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

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Abstract

The potential to exercise market power between regulated and unregulated businesses has led to restrictions on vertical integration in some industries. While the usual example is a firm using its downstream regulated assets to increase the price of its output, another possibility is a firm using its upstream regulated assets to reduce the price of its inputs. This paper provides evidence of the latter scenario for a vertically-integrated refiner and pipeline owner in the U.S. crude oil market. The manner in which the firm operated a major oil pipeline during 2011 was inconsistent with maximizing profits from the pipeline assets. The inefficient operation of the pipeline contributed to the observed differential in U.S. crude oil prices after 2010. This price differential reduced the input prices for the firm’s oil refineries, so that the firm’s behavior was consistent with profit maximization for its combined refining and pipeline assets. The results suggest that changes to the regulation of oil pipelines, 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. Only one segment of the oil industry—interstate oil pipelines—is regulated by the Federal Energy Regulatory Commission (“FERC”). FERC is responsible for ensuring that shippers have equal access to interstate oil pipelines. It is also responsible for approving pipeline tariff schedules. However, FERC has no jurisdiction over the construction, maintenance and safety aspects of pipeline operation.

In this paper I show how integrated oil firms can use their control of pipeline networks to benefit upstream or downstream operations. Although the rates for pipeline use are regulated by FERC, other important aspects of pipeline operation, including the flow direction of the pipeline, are not regulated. Changing the flow direction 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
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 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. 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

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1 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 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. 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

\footnote{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 had approximately $1.2-2.7 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 a pipeline owner and a downstream consumer. 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).\(^3\) 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,

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\(^3\)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.

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 Oil pipelines

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 own-
ing 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”. Several 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 (“trended original cost”). 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. 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

4The 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).

3 Model

In this section I provide a highly stylized model of the decision by a profit-maximizing oil pipeline owner for how to configure the pipeline operation, in particular, how to choose the direction of flow for the pipeline. Reversing the flow of an oil pipeline is a time-consuming and expensive process that withdraws the pipeline from operation for several months. I show how the ownership of the pipeline affects the flow direction 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 $R_{\text{max}}$ 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:

$$R = \min(R_{\text{max}}, \max(0, P_S - P_N))$$
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 Refinery owner in the north

The oil refinery in the north has input capacity $K$, measured in barrels per day. The price that the refinery receives for its output, $P_N^G$, is determined exogenously and are not affected by the crude oil price in the north. The price that the refinery pays for its crude oil input is $P_N^G$. Although the refinery could act as an oligopsonist by reducing its crude oil input in order to reduce the input price $P_N^G$, 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:

$$\Pi = K(P_N^G - P_N^G - c)$$

### 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 $P_N^G$. 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 $D_N^N$. 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:

\[
\Pi(S \to N) = K(P_G^N - P_1^N - c)
\]

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:

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

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:

\[
K(P_G^N - P_1^N - c) \geq R_{max} F + K(P_G^N - P_{1X}^N - c)
\]

\[
K(P_{1X}^N - P_1^N) \geq R_{max} F
\]

Otherwise the integrated firm will configure the pipeline to flow from north to south.

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. By delaying the pipeline
reversal, profits of the ConocoPhillips’ refineries in the Midwest were between $1.2 and $2.7 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

As described in Section 2.1, oil pipeline owners are regulated by FERC and must submit their proposed rate charts to FERC for approval. They receive a fixed price per barrel transported along their pipelines. Oil shippers with access to the pipeline pay this fixed price and can earn profits based on the price differential between the two ends of the pipeline. If the price is higher at the start of the pipeline than at the end of the pipeline, then there is little incentive for shippers to use the pipeline.

For the Seaway pipeline, the 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 the 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.

