What is different about differentials?

Understanding the price of oil in western Canada

17 December 2020

Kevin Birn
Vice President

Crude Oil Markets | **Strategic Report**

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What is different about differentials?

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Kevin Birn, Vice President[1]

A crude oil differential is the difference in price that can emerge as a result of variations in composition (also known as quality) and location among crude oils. In western Canada, differentials are of great interest because the value of heavy, sour crude oil—Canada's largest source of crude oil export—typically obtains a price lower than many commonly traded US and global benchmarks. In fact, so common is the perception that Canadian crude is lower value that "discount" is used synonymously with differentials. But there is a big difference: differentials are not the same as discounts. But what gives rise to the differential in western Canada, and what factors influence it? Understanding these dynamics is key to understanding the value of Canadian oil.

Key messages

- Differences in the price of crude oil exist globally because production can occur distant from refineries, incurring transportation cost to market, and because crude oil is not homogenous, which affects the price refineries are willing to pay.

- Differentials tend to be smaller for offshore, waterborne crude oils than for inland crudes. Overland transportation tends to be more costly and less liquid (lower volume) than marine transport, which can give rise to more pronounced localized price disparity.

- Western Canadian production is both inland and distant to market, which contributes to sustained price differentials for heavy and light crude oil. However, differences in inland North American supply and demand and crude quality contribute to larger differentials for heavy versus light crude oil in western Canada.

- Canadian light crude enjoys strong inland demand relative to supply, typically travels shorter distances to market, and has a similar quality compared with WTI—the principal North American benchmark crude. Assuming pipeline transport, lighter crude oils in Alberta should obtain prices between $3 below and $2 above WTI.

- Western Canadian Select (WCS)—western Canada's principal heavy, sour benchmark crude oil—has a larger quality differential to WTI compared with western Canadian light oil, and it typically must travel farther to market and incur higher transportation costs. Assuming western Canadian heavy crude oil is able to reach US markets by pipeline, it should obtain $9–15/bbl less than WTI.

- Delays in the expansion of pipeline export capacity have contributed to wider differentials and lower prices in western Canada than otherwise would have been expected. Over the past half decade (2015–19), IHS Markit estimates WCS alone obtained, on average, at least $3/bbl less than would have been expected.

—17 December 2020

1. Special thank you to Ashok Dutta for his contributions to this report.

About this report

Purpose. A crude oil price differential is the difference in the price of crude oils that can emerge as a result of quality and location differences. In western Canada, differentials are of great interest because the value of heavy, sour crude oil—Canada's largest source of crude oil export—typically obtains a price lower than many commonly traded US and global benchmarks. In fact, so common is the perception that Canadian crude is lower value that "discount" is used synonymously with differential. But there is a big difference: differentials are not the same as discounts. This report seeks to answer what gives rise to the differential in western Canada, what factors influence it, and what should be the price expectation.

Context. Since 2009, IHS Markit has made public some of its research on issues surrounding the development of the Canadian oil sands. This report is part of a series of reports from the Canadian Oil Sands Dialogue. The dialogue convenes stakeholders to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands.

This report and past Oil Sands Dialogue reports can be downloaded at www.ihsmarkit.com/oilsandsdialogue.

Methodology. IHS Markit conducted extensive research and analysis on this topic, both independently and in consultation with stakeholders. IHS Markit has full editorial control over this report and is solely responsible for its content (see the end of the report for the IHS Markit team).

Disclaimer. This report explores the pricing relationship among western Canadian crudes and inland US and global benchmark crudes. Please note that price relationships can be very complicated. The purpose of this report was not to present a forecast. Rather, it was to discuss the factor influencing the differentials in the western Canadian oil market. As a result, a number of simplifications and a wider set of assumptions were used than would be deployed in the IHS Markit pricing outlook. For example, this report made use of average pipeline tolls, as well as committed and uncommitted tolls, to arrive at estimate pricing relationships among benchmark crudes. Actual differentials faced by an individual producer may also vary and can and do fluctuate. This report should not be taken as fixed viewed, nor is the information contained in this report substitute for a detailed crude valuation study or analysis.

This report has four sections.

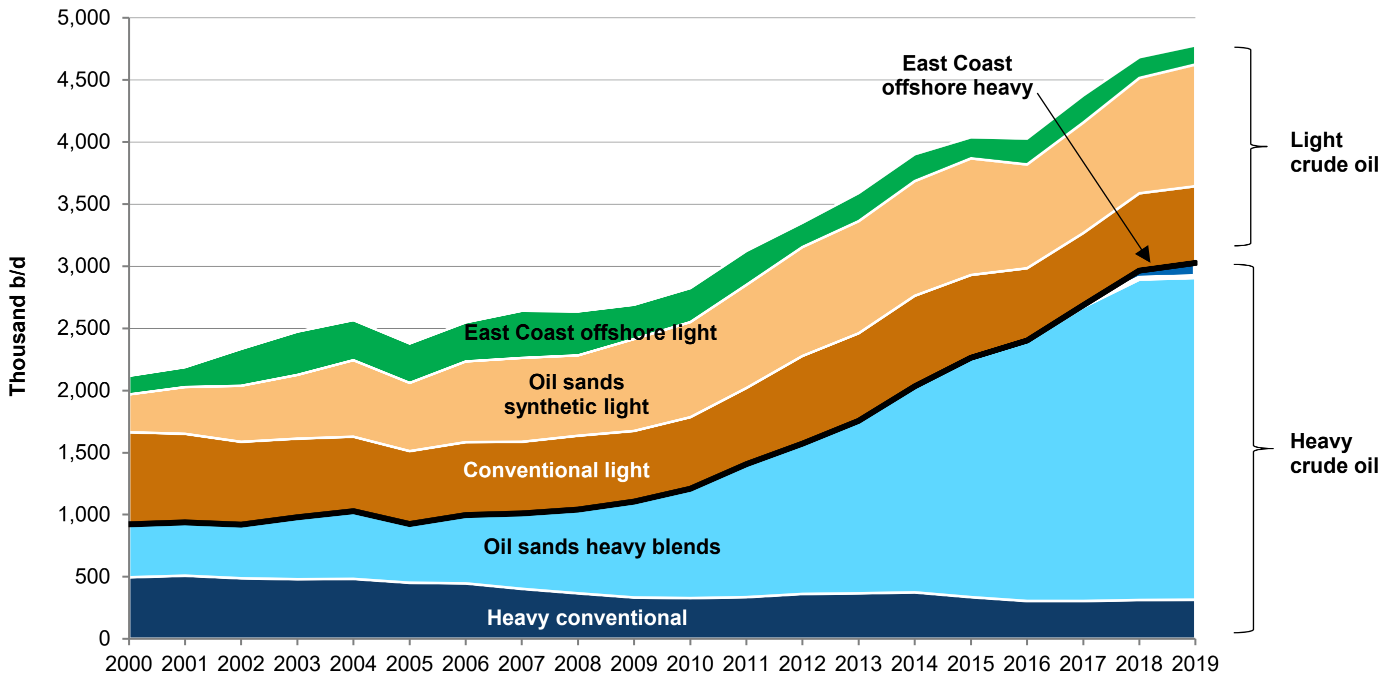
- Introduction
- Understanding a crude oil price differential
  - Crude quality complicates comparisons
  - Transportation distance reduces prices (more so for inland crudes)
- Understanding the price of oil in western Canada
  - Inland demand narrows the differential for western Canadian light oil
  - Greater supply increases distance and differentials for western Canadian heavy oil
- The opportunity to lower western Canadian differentials

Introduction

For more than a decade, Canada has been among the fastest-growing producers of crude oil in the world. Although growth has come from all grades—light to heavy—heavy, sour crude oil from the Canadian oil sands has dominated (see Figure 1). From 2000 to 2019, Canadian oil sands output rose more than 1.5 MMb/d, pushing Canadian production above 4.6 MMb/d. This growth made Canada the fourth-largest producer in the world.

