Reduced Throughput and Tighter Margins
U.S. refining review 2019.

Morningstar Commodities Research
21 January 2020

Sandy Fielden
Director, Oil and Products Research
+1 512 431-8044
sandy.fielden@morningstar.com

Data Sources for This Publication
EIA
CME Group
The ICE

To discover more about the data sources used, click here.

Continued Access to Cheap Crude

After a record-breaking 2018, U.S. refiners enjoyed a quieter 2019 with reduced throughput and tighter margins. During the first quarter crude production limits imposed by Alberta Province narrowed Canadian crude discounts. That impacted Midwest refining margins, but the differentials widened again later in the year and in general U.S. refiners continued to enjoy access to cheaper domestic crude. East Coast refiners remain tied to a diet of international feedstock and suffered the lowest margins as a result. A number of refiners sought to divest plants during the year, but major expansion investments were also announced. Environmental hurdles continue to add costs, but regulations mandating biodiesel plants and lower sulfur levels in shipping fuels present upside opportunities. This note reviews U.S. refining in 2019.

Capacity and Processing

According to the Energy Information Administration's annual refining capacity report released in June 2019, operable capacity for the U.S. fleet was a record 18.8 million barrels per calendar day on Jan. 1, 2019. Monthly average operable capacity in 2019 was also 18.8 mmb/d between January and October, up from an average 18.6 mmb/d in 2018. Despite higher operating capacity, crude throughput, based on weekly EIA supply data, fell from a record 17.0 mmb/d in 2018 to 16.6 mmb/d in 2019. Lower crude throughput during 2019 reflected reduced refinery runs in general as well as the closure of the Philadelphia Energy Solutions 335 thousand barrel/day refinery in Philadelphia, Pennsylvania, after a plant fire in June.

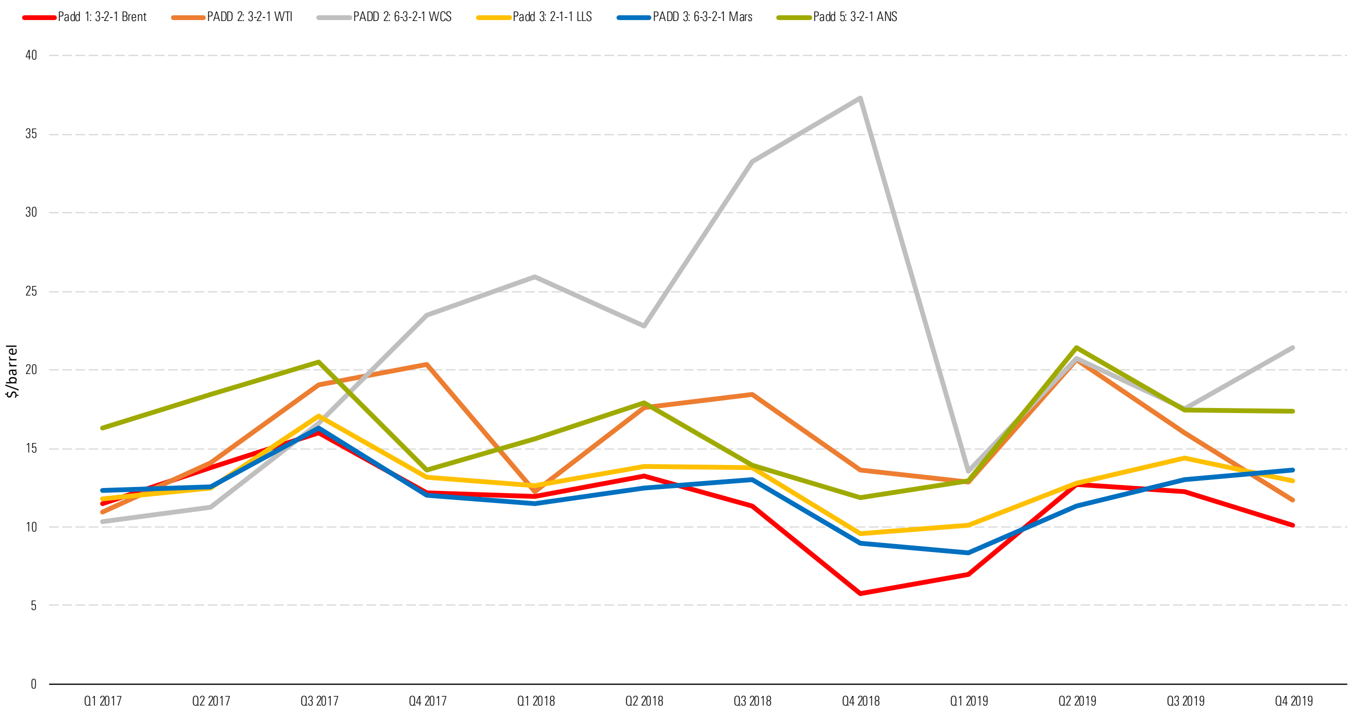
Since the shale era began boosting crude output in 2011, U.S. refiners have increased their processing of domestic crude, but imported supplies are still required. Annual average U.S. crude production increased for the fourth year running in 2019 to reach an estimated 12.2 mmb/d. But with production less than 16.6 mmb/d refinery demand, the U.S. needed to import at least 4.4 mmb/d (16.6-12.2) to balance the market. However, quality differences between light domestic shale crude and refinery demand for heavier grades meant actual imports were higher—averaging 6.8 mmb/d in 2019. Since refineries aren't configured to absorb more light shale crude and since a ban on crude exports was lifted at the end of 2015, increasing domestic output has spurred growing exports of light crude. On average, crude exports increased by an estimated 1.0 mmb/d to 3.0 mmb/d in 2019 while imports declined by an estimated 1 mmb/d. That reduced net imports to an average 3.8 mmb/d in 2019. So, the U.S. reduced dependency on imported crude during 2019 but remains a long way short of crude independence. Nevertheless, crude supply is arguably more secure with an increasing percentage of shrinking imports coming from Canada instead of the politically less stable Middle East and Latin America.

