# Vertical Integration and Price Differentials in the U.S. Crude Oil Market*

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**Abstract**

Vertical integration between regulated and unregulated businesses may create opportunities for upstream regulated assets to reduce input prices for their downstream operations. I provide the example of a refiner and pipeline owner in the U.S. crude oil market. During 2011, the configuration of the firm's pipelines was inconsistent with maximizing pipeline profits. However, by reducing input prices for the firm's refineries, the inefficient pipeline operation was consistent with profit maximization for the integrated firm. Changes to pipeline regulation, either through vertical separation or through market-based pricing, may enhance the efficiency of oil transportation networks.

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# 1 Introduction

An important component of restructuring in regulated industries is the vertical separation between competitive segments and those segments that continue to be regulated. The break-up of AT&T in 1984 separated regulated local telephone networks from competitive long-distance service (Joskow and Noll, 1999). In the electricity industry, generation firms in newly-formed competitive markets are separated from regulated transmission networks. This is because of the perceived risk that firms will build and operate their transmission network in a way that favors their own generation plants, at the expense of competing generators (Joskow, 1997).

Vertical integration is common in the oil industry. Most major oil firms own upstream exploration and production as well as downstream refining and distribution assets. In the United States, only one segment of the oil industry—interstate oil pipelines—is subject to economic regulation, by the Federal Energy Regulatory Commission ("FERC").[1] FERC approves tariff schedules and ensures that shippers have equal access to pipelines. However, it has no jurisdiction over pipeline construction, maintenance and safety.

I show how integrated firms can control their pipelines to benefit their upstream or downstream operations. Although FERC regulates pipeline rates, it does not regulate other characteristics of pipeline operation, such as the flow direction. Reversing the flow of a pipeline is an expensive process requiring several months of downtime and equipment upgrades. Where there are capacity constraints in the pipeline network, the flow direction of a single pipeline can have large local market effects for oil producers and oil refiners. This means that a vertically integrated firm may choose to operate its pipelines in an inefficient manner in order to benefit its other facilities. This was the concern that led to separation between generation and transmission in the electricity industry.

In this paper I analyze this theoretical possibility using the example of the Seaway oil pipeline, a major north-south pipeline that links the U.S. Gulf Coast to the Midwest oil hub at Cushing, Oklahoma. From 1996 until 2012, this pipeline carried crude oil from production facilities and import terminals in the Gulf Coast to refineries in the Midwest. There was a need to transport oil north from the coast because oil production in the Midwest was much lower than refinery demand. However, starting around 2010, technological innovation in the drilling industry led to a large increase in oil production in the northern U.S., particularly in the Bakken Shale region of North Dakota. This new production, combined with increased oil

[1] All parts of the industry are subject to environmental and safety regulation, at both federal and state levels.

imports from oil sands production in Alberta, exceeded the refinery capacity in the Midwest and created an oil glut at the Cushing hub.

The excess supply of oil at Cushing led to an unprecedented separation in the crude oil price between the Midwest (West Texas Intermediate, WTI) and the Gulf Coast (Light Louisiana Sweet, LLS). At its greatest extent in September 2011, the WTI price was $29.75 per barrel below the LLS price. The Seaway pipeline was the only major pipeline connecting the two regions. Throughout 2011, the pipeline was configured to flow from south to north—from the high-price region to the low-price region. Thus, there was little reason for any shipper to use the pipeline, and pipeline flows were minimal. If the pipeline had instead been configured to flow from north to south, it would have immediately been used to capacity, as shippers sought to exploit the arbitrage opportunity between oil prices in the two regions. This would have caused the WTI and LLS prices to at least partially converge.

In 2011 the Seaway pipeline was jointly owned by ConocoPhillips, a major U.S. oil production and refining company, and Enterprise Products Partners LP, a pipeline company.[2] The pipeline owners could choose how to configure the pipeline, including the direction of flow. Given the extreme price differential, if the pipeline owners had been acting to maximize pipeline profits, they would have reversed the pipeline flow immediately. Indeed, there was disagreement between the two owners about how to operate the pipeline. In November 2011, the chief executive of Enterprise said that the company had "been trying to convince ConocoPhillips to reverse it" (Gold et al., 2011).

ConocoPhillips benefited from not reversing the pipeline flow because, unlike Enterprise, it was a vertically integrated company with both pipeline and refining operations. Although not reversing the pipeline did not maximize pipeline profits, it did keep downward pressure on the WTI price by maintaining the excess supply in Cushing. This was beneficial for ConocoPhillips because the WTI price determined the cost of inputs for many of its oil refineries. In effect, the vertically integrated ConocoPhillips was able to use its control of the Seaway pipeline to exercise monopsony power in the U.S. crude oil market. The profitability of this strategy was implicitly acknowledged by the company in March 2011, when its chief executive said, "in terms of reversal of the Seaway line, we don't really think that's necessarily really in our interest" (DiColo, 2011).

This strategy was extremely profitable for ConocoPhillips even though most of its refining capacity was located in the Gulf Coast, not the Midwest. The WTI price was the benchmark

[2] Enterprise acquired its 50 percent stake in the Seaway pipeline in 2009, when it acquired Teppco Partners LP (Casselman and Buurma, 2009). Teppco had acquired its stake from ARCO in 2000 as part of an antitrust settlement that enabled BP Amoco to acquire ARCO (Labaton, 2000).

price for a large share of global oil trade. This meant that even in its Gulf Coast refineries, a fraction of the oil inputs used by ConocoPhillips were benchmarked to WTI and may have benefited from the lower price.

This situation could not last indefinitely. Oil producers shifted away from pricing the output using the WTI benchmark, reducing the potential gains to refineries. More importantly, alternative pipelines were proposed that would have bypassed the Seaway pipeline. This would have reduced the pricing advantage for ConocoPhillips' refineries and diminished the value of its pipeline. In November 2011, ConocoPhillips announced the sale of its stake in the pipeline.[3] The new owners completed the reversal of the pipeline in May 2012 and since then have greatly expanded its capacity. Despite the reversal, continued increases in supply from the northern U.S. have maintained the price differential, although it has never returned to its level when ConocoPhillips owned the pipeline.

In this paper I empirically analyze the decision by ConocoPhillips to delay the pipeline reversal. I construct the difference in profits for ConocoPhillips under a counterfactual scenario in which it had allowed the Seaway pipeline to be reversed one year earlier. This requires an estimate of how pipeline profits and refinery profits would have changed. One estimate of the foregone pipeline profits can be obtained from the pipeline revenues observed in the year after the reversal occurred. These suggest that ConocoPhillips gave up about \$200,000 per day in pipeline profits from not reversing the pipeline.

A more challenging exercise is estimating the change to crude oil input prices under the counterfactual scenario. Observed WTI and LLS oil prices are an equilibrium outcome from the complex interaction of global oil supply and demand. Rather than attempt to model the entire market, I use an event study framework to recover an estimate for the effect of the Seaway pipeline on the WTI-LLS price difference. The primary event that I use is the announcement by ConocoPhillips of the sale and reversal of the pipeline. This was associated with fall of between \$3.32 and \$7.52 in the WTI price.

I then use monthly EIA data on the price of crude oil purchases in order to estimate the passthrough of WTI prices to refinery input costs. These are essentially one-to-one for the Midwest region. In the Gulf Coast, approximately 43 percent of WTI price changes

[3]On July 14, 2011, ConocoPhillips announced its plan to spinoff its pipeline, refining and marketing operations into a separate company (`http://www.conocophillips.com/newsroom/Pages/news-releases.aspx?docid=1771315`). The exploration and production business kept the ConocoPhillips name and the new refining and marketing company was called Phillips 66. The spinoff was completed on April 30, 2012. This paper focuses on the 2011 period when the company was still integrated and I refer to it throughout as "ConocoPhillips", although most of the analysis is about the refining and pipeline operations that are now known as "Phillips 66".

were passed on in refinery input costs over the period 2004 to 2013. These lower input costs may not be reflected in higher profits if output prices also change. However, Borenstein and Kellogg (2014) show that the lower crude oil prices in the Midwest were not reflected in gasoline prices. This was because the refined products transportation network, unlike the crude oil network, was not constrained during this period.

Overall the results suggest that ConocoPhillips' refineries in the Midwest alone had approximately \$2 million per day in higher profits because of the delay in reversing the pipeline. This was much higher than the potential pipeline profits that the firm gave up. As an independent pipeline owner, ConocoPhillips would have reversed the pipeline flow immediately. However, as a vertically integrated firm, the profit-maximizing strategy for ConocoPhillips was to delay the pipeline reversal and, by doing so, push down the input costs for its refineries.

Although I study the example of a single pipeline and refinery owner, this example is of general interest for several reasons. First, it provides an empirical demonstration of the potential market power consequences of vertical integration between infrastructure assets and downstream purchasers. This has been a long-standing concern for antitrust authorities. Flexner (1979) described the theoretical possibility: "The incentives of an independent pipeline company thus differ from those of a vertically integrated pipeline company, which seeks to maximize overall profits, not just transportation profits... if a vertically integrated pipeline owner is a significant buyer in the upstream market, and if the pipeline owner has market power upstream, the owner may have an incentive to limit throughput to depress the upstream market price." (p.7).[4] The Department of Justice was concerned that vertically integrated firms could achieve this through deliberate undersizing of the pipeline capacity. Erickson et al. (1979) regarded this as implausible because such a strategy would lead to entry by new pipelines. The model in this paper is a variant of the undersizing model, but for a reversible decision on pipeline direction instead of an irreversible decision on pipeline capacity.

This study also provides suggestive evidence about the potential to profit from distortions in pricing benchmarks. The profitability of the strategy to not reverse the pipeline was enhanced by the WTI price being used as a benchmark for oil purchases in other locations,

[4]The same theoretical possibility was described for electricity transmission networks by Joskow and Tirole (2000), in the case where monopsonist consumers own physical rights to use the transmission network: "Buyers located in an exporting region may try to exploit a physical rights system by engaging in collective action to withhold export rights in order to drive the local price for power down below competitive levels." (p.474).

not just the Midwest. Many transactions are priced using the WTI benchmark, but these do not affect the supply and demand equilibrium that determines the WTI price. Instead, as discussed by Fattouh (2011), the WTI spot price is set in a small and illiquid market, although spot transactions in this market are usually priced using the NYMEX WTI futures price as a reference. Manipulation of other pricing benchmarks—most notably LIBOR—has been widely reported. In 2013, the European Commission began an investigation into the price reporting agency Platts to assess whether manipulation of crude oil benchmarks had occurred. The apparent ease of manipulating the price benchmarks and the large potential profits that can be achieved by doing so suggest that proposals to replace the benchmarks with more transparent pricing mechanisms may have merit.