Figure 1

Composition of Canadian production, 2000–19



Source: IHS Markit

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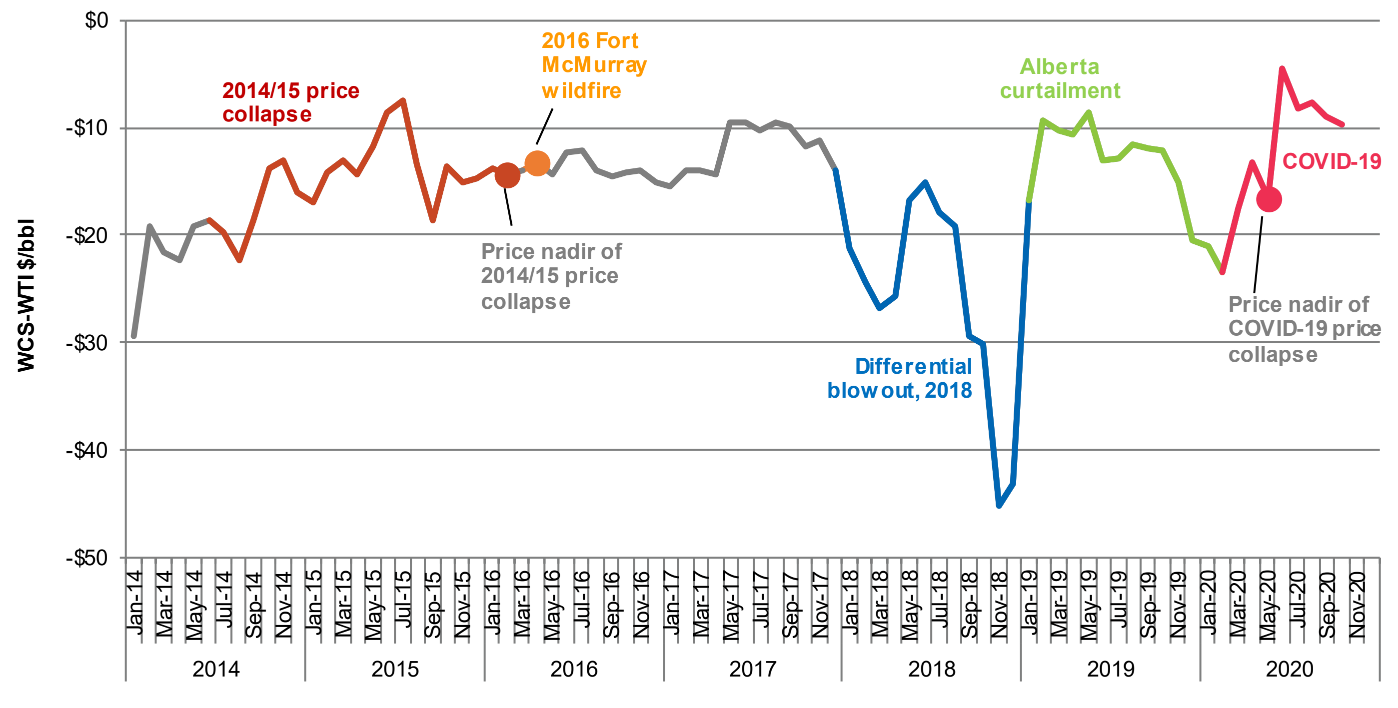
Throughout this period, pipeline projects have been proposed in anticipation of rising production. However, all the projects have faced opposition and, ultimately, delay. As a result, export pipeline capacity has struggled to keep up with demand.[1]

During the past three-quarters of a decade, there were several periods when western Canadian output exceeded regional demand and takeaway capacity. During these periods, the price of oil in western Canada fell relative to inland US and global oil prices. The most infamous episode to date occurred in the fall of 2018, when differentials for heavy crude widened to as much as $50/bbl below WTI, the inland US light oil benchmark (see Figure 2). Absolute prices fell into the midteens—worse than during the nadir of the global price collapse in early 2016. Only the most recent price rout driven by the COVID-19 global oil demand shock sent Canadian prices to a lower level.

1. The history of the timing of western Canadian pipeline infrastructure was covered extensively in the IHS Markit Strategic Report Pipelines, Prices, and Promises: The story of western Canadian market access.

Figure 2

Western Canadian heavy, sour differential to WTI, monthly average 2014–20 year to date



Source: Argus Media, IHS Markit

Because crude oil is not homogenous, its price will vary depending on where it is produced and on its quality. These price differences are known as a "basis differential," or simply "a differential." In western Canada, differentials are of great interest because the value of heavy, sour crude oil—Canada's largest source of crude oil export—obtains a price lower than many commonly traded US and global benchmarks. In fact, so common is the perception that Canadian crude is lower value that "discount" is used synonymously with differential. But what gives rise to the differential in western Canada, and what factors influence it?

This report seeks to explain the factors that help set the price of oil in western Canada. In addition to this introduction, the report has three sections. In the first section, we explain how both crude oil quality and transportation cost influence crude oil price differentials. In the second section, we explore how these factors influence the price of oil in western Canada. The final section briefly discusses the outlook and opportunities for western Canadian differentials.

It should be noted that in extremely low price environments such as during early 2016 or over 2020, price differentials typically narrow. However, these episodes do not represent average or typical operating conditions. Comparisons made in this study make use of historical pricing relationships, which are likely to resume once the market recovers from the current oil surplus.

Throughout this report, there are references to various terminology and characteristics that differentiate crude oil quality. For more information on the characteristics that give rise to quality differences among crude oils, please see the box "Crude quality primer."

