Analysis of the RFS Program and the 2019 Proposed Standards

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I. Executive Summary

The Environmental Protection Agency's ("EPA") Renewable Fuel Standard ("RFS") program is intended to promote the use of "renewable" fuels, generated from biological sources, in place of fuels created from crude oil and other fossil sources. For the current year, 2018, the RFS program effectively requires that gasoline be blended with 10.67% percent renewable fuel. Under the EPA's proposed standards for 2019, this percentage would go up to 10.88%.[2]

Until 2013, gasoline blenders were able to meet the RFS requirements by blending petroleum-based gasoline with corn-based ethanol. Ethanol can be blended up to slightly less than 10 percent into gasoline with no detrimental effects on car engines, and some benefits to performance. However, at higher levels, ethanol causes corrosion in some car engines—to the point where car manufacturers may not guarantee the warranty on a car that uses fuel blended with higher levels of ethanol.

Because of this barrier, referred to as the "blend wall," refiners have been forced to find other ways to meet the EPA's renewable fuel requirements. The RFS program allows refiners to purchase renewable fuel credits from other biofuel sources to cover shortfalls in the renewable fuel content of gasoline. Biodiesel has been the market of choice for refiners trying to meet the standard. However, meeting the standard by subsidizing biodiesel production is expensive, and has the effect of raising prices to consumers and reducing the profitability of producers.

The cost of meeting the RFS mandate has fallen particularly heavily on East Coast refiners. These refiners have faced substantial economic headwinds in recent years, ranging

[2] *See* Exhibit 1.

from weaker than expected gasoline demand to lowered margins due to increased reliance on imported sources of crude oil. The additional cost of meeting the RFS mandate has further reduced the profitability of these refineries.

The EPA's proposed 2019 RFS requirements have the potential to make a number of East Coast refineries unprofitable. This will increase the probability that one or more of these refineries may be unable to continue production.

While refineries represent a fairly small portion of jobs on the East Coast, they are important employers in their home counties. A refinery shutdown in one of these counties could result in a substantial number of employees who would be out of work.

If the EPA were to revise the 2019 proposal to be at 2012 standards, this would reduce the financial strain on East Coast refiners and avoid the potential for job losses from a refinery shutdown.

II. Background: The Renewable Fuel Standard

A. Overview of the RFS Program

The RFS requires the use of renewable fuel to replace or reduce fossil fuel-based transportation fuel, heating oil and jet fuel.[3] In essence, the program is meant to serve as a subsidy for qualified renewable fuels. First created in 2005 and subsequently expanded in 2007 under the Energy Independence and Security Act, the program is implemented by the EPA in

[3] "Overview for Renewable Fuel Standard", EPA, *available at* https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard ("EPA's Overview for Renewable Fuel Standard").

collaboration with the Departments of Energy ("DOE") and Agriculture ("USDA").[4] The program defines annual volume standards across four categories: biomass-based diesel ("BBD"), cellulosic biofuel ("CB"), advanced biofuel, and total renewable fuel. Each year, the EPA sets a corresponding percentage standard based on the estimated energy demand of the prior year. Gasoline and diesel refiners and importers ("Obligated Parties") must meet renewable volume obligations ("RVOs") which are based on the percentage standards defined by the EPA and volume of gas and diesel that the Obligated Parties have produced or imported in the calendar year.[5]

B. Renewable Fuel Annual Standards

When the RFS program was expanded in 2007, initial statutory targets were established for the different types of biofuels that extended to the year 2022 to reach a target of 36 billion gallons. The required standards are structured in a hierarchy based on the greenhouse gas ("GHG") reduction amounts associated with the fuel. Fuels with higher GHG reduction amounts can be applied to multiple standards, whereas fuels with lower GHG reduction amounts qualify for fewer standards. The most restrictive standards are for both cellulosic biofuel ("D3") and biomass-based diesel ("D4"), where only those specific fuels qualify to meet the corresponding standards.[6] Next, there is a standard for advanced biofuels, which can be met by D3, D4, or

[4] The main changes enacted in 2007 included increasing the long term renewable fuel goal to 36 billion gallons, extending annual volume requirements to 2022, clarifying the definitions for qualified renewable fuels, and providing for specific waiver authorities. *See* EPA's Overview for Renewable Fuel Standard.

[5] EPA's Overview for Renewable Fuel Standard.

[6] EPA's Overview for Renewable Fuel Standard.

advanced D5 fuels.[7] Finally, there is a total renewable fuel standard, which can be met by any qualified fuel and is generally met first with conventional corn-based ethanol ("D6").[8]

The EPA has the ability to waive the RFS requirement in any given year, in part or in whole, if it determines there is inadequate domestic supply, or if the requirements cause severe economic harm.[9] The agency is mandated to finalize annual percentage standards for each year by November 30th of the preceding year; the biomass-based diesel volume standards must be finalized 14 months prior to the compliance year.[10] In recent years, the EPA has set annual standards below the statutory targets due to the EPA's projections of the inability of the industry to produce statutory target quantities of biofuels and the market's inability to absorb those target quantities.

C. Proposed Standards for 2019

On November 30, 2017, the EPA finalized the biomass-based diesel volume requirement for 2019, which remained unchanged from the prior year at 2.1 billion gallons.[11] On June 26, 2018, the EPA proposed 2019 volume requirements for cellulosic biofuel, advanced biofuel, and

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[7] EPA's Overview for Renewable Fuel Standard; "Approved Pathways for Renewable Fuel", EPA, *available at* https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel.

[8] EPA's Overview for Renewable Fuel Standard.

[9] EPA's Overview for Renewable Fuel Standard.

[10] "Renewable Fuel Annual Standards," EPA, *available at* https://www.epa.gov/renewable-fuel-standard-program/renewable-fuel-annual-standards.

[11] "EPA Finalizes RFS Volumes for 2018 and Biomass Based Diesel Volumes for 2019", EPA, *available at* https://www.epa.gov/newsreleases/epa-finalizes-rfs-volumes-2018-and-biomass-based-diesel-volumes-2019.

total renewable fuel.[12] The 2018 and proposed 2019 standards are summarized in Exhibit 1. The proposed renewable fuel mandated levels increase the overall requirement by over 3%, and the advanced biofuel mandate increases by over 13%. The largest change is for cellulosic biofuels, which increases by 32.3%, although this category is still the smallest, with only 381 million gallons required.

D. RINs

The RFS program requires Obligated Parties to demonstrate compliance with their RVOs by submitting Renewable Identification Numbers ("RINs") to the EPA.[13] RINs are created as the biofuel is created, and each category of biofuel has a separate RIN category. For example, for each gallon of ethanol produced, one corresponding D6 RIN is created.[14] Subsequently, when each gallon of biofuel is sold, it comes with an attached RIN.[15] Once the biofuel is blended, the RIN becomes detached, and it can be either submitted to the EPA to fulfill a RVO or sold separately on the secondary market. Refiners with blending facilities accumulate RINs as they blend the refined oil with biofuel to create the finished product. Importantly, refiners without sufficient blending facilities ("merchant refiners") are still obligated to provide RINs to the EPA each year, and must buy most or all of their RINs in the secondary market. RINs can be

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[12] "Proposed Volume Standards for 2019, and the Biomass-Based Diesel Volume for 2020", EPA, *available at* https://www.epa.gov/renewable-fuel-standard-program/proposed-volume-standards-2019-and-biomass-based-diesel-volume-2020.

[13] EPA's Overview for Renewable Fuel Standard.

[14] The RIN system is calibrated to ethanol, meaning one RIN is equivalent to one gallon of ethanol. Biodiesel fuel has a higher energy content, and therefore a single biodiesel gallon generates 1.5 RINs. *See* Brent D. Yacobucci, "Analysis of Renewable Identification Numbers (RINs) in the Renewable Fuel Standard (RFS)", Congressional Research Service, July 22, 2013, *available at* https://fas.org/sgp/crs/misc/R42824.pdf ("CRS RINs"), p. 3.

[15] CRS RINs, p. 3.

used either in the year they are created, or they can be banked and used the following year, but only 20% of the RVO can be met by prior year RINs.[16]

The EPA has set up an in-house EPA Moderated Transaction System ("EMTS") through which all RIN transactions much be cleared. Although most RINs are bought and sold through private contracts, these private contracts must be registered with EMTS.[17] The EPA views the EMTS solely as a "screening" system, and all due diligence remains the duty of the obligated parties.[18] Further, the EPA reports total RINs registered by month, but does not report trades and RIN price data collected through EMTS.[19]

RIN prices are highly volatile. For example, after August of 2009, D6 RIN prices stayed in a narrow band under 10 cents. However in early 2013, prices jumped significantly, surpassing one dollar in March of that year.[20] Other RIN types have had similarly large price movements. In general, the RIN prices of the different fuel types reflect the hierarchy of the standards. In other words, cellulosic, which has the greatest GHG reduction effect, and the lowest volume requirements, is the highest priced RIN.[21] Ethanol RINs, which can only be used for the general requirement, have the lowest prices.[22] Exhibit 2 shows historical prices for three of the RIN

[16] "[U]nlike other commodities, RINs generally may only be used in the year they are generated or for one additional year, although suppliers may only meet up to 20% of their current-year obligation with the previous year's RINs." *See* CRS RINs, pp. 5–6.

[17] CRS RINs, p. 4.

[18] CRS RINs, pp. 4, 11.

[19] CRS RINs, p. 9.

[20] *See* Exhibit 2.

[21] *See* OPIS data on historic RIN price; CRS RINs, p. 15.

[22] *See* Exhibit 2.

types (cellulosic D3 RINs are not included due to volatility and limited data). The price of RINs is crucially important for merchant refiners, who must buy most or all RINs in the secondary market to comply with EPA rules.

E. The Binding Blend Wall Results in Volatile and High Prices for RINs Refiners Need to Purchase

The EPA regulates motor vehicle fuels and fuel additives in accordance with the Clean Air Act, which includes regulating the proportion of ethanol blended with motor gasoline, and which vehicles are permitted to use the different fuel blends. The majority of vehicles in the United States use E10 fuel, which includes up to 10% ethanol by volume. Most gas stations do not sell fuels with higher ethanol blends, such as E15 (10.5% - 15% ethanol content).[23] As a result, the demand for ethanol is constrained by the 10% blend level of ethanol that the total volume of E10 fuel can absorb. This constraint is referred to as the "blend wall." The significance of the blend wall is that as the EPA requirements surpass the volume of ethanol that can be used to blend with E10 fuel, additional types of biofuel RINs are needed to meet the general mandate.

Exhibit 3 shows the volume of blended ethanol as a proportion of supplied gasoline (before any ethanol is added). Ethanol usage increased significantly beginning around 2002, until around 2012 when it nearly reached the 10% mark, where it has hovered ever since.

Importantly, the conventional portion of the renewable fuel standard volume requirement exceeds the supplied ethanol volume. In other words, the mandate exceeded the production of

[23] "Almost all U.S. gasoline is blended with 10% ethanol," EIA, May 4, 2016, *available at* https://www.eia.gov/todayinenergy/detail.php?id=26092.

ethanol. Exhibit 4 shows the gap between the supplied ethanol and the conventional portion of the renewable fuel requirement which contributes to the high RIN prices. When the gap increased substantially in 2013, around the same time the 10% blend wall was hit, RIN prices increased substantially.[24] The gap in 2016 was over four hundred million gallons. In 2017, the conventional portion of the standard increased by half a billion gallons (from 14.5 to 15),[25] but supplied ethanol was essentially unchanged from the prior year, and therefore the gap approached one billion gallons. As RIN prices increase or become more volatile, the prices refiners must pay for RINs in the secondary market increase or become more volatile.

III. Refineries in the East Coast Region Have Faced Significant Economic Headwinds

The refining industry on the United States East Coast, called PADD 1 by the EIA,[26] has faced significant economic headwinds both before and after the implementation of the RFS mandates. When RIN prices spiked in 2013 due to increased RFS requirements,[27] the refining industry on the East Coast PADD 1 was earning historically large refining margins due to the simultaneous timing of the shale oil boom in the United States that provided cheap feedstock.

The temporary benefit from the US's shale oil boom delayed the full impact on refiners of the RFS mandates. In recent years, the temporary benefit from the shale oil boom has largely

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[24] *See also* Exhibit 2 and Exhibit 3.

[25] "Final Renewable Fuel Standards for 2017, and the Biomass-Based Diesel Volume for 2018", EPA, *available at* https://www.epa.gov/renewable-fuel-standard-program/final-renewable-fuel-standards-2017-and-biomass-based-diesel-volume.

[26] *See* Glossary for Petroleum Administration for Defense District (PADD), *available at* https://www.eia.gov/tools/glossary/index.php?id=petroleum%20administration%20for%20defense%20district.

[27] *See* Exhibit 2.

dissipated and the PADD 1 refining industry is facing pressures due to weaker than expected demand for gasoline and high stocks of gasoline, in addition to compliance pressures from the RFS program.

A. Decline in the Number of Refiners in PADD 1

The economic obstacles facing PADD 1 refineries are evidenced by the substantial decline in the number of refineries over the past 18 years. Exhibit 5 shows this decline: in 2000, sixteen refineries operated in the region; by 2018, this number had dropped to only 8. Between 2009 and 2018 alone, seven refiners accounting for 641,300 barrels per day of operable capacity closed, as shown in Exhibit 6. Two of the refiners, the Axeon refinery in Savannah, GA, and the Western Refining facility in Yorktown, VA, were the only refining facilities in their respective states. Currently, just 8 refiners operate in the East Coast region, with capacity equal to 1,223,500 barrels per day. Exhibit 7 lists these 8 refiners and their operable capacity, which ranges from 22,300 barrels at Ergon's Newell, WV plant to 335,000 at Philadelphia Energy Solutions in south Philadelphia. [28]

Accompanying this reduction in the number of refiners has been a reduction in the amount of refined crude oil products produced. Exhibit 8 shows that in 2005, East Coast refineries produced over 600 million barrels of refined products per year in 2005; by 2017, this number was down to just over 250 million barrels.

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[28] Exhibit 5 only includes operating refineries and excludes idle (but operable) refineries, while Exhibits 6 and 7 include operable refineries. There were three idle refineries in 2010, for example. *See* "East Coast (PADD 1) Number of Idle Refineries as of January 1", EIA, June 25, 2018, *available at* https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=8_NA_8OI_R10_C&f=A.

B. Decrease in Employment at Refineries in PADD 1

As the number of refineries in PADD 1 has decreased, employment in the refinery industry has also decreased. Employment in refineries encompasses a number of occupations, some of which involve skills that are specific to the industry and others of which involve skills that can be used in a number of industries. The orange and blue lines in Exhibit 9 estimate the level of employment associated with the refining industry in PADD 1 using the industry category Petroleum and Coal Products Manufacturing Industry.[29] Although this industry definition includes non-refinery coal employment, I reduced the potential number of non-refinery jobs by collecting data only from counties that had active refineries during the time period. After an increase between 2005 and 2008, employment in this job category fell rapidly during the recession. Since 2012-2013, employment in this category has remained fairly stable.

C. Weak Demand for Gasoline Heavily Impacts PADD 1

Exhibit 10 shows that PADD 1 refineries are highly dependent on gasoline production. Weaker than expected demand for gasoline has led to historically high gasoline stocks. Exhibit 11 shows how stocks have increased since 2000 and peaked in 2016. While stocks can experience fairly large quarterly shifts, the overall trend has been upward since 2013. The combination of high stocks and weaker than expected demand has put downward pressure on prices, which in turn places refiners under greater financial pressure.

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[29] The associated 4-digit NAICS code is 3241.

D. Diminishing Effects of the Shale Boom that Provided Low Cost Crude Oil

In the early years of this decade, the shale boom in the western United States (e.g., North Dakota, Bakken shale formation) provided a new supply of crude oil to PADD 1. This increased supply of low cost crude was partly a result of increased domestic production of light crude, and partly a result of transportation bottlenecks that made PADD 1 a more attractive destination for Bakken crude. Between 2010 and 2016, U.S. domestic crudes were considerably cheaper than international crudes, and PADD 1 refiners had similar acquisition costs of these domestic crudes, relative to the Gulf Coast refiners (Exhibit 12).[30] However, resolution of the supply bottlenecks and a lift on the U.S. crude export ban led to a decline in the price differential between domestic and international crude and subsequently a decline in rail shipments from the Midwestern United States to PADD 1. Exhibit 13 shows this decline and the accompanying increase in crude oil imports to PADD 1 refineries. In other words, for a time East Coast refineries were able to cheaply source the feedstock, crude oil, from domestic sources, but as the U.S. domestic price moved closer to international prices, the price of crude oil for East Coast refineries increased.

The effects of the shale boom can also be seen by examining crack spreads (a proxy for gross margins that measures the difference between the price of a barrel of refined product and the price of a barrel of crude) for PADDs 1–3. Exhibit 14 shows the crack spreads from 2004 to 2018. PADD 1's crack spread is consistently lower than those of the other two PADDs, but its disadvantage narrowed during the period when it received the most benefit from the shale boom.

