a significant ownership interest in a petrochemicals business. We conduct our Chemicals operations through a 50 percent equity investment in Chevron Phillips Chemical Company LLC (CPChem), a joint venture with Chevron U.S.A. Inc., a wholly owned subsidiary of Chevron Corporation. CPChem is one of the world's top producers of olefins and polyolefins and a leading supplier of aromatics and styrenics.

CPChem has been a top performer over the last four years relative to its peers. Its competitive advantage stems from having capacity in low-cost feedstock areas in the United States and the Middle East. CPChem has a strong technology portfolio for production of plastics, normal alpha olefins, aromatics and specialty chemicals. This proprietary technology enables CPChem to build plants with lower capital investments and operating costs and provides access to a broader slate of product applications. Its extensive marketing network ensures high plant utilization, higher value-added sales and the capability to develop world-scale projects at any location in the world.

CPChem had an impressive year in 2012, contributing $980 million of adjusted earnings to Phillips 66, up from $716 million in 2011. This increase was primarily due to strong margins in its Olefins and Polyolefins (O&P) business. CPChem's average O&P capacity utilization was 93 percent in 2012. CPChem also strengthened its financial position by retiring $1 billion of debt.

In addition to an outstanding financial performance, CPChem also made progress on its growth strategy in 2012. Much of its current growth strategy is concentrated in the U.S. Gulf Coast area; however, CPChem maintains a significant and growing presence in the Middle East. In 2012, Saudi Polymers Company (SPCo), a 35-percent-owned joint venture company of CPChem, began commercial production at its petrochemicals complex in Jubail Industrial City, Saudi Arabia.

**CPCHEM OPERATING HIGHLIGHTS**

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Number of Manufacturing Sites | 36 | 35 | 34 |
| Net Processing Capacity* (BLb/Y) | 33.6 | 31.3 | 31.1 |
| Olefins and Polyolefins Utilization (percent) | 93 | 94 | 91 |

*As of year-end.

The facility produces ethylene, propylene, polyethylene, polypropylene, polystyrene and 1-hexene. The SPCo Complex is expected to enhance CPChem's performance by increasing processing capacity and utilization of advantaged feedstocks. Access to competitive feedstocks is critical to CPChem's profitability and helps provide an advantage over its peers.

CPChem has a number of other organic growth projects planned or in execution with expected startup ranging from 2013 to 2017, including a $5 billion Gulf Coast petrochemicals project.

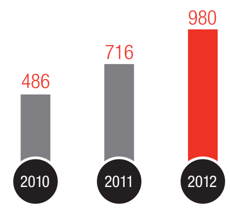
Now in its 13th year of operation, CPChem has a workforce that includes approximately 4,700 people at 36 global manufacturing facilities in eight countries, with two research and development centers that employ scientists, researchers and engineers. CPChem is well-positioned globally and is selling products in more than 125 countries. CPChem is headquartered in The Woodlands, Texas.


"Our 2012 performance marked incredible growth for Chevron Phillips Chemical Company. Our vision is to be the premier chemical company on the planet, and we are well on our way to achieving that vision with leading safety performance, customer service and profitability."

– Peter Cella, president and chief executive officer of CPChem

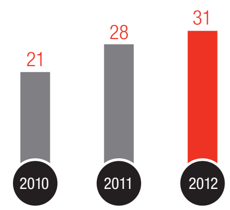
## CHEMICALS ADJUSTED EARNINGS

($ in millions)




## CHEMICALS ROCE

(percent)



# OUR STRATEGIC FOCUS

Alliance Refinery / Belle Chasse, La.

The U.S. shale oil and gas revolution has transformed the energy business and created tremendous opportunity. Several market trends influence our business: increased supply of lower-cost domestic oil and gas, complex domestic refining capacity and advantaged U.S. chemicals feedstocks.

With a diverse portfolio of energy manufacturing facilities and logistics infrastructure situated primarily in the United States, Phillips 66 is in a unique position to capture these opportunities across the downstream value chain. Building on our competitive strengths, our strategy consists of six key elements to capture these market opportunities.

## • Improving operating excellence

We supply energy and energy products reliably, safely, efficiently and in an environmentally sound manner.

## • Delivering profitable growth

We are expanding our midstream and logistics infrastructure, growing chemicals capacity, and making targeted growth investments in our marketing and specialties businesses.

## • Enhancing return on capital

We are making disciplined investment allocations to our most valuable opportunities, increasing utilization of cost-advantaged feedstocks in our refineries, expanding our refined-product exports, enhancing yields of clean-fuel petroleum products, and optimizing our portfolio.

## • Growing shareholder distributions

We intend to continue our strong heritage of being a shareholder-friendly company by delivering annual dividend increases and, when possible, allocating discretionary cash flow to share repurchases.

## • Building a high-performing organization

Our culture is one that encourages collaboration, ensures personal accountability, develops talent and skills, cultivates diversity of thought and exemplifies our values.

## • Driving financial strength and flexibility

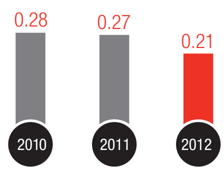
Generating sufficient cash and liquidity enables us to invest in high-return projects, strengthen our balance sheet and maintain an investment grade credit rating. This helps us remain financially flexible throughout the business cycle.

# IMPROVING OPERATING EXCELLENCE

## A Continuous Commitment to Superior Performance

**TOTAL RECORDABLE INJURY RATE COMBINED WORKFORCE**

(Incidents per 200,000 hours worked)

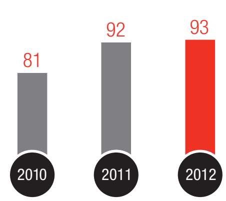



*Excludes DCP Midstream and CPChem.*

> "Our company has a deep commitment to the principles of operating excellence, including personal safety, process safety, environmental excellence, reliability and cost management."
>
> – Greg Garland, chairman, president and chief executive officer

**REFINERY CAPACITY UTILIZATION**

(percent)




To be successful in this business, it is essential to maintain a safe workplace. We have a good track record of improving safety, and we are among the industry's leaders. After 10 years of annual improvement, we continued to better our safety performance in 2012, finishing with a combined employee and contractor total recordable incident rate of 0.21 – our best year ever – and bringing us closer to our goal of zero. We believe strong leadership and an engaged workforce are the foundation to attain our goal of zero injuries, illnesses or incidents.

Financial, environmental and social responsibility are embodied in everything we do. Operating excellence is the foundation of our success. Each of our operated refineries is required to implement more than 50 mandatory standards. These expansive requirements are broken down into three areas: mechanical integrity, Health, Safety and Environment (HSE) work practices and operating excellence. The rigorous standards help us deliver operational reliability above the industry average, reduce operating risk and lessen our environmental footprint.

Our new HSE Management System was implemented on Jan. 1, 2013. This single-management system focuses on a cycle of continuous improvement in the areas of health and safety, process safety, environmental and security systems. Our systematic approach requires every operating business group to review its HSE performance and evaluate system effectiveness to determine what enhancements may be required. HSE goals and objectives are established annually by each of our businesses, and performance against these targets is a component in our employee compensation programs.

We focus on ensuring equipment integrity, maximizing reliability and making operational improvements that increase yields of high-valued cleaner-burning fuels. Managing utilities and energy costs is also critical to our profitability. We have lowered these costs through optimized unit operations and by implementing findings from energy efficiency studies. Additionally, we continue to improve refinery utilization rates, resulting in lower per-unit costs.

As a company, we are committed to complying with all government regulations and mandates. Over the past 10 years, we have significantly decreased criteria pollutant emissions. In 2012, we implemented environmental improvement projects at the Alliance Refinery in Louisiana, Wood River Refinery in Illinois and Borger Refinery in Texas to reduce flaring and $SO_2$ emissions. Our industry continues to operate in an

Billings Refinery / Billings, Mont.

"Across the company, we maintain a relentless focus on safe, environmentally responsible operations. It is fundamental to our success."

— Bob Herman, senior vice president, Health, Safety and Environment

evolving regulatory environment. Renewable fuels mandates, low-carbon standards and potential greenhouse gas regulation present ongoing compliance costs and challenges associated with meeting government-established long-term targets.

In 2012, our total hydrocarbon spill volume was 1,309 barrels, a significant decrease from 2,462 barrels in 2011. During 2012, the company experienced 14 process safety events, down from 23 in 2011.

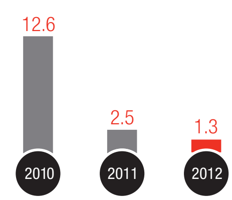
Operating excellence does not end at the company's fence lines. We believe in being involved in the communities where we operate. All of our 11 U.S. refineries have Citizens Advisory Panels to foster and strengthen our relationships with neighbors. These panels include community representatives and refinery management team members, who meet on a regular basis to discuss refinery plans and performance. The meetings provide us with an opportunity to connect with neighbors, inform them about our operations, consult with them on special issues or concerns, and gather feedback on our performance.

While prevention is always the first defense, we are prepared and capable of responding effectively if an incident occurs. As part of our preparedness, we have developed an extensive Crisis Management/Emergency Response Management Plan, which is directly aligned with our HSE Management System. We exercise these plans regularly with federal, state and local agencies, along with mutual aid organizations to enhance our response capabilities.

Protecting our people, our environment and communities is a core value and guides everything we do.

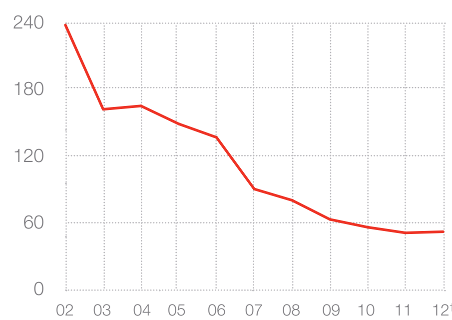
**TOTAL VOLUME OF HYDROCARBON SPILLS**

(MBbls)




**U.S. REFINING EMISSIONS***

(in Lb/MBbl)




*Includes criteria pollutant emissions (SOx, NOx and particulate matter).
†Through Q3 2012.
Excludes the Trainer and Wilhelmshaven refineries.

## Technological Expertise Improves Operations

Phillips 66 Research Center / Bartlesville, Okla.

We utilize the diverse perspectives and expertise of our employees to create value across the Phillips 66 enterprise. The Technology organization at Phillips 66 employs more than 250 dedicated researchers and technicians who work on solving problems and developing energy solutions for the future. Two of those researchers are Bruce Newman and Dean Camper, chemical engineers who are developing technology to prevent fouling, or unwanted material buildup, in refinery processing equipment. Fouling reduces energy efficiency and throughput capacity, and often leads to early shutdowns, particularly in coker furnaces.

Newman and Camper helped develop new tools to measure and predict the stability of asphaltenes (high-molecular weight constituents in crude oil) that can determine which crude mixtures will cause fouling. For example, at the Lake Charles Refinery in Louisiana, these tools enabled the use of more paraffinic light crude oil that otherwise could destabilize the crude mixture. This resulted in a significant cost savings for the refinery.

"This development comes at an opportune time, as we pursue increasing the volumes of advantaged crudes we process."