Crude quality primer

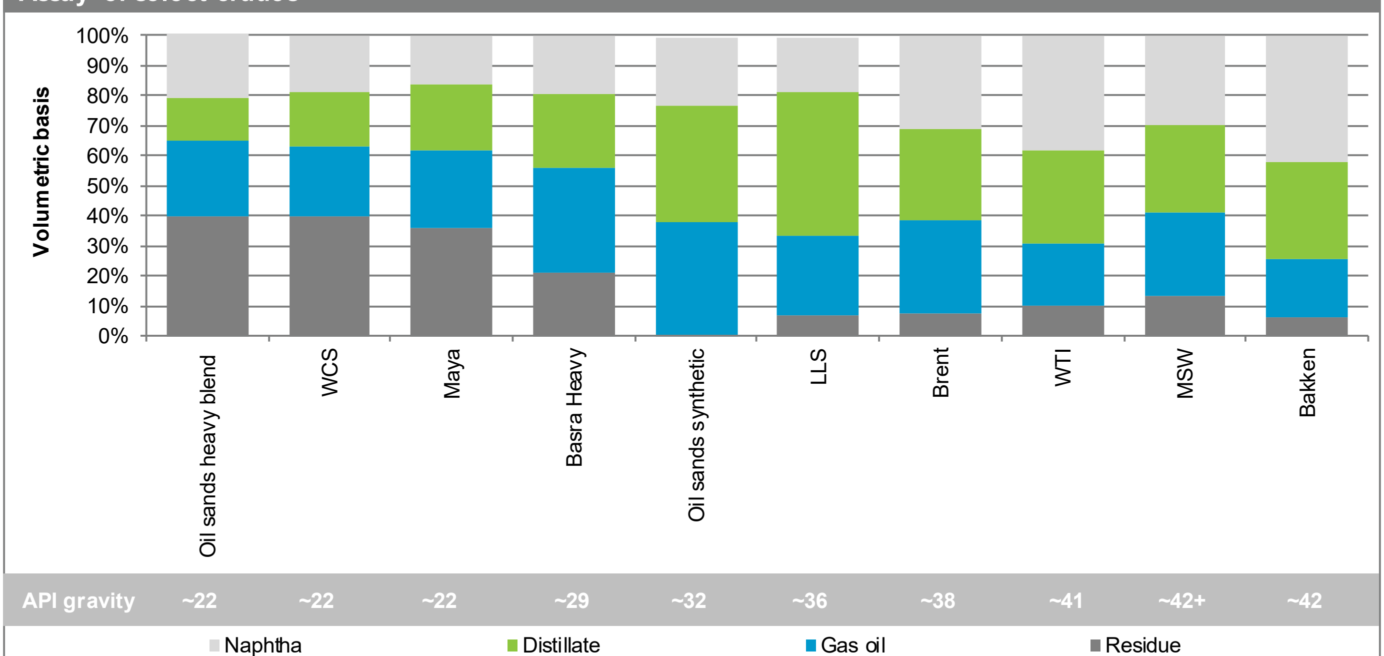
Crude oil is not homogeneous. Crude oils have different densities (which determine whether a crude is described as “light” or “heavy”) and have varying levels of impurities such as sulfur (which give rise to crude oil descriptors such as “sweet” [low sulfur] or “sour” [high sulfur]).

Density is by far the most common metric of quality, which is often measured according to API gravity. Based on IHS Markit definitions, light crude oil has an API gravity of 32° or greater. Heavy crude oil has an API gravity 24° or less (with the API gravity for extra-heavy crude oil below 10°). Medium crudes have an API gravity between light and heavy crudes. IHS Markit considers crude oil that has a sulfur content that is less than 1% by weight a sweet crude, and all levels above this are considered sour.

Differences in the density of crude oil result from the composition of hydrocarbons found in each crude oil. Within any given barrel of crude oil, there are various fractions, or groupings of hydrocarbons that distill or boil at distinct temperature ranges. Naphtha is the lightest fraction and boils at a lower temperature. Gasoline is generally derived from naphtha. Kerosene (jet fuel) and diesel are found in the distillate range, boiling at temperatures between 180 degrees Celsius (°C) and 350°C. Vacuum gasoil and residue are viscous materials that nominally boil between 350°C and 550°C and above 550°C, respectively. These heavier fractions with higher boiling points require additional processing (via catalytic or thermal processes) to be converted into lighter fractions of distillate and naphtha, which can then be converted into higher-value products. Less complex refineries (facilities that lack additional heavy crude oil processing technology) will not be able to process these heavier fractions into lighter products. As a result, they will pay a premium for lighter crude oil because its heavier fractions are minimal. By contrast, more complex refineries—facilities that have invested in specialized units capable of converting heavy fractions to light products—will seek out crude oil with larger fractions of heavier molecules. Because of the complexity and cost required to process heavier crude oils, they typically are cheaper than lighter crude oil.

Figure 3

Assay of select crudes



Note: Crude assays vary. Values are approximations and vary by cut point and reservoir quality, which does vary across a play and over time. Estimates are assembled from various sources and adjusted based on feedback.

Source: Derived and adapted from IHS Markit, Energy Information Administration (EIA), BP Global Energy Trading, and CrudeMonitor.ca

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Understanding a crude oil price differential

A crude oil price differential is influenced by the transportation cost between markets and differences in the composition of the oil—often referred to as quality—between the crude oils being compared. This section breaks down how these factors can contribute to price variations among crude oils.