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[30] "Widening Brent-WTI price spreads unlikely to change East Coast crude oil supply," EIA, November 1 2017, *available at* https://www.eia.gov/todayinenergy/detail.php?id=33572.

This Exhibit also shows that the largest beneficiary of the shale boom was PADD 2, which benefited from proximity and from the transportation bottlenecks.

Exhibit 15 shows the difference in crack spreads relative to PADD 1. This shows that PADD 1 is almost always at a disadvantage, but its disadvantage relative to PADD 3 was substantially reduced in the years where it received large rail shipments of Bakken crude. Exhibits 16 and 17 show the average annual crack spreads and the average annual differences. These exhibits demonstrate more clearly PADD 1's disadvantage relative to the other two. PADD 1 not only has the lowest crack spreads, but since the refineries in PADD 1 tend to be older and less efficient than PADD 2, margin differences tend to understate the relative disadvantage of PADD 1 refiners.

E. Crack Spreads Are Lower for East Coast Refiners Relative to the Midwest and Gulf Coast Refiners and RFS Requirements Lower Crack Spreads Even Further

As already explained, the crack spreads for refiners in PADD 1 are almost always lower than the spreads in the other two PADDs. The shale boom decreased the differences in spreads between PADDs 1 and 3, temporarily improving the financial prospects of PADD 1 refiners.

Exhibit 2 shows the RIN prices over time. These prices are incorporated into Exhibits 18 and 19, which show the monthly and annual crack spreads after removing the cost of RFS compliance. When RIN prices increased substantially in 2013, the RIN adjusted crack spread visibly diverged from non-adjusted crack spreads. After accounting for RFS compliance, current PADD 1 spreads appear to be close to 2009 and 2010 levels, when the United States was in a deep recession and many PADD 1 refiners went out of business.

IV. Supply and Demand Model Estimation: The 2019 RFS Requirements Impose Substantial Costs on PADD 1 Refiners and Consumers

Through my estimation of a supply and demand model, I analyze two scenarios: (1) a fractional compliance standard that does not cause a binding blend wall, and (2) the proposed 2019 standard.[31] I focus on PADD 1, though similar results hold for PADDs 2 and 3. The first scenario is equivalent to the standard for 2012, when the D6 RIN price was close to zero and the blend wall was not binding. The model used to predict prices and quantities in the two scenarios is described in further detail in Section VII.

In the short run, moving from a zero RIN price (RFS requirements that are below the blend wall) to the proposed 2019 standard would cause a roughly 1 percent reduction in the quantity of refined product produced.

Most of the effect of the proposed 2019 standard will be accounted for in the price of refined products (gasoline, diesel, and middle distillates). Moving from a zero RIN price (non-binding blend wall) fractional standard to the proposed 2019 standard reduces the prices received by refiners in PADD 1 by 1.7 percent, or about $1.27 per barrel. This price reduction is material because it reduces top line revenue but not production cost. Thus, at current prices, a 1.7 percent ($1.27) decline in the wholesale price of refined petroleum products represents a 12.3 percent decline in PADD 1 refinery margins (Exhibit 20).[32] These changes reduce refiner economic

[31] In the analysis, the models are calibrated to match fuel production, consumption and prices, and RIN prices, as of January 2018.

[32] 1.7% is the reduction in the top line price of refined product. The 12.3% reduction in the crack spread is the reduction in the differential between the barrel of crude and refined product after reducing the price of the refined product by 1.7%.

profits in PADD 1 by approximately $1.6 billion. Exhibit 21 shows these profit losses for all three PADDs. Although they appear similar across PADDs, PADD 1 production is much lower. Exhibit 22 shows that in per-barrel terms, the loss is much higher for PADD 1. Based on an estimate of Monroe's market share in PADD 1 of 15.5%[33], I calculate lost economic profits (not accounting) to Monroe are estimated at $248 million (Exhibit 23).

It is important to note that consumers will also pay considerably higher retail prices due to the 2019 standards. The price paid by consumers for a gallon of gas will increase by 3.6 percent.

V. The Proposed 2019 RFS Requirements Heighten the Risk of Shutdown at Several East Coast Refiners

As I discussed previously, refineries on the East Coast face a number of difficult circumstances that affect their profitability, and the economic vulnerability of these refiners cannot be blamed solely on the RFS requirements. However, my analysis shows that the 2019 RFS proposed requirements are likely to substantially exacerbate the financial difficulties of these refiners, potentially pushing profitable refiners into unprofitability.

A. Monroe Energy Would Be Consistently Unprofitable Under the 2019 Requirements

Exhibit 24 shows a comparison of Monroe Energy's actual operating income and per-barrel profit to my estimates of Monroe's operating income and per-barrel profit if the 2019 proposed RFS standards were implemented. Monroe was intermittently profitable between 2012

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[33] *See* Exhibit 7.

and 2017: it had positive operating income in 2014, 2015, and 2017 and negative income in 2012, 2013, and 2016. My model estimates that the implementation of the proposed 2019 standards would subtract about 12.3% from gross revenue, while leaving costs unchanged. This estimate would potentially result in a reduction in profits that would have made Monroe unprofitable in all years between 2012 and 2017. For example, while Monroe made a profit of about $1.03 per barrel in 2017, under the requirements in the proposed 2019 standards, it would have taken a loss of $4.78 per barrel. In 2014, when Monroe had a gain of $0.92 per barrel under that year's standards, it would have taken a loss of $7.32 per barrel under the proposed 2019 standards.

B. United Refining Company Would Move from Mostly Profitable to Unprofitable Under the 2019 RFS Requirements

Exhibit 25 shows that United Refining Company would have moved from an overall positive operating income to a generally negative operating income if the proposed 2019 standards had been in place between 2008 and 2016. For example, in 2014 and 2015 United Refining had positive margins of $5.47 and $5.30 per barrel. However, if the proposed 2019 standards had been in effect, United Refining would have taken losses of $2.35 per barrel in 2014 and $1.17 per barrel in 2015. Even in 2012, when United Refining had a very good year, the proposed standards would have taken it from a profit of $14.54 per barrel to only $2.69 per barrel.

C. PBF Energy Would Move from Consistently Profitable to Consistently Unprofitable Under the 2019 RFS Requirements

Exhibit 26 shows that, similarly to United Refining, PBF Energy would have had consistently negative operating income under the proposed 2019 standards, despite having consistently positive operating income under existing standards between 2012 and 2017. For example, in 2017 PBF made a profit of $1.54 per barrel; this would have been a loss of $4.12 per barrel had the proposed 2019 standards been in effect.

D. Philadelphia Energy Solutions Cited RFS Requirements in its Bankruptcy Filing

The actual experience of Philadelphia Energy Solutions (PES), the largest refiner in the mid-Atlantic region, demonstrates the financial fragility of the PADD 1 refiners. On January 21, 2018, PES filed for Chapter 11 bankruptcy, claiming an inability to comply with the Renewable Fuel Standard requirements. PES had previously announced layoffs in October 2016 of approximately 100 people.[34]

On March 12, 2018, PES proposed a settlement regarding its outstanding RFS obligation. PES agreed to retire 138 million of its 210 million RINs, for a total value of about $75 million, to meet its 2016 and 2017 obligations, and an additional 64.6 million RINs to be applied to its 2018 obligation. The settlement would forgive approximately 70% of PES's renewable fuel obligation.[35]

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[34] Reuters, "Exclusive: Philadelphia Energy Solutions to file for bankruptcy – memo," January 21, 2018, *available at* https://www.reuters.com/article/us-philadelphiaenergysolutions-bankruptc/exclusive-philadelphia-energy-solutions-to-file-for-bankruptcy-memo-idUSKBN1FA18P; Reuters, "Philadelphia Energy Solutions laying off nonunion workers: sources," October 10, 2016, *available at* https://www.reuters.com/article/us-usa-refineries-pes-idUSKCN12A1VM. The number of layoffs comes from https://www.businessinsider.com/r-four-years-after-rescue-us-refinery-reels-as-investors-profit-2016-11, which states that 25% of the nonunion labor force was laid off, and https://www.reuters.com/article/us-usa-refineries-pes-idUSKCN12A1VM, which lists the number of nonunion employees in 2014.

[35] Consent Decree and Environmental Settlement Agreement, *In re: PES Holdings, LLC, et al., Debtors*, dated March 12, 2018.

VI. A Refinery Shutdown Would Put a Substantial Number of Jobs at Risk

Refineries employ a wide range of people across a number of job categories. Exhibit 27 shows the percent of refinery employment in different geographic areas. While this shows that refineries do not account for a large share of employment within the entire PADD, it also shows that they are very important locally. In 2018, refineries accounted for about 0.1% of the jobs in New Jersey, Delaware, Pennsylvania, and West Virginia, but a full 3.69% of the jobs in McKean County, PA, located in the northwestern part of the state. Refinery shutdowns, such as the one that hit York County, VA have the potential to be highly disruptive locally.[36]

In 2012, the Pennsylvania Center for Workforce Information and Analysis conducted a reemployment and economic impact study for potential closings of the ConocoPhillips and Sunoco facilities in Delaware County, PA.[37] This study used an estimate that 18.3 jobs would be lost in Southeast Pennsylvania for each refinery layoff in the region, and 22 jobs would be lost across Pennsylvania as a whole. These lost jobs are either indirect ("in related industries" such as suppliers to or customers of the refinery industry) or induced (in industries impacted by reduced spending).[38] A job loss multiplier of 18.3 implies that for every 100 lost refinery jobs in Pennsylvania 1,830 total jobs would be lost (or 1,730 additional jobs), while a multiplier of 22 implies that for every 100 lost refinery jobs, 2,200 total jobs would be lost. If a large refinery

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[36] The latest quarter with employment data prior to the refinery closing in York County, VA was Q2 2009, with a percent of refinery employment of 1.2%. *See* U.S. Census Bureau, Quarterly Workforce Indicators data, *available at* https://qwiexplorer.ces.census.gov.

[37] Reemployment Assessment and Economic Impact of ConocoPhillips and Sunoco Closings, Center for Workforce Information & Analysis, January 9, 2012 ("CWIA 2012").

[38] CWIA 2012, Appendix C. The report also includes a national multiplier of 61. However, the national multiplier may have ignored the possibility that refiners in the Midwest and Gulf Coast would increase production in response to the East Coast refinery closure.

with approximately 800 jobs were shut down and only half of the employees were reemployed, the Pennsylvania Center's 18.3 multiplier would suggest that over 7,300 jobs might be lost in the region and over $539 million would be lost in labor income and 8,800 jobs might be lost in the state (Exhibit 28). If these significant job losses were to be realized, it would constitute a substantial negative economic impact on the local and regional economy.

VII. Technical Description of the Analysis

This section provides technical details of the analysis used above. Basic economics can be used to understand and quantify the impact of the RFS on refiners and consumers of motor fuels. Specifically, positive RIN prices effectively serve as a tax on the consumption and production of conventional fuels, and with some modifications a standard economic framework—tax incidence analysis—can be used to trace out the effects of the RFS.

A. The Effect of the RFS on Gasoline Supply and Demand

A standard supply-demand diagram illustrates the effects of the Renewable Fuel Standard. In Exhibit 29, the upward sloping line is the supply of refined petroleum products, with the quantity of production on the horizontal axis and the price on the vertical axis. The downward sloping line is the demand curve. In the absence of a binding blend wall for gasoline, the price $P*$ and quantity $Q*$ of fuel is determined by the intersection of the supply and demand curves.

The RFS compliance mandate falls on refiners. When the blend wall binds, refiners must purchase excess RINs, raising the RIN price above zero. The supply curve (which represents the marginal cost of supply) shifts up by the price of the RIN, P^{RIN}.[39] The intersection of the RIN-inclusive supply curve and the demand curve shifts to P^R and Q^R. Note that the quantity of consumption and production declines. Further, P^R is the price that consumers pay, but producers receive only P^R- P^{RIN} because they must pay for the RINs required to achieve compliance. This point is given by the point on the net-of-RIN supply curve corresponding to Q^R.

Thus, a positive RIN price increases the price that consumers pay for fuel, reduces the price that refiners receive, and reduces the quantity of conventional fuel consumed. These price and quantity changes result in transfers from consumers and refiners to the sellers (and producers) of RINs, biofuel producers, who effectively collect the RIN tax.

B. Determining the Price of a RIN

Normally in an analysis of tax effects on price and quantity, the tax would be a fixed amount (e.g., as in the case of state and federal gasoline taxes) or a percentage of the price. In the case of the RFS, the "tax" is not a fixed amount or a fixed percentage. Instead, the RIN price depends on the demand and supply for RINs. The demand for RINs is determined by the gasoline market and by the amount of biofuel required by the RFS. The supply of RINs is determined by the production of biofuel and by the physical constraint of the ethanol "blend wall."

First consider the demand for RINs. Gasoline blenders buy refined motor gasoline from refiners and ethanol from ethanol producers. Blenders then sell the RINs associated with the

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[39] The price and quantity effects do not depend on where the compliance burden falls. If consumers must acquire RINs, the demand curve falls by P^{RIN} and the prices paid by consumers and received by refiners, and the equilibrium quantity, are the same as when the compliance burden falls on refiners. Here P^{RIN} is the price per gallon of RINs multiplied by the fractional compliance standard.

ethanol back to refiners, who return the RINs to the EPA. Exhibit 30 shows the outcome with two different RIN prices, P^{RIN} and P^{RIN*}. Note that with the higher RIN price, the quantity of fuel consumed declines. The total quantity of RINs demanded is equal to the product of the fractional compliance amount and the quantity of fuel consumed. Thus, for a given fractional compliance standard, with a higher RIN price, fewer RINS are demanded. This is illustrated as a movement along the D_{RIN} curve in Exhibit 31. As the compliance standard increases, the demand for RINs shifts outward because at any given quantity of fuel, more RINs are required from refiners. This is seen in the shift from D_{RIN} to $D_{RIN'}$ in Exhibit 31.

Now consider the supply of RINs. RINs are supplied when biofuels are produced, with the amount of RINs per gallon depending on the type of biofuel. In the gasoline market, as long as the RFS requirements can be met by adding ethanol to gasoline, the cost (and therefore the price) of producing a RIN is effectively 0, aside from any administrative costs that vary by the number of RINs. The reason is that blenders purchase the RIN along with the ethanol. If the blenders were to sell the acquired RINs to refiners at a price greater than 0, refiners' costs would increase and they would have to increase their prices by the amount of the RIN price to compensate.

The cost of a RIN changes once the RFS requirements reach the physical constraint of the "blend wall." The amount of ethanol that can be consumed in conventional automobile engines is limited by technical constraints to approximately 10 percent—an amount of renewable fuel that is lower than what the RFS currently requires. The additional RINs necessary to meet the requirement must come from the production of other types of biofuel. The structure of the RFS program allows RINs from other types of biofuel—either advanced biofuel or biodiesel—to be used in place of RINs generated from ethanol. In the RFS program's terminology, D4 and D5 RINs (from biodiesel and advanced biofuel) can be used to cover the D6 RIN obligation. Thus, an RFS fractional compliance standard that is sufficiently strict to cause the blend wall to bind creates a demand for D4 and D5 RINs, which in turn creates a demand for biodiesel.[40]

Exhibit 31 illustrates the supply and demand for RINS. The demand curve for RINs is derived from the market for blended gasoline shown in Exhibit 30. The quantity of RINs demanded for a given RIN price depends on the equilibrium quantity of gasoline, taking into account the supply shift from the cost of the RIN. The supply curve of RINs is determined by the difference between the marginal cost of producing biodiesel and the price of diesel fuel: biodiesel is more expensive to produce than conventional diesel, but sells at the conventional diesel price, so biodiesel will be produced only if the value of the RIN generated from the production of biodiesel covers this higher cost. The market-clearing D4/D5 RIN price is given by the intersection of the supply and demand curves. Further, when the blend wall is binding, and both D6 and D4/D5 RINs can be used to achieve D6 compliance, the prices of these RINs are (approximately) the same.

Recall that changing the fractional compliance amount shifts the demand curve for RINs. Thus, changing this amount affects the price of RINs—and the magnitude of the RIN tax—in a similar way as an increase in the RIN price, as illustrated in Exhibit 32. In this exhibit, an increase in the fractional compliance amount shifts the blended gas supply curve upward,

[40] For a deeper analysis of this mechanism, see Scott Irwin and Darrell Good, "Is Speculation Driving Up the Price of RINS?" *farmdoc daily* (3): 77, Department of Agricultural and Consumer Economics, University of Illinois at Urbana-Champaign, April 24, 2013. *Farmdoc daily* contains numerous other articles describing this mechanism.

shifting out the demand curve for RINs, which given the upward-sloping supply curve, drives up the price of RINs. This, in turn, increases the RIN tax, which reduces the price refiners receive for conventional fuels, and increases the price that consumers pay for them.

To summarize, positive RIN prices serve as a tax on the consumption and production of conventional fuels, and the larger the fractional compliance quantity is, the larger the size of the tax. Thus, increasing the fractional compliance amount increases the prices consumers pay for fuel, and reduces the prices refiners receive.