Figure 2 shows quarterly revenues of the Seaway pipeline from 2008 to 2013.\footnote{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.} Revenues fell from an average of $175,000 per day in 2009 to $60,000 per day in 2011. 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 a price of $4.00 per barrel, the fourth quarter revenues in 2012 imply shipments of 132,000 barrels per day, or 88 percent of capacity.\footnote{Available capacity is lower for heavier grades of oil.}

Reversal of the pipeline flow is a time-consuming process that requires the pipeline to be taken out of operation for several months and, in some cases, pumping station equipment to be upgraded. FERC approval is required for the new rate structure of a reversed pipeline, although no specific regulatory approval is required to reverse the pipeline flow. Given the
price differential that existed throughout 2011, it is highly plausible that the full capacity of the pipeline would have been used from north to south if the pipeline had been reversed earlier. This decision depends on expected future flow volumes and prices. It is not worth reversing the pipeline flow to take advantage of a short-term arbitrage opportunity. Instead, investments in flow reversal occur only when there has been a structural change in the market that alters the long-term pattern of supply and demand. However, by the end of 2010, it was clear that such a change had taken place in the North American oil market.

4.2 Effect of Seaway pipeline on WTI-LLS spread

Figure 6 shows the price history of the daily Brent and WTI crude oil spot prices. The difference between the two prices is shown in Figure 7. In 2010 these two prices remained very close to each other—the difference was rarely above $5. This was consistent with the history of the price series.. 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 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. 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

\footnote{Oil price benchmark data are from Bloomberg.}
“cause inventories to rebalance and prices to realign between inland and coastal locations”. 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.

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:

$$\Delta P_t^N = \alpha + \beta \Delta P_t^S + \gamma \text{Event}_t + \epsilon_t$$

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 $\text{Event}_t$ is a dummy variable scaled by the length of the event window. 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.

Results from the estimation of equation (1) are shown in Table 1. Columns 1 through 3 use only the daily change in the LLS price to predict the change in the WTI price. The estimated $\gamma$, corresponding to the cumulative increase in the WTI price at the time of the pipeline announcement, after controlling for changes in the LLS price, are $3.32$, $6.22$, and $7.52$ per barrel, for the 3-day, 11-day, and 21-day event windows respectively. 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 refineries, 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 for all 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):

$$
\Delta P_t = \alpha + \beta_1 \Delta P_{t}^{WTI} + \beta_2 \Delta P_{t}^{LLS} + \epsilon_t
$$

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. 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

\[\text{It is not possible to run the PADD 1 regression for domestic oil purchases because the publicly available data has many missing observations, reflecting the relatively low proportion of domestic purchases by East Coast refineries.}\]
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 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 5 summarizes the results. The first block shows the effect of reversing the pipeline on the profits for the pipeline division. From Figure 3, 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.

The second block in Table 5 shows the effect on ConocoPhillips’ refining operations. Assuming a 90 percent capacity utilization, the daily crude oil input for the firm’s share of
its Midwest refineries (Table 2) would be 382,000 barrels. The event study analysis in Table 1 provides a range for the potential increase in input prices that Based on the results from a 3-day and 21-day event window, the price increase would have been between $3.32 and $7.52 per barrel. This translates into an overall increase in input costs (or reduction in profits) for the Midwest refineries of between $1.268 and $2.873 million per day.

Combining this result with the change in pipeline profits, the integrated firm would have lost between $1.055 and $2.660 million per day as the result of the pipeline reversal. For the entire year, the upper figure implies a reduction in profits of nearly $1 billion. The potential losses in the refining division were at least six times as large (and possibly much more) than the small additional profit that the firm would have received from efficient operation of the pipeline. 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 vertically integrated firm.

The remaining four columns of Table 5 show two additional cases. First, the “Max Product Market” columns incorporate the potential increase in refined product prices in the Midwest as a result of the increase in input prices. This uses the upper bound of the 95 percent confidence interval of the change in refined product price from Borenstein and Kellogg (2014): 5 cents/barrel for every $1/barrel reduction in the WTI-LLS crude oil price differential. Even taking the upper bound of the refined product price change, the integrated profits would still be much lower after the pipeline reversal.