Finally, this study contributes to the existing analyses of the post-2010 separation between oil benchmark prices. Buyuksahin et al. (2013) find that both physical variables (such as storage utilization) and financial variables (such as aggregate futures positions) predict the discount of WTI with respect to Brent. Omar (2014) studies the effect of production outages and other supply disruptions on the price differential between WTI and Brent. Kao and Wan (2012) argue that WTI was surpassed by Brent in 2004 in terms of its ability to reflect market conditions, although Elder et al. (2014) use higher frequency data and find a continuing dominant role for WTI. This previous literature does not focus on the industrial structure of the oil industry and its relationship to benchmark prices.

Section 2 provides relevant background on the oil industry. In Section 3 I provide a stylized model of the pipeline configuration decision, for an independent and a vertically integrated pipeline owner. Section 4 provides an empirical analysis of this decision for the Seaway pipeline in 2011-12. Section 5 discusses the policy implications of these findings.

# 2 Institutional background

## 2.1 Pipeline regulation

Federal regulation of oil pipelines in the United States began with the Hepburn Act of 1906. This law gave the Interstate Commerce Commission the ability to set maximum rates for common carriers. It also extended the common carrier definition to include oil pipelines. This meant that oil pipelines were required to provide non-discriminatory service at just and reasonable rates to anyone who wanted to transport oil.

An important feature of the Hepburn Act was the exclusion of oil pipelines from the "commodities clause". This was an amendment that prohibited common carriers from owning the commodities that they were transporting. If this had been applied to oil pipelines, then vertical integration between pipelines and producers or refiners would have been barred. Instead, the Hepburn Act created a curious regulatory situation for oil pipelines: although they could be owned by an integrated firm, they could not provide preferential access for their own firm's products. This regulatory structure has remained essentially unchanged for more than a century.

Oil pipeline tariffs were regulated by the Interstate Commerce Commission until 1977, when jurisdiction was passed to FERC. Compared to other industries, price regulation for oil pipelines is regarded as relatively "light-handed". Four different methodologies are available for setting rates (Regulatory Economics Group, LLC, 2009). Cost-of-service rates are set to recover operating expenses (including depreciation) plus an allowed rate of return on inflation-adjusted historic costs. Settlement rates can be set at any level that is agreed to by the pipeline owner and the pipeline user. Indexed rates are adjusted each year based on an inflation index set by FERC. Finally, pipeline owners can apply to use market-based rates. These require the firm to demonstrate that they have no significant market power in the origin or destination markets.

FERC's involvement in the regulation of oil pipelines is limited to information disclosure and price regulation. Federal regulatory approval is not required to build a new oil pipeline, to reconfigure or expand the capacity of an existing pipeline, or to shut down a pipeline.[5] Safety aspects of pipeline construction and operation are regulated by the Pipeline and Hazardous Materials Safety Administration within the U.S. Department of Transportation. State-level approvals will also be required for pipeline construction, although these will also typically be focused on safety and environmental issues.

The regulatory status of oil pipelines is the complete opposite to that of natural gas pipelines. These were specifically excluded from the Hepburn Act and remained unregulated until the Natural Gas Act of 1938. Natural gas pipelines are treated as private carriers, not common carriers, so that existing pipeline customers have priority over new customers. Capacity rights to pipelines can be traded among shippers. All new natural gas pipelines need to be approved by FERC. Although the Natural Gas Act did not extend the commodities clause to natural gas pipelines in 1938, FERC effectively did so in 1992. Makholm (2012) compares the end result of the different regulatory approaches for oil and natural gas pipelines: "Somehow, contrary to the persistent vertical integration in the oil pipeline

[5] The widely-reported case of the proposed Keystone XL pipeline required State Department approval only because it crossed an international border.

industry, gas pipeline transport transformed over the course of sixty-five years into an industry that exhibits true Coasian bargaining in transport entitlements and supports the world's only vigorously competitive and openly transparent gas market with an equally vigorous futures market." (p. 119).

## 2.2 Pipeline reversals

Supply and demand shifts in energy markets create incentives to alter the configuration of pipeline networks. Changes may include increasing pipeline capacity, changing the flow direction, or even switching the product carried between crude oil, refined products, and natural gas. Many pipelines in North America have been reversed or changed service multiple times.

Unlike electricity transmission networks, oil pipelines are normally designed to be unidirectional. The optimal pipeline size, wall thickness, and pumping station locations are determined from hydraulic calculations based in part on the topography of the pipeline route (Miesner and Leffler, 2006). The optimal design will be different for a pipeline running uphill than for a pipeline running downhill. Reversing the flow direction requires emptying the pipe, redesigning and possibly relocating the pumping stations, and reconfiguring connections at both ends of the pipeline (Hull, 2005).

Flow reversals can affect the integrity of the pipeline. The pressure gradient and the location, magnitude and frequency of pressure surges will change (Pipeline and Hazardous Materials Safety Administration, 2014). Two crude oil pipelines—the High Plains Pipeline in North Dakota and the Pegasus Pipeline in Arkansas—failed after their flow was reversed, in both cases leading to major oil spills. Leak detection and pipeline monitoring systems need to be adjusted for the new flow direction. In many cases, the PHMSA recommends additional integrity tests before reversed pipelines are restarted.

Depending on the number of modifications that are required, the cost and time requirement for a flow reversal project can be high. For the Seaway pipeline, about \$45 million in capital expenditure was reported during the three quarters up to and including the initial pipeline reversal (Figure 2).[6] The Longhorn pipeline, running from west Texas to Houston, was converted to crude oil and reversed in 2013, at a cost of about \$375 million for the

[6]The high capital expenditure in the figure after the flow reversal reflects pumping station additions that increased the capacity from 150,000 to 400,000 barrels per day, followed by the construction of a parallel pipeline that further increased the capacity to 850,000 barrels per day. The capital expenditure in the second quarter of 2012 may include some of the cost for these expansion projects. This suggests that \$45 million is an upper bound on the cost of the initial pipeline reversal.

initial phase (Hays and Choy, 2015). Further capital expenditure would be required if the pipeline is subsequently returned to its original configuration. For example, the Enbridge Line 9 pipeline between Sarnia and Montreal was built in 1976 flowing from west to east, reversed in 1998, and is currently being reversed to its original direction at a cost of $400 million (Dawson, 2014).

## 2.3 Crude oil prices

Most physical transactions of crude oil are organized through long-term contracts between buyers and sellers (Fattouh, 2011). These contracts specify the delivery date, location, and volume, as well as a formula for calculating the price. Prices are usually set as a differential to a benchmark price that can be observed on the date of delivery. The pricing differential reflects both locational factors and differences in the quality of the crude oil.

The two most widely used benchmark prices are WTI and Brent. The Brent spot prices are based on transactions of waterborne crude from the North Sea, which can be transferred to tankers for shipment to refineries in Europe or even the U.S. The WTI spot market is based on transactions of crude for delivery in Cushing, Oklahoma. Several major crude oil pipelines converge at Cushing and large oil storage facilities are located there.

Benchmark pricing has enabled the development of a liquid futures market around the WTI and Brent prices. The volume of futures transactions far exceeds physical deliveries of WTI and Brent oil. Nevertheless, these physical transactions have considerable influence on the world oil market. Price reporting agencies such as Platts and Argus collect information from market participants about their transactions, which they use to calculate an assessed benchmark price each day. Local infrastructure constraints, particularly at the Cushing hub, affect the WTI spot price and feed through to the pricing of other transactions that use this benchmark.

The price formation process in the crude oil market is complex from both theoretical and empirical perspectives. Most commodity futures contracts allow the holder to take physical delivery of the underlying commodity at expiration, so the possibility of arbitrage should ensure that the futures price converges to the spot price. Conversely, in the opaque and illiquid spot market, the pricing for most physical transactions is based on the publicly observable futures price.

# 3 Model

In this section I provide a highly stylized model of the decision by a profit-maximizing oil pipeline owner about the configuration of its the pipeline operation, in particular, the choice of flow direction. I show how ownership of the pipeline affects this decision. In particular, the choice for a pipeline owned by a refiner in an exporting region may be different from the choice by an independent pipeline owner.

## 3.1 Independent pipeline owner

The oil pipeline has capacity $F$ for transportation in either direction between the north region $N$ and south region $S$, measured in barrels per day. The pipeline owner can charge independent shippers a maximum regulated price $R_{max}$ for use of the pipeline, measured in dollars per barrel transported. Marginal cost for transportation by the pipeline is assumed to be zero.

The pipeline owner has two decision variables: the price to charge shippers $R$ and the direction of flow in the pipeline, $N$ to $S$ or $S$ to $N$. If the pipeline is configured from $N$ to $S$, independent shippers will transport quantity $F$ from $N$ to $S$ if the following condition holds:

$$P^N + R \leq P^S$$

In this case profit for the pipeline owner is $RF$. If this condition does not hold, independent shippers will transport zero.

Clearly, if $P^N < P^S$, the profit-maximizing choice for an independent pipeline owner will be to configure the pipeline from $N$ to $S$ and set the price equal to:

$$R = \min(R_{max}, \max(0, P^S - P^N))$$

That is, the pipeline owner will extract the arbitrage profits from the difference in prices between the two regions, up to the maximum rate that the regulator allows.

Conversely, if $P^S > P^N$, the pipeline owner will configure the pipeline from $S$ to $N$ and set the price $R$ accordingly.

## 3.2 Independent refinery owner

The oil refinery in the north has input capacity $K$, measured in barrels per day. The price that the refinery receives for its output, $P_G^N$, is determined exogenously and is not affected by the crude oil price in the north. The price that the refinery pays for its crude oil input is $P^N$. Although the refinery could act as an oligopsonist by reducing its crude oil input in order to reduce the input price $P^N$, the refinery is assumed to operate at its full capacity $K$. Other variable production costs are $c$.

The daily profit of the independent refinery is given by:

$$\Pi = K(P_G^N - P^N - c)$$

## 3.3 Integrated refinery and pipeline owner

As a standalone operation, the refinery is assumed to be unable to affect the price of its crude oil input $P^N$. However, when combined with the pipeline, the integrated firm is able to affect crude oil input prices through the configuration of its pipeline operation.