C. Predicting the RIN Price Under Different Scenarios

Putting the above theoretical analysis into a practical model required determining the following: (1) the supply curve for refined products; (2) the supply curve for biodiesel; (3) the demand curve for gasoline. I estimate the first two using publicly available data, and use estimates from the academic literature on gasoline demand for the third.

Retail gasoline sold at the pump is a blend of petroleum-derived motor gasoline and ethanol, which are blended in fixed proportions. Because of the blend wall discussed previously, a gallon of retail gas is currently 90% motor gasoline and 10% ethanol (a blend referred to as E10). The EPA Renewable Fuel Standard implicitly sets the renewable fuel requirement higher, and the current proposal for 2019 is 10.88%. This higher requirement, because it cannot be met by blending ethanol at 10.88%, is met through the purchase of RINs generated through the production of other biofuels. One can therefore treat the price of retail gas as 0.9 times the price of refined gas plus 0.1 times the price of ethanol plus the cost of the RINs necessary to meet EPA requirements.

The cost of producing a gallon of gasoline is somewhat difficult to quantify because of the nature of the production process. Refined products such as motor gasoline, diesel, aviation fuel, and kerosene are produced from a single barrel of crude oil through fractional distillation, and producing gasoline alone could only be done by throwing away the other components.[41] Since motor gasoline is only produced in combination with other refined products, gasoline supply is best thought of in terms of the supply of refined products generally.

To estimate the cost of manufacturing a gallon of refined products from crude oil, I assume that the marginal cost of production is a translog function of the quantity produced. This means that for every percent increase in quantity produced, cost will increase by some fraction of a percent. This is a common functional form for estimating production costs. More specifically, I regress the natural log of marginal production cost of a gallon of refined product on the natural log of quantity of refined product and the natural log of the price of a barrel of crude.

In a competitive market, price is equal to the marginal cost of production, so I use price as a proxy for marginal cost. To assign a single price to the full range of refined products created from a barrel of crude oil, I weight the price of the product by the portion of the output it accounts for, e.g. if motor gas accounts for 42% of the output, the wholesale price of motor gas gets a weight of 42% in the price of finished product. It was not possible to match all refined products with their equivalent prices, particularly for products that make up smaller fractions of the total refined product. I therefore used only the 5 refined products that made up the largest

[41] "Oil: Crude and Petroleum Products Explained, Refining Crude Oil," EIA, *available at* https://www.eia.gov/energyexplained/index.php?page=oil_refining#tab2.

shares of the total. These refined products accounted for between about 80 and 95 percent of the total refined product volume.

An important complication in the estimation of supply curves is that changes in price and quantity can be due to movement along the supply curve (in which case the price and quantity pairs trace out the supply curve) or due to shifts in the supply curve. A shift in the supply curve could be a result of a number of factors, such as changes in the availability of imported gas.[42] A standard approach is to use instrumental variables estimation to identify the supply curve, where the instrumental variables are demand shifters.[43] The demand shifters used were the unemployment rate, average temperature, air miles traveled, and freight carloads shipped.

Data for the estimation come from several sources. Data on number of barrels processed and prices and quantities of finished products are from the Energy Information Agency ("EIA"). I use the Producer Price Index to rescale all prices to 2018 dollars. The EIA also supplies information on the percent utilization of refining capacity, which can be used to infer total refining capacity in barrels of crude. Unemployment rates are from the Bureau of Labor Statistics. Data on average temperatures are from NOAA. Time series on air miles traveled and freight carloads shipped are available from the St. Louis Federal Reserve Bank.

Observations in the data are defined by month at the level of the PADD. PADD 1 encompasses the East Coast states, including West Virginia and all of New England. PADD 2 encompasses the Midwestern states, including Kentucky and Tennessee. PADD 3 consists of the

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[42] Weinhagen, J. 2003. "Consumer gasoline prices: An empirical investigation." *Monthly Labor Review* July 2003: 3–10.

[43] Peter Kennedy, *A Guide to Econometrics*, Fifth Edition, MIT Press, 1998, pp. 182–186.

Gulf Coast states, excluding Florida, plus Arkansas and New Mexico. PADDs 4 and 5, which are not included in the analysis presented here, consist of the Rocky Mountain states and the West Coast. I disregard PADDs 4 and 5 because most inter-PADD shipments occur between PADDs 1, 2, and 3.[44]

I use these data to estimate the translog cost function, with the natural log of refined product price as the dependent variable. The estimated coefficient on log quantity was 0.75 and the coefficient on log input price was 0.89; both were significant at 1 percent. This means that a one percent change in output is associated with a 0.75 percent change in marginal production cost, and that a one percent change in the price refiners pay for crude increases cost by 0.89 percent.

The cost curve for biodiesel is important because biodiesel is used to meet the RIN requirement for gasoline. If biodiesel is cheap to produce, it will be cheap to meet the RFS requirement for blended gasoline. If biodiesel is expensive, meeting the requirement will also be expensive.

Biodiesel can be made from a number of different feedstocks, but soy oil is by far the most common, accounting for about half of the feedstock used in 2017. Corn and canola oil accounted for an additional 26%.[45] Other important inputs to biodiesel include methanol and natural gas.

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[44] "PADD regions enable regional analysis of petroleum product supply and movements," Feb. 7, 2012, *available at* https://www.eia.gov/todayinenergy/detail.php?id=4890.

[45] EIA, "Monthly Biodiesel Production Report With data for April 2018," Independent Statistics & Analysis, June 2018, available at https://www.eia.gov/biofuels/biodiesel/production/biodiesel.pdf, accessed on July 19, 2018.

I estimate cost curves for biodiesel taking a similar approach to the cost curves for refined products. As with refined products, I use an exponential cost function and employ air miles traveled and freight carloads shipped as demand shifters. I used data from 2012 and later, since biodiesel production was very low prior to that point. The regression determines the relationship between output price and quantity, controlling for the input prices of soy oil, methanol, and natural gas. Data on biodiesel prices are from the U.S. Alternative Fuel Data Center. Data on prices for the other inputs are from the EIA, with the exception of methanol prices, which are from the Methanex corporation. PADD-level detail is not available for all variables, so observations are at the monthly level for the entire United States. The coefficient on log quantity produced was 0.006, and the coefficient on soy oil price was 0.19, and the coefficient on soy oil price was 1.1. Both were statistically significant at the 1 percent level.

Finally, the model requires estimates of the elasticity of demand for gasoline. The demand for gasoline has been a popular topic in economics, so I select estimates of gasoline demand from the literature, rather than create an additional estimate here.

Most studies have found that gasoline demand is highly price-inelastic, i.e., consumers do not adjust their behavior very much in response to price. Recent estimates of the price elasticity of retail gasoline are in the range of -0.04 to -0.25, which means that a 10 percent increase in the price of gas would reduce consumption by between 0.4 and 2 percent.[46] One set of estimates

[46] *See* Hughes, JE; Knittel, CR, Sperling, D. (2008). "Evidence of a Shift in the Short-Run Price Elasticity of Gasoline Demand." *The Energy Journal* 29 (1): 113–134. Park, Sung Y.; Zhou, Guochang (2010). "An estimation of U.S. gasoline demand: A smooth time-varying cointegration approach," *Energy Economics 32*, 110–120.

puts the elasticity higher, at -0.25 to -0.30, which would mean that a 10 percent increase in the price of gas results in a 3 percent reduction in the amount of gas consumed.[47]

The above elasticity estimates differ substantially from each other, but all indicate that consumers are relatively unresponsive to price. When the elasticity of demand is close to zero, an increase in production costs can be passed through to consumers in the form of higher prices, leaving producers' profits relatively unaffected. One study of the RFS program, using RIN price and wholesale fuel price spreads for the years 2013-2015, shows that RIN prices are rapidly incorporated into the wholesale price of gas.[48] However, a later study shows that pass-through rates were lower for domestic products in 2015 and 2016.[49] This second study suggests that refiners are at risk for additional costs from the RFS program. Note that, based on the analysis in Section V, even with a high RIN price pass-through rate, refiners' profits can be adversely affected in a way that may affect their survival.

A final point worth noting is that biodiesel may have some important limitations. It has been linked with clogged fuel filters due to impurities like bacteria and sterol glucosides.[50] It also is more difficult to store than petroleum diesel, since biodiesel can degrade over time.[51]

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[47] Levin, Laurence; Lewis, Matthew; Wolak, Frank (2017). "High Frequency Evidence on the Demand for Gasoline," *American Economic Journal: Economic Policy Vol. 6, No. 3,* 314–347.

[48] Knittel, CR; Meiselman, BS; Stock, JH. 2017. "The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard." *Journal of the Association of Environmental and Resource Economists* 4 (4): 1081–1119.

[49] "Re-examining the Pass-through of RIN Prices to the Prices of Obligated Fuels", Charles River Associates, October, 2016, pp. 8–9.

[50] Intertek, "Biodiesel Fuel Filter Blocking Problems," *available at* http://www.intertek.com/biofuels/biodiesel/fuel-filter-blocking-problems/, accessed on July 19, 2018.

[51] Biofuel.org.UK, "Biofuel Chemistry: What are Biofuels and How are They Made?" *available at* http://biofuel.org.uk/how-are-biofuels-produced.html, accessed on July 19, 2018.

Although not addressed here, these problems may limit the degree to which biodiesel can be added to the fuel supply.

Based on the above estimates, and the model calibrated using those estimates, I calculate consumer and refiner deadweight loss and transfers to biodiesel producers, as well as deadweight loss from biodiesel production. Under the 2019 RFS requirements, a total of $13 billion would be transferred from consumers to biofuel manufacturers, of which $8.6 billion is through gasoline. Refiners would lose about $4.7 billion in transfers to biodiesel producers, with the amount split roughly equally across PADDs. However, it is important to note that these are absolute amounts, not per barrel or percentages of production. As Exhibit 22 showed, in terms of the cost per barrel produced, the burden falls much more heavily on PADD 1 refiners. The deadweight loss is fairly limited, since the quantity of refined product produced does not change much. Deadweight loss to consumers comes to $109 million under the 2019 proposed standards, most of which (as with the transfers) occurs in the gasoline market. Refiner deadweight loss is $42.5 million. Biodiesel producers receive a benefit of $1.8 billion in transfers from consumers and refiners. The remainder of the transfer from consumers and refiners goes to ethanol producers in the form of higher RIN prices. Finally, the deadweight loss from the biodiesel market is $472 million, which comes from production of an inefficiently large amount of biodiesel.

VIII. Conclusion

Economically, the RFS acts as a tax on the production and consumption of motor fuels. Like all taxes, the RIN tax increases the prices consumers pay for these products, and reduces the prices refiners receive. The crucial distinction between the RIN tax and conventional taxes is that it is not in a fixed amount, but has a size that depends on the RFS mandates adopted by the EPA: when the EPA increases the mandated consumption of biofuels, it imposes a larger tax, and hence larger impacts on producers and consumers.

Using standard economic analysis, and extensive data on the production and refining of motor fuels and biofuels, I quantify the impact of moving from a mandate where the price of RINs are zero, to the mandate proposed by the EPA for 2019. This impact is large, on both consumers and producers.

The impact will fall particularly heavily on refiners on the East Coast of the United States. I estimate that refining margins (the gross profit per barrel) will fall by 12.5 percent in this region as a result of the 2019 EPA proposal as compared to a mandate level at which the price of RINs is zero. This decline in gross margin is large enough to make many refineries on the East Coast unprofitable, and thereby is large enough to cause some refineries to shut down, with a consequent loss of jobs.

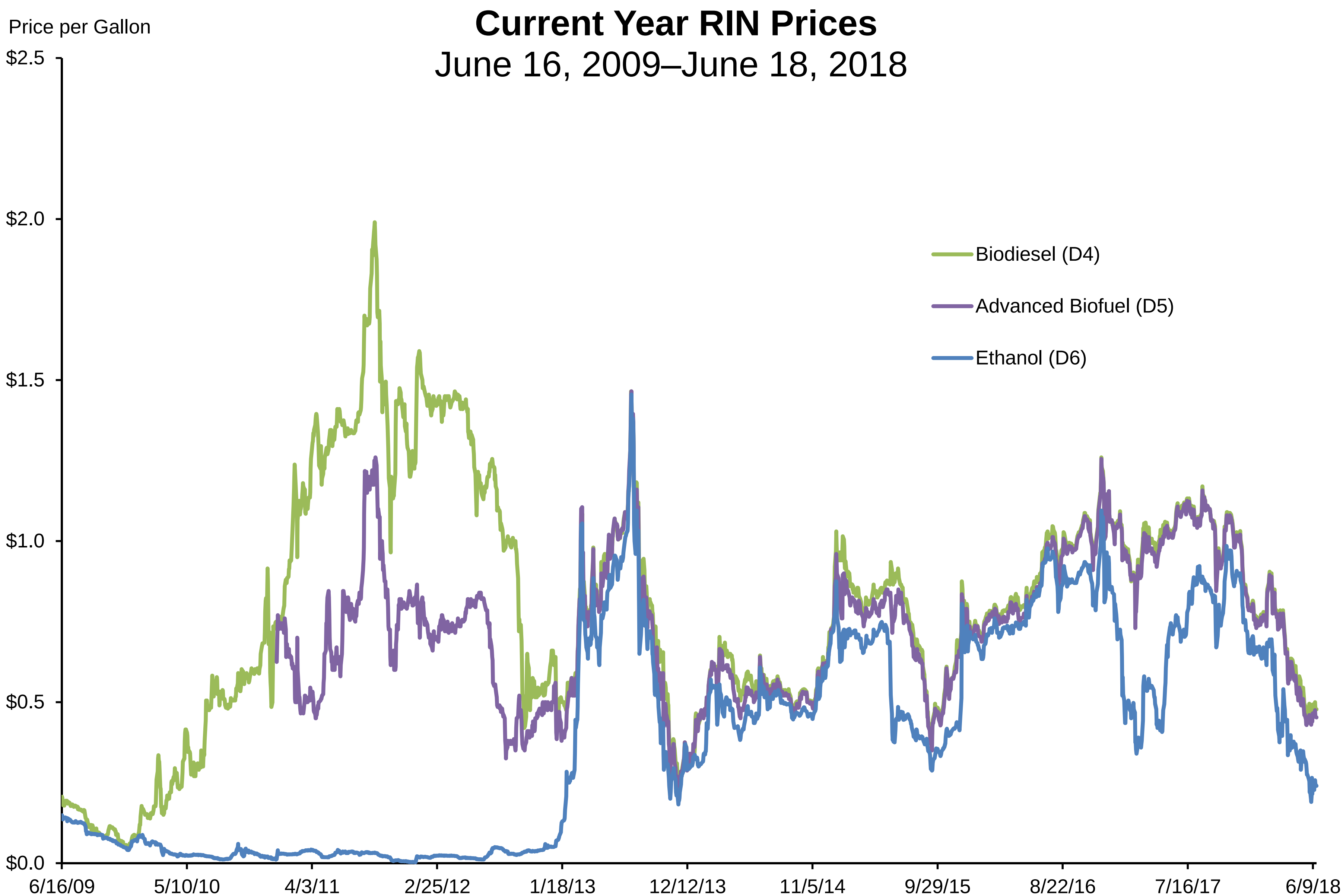
Exhibit 1

Renewable Fuel Standard Mandates

	Volume Required (in Billion Gallons)				Percent Required			
	Cellulosic Biofuel	Biomass-Based Diesel	Advanced Biofuel	Renewable Fuel	Cellulosic Biofuel	Biomass-Based Diesel	Advanced Biofuel	Renewable Fuel
2018 Mandates	0.288	2.10	4.29	19.29	0.159%	1.74%	2.37%	10.67%
2019 Proposal	0.381	2.10	4.88	19.88	0.209%	1.72%	2.67%	10.88%
Percent Change	32.3%	0.0%	13.8%	3.1%	31.4%	-1.1%	12.7%	2.0%