The above results only consider the potential reduction in input prices for the Midwest refineries. The final two columns incorporate a potential reduction in Gulf Coast input costs, to the extent that these are benchmarked to the WTI price. Using aggregate refinery data for 2004 to 2013, Table 3 suggests that 43 percent of the change in the WTI price is passed on as lower crude oil input costs for Gulf Coast refiners. Taking this estimate as the passthrough of WTI prices for ConocoPhillips in 2011, this would lead to an additional $0.942 to $2.134 million in daily lost profit for the Gulf Coast refineries as the result of early reversal of the Seaway pipeline. The annual reduction in profit for the firm would be between $0.729 and $1.750 billion. This would have made reversal of the pipeline even less desirable for the firm.

The reported financial results for ConocoPhillips in 2011 provide a useful check on the plausibility of these estimates. Figure 5 shows the per-barrel refining margins for ConocoPhillips broken down by region. In 2009 and 2010, before the WTI price differential,

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13 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.
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) were also much higher than the Atlantic margins during the first three 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.

Overall, the after-tax profit for the firm’s U.S. refining and retailing segment was $879 million in 2010. This increased to $2,373 million in 2011.\textsuperscript{14}

5 Policy Implications

The above analysis illustrated how ConocoPhillips, a vertically-integrated oil producer, refiner, and pipeline owner, was able to earn at least $400 million in additional refining 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

\textsuperscript{14}These figures are from the ConocoPhillips Summary of Income by Segment results for 2011.
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 8 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 leads 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 pipeline sector would contribute to the continued development of the energy sector in the United States.
References


Elder, John, Hong Miao, and Sanjay Ramchander, “Price discovery in crude oil futures,” *Energy Economics*, 2014, 46, *Supplement 1* (0), S18 – S27. Special Issue on Recent Approaches to Modelling Oil and Energy Commodity Prices.


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

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

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

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

\(^1\) 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

<table>
<thead>
<tr>
<th></th>
<th>(1)</th>
<th>(2)</th>
<th>(3)</th>
<th>(4)</th>
<th>(5)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>∆ PADD 1 import price</td>
<td>∆ PADD 2 import price</td>
<td>∆ PADD 3 import price</td>
<td>∆ PADD 4 import price</td>
<td>∆ PADD 5 import price</td>
</tr>
<tr>
<td>∆ WTI Price</td>
<td>0.030</td>
<td>1.086*</td>
<td>0.428*</td>
<td>1.268*</td>
<td>0.736*</td>
</tr>
<tr>
<td></td>
<td>(0.131)</td>
<td>(0.115)</td>
<td>(0.075)</td>
<td>(0.121)</td>
<td>(0.116)</td>
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<tr>
<td>∆ LLS Price</td>
<td>0.828*</td>
<td>-0.232*</td>
<td>0.467*</td>
<td>-0.428*</td>
<td>0.172</td>
</tr>
<tr>
<td></td>
<td>(0.130)</td>
<td>(0.100)</td>
<td>(0.093)</td>
<td>(0.123)</td>
<td>(0.114)</td>
</tr>
<tr>
<td>Constant</td>
<td>0.127</td>
<td>-0.091</td>
<td>0.053</td>
<td>-0.091</td>
<td>0.081</td>
</tr>
<tr>
<td></td>
<td>(0.123)</td>
<td>(0.205)</td>
<td>(0.126)</td>
<td>(0.198)</td>
<td>(0.144)</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th></th>
<th>(1)</th>
<th>(2)</th>
<th>(3)</th>
<th>(4)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>∆ PADD 2 dom. price</td>
<td>∆ PADD 3 dom. price</td>
<td>∆ PADD 4 dom. price</td>
<td>∆ PADD 5 dom. price</td>
</tr>
<tr>
<td>∆ WTI Price</td>
<td>0.820*</td>
<td>0.767*</td>
<td>0.928*</td>
<td>0.688*</td>
</tr>
<tr>
<td></td>
<td>(0.075)</td>
<td>(0.138)</td>
<td>(0.048)</td>
<td>(0.104)</td>
</tr>
<tr>
<td>∆ LLS Price</td>
<td>0.031</td>
<td>0.045</td>
<td>-0.000</td>
<td>0.199*</td>
</tr>
<tr>
<td></td>
<td>(0.056)</td>
<td>(0.106)</td>
<td>(0.047)</td>
<td>(0.089)</td>
</tr>
<tr>
<td>Constant</td>
<td>0.065</td>
<td>0.110</td>
<td>-0.047</td>
<td>0.112</td>
</tr>
<tr>
<td></td>
<td>(0.143)</td>
<td>(0.196)</td>
<td>(0.078)</td>
<td>(0.148)</td>
</tr>
</tbody>
</table>