– Bruce Newman, fellow, Refining Research

"This development comes at an opportune time, as we pursue increasing the volumes of advantaged crudes we process. Without this technology, these lighter crudes can pose a special challenge when mixed with heavier asphaltenic crudes, such as those from Alberta," Newman said.

# DELIVERING PROFITABLE GROWTH

## Increasing Capacity of Profitable Businesses

With a strong balance sheet and financial flexibility, we are well-positioned to grow the capacity of our Midstream and Chemicals operations, as well as our Marketing and Specialties businesses, throughout the business cycle.

### DCP Midstream

DCP Midstream has integrated assets with scale and scope in the most attractive basins, such as the Eagle Ford, Permian and Denver-Julesburg. DCP Midstream is expanding its position and plans to place $6 billion of growth projects into service between 2013 and 2015.

"The increase of oil and natural gas production in the United States is creating significant growth potential for our Midstream and Chemicals businesses. We are investing substantial capital to expand capacity in these sectors and capture this market opportunity."

– Tim Taylor, executive vice president, Commercial, Marketing, Transportation and Business Development

DCP Midstream expects to leverage its existing gathering and processing operations and extend its value chain by building two long-haul natural gas liquids (NGL) pipelines totaling $2 billion to $3 billion. The two major pipeline projects, the Sand Hills and Southern Hills pipelines, will connect Eagle Ford, Permian and Midcontinent production to the Mont Belvieu, Texas, market and add additional fee-based margins. To enable DCP Midstream to continue executing its growth plan, Phillips 66 acquired a direct one-third ownership interest in the pipelines, representing a total estimated investment of $800 million, including future capital expenditures.

In 2012, DCP Midstream completed the first phase of the Sand Hills Pipeline, with service from Eagle Ford to Mont Belvieu. The second phase of the project, with deliveries from the Permian Basin, is expected to be complete in the second quarter of 2013. DCP Midstream anticipates the total 720-mile Sand Hills Pipeline will have initial capacity of 200,000 barrels per day (BPD), with potential expansion up to 350,000 BPD. The proposed Southern Hills Pipeline will travel 800 miles through the Midcontinent to Mont Belvieu, with completion expected in mid-2013. DCP Midstream expects the Southern Hills Pipeline to have initial capacity of approximately 150,000 BPD, and intends to expand the pipeline's capacity up to 175,000 BPD.

Additional growth projects in DCP Midstream's other business units are expected to provide new infrastructure to support the rapidly growing natural gas and NGL markets. These include the Eagle Plant in Edna, Texas, the Goliad Plant in South Texas and the LaSalle Plant in Weld County, Colo., as well as additional NGL production and other projects.


Sand Hills Pipeline / Houston, Texas

### Phillips 66 Master Limited Partnership

Consistent with Phillips 66's strategy to grow our Midstream and Transportation businesses, in December 2012 we announced plans to form a master limited partnership (MLP) with a portion of our transportation assets. We believe a Phillips 66 MLP will provide value to Phillips 66 shareholders, highlight the value of our logistics and infrastructure assets, and be an integral vehicle to support growth in transportation and midstream infrastructure.

Phillips 66 plans to retain majority ownership of the proposed Phillips 66 MLP and would act as the general partner with full management and operating responsibility for the business. The remaining minority, or noncontrolling interest, consisting of limited partner units, is planned to be sold in an initial public offering during the second half of 2013. We intend to file a registration statement with the U.S. Securities and Exchange Commission in the second quarter of 2013.

### Chevron Phillips Chemical Company

With substantial growth in the Middle East, including five mega projects in the past 12 years, Chevron Phillips Chemical Company (CPChem) now has a renewed focus and opportunity on the U.S. Gulf Coast with the development of significant shale gas resources. The shale oil and gas production growth is providing cost-advantaged NGL feedstocks and low energy costs.

CPChem is expanding its NGL fractionator complex in Old Ocean, Texas. The expansion will increase capacity by 19 percent, or approximately 22,000 BPD, and is expected to start up in 2013.

## Marketing, Specialties and Other

- Combined, Marketing, Specialties and Other added approximately $700 million of adjusted earnings to Phillips 66's R&M business in 2012. These are strong, stable, high-returning businesses in which we will continue to invest in growth projects over the next few years.
- Our U.S. branded marketing is focused on integrated markets on the West Coast under the 76® brand, and in the Central Corridor region under the Phillips 66® and Conoco® brands. In Europe, we market through the JET® fuel brand with growth centered in Germany. Over the long term, we plan to build 170 new retail sites in Germany, which is expected to increase retail marketing net income by 50 percent. The company also has an equity interest in a joint venture that markets products in Switzerland under the Coop® brand.
- In the Lubricants business, we manufacture and market motor oils under four major lubricant brands: Phillips 66®, Conoco®, 76® and Kendall®. We also market Group II Pure Performance® base oils globally, as well as Group III Ultra-S base oils through an exclusive North American agreement with Korea's S-Oil corporation. Since 2003, our lubricant sales have grown 35 percent, and we are now one of the largest marketers of lubricants in the United States.
- We have several high-return Specialties businesses that provide unique growth opportunities. For example, our flow improver business has grown in volume by 70 percent over the last five years. A significant portion of the growth is coming from North American shale plays. As the inventor of the technology with 30 years of market leadership, we believe this business has significant growth potential.

CPChem Cedar Bayou Complex / Baytown, Texas

In April 2012, CPChem announced plans to build the world's largest on-purpose 1-hexene plant capable of producing up to 550 million pounds per year at its Cedar Bayou Chemical Complex in Baytown, Texas. A normal alpha olefin, 1-hexene is a key component in the manufacturing of polyethylene, a plastic resin commonly converted into film, pipe, detergent bottles, and food and beverage containers. Construction is under way, and CPChem expects the project to be complete during the first half of 2014.

In addition, CPChem is currently developing a new 3.3 billion-pound-per-year world-scale ethane cracker and two 1.1 billion-pound-per-year polyethylene facilities on the Gulf Coast. It is expected to be one of the first major cracker complexes developed on the Gulf Coast and will utilize the more advantaged ethane feedstocks. The $5 billion project is scheduled to begin operation in 2017 and is expected to increase CPChem's U.S. ethylene capacity by more than 40 percent. CPChem anticipates the final investment decision to occur in 2013.

# ENHANCING RETURN ON CAPITAL

## Optimizing Assets, Improving Margins

Phillips 66 is improving return on capital employed (ROCE) in Refining and Marketing (R&M) through a disciplined capital allocation process, implementing projects designed to process more advantaged crude, enhance export capability and improve clean product yield. We also continuously evaluate our portfolio of assets and maintain a rigorous focus on cost management.

> "All of our U.S. refineries are currently processing cost-advantaged crudes. These efforts are expected to significantly enhance our Refining returns and ultimately improve our financial results."
>
> – Ron Armstrong, manager, Refining Services

### Advantaged Crude Strategy

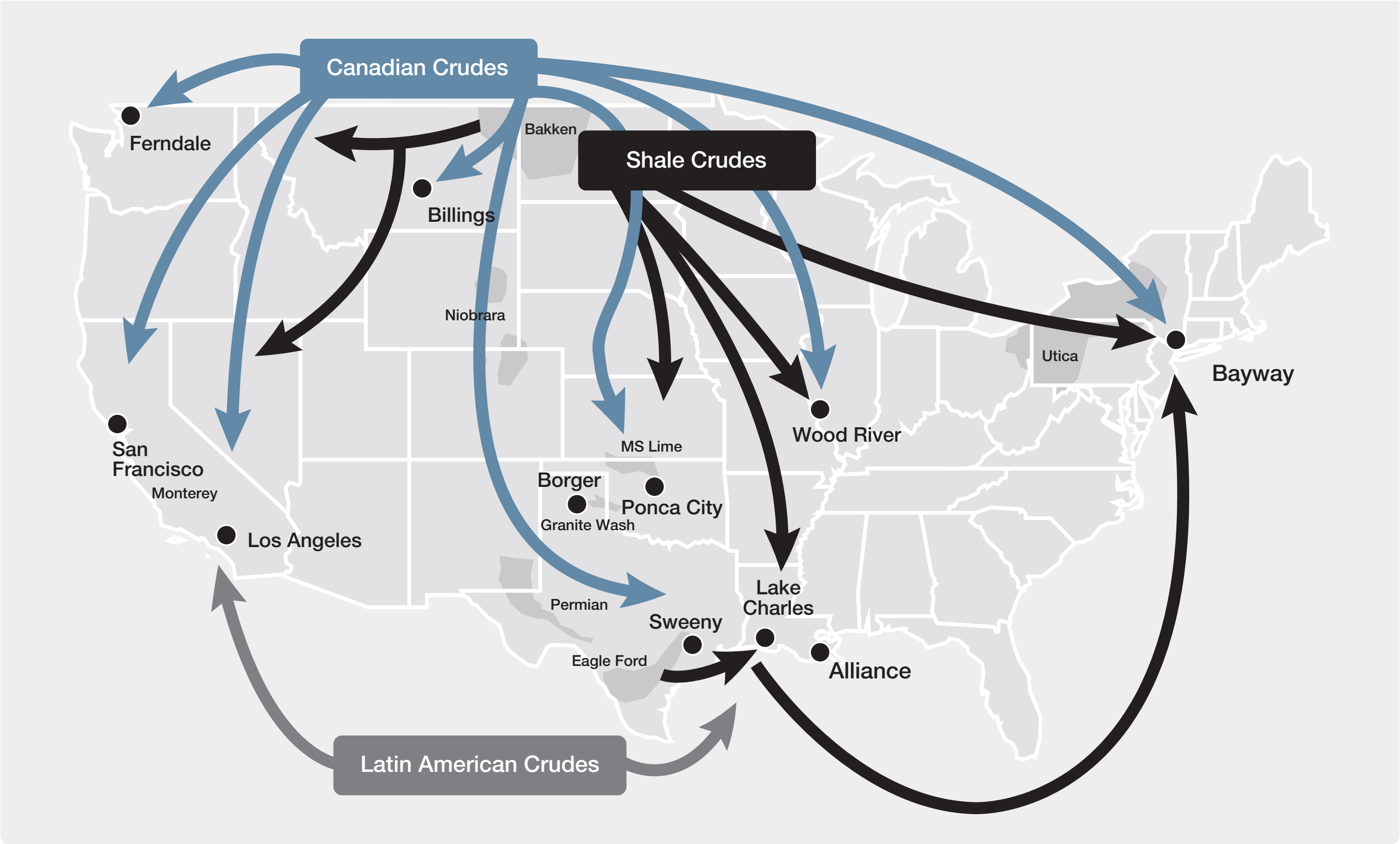
The cost of crude is the largest driver of our Refining margins. In the United States, the shale oil and gas revolution is creating new opportunities for domestic refineries by providing abundant, lower-cost crudes. With more than half of our refining capacity situated in the Central Corridor and Gulf Coast, our Refining business is well-positioned to capture this opportunity. In addition, our refineries on the East and West Coasts are beginning to benefit from the growth in domestic crude supply. We are steadily making a number of investments in transportation infrastructure to deliver, receive and process greater quantities of advantaged crude oil in our U.S. refineries. A cross-functional team from our Business Development, Commercial, Refining and Transportation groups is developing and implementing plans for accessing, transporting and processing this advantaged crude in our refineries.