Figure 1 shows a stylized model of the crude oil market with two regions. For the north, demand for crude oil from oil refineries is given by the curve $D^N$. At low prices, crude oil demand is nearly vertical due to capacity constraints at the oil refineries in the region.

Supply of crude oil from oil producers in the north is given by the curve $S_1^N$. At high prices, crude oil supply is nearly vertical because of short-term capacity constraints on oil production. The equilibrium price of crude oil in the north, before considering potential imports or exports, is $P_1^N$.

The right figure shows the crude oil market in the south. The equilibrium price of crude oil in the south, before considering potential imports or exports, is $P_1^S$. There is a pipeline with capacity $F$ between the two regions. As the figures are drawn, $P_1^N < P_1^S$. If the pipeline is configured to flow from south to north, no independent shippers will choose to send oil from the high-price region to the low-price region. So the prices in both regions would not change.

Conversely, if the pipeline is configured to flow from north to south, independent shippers will send the full pipeline capacity $F$ from the low-price to the high-price region. This will cause the local supply curve for oil in the north to shift in, from $S_1^N$ to $S_{1X}^N$, raising the price of oil in the north from $P_1^N$ to $P_{1X}^N$. The local supply curve for oil in the south will shift out, from $S_1^S$ to $S_{1M}^S$. However, the size of the market in the south is assumed to be an order of magnitude larger than in the north, so the effect on the southern price of the additional imports is negligible.

I now consider the decision on pipeline configuration for an integrated northern refiner and pipeline owner. The price difference between the two regions is assumed to be large enough for the regulated price on pipeline shipments, $R_{max}$, to be binding.

If the firm configures the pipeline from south to north, no oil will be transported along the pipeline, so pipeline profits are zero. Total daily profits for the firm are:

$$\Pi(S \text{ to } N) = K(P_G^N - P_1^N - c)$$

If the firm configures the pipeline from north to south, $F$ barrels of oil will be transported along the pipeline, so pipeline profits will be $R_{max}F$. Total profits for the firm are:

$$\Pi(N \text{ to } S) = R_{max}F + K(P_G^N - P_{1X}^N - c)$$

The firm will choose the direction of pipeline flow by comparing these two profit expressions. The pipeline will be configured to flow from south to north if:

$$\begin{aligned} K(P_G^N - P_1^N - c) &\geq R_{max}F + K(P_G^N - P_{1X}^N - c) \\ K(P_{1X}^N - P_1^N) &\geq R_{max}F \end{aligned}$$

That is, if the reduction in refinery input costs exceeds the revenue from operating the pipeline, it is more profitable to leave the pipeline unused. Otherwise the integrated firm will configure the pipeline to flow from north to south, and it will be used to capacity.

For simplicity, the model described above is static. In practice, there will be a large fixed cost associated with pipeline reversal, which can be recovered over time from higher pipeline profits. The reversal decision will depend on the net present value of the stream of future profits from the reversed pipeline. These, in turn, will depend on expectations about future oil prices and volumes.

# 4 Empirical analysis

In this section I describe the empirical analysis I use to estimate profits of the combined pipeline-refinery owner and the counterfactual profits of the two segments in the absence of vertical integration. I show that the delay in the reversal of the Seaway pipeline reduced daily pipeline profits in 2011 by about $0.2 million. The capital cost associated with the reversal of the pipeline could have paid for itself in less than 4 months. However, by delaying the pipeline reversal, profits of the ConocoPhillips' refineries in the Midwest alone were about $2 million per day higher in 2011 than they would have been otherwise. The most plausible explanation for the delay in reversing the pipeline flow was the potential for ConocoPhillips to increase its overall profit.

## 4.1 Pipeline profits

Revenues for pipeline owners depend on the volume shipped and the regulated rate per barrel. Pipelines submit their proposed rates to FERC for approval (Section 2.1). Oil shippers with access to the pipeline pay these predetermined rates and earn profits based on the price differential between the two ends of the pipeline. If local supply and demand conditions create a higher price at the start than at the end of the pipeline, there is little incentive to use it. This would lead to low volumes and revenue for the pipeline owner.[7]

One solution to overcome unfavorable price differentials is to reverse the pipeline, so that the higher commodity price is at the end rather than the start of the pipeline.[8] Flow reversal is a potentially expensive investment that requires the pipeline to be out of service for several months (Section 2.2). Returning to the original flow direction may also be costly. As a result, it is not worth reversing the pipeline flow to take advantage of a short-term arbitrage opportunity. The flow reversal decision depends on expectations about future supply and demand conditions in the crude oil market and their effect on flow volumes.

For the Seaway pipeline, flow reversal had two potential effects on revenue: an increase in the rate per barrel as well as an increase in the volume shipped. The previous rate to ship crude oil from the Texas Gulf Coast to Cushing was $1.10 per barrel in 2010 (Federal Energy Regulatory Commission, 2010). For the reversed pipeline, the rate to ship light crude oil from Cushing to the Gulf Coast varies from $2.38 (for 10-year contracts with volumes exceeding 100,000 barrels per day) to $4.00 per barrel (for uncontracted shippers). There was considerable legal uncertainty surrounding these higher rates for the reversed pipeline. FERC did not allow an initial application by the pipeline to set market-based rates. Subsequently, an administrative law judge overturned committed rates that Seaway had negotiated with its major shippers (Prezioso and Zawadzki, 2013). This decision was later reversed by FERC.

[7]Some of the risk around future volumes can be passed from the pipeline owner to the shippers, by the use of fixed-term contracts with minimum volume requirements.

[8]For crude oil pipelines, although FERC approval is required for changes to the rate structure, there is no requirement for approval by economic regulators before reversing the pipeline flow.

In terms of pipeline volumes, it was clear by the start of 2011 that a structural change had taken place in the North American oil market. Figure 5 plots the time series of the WTI-Brent futures price differential, at 1-month, 12-month and 24-month horizons, from 2010 to 2013. During 2010, even though the spot price differential sometimes reached \$5/barrel, the one and two-year futures price differentials remained close to zero. This began to change in January 2011. The one-year futures price differential reached \$5/barrel on February 14, 2011 and remained above that level thereafter.

As illustrated by the figure, after February 2011 market expectations were that the price differential would exceed \$5/barrel for at least the following two years. This was even true after the eventual announcement of the pipeline reversal. Given the price differential that existed throughout 2011, the Seaway pipeline owners could have anticipated that the full capacity of the pipeline would have been used if it were reversed earlier. The long-term futures price differential suggest that the higher pipeline volumes would not just be a temporary effect.

This discussion is supported by the observed financial performance of the Seaway pipeline before and after it was reversed. Pipeline revenues fell from an average of \$175,000 per day in 2009 to \$60,000 per day in 2011 (Figure 3).[9] This reflects a large decline in pipeline use following the divergence between the WTI and LLS prices in 2010. Once the pipeline flow was reversed in May 2012, revenues were over \$500,000 per day at the end of 2012. Assuming the pipeline was used to capacity, the fourth quarter revenues in 2012 imply an average price received of \$3.52 per barrel shipped, consistent with the rate schedule.[10]

## 4.2 Effect of Seaway pipeline on WTI-LLS spread

Before 2011, the Brent and WTI crude oil spot prices remained very close to each other (Figure 7). The difference between them was rarely more than \$5 (Figure 8). Starting in January 2011 the prices began to diverge. This divergence increased throughout 2011 until it reached an all-time high of \$29.75 in September 2011.

The relevant question for the current analysis is the extent to which the price divergence would have been reduced if the Seaway pipeline had been operating from north to south during 2011. One methodology to calculate this counterfactual value would be to estimate a structural model of regional crude oil demand and supply for the United States. Such

[9]This data is from the FERC Form 6 Annual and Quarterly Report data for the Seaway pipeline. Note that ConocoPhillips owned a 50 percent stake in the pipeline, so its share of pipeline revenues and earnings was 50 percent of the totals shown in the graphs.

[10]Both the shipment rate and the pipeline capacity will differ based on the grade of oil.

a model would need to account for capacity constraints in production, transportation, and consumption (refining), as well as the interaction between physical, futures, and storage markets. Constructing and estimating such a model would be a challenging exercise.

Instead, I take advantage of the observed change in oil price differentials after the announcement that the pipeline would be reversed. On November 16, 2011, the Canadian pipeline company Enbridge announced its acquisition of the 50 percent shareholding in the Seaway pipeline owned by ConocoPhillips. At the same time, Enbridge and the other 50 percent shareholder Enterprise Products Partners announced their plan to reverse the flow of the pipeline and subsequently expand its capacity. The price differential between the WTI and Brent benchmarks fell from \$16.48 on November 9, 2011, one week before the announcement, to \$8.49 after the announcement.[11] The pipeline reversal and its effect on oil price differentials were widely reported in the financial press. Antoine Halff, an economist at the Energy Information Administration, suggested that it would resolve the bottleneck and "cause inventories to rebalance and prices to realign between inland and coastal locations".[12] JP Morgan, an investment bank, raised its forecast of the WTI price for the following year by \$12.50/barrel after the pipeline reversal announcement.[13]

I formalize the anecdotal evidence from oil market analysts and commentators using an event study of oil prices around the time of the pipeline reversal announcement. The change in the WTI price on day $t$ is written as:

$$\Delta P_t^N = \alpha + \beta \Delta P_t^S + \gamma Event_t + \varepsilon_t \tag{1}$$

where $\Delta P_t^N$ is the difference between the WTI prices on day $t$ and day $t-1$, $\Delta P_t^S$ is the difference between the Light Louisiana Sweet (LLS) price on day $t$ and day $t-1$, and $Event_t$ is a dummy variable scaled by the length of the event window.[14] The coefficient $\gamma$ is interpreted as the cumulative increase in the WTI price at the time of the pipeline announcement, after controlling for changes in the LLS price.[15]

[11]Oil price benchmark data are from Bloomberg.

[12]Quoted in Meyer, Gregory, "US crude hits \$100 on pipe plan", *Financial Times*, November 17, 2011.

[13]Farchy, Jack, "Crude supply switch triggers US oil recovery", *Financial Times*, November 18, 2011.

[14]I consider an event window 1 day, 1 week, and 2 weeks either side of the announcement date of November 16, 2011, including the day of the announcement itself. These event windows have 3 trading days, 11 trading days, and 21 trading days respectively. Adapting the framework from Bushnell et al. (2013), the $Event_t$ variable will be equal to 1/3, 1/11, and 1/21 for the days in each respective event window, and zero otherwise.