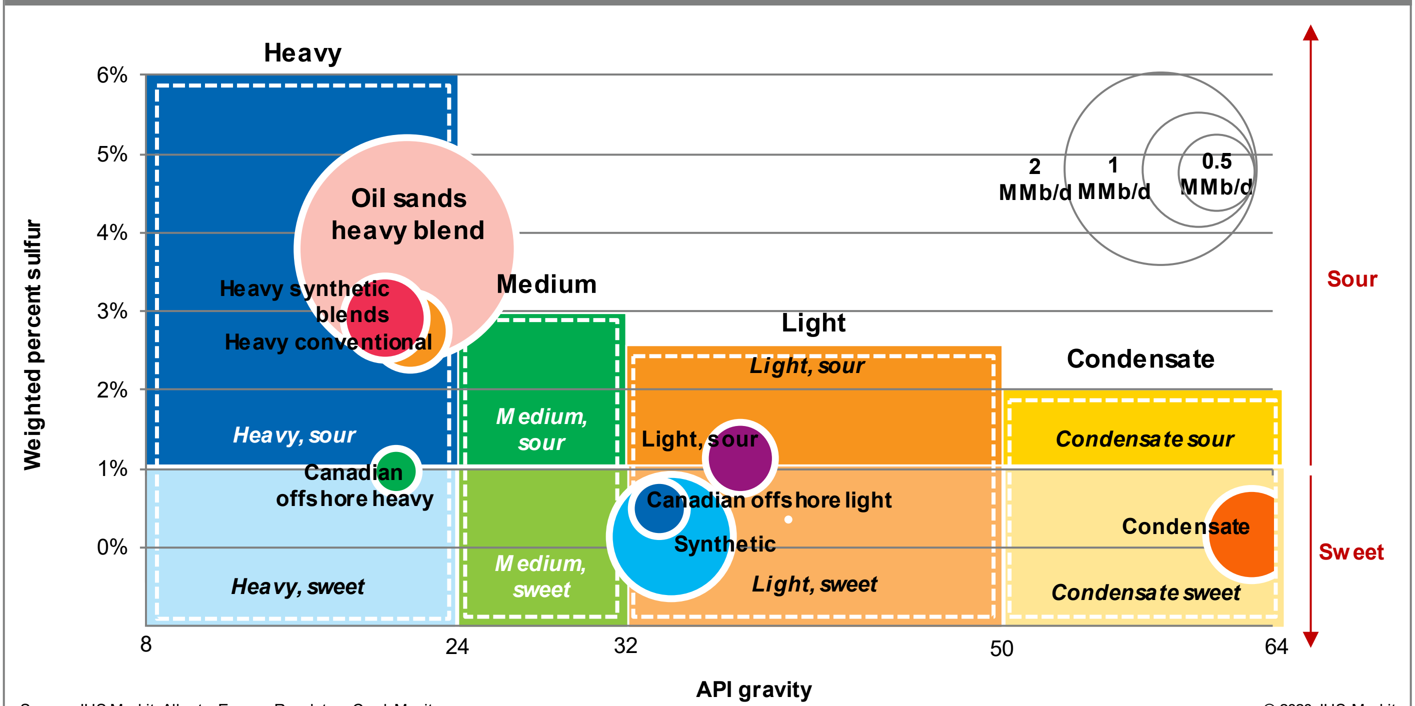
Crude quality complicates comparisons

Crude oil is not homogenous. Crude oil is most commonly differentiated by density—light or heavy, which relates to the distillation of the crude oil—and the presence of impurities such as sulfur, acid, or solids, which gives rise to qualifiers such as "sweet" (low-sulfur crude) or "sour" (high-sulfur crude). For more information, see the box "Crude quality primer."

Canada produces a diversity of crude oils, from ultralight natural gas condensates (crude oil that exists in vapor form in the reservoir and becomes liquid at atmospheric temperatures and pressure) to extra-heavy, sour crudes (crude oil that is semisolid at room temperature) (see Figure 4). In western Canada, nearly every form of onshore extractive technology is in use, from conventional wells, to multistage horizontal stimulation (hydraulic fracturing), to large-scale oil sands mining projects. Although there is a great variety of crude oils being produced, growth has been dominated by heavy, sour crude oil from the oil sands.

Figure 4

Distribution of Canadian crude by quality



Source: IHS Markit, Alberta Energy Regulator, CrudeMonitor.ca

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Heavier crude oil generally contains a greater share or fractions of heavier hydrocarbons, which have higher boiling points, such as residue (boils at temperatures over 550°C). These heavier fractions require specialized capital-intensive refinery processing units to be converted into higher-value refined product, such as gasoline or diesel. Additional refining units, such as hydrotreaters, are required to remove sulfur and other impurities to meet product specifications. These differences in processing requirements influence the cost of processing, the yield of refined products that can be derived from various crude oils, and their market—refineries capable of converting heavier, more complex crude oil into higher-value refined product. These factors, in turn, influence the value refiners place on a given crude oil and thus the price it obtains.[2]

In this way, variations in crude quality can result in price differences among crude oils, even within the same region. The price difference is smaller for similar-quality crudes and is greater for ones with larger differences in properties.

The light-heavy differential

A commonly cited metric to measure the degree of quality price disparity is known as the *light-heavy differential*, which compares the price of a light, sweet crude oil against heavier, more sour crudes.

The *light-heavy differential* is important for refineries since it influences the economics of processing heavy versus light crude oil. This metric is of particular interest in Canada because it is a major producer of heavy, sour crude.

A generally accepted measure of the global *light-heavy differential* is that of Mexican Maya (Maya)—a globally traded waterborne heavy, sour crude oil, priced in the Gulf of Mexico—and Louisiana Light Sweet (LLS)—a light, sweet crude oil traded at Louisiana oil hubs.[3] During the past five years (2015–19), the price difference between LLS and Maya averaged just over $7/bbl.[4]

The quality differential is not static

Although the price difference between two geographically approximate crude oils will be dominated by variations in quality, the price that refineries assign to quality differences can change over time. For this reason, history may not always be a reliable predicator of the future value of a quality differential. Some more common supply and demand factors that have influenced quality differentials in recent years include

- **Global oil price.** Quality differentials tend to widen in higher prevailing oil price environments and narrow in lower price environments. For example, from 2012 to 2014, when the price of oil averaged about $100/bbl, the LLS-Maya light-heavy differential averaged about $11/bbl, or about $4–5/bbl greater than in recent years when absolute prices were lower. During 2020, the spread has narrowed further—averaging below $4/bbl—but this result has also been supported by reductions in the availability of heavy, sour crude oil discussed below.[5]

- **Changes in refined product prices.** The value of refined products, such as gasoline, diesel, or fuel oil, fluctuates based on changes in consumer supply and demand. This variation influences the relative value of different crude oils based on the underlying fractions of refined product that can be derived from them. A notable example is the International Maritime Organization's (IMO) implementation of the sulfur dioxide regulations for bunker (ship) fuel, which was anticipated to reduce the demand, and thus value, of high-sulfur fuel oil. This result, in turn, was expected to affect the price of heavier, more sour crude oils globally, because they tend to have a larger fraction of sulfurous heavy bottoms (like residue).

2. According to "last barrel" economics, the price of a grade of crude oil is determined by how it is valued in the marginal refinery configuration. For example, if the incremental barrel of heavy crude oil is valued in a "cracking" refinery (with no coking or ability to process the heaviest hydrocarbons), that barrel will be valued less than by a refinery with deeper processing units. Persistently lower prices for heavy crude relative to lighter crudes in turn provide the economic incentive for a refiner to invest in additional heavy crude oil handling, such as construction of a coking unit.

3. WTI—a light, sweet crude oil priced in Cushing, Oklahoma—is the most commonly cited light oil in North America. However, because it is located inland and distant to tidewater, it can face additional transportation-driven differentials, which is why we chose to focus on two waterborne crude oils.

4. The Maya crude oil benchmark price is based on a formula managed by Pemex. In the short term, this formula can result in some divergences from what would normally be anticipated, but over the long term, for Maya to maintain its competitiveness against other crudes, it generally converges or tracks other globally traded crudes.

5. Based on the first 10 months of 2020.

- **Changes in the relative supply of light and heavy crudes.** Since late 2018, the global light-heavy differential narrowed. During this period, the LLS-Maya differential averaged about $5/bbl, which is about $3/bbl less than the 2015–17 average. During 2020, this narrowing has been helped by lower prices; additionally, the world has seen further reductions in availability of heavy, sour crude oil. The reduction in available heavy, sour crude oil has occurred owing principally to the accelerated decline in the availability of Venezuelan heavy, sour crude oil and ongoing declines in Mexican and Iranian output. This narrowing was helped along until 2020 by rising light, sweet crude oil production from the United States. The combined effect put upward pressure on the price of heavy, sour crude oil and downward pressure on lighter crudes—narrowing the difference in price between the two.