> "Our advantaged crude team includes employees from several key areas of the company. Together we are considering various options to secure advantaged crude for our refineries—pipelines, railcars and marine vessels, among others."
>
> – Glenn Simpson, general manager, Crude and International Supply

We have secured access to a third-party rail loading facility in the Bakken Basin in North Dakota and have begun to receive 2,000 railcars that can be used to ship Bakken crude oil west to our Ferndale Refinery in Washington and east to our Bayway Refinery in New Jersey. Eagle Ford crude oil will continue to be delivered to our coastal refineries via pipelines, trucks, barges and other marine vessels, including two medium-range Jones Act, or U.S. flagged, tankers chartered in 2012. In addition, an agreement with a third-party pipeline operator, along with investments in our Oklahoma transportation assets, will supply our Ponca City Refinery with crude oil from the Mississippian Lime play. Another pipeline agreement will supply Eagle Ford crude oil to our Sweeny Refinery in Texas beginning in 2014. More recently, in January 2013, we entered into a five-year transportation and logistics contract to transport 91 million barrels of Bakken crude to the Bayway Refinery using a third-party network of loading facilities and offloading terminals.

R&M is also making modest investments in its assets to facilitate the delivery of lower-cost crude oil. Recent expansion of the truck offloading racks at the Ponca City Refinery enabled the delivery of increased volumes of locally produced advantaged crudes. Additional modification projects aimed at increasing advantaged crude processing capabilities are planned

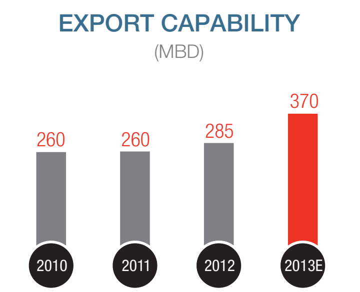
## ACCESSING ADVANTAGED CRUDE




Sweeny Refinery / Old Ocean, Texas

at the company's Humber Refinery in the United Kingdom and the Alliance Refinery in Louisiana. Phillips 66 expects to process over 200,000 BPD of domestic shale crude in 2013, an increase from the 2012 average of 112,000 BPD.

## Export Capability

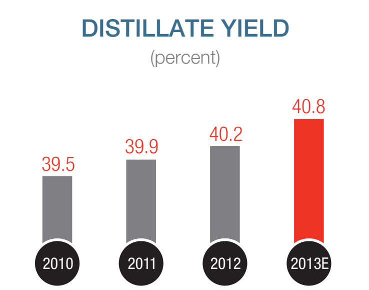



*Excludes the Trainer and Wilhelmshaven refineries.*

The ability of U.S. refiners to access lower-cost crudes and natural gas provides a unique competitive advantage over many international refiners. The United States has more than enough refining capacity to meet domestic demand, and studies show that much of the growth in demand for refined products will come from rapidly developing nations, such as China, India and Brazil, with lower demand in the more developed regions of the world. The potential to export enables U.S. refineries to maintain high capacity utilization, resulting in lower per-unit costs and sustaining jobs at the facilities.

Phillips 66 will continue to primarily serve domestic markets and will explore opportunities to meet growing demand overseas when opportunities exist. At the end of 2012, we had the capability to export up to 285,000 BPD of refined products from our domestic refineries. Several projects to further expand our export capability in our Gulf and West Coast refineries are expected to increase our total export capability to 370,000 BPD by the end of 2013. This represents 30 percent of the clean products produced in our coastal refineries. We expect exports to be a key source of improving R&M margins over the next several years.

## Clean Product Yield




*Excludes the Trainer and Wilhelmshaven refineries.*

Phillips 66 continues to optimize refinery clean product yields. We are implementing projects at all of our refineries to increase yield of gasoline and diesel. In 2012, the company's clean product yield was 84 percent. We had an industry-leading position in distillates with a distillate yield of 40 percent. This was 3 percentage points higher than the U.S. industry average, representing a total of approximately $150 million in net income based on recent market conditions.

## Portfolio Optimization and Cost Management

In 2012, we completed the sale of the 185,000 BPD Trainer Refinery in Pennsylvania, reducing the company's exposure to higher-priced Brent-based crudes. We also sold the Riverhead storage terminal in New York.

Another part of our efforts to improve R&M margins is to maintain a competitive cost structure. In controllable cost benchmarking surveys, more than 60 percent of our refineries rank in the top third versus competitors in their respective regions. We intend to further reduce our operating costs, mainly through improved turnaround execution and lower energy consumption. For example, an energy reduction program being piloted at two refineries has led to cost savings and margin improvements totaling approximately $20 million before-tax. The program has led to the use of software-driven dashboards with targets that help refinery personnel manage energy consumption of processing units.

## Insights Lead to Major Railcar Order

The recent development of shale plays in the United States has created numerous opportunities for energy companies. However, limited domestic pipeline infrastructure creates a challenge to accessing and transporting these lower-cost crudes. With insight into the market and the position to move quickly, Phillips 66 found a solution. In 2012, we reached an agreement with a railcar supplier to manufacture 2,000 crude oil railcars for the transport of shale crude to our East and West Coast refineries.

"Representatives from key areas of our business had been working on our crude-by-rail strategy," said Joe Gallagher, director, Commercial Truck and Rail. "We wanted to get a railcar order in quickly so we could get the cars in service and deliver cost-advantaged crude to our refineries as soon as possible."

However, we weren't the only company looking for railcars, making the market extremely competitive. Production backlogs across the industry presented numerous challenges to the team, but the magnitude of our order, coupled with our speed to the market, provided us with significant attention and momentum from railcar supply companies.

"We've invested a great deal of effort into developing relationships with the railroads and railcar suppliers, which helped us in the bidding and negotiating process," said Gallagher. "It was also important for us to work with a company that would manufacture the cars in the United States. Our existing relationship with the eventual supplier and the size of our order helped us secure favorable terms and an earlier delivery window compared to other proposals."

More than 100 of the new railcars were in service by the end of February 2013, and the remaining cars will be delivered throughout 2013 and early 2014. These railcars provide a "pipeline on wheels" for us to deliver crude to a number of our refineries.

"Delivery of these railcars will further enable us to capture significant value by transporting advantaged crude across the United States."

– Debbie Adams, president, Transportation


Phillips 66 Railcars / Central Texas

# GROWING SHAREHOLDER DISTRIBUTIONS

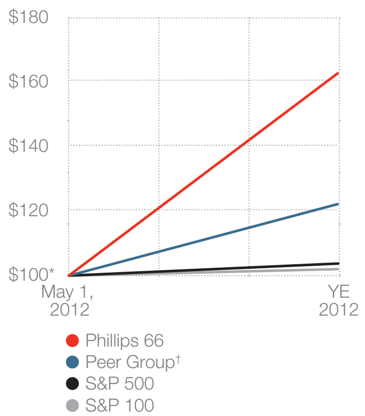
## Reliable and Growing Returns

### DISTRIBUTIONS AS A PERCENT OF CASH FROM OPERATIONS

(percent)


### CUMULATIVE TOTAL SHAREHOLDER RETURN

($100 invested on May 1, 2012)




*Closing prices on May 1, 2012.
†Dow, Marathon Petroleum, Tesoro and Valero.

Through our legacy companies, we have a long heritage as a shareholder-friendly company, and we understand our shareholders must share in our success. We are committed to growing shareholder distributions.

Since our May 1 launch, we returned $638 million of capital to our shareholders through dividends and share repurchases, representing approximately 15 percent of our 2012 cash from operations. Our total shareholder return was 64 percent, which exceeded our peer group average as well as the S&P 500 Index.

Our first priority in delivering strong shareholder returns is to maintain a competitive and growing dividend. Phillips 66 paid its first dividend in the third quarter of 2012. Our board of directors subsequently approved a 25 percent increase in the fourth-quarter dividend, raising the dividend to 25 cents per share. In December, our board of directors approved an additional 25 percent increase in the dividend, which raises the annual dividend rate to $1.25 per share for 2013.

Our dividend is supplemented by a share repurchase plan, funded with cash from operations. Over the course of last year, we announced plans to repurchase a total of $2 billion of outstanding common stock. Shares are repurchased from time to time in the open market at the company's discretion and in accordance with applicable regulatory requirements.

At the end of 2012, we had paid $282 million in dividends and repurchased 7.6 million shares of common stock totaling $356 million.

Disciplined capital allocation and strong operating cash flow support increasing shareholder value. We intend to continue allocating capital to dividends and repurchases, while also investing in the growth of our business.


NYSE/New York, NY

# 2012 SHAREHOLDER DISTRIBUTION ANNOUNCEMENTS

**May 1**

Phillips 66 begins regular way trading on the New York Stock Exchange as PSX.

**July 11**

Phillips 66 announces first quarterly dividend of 20 cents per share.

**Aug. 1**

Phillips 66 announces $1 billion share repurchase plan.

**Oct. 3**

Phillips 66 announces 25 percent increase in quarterly dividend to 25 cents per share.

**Dec. 7**

Phillips 66 expands share repurchase plan to $2 billion and announces another 25 percent increase in annual dividend effective in first quarter of 2013.

# BUILDING A HIGH-PERFORMING ORGANIZATION

## A Winning Team and a Great Place to Work

In 1927, a car testing a new high-octane gasoline reached 66 miles per hour on Route 66 – and the Phillips 66 brand was born. Today, our company continues to deliver on high performance, reflected in the way our 13,500 employees work together.

### Strong Foundation

We established our vision and values to serve as the single, shared purpose for our workforce. The Phillips 66 vision, providing energy and improving lives, reflects our role as an energy manufacturing company. This vision is much broader than delivering fuel to consumers; we deliver a number of energy products that help grow economies and nations around the world. We also provide high-quality jobs for our employees, as well as indirect jobs in the communities in which we operate. Underlying this vision is a strong foundation of values: safety, honor and commitment. We protect each other, our environment and our communities. We stand behind our word, and you can count on us to do the right thing, always. We are inspired to achieve the highest levels of performance in everything we do. Our vision and values guide our operations – day in and day out. We are excited about our work. Together we are helping shape the energy revolution.

### High-Performing Team

A high-performing organization is fundamental to the company's long-term success and overall shareholder value creation. At the inception of our company, we implemented purposeful enhancements to our health and welfare benefits, compensation, talent learning and development, performance management and goal alignment programs. These enhancements drive employee behaviors and performance to execute our company's strategy which is aligned with shareholder interests.

In today's marketplace, we must be agile and ensure our company has deep and broad organizational capability to deliver on our strategy. Our ability to quickly adapt to the changing environment stems from diverse skill sets in our workforce and among our leadership ranks. To build upon our strengths, we are enhancing training and talent development programs and providing new learning opportunities. Additionally, we are establishing robust career development programs that ensure employees at all levels remain fully engaged and successful in their current roles, while supporting them to reach their fullest potential. We also recognize the need to plan for tomorrow. We place a strong emphasis on succession planning and strategic workforce planning, which ensures the sustainability of our business and enables us to execute our growth strategy.