Performance

Average refining margins across Department of Energy Petroleum Administration for Defense Districts, or PADDs, were down 10% in 2019 compared with 2018 according to our analysis of market pricing. Exhibit 1 shows six crack spread calculations that approximate quarterly refining margins between Quarter 1 2017 and Quarter 4 2019 on the East Coast (PADD 1 red line), West Coast (PADD 5 green line), Midwest (PADD 2 heavy crude grey line, PADD 2 light crude orange line), and Gulf Coast (PADD 3 heavy crude blue line, PADD 3 light crude yellow line). The average of these margins in 2019 was $1.53 lower than 2018 at $14.26/barrel, but there was considerable regional variation during the year. The best margins were for PADD 2 heavy crude based on a 6-3-2-1 crack spread processing six barrels of Western Canadian Select crude to produce three barrels of gasoline, two barrels of diesel, and one barrel of fuel oil. The WCS 6-3-2-1 crack averaged a whopping $37.32/barrel in the final quarter of 2018 when Canadian pipeline congestion caused significant price discounting. That bounty reversed dramatically in the first quarter of 2019 after the Alberta provincial government introduced production controls to relieve low crude prices. WCS 6-3-2-1 margins in PADD 2 crashed 64% to $13.54/barrel as crude discounts narrowed sharply—also impacting refiner PBF that ships Canadian crude to its two PADD1 plants (see "East Coast Refiners Lose Canadian Heavy Card"). However, discounts for Canadian crude widened during the remainder of 2019 delivering the best margins to Midwest refineries with pipeline access to these cheap supplies. Although not shown in Exhibit 1, margins for PADD 4 Rocky Mountain refiners that also have access to discounted Canadian crude were similarly buoyant.

Also outperforming the U.S. market in 2019 were west coast refineries processing Alaska North Slope crude—primarily in Washington State and California. We've previously detailed the precarious market that California refiners operate in—hampered by the State's strong environmental regulations yet boosted by limited competition from out of state suppliers pushing up prices and margins whenever capacity outages constrain supply. This was the case again in 2019 with ANS 3-2-1 margins neck and neck with Midwest heavy crude processors in the second and third quarters (see our June note "California Gasoline Shortage Boosts Refinery Margins"). Although margins are robust when capacity is constrained, refiners aren't comfortable with the Golden State's environmental heavy hand, and 2019 saw Shell agreeing to sell its Martinez refinery to PBF Energy (see our July note "PBF Extends Heavy Bet in California") although the deal has yet to finalize.

Exhibit 1 U.S. Regional Quarterly Crack Spreads 2017-19



Source: CME Group, ICE, and Morningstar.

Despite the advantage enjoyed by Midwest refiners with access to Canadian heavy crude, refiners on the Gulf Coast with plants configured to process heavy barrels (blue line in Exhibit 1) fared little better than their counterparts processing light crude in PADD 3 (yellow line) during 2019. That reflected relatively higher prices at the Gulf Coast for heavy grades such as Gulf of Mexico Mars that saw strong demand in the export market as production cuts by OPEC and sanctions on Iran and Venezuela tightened supply, narrowing typical discounts for harder to process heavy crudes versus lighter barrels. Overall, Gulf Coast refiners realized only a slight 1% improvement over 2018 with average margins of $12.06/barrel in 2019.