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: Profit effect for integrated firm from counterfactual early pipeline reversal

<table>
<thead>
<tr>
<th></th>
<th>Base Case</th>
<th></th>
<th>Output market</th>
<th></th>
<th>WTI benchmark</th>
<th></th>
</tr>
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<tbody>
<tr>
<td></td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
<td>Low</td>
<td>High</td>
</tr>
<tr>
<td><strong>Pipeline division</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Δ profit ($ m/day)</td>
<td>0.213</td>
<td>0.213</td>
<td>0.213</td>
<td>0.213</td>
<td>0.213</td>
<td>0.213</td>
</tr>
<tr>
<td><strong>Refining division</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Central region</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Input (m barrels/day)</td>
<td>0.382</td>
<td>0.382</td>
<td>0.382</td>
<td>0.382</td>
<td>0.382</td>
<td>0.382</td>
</tr>
<tr>
<td>Δ input price ($/barrel)</td>
<td>3.32</td>
<td>7.52</td>
<td>3.32</td>
<td>7.52</td>
<td>3.32</td>
<td>7.52</td>
</tr>
<tr>
<td>Δ output price ($/barrel)</td>
<td>0.17</td>
<td>0.38</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Δ profit ($ m/day)</td>
<td>-1.268</td>
<td>-2.873</td>
<td>-1.205</td>
<td>-2.729</td>
<td>-1.268</td>
<td>-2.873</td>
</tr>
<tr>
<td>Gulf Coast</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Input (m barrels/day)</td>
<td>0.660</td>
<td>0.660</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Δ WTI price ($/barrel)</td>
<td>3.32</td>
<td>7.52</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>% benchmarked</td>
<td>43%</td>
<td>43%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Δ profit ($ m/day)</td>
<td>-0.942</td>
<td>-2.134</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td><strong>Integrated firm</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Δ daily profit ($ m/day)</td>
<td>-1.055</td>
<td>-2.660</td>
<td>-0.992</td>
<td>-2.516</td>
<td>-1.997</td>
<td>-4.794</td>
</tr>
<tr>
<td>Δ annual profit ($ billion)</td>
<td>-0.385</td>
<td>-0.971</td>
<td>-0.362</td>
<td>-0.918</td>
<td>-0.729</td>
<td>-1.750</td>
</tr>
</tbody>
</table>

*Note:* This table shows how the profits of ConocoPhillips would have changed if the Seaway pipeline had been reversed in 2011 instead of 2012. The low and high cases are the changes in the WTI price due to the reversal, from Table 1, for the 3-day and 21-day event windows respectively.
Figure 1: Stylized model of the oil market and pipeline
Figure 2: Quarterly revenue of Seaway crude pipeline, 2008–2013

Figure 3: 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 4:** 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 5: Quarterly refining margins for ConocoPhillips / Phillips 66, 2009–2013

Figure 6: WTI and LLS crude oil prices, 2010–2013

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

Source: Bloomberg.
**Figure 8:** 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”.

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