Source: EPA

Exhibit 2



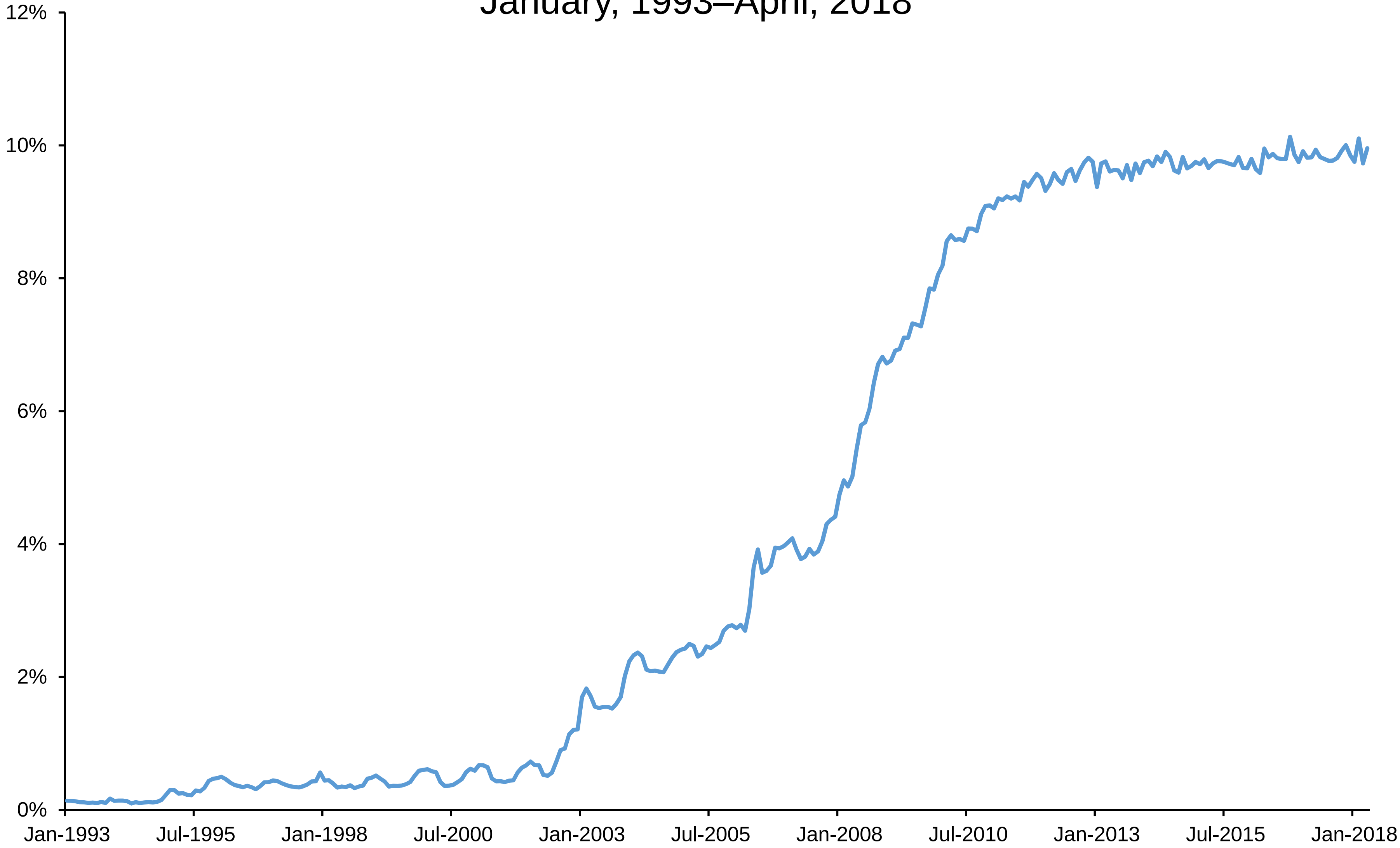
Source: OPIS

Note: Daily average prices are shown on the graph.

Exhibit 3

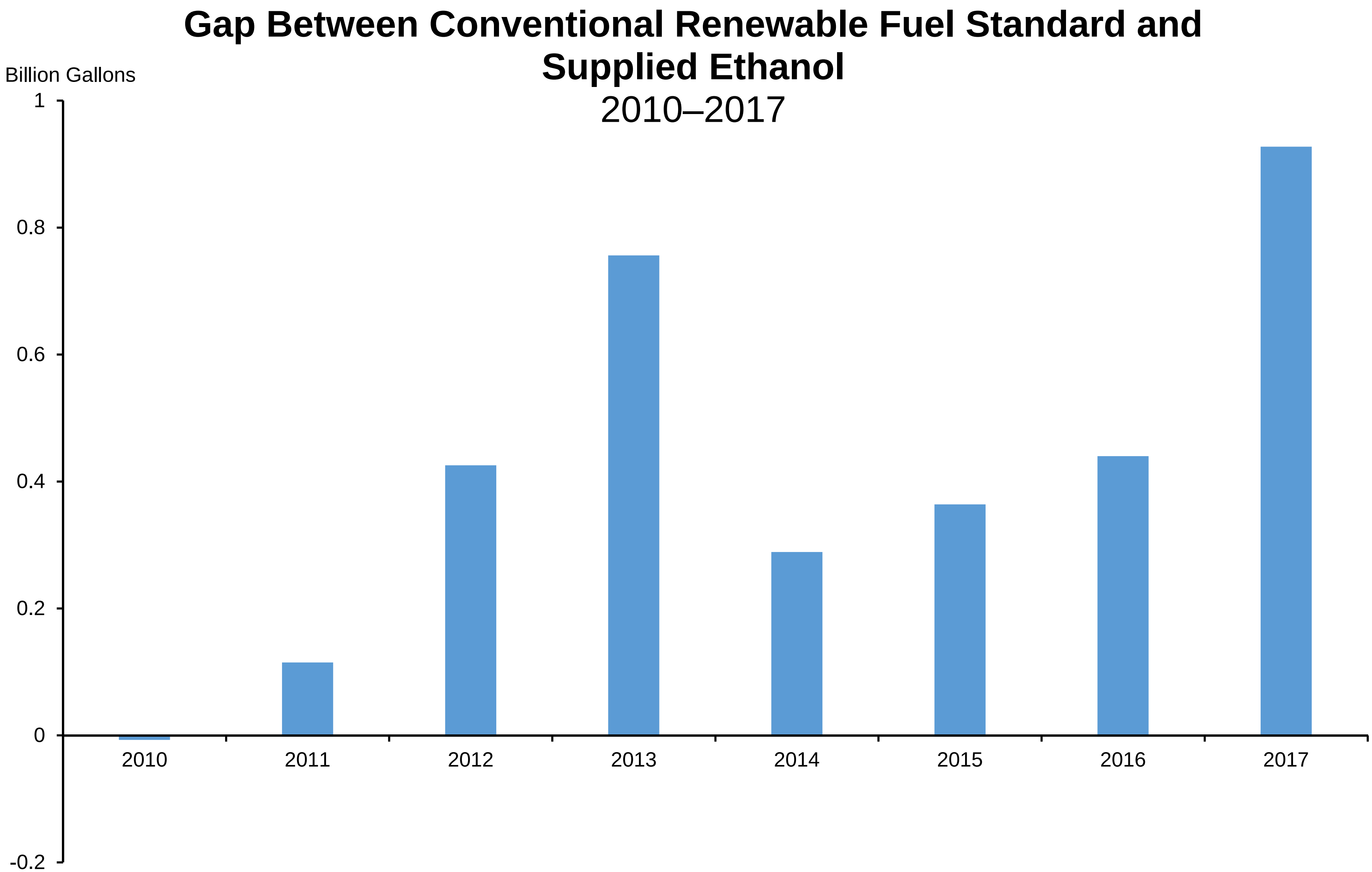
U.S. Refinery and Blender Net Ethanol Input as a Percentage of Supplied Finished Motor Gasoline

January, 1993–April, 2018



Source: EIA

Exhibit 4

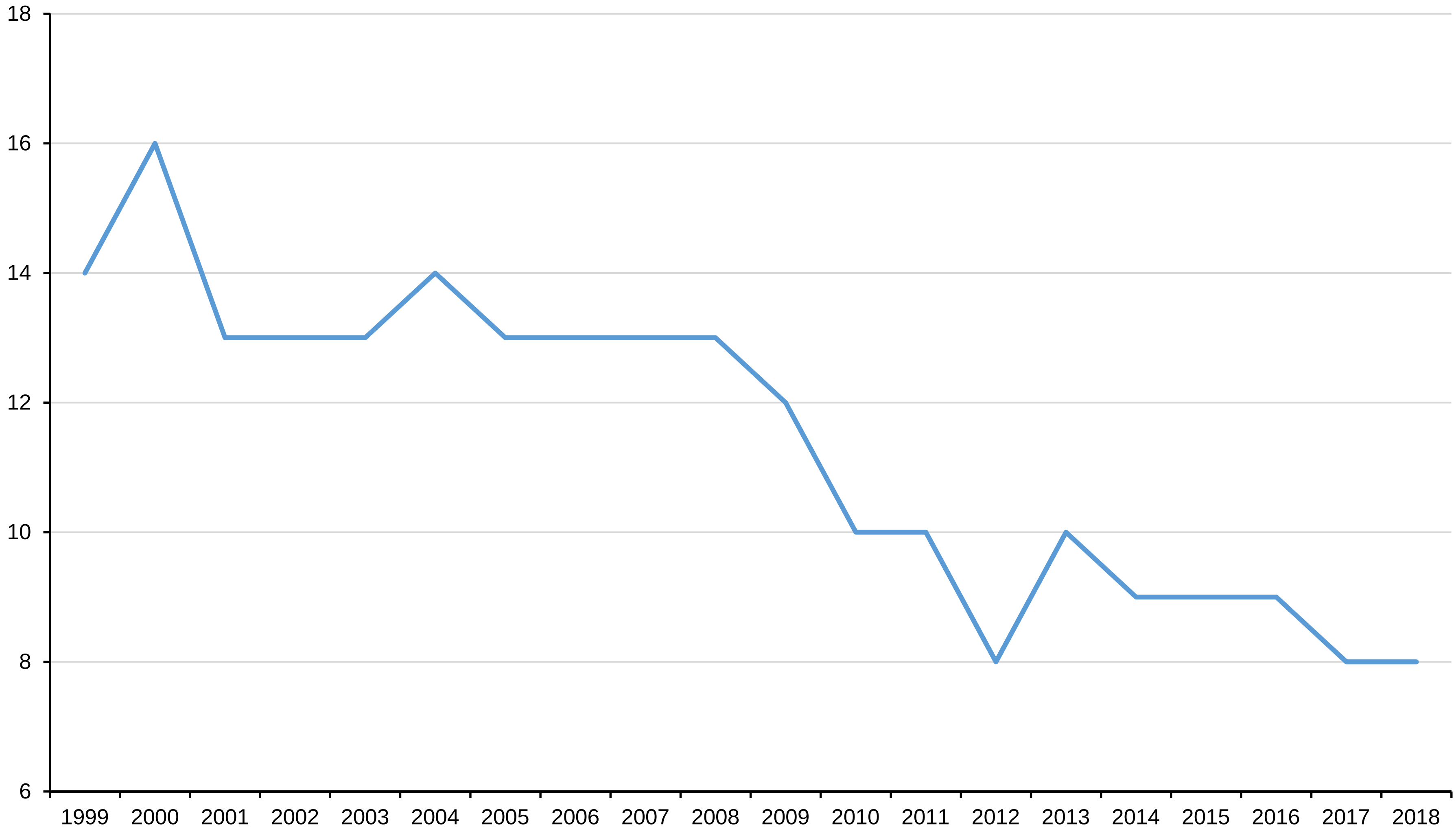


Source: EIA; EPA

Note:
[1] Conventional renewable fuel standard is calculated by subtracting advanced biofuel volume mandates from renewable fuel mandates.
[2] The gap is calculated by subtracting U.S. refinery and blender net input of fuel ethanol from conventional renewable fuel standards.

Exhibit 5

PADD 1 Number of Operating Refineries
1999–2018



Source: EIA

Note:
Only included operating refineries and excluded idle (but operable) refineries. There were three idle refineries in 2010, for example. *See* "East Coast (PADD 1) Number of Idle Refineries as of January 1", EIA, June 25, 2018, *available at* https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=8_NA_8OI_R10_C&f=A.

Refinery Closures in PADD 1
2010–2017

Company Name[1]	State	Site	Year of Closure[2]	Total Operable Capacity[3] (Barrels per Calendar Day)
Sunoco Inc	New Jersey	Westville	2010	145,000
Western Refining Yorktown Inc	Virginia	Yorktown	2011	66,300
Sunoco Inc	Pennsylvania	Marcus Hook	2011	178,000
Chevron USA Inc	New Jersey	Perth Amboy	2012	80,000
Hess Corporation	New Jersey	Port Reading	2013	70,000
Axeon Specialty Products LLC	Georgia	Savannah	2014	28,000
Axeon Specialty Products LLC	New Jersey	Paulsboro	2017	74,000
Total Capacity Closed				641,300

Source: EIA

Note:
[1] Included all operable refineries, including idle (but operable) refineries. There were three idle refineries in 2010, for example. *See* "East Coast (PADD 1) Number of Idle Refineries as of January 1", EIA, June 25, 2018, *available at* https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=8_NA_8OI_R10_C&f=A.
[2] Considered the year in which a facility was shut down to be the year of closure.
[3] Recorded total operable capacity as of the year of closure. Total operable capacity refers to atmospheric crude distillation capacity. Used cat cracking fresh feed downstream charge capacity for the current year for Hess Corporation, because total operable capacity is not available.

Exhibit 7

PADD1 Refineries

January 1, 2018

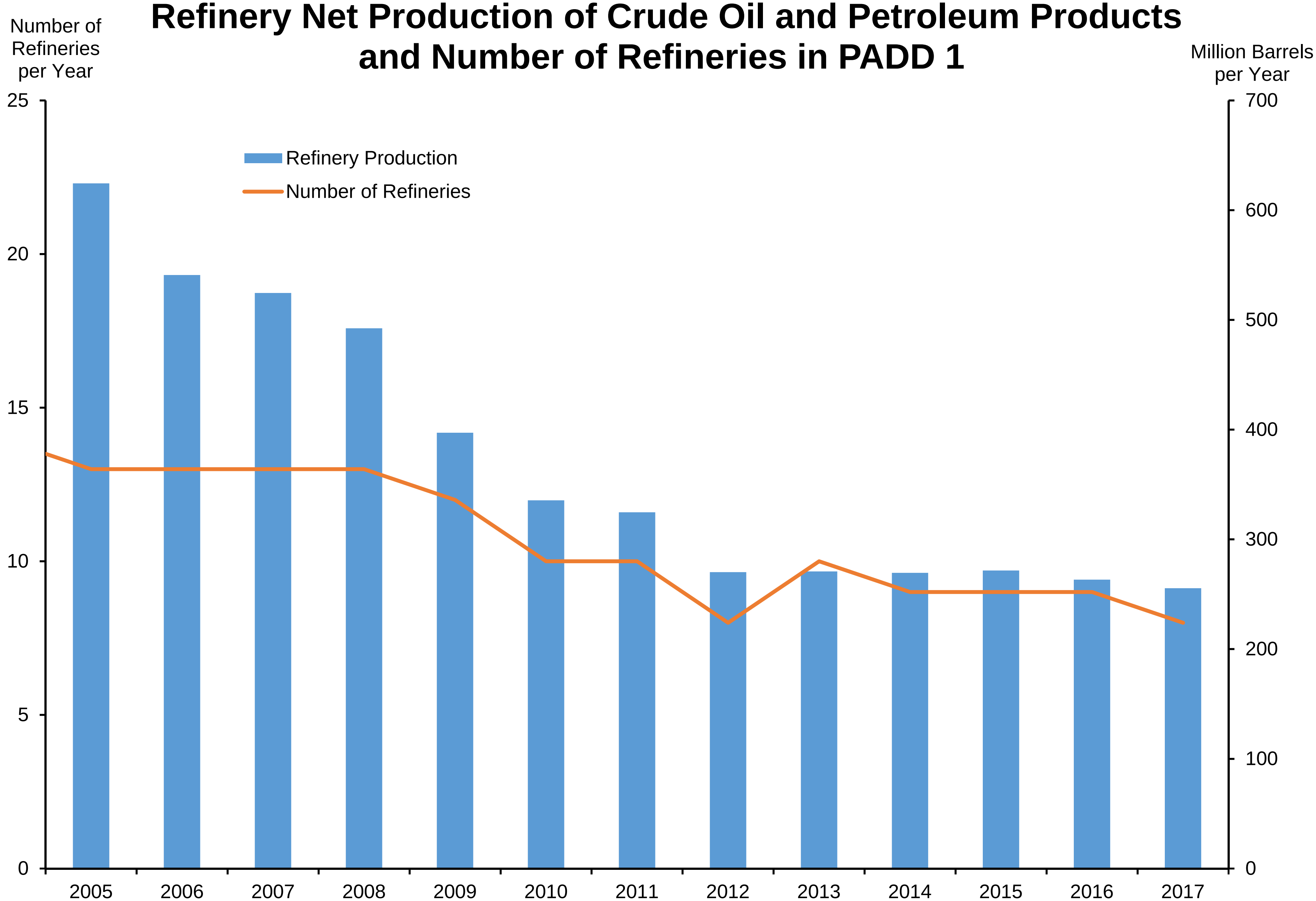
	Company	Corporation	State	Site	Total Operable Capacity[1] (Barrels per Calendar Day)	Percent of Total
1	American Refining Group Inc	American Refining Group Inc	Pennsylvania	Bradford	11,000	0.9%
2	Delaware City Refining Co LLC	PBF Energy Co LLC	Delaware	Delaware City	182,200	14.9%
3	Ergon West Virginia Inc	Ergon Inc	West Virginia	Newell	22,300	1.8%
4	Monroe Energy LLC	Delta Air Lines Inc	Pennsylvania	Trainer	190,000	15.5%
5	Paulsboro Refining Co LLC	PBF Energy Co LLC	New Jersey	Paulsboro	160,000	13.1%
6	Philadelphia Energy Solutions	Carlyle Group	Pennsylvania	Philadelphia	335,000	27.4%
7	Phillips 66 Company	Phillips 66 Company	New Jersey	Linden	258,000	21.1%
8	United Refining Co	Red Apple Group Inc	Pennsylvania	Warren	65,000	5.3%
	Total				**1,223,500**	**100.0%**

Source: EIA

Note:
[1] Total operable capacity refers to atmospheric crude distillation capacity.