- **Changes in global refining conversion capacity/utilization.** The availability of heavy residue conversion capacity (e.g., delayed coking)—required to economically process heavy crude oil—also influences the light-heavy differential. Increases in conversion capacity boost demand for heavy crude oil, relative to supply. Delayed coking capacity has historically been added in cycles, as refiners respond to the price signals triggered by increases in heavy crude supply.

Estimating quality differentials

IHS Markit estimates the quality differential among different crude oils based on the value of the refined product that can be obtained from processing these crudes in different refinery configurations and in different regions. The two bookends for this range are derived from the relative value that a less complex refinery may realize versus the value obtained in a more complex refinery. A less complex refinery obtains less value from processing a heavier crude oil, because of its inability to convert the heaviest fractions into higher-value refined product, leaving them with a greater share of the barrel of oil as lower-value intermediate product. Conversely, a more complex refinery would put greater value on heavier oil because it is able to convert the heaviest fractions into higher-value refined product such as gasoline and diesel. In general, this situation provides more complex refineries greater flexibility, but it also requires a higher degree of capital investment.

In this way, the properties being compared are more complex than a simple measurement of density (light or heavy), because the fractions of even similar density crudes can vary (see the box “Crude quality primer”).

Although quality differentials will fluctuate according to underlying market forces, as discussed above, they tend to do so within the bookends set by the value obtained from low-complexity and high-complexity refineries. Should the value of heavier crude oil relative to lighter crude oil widen sufficiently, the potential savings in feedstock cost can incentivize even less complex refineries to process more heavy crude, even if it means they are left selling more lower-value intermediate product such as heavy fuel oil.[6] Conversely, should the value of heavy crude oil appreciate, it can push even more complex refineries to consume lighter grades, since there is greater cost associated with processing heavier oils.[7] In this way, the value of the quality differential tends to track between these two goalposts.

Transportation distance reduces price (more so for inland crudes)

Oil-producing regions are often remote from consuming markets, and the crude oil must be transported to market, which comes at a cost. Transportation cost affects the price producers obtain for their crude, because producers must pay to move their crude oil to market to compete with other crudes for refinery space.

All things being equal, the greater the distance a producing region is from the market or demand center, the greater the cost and the lower the price a producer will receive for their crude. This situation is known as a

6. Most of the low-complexity or “light” crude oil refiners will face technical limits in their ability to process heavy oil (i.e., most cannot run 100% heavy crude).

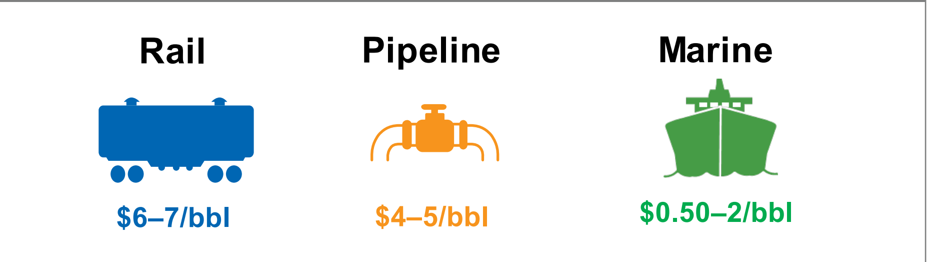
7. Although complex refineries are more flexible in the crude slate they can process, they can still face technical limitations in their ability to process high percentages of light crude oil (i.e., a complex refinery designed to process heavy, sour crude cannot run 100% of light crude).

netback price (the price obtained in a distant market, netted back to the producing region by subtracting the transport cost). Price differences between regions can result, even for similar-quality crudes.

However, things are not always equal. Different regions may have access to different modes of transport, and different modes of transport have varying operational characteristics and ultimately different costs. These distinctions influence transportation-driven price differentials between regions.

Figure 5

Simplified cost comparison to transport a barrel of oil approximately 1,000 miles



Note: Cost ranges presented are approximations, and actual cost can and will vary depending on committed/fixed term or uncommitted/spot contracts, density of crude oil, distance, scale such as pipeline gauge, tank car specification, and/or vessel size/class, etc. Pipeline and rail costs based on North American transportation systems.
Source: IHS Markit

Figure 5 provides a simplified cost comparison of the major modes of long-distance crude oil transport. It is important to note that even within each mode of transport shown in Figure 5, there are further differences that exist that influence the relative cost structure. For example, vessel size, pipeline size/gauge, or crude train configurations (dedicated trains known as unit trains, or mixed-use trains known as manifest trains) affect the cost of transport. Additional factors such as routing (whether the movement must move through more or less congested areas) and contractual terms (such as fixed long-term contracts versus common carrier) also influence cost.

Transportation differentials tend to be smaller for waterborne crudes compared with inland crudes

For globally traded waterborne crude oils, price differences due to transportation tend to be relatively contained. Crude oil production on or near tidewater benefits from access to the relative efficiency and flexibility of marine transport. Marine transportation enables crude oil to move freely to the highest price point globally—away from regions that become temporarily oversupplied and that would provide lower prices. This result is known as arbitrage and helps stabilize the price differences between regions. For these reasons, the price differences among globally traded (waterborne) crude oils tend to be relatively small. For example, the variation in the price of key waterborne light, sweet crude oil benchmark prices around the world was on average less than about $3/bbl in 2019 despite thousands of miles between regions (and even some subtle quality differences).[8]

For onshore, inland crudes, more costly and less flexible transportation modes contribute to larger sustained transportation-driven price differences between regions. For example, in 2017, when the North American market was largely free of any pronounced transportation disruptions or bottlenecks, the price of light, sweet oil in western Canada, as measured by the Mixed Sweet Blend (MSW) benchmark, traded on average about $5 below waterborne LLS in the US Gulf Coast (USGC) offshore—a distance of about 2,000 miles (3,200 km) compared with some global waterborne distances listed above that easily exceed about 4,000 miles (6,500 km).

We make reference to 2017 to illustrate the pricing relationship that would be expected in the absence of transportation system bottlenecks. There were well-documented transportation system bottlenecks that occurred in western Canada and in inland US markets in 2018 and 2019 that affected transportation-driven pricing relationships.[9]

8. Comparison is based on $63; LLS, St. James (FOB): $63; Brent, North Sea: $64; Arab Light, Sidi Kerir (FOB): $64; Bonny Light, Nigeria (FOB): $66; Hibernia, Whiffen Head: $64. Source: Argus Media.

9. In 2018, western Canada experienced a significant oversupply situation owing to insufficient export pipeline capacity that led to a dramatic reduction in western Canadian prices compared with other inland US and global benchmarks. In 2019, western Canada registered increasing demand for higher-cost crude-by-rail transportation from the basin, and in the United States transportation bottlenecks from the Permian Basin to Cushing, Oklahoma (Cushing), and the USGC contributed to additional price dislocations for inland crude oils. To be fair, 2017 is not without issues as well; however, these issues arose more from regional supply than transportation infrastructure.