### Great Place to Work

At Phillips 66, we promote a culture of trust, collaboration and inclusion that attracts, develops and retains high-caliber talent. Leaders collaborate with and engage their teams to advance the business. We value diversity of thought, inclusion, varied backgrounds and global experiences, which collectively help our company succeed. We aspire to be a great place to work today and for many generations to come.

"Each day brings a different project, and I learn more every day. When problems arise, I brainstorm with my teammates, sharing ideas for a possible solution, and we end up coming up with a resolution together."

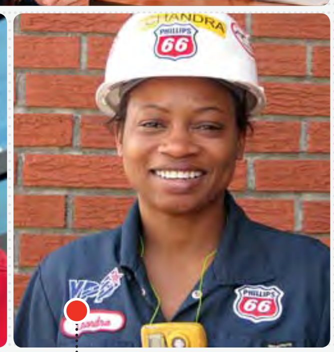
– Lauren Turner,
process engineer,
Ferndale Refinery

"I've had great opportunities with our heritage companies to grow the businesses I oversee and work with talented people. I am looking forward to new challenges at Phillips 66."

– Jay Hong,
manager, Base Oils
and Special Products,
Lubricants

"We work together as a team – as a family. We take great satisfaction in what we accomplish and what we stand for as a company."

– Bob Allman,
terminal operator,
Pasadena Terminal

"Phillips 66 provides us with opportunities to work on challenging projects, gain new skills and continually develop. We are encouraged to ask questions and our input is always valued."

– Duncan Crosbie,
business team lead,
Oil Storage and Movements,
Humber Refinery

"We guard each other's safety, and we're committed to doing things honorably in all of our day-to-day operations."

– Chandra Guillory,
process engineer,
Lake Charles Refinery

# DRIVING FINANCIAL STRENGTH AND FLEXIBILITY

## A Rock-Solid Platform That Supports Growth


### *Optimize 66*

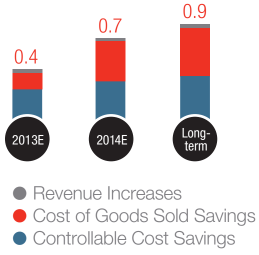
As a new company, we have an opportunity to optimize our business through both cost management and revenue growth. We estimate the dis-synergies following the repositioning to be approximately $170 million, resulting from establishing a separate set of systems, processes and staff groups – elements that are vital to our success. We launched the *Optimize 66* initiative to identify new ways to capture value and cost savings across the company.

With safety of employees and the community as top priority, our business units and staff groups provided innovative solutions to reduce controllable costs and capture more value from our operations. As a result of this work, we expect 2013 controllable costs to be $200 million lower than they would have been without implementation of this initiative. Additionally, we have identified opportunities to improve margins by processing more advantaged crude and increasing transportation revenues. In total, *Optimize 66* is expected to result in pre-tax value capture of more than $400 million by the end of 2013.

By tracking and sustaining these savings over the next several years, we expect to improve our overall effectiveness significantly.

OPTIMIZE 66

($ in billions)



## Capital Allocation

Our approach to capital allocation is designed to fund sustainability investments and growth projects, while increasing shareholder distributions and strengthening our balance sheet.

For 2013, we intend to spend approximately $1 billion of sustaining capital to ensure the safety and viability of our business. This includes reliability, safety, maintenance and environmental projects that are crucial to our success. Cash in excess of sustaining capital and our 2013 dividend commitment will be directed toward projects that deliver growth and enhance returns, as well as to increase shareholder distributions and reduce debt.

> "Our financial strategy has three main pillars. We take a balanced and disciplined approach to capital allocation. We maintain effective cost management, and we continue strengthening our balance sheet. Collectively, we believe these pillars will enable us to build shareholder value."
>
> – Greg Maxwell, executive vice president, Finance and chief financial officer

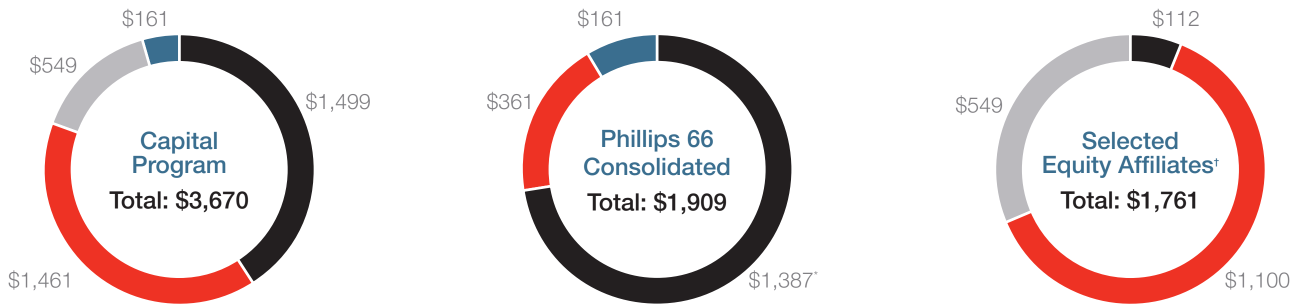
## Creating Shared Prosperity

The increase of manufacturing activity in response to the North American energy revolution is creating opportunity for great prosperity – for businesses, communities and families alike. Throughout this report, we discuss our operations and growth areas in relation to the positive impacts made by our company for our shareholders. Our business also has positive impacts on a much larger scale. Including our joint ventures, our businesses provide nearly 100,000 American jobs, directly and indirectly, through our operations.

We are also investing in major capital projects that are expected to provide additional high-quality jobs and promote economic success. The proposed construction of a world-scale ethane cracker at CPChem's Cedar Bayou Complex in Baytown, Texas, and two polyethylene facilities in Old Ocean, Texas, is expected to create 10,000 engineering and construction jobs and approximately 400 direct, long-term jobs. The two major pipeline projects, Sand Hills and Southern Hills, in development by DCP Midstream, will require nearly 2,000 contract workers during construction and 90 employees for operations post-completion. In 2011, Phillips 66 completed its coker and refinery expansion (CORE) project at the Wood River Refinery. This four-year project required 2,600 temporary workers and created approximately 75 permanent refinery positions.

The downstream energy industry is one of America's great, and often overlooked, manufacturing success stories. A recent study by IHS estimated that unconventional energy activity, including the shale oil and gas revolution, will support a total of 3.5 million jobs, up from 1.7 million today, as well as contribute $475 billion to the U.S. gross domestic product by 2035. America is poised for a manufacturing renaissance. With a strong portfolio of businesses well-positioned to promote economic prosperity and improve lives, Phillips 66 is excited about the future of energy.

## 2013 CAPITAL PROGRAM
($ in millions)




- Refining and Marketing
- Midstream
- Chemicals
- Corporate and Other

*R&M spending includes noncash capitalized lease of $152 million.
†Includes Phillips 66's share of capital spending by DCP Midstream, CPChem and WRB Refining, which is expected to be self-funding in 2013.

## Capital Program

Phillips 66's 2013 planned capital program is $3.7 billion, which represents a 3 percent increase over the 2012 capital program of $3.6 billion.

The capital program includes our portion of planned capital spending by DCP Midstream, CPChem and WRB Refining totaling $1.8 billion, which is not expected to require cash outlays by Phillips 66. These investments are primarily related to growth in DCP Midstream and CPChem.

The other $1.9 billion represents Phillips 66's direct investments in R&M, Midstream, and Corporate and Other. This includes our ongoing direct one-third investments in the Sand Hills and Southern Hills NGL pipelines; sustaining capital, and growth and optimization spending in R&M; and investments related to information technology, facilities, and research and development.

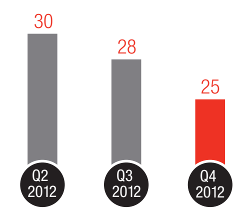
## Balance Sheet Strength

A strong balance sheet is a critical element in our financial flexibility, as it enables us to make investments in promising projects and future opportunities throughout the business cycle. This strength is our foundation for long-term stability and growth.

At the time of repositioning, we issued $7.8 billion of debt, and we achieved our objective to obtain an investment grade credit rating. In December, the company prepaid $1 billion of its three-year, $2 billion term loan. With strong financial results and debt repayments, we improved our debt-to-capital ratio from 30 percent to 25 percent by year-end.

Additional debt reduction and equity growth are expected to further improve our debt-to-capital ratio to the lower end of our target 20 percent to 30 percent range by the end of 2013.

## DEBT-TO-CAPITAL RATIO
(percent)




**BBB & Baa1**

**CREDIT RATINGS**

*Designated by S&P and Moody's rating agencies, respectively.*


Billings Refinery / Billings, Mont.

# FINANCIAL HIGHLIGHTS



### Units of Measure

| | |
|---|---|
| MBbls | Thousands of barrels |
| BPD | Barrels per day |
| MBD | Thousands of barrels per day |
| TBTUD | Trillion British thermal units per day |
| BLb/Y | Billion pounds per year |
| Lb/MBbl | Pounds per thousand barrels |

## Report of Independent Registered Public Accounting Firm on Condensed Financial Statements

The Board of Directors and Stockholders
Phillips 66

We have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Phillips 66 at December 31, 2012 and 2011 and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2012 (not presented separately herein) and in our report dated February 22, 2013, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated financial statements as of December 31, 2012 and 2011 and for each of the three years in the period ended December 31, 2012 (presented on pages 37 through 40) is fairly stated, in all material respects, in relation to the consolidated financial statements from which it has been derived.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Phillips 66's internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2013 (not presented separately herein) expressed an unqualified opinion thereon.

Ernst & Young LLP

Houston, Texas
February 22, 2013

# Consolidated Statement of Income

Phillips 66

Millions of Dollars

| Years Ended December 31 | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Revenues and Other Income** | | | |
| Sales and other operating revenues* | $ 179,460 | 196,088 | 146,561 |
| Equity in earnings of affiliates | 3,134 | 2,843 | 1,765 |
| Net gain on dispositions | 193 | 1,638 | 241 |
| Other income | 135 | 45 | 89 |
| Total Revenues and Other Income | 182,922 | 200,614 | 148,656 |
| **Costs and Expenses** | | | |
| Purchased crude oil and products | 154,483 | 172,837 | 125,092 |
| Operating expenses | 4,032 | 4,072 | 4,189 |
| Selling, general and administrative expenses | 1,722 | 1,409 | 1,384 |
| Depreciation and amortization | 913 | 908 | 880 |
| Impairments | 1,158 | 472 | 1,699 |
| Taxes other than income taxes* | 13,741 | 14,288 | 13,985 |
| Accretion on discounted liabilities | 25 | 21 | 22 |
| Interest and debt expense | 246 | 17 | 1 |
| Foreign currency transaction (gains) losses | (29) | (34) | 85 |
| Total Costs and Expenses | 176,291 | 193,990 | 147,337 |
| Income before income taxes | 6,631 | 6,624 | 1,319 |
| Provision for income taxes | 2,500 | 1,844 | 579 |
| Net income | 4,131 | 4,780 | 740 |
| Less: net income attributable to noncontrolling interests | 7 | 5 | 5 |
| **Net Income Attributable to Phillips 66** | $ 4,124 | 4,775 | 735 |
| **Net Income Attributable to Phillips 66 Per Share of Common Stock** (dollars) | | | |
| Basic | $ 6.55 | 7.61 | 1.17 |
| Diluted | 6.48 | 7.52 | 1.16 |
| **Dividends Paid Per Share of Common Stock** (dollars) | $ 0.45 | — | — |
| **Average Common Shares Outstanding** (in thousands) | | | |
| Basic | 628,835 | 627,628 | 627,628 |
| Diluted | 636,764 | 634,645 | 634,645 |
| *Includes excise taxes on petroleum product sales: | $ 13,371 | 13,955 | 13,689 |

For Phillips 66's complete consolidated financial statements, including notes, as well as Management's Discussion and Analysis of Financial Condition and Results of Operations and other financial information, please refer to Appendix B of the company's 2013 Proxy Statement.