Exhibit 8

Refinery Net Production of Crude Oil and Petroleum Products and Number of Refineries in PADD 1

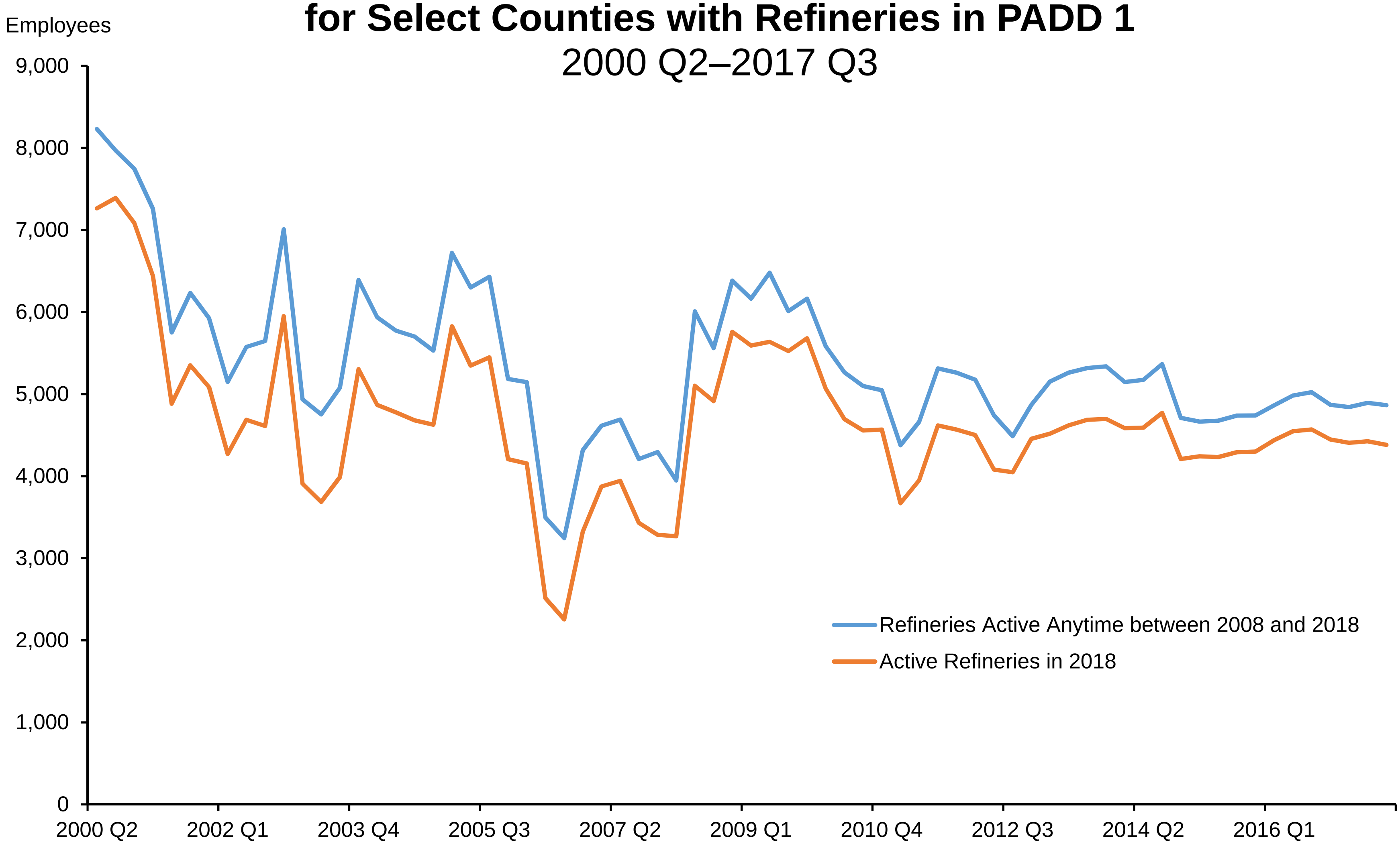


Source: EIA

Exhibit 9

Employments in Petroleum and Coal Products Manufacturing for Select Counties with Refineries in PADD 1

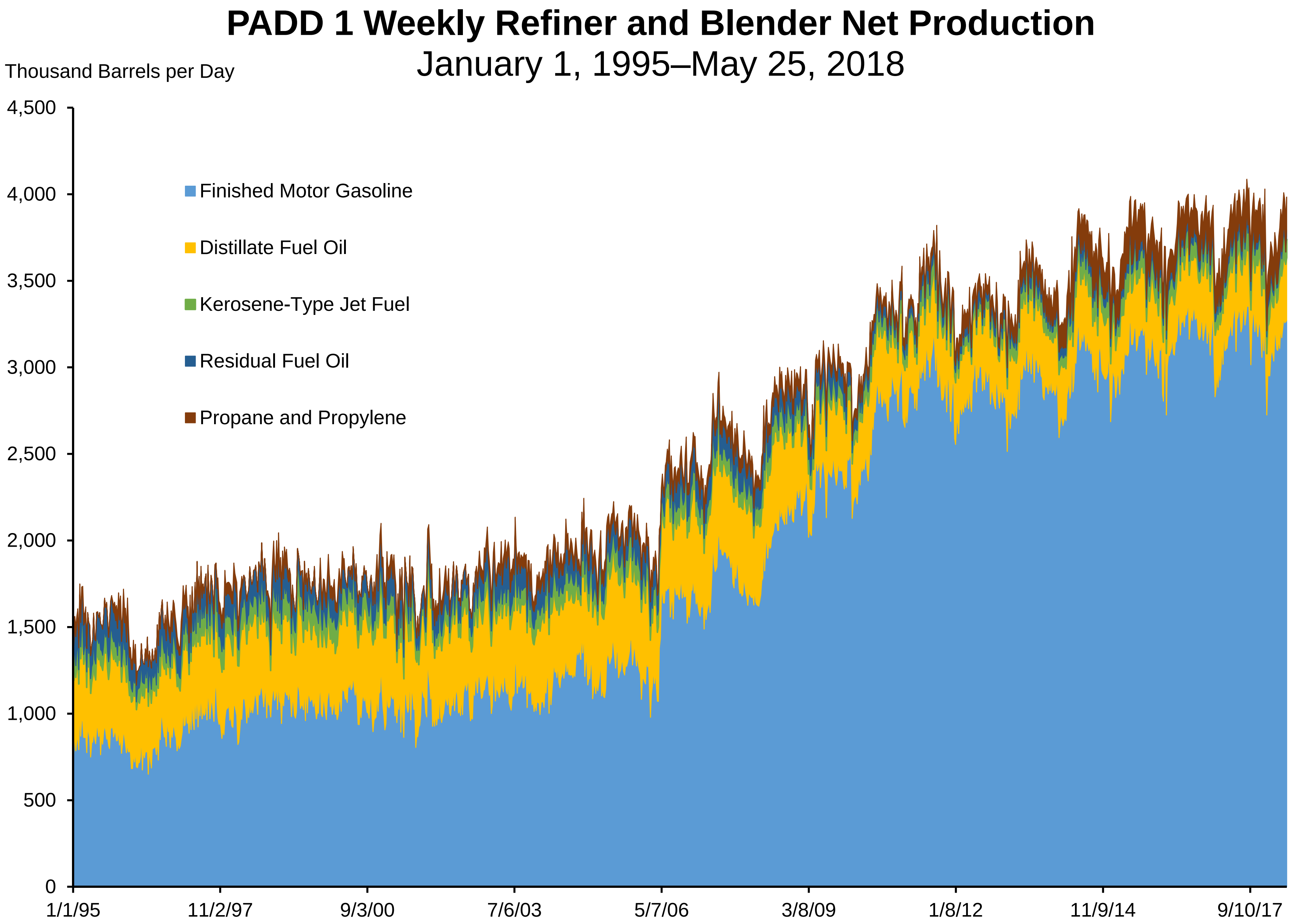
2000 Q2–2017 Q3



Source: U.S. Census Bureau; EIA

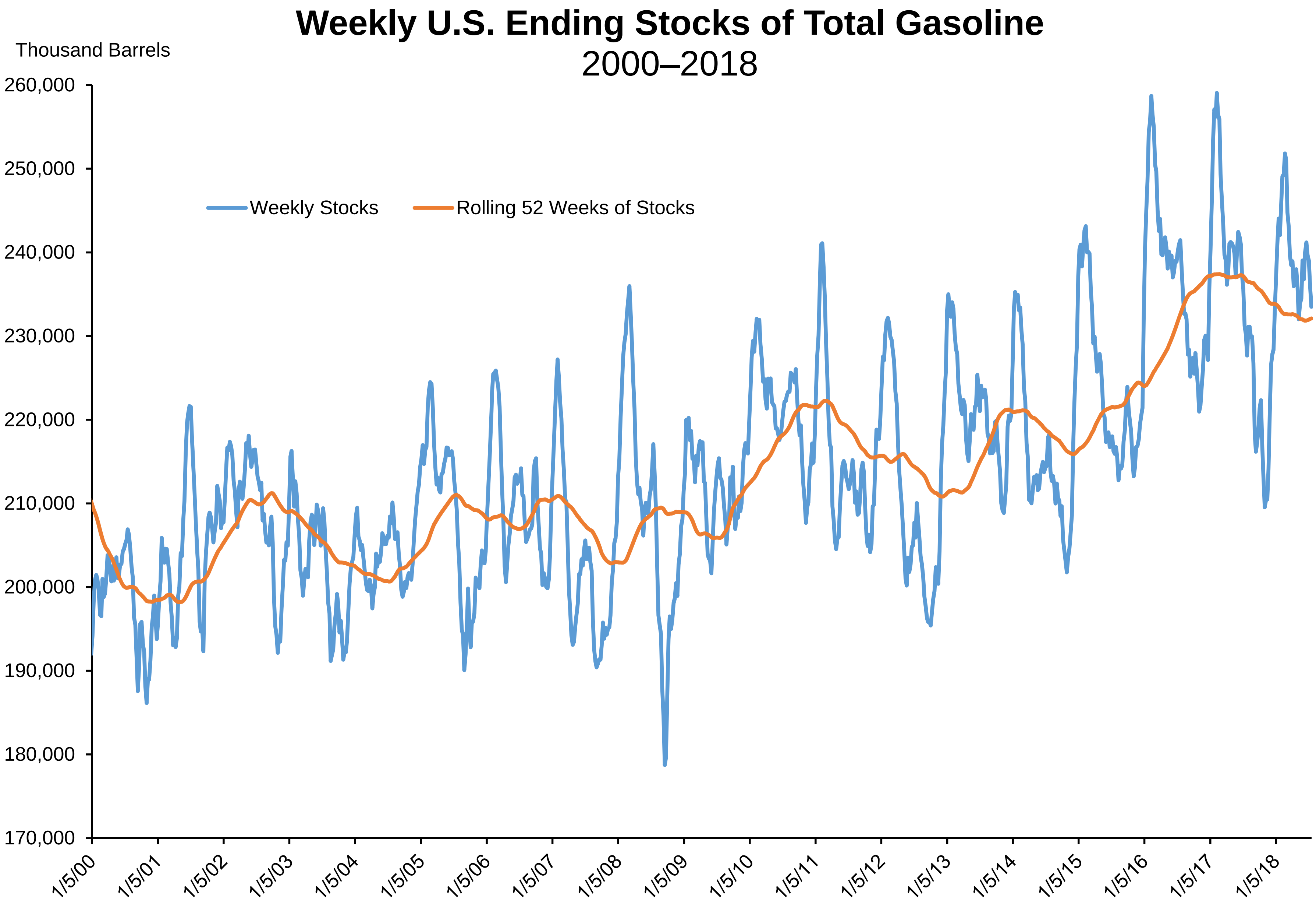
Note: Employments in the following counties are included for refineries active anytime between 2008 and 2018: York County, VA; New Castle County, DE; Hancock County, WV; Chatham County, GA; Gloucester County, NJ; Union County, NJ; Middlesex County, NJ; Warren County, PA; Delaware County, PA; Philadelphia County, PA; and McKean County, PA. Employments in York County, VA, Chatham County, GA, and Middlesex County, NJ are excluded from the currently active refineries series. Refinery employment is defined as jobs under NAICS code 3241. Some employment data points are fuzzed values.