Understanding the price of oil in western Canada

All Canadian crude oil tracks globally traded crudes, subject to transportation cost and quality differences. In Canada, most production occurs inland, in western Canada, distant to and/or with limited access to marine export terminals. As a result, there is a greater reliance on overland transport—principally pipelines, but crude by rail has also increased in recent years. The inland location of Canadian producers comes at a cost, with pipeline transport a relatively more expensive and less flexible transportation option than marine transport.

The size of the price differential for Canadian producers depends on how far (and by what mode) crude oil must be transported to market and any quality differences among the crudes being compared. Western Canadian light oil has experienced a smaller transportation-driven differential to globally traded crude oil than heavy crude because Canadian light crude typically travels a shorter distance to its end market. Because of these differences, the pricing relationships for western Canadian light and heavy oil are discussed separately.

Inland demand narrows the differential for western Canadian light oil

Western Canada produces more than 1 MMb/d of light oil. Although most of it is consumed domestically within western Canada, production still exceeds regional demand and must be exported. The most significant geographically approximate market is the US Midwest, which is accessed by pipeline. From a price-setting standpoint, the US Midwest has become the most important market for western Canadian light oil because this is where it competes with other sources of supply from North Dakota, Texas, and elsewhere for refinery space.

As shown in Figure 6, reaching the US Midwest requires western Canadian producers to cover the transportation cost to deliver their crude oil into that region. As a result, the price of western Canadian light crude oil tracks the price of light oil in the US Midwest—linking the two market prices by the cost of transport. Under existing pipeline infrastructure and tolls, it costs about \$3–4/bbl to transport western Canadian light oil from central Alberta (Edmonton area) into the Chicago area.[10]

US Midwest refinery demand for light oil is greater than can

Figure 6

Western Canadian light crude oil path to market

Source: Argus Media/ IHS Markit: ER2020-55

10. The actual cost varies by loading area, destination, and commercial terms of the transport such as whether the shipper has a long-term contract or is uncommitted. There are several on-ramps where western Canadian and northern US production can access Canadian export pipeline systems that generally run southeast from Alberta to Manitoba.

be supplied from Canada and other Northern Tier crudes, such as from North Dakota, and crude oil must be delivered north from the market hub in Cushing, Oklahoma. Unlike Northern Tier crudes, which are landlocked with all the pipeline infrastructure pointing south, Cushing is a major crude oil trading hub. Crude oil in Cushing can flow north into the Midwest or south to refineries or export terminals in the USGC region. As a result, Midwest refineries must compete with USGC and global export opportunities for crude oil in Cushing. To obtain the crude oil they need, refineries in the US Midwest must pay the prevailing price in Cushing and then the cost of transport into the US Midwest. Based on pipeline transport from Cushing to the Chicago area, the price of light oil in the US Midwest must be, on average, about $2–3/bbl higher than Cushing. In turn, depending on the prevailing tariff rate, the pipeline transport toll sets the price of oil in Cushing at about $3–4/bbl below the price in the Houston area, where the price is more closely tied to globally traded waterborne crude oil (or $4–5/bbl to offshore markets, which would reflect an additional cost of about $1/bbl to reach global markets). Accounting for all these relationships implies that the price of light oil in western Canada should, on average, track about $4–6/bbl below comparable crudes in offshore USGC ($3–4/bbl – $2–3/bbl + $3–4/bbl + $1/bbl) and just over $1–2.5/bbl compared with Cushing. In 2017, this relationship fit well with MSW averaging about $49/bbl and LLS at $54/bbl—a difference of about $5/bbl.

It is important to note that the availability of crude oil pricing information can vary by region. For example, there are currently no posted light crude oil benchmark prices in the Chicago area—the central refining area of the US Midwest. In fact, there are no Canadian light crude oil benchmark prices tracked south of the 49th parallel. WTI is tracked in multiple locations and is a commonly accepted comparable crude oil that can be used for comparison with Canadian lights, but there can be quality differences. On the other hand, Canadian heavy oil enjoys greater liquidity in the United States and is tracked by price reporting services at multiple locations: Western Canadian Select (WCS), the principally western Canadian heavy, sour crude oil benchmark is reported at Hardisty, Cushing, and Houston. For more information on benchmark prices, see the box "Benchmark crude oil prices."

Benchmark crude oil prices

Benchmark crudes are crude oils that serve as common transparent markers as to the value of crude oil being bought or sold in a particular location. There are many benchmark crudes that are used to represent different regions or quality grades. The most common ones globally are Brent, which is a waterborne light crude oil produced and traded in the North Sea, and WTI, which is the US inland light crude oil marker traded in Cushing, Oklahoma. Some examples of other common benchmarks include OPEC basket, LLS, Dubai, and Urals.

Many benchmark crude prices are tracked at multiple locations (in addition to their principal location), and for some, the pricing can be for future possession. It is important to note the terms of each benchmark to ensure an apple-to-apple comparison. Unless otherwise stated, the benchmark prices used in this report are for their principal geographical location (e.g., WTI in Cushing, WCS in Hardisty).

Even though there are various crude benchmarks by quality and geography, the variety of crude oil globally is even more diverse, and often transactions will be linked via a differential to a specified benchmark crude at a specified geography.

This situation is true in western Canada as well. For example, WCS is a purposely designed cocktail of heavy, sour oil sands crude (bitumen); light, sweet crude oil; condensate; and even some synthetic crude oil (SCO) that was created to provide greater western Canadian heavy, sour oil price transparency. Although WCS has become the dominate benchmark for western Canadian heavy, sour crude oil, most heavy, sour crude oil production is a blend of bitumen and condensate—a dilbit. These heavy oil sands blends have subtle differences to WCS, which would generally result in dilbit obtaining a modestly lower value or facing a larger quality difference to other crudes than WCS (see Figure 3).

Comparing western Canadian light oil to WTI

Although transportation to the US Midwest and regional supply and demand dynamics are likely the most important factors influencing the price of light oil in western Canada relative to globally traded crudes, quality also plays a role. Within North America, the most common basis of comparison for inland crude oil is to WTI, Cushing.