# Consolidated Statement of Comprehensive Income

Phillips 66

Millions of Dollars

| Years Ended December 31 | 2012 | 2011 | 2010 |
|---|---|---|---|
| Net Income | $ 4,131 | 4,780 | 740 |
| Other comprehensive income (loss) | | | |
| Defined benefit plans | | | |
| Prior service cost/credit: | | | |
| Prior service credit arising during the period | 18 | — | — |
| Amortization to net income of prior service cost | 1 | — | — |
| Actuarial gain/loss: | | | |
| Actuarial loss arising during the period | (152) | (8) | (8) |
| Amortization to net income of net actuarial loss | 55 | 3 | 2 |
| Plans sponsored by equity affiliates | (33) | (41) | (23) |
| Income taxes on defined benefit plans | 18 | 17 | 12 |
| Defined benefit plans, net of tax | (93) | (29) | (17) |
| Foreign currency translation adjustments | 148 | 28 | (95) |
| Income taxes on foreign currency translation adjustments | 48 | (92) | (4) |
| Foreign currency translation adjustments, net of tax | 196 | (64) | (99) |
| Hedging activities by equity affiliates | 1 | 2 | 2 |
| Income taxes on hedging activities by equity affiliates | — | (1) | (1) |
| Hedging activities by equity affiliates, net of tax | 1 | 1 | 1 |
| Other Comprehensive Income (Loss), Net of Tax | 104 | (92) | (115) |
| Comprehensive Income | 4,235 | 4,688 | 625 |
| Less: comprehensive income attributable to noncontrolling interests | 7 | 5 | 5 |
| Comprehensive Income Attributable to Phillips 66 | $ 4,228 | 4,683 | 620 |

For Phillips 66's complete consolidated financial statements, including notes, as well as Management's Discussion and Analysis of Financial Condition and Results of Operations and other financial information, please refer to Appendix B of the company's 2013 Proxy Statement.

# Consolidated Balance Sheet

Phillips 66

Millions of Dollars

| At December 31 | 2012 | 2011 |
|---|---|---|
| **Assets** | | |
| Cash and cash equivalents | $ 3,474 | — |
| Accounts and notes receivable (net of allowance of $50 million in 2012 and $13 million in 2011) | 8,593 | 8,354 |
| Accounts and notes receivable – related parties | 1,810 | 1,671 |
| Inventories | 3,430 | 3,466 |
| Prepaid expenses and other current assets | 655 | 457 |
| Total Current Assets | 17,962 | 13,948 |
| Investments and long-term receivables | 10,471 | 10,306 |
| Net properties, plants and equipment | 15,407 | 14,771 |
| Goodwill | 3,344 | 3,332 |
| Intangibles | 724 | 732 |
| Other assets | 165 | 122 |
| Total Assets | $ 48,073 | 43,211 |
| **Liabilities** | | |
| Accounts payable | $ 9,731 | 10,007 |
| Accounts payable – related parties | 979 | 785 |
| Short-term debt | 13 | 30 |
| Accrued income and other taxes | 901 | 1,087 |
| Employee benefit obligations | 441 | 64 |
| Other accruals | 417 | 411 |
| Total Current Liabilities | 12,482 | 12,384 |
| Long-term debt | 6,961 | 361 |
| Asset retirement obligations and accrued environmental costs | 740 | 787 |
| Deferred income taxes | 5,444 | 5,803 |
| Employee benefit obligations | 1,325 | 117 |
| Other liabilities and deferred credits | 315 | 466 |
| Total Liabilities | 27,267 | 19,918 |
| **Equity** | | |
| Common stock (2,500,000,000 shares authorized at $.01 par value) | | |
| Issued (2012 – 631,149,613 shares) | | |
| Par value | 6 | — |
| Capital in excess of par | 18,726 | — |
| Treasury stock (at cost: 2012 – 7,603,896 shares) | (356) | — |
| Retained earnings | 2,713 | — |
| Net parent company investment | — | 23,142 |
| Accumulated other comprehensive income (loss) | (314) | 122 |
| Total Stockholders' Equity | 20,775 | 23,264 |
| Noncontrolling interests | 31 | 29 |
| Total Equity | 20,806 | 23,293 |
| Total Liabilities and Equity | $ 48,073 | 43,211 |

For Phillips 66's complete consolidated financial statements, including notes, as well as Management's Discussion and Analysis of Financial Condition and Results of Operations and other financial information, please refer to Appendix B of the company's 2013 Proxy Statement.

# Consolidated Statement of Cash Flows

Phillips 66

Millions of Dollars

| Years Ended December 31 | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Cash Flows From Operating Activities** | | | |
| Net income | $ 4,131 | 4,780 | 740 |
| Adjustments to reconcile net income to net cash provided by operating activities | | | |
| Depreciation and amortization | 913 | 908 | 880 |
| Impairments | 1,158 | 472 | 1,699 |
| Accretion on discounted liabilities | 25 | 21 | 22 |
| Deferred taxes | 221 | 931 | (33) |
| Undistributed equity earnings | (872) | (951) | (723) |
| Net gain on dispositions | (193) | (1,638) | (241) |
| Other | 69 | 167 | (53) |
| Working capital adjustments | | | |
| Decrease (increase) in accounts and notes receivable | (143) | (186) | (3,019) |
| Decrease (increase) in inventories | 55 | 616 | (344) |
| Decrease (increase) in prepaid expenses and other current assets | (48) | 28 | (2) |
| Increase (decrease) in accounts payable | (985) | 58 | 3,003 |
| Increase (decrease) in taxes and other accruals | (35) | (200) | 163 |
| Net Cash Provided by Operating Activities | 4,296 | 5,006 | 2,092 |
| **Cash Flows From Investing Activities** | | | |
| Capital expenditures and investments | (1,721) | (1,022) | (1,150) |
| Proceeds from asset dispositions | 286 | 2,627 | 662 |
| Advances/loans – related parties | (100) | — | (200) |
| Collection of advances/loans – related parties | — | 550 | 20 |
| Other | — | 337 | 16 |
| Net Cash Provided by (Used in) Investing Activities | (1,535) | 2,492 | (652) |
| **Cash Flows From Financing Activities** | | | |
| Distributions to ConocoPhillips | (5,255) | (7,471) | (1,411) |
| Issuance of debt | 7,794 | — | — |
| Repayment of debt | (1,210) | (26) | (26) |
| Issuance of common stock | 47 | — | — |
| Repurchase of common stock | (356) | — | — |
| Dividends paid on common stock | (282) | — | — |
| Other | (39) | (1) | (3) |
| Net Cash Provided by (Used in) Financing Activities | 699 | (7,498) | (1,440) |
| **Effect of Exchange Rate Changes on Cash and Cash Equivalents** | 14 | — | — |
| **Net Change in Cash and Cash Equivalents** | 3,474 | — | — |
| Cash and cash equivalents at beginning of year | — | — | — |
| Cash and Cash Equivalents at End of Year | $ 3,474 | — | — |

For Phillips 66's complete consolidated financial statements, including notes, as well as Management's Discussion and Analysis of Financial Condition and Results of Operations and other financial information, please refer to Appendix B of the company's 2013 Proxy Statement.

# Selected Financial Data

Phillips 66

Millions of Dollars Except Per Share Amounts

| | 2012 | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Sales and other operating revenues | $ 179,460 | 196,088 | 146,561 | 112,692 | 171,706 |
| Net income | 4,131 | 4,780 | 740 | 479 | 2,665 |
| Net income attributable to Phillips 66 | 4,124 | 4,775 | 735 | 476 | 2,662 |
| Per common share | | | | | |
| Basic | 6.55 | 7.61 | 1.17 | 0.76 | 4.24 |
| Diluted | 6.48 | 7.52 | 1.16 | 0.75 | 4.19 |
| Total assets | 48,073 | 43,211 | 44,955 | 42,880 | 38,934 |
| Long-term debt | 6,961 | 361 | 388 | 403 | 417 |
| Cash dividends declared per common share | 0.45 | — | — | — | — |

# Segment Profile

Phillips 66

Millions of Dollars

| | Sales and Other Operating Revenues | | | Net Income Attributable to Phillips 66 | | | Capital Expenditures and Investments | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| R&M | | | | | | | | | |
| Refining | $ 39,164 | 51,040 | 36,318 | 3,158 | 1,533 | (466) | 738 | 770 | 886 |
| Marketing, Specialties & Other | 134,128 | 136,763 | 103,250 | 571 | 2,315 | 612 | 316 | 218 | 188 |
| Total R&M | 173,292 | 187,803 | 139,568 | 3,729 | 3,848 | 146 | 1,054 | 988 | 1,074 |
| Midstream | 6,144 | 8,271 | 6,976 | 6 | 403 | 262 | 527 | 17 | 68 |
| Chemicals | 11 | 11 | 11 | 823 | 716 | 486 | — | — | — |
| Corporate and Other | 13 | 3 | 6 | (434) | (192) | (159) | 140 | 17 | 8 |
| Total | $ 179,460 | 196,088 | 146,561 | 4,124 | 4,775 | 735 | 1,721 | 1,022 | 1,150 |

# Operating Overview

Phillips 66

## R&M

| Years Ended December 31 | 2012 | 2011 | 2010 |
|---|---|---|---|
| Dollars Per Barrel | | | |
| **Refining Margins** | | | |
| Atlantic Basin/Europe | $ 9.36 | 5.96 | 6.81 |
| Gulf Coast | 9.02 | 8.01 | 7.24 |
| Central Corridor | 25.06 | 19.68 | 7.96 |
| Western/Pacific | 11.04 | 9.13 | 8.10 |
| Worldwide | 13.42 | 9.70 | 7.38 |

| | | | |
|---|---|---|---|
| Dollars Per Gallon | | | |
| **U.S. Average Wholesale Prices*** | | | |
| Gasoline | $ 3.00 | 2.94 | 2.24 |
| Distillates | 3.19 | 3.12 | 2.30 |