Exhibit 10



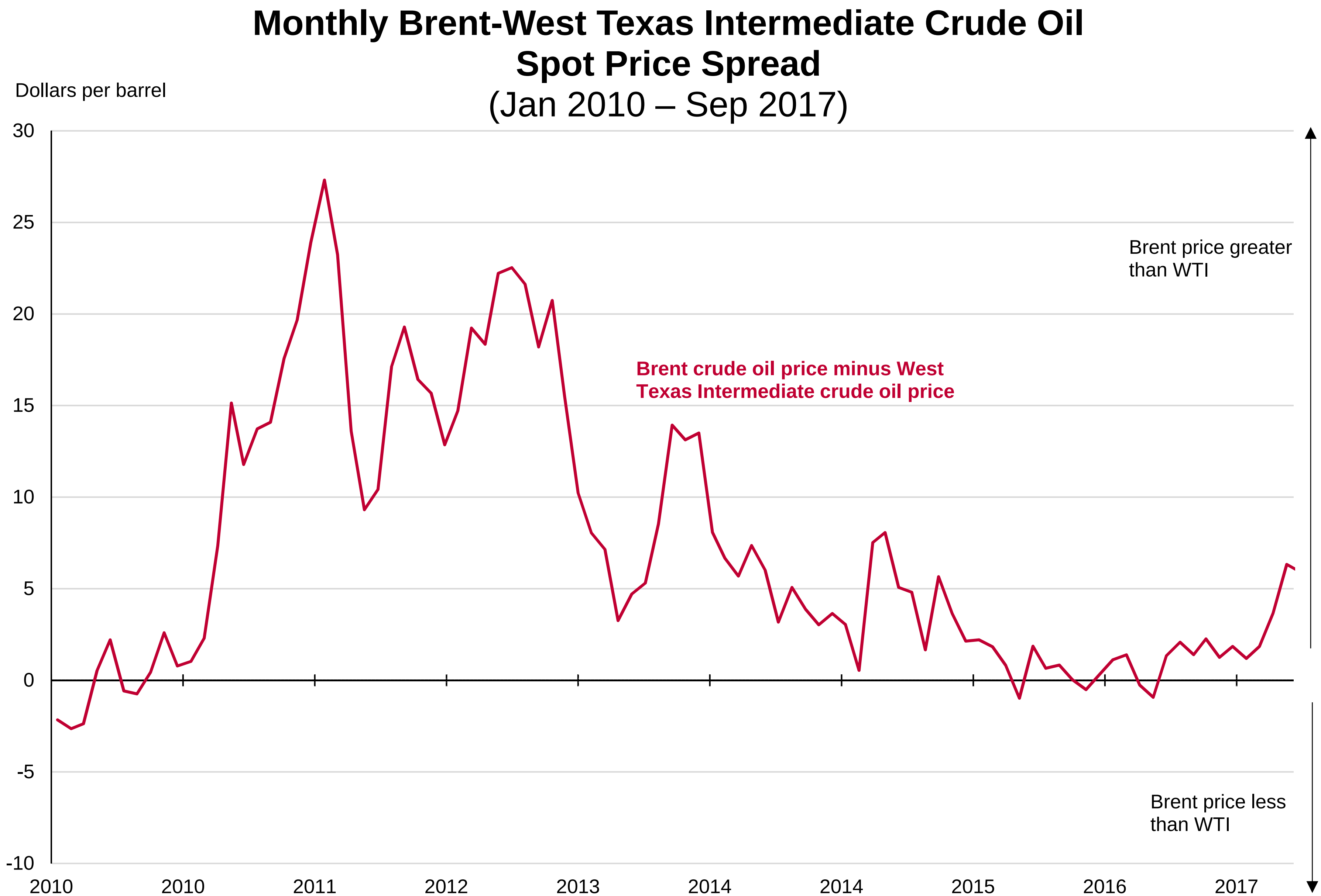
Source: EIA

Exhibit 11

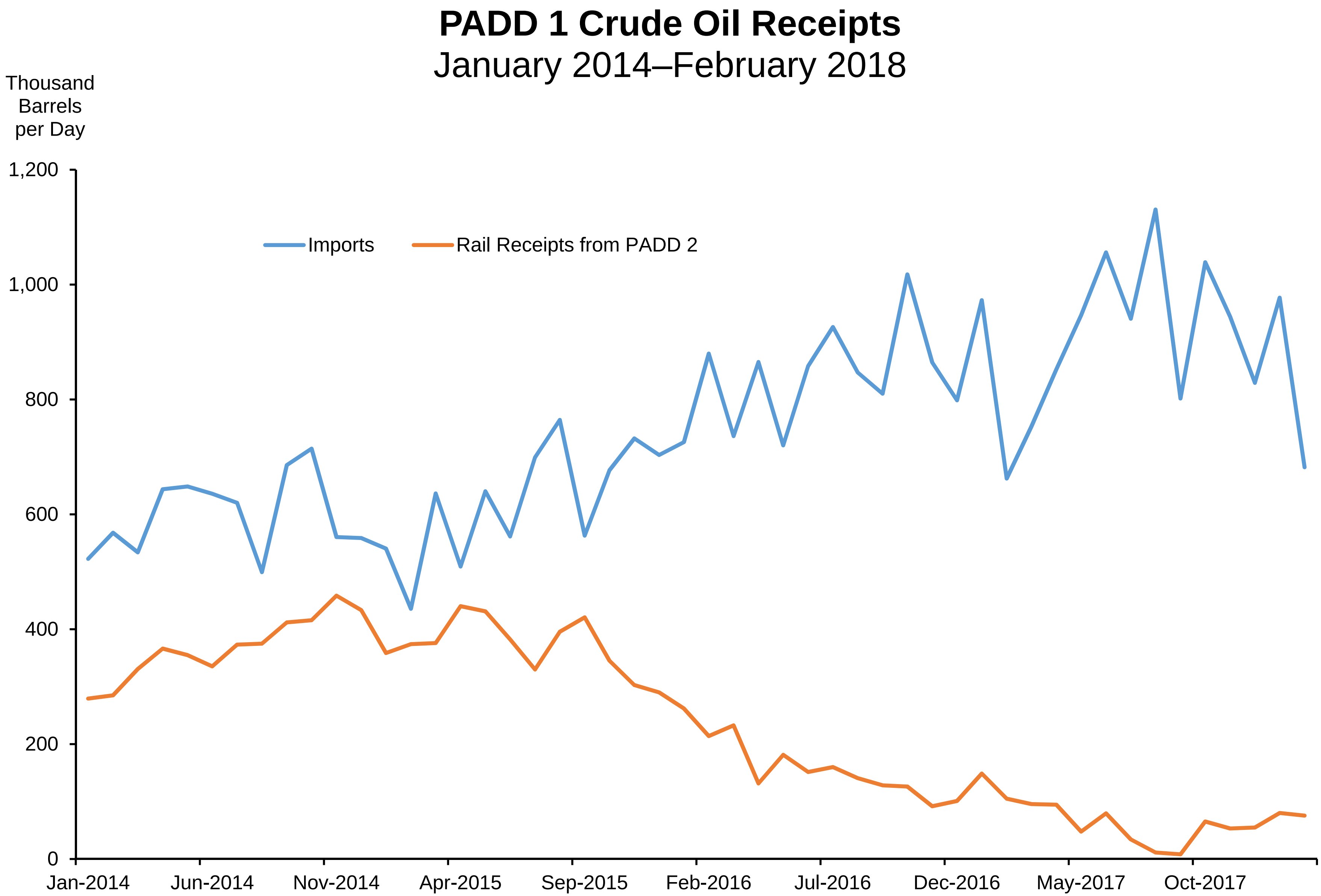


Source: EIA

Exhibit 12

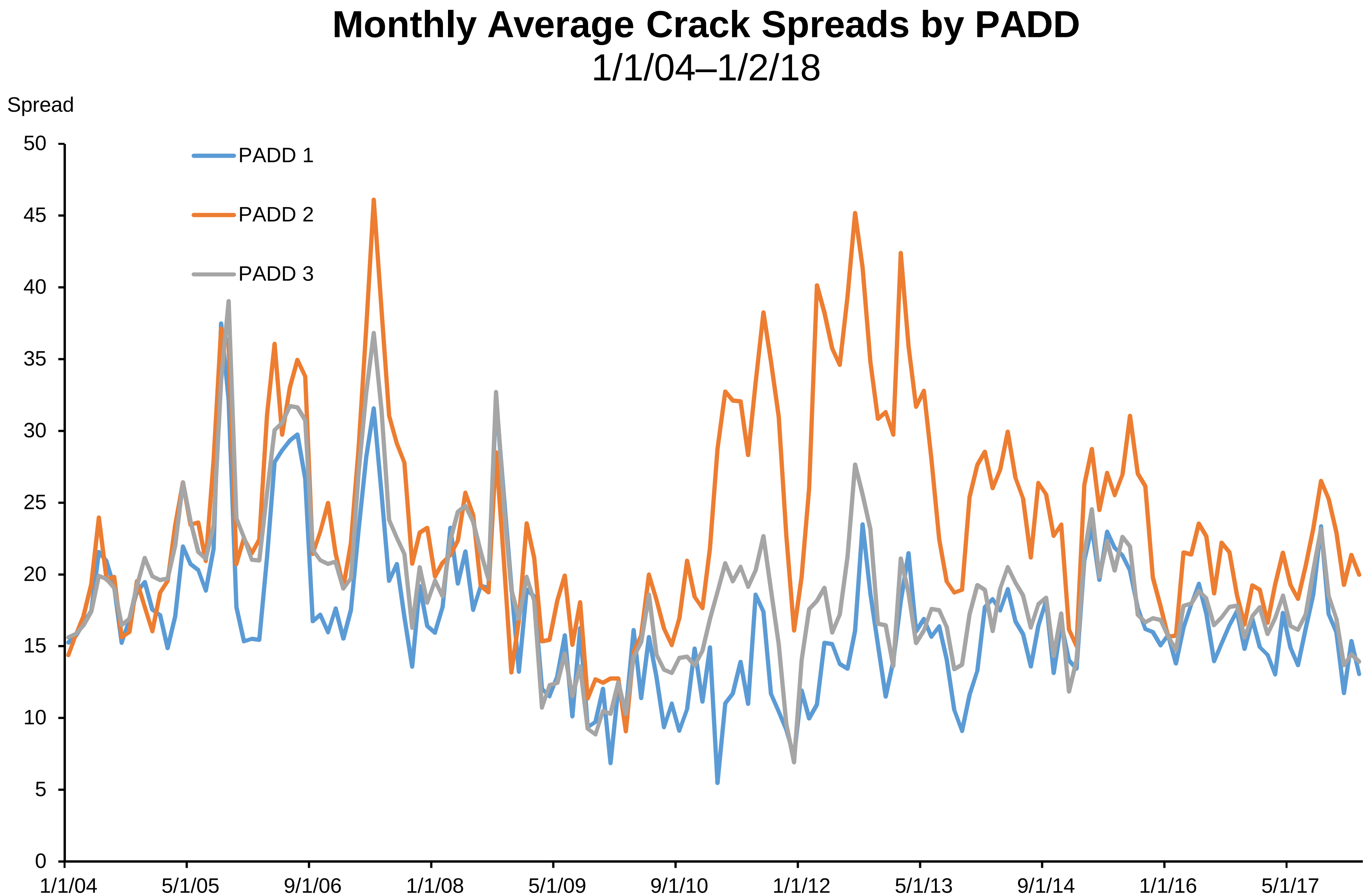


Source: EIA


PADD 1 Crude Oil Receipts
January 2014–February 2018
Thousand Barrels per Day
1,200
1,000
800
600
400
200
0
Imports
Rail Receipts from PADD 2
Jan-2014
Jun-2014
Nov-2014
Apr-2015
Sep-2015
Feb-2016
Jul-2016
Dec-2016
May-2017
Oct-2017

Source: EIA

Exhibit 14



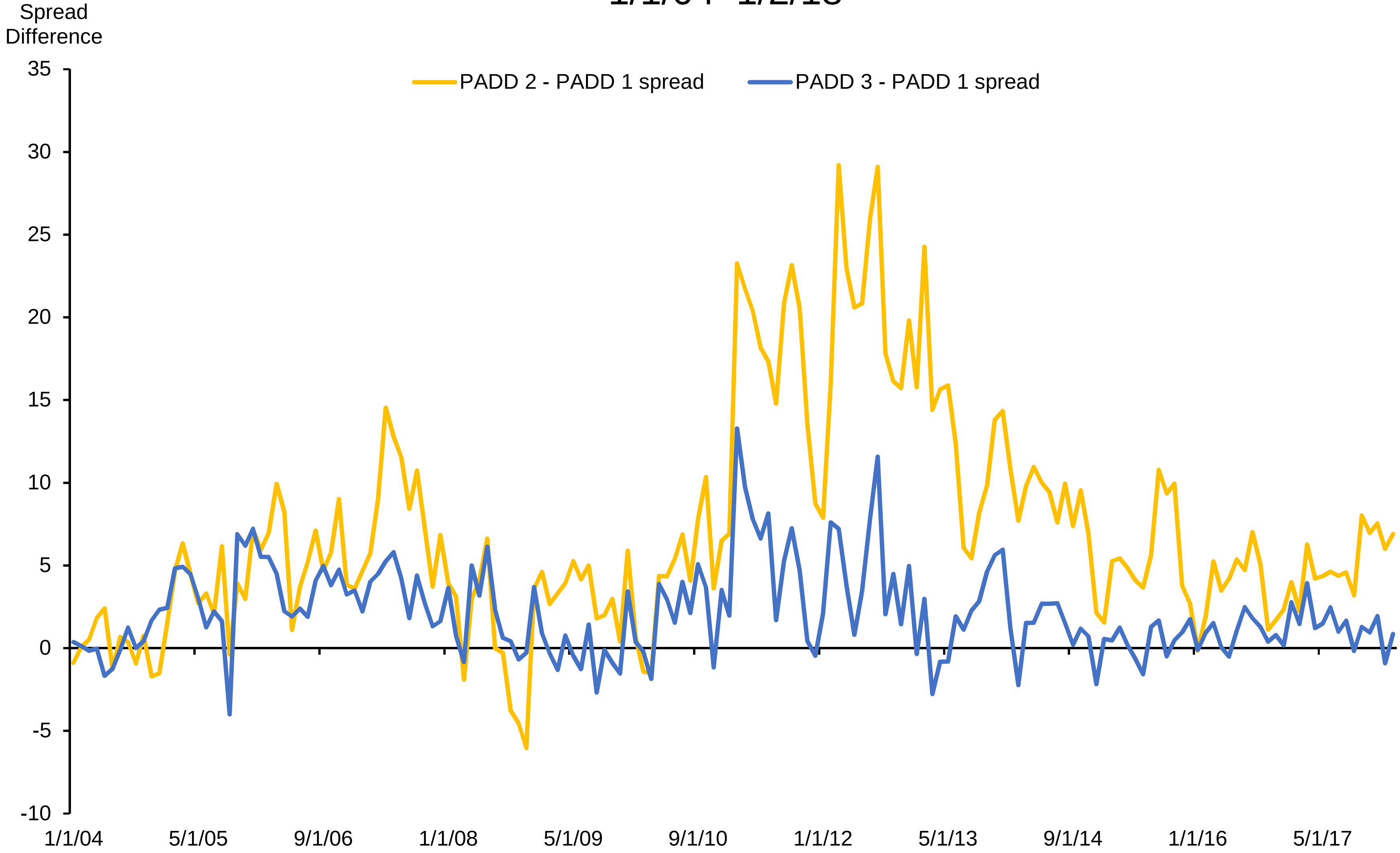
Source: EIA; FRED

Note: Crack spreads are calculated by taking the difference between the average price of refined products weighted by output and the input price for crude (composite), adjusted for inflation using the producer price index.

Exhibit 15

Monthly Difference Between PADD 1 Spreads and PADDs 2 and 3 Spreads

1/1/04–1/2/18

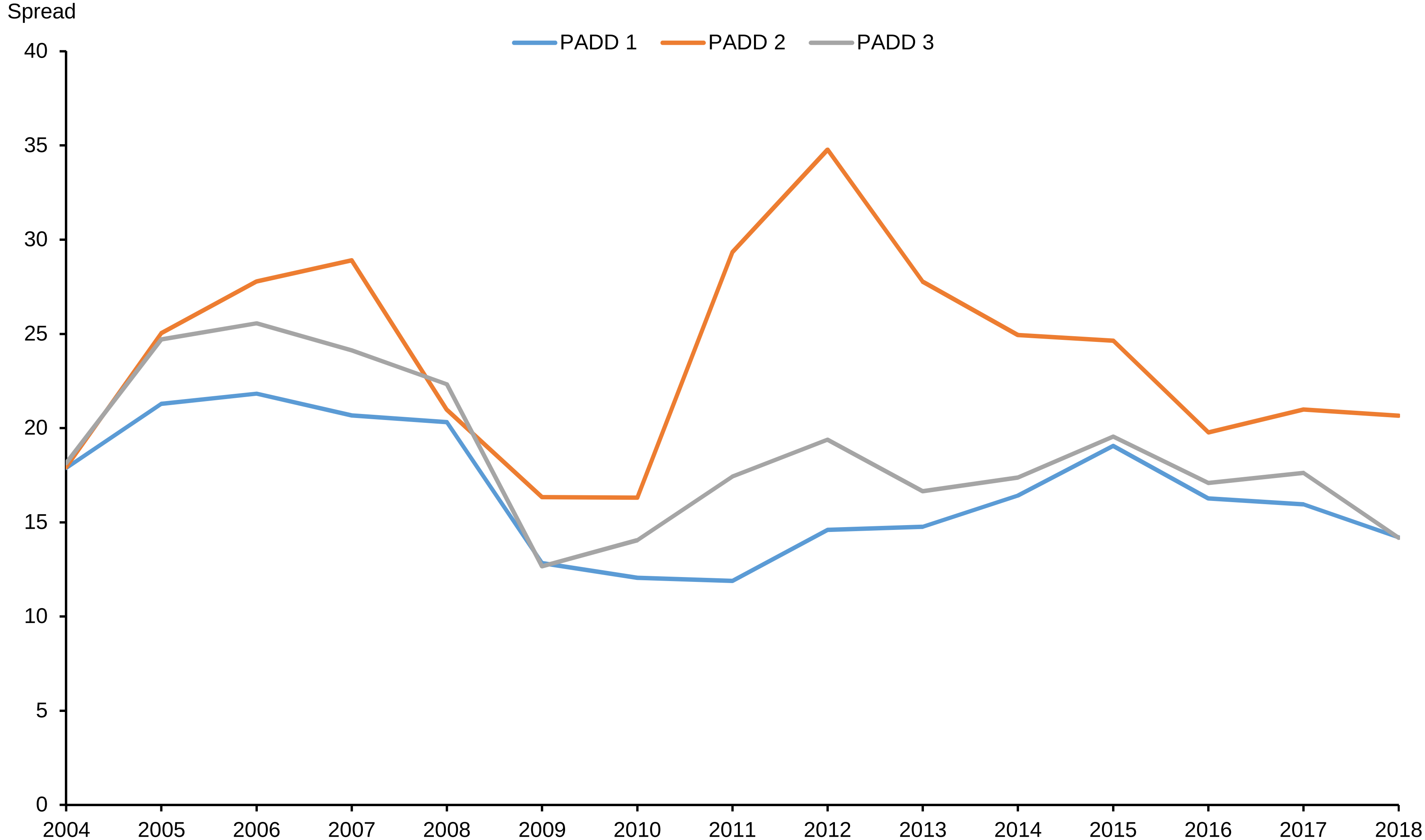


Source: EIA; FRED

Note: Crack spreads are calculated by taking the difference between the average price of refined products weighted by output and the input price for crude (composite), adjusted for inflation using the producer price index.