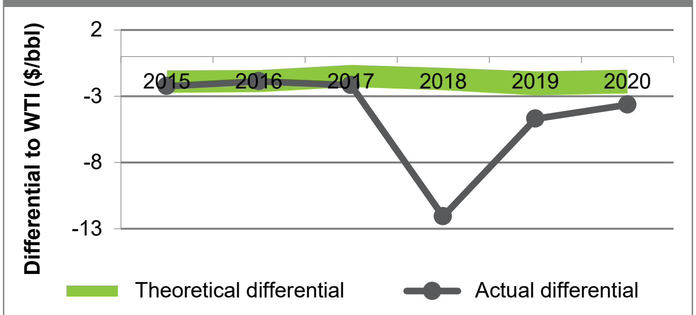
In western Canada, there are two primary light crude oil benchmark crude oils—MSW and SCO. As shown in Figure 3, these two crude oils have distinct properties compared with each other and with WTI. MSW has modestly larger fractions of gasoil and residue and less naphtha compared with WTI. Although the larger share of gasoil can result in greater yield of higher-value diesel over gasoline, this result is more than offset by the larger fraction of lower-value residue. SCO, on the other hand, is a unique product of upstream oil sands upgraders, which do the work of heavy oil processing units typically found at downstream refineries. In upgrading, the heaviest fraction found in bitumen, residue, is converted into lighter products. As a result, less complex refineries can process SCO and yield an greater share of higher-value product than WTI.

Putting aside transportation cost and considering only the value a refinery can derive from these crudes, on average MSW should obtain $0–1 below WTI (closer to -$0.25 to -$0.75), while SCO should obtain a $1–3/bbl premium. These differences in value are known as the quality differential.

All else being equal, the collective differences in crude quality and transportation can explain the price of oil in western Canada. Despite geographical distance of nearly 1,500 miles (2,300 km), MSW in Edmonton should be expected to trade, on average, between $1 and 3/bbl beneath WTI in Cushing (accounting for net pipeline transport of $1–2/bbl and a quality discount to WTI of $0–1/bbl). Meanwhile, the higher-quality SCO in Edmonton should fetch between $1/bbl below and $2/bbl above WTI in Cushing (net pipeline transport of $1–2/bbl and a quality premium to WTI of $1–3/bbl). Figures 7 and 8 provide a more detailed comparison of the expected differential range for MSW and SCO based on pipeline transport and adjusting for quality differential each year (estimated by refining value) versus the actual differential over the past five years as derived from Argus Media.[11]

Figures 7 and 8

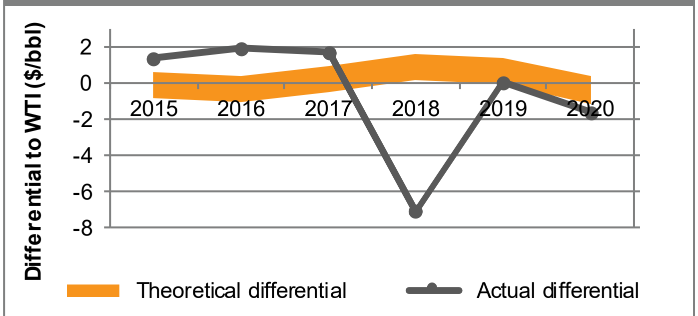
MSW-WTI theoretical differential to actual differential



Note: Differential estimated based on anticipated refinery value and pipeline transportation cost. Actuals derived by IHS Markit using Argus Media. Note the theoretical range based on estimated transportation tolls and refinery value, which will change from year to year. These figures make use of a wider set of potential transportation tolls and refinery valuation than deployed in the IHS Markit pricing methodology to provide a wider range of potential outcomes. Estimate for year 2020 based on first nine months.

Source: Argus Media, IHS Markit © 2020 IHS Markit

SCO-WTI theoretical differential to actual differential



Note: Differential estimated based on anticipated refinery value and pipeline transportation cost. Actuals derived by IHS Markit using Argus Media. Note the theoretical range based on estimated transportation tolls and refinery value, which will change from year to year. These figures make use of a wider set of potential transportation tolls and refinery valuation than deployed in the IHS Markit pricing methodology to provide a wider range of potential outcomes. Estimate for year 2020 based on first nine months.

Source: Argus Media, IHS Markit © 2020 IHS Markit

It is clear from Figures 7 and 8 that the market reality can vary from expectation. The ranges shown in both figures are not forecasts but an expected outcome based on a range of pipeline transportation cost and the differences in the relative value of the products a refinery may obtain from the crude oils in each year.[12]

11. As previously discussed, quality differentials are not static and contribute to changes in expected value from year to year but generally hold within the broader average differential discussed in this paragraph.

12. Playing with potential refinery yields and/or configurations can accentuate the range of potential values, but they should generally center on the range shown.

In reality, additional factors, such as unanticipated shifts in global supply and demand or unforeseen transportation system upsets, also play an important role. For example, in both Figures 7 and 8 the differential range shown assumes that production is able to reach market by pipeline. The large divergence between expectations and reality in 2018 was the result of supply overtaking available pipeline export capacity, which led to a temporary but dramatic reduction in western Canadian prices. In addition, SCO is produced from only four facilities, which makes each operation material to overall supply. In 2016, 2017, and 2018, there were incidents that contributed to a temporary tightening of SCO supply, which likely supported some of its price strength (although the impact in 2018 was muted by larger regional oversupply).[13] The year 2020 had its own set of very unique market fluctuations as a result of the global pandemic.

Greater supply increases distance and differentials for western Canadian heavy oil

Over the past decade (and more), western Canadian heavy, sour crude oil supply growth has outpaced light oil. Western Canada produced about 3 MMb/d of heavy supply in 2019.[14] As supply grew, it overtook demand in the traditional markets of western Canada, the US Rockies, and the US Midwest. In response, export pipeline infrastructure expanded, and lengthened, to reach increasingly distant markets in Canada and farther south in the United States. The USGC region, which was already the largest heavy, sour oil–consuming region in the world, has provided a readily available market for growing Canadian supply.[15] However, the longer distances to market contribute to a greater transportation-driven differential and smaller netback value compared with western Canadian light oil. Western Canadian heavy oil currently competes against globally traded heavy crudes of similar quality in the USGC region.

Figure 9

Western Canadian heavy crude oil path to market

Source: Argus Media/ IHS Markit: ER2020-56

As shown in Figure 9, this result makes the transportation costs all work in the same direction for heavy oil and increases the transportation-driven differential to global crudes compared with western Canadian light crude oils.[16]

The majority of existing western Canadian heavy crude oil pipeline export infrastructure transits through the US Midwest, with

13. In 2016, the Fort McMurray wildfire impacted several integrated mining operations that market SCO. In 2017 and 2018, there were unanticipated outages at the Syncrude facility.

14. Heavy conventional, blended bitumen, and heavy SCO.

15. See the IHS Markit Strategic Report Looking north: A US perspective on Canadian heavy oil.

16. The exception was in 2020, when reductions in upstream supply were so acute that the price-setting market temporarily moved further north.

additional capacity able to move supply farther south, onto Cushing and then the USGC. Canadian crude then competes for refinery space against globally traded waterborne crudes in the Houston, Texas, and Port Arthur, Texas, refining hubs. Assuming pipeline transport, the cost to move Canadian crude to the USGC includes $4–5/bbl to transport heavy oil from western Canada to the US Midwest, then $1–3/bbl from the US Midwest to Cushing, and then $3–4/bbl from Cushing to Houston. In total, these costs imply Canadian heavy should track crude oil of similar quality in the Houston area by $8–12/bbl (depending on pipeline route and committed versus uncommitted contracts). Demand for heavy, sour crude oil in the USGC region exceeds available onshore supply, and offshore imports are required. To attract waterborne cargoes, the onshore price should be modestly higher (about $1/bbl) than waterborne crude oil to cover the cost of landing the crude oil relative to competition elsewhere in the world. Taken together, Canadian heavy, sour crude oil should trade about 7–11/bbl ($4–5/bbl + $1–3/bbl + $3–4/bbl – $1/bbl) below globally traded crudes of similar quality.