*Excludes excise taxes.*

| | | | |
|---|---|---|---|
| Thousands of Barrels Daily | | | |
| **Operating Statistics** | | | |
| Refining operations** | | | |
| Atlantic Basin/Europe | | | |
| Crude oil capacity | 588 | 726 | 1,033 |
| Crude oil processed | 555 | 682 | 686 |
| Capacity utilization (percent) | 94% | 94 | 66 |
| Refinery production | 599 | 736 | 746 |
| Gulf Coast | | | |
| Crude oil capacity | 733 | 733 | 733 |
| Crude oil processed | 657 | 658 | 668 |
| Capacity utilization (percent) | 90% | 90 | 91 |
| Refinery production | 743 | 748 | 757 |
| Central Corridor | | | |
| Crude oil capacity | 470 | 471 | 471 |
| Crude oil processed | 454 | 433 | 427 |
| Capacity utilization (percent) | 97% | 92 | 91 |
| Refinery production | 471 | 448 | 443 |
| Western/Pacific | | | |
| Crude oil capacity | 439 | 435 | 420 |
| Crude oil processed | 398 | 393 | 375 |
| Capacity utilization (percent) | 91% | 91 | 89 |
| Refinery production | 419 | 419 | 395 |
| Worldwide | | | |
| Crude oil capacity | 2,230 | 2,365 | 2,657 |
| Crude oil processed | 2,064 | 2,166 | 2,156 |
| Capacity utilization (percent) | 93% | 92 | 81 |
| Refinery production | 2,232 | 2,351 | 2,341 |

***Includes our share of equity affiliates.*

# Operating Overview
Phillips 66

## R&M (continued)

| Years Ended December 31 | 2012 | 2011 | 2010 |
|---|---|---|---|
| Thousands of Barrels Daily | | | |
| Petroleum products sales volumes | | | |
| Gasoline | 1,218 | 1,309 | 1,292 |
| Distillates | 1,141 | 1,219 | 1,189 |
| Other products | 502 | 600 | 559 |
| | 2,861 | 3,128 | 3,040 |

## Midstream

| Years Ended December 31 | 2012 | 2011 | 2010 |
|---|---|---|---|
| Dollars Per Barrel | | | |
| Average Sales Prices | | | |
| U.S. NGL* | | | |
| Equity affiliates | $ 34.24 | 50.64 | 41.28 |

**Based on index prices from the Mont Belvieu and Conway market hubs that are weighted by NGL component and location mix.*

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Thousands of Barrels Daily | | | |
| Operating Statistics | | | |
| NGL extracted* | 201 | 192 | 184 |
| NGL fractionated** | 105 | 112 | 120 |

**Includes our share of equity affiliates.*
***Excludes DCP Midstream.*

## Chemicals

| Years Ended December 31 | 2012 | 2011 | 2010 |
|---|---|---|---|
| Millions of Pounds | | | |
| CPChem Externally Marketed Sales Volumes* | | | |
| Olefins and polyolefins | 14,967 | 14,305 | 12,585 |
| Specialties, aromatics and styrenics | 6,719 | 6,704 | 6,318 |
| | 21,686 | 21,009 | 18,903 |

**Represents 100 percent of CPChem's outside sales of produced petrochemical products, as well as commission sales from equity affiliates.*

# Board of Directors

Standing from left to right: Harold W. McGraw III, John E. Lowe, William R. Loomis Jr., Greg C. Garland

Seated from left to right: Victoria J. Tschinkel, Marna C. Whittington, Glenn F. Tilton, J. Brian Ferguson

## Greg C. Garland, 55

Mr. Garland is chairman, president and chief executive officer of Phillips 66. Previously, he served as senior vice president, Exploration and Production, Americas for ConocoPhillips. Prior to joining ConocoPhillips, Mr. Garland was president and chief executive officer of Chevron Phillips Chemical Company (CPChem) from 2008 to 2010, having served as senior vice president, Planning and Specialty Products, CPChem, from 2000 to 2008. Mr. Garland currently serves on the board of directors of DCP Midstream. (2)

## J. Brian Ferguson, 58

Mr. Ferguson retired as chairman of Eastman Chemical Company (Eastman) in 2010 and as chief executive officer of Eastman in 2009. He became the chairman and chief executive officer of Eastman in 2002. Mr. Ferguson serves as a director of NextEra Energy, Inc. (formerly FPL Group) and Owens Corning, and is a member of The University of Tennessee Board of Trustees. (2, 3, 4)

## William R. Loomis Jr., 64

Mr. Loomis has been an independent financial advisor since 2009. He was a general partner and managing director of Lazard Freres & Co. from 1984 to 2002, the chief executive officer of Lazard LLC from 2000 to 2001, and a limited managing director of Lazard LLC from 2002 to 2004. He currently serves on the board of Limited Brands Inc., and is also a senior advisor to Lazard LLC and China International Capital Corporation. (1, 2, 5)

## John E. Lowe, 54

Mr. Lowe served as assistant to the chief executive officer of ConocoPhillips, a position he held from 2008 until the spin-off of Phillips 66 in 2012. He previously held a series of executive positions with ConocoPhillips, including executive vice president, Exploration and Production, from 2007 to 2008; and executive vice president, Commercial, from 2006 to 2007. He is a former board member of CPChem, DCP Midstream, and DCP Midstream GP, the general partner of DCP Midstream Partners. Mr. Lowe is a Special Executive Advisor to Tudor, Pickering, Holt & Co. and serves on the board of Agrium, Inc. (5)

## Harold W. McGraw III, 64

Mr. McGraw is chairman, president and chief executive officer for The McGraw-Hill Companies, a position he has held since 2000. He was president and chief executive officer from 1998 until 2000, and president and chief operating officer from 1993 to 1998. He has been a member of The McGraw-Hill Companies' board of directors since 1987. Mr. McGraw is also a director of United Technologies Corporation. (2, 3, 4)

## Glenn F. Tilton, 64

Mr. Tilton currently serves as Midwest chairman, JPMorgan Chase & Co. From 2002 to 2010, he served as chairman, president and chief executive officer of UAL Corporation, a holding company, and United Air Lines, Inc., an air transportation company and wholly owned subsidiary of UAL Corporation. He previously spent more than 30 years in increasingly senior roles with Texaco Inc., including chairman and chief executive officer in 2001. He currently serves on the boards of United Continental Holdings Inc. (as non-executive chairman), Abbot Laboratories and AbbVie Inc. (3, 4)

## Victoria J. Tschinkel, 65

Ms. Tschinkel currently serves on the executive commitee of 1000 Friends of Florida and was previously its chairwoman. She served as state director of the Florida Nature Conservancy from 2003 to 2006, was the senior environmental consultant to the law firm Landers & Parsons from 1987 to 2002, and was the Secretary of the Florida Department of Environmental Regulation from 1981 to 1987. (1, 2, 5)

## Marna C. Whittington, 65

Dr. Whittington was chief executive officer of Allianz Global Investors Capital from 2002 to 2012. She was chief operating officer of Allianz Global Investors, the parent company of Allianz Global Investors Capital, from 2001 to 2011. Prior to that, Dr. Whittington was managing director and chief operating officer of Morgan Stanley Asset Management. She was executive vice president and chief financial officer of The University of Pennsylvania from 1984 to 1992. Earlier, she served as budget director, and later, Secretary of Finance for the state of Delaware. She currently serves on the board of directors of Macy's, Inc. and Oaktree Capital Group. (1, 5)

(1) Member of the Audit and Finance Committee.
(2) Member of the Executive Committee.
(3) Member of the Human Resources and Compensation Committee.
(4) Member of the Nominating and Governance Committee.
(5) Member of the Public Policy Committee.

*As of Feb. 28, 2013*

# Executive Leadership Team

## Greg Garland

Chairman, President and Chief Executive Officer

Garland has more than 30 years of industry experience in technical and executive leadership positions within the oil and gas and chemical industries.

## Phillip Brady

Senior Vice President, Government Affairs

Brady has more than 30 years of experience serving in government and related positions in Washington, D.C. Before joining Phillips 66, Brady served as president of the National Automobile Dealers Association (NADA) since June 2001. Prior to joining NADA, Brady served five years as the vice president and general counsel for the American Automobile Manufacturers Association.

## Bob Herman

Senior Vice President, Health, Safety and Environment

Herman has 30 years of experience in various technical and leadership roles within the oil and gas industry. Herman was vice president, HSE for ConocoPhillips. He also served ConocoPhillips as president, Refining, Marketing and Transportation for Europe. Herman currently serves on the board of directors for Chevron Phillips Chemical Company (CPChem).

## Paula Johnson

Senior Vice President, Legal, General Counsel and Corporate Secretary

Johnson has 25 years of legal experience. Before assuming her current role, Johnson was deputy general counsel, Corporate, and chief compliance officer for ConocoPhillips. Prior roles with ConocoPhillips included managing counsel for litigation and claims from 2006 to 2009.

## Merl Lindstrom

Vice President, Technology

Lindstrom has more than 35 years of experience in research and development roles focusing on the downstream business. Before assuming his current role, Lindstrom was senior vice president, Technology, for ConocoPhillips. He served as a manager in a number of technological, and research and development roles with ConocoPhillips.

## Greg Maxwell

Executive Vice President, Finance and Chief Financial Officer

Maxwell has more than 34 years of experience in various financial roles within the chemical and oil and gas industries. Prior to his current role, Maxwell served as senior vice president, chief financial officer and controller for CPChem. Maxwell serves on the board of directors for DCP Midstream and DCP Midstream Partners.

## Ann Oglesby

Vice President, Communications and Public Affairs

Oglesby has 25 years of experience in the oil and gas industry. Prior to her current role, Oglesby was vice president, Communications and Public Affairs, for ConocoPhillips. She also served ConocoPhillips as general manager, Corporate Planning and Strategy, and manager, Climate Change and Sustainable Development.

## Clayton Reasor

Senior Vice President, Investor Relations, Strategy and Corporate Affairs

Reasor has more than 30 years of experience in the oil and gas industry. Before assuming his current role, he was vice president, Corporate and Investor Relations for ConocoPhillips. Reasor currently serves on the board of Stage Stores Inc.

## Tim Taylor

Executive Vice President, Commercial, Marketing, Transportation and Business Development

Taylor has more than 35 years of experience in the chemical and oil and gas industries. Before being named to his current role, Taylor served as chief operating officer of CPChem. Taylor is a board member for CPChem.

## Chantal Veevaete

Vice President, Human Resources

Veevaete has more than 30 years of experience in human resources roles, spending much of her time in the chemical and oil and gas industries. Prior to her current role, Veevaete served as vice president, Human Resources, for CPChem and as vice president, Human Resources, for the Accredo division of Medco Health Solutions.

## Larry Ziemba

Executive Vice President, Refining, Project Development and Procurement

Ziemba has 35 years of experience in the oil and gas industry. Before assuming his current role, Ziemba served ConocoPhillips as president, Global Refining, a role he took on after serving as president, U.S. Refining, since 2003.