[15]The interpretation of $\gamma$ as a causal effect of the Seaway pipeline announcement requires the absence of any other event occuring at the same time that affects the WTI price but not the LLS price. One possible confounding event was a statement to investors on the same day by TransCanada executives that they were considering splitting their Keystone XL pipeline project into two phases, constructing the Cushing to

The estimated $\gamma$, corresponding to the cumulative increase in the WTI price at the time of the pipeline announcement, was \$7.52 per barrel for the 21-day event window (Column 3, Table 1). Results for the 3-day and 11-day event windows were smaller, though still positive and statistically significantly different from zero. Columns 1 through 3 in the table use only the daily change in the LLS price to predict the change in the WTI price. Columns 4 through 6 also include the daily change in the Brent price. In this specification the increase in the WTI price is even greater.

### 4.3 WTI and refinery input prices

The decision not to reverse the Seaway pipeline earlier meant that the WTI price—the price of crude oil in the Midwest—was lower than it would otherwise have been in 2011. The refining operations of ConocoPhillips benefited to the extent that they could acquire oil at this lower price. However, as shown in Table 2, only three out of the firm's twelve refiners, comprising 21 percent of its net refining capacity, were located in the Midwest. The largest share of ConocoPhillips' refining capacity (37 percent) was located on the Gulf Coast.

Although only a small proportion of its crude oil inputs were acquired in the Midwest, ConocoPhillips' other refineries could also benefit from the low WTI price. This is because the WTI price acts as a benchmark price for many transactions in the world oil market, even when there is no physical connection to supply and demand in the Midwest. In particular, many oil producers sold their product under forward contracts in which the price paid on delivery of the oil was linked to the WTI price at the delivery date. This meant that ConocoPhillips could reduce the input price, not just for the three refineries in the Midwest region, but for all refineries at which the input price was linked to the WTI benchmark.

I analyze the extent to which crude oil input prices depend on the oil benchmark prices. From publicly available data, I have the monthly average crude oil acquisition cost aggregated across refineries in a PADD region, separated by domestic and imported purchases. I write the change in this acquisition cost in month $t$ as shown in Equation (2):

$$\Delta P_t = \alpha + \beta_1 \Delta P_t^{WTI} + \beta_2 \Delta P_t^{LLS} + \varepsilon_t \tag{2}$$

Houston leg first while awaiting approval from U.S. regulatory authorites for the Alberta to Cushing leg (Penty, Rebecca, "Crude eclipses \$100 on pipeline plans; Tackling Oil Transportation Glut; Bids to increase capacity reduce U.S. oil discount", *The Calgary Herald*, November 17, 2011). This proposal contained fewer details and was considerably more uncertain than the Seaway pipeline reversal announcement. Most of the financial press focused on the Seaway pipeline announcement as the cause of the narrowing in oil price differentials.

In this equation, $\Delta P_t^{WTI}$ is the change in the monthly mean WTI benchmark price and $\Delta P_t^{LLS}$ is the change in the monthly mean LLS benchmark price.

The results from the estimation in Equation (2) are shown in Table 3 for imported prices and Table 4 for domestic prices. In the East Coast region (PADD 1), the price paid for imported oil does not depend at all on the WTI benchmark.[16] In the Midwest region (PADD 2), I cannot reject a one-for-one relationship between changes in the WTI price and changes in imported crude oil input prices. Most importantly, for the Gulf Coast region (PADD 3), both WTI and LLS benchmarks affect import prices approximately equally. The relationship between the WTI benchmark and input prices in this region is even stronger for domestic crude oil purchases. The WTI benchmark also appears to be strongly correlated with input price changes in the western part of the U.S. (PADD regions 4 and 5).

It is important to note that these results are based on aggregate input prices at all refineries, not just ConocoPhillips. They provide suggestive evidence that ConocoPhillips could benefit from lower WTI prices, not just for its refineries located near the Cushing pipeline hub, but also for refineries in other regions. The exact extent to which WTI prices affect input prices for ConocoPhillips could be larger or smaller than the pass-through estimates in Tables 3 and 4.

The losers in this situation are the oil producers who are selling their output at a lower price than the market price in the region of sale. It seems unlikely that this could persist over the long term. Instead, oil producers would prefer to shift their contracts away from the WTI benchmark to alternative benchmarks that better reflect market conditions in the region of sale. Anecdotal evidence suggests that this was exactly the response of many oil producers. Such a change would have greater reduced the incentives for ConocoPhillips to keep the WTI price low.

## 4.4 WTI and refinery output prices

The previous section showed that the reduction in the WTI benchmark price reduced crude oil input costs for refineries in both the Midwest and Gulf Coast. However, if these lower costs were completely passed through to output prices, there would be no net effect on refinery profits.

I replicate the analysis in Borenstein and Kellogg (2014) for the geographic regions and

[16] It is not possible to run the PADD 1 regression for domestic oil purchases because the publicly available data has many missing observations, reflecting the relatively low proportion of domestic purchases by East Coast refineries.

time period used in Section 4.3. The estimation equation is the same as Equation (2). However, instead of using the change in refinery input costs as the dependent variable, I use the change in monthly PADD-level wholesale prices received by refiners for their two major products: gasoline and diesel.[17]

In all five PADD regions, I do not reject a one-for-one passthrough from the LLS crude oil price to the wholesale gasoline price (Table 5). By contrast, the passthrough from the WTI price to wholesale gasoline prices is not significantly different from zero in every PADD region. For diesel, the point estimates for the passthrough from WTI to wholesale diesel prices are positive (between 0.07 and 0.21), although not significantly different from zero at a five percent level (Table 6).

These results imply that the lower WTI prices due to the Seaway pipeline not being reversed had almost no effect on refined product prices. Instead, refinery profits increased by almost the full amount of the reduction in crude oil input costs. Borenstein and Kellogg (2014), who show this result for gasoline and diesel prices in the PADD 2 region, explain that it is due to differences in infrastructure constraints between crude oil and refined products. Unlike crude oil, there were few bottlenecks in the refined product distribution network. Because arbitrage was possible for refined products, gasoline and diesel prices were determined in an integrated market based on international crude oil prices.

### 4.5 Counterfactual analysis of pipeline reversal decision

In this section I combine the previous analyses to investigate the profitability of the decision to delay reversal of the Seaway pipeline. The objective is to calculate the change in the profits for ConocoPhillips if, **counter to fact**, the Seaway pipeline had been reversed in 2011. Earlier reversal of the pipeline would have increased the profits from the pipeline operations, suggesting that reversal would have been an obvious decision for an independent pipeline owner. However, for the integrated firm, these higher profits from the pipeline would have been more than offset by lower profits from the refining operations. This strongly suggests that the decision to delay reversal was profit-maximizing, not for the standalone pipeline, but only for the vertically-integrated firm.

Table 7 shows the parameter assumptions required for the calculations. Table 8 summarizes the effect of the pipeline reversal on daily profits. These calculations use a combination

[17]Gasoline and diesel prices are reported in dollars per gallon (excluding taxes). For consistency with the oil prices, I convert these to dollars per barrel, using the conversion factor of 42 gallons = 1 barrel. In 2014, the average U.S. refinery produced 12 gallons of diesel and 19 gallons of gasoline from each barrel of crude oil, along with many other petroleum products.

of all of the results from Tables 1 to 6. I combine the individual estimation equations in a Seemingly Unrelated Regression framework and use the delta method to calculate standard errors for the profit results, which are a nonlinear combination of the regression coefficients.

The first line of Table 8 shows that flow reversal would have increased pipeline profits for ConocoPhillips by $0.244 million per day. This is calculated using the assumptions that pipeline capacity utilization increased from 0 percent to 100 percent after the reversal, the tariff rate was $3.25 per barrel, and there was no change in operating costs. The result is slightly higher than the observed change in Seaway pipeline profits after the reversal.[18]

The second line in Table 8 shows the effect of reversal on ConocoPhillips' refining operations in the Midwest. Assuming a 91 percent capacity utilization, the daily crude oil input for the firm's share of its Midwest refineries (Table 2) would be 386,000 barrels. The event study analysis in Table 1 shows that the reversal would have increased the WTI price by $6.22 per barrel. The results in Table 4 and Table 3 show how this increase in WTI price would translate into lower refinery crude oil input costs. I use a weighted average of the domestic and import coefficients, with the weights based on the observed import share of total crude oil inputs for the three refineries. I also use a weighted average of the coefficients in Tables 5 and 6 to calculate the (relatively small) effect of the higher WTI price on output prices. Accounting for the effects of the WTI price on input and output prices, profits for the Midwest refineries would have been $2.036 million per day lower if the Seaway pipeline had been reversed earlier.

The profit effect of the pipeline reversal on the Gulf Coast refineries would have been similar in magnitude to the Midwest, even though their input capacity is 73 percent higher. This is because the Gulf Coast refineries rely more on imported crude oil. Based on the results in Table 3, the passthrough from the WTI price to Gulf Coast import prices is smaller. Overall, the profits for ConocoPhillips Gulf Coast refineries would have been $2.272 million per day lower if the pipeline had been reversed earlier.

The discussion assumes that the vertical integration in the firm is between a crude oil pipeline operator and a crude oil refiner. Before 2012, ConocoPhillips contained crude oil exploration and production assets as well as pipeline and refining operations. If the Seaway pipeline had been reversed earlier, the U.S. and Canada production operations would have

[18]From Figure 4, the Seaway pipeline had an average quarterly loss of $2.7 million in 2011. By the last quarter of 2012, after the pipeline was reversed but before the capacity expansion occurred, the Seaway pipeline had a quarterly profit of $36.2 million. The quarterly change in profit was $38.9 million, or $0.427 million per day. Because ConocoPhillips owned a 50 percent share of the pipeline, this would have increased its profits by $0.213 million per day.

benefited from selling their output at a higher price. Column 3 in Table 8 shows that production profits would have increased by $1.281 million per day.[19]

Whether or not to include the potential oil production revenue depends on the internal structure for decision making at ConocoPhillips. The two major segments of the firm were Exploration & Production and Refining & Marketing. In April 2012, ConocoPhillips spun off its pipeline, refining and marketing businesses into a new company called Phillips 66. ConocoPhillips kept the exploration and production operations. If the downstream business was already being operated in 2011 as if it were a separate entity, then executives may not have considered the effect of pipeline reversal on production profits. To be conservative, I assume that their objective was to maximize profits for the combined firm as it was in 2011, including the production segment.