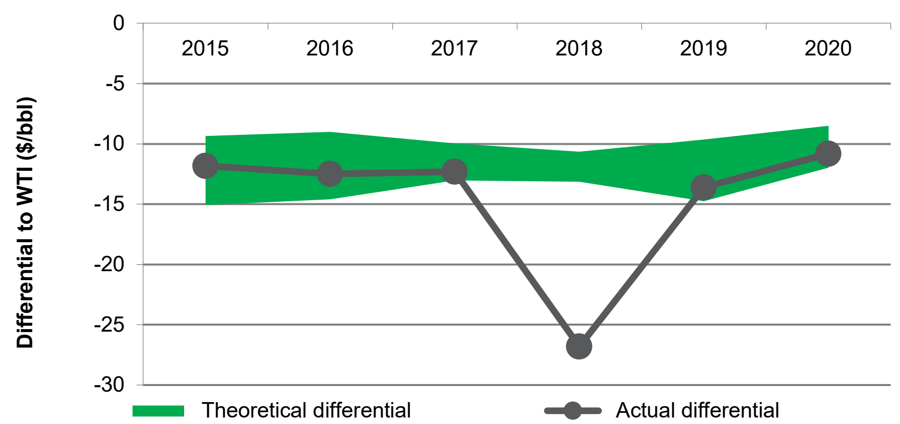
The most common basis of comparison for western Canadian heavy, sour crude oil to global crude oil of similar quality in the USGC region has historically been Maya. In 2017, WCS in western Canada traded down to Maya crude within the expected range averaging $8/bbl. Again, owing to transportation system limitations in both 2018 and 2019, the year 2017 was chosen for this illustration.

The larger Canadian heavy-light differential

Even though WCS will track globally traded crude oils of similar quality like Maya, the common basis of comparison for inland North American crude oils is to WTI in Cushing. In a very general sense, WCS in Alberta should tend to trade within $9–15/bbl less than WTI in Cushing (net pipeline transport of $5–7/bbl and quality discount to WTI of $4–7/bbl) (see Figure 10). Excluding the exceptional pipeline export situation that occurred in 2018, from 2015 to 2019 (thus also excluding COVID-19–led 2020 market impacts), WCS in Alberta obtained about $13/bbl below WTI, Cushing.[17]

Figure 10

WCS-WTI theoretical differential to actual differential



Note: Differential estimated based on anticipated refinery value and pipeline transportation cost. Actuals derived by IHS Markit using Argus Media. Note the theoretical range based on estimated transportation tolls and refinery value, which will change from year to year. These figures make use of a wider set of potential transportation tolls and refinery valuation than deployed in the IHS Markit pricing methodology to provide a wider range of potential outcomes. Estimate for year 2020 based on first nine months.

Source: Argus Media, IHS Markit

The opportunity to narrow western Canadian differentials

Western Canadian production is inland and distant to market, which contributes to higher transportation costs and therefore larger differentials to benchmark crude markers than typically experienced by waterborne crude oils. Differentials for western Canadian heavy crude against light crude markers are accentuated by the fact that these barrels can only be processed efficiently by complex refineries. Together, transportation cost and quality differences have made differentials part of the western Canadian lexicon. Yet, in the public

17. The potential range of expected value is greater than the Canadian light comparison made earlier (for example, $9–15 for heavy versus $1–3 for MSW) because of a greater range of potential transportation costs and a wider potential variation in quality valuation.

dialogue around the value of western Canadian production there has been confusion about what level of differential is "normal" or to be expected.

There can be little doubt that a key source of this confusion is linked to the fact that differentials can be complicated to unpack—requiring an understanding of regional supply and demand, crude oil flows, transportation costs, and refinery valuations. Differentials can also be volatile—moving around from day to day—based on market forces.

In western Canada, however, uncertainty about the value of differentials is also linked to the region's long-running struggle to bring online adequate pipeline export capacity. Pipeline export constraints have contributed to larger differentials, and lower returns for Canadian crude oil, than otherwise would have been expected. Although the impact on differentials has been sporadic, had there not been any transportation constraints over the past half decade (2015–19), IHS Markit estimates that western Canadian heavy crude oil would have obtained, on average, at least $3/bbl more compared with WTI, Cushing. The impact of this lost value over millions of barrels produced each day during the last past half decade is significant—about $14 billion (US dollars). Moreover, this estimate is likely conservative, since it is based on differentials only in excess of the uppermost bound of the anticipated range and only considers the impact on heavy, sour crude oil (see Figure 10).[18]

Looking forward, with a number of pipeline export projects now in construction, the opportunity exists for narrower differentials, on average, for the western Canadian market than over the past half decade. This would support greater price stability within the region and help prevent the abnormally wide differentials of the past half decade.

It is hoped that this report will shed some light and understanding on the factors that shape the price of oil in western Canada and the approximate value exports should obtain based on a free and functioning market.

18. The IHS Markit estimate is based on average daily differentials between WTI, Cushing, and WCS, Hardisty, from the start of 2015 to the end of 2019 as derived from Argus Media compared against a scenario in which the differential did not exceed $15/bbl—the upper bound of the range provided in the prior section. The estimated financial impact is based on value reduction associated with the abnormal differential each year from 2015 to 2019 multiplied by the annualized western Canadian heavy, sour supply less regional refinery consumption. It is reasonable to assume some producers with access to their own firm pipeline export capacity would have been able to insulate some of their production reducing the volume of exports exposed to abnormal differentials. Conversely, the estimated differential impact is likely greater than estimated. The use of $15/bbl was the maximum of the upper bound of the range during 2015–19 shown in Figure 10. Meanwhile, the average of the upper bound was just over $14/bbl, with the average of the actual differential, excluding the year 2018, nearly $13/bbl. Because WTI, Cushing, was subject to its own transportation bottlenecks during this period, a comparison was also made between WCS, Hardisty, and Maya, FOB. In this comparison, the estimated loss was greater. For these reasons, we view our estimate as conservative. This estimate also only considers the impact on heavy, sour crude oil and not exports of lighter grades.

IHS Markit Customer Care

CustomerCare@ihsmarkit.com
Americas: +1 800 IHS CARE (+1 800 447 2273)
Europe, Middle East, and Africa: +44 (0) 1344 328 300
Asia and the Pacific Rim: +604 291 3600

IHS Markit®