*As of Feb. 28, 2013*

Standing from left to right: Phillip Brady, Greg Garland, Greg Maxwell, Tim Taylor, Chantal Veevaete, Merl Lindstrom, Clayton Reasor

Seated from left to right: Paula Johnson, Larry Ziemba, Bob Herman, Ann Oglesby

## Other Corporate Officers

**Joe Frana**, General Auditor
**Doug Johnson**, Vice President and Controller
**Audrey Miller**, General Tax Officer
**Brian Wenzel**, Vice President and Treasurer

## Operational and Functional Organizations

**Debbie Adams**, President, Transportation
**Rex Bennett**, President, Specialties and Business Development
**Maria Hooper**, Vice President, Global Trading
**Mike Kenney**, Vice President, Regional Manager – Refineries
**Kay Sallee**, Chief Information Officer
**Andy Viens**, President, Global Marketing
**John Wright**, Senior Vice President, Commercial

# Shareholder Information

## Annual Meeting

Phillips 66's annual meeting of stockholders will be held:
Wednesday, May 8, 2013
Houston Marriott Westchase
2900 Briarpark Drive
Houston, TX

Notice of the meeting and proxy materials are being sent to all shareholders.

## Direct Stock Purchase and Dividend Reinvestment Plan

Phillips 66's Investor Services Program is a direct stock purchase and dividend reinvestment plan that offers shareholders a convenient way to buy additional shares and reinvest their common stock dividends. Purchases of company stock through direct cash payment are commission-free.

Please call the Computershare Material Fulfillment Center to request an enrollment package:

Toll-free number: 866-353-7849

You may also enroll online at www.computershare.com/investor.

Registered shareholders can access important investor communications online and sign up to receive future shareholder materials electronically by going to www.computershare.com/investor and following the enrollment instructions.

## Principal and Registered Offices

Phillips 66
P.O. Box 4428
Houston, TX 77210

2711 Centerville Road
Wilmington, DE 19808

## Stock Transfer Agent and Registrar

Computershare
250 Royall Street
Canton, MA 02021
www.computershare.com/investor

## Information Requests

For information about dividends and certificates, or to request a change of address form, shareholders may contact:

Computershare
P.O. Box 43006
Providence, RI 02940-3006
Toll-free number: 866-437-0009
Outside the U.S.: 201-680-6578
TDD for hearing impaired: 800-231-5469
TDD outside the U.S.: 201-680-6610
www.computershare.com/investor

Personnel in the following offices also can answer investors' questions about the company:

## Institutional Investors

Phillips 66 Investor Relations
3010 Briarpark Drive
Houston, TX 77042
800-624-6440
investorrelations@p66.com

## Individual Investors

Phillips 66 Shareholder Relations
3250 Briarpark Drive – RW – 1053E
Houston, TX 77042
832-765-1876
shareownerservicesp66@p66.com

## Compliance and Ethics

For guidance, or to express concerns or ask questions about compliance and ethics issues, call Phillips 66's Ethics Helpline toll-free: 855-318-5390, available 24 hours a day, seven days a week.

The ethics office also may be contacted via email at ethics@p66.com, the Internet at www.phillips66.ethicspoint.com or by writing:

Attn: Global Ethics Office
Phillips 66
3010 Briarpark Drive
Houston, TX 77042

## Copies of Form 10-K, Proxy Statement and Summary Annual Report

Copies of the Annual Report on Form 10-K and the Proxy Statement, as filed with the U.S. Securities and Exchange Commission, are available free by making a request on the company's website, calling 918-977-4133 or writing:

Phillips 66 – 2012 Form 10-K
310 W 5th
PRN-252
Bartlesville, OK 74004

Additional copies of this Summary Annual Report may be obtained by calling 918-977-4133 or writing:

Phillips 66
2012 Summary Annual Report
310 W 5th
PRN-252
Bartlesville, OK 74004

## Internet Website:

www.phillips66.com

The site includes resources of interest to investors, including news releases and presentations to securities analysts; copies of Phillips 66's Annual Report and Proxy Statement; reports to the U.S. Securities and Exchange Commission; and data on Phillips 66's health, safety and environmental performance.

Other websites with information on topics included in this Summary Annual Report include:
www.cpchem.com
www.dcpmidstream.com

## Disclosure Statements

Certain disclosures in this Summary Annual Report may be considered "forward-looking" statements. These are made pursuant to "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The "Cautionary Statement" in Management's Discussion and Analysis in Appendix B of Phillips 66's 2012 Proxy Statement should be read in conjunction with such statements. "Phillips 66," "the company," "we," "us" and "our" are used interchangeably in this report to refer to the businesses of Phillips 66 and its consolidated subsidiaries. References to earnings refer to net income attributable to Phillips 66.

A registration statement relating to the common units of the master limited partnership that would be sold in the offering referred to in this report is expected to be filed with the U.S. Securities and Exchange Commission but has not been filed or become effective. This report does not constitute an offer to sell, or the solicitation of an offer to buy, any securities. This report is being issued pursuant to, and in accordance with, Rule 135 under the Securities Act of 1933.

# Non-GAAP Reconciliations

Phillips 66

| Millions of Dollars | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Reconciliation of Earnings to Adjusted Earnings** | | | |
| **Consolidated** | | | |
| Earnings (loss) | $ 4,124 | $ 4,775 | $ 735 |
| Adjustments: | | | |
| Net (gain) loss on asset sales | (106) | (1,545) | (116) |
| Impairments | 979 | 318 | 1,118 |
| Pending claims and settlements | 34 | — | (35) |
| Canceled projects | — | 28 | 29 |
| Severance accruals | — | 15 | 28 |
| Premium on early debt retirement | 89 | — | — |
| Repositioning costs | 55 | — | — |
| Repositioning tax impacts | 177 | — | — |
| Hurricane-related costs | 35 | — | — |
| Adjusted earnings | $ 5,387 | $ 3,591 | $ 1,759 |
| **R&M** | | | |
| Earnings (loss) | $ 3,729 | $ 3,848 | $ 146 |
| Adjustments: | | | |
| Net (gain) loss on asset sales | (106) | (1,545) | (116) |
| Impairments | 633 | 318 | 1,118 |
| Pending claims and settlements | 57 | — | (35) |
| Canceled projects | — | 28 | 29 |
| Severance accruals | — | 15 | 28 |
| Repositioning tax impacts | 136 | — | — |
| Hurricane-related costs | 35 | — | — |
| Adjusted earnings | $ 4,484 | $ 2,664 | $ 1,170 |
| **Midstream** | | | |
| Earnings (loss) | $ 6 | $ 403 | $ 262 |
| Adjustments: | | | |
| Impairments | 303 | — | — |
| Pending claims and settlements | (23) | — | — |
| Adjusted earnings | $ 286 | $ 403 | $ 262 |
| **Chemicals** | | | |
| Earnings (loss) | $ 823 | $ 716 | $ 486 |
| Adjustments: | | | |
| Impairments | 27 | — | — |
| Premium on early debt retirement | 89 | — | — |
| Repositioning tax impacts | 41 | — | — |
| Adjusted earnings | $ 980 | $ 716 | $ 486 |
| **Marketing, Specialties and Other** | | | |
| Earnings (loss) | $ 571 | | |
| Adjustments: | | | |
| Net (gain) loss on asset sales | (2) | | |
| Impairments | 27 | | |
| Pending claims and settlements | 38 | | |
| Repositioning tax impacts | 63 | | |
| Hurricane-related costs | 2 | | |
| Adjusted earnings | $ 699 | | |

| | Phillips 66 | | | R&M | | | Midstream | | | Chemicals | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| **Numerator ($MM)** | | | | | | | | | | | | |
| Net Income | 4,131 | 4,780 | 740 | 3,736 | 3,853 | 151 | 6 | 403 | 262 | 823 | 716 | 486 |
| After-tax interest expense | 160 | 11 | 1 | — | — | — | — | — | — | — | — | — |
| GAAP ROCE earnings | 4,291 | 4,791 | 741 | 3,736 | 3,853 | 151 | 6 | 403 | 262 | 823 | 716 | 486 |
| Special Items | 1,263 | (1,184) | 1,024 | 755 | (1,184) | 1,024 | 280 | — | — | 157 | — | — |
| Adjusted ROCE earnings | 5,554 | 3,607 | 1,765 | 4,491 | 2,669 | 1,175 | 286 | 403 | 262 | 980 | 716 | 486 |
| **Denominator ($MM)** | | | | | | | | | | | | |
| GAAP average capital employed* | 25,732 | 25,064 | 26,906 | 20,025 | 21,366 | 23,289 | 1,296 | 1,355 | 1,488 | 3,144 | 2,570 | 2,282 |
| Adjusted ROCE | 22% | 14% | 7% | 22% | 12% | 5% | 22% | 30% | 18% | 31% | 28% | 21% |
| GAAP ROCE | 17% | 19% | 3% | 19% | 18% | 1% | 0% | 30% | 18% | 26% | 28% | 21% |

**Total equity plus total debt*

Providing Energy, Improving Lives.

Safety. Honor. Commitment.

Phillips 66
P.O. Box 4428
Houston, TX 77210

Phone: 281-293-6600
www.phillips66.com

# Exhibit E

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Bloomberg

# Bakken Boom Cutting West Coast Imports of Crude: Energy Markets

By Lynn Doan and Dan Murtaugh - Jun 21, 2013

The West Coast is bringing in record amounts of crude from the interior of the U.S., cutting the price of foreign supplies and heralding the end of some overseas imports by next year.

California, the world's ninth-largest economy, shipped via rail more oil than ever in February from North Dakota's Bakken formation, while Russian imports to the region slid to 713,000 barrels from a June 2012 record of 6.53 million. The premium for Russia's East Siberia-Pacific Ocean oil has retreated 60 percent against U.S. benchmark West Texas Intermediate since Feb. 20.

The drop in foreign purchases underscores the U.S.'s shifting needs as soaring output in states such as North Dakota and Texas put the country on course for energy self-sufficiency for the first time since Harry Truman was president in 1952. The West coast, home to 17 percent of the nation's refining capacity, may be able to dispense with overseas light, sweet oil even as output from Alaska's North Slope and California wanes.

"The crude supply on the West Coast is changing as we speak," said Hege Dammen, a Weston, Connecticut-based solutions manager at Spiral Software, an oil-trading and refining software provider, and former crude trader for Norwegian Norsk Hydro ASA. (NHY) "There's been a lot of focus on getting oil by rail to the Gulf Coast, and the West Coast is moving forward now."

## ESPO Crude

ESPO crude, a light grade shipped by pipeline from fields in eastern Siberia to the Pacific port of Kozmino for export, dropped $1.79, or 1.7 percent, to $103.67 a barrel today, the lowest since June 13, data compiled by Bloomberg show. The oil has declined 12 percent from this year's peak of $118.36 a barrel reached on Feb. 14.

The premium for Arab Light crude against WTI weakened to 85 cents a barrel, the lowest level since January 2011 and less than a 10th of what it was a year ago. It has averaged $10.56 this year.

Oil imports to the West Coast in the week ended June 14 averaged 1.2 million barrels a day, 9.5 percent below a year earlier, according to the Energy Information Administration, the Energy

Department's statistical arm. The western region, classified by the EIA as PADD 5, covers Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington.

California, PADD 5's largest refiner, received an unprecedented 206,172 barrels of Bakken crude by rail in February, eight times the volume from a year ago. The state took in 94,695 barrels of Bakken crude in March, up from 70,706 a year earlier, according to the latest data available from the California Energy Commission.

Last year, Bakken oil began arriving in California on marine vessels for the first time, totaling 89,462 barrels, according to the commission's data.