The potential losses for the refining operations outweigh the potential gains from higher pipeline and crude oil production revenue. Overall profits for the integrated firm would have been $2.783 million per day lower in 2011 if the Seaway pipeline had been reversed earlier. Annual profits for the firm would have been $1 billion lower. Thus, it is highly plausible that the reason ConocoPhillips did not allow the pipeline flow to be reversed earlier was because it wished to maximize profits of the integrated firm.

The reported financial results for ConocoPhillips in 2011 provide a useful check on the plausibility of these estimates. The after-tax profit for the firm's U.S. refining and retailing segment was $879 million in 2010. and increased to $2,373 million in 2011.[20] Figure 6 shows the per-barrel refining margins for ConocoPhillips broken down by region.[21] In 2009 and 2010, before the WTI price differential, there was a difference of about $2 per barrel in these margins across regions. By the third quarter of 2011, the refining margin for the Midwest region (PADD 2) had increased to $27 per barrel, more than $20 per barrel higher than the margin in the Atlantic region (PADD 1). This result demonstrates the extremely beneficial effect of the oil price separation—which reduced refining input costs but had little effect on output prices—on refinery profits in the Midwest. The refining margin for the Gulf Coast region (PADD 3) was also much higher than the Atlantic margins during the first three

[19] Crude oil production excludes 215,000 barrels per day in Alaska. The price received for Alaskan crude is linked to international oil prices and not WTI. In 2011, ConocoPhillips received $105.95/barrel for Alaska crude oil compared to $74.09 for crude oil from the lower 48. The average price received for Canadian crude oil was $66.07.

[20] These figures are from the ConocoPhillips Summary of Income by Segment results for 2011.

[21] Margins for the West Coast refineries (PADD 5), not shown on the graph, have a similar pattern to the Gulf Coast margins. The Atlantic results include a refinery in the United Kingdom and a refinery in Ireland, as well as the East Coast refineries shown in Table 2.

quarters of 2011. This result provides supporting evidence that ConocoPhillips' refineries on the Gulf Coast were able to use cheaper crude oil indexed to the WTI price, as discussed in Section 4.3. After the third quarter of 2011, the difference between the PADD 1 and PADD 3 margins was much narrower or even reversed, possibly because many international oil producers were no longer using the WTI benchmark in their sales contracts.

# 5 Policy Implications

The above analysis illustrated how ConocoPhillips, a vertically-integrated oil producer, refiner, and pipeline owner, was able to earn approximately $1 billion in additional profits through inefficient operation of a major pipeline. By not reversing the flow of the Seaway pipeline in 2011, the price differential between the Midwest and the Gulf Coast was larger than it would have been otherwise, reducing the input costs for ConocoPhillips' refineries. The losers from this strategy were the oil producers in the northern U.S. and Canada who received a lower price for their crude oil. Another group of losers were the oil producers in other parts of the world with prices tied to the WTI benchmark. Although most of these losses were transfers from oil producers to oil refiners, there was an overall welfare loss arising from inefficient transportation of oil. While the Seaway pipeline was left unused, more expensive forms of transportation (such as rail car) were used to ship oil south to the Gulf Coast. The failure to reverse the pipeline earlier also led to development of an alternative pipeline plan that was later cancelled.

ConocoPhillips' use of a regulated asset to benefit its downstream operations raises the issue of an appropriate policy response. One possibility would be to follow the example of other industries and require the separation of regulated pipeline assets from upstream and downstream competitive businesses. This would correspond to an extension of the commodities clause in the 1906 Hepburn Act to cover oil pipelines. During the past century, this policy has been suggested many times but never implemented. For example, in 1931, the House Committee on Interstate and Foreign Commerce considered a bill H. R. 16695 with the purpose "to divorce pipe-line companies transporting oil in interstate pipe lines from the oil business, except the transportation of oil." (Pipe Lines, 1931). Nowadays there are several large firms that specialize in oil transportation, storage and logistics, with no upstream or downstream activities. However, many crude oil pipelines are still owned by vertically integrated oil firms. Figure 9 shows the ownership status of crude oil pipelines in the United States. The map shows that integrated firms still own several major pipelines that connect oil producing and consuming regions.

The example of the Seaway pipeline described in this paper is not an isolated case. The Capline pipeline runs from Louisiana to Illinois and has a capacity of 1.2 million barrels per day. Just like the Seaway pipeline before its reversal, the Capline pipeline currently operates from south to north. The oil price differential between the Gulf Coast and the Midwest has led to very low utilization of the pipeline and, at one point, its temporary closure. The pipeline is owned by two integrated firms (Marathon and BP) and an oil transportation firm Plains All American Pipeline. These firms, like ConocoPhillips, benefit from cheaper crude oil inputs as a result of the price differential.

A different policy response would be to reconsider the regulation of oil pipeline rates, at least for major trunk pipelines. There are several competitive alternatives to transportation of oil by pipeline: barge, truck and rail car. Kaminski (2014) said that although rail transportation had been seen as a temporary stop-gap measure, it "has become a permanent feature of the North American oil industry". The tension between these competitive alternatives and the regulated oil pipelines is especially great when there are binding transportation constraints that create price arbitrage opportunities, such as the case of the Seaway pipeline.

After the Seaway pipeline was reversed, the new rates of about \$4 per barrel were still much lower than the prevailing crude oil price differential at the time. In spite of this, the owners faced several years of legal challenges to the rates. Because the pipeline shipment rates were lower than the price difference at both ends, it is unsurprising that there was excess demand by shippers for access to the pipeline. In April 2013, new shippers requested movement of 70 million barrels per day through the pipeline—about 75 percent of total world oil production. This led to the implementation of a lottery system to provide pipeline access for new shippers (Federal Energy Regulatory Commission, 2013).

The regulated rates transfer rents from the pipeline owners to the shippers or speculators who are lucky enough to obtain access to pipeline capacity. If the pipeline owners had been able to set a market price for pipeline access, they would have been able to capture the arbitrage profits. This may have reduced the delay to reversing the pipeline. It may have been profitable for ConocoPhillips to reverse the pipeline in 2011 if it could have earned a 50% share of a \$20 price difference, instead of just the regulated pipeline rate. Given the existence of competitive alternatives, the continued regulation of oil pipeline rates for major pipelines (without a stranded shipper) may be unnecessary and lead to inefficient use of the pipeline network.

# 6 Conclusion

The past decade has witnessed an historic transformation of the oil industry in the United States. Oil production has increased by 75 percent since 2008. A substantial portion of this increase has occurred in places such as North Dakota where production had been very low. This required a reconfiguration of the oil transportation infrastructure in order to move this oil to refineries and the refined products on to consumers.

Despite the technological revolution in oil production, there have been few changes in the economic regulation of the sector. The regulatory framework for oil pipelines is essentially the same as it was in 1906. One result of this is that oil pipelines have been slow to reconfigure their operations to adapt to the changed environment. In this paper, I showed how vertical integration between pipelines and refineries creates an incentive to delay changes to pipeline operation, in order to increase refining profits through lower input costs. This behavior lowers the prices received by oil producers and reduces their incentive to increase oil supply. It also encourages the use of more expensive (and less safe) forms of oil transportation. Alternative approaches to the regulation of the oil pipeline sector would contribute to the continued development of the energy sector in the United States.

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**Table 1:** Effect of Seaway pipeline reversal announcement on WTI price

| | (1) 3 day window | (2) 11 day window | (3) 21 day window | (4) 3 day window | (5) 11 day window | (6) 21 day window |
|---|---|---|---|---|---|---|
| Announcement event | 3.323* | 6.218* | 7.520* | 3.850* | 6.613* | 7.706* |
| | (1.398) | (2.690) | (3.733) | (1.330) | (2.559) | (3.553) |
| Δ LLS Price | 0.795* | 0.795* | 0.793* | 0.567* | 0.569* | 0.568* |
| | (0.015) | (0.015) | (0.015) | (0.026) | (0.026) | (0.026) |
| Δ Brent Price | | | | 0.293* | 0.291* | 0.290* |
| | | | | (0.027) | (0.027) | (0.027) |
| Observations | 1005 | 1005 | 1005 | 968 | 968 | 968 |
| Adjusted $R^2$ | 0.731 | 0.731 | 0.731 | 0.759 | 0.759 | 0.758 |

*Note:* The dependent variable is the daily change in the WTI oil price. The announcement date for the Seaway pipeline divestiture and reversal was 16 November 2011. The event windows comprise one day, one week, and two weeks before and after this event. The sample range is 16 November 2009 to 16 November 2013. Price data are from Bloomberg.

* $p < 0.05$ (two-tailed test for difference from zero).

**Table 2:** ConocoPhillips U.S. refinery capacity in 2011

| Name | Location | Capacity 000 barrels/day | Percent of total |
|---|---|---|---|
| **PADD 1: East Coast** | | | |
| Bayway | Linden, NJ | 238.0 | 11.9% |
| Trainer[1] | Trainer, PA | 185.0 | 9.3% |
| Total | | 423.0 | 21.2% |
| **PADD 2: Midwest** | | | |
| Ponca City | Ponca City, OK | 198.4 | 9.9% |
| Wood River[2] | Roxana, IL | 153.0 | 7.7% |
| Borger[2,3] | Borger, TX | 73.0 | 3.7% |
| Total | | 424.4 | 21.2% |
| **PADD 3: Gulf Coast** | | | |
| Alliance | Belle Chasse, LA | 247.0 | 12.4% |
| Lake Charles | Westlake, LA | 239.4 | 12.0% |
| Sweeny | Sweeny, TX | 247.0 | 12.4% |
| Total | | 733.4 | 36.7% |
| **PADD 4 and 5: West Coast** | | | |
| Billings[4] | Billings, Montana | 58.0 | 2.9% |
| San Francisco | Rodeo, CA | 120.2 | 6.0% |
| Los Angeles | Wilmington, CA | 139.0 | 7.0% |
| Ferndale | Ferndale, WA | 100.0 | 5.0% |
| Total | | 417.2 | 20.9% |

[1] The Trainer refinery was idled in October 2011 and sold to Delta Air Lines in 2012.
[2] ConocoPhillips owned a 50% share in the Wood River and Borger refineries. The capacities reported in the table represent the 50% net share.
[3] Borger is located in the Texas Panhandle. Although this is technically part of the PADD 3 region, for the purpose of the current analysis I consider it part of the Midwest region, because it is connected directly by pipeline to the intercontinental hub at Cushing.
[4] The Billings refinery is located in the PADD 4 region. I report the PADD 4 and PADD 5 refineries together for consistency with the financial reporting by ConocoPhillips.