Exhibit 16

Annual Average Crack Spreads by PADD
2004–2018



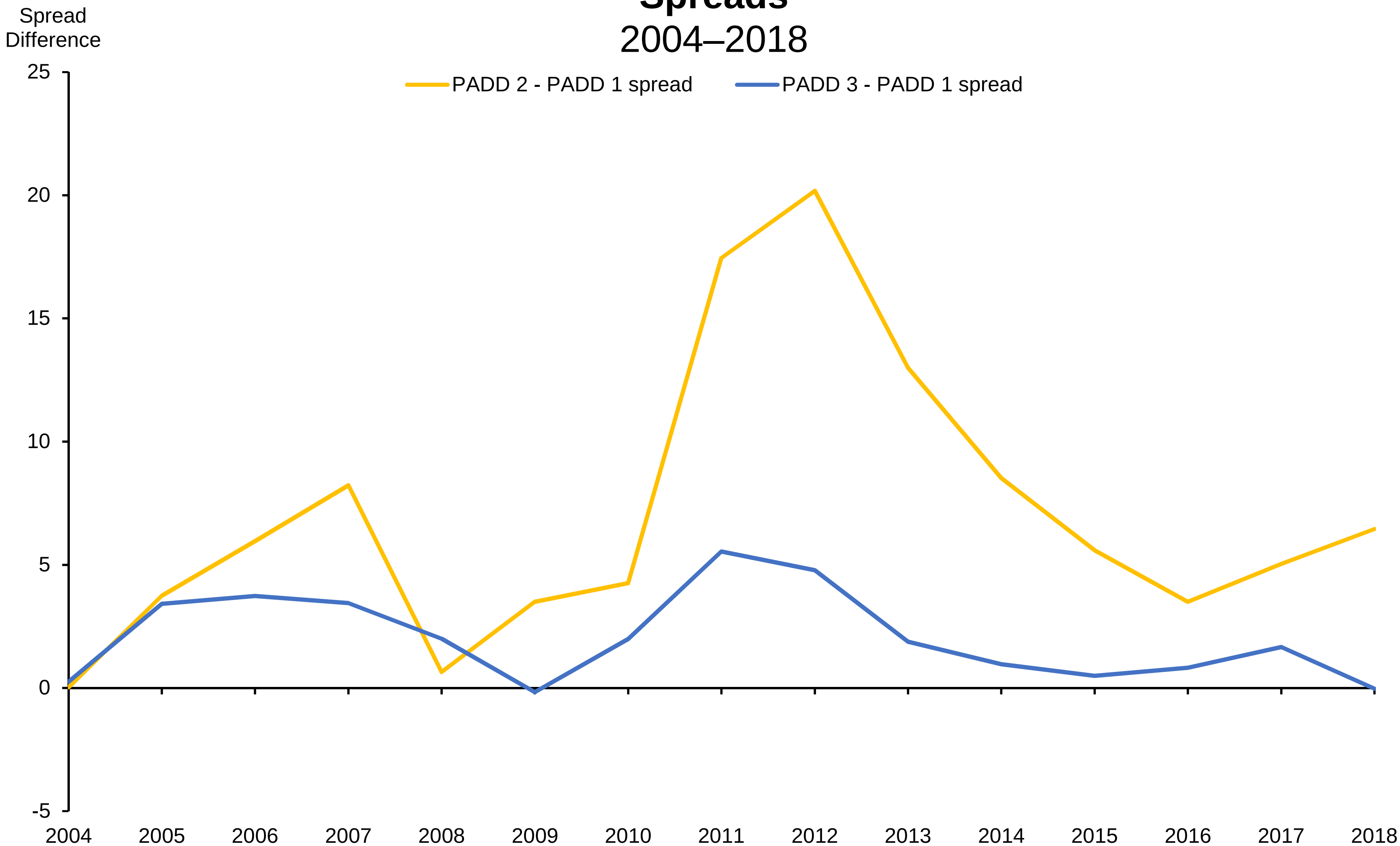
Source: EIA; FRED

Note: Crack spreads are calculated by taking the difference between the average price of refined products weighted by output and the input price for crude (composite), adjusted for inflation using the producer price index.

Exhibit 17

Annual Average Difference Between PADD 1 Spreads and PADDs 2 and 3 Spreads

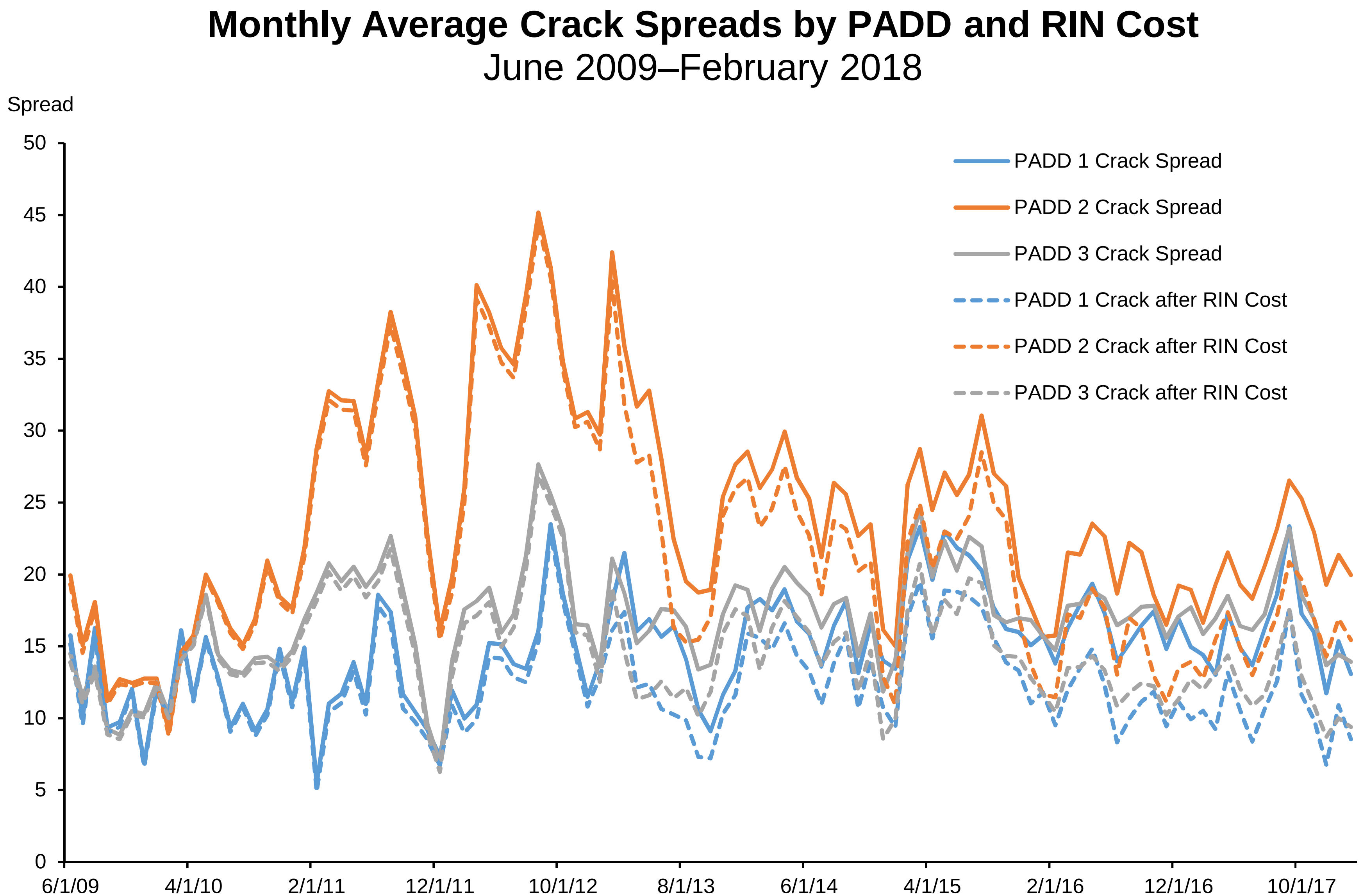
2004–2018



Source: EIA; FRED

Note: Crack spreads are calculated by taking the difference between the average price of refined products weighted by output and the input price for crude (composite), adjusted for inflation using the producer price index.

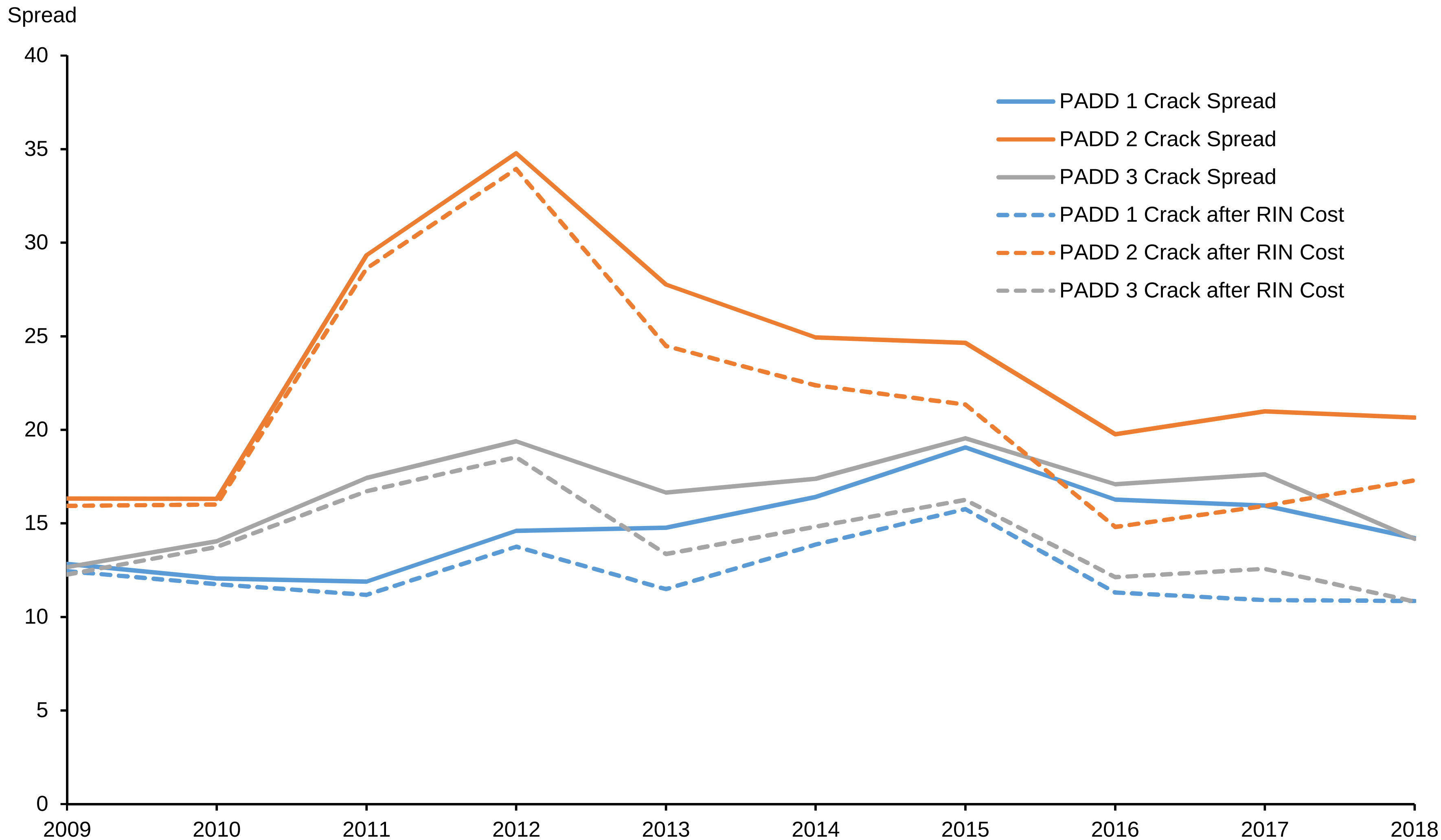
Exhibit 18



Source: EIA; FRED; OPIS; EPA

Note: Crack spreads are calculated by taking the difference between the average price of refined products weighted by output and the input price for crude (composite), adjusted for inflation using the producer price index. RIN cost per barrel is aggregated at the monthly level using daily RIN price, assuming that renewable fuel standards are met.

Annual Average Crack Spreads by PADD and RIN Cost
2009–2018



Source: EIA; FRED; OPIS; EPA

Note: Crack spreads are calculated by taking the difference between the average price of refined products weighted by output and the input price for crude (composite), adjusted for inflation using the producer price index. RIN cost per barrel is aggregated at the monthly level using daily RIN price, assuming that renewable fuel standards are met. RIN data are available starting in June 2009 through February 2018.

Changes in Crack Spreads Under Different Scenarios

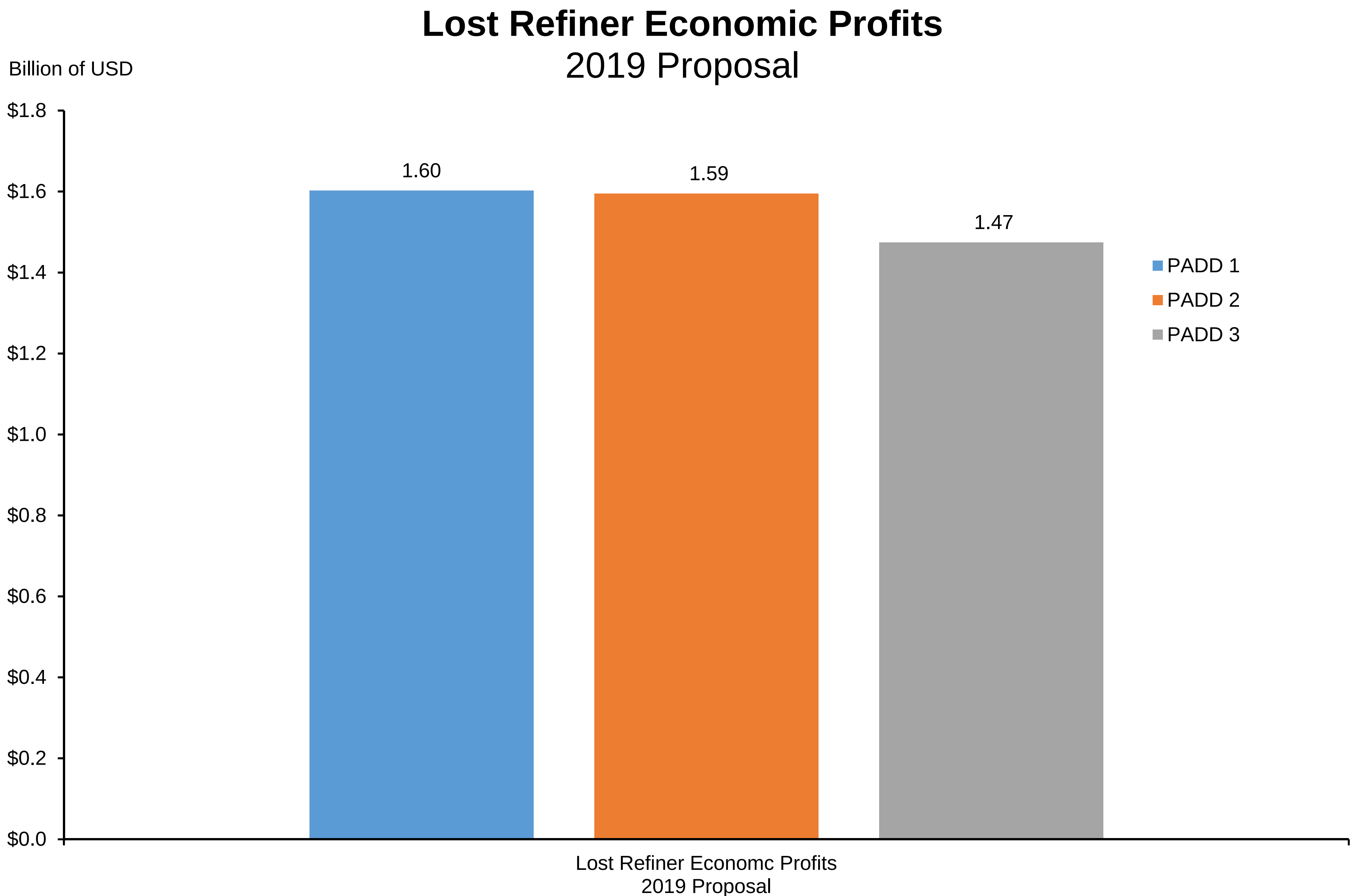
Relative to Zero RIN Price

	2019 Proposal
Crack Spread Difference (RIN Price Is Removed) per Barrel	
PADD 1	-$1.27
PADD 2	-$1.13
PADD 3	-$0.68
Percent Reduction in Crack Spread[1]	
PADD 1	-12.3%
PADD 2	-5.9%
PADD 3	-4.4%

Source: EIA; OPIS

Note:
[1] Percent reduction in Crack Spread was calculated by dividing Crack Spread Difference per Barrel by the difference between RIN price and crude price.