As they have done for the past several years, crack spread margins for East Coast refineries processing light crude came bottom in the U.S. regional table (red line in Exhibit 1). The average 3-2-1 crack spread in 2019 for PADD 1 refiners with limited access to domestic crude that typically buy feedstock based on pricier international benchmark Brent, was $10.51/barrel, a few cents lower than for the same region in 2018 but $3.75/barrel lower than the national average $14.26/barrel. The poor results came despite the closure of the region's largest refinery in June after a disastrous fire that took 335 mb/d of capacity offline (see our July note "Central Atlantic Region Impacted by PES Closure"). The perennial woes of East Coast refiners reflect high feedstock costs resulting in uncompetitive product prices that can't compete with Gulf Coast plants. In 2020 East Coast refiners face new competition in the shape of private equity financed Limetree Bay refinery expected online in St. Croix, U.S. Virgin Islands, during the first quarter (see our September note "Limetree Bay Restart Can Help East Coast Product Balance"). The Limetree restart—formerly operated by HOVENSA—can ship refined product to the East Coast in non-U.S. flagged vessels under a waiver of Jones Act regulations that otherwise make crude and product shipments to the East Coast from other regions like the U.S. Gulf uncompetitive.

For Sale

On Jan. 10, 2020, Reuters reported U.S. refiners were trying to sell over 5% of installed capacity by the end of 2019. The refineries reported for sale are listed in Exhibit 2. The sale of one of these plants—Shell's 156.4 mb/d Martinez, California, refinery was announced in June 2019 but the sale to PBF has yet to close. Shell is now apparently trying to sell its 145 mb/d Anacortes, Washington, refinery as well, reducing its U.S. footprint to the Gulf Coast region. Two refineries owned by CVR Energy in Wynnewood, Oklahoma, and Coffeyville; Kansas, are being considered for divestiture by the company that also operates a nitrogen fertilizer business. These independent refineries are well positioned close to the Cushing, Oklahoma, trading hub but have proven vulnerable to environmental legislation such as ethanol blending obligations. The PES Philadelphia refinery that shut down in June and hasn't reopened since its owners entered bankruptcy protection shortly afterward is being sold by auction this month (January 2020). Only one of the current bidders wants to reopen PES that struggled to make money after losing advantaged access to domestic crude delivered by rail when the latter became uneconomic in 2015. The refinery is more likely to reopen as a storage and distribution terminal for the East Coast. Finally, another East Coast plant, the 190 mb/d Trainer, Pennsylvania, refinery owned by Delta Airlines and operated by Monroe Energy has been on the block for some time without finding a buyer. The Trainer refinery faces similar economic challenges to PES and although it arguably helped Delta keep the lid on U.S. jet kerosene fuel prices, it has been a cost sink at times.

Exhibit 2 U.S. Refineries for Sale

Owner	Location	I Capacity	Coker	Status
ExxonMobil	Billings, MO	61.5	Y	For Sale
Shell	Martinez, CA	156.4	Y	Sale to PBF Pending
Shell	Anacortes, WA	145.0	Y	For Sale
CVR Energy	Wynnewood, OK	74.5	N	For Sale
CVR Energy	Coffeyville, KS	132.0	Y	For Sale
Carlyle/PES	Philadelphia, PA	335.0	N	Shutdown - Auction
Monroe / Delta	Trainer, PA	190.0	N	For Sale
	Total	**1,094**		

Source: Reuters, Company Presentations.

Buy or Build?

While 5% of the nation's refining capacity may be for sale, that hasn't dampened the enthusiasm of existing and prospective owners to build new capacity or extend existing plants. A year ago, in January 2019, ExxonMobil announced a final investment decision to expand its 366 mb/d Beaumont, Texas, plant by 250 mb/d to create the country's largest refinery at 616 mb/d. The ExxonMobil investment is being made alongside smaller additions to its Baytown, Texas, and Baton Rouge, Louisiana, plants and majority ownership of a 1 mmb/d plus pipeline from the Permian in West Texas to the Gulf Coast (see our February 2019 note "Permian Majors Expand Downstream Processing"). Another super major Chevron purchased a 116 mb/d Pasadena, Texas, refinery from Petrobras in 2019. Smaller West Coast regional player Par Pacific Energy closed its purchase of U.S. Refining's 42 mb/d Tacoma, Washington, plant from Trailpoint. Par Pacific also merged two refineries in Oahu, Hawaii, after purchasing and closing a smaller plant owned by Island Energy. In January 2019, Targa Resources opened a 35 mb/d condensate splitter at Channelview, Texas, to process ultralight condensate crude that is generating income under a disputed throughput agreement with trader Vitol that inherited the deal from Noble Resources.