*Note:* Data are from the ConocoPhillips Form 10-K for the year ending December 31, 2011 and from the EIA Refinery Capacity Data by individual refinery as of January 1, 2012.

**Table 3:** Oil price benchmarks and U.S. refinery acquisition costs for imported oil

| | (1) Δ PADD 1 import price | (2) Δ PADD 2 import price | (3) Δ PADD 3 import price | (4) Δ PADD 4 import price | (5) Δ PADD 5 import price |
|---|---|---|---|---|---|
| Δ WTI Price | 0.030 | 1.086* | 0.428* | 1.268* | 0.736* |
| | (0.131) | (0.115) | (0.075) | (0.121) | (0.116) |
| Δ LLS Price | 0.828* | -0.232* | 0.467* | -0.428* | 0.172 |
| | (0.130) | (0.100) | (0.093) | (0.123) | (0.114) |
| Constant | 0.127 | -0.091 | 0.053 | -0.091 | 0.081 |
| | (0.123) | (0.205) | (0.126) | (0.198) | (0.144) |
| Observations | 119 | 119 | 119 | 119 | 119 |

*Note:* The dependent variable is the monthly change in the average imported crude oil acquisition cost for refiners in each PADD region, in dollars per barrel. The sample range is February 2004 to December 2013. Standard errors are Newey-West with 12 lags.

* $p < 0.05$ (two-tailed test for difference from zero).

**Table 4:** Oil price benchmarks and U.S. refinery acquisition costs for domestic oil

| | (1) Δ PADD 2 dom. price | (2) Δ PADD 3 dom. price | (3) Δ PADD 4 dom. price | (4) Δ PADD 5 dom. price |
|---|---|---|---|---|
| Δ WTI Price | 0.820* | 0.767* | 0.928* | 0.688* |
| | (0.075) | (0.138) | (0.048) | (0.104) |
| Δ LLS Price | 0.031 | 0.045 | -0.000 | 0.199* |
| | (0.056) | (0.106) | (0.047) | (0.089) |
| Constant | 0.065 | 0.110 | -0.047 | 0.112 |
| | (0.143) | (0.196) | (0.078) | (0.148) |
| Observations | 119 | 119 | 119 | 119 |

*Note:* The dependent variable is the monthly change in the average domestic crude oil acquisition cost for refiners in each PADD region, in dollars per barrel. The sample range is February 2004 to December 2013. Standard errors are Newey-West with 12 lags.

* $p < 0.05$ (two-tailed test for difference from zero).

**Table 5:** Oil price benchmarks and wholesale gasoline prices

| | (1) Δ PADD 1 gas price | (2) Δ PADD 2 gas price | (3) Δ PADD 3 gas price | (4) Δ PADD 4 gas price | (5) Δ PADD 5 gas price |
|---|---|---|---|---|---|
| Δ WTI Price | -0.032 | 0.022 | -0.029 | -0.193 | -0.156 |
| | (0.156) | (0.145) | (0.138) | (0.165) | (0.171) |
| Δ LLS Price | 1.078* | 1.029* | 1.064* | 1.115* | 1.103* |
| | (0.179) | (0.185) | (0.157) | (0.207) | (0.199) |
| Constant | -0.027 | -0.092 | -0.045 | -0.036 | -0.005 |
| | (0.194) | (0.234) | (0.187) | (0.296) | (0.242) |
| Observations | 119 | 119 | 119 | 119 | 119 |

*Note:* The dependent variable is the monthly change in the average wholesale gasoline price received by refiners in each PADD region, in dollars per barrel. The sample range is February 2004 to December 2013. Standard errors are Newey-West with 12 lags.

* $p < 0.05$ (two-tailed test for difference from zero).

**Table 6:** Oil price benchmarks and wholesale diesel prices

| | (1) Δ PADD 1 dist. price | (2) Δ PADD 2 dist. price | (3) Δ PADD 3 dist. price | (4) Δ PADD 4 dist. price | (5) Δ PADD 5 dist. price |
|---|---|---|---|---|---|
| Δ WTI Price | 0.149 | 0.206 | 0.154 | 0.068 | 0.130 |
| | (0.118) | (0.110) | (0.121) | (0.133) | (0.091) |
| Δ LLS Price | 0.838* | 0.794* | 0.819* | 0.969* | 0.957* |
| | (0.109) | (0.102) | (0.110) | (0.134) | (0.082) |
| Constant | 0.176 | 0.152 | 0.162 | 0.152 | 0.095 |
| | (0.210) | (0.227) | (0.231) | (0.263) | (0.187) |
| Observations | 119 | 119 | 119 | 119 | 119 |

*Note:* The dependent variable is the monthly change in the average wholesale No. 2 Distillate price received by refiners in each PADD region, in dollars per barrel. No. 2 Distillate can be used as either diesel fuel or heating oil. The sample range is February 2004 to December 2013. Standard errors are Newey-West with 12 lags.

* $p < 0.05$ (two-tailed test for difference from zero).

**Table 7:** Parameter assumptions for counterfactual profit calculation

| Parameter | Value |
|---|---|
| **Pipeline segment** | |
| Pipeline capacity (barrels/day)[1] | 150,000 |
| Shipment rate ($/barrel)[2] | 3.25 |
| Ownership share of pipeline | 50% |
| **Refining segment** | |
| Refinery capacity utilization[3] | 91% |
| PADD 2 imported share of input[4] | 26% |
| PADD 3 imported share of input[4] | 66% |
| Gasoline share of output[5] | 54% |
| Diesel share of output[5] | 46% |
| **Production segment** | |
| North America crude oil production (barrels/day)[6] | 206,000 |

[1] Pipeline capacity after service reversal but before capacity expansion (`http://seawaypipeline.com/`).
[2] Initial heavy crude rate for 5-year committed shippers with volumes below 100,000 barrels per day (Federal Energy Regulatory Commission, 2012).
[3] ConocoPhillips U.S. R&M Crude Oil Capacity Utilization in 2011, from Supplemental Earnings Report.
[4] Refinery-level imports for ConocoPhillips calculated from EIA import data for 2011. To calculate import share, total crude oil inputs are based on previous assumptions about capacity and capacity utilization.
[5] Calculated as U.S. gasoline production for ConocoPhillips in 2011, divided by the sum of gasoline and distillate production. Data from ConocoPhillips Supplemental Earnings Report.
[6] Crude oil and natural gas liquids production for ConocoPhillips in the U.S. and Canada, excluding Alaska, in 2011. Data from ConocoPhillips Supplemental Earnings Report.

**Table 8:** Change in profits for integrated firm from counterfactual early pipeline reversal

| \$ million per day | (1) PADD 2 only | (2) PADD 2 and 3 | (3) Incl. prod. | (4) 3 day window | (5) 21 day window |
|---|---|---|---|---|---|
| Pipeline | 0.244 | 0.244 | 0.244 | 0.244 | 0.244 |
| Refining (PADD 2) | -2.036 | -2.036 | -2.036 | -1.088 | -2.463 |
| | (1.173) | (1.173) | (1.173) | (0.691) | (1.378) |
| Refining (PADD 3) | | -2.272 | -2.272 | -1.214 | -2.748 |
| | | (1.350) | (1.350) | (0.791) | (1.590) |
| Oil production | | | 1.281 | 0.684 | 1.549 |
| | | | (0.700) | (0.416) | (0.820) |
| Combined profit | -1.793 | -4.064 | -2.783 | -1.374 | -3.417 |
| | (1.173) | (2.442) | (1.777) | (1.043) | (2.090) |

*Note:* This table show a decomposition of how pretax profits of ConocoPhillips would have changed if the Seaway pipeline had been reversed in 2011 instead of 2012. Column 1 shows only the effect of the pipeline and the Midwest refineries. Column 2 adds the Gulf Coast refineries. Column 3 includes additional revenue for the exploration and production division from higher crude oil prices. Columns 4 and 5 show the results using the WTI price change for the 3-day and 21-day windows in Table 1.