## Oregon Terminal

A complex along the Columbia River in Oregon, owned by Waltham, Massachusetts-based Global Partners LP (GLP), began in November off-loading trains of oil to send it by water to markets along the Pacific Ocean.

"Global Partners is getting some of this Bakken from rail-cars onto the water, and a number of California's refiners are willing to buy it from them, just to get a taste of it," Dave Hackett, president of energy consulting firm Stillwater Associates in Irvine, California, said by telephone. "It'll back out the foreign stuff. That's the first stuff that gets knocked out."

Tesoro Corp. (TSO) and Savage Companies, based in Salt Lake City, are planning a similar rail-to-water project at the Port of Vancouver in Washington that could move as many as 120,000 barrels of oil a day from railcars onto marine vessels.

## Tesoro Shipments

Tesoro, based in San Antonio, is already using rail to bring 50,000 barrels a day of Bakken to its Anacortes refinery in Washington and 5,000 barrels to the Golden Eagle plant in Northern California. Alon USA Energy Inc. (ALJ), Phillips 66 (PSX), BP Plc (BP/) and Valero Energy Corp. (VLO) are planning rail-offloading stations at their West Coast refineries.

Plains All American Pipeline LP (PAA), based in Houston, plans to start taking oil off railcars at a 140,000-barrel-a-day complex near Bakersfield, California, in the first half of 2014 and ship it by pipeline to refineries in the state.

The West Coast will more than double rail unloading capacity to about 600,000 barrels a day by the end of 2014 from 250,000 barrels a day currently, according to Andy Lipow, president of Lipow Oil Associates LLC in Houston.

The boom in oil production, driven largely by a combination of hydraulic fracturing and horizontal drilling, helped the U.S. meet 84 percent of its energy needs last year, the highest annual level since 1991, EIA data show.

Sending Bakken by rail to the West has proven so affordable that Kinder Morgan Energy Partners LP (KMP), based in Houston, suspended a proposal last month to build a pipeline that would have carried oil from Texas's Permian Basin to California after failing to attract enough interest from shippers.

## Rail Costs

Carrying crude from the Bakken formation on railcars costs about $9.75 a barrel to Washington state, $13 to Northern California and $14 to the Los Angeles area, Tesoro Logistics LP (TLLP) estimated in a presentation June 7.

The increasing volume of domestic oil making its way to the West Coast will drive light oil imports out of the region by the end of 2014, Paul Y. Cheng, an analyst at Barclays Plc (BARC)'s investment-banking unit in New York, said.

"The entire non-imported West Coast crude slate could undergo a $3- to $4-a-barrel downward shift as the marginal price-setting barrel switches from Alaska North Slope or imported light to Bakken crude rail on a spot basis," Cheng said in a research note.

## Crude Blending

West Coast refineries, capable of running crudes more sour and heavier than the light, sweet oils coming out of U.S. shale plays, are blending Bakken and Canadian heavy in attempts to come up with Alaska North Slope "look-alikes," said Dammen, the software solutions manager for Cambridge, England-based Spiral.

"When you blend them, you can actually come fairly close to ANS, maybe even having the same yield curve," she said.

Alaska North Slope crude, about a 10th of California's oil diet, is trading near a 16-month low against the U.S. benchmark West Texas Intermediate crude, according to data compiled by Bloomberg. The oil was unchanged versus WTI today at a premium of $9.40 a barrel.

California's Kern River and Midway-Sunset grades both weakened to 18-month lows versus WTI futures last week.

Saudi Arabia, the largest oil exporter to the West Coast, supplied 207,000 barrels a day in March, the lowest for that month since 2010, EIA data show. Arab Light crude to the U.S. dropped $2.28, or 2.4 percent, to $94.44 a barrel today, a two-month low and down 12 percent this year, according to data compiled by Bloomberg.

## Record Output

Bakken crude for delivery at Clearbrook, Minnesota, was unchanged at $1 a barrel below WTI today, data compiled by Bloomberg show. North Dakota's output of the oil climbed to a record 727,149 barrels a day in April, preliminary data compiled by the state's Industrial Commission show. Production was up 33 percent from a year earlier.

West Coast refineries may eventually reach a limit to the amount of light, sweet domestic oil they can blend and run, according toAndrew Layton, a consultant with Walton-On-Thames, England-based KBC Advanced Technologies Plc. (KBC)

Mixing the wrong kinds and percentages of light, shale oil with other crudes such as heavy Canadian can produce elements that damage plant equipment, a phenomenon known as "incompatibility," Layton said. A "cocktail" of chemicals injected into crude blends can also corrode refinery equipment if not handled and monitored properly, he said.

"Individually, they may look innocuous," Layton said. "Together, they may cause a problem."

## Equipment Upgrades

To push past the blending limits, the region's plants could consider equipment upgrades, Hackett said. The refiners would have to weigh any long-term investments against increasing environmental regulation, particularly in California, he said.

The state's cap-and-trade program regulates greenhouse-gas emissions from industrial plants including oil refineries with a goal of cutting pollution roughly 15 percent by 2020. California's low-carbon fuel standard punishes fuel manufacturers who use crudes requiring more carbon to produce and transport than others.

"Investing in new equipment presumes that refiners still want to invest here," Hackett said. "If they wanted to make changes to run more light, they could, but it's kind of a bridge too far to say they will just yet."

To contact the reporters on this story: Lynn Doan in San Francisco at ldoan6@bloomberg.net; Dan Murtaugh in Houston at dmurtaugh@bloomberg.net

To contact the editor responsible for this story: Dan Stets at dstets@bloomberg.net

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# Exhibit F

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# Western Canadian Select (WCS) fact sheet

## Creating new benchmark crude

In conjunction with Canadian Natural Resources Limited, Suncor and Talisman Energy Inc., we have implemented a new heavy oil stream named Western Canadian Select (WCS).

WCS — produced out of Western Canada — is made up of existing Canadian heavy conventional and bitumen crude oils blended with sweet synthetic and condensate diluents. It is a consistent high quality crude blend that was launched in December 2004 with volumes of approximately 250,000 barrels per day, and is well-positioned to become a North American benchmark.

## A diverse Canadian oil market

There are approximately 25 separate heavy oil streams marketed out of Western Canada and this number continues to grow. The abundance of streams results in several inefficiencies. WCS offers an ideal solution:

| Issue | 25+ separate oil streams | WCS Solution |
|---|---|---|
| **infrastructure** | — requires more tankage which increases costs | — a blend of crudes reduces the number of streams<br><br>— more effective use of existing tankage in the pipeline delivery systems out of Western Canada |
| **Crude quality and consistency** | — increases the risk of downstream quality deterioration due to mixing of varying grades in tanks en-route to market | — by virtue of its stream size, minimizes contamination caused by mixing of various grades<br><br>— delivers more consistent quality to the buyer |
| **Conventional diluent supply** | — most Western Canadian heavy oil streams require diluent for transportation<br><br>— as Canadian production continues to grow, the demand for diluent is expected to increase, yet the supply is expected to remain flat | — using sweet synthetic and condensate as a diluent reduces dependence on conventional diluent alone and improves reliability |
| **Market liquidity** | — a growing number of separate heavy oil streams results in reduced liquidity in any one stream, reducing crude acceptance and narrowing the ability for it to trade | — as a large stream of consistent quality crude, WCS can increase liquidity and should constitute a highly acceptable, more widely traded crude for producers and refiners alike |

**WCS Potential**

West Texas Intermediate (WTI) and Brent are recognized as benchmark crudes. WCS has satisfied much of the criteria to become a benchmark. WCS has achieved threshold volumes of approximately 250,000 barrels per day and may grow from those numbers, whereas WTI and Brent are both declining from their current volume of about 350,000 barrels a day each. Furthermore, as a new benchmark, WCS is more effective than WTI as a means of financially hedging price risk against North American heavy oil grades because WCS addresses issues around product, price and location.

**Benefits to producers and refiners**

**Producers:** improved use of existing downstream pipeline facilities means that producers can deliver consistent quality crude with reliable on-time delivery to market. In addition, the improved stream liquidity will make WCS a more widely traded crude.

**Refiners:** refiners will have access to a stable, reliable and rateable crude, stringently monitored by the producing parties.

**Our market development initiatives**

To recognize the full value of Canadian crude oil, we are committed to:

- Creation of WCS, a new heavy oil steam benchmark that will provide greater operational efficiency; greater market reach; and greater liquidity.
- Developing new markets, such as the Southern mid-Continent, the Gulf of Mexico, and the West Coast, for heavy crude oil.
- Promoting the development of new heavy oil conversion projects in core markets.

## WCS Crude Oil Quality

| | **WCS** |
|---|---|
| Gravity (API) | 20.5 |
| Density (kg/m3) | 930.1 |
| MCR (Wt%) | 9.6 |
| Sulphur (Wt%) | 3.51 |
| TAN (Mg KOH/g) | 0.93 |

Crude quality data from Crude Quality Inc. average for 2009.

## Exhibit G

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Bakken Oil Moving Back To Pipelines As Differentials Narrow

Next→
Magellan Petroleum Planning CO2 EOR Pilot Test At Poplar Dome

# Bakken Producing Sour Gas? H2S Problem In North Dakota

*The Source Of The H2S Is Still Unknown*

May 30, 2013 By R.T. Dukes 4 Comments

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H2S Warning Sign | Click to Enlarge

Is the Bakken producing higher volumes of H2S? That's the question you have to ask yourself when you see pipelines implementing H2S standards for the first time.

On May 8, Enbridge submitted an emergency application to the Federal Energy Regulation Commission (FERC) asking to amend its conditions of carriage to 5 ppm of H2S or less. If accepted, Enbridge would have the right to reject crude with higher levels of H2S.

H2S limits that have been implemented this year include:

- Tesoro's High Plains Pipeline – 5 ppm since January 1
- Bridger & Bella Fourche Pipelines – 10 ppm since April 1

When those limits went into place, it seems as if producers with high H2S concentrations might have shifted production to the Enbridge system.

Enbridge acted after it found concentrations of 1,200 ppm in a crude tank at its Berthold Terminal. 20 ppm is the limit allowed by OHSA and an average of 10 ppm of exposure is all that is allowed over an 8-hour work day.

Both Plains Marketing and Murex Petroleum objected to the FERC application, but it looks as if they solved their differences when Enbridge notified FERC it wasn't planning

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an outright ban on crude with higher H2S concentrations. The two companies weren't against the change, but were afraid they couldn't comply in the time frame planned.

You can read more about the topic in an article at reuters.com

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***R.T. Dukes***
Managing Editor at BakkenShale.com

R.T. is the managing editor and a contributor to BakkenShale.com and EagleFordShale.com. His experience includes research and consulting roles where he advised major oil companies. His current life revolves around his wife, two kids, and shale plays. He has been following the Bakken since early 2006. 2503 Robinhood, Houston, TX, 77005, U.S.A. | Telephone: 832.429.4790

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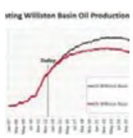
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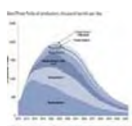
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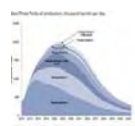
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