Elsewhere in the refining patch, the 49 mb/d new build Davis refinery planned by Meridian in North Dakota is still proceeding through permitting, and the company is planning another 58 mb/d refinery at Walton Station in the West Texas Permian basin. In August 2019 Texas International Terminals announced plans to process 50 mb/d of domestic crude at its Galveston, Texas, terminal to produce low sulfur bunkers and gasoil for affiliate GCC Bunkers. The smaller MMEX Resources Pecos Refinery project in Stockton, Texas, will consist of an initial 10 mb/d diesel refinery followed by a larger nearby 100 mb/d plant. Although Pecos received an environmental permit in 2017, the project doesn't appear to have advanced recently.

Environment

U.S. refiners keep a constant eye out for environmental rules that typically increase their costs. These burdens have risen despite the Trump administration's promise to roll back regulation. One such thorn in their sides since 2007 has been the federal Renewable Fuel Standard mandating increased blending of biodegradable fuels, such as ethanol made from corn, into gasoline and diesel. Blending ethanol in gasoline reduces refiners' market share and incurs costs administering the program. The extent of refiner obligations to blend ethanol in gasoline is subject to an annual dispute between the Environmental Protection Agency, refiners, and corn farmers. That dispute reached a stalemate in 2019 as the Trump administration tried to keep both refiners and farmers happy by issuing refinery waivers and extending ethanol blend limits but appeared to frustrate both in the process (see our July note "Trump Walks Ethanol Mandate Tightrope"). While ethanol blend requirements burden refiners, the RFS mandate also requires biodiesel blending with diesel fuel that offers potential benefits. Those opportunities come from converting existing refinery units or adding capacity to process waste product biofuels. As we detailed in October, refiners are adding capacity to protect their share of the diesel market (see "Six-fold Increase in Renewable Diesel Capacity").

Coming Soon

On the horizon for 2020 are Tier III regulations governing the sulfur content of gasoline. Most refiners have been able to delay implementation of the new standard until this year. Now they have to comply or purchase potentially expensive sulfur credits to meet their obligations (see our December 2019 note "Tier III Gasoline Compliance Challenges").

Also on deck this year are the International Maritime Organization's regulations limiting the sulfur content of ships bunker fuel to 0.5% from Jan. 1, 2020. Last year U.S. refiners prepared for the IMO rules by reducing fuel oil output and in some cases processing high sulfur fuel oil through coker units to increase margins (see our November 2019 note "High Sulfur Fuel Oil Competing With Crude"). During the coming year we'll report further on the impact of the IMO regulations on the bunker market and refinery crude slates.

About Morningstar® Commodities Research™

Morningstar Commodities Research provides independent, fundamental research differentiated by a consistent focus on the competitive dynamics in worldwide commodities markets. This joint effort between Morningstar's Research and Commodities & Energy groups leverages the expertise of Morningstar's 23 energy, utilities, basic materials, and commodities analysts as well as Morningstar's extensive data platform. Morningstar Commodities Research initially will focus on North American power and natural gas markets with plans to expand coverage of other markets worldwide.

Morningstar, Inc. is a leading provider of independent investment research in North America, Europe, Australia, and Asia. The company offers an extensive line of products and services for individuals, financial advisors, and institutions. Morningstar's Commodities & Energy group provides superior quality market data and analytical products for energy data management systems, financial and agricultural data management, historical analysis, trading, risk management, and forecasting.

For More Information

+1 800 546-9646 North America
+44 20 3194 1455 Europe
commoditydata-sales@morningstar.com

MORNINGSTAR®

22 West Washington Street
Chicago, IL 60602 USA

©2020 Morningstar. All Rights Reserved. Unless otherwise provided in a separate agreement, you may use this report only in the country in which its original distributor is based. The information, data, analyses, and opinions presented herein do not constitute investment advice; are provided solely for informational purposes and therefore are not an offer to buy or sell a security; and are not warranted to be correct, complete, or accurate. The opinions expressed are as of the date written and are subject to change without notice. Except as otherwise required by law, Morningstar shall not be responsible for any trading decisions, damages, or other losses resulting from, or related to, the information, data, analyses, or opinions or their use. References to "Morningstar Credit Ratings" refer to ratings issued by Morningstar Credit Ratings, LLC, a credit rating agency registered with the Securities and Exchange Commission as a nationally recognized statistical rating organization ("NRSRO"). Under its NRSRO registration, Morningstar Credit Ratings issues credit ratings on financial institutions (e.g., banks), corporate issuers, and asset-backed securities. While Morningstar Credit Ratings issues credit ratings on insurance companies, those ratings are not issued under its NRSRO registration. All Morningstar credit ratings and related analysis are solely statements of opinion and not statements of fact or recommendations to purchase, hold, or sell any securities or make any other investment decisions. Morningstar credit ratings and related analysis should not be considered without an understanding and review of our methodologies, disclaimers, disclosures, and other important information found at https://ratingagency.morningstar.com. The information contained herein is the proprietary property of Morningstar and may not be reproduced, in whole or in part, or used in any manner, without the prior written consent of Morningstar. To license the research, call +1 312 696-6869.