**Figure 1:** Stylized model of the oil market and pipeline

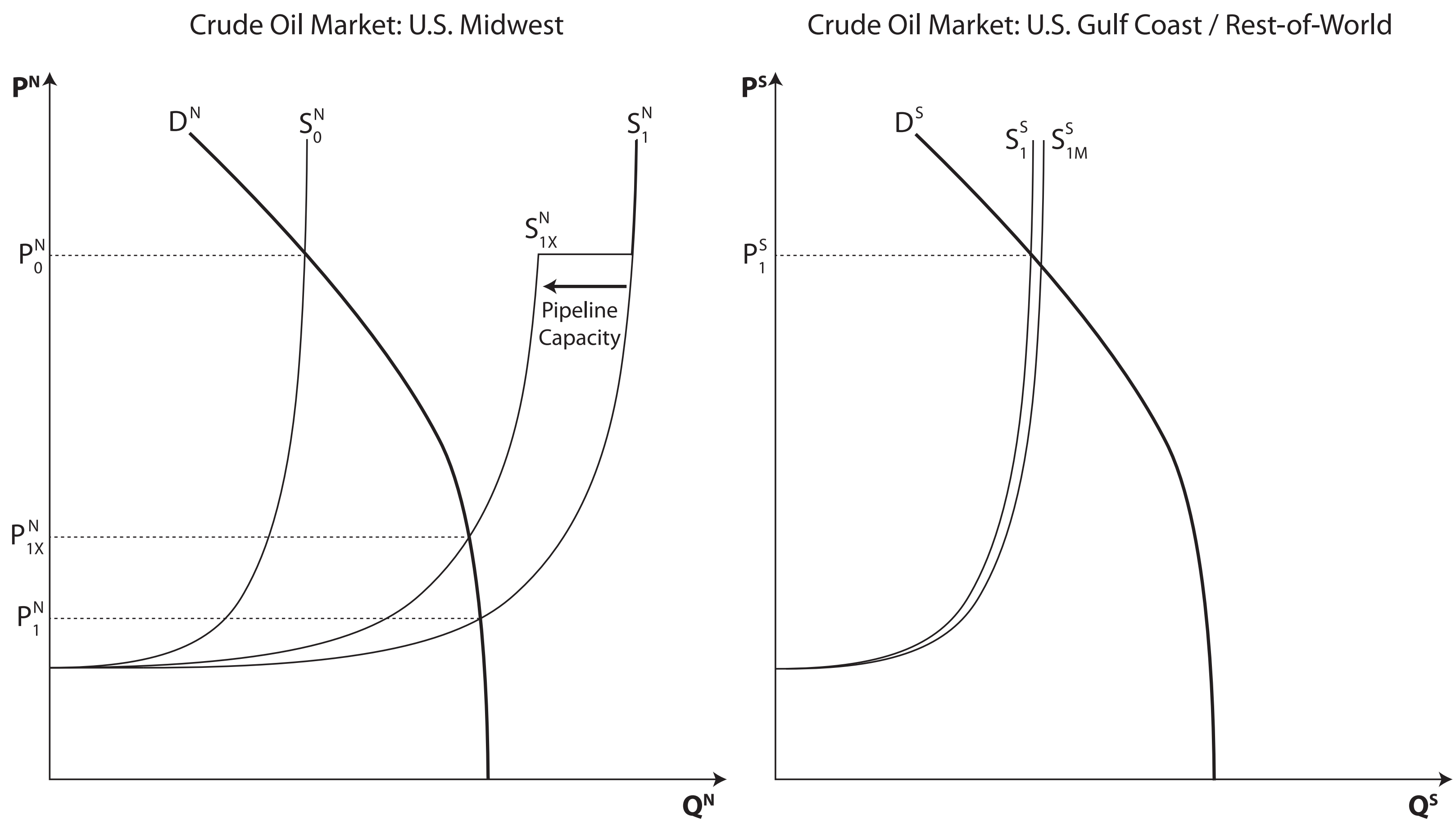
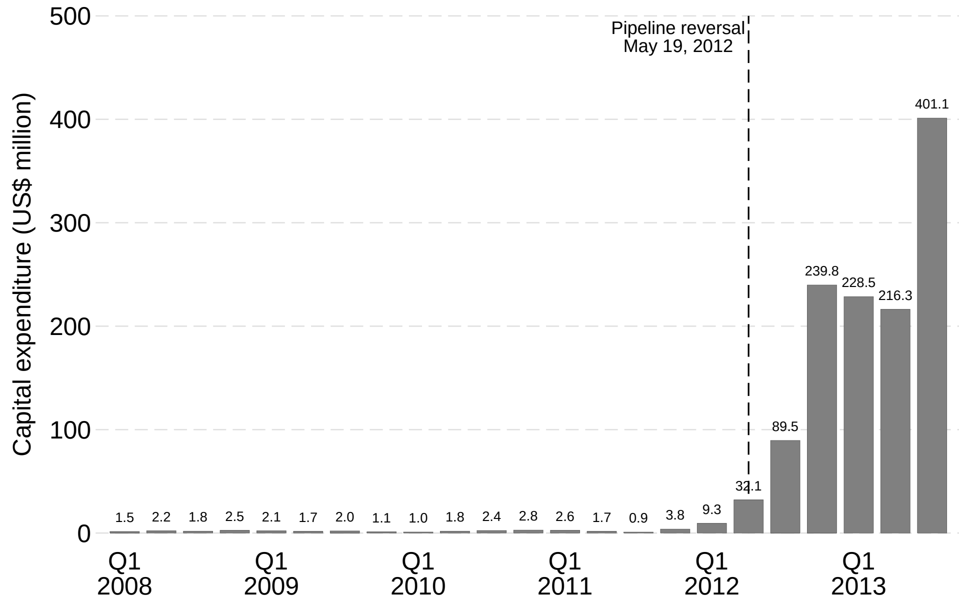


**Figure 2:** Quarterly capital expenditure of Seaway crude pipeline, 2008–2013




*Source:* Federal Energy Regulatory Commission. Form 6 Annual and Quarterly Report data for Seaway Crude Pipeline Company LLC.

**Figure 3:** Quarterly revenue of Seaway crude pipeline, 2008–2013

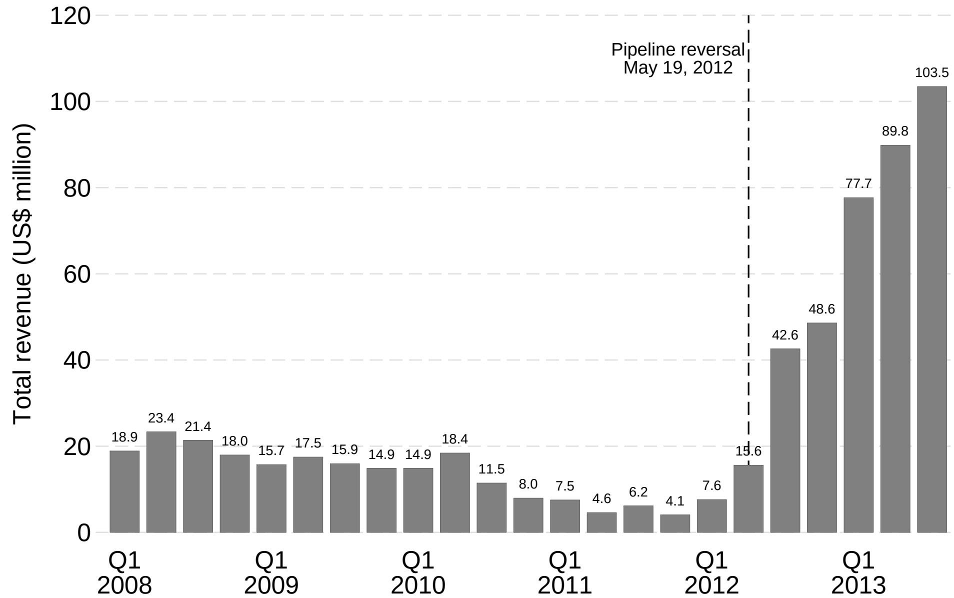
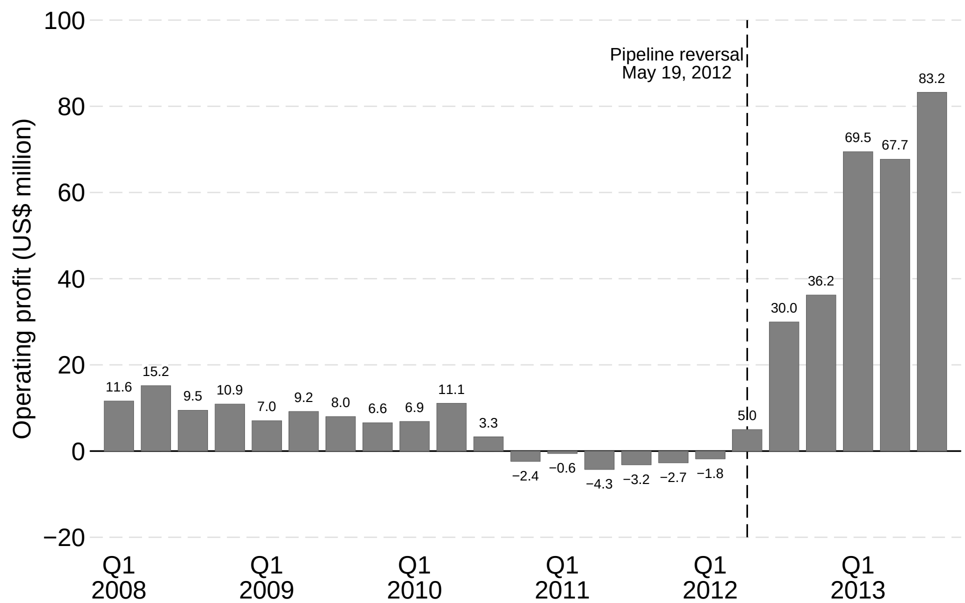



**Figure 4:** Quarterly operating profit of Seaway crude pipeline, 2008–2013




*Source:* Federal Energy Regulatory Commission. Form 6 Annual and Quarterly Report data for Seaway Crude Pipeline Company LLC.

**Figure 5:** Difference between 1-month, 12-month and 24-month WTI and Brent futures prices, 2010–2013

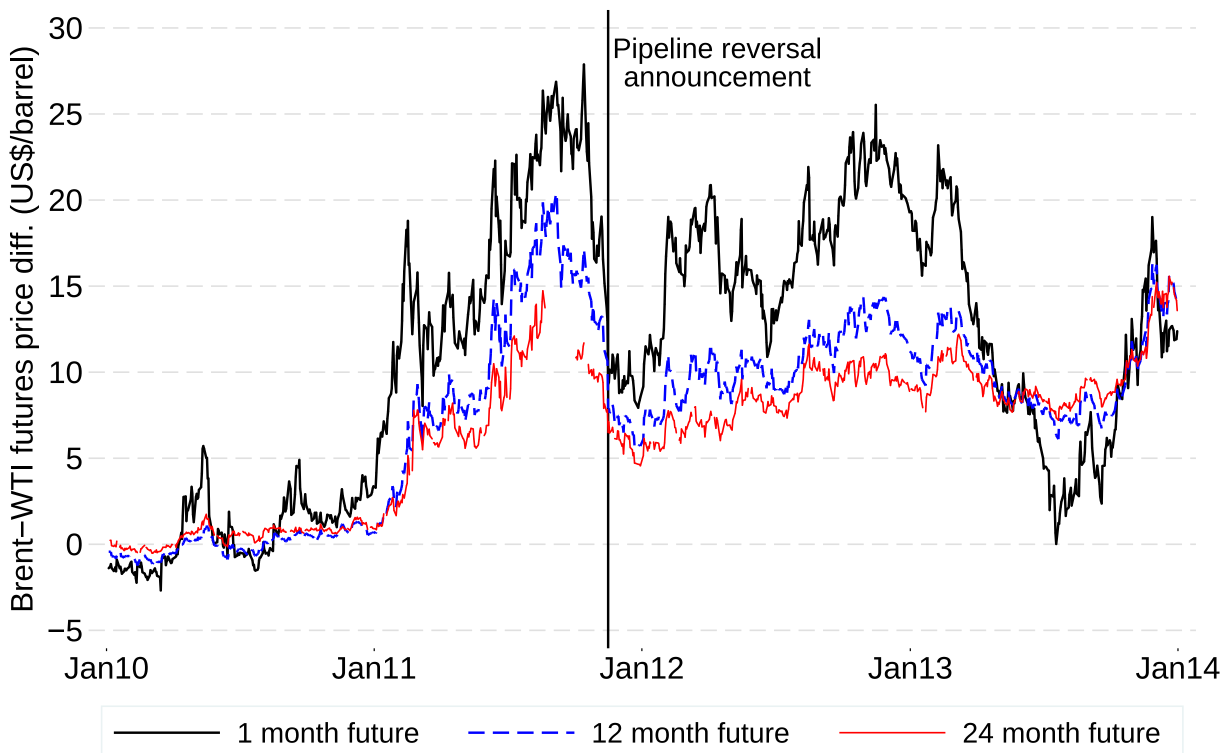
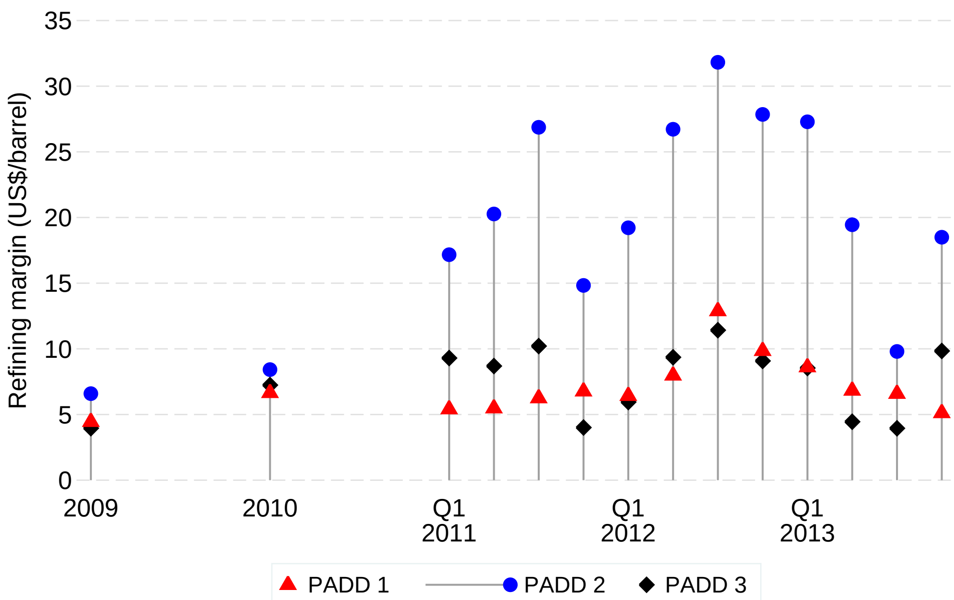


**Figure 6:** Quarterly refining margins for ConocoPhillips / Phillips 66, 2009–2013




*Source:* Phillips 66 Earnings Release Supplemental Data, 2009-2010 and Q4 2013. `http://investor.phillips66.com/investors/financial-information/supplemental-reports/default.aspx`

**Figure 7:** WTI and LLS crude oil prices, 2010–2013

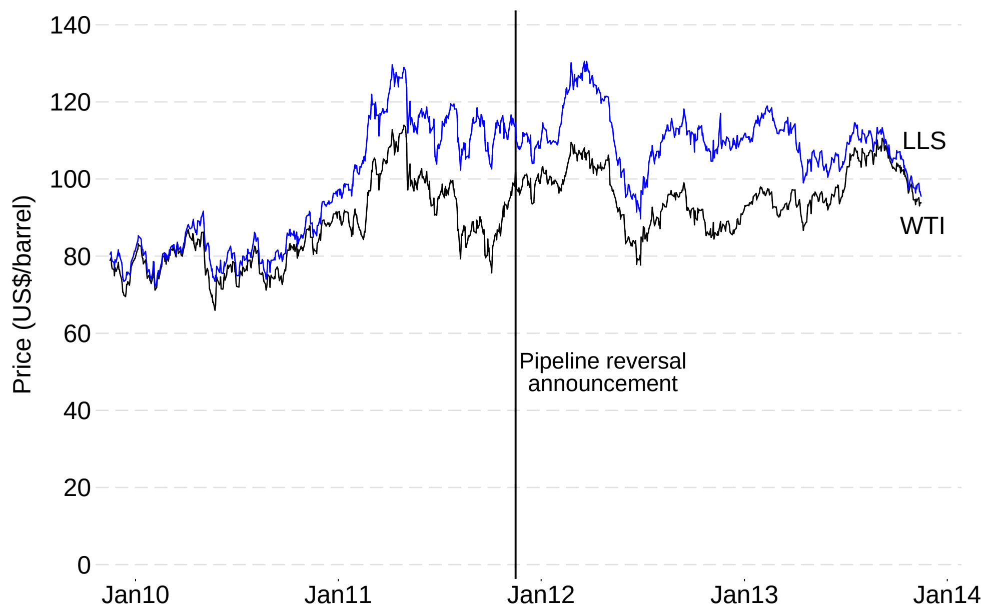
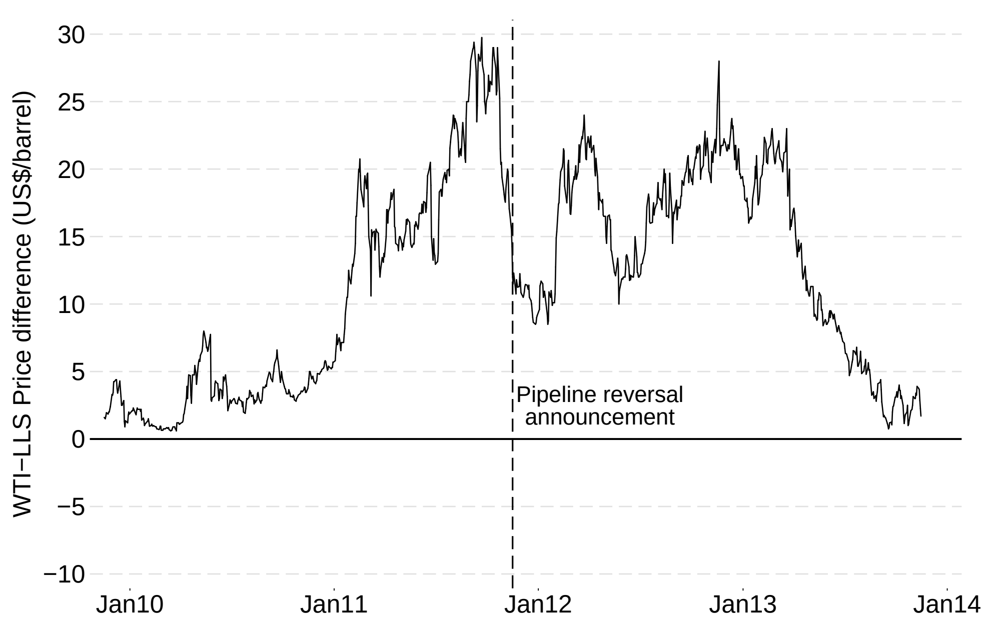
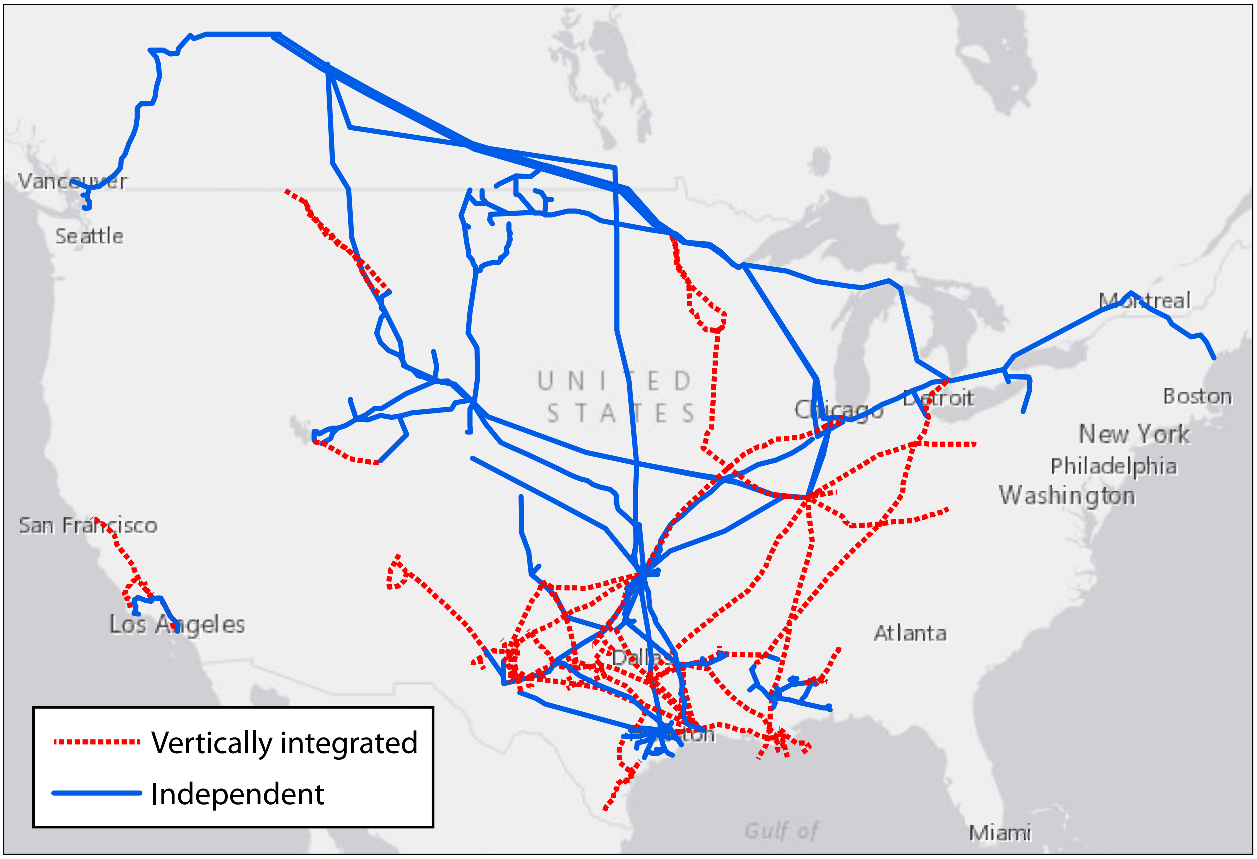



**Figure 8:** Difference between WTI and LLS crude oil prices, 2010–2013




*Source:* Bloomberg.

**Figure 9:** Ownership of U.S. Crude Oil Pipelines in 2015




*Source:* Geographic data for pipelines is from the EIA crude oil shapefile (`http://www.eia.gov/maps/layer_info-m.cfm`). Pipeline ownership status was determined from FERC Form 6 annual filings and the web sites of individual pipelines. "Vertically integrated" means that the pipeline is owned or partially owned by a firm that also has crude oil production or refining businesses. Otherwise the pipeline is classified as "independent".