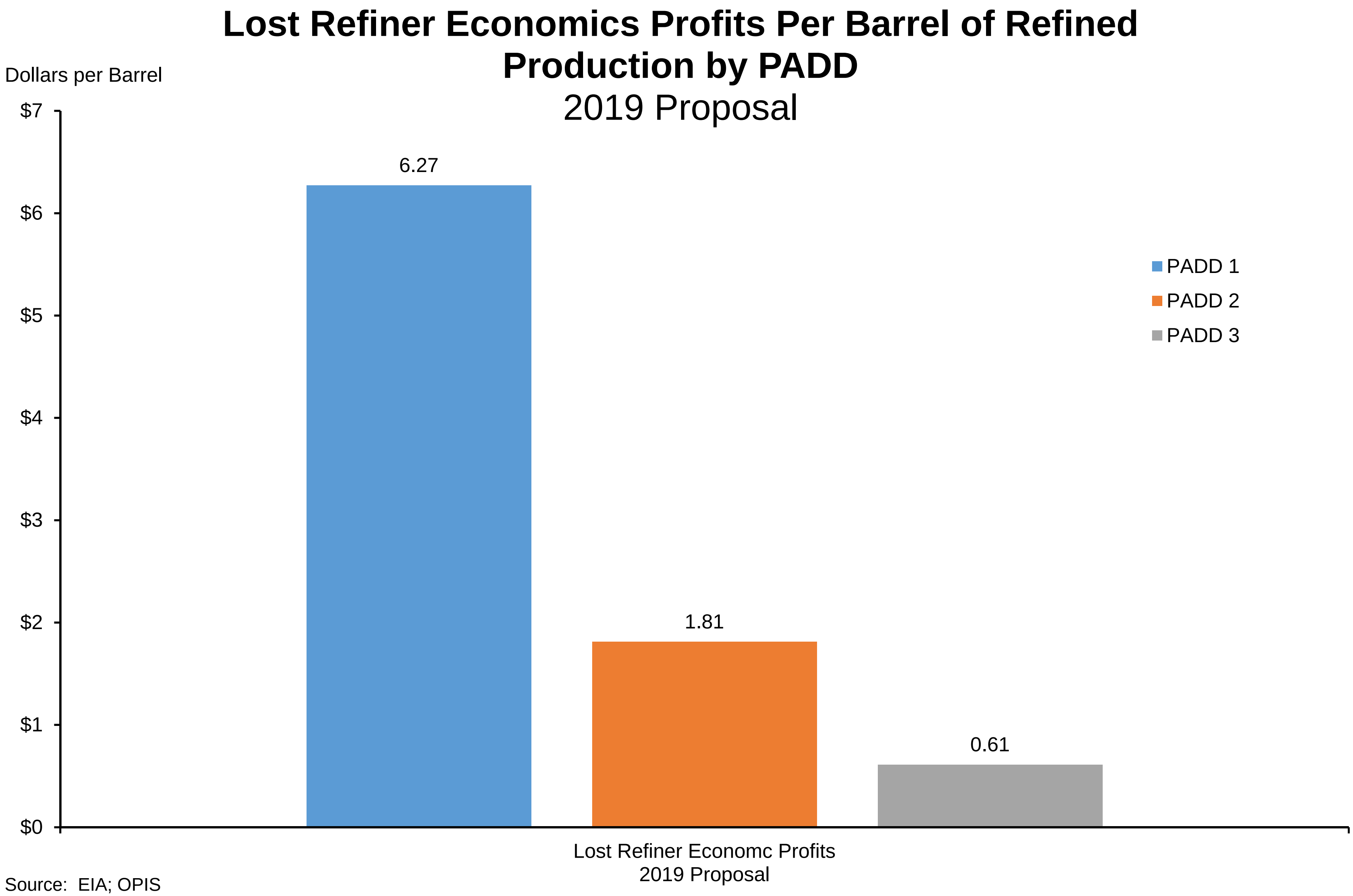
Exhibit 21



Source: EIA; OPIS

Note:
Economic profits differ from accounting profits in that they include opportunity costs and do not include sunk fixed costs of production.

Exhibit 22



Source: EIA; OPIS

Note:
Economic profits differ from accounting profits in that they include opportunity costs and do not include sunk fixed costs of production. Calculated using total lost refiner economic profits under the 2019 Proposal scenario divided by 2017 refinery net production of crude oil and petroleum products for each PADD, respectively.

Summary of Annual Economic Impact to Monroe

Scenario	Total PADD 1 Lost Profits (in millions) Relative to Non-Binding Blend Wall	Monroe's Market Share[1]	Lost Profits to Monroe (in millions)
2019 Proposal	$1,602	15.5%	$248

Source: EIA; OPIS

Note:
[1] Estimated based on 2018 Operable Capacity data from the EIA.

Exhibit 24

Monroe Energy LLC: Trainer, PA Refinery[1]
Operating Financials[2]
2012–2017

		Actual Results							Adjusted Results[7]				
Year	Total Operable Capacity[3] [A]	Average Assets (millions)[4] [B]	Operating Revenue (millions)	Costs (millions)[5]	Operating Income After Taxes (millions)[6] [C]	Profit (Loss) by Barrel [C] / [A]	Return on Assets [C] / [B]	Crack Spread (Gross Revenue) Reduction	Operating Revenue (millions)	Costs (millions)[5]	Operating Income After Taxes (millions)[6] [C]	Profit (Loss) by Barrel [C] / [A]	Return on Assets [C] / [B]
2012[8]	-	$1,164	$1,347	($1,410)	($41)	-	-4%	0.877	$1,181	($1,410)	($149)	-	-13%
2013	67,525,000	$1,168	$7,003	($7,119)	($75)	($1.12)	-6%	0.877	$6,142	($7,119)	($635)	($9.41)	-54%
2014	67,525,000	$1,141	$6,959	($6,863)	$62	$0.92	5%	0.877	$6,103	($6,863)	($494)	($7.32)	-43%
2015	67,525,000	$1,229	$4,741	($4,451)	$189	$2.79	15%	0.877	$4,158	($4,451)	($191)	($2.82)	-16%
2016	69,350,000	$1,340	$3,843	($3,968)	($81)	($1.17)	-6%	0.877	$3,370	($3,968)	($388)	($5.60)	-29%
2017	69,350,000	$1,729	$5,039	($4,929)	$72	$1.03	4%	0.877	$4,419	($4,929)	($331)	($4.78)	-19%

Source: EIA; SEC Form 10-Ks; Reuters

Note:
[1] Monroe Energy LLC was acquired by Delta Air Lines in 2012. Financial information is not available for Monroe Energy prior to 2012.
[2] Dollars are shown in millions, except for Profit (Loss) by Barrel, which is shown in dollars.
[3] Total operable capacity refers to atmospheric crude distillation capacity, shown in barrels per year. Data are as of January 1 of the relevant year.
[4] Average assets are calculated by taking the average of the current year total assets and the total assets from the previous year.
[5] Costs are calculated by taking the difference between operating revenue and operating income.
[6] A 35% tax rate is assumed.
[7] Adjusted results are calculated with the assumption that operating revenues are reduced by the crack spread reduction. Costs are held constant from actual results.
[8] The Trainer, PA refinery shut down in September 2011 and did not reopen until September 2012.

Exhibit 25

United Refining Company
Operating Financials[1]
2008–2016

Year	Total Operable Capacity[2] [A]	Actual Results: Average Assets (millions)[3] [B]	Actual Results: Operating Revenue (millions)	Actual Results: Costs (millions)[4]	Actual Results: Operating Income After Taxes (millions)[5] [C]	Actual Results: Profit (Loss) by Barrel [C] / [A]	Actual Results: Return on Assets [C] / [B]	Crack Spread (Gross Revenue) Reduction	Adjusted Results[6]: Operating Revenue (millions)	Adjusted Results[6]: Costs (millions)[4]	Adjusted Results[6]: Operating Income After Taxes (millions)[5] [C]	Adjusted Results[6]: Profit (Loss) by Barrel [C] / [A]	Adjusted Results[6]: Return on Assets [C] / [B]
2008	23,725,000	$498	$1,658	($1,710)	($33.40)	($2.17)	-2%	0.877	$1,454	($1,710)	($165.99)	($7.00)	-33%
2009	23,725,000	$472	$1,174	($1,116)	$37.61	$2.44	3%	0.877	$1,029	($1,116)	($56.22)	($2.37)	-12%
2010	23,725,000	$505	$1,295	($1,378)	($53.66)	($3.48)	-4%	0.877	$1,136	($1,378)	($157.23)	($6.63)	-31%
2011	23,725,000	$497	$1,543	($1,510)	$21.22	$1.38	1%	0.877	$1,353	($1,510)	($102.15)	($4.31)	-21%
2012	23,725,000	$531	$2,005	($1,660)	$224.17	$14.54	11%	0.877	$1,758	($1,660)	$63.88	$2.69	12%
2013	23,725,000	$586	$1,960	($1,639)	$208.71	$13.53	11%	0.877	$1,719	($1,639)	$52.03	$2.19	9%
2014	23,725,000	$649	$1,751	($1,621)	$84.29	$5.47	5%	0.877	$1,535	($1,621)	($55.68)	($2.35)	-9%
2015	23,725,000	$696	$1,369	($1,244)	$81.69	$5.30	6%	0.877	$1,201	($1,244)	($27.79)	($1.17)	-4%
2016	23,725,000	$698	$967	($946)	$13.84	$0.90	1%	0.877	$848	($946)	($63.47)	($2.68)	-9%

Source: EIA; SEC Form 10-Ks

Note:
[1] Results are shown for the Wholesale segment of United Refining Company, which includes sales of finished products produced at United Refining Company's refineries in Pennsylvania and New York. United Refining Company's fiscal year ends on August 31.
[2] Total operable capacity refers to atmospheric crude distillation capacity, shown in barrels per year. Data are as of January 1 of the relevant year.
[3] Average assets are calculated by taking the average of the current year total assets and the total assets from the previous year.
[4] Costs are calculated by taking the difference between operating revenue and operating income.
[5] A 35% tax rate is assumed.
[6] Adjusted results are calculated with the assumption that operating revenues are reduced by the crack spread reduction. Costs are held constant from actual results.

PBF Energy Inc.: All Refineries[1]
Operating Financials[2]
2012–2017

		Actual Results							Adjusted Results[7]				
Year	Total Operable Capacity[3] [A]	Average Assets (millions)[4] [B]	Operating Revenue (millions)	Costs (millions)[5]	Operating Income After Taxes (millions)[6] [C]	Profit (Loss) by Barrel [C] / [A]	Return on Assets [C] / [B]	Crack Spread (Gross Revenue) Reduction	Operating Revenue (millions)	Costs (millions)[5]	Operating Income After Taxes (millions)[6] [C]	Profit (Loss) by Barrel [C] / [A]	Return on Assets [C] / [B]
2012	183,303,000	$3,937	$20,139	($19,218)	$598	$3.26	15%	0.877	$17,662	($19,218)	($1,012)	($5.52)	-26%
2013	183,303,000	$4,334	$19,151	($18,823)	$213	$1.16	5%	0.877	$16,796	($18,823)	($1,318)	($7.19)	-30%
2014	183,303,000	$4,789	$19,828	($19,680)	$96	$0.52	2%	0.877	$17,389	($19,680)	($1,489)	($8.12)	-31%
2015	183,303,000	$5,635	$13,124	($12,764)	$234	$1.28	4%	0.877	$11,510	($12,764)	($815)	($4.45)	-14%
2016	253,565,500	$6,864	$15,920	($15,422)	$324	$1.28	5%	0.877	$13,962	($15,422)	($949)	($3.74)	-14%
2017	307,731,500	$7,870	$21,787	($21,056)	$475	$1.54	6%	0.877	$19,107	($21,056)	($1,267)	($4.12)	-16%

Source: EIA; SEC Form 10-Ks; Reuters

Note:
[1] PBF Energy owns and operates five domestic oil refineries and related assets, which they acquired in 2010, 2011, 2015, and 2016. These refineries are: Paulsboro Refining Company LLC, Delaware City Refining Company LLC , Chalmette Refining, L.L.C., PBF Western Region LLC, Torrance Refining Company. PBF Energy does not provide operating financials at a refinery level, so data are presented for their entire refinery sector. PBF Energy had an IPO in December 2012. Operating Financials are not available for their refining segment prior to 2012.
[2] Dollars are shown in millions, except for Profit (Loss) by Barrel, which is shown in dollars.
[3] Total operable capacity refers to atmospheric crude distillation capacity, shown in barrels per year. Data are as of January 1 of the relevant year.
[4] Average assets are calculated by taking the average of the current year total assets and the total assets from the previous year. PBF Energy restated its reported total assets for 2014 in their 2015 10-K. The restated figure is used for calculations.
[5] Costs are calculated by taking the difference between operating revenue and operating income. PBF Energy restated its reported operating income for 2013 and 2014 in their 2015 10-K. The restated figures are used for calculations.
[6] A 35% tax rate is assumed.
[7] Adjusted results are calculated with the assumption that operating revenues are reduced by the crack spread reduction. Costs are held constant from actual results.

Percent of Refinery Employment by Area[1]

	Percent As of 2017 Third Quarter
Mid-Atlantic PADD 1 States with Active Refineries[2]	0.10%
States in PADD 1[3]	0.04%
Gloucester County, NJ[4]	0.70%
Warren County, PA[4]	2.50%
McKean County, PA[4]	3.69%

Source: U.S. Census Bureau; EIA

Note:
[1] Refinery employment is defined as jobs under NAICS code 3241. Some employment data points are fuzzed values.
[2] The states in PADD 1 with active refineries as of January, 2018 are Delaware, New Jersey, Pennsylvania, and West Virginia.
[3] The states in PADD 1 are Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, Delaware, District of Columbia, Maryland, New Jersey, New York, Pennsylvania, Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia.
[4] The county has one or more active refineries as of January, 2018.

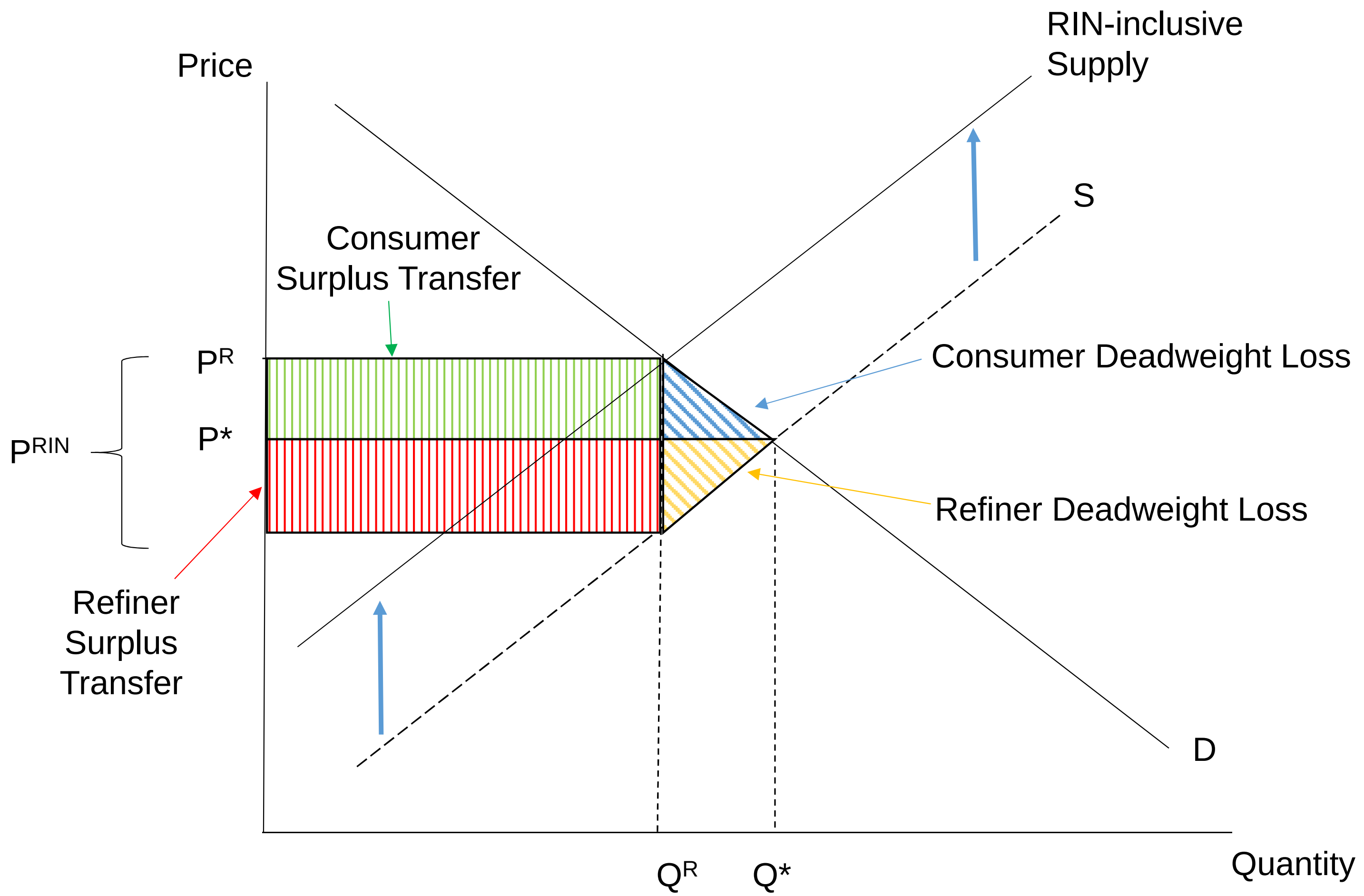
Direct, Indirect, and Induced Impact on Employment Assuming Closure of Large Refinery

	Based on ConocoPhillips and Sunoco Report in 2012[1]	State Level[2]
Assume 800 total employees and half of them are reemployed		
Multiplier [A]	18.31	22.00
Direct, Indirect, and Induced Job Losses[3] [B] = [A] * 400	7,324	8,800
Average Labor Income Loss[4] [C]	$73,601	–
Labor Income Loss from Direct, Indirect, and Induced Job Losses [D] = [B] * [C]	$539,051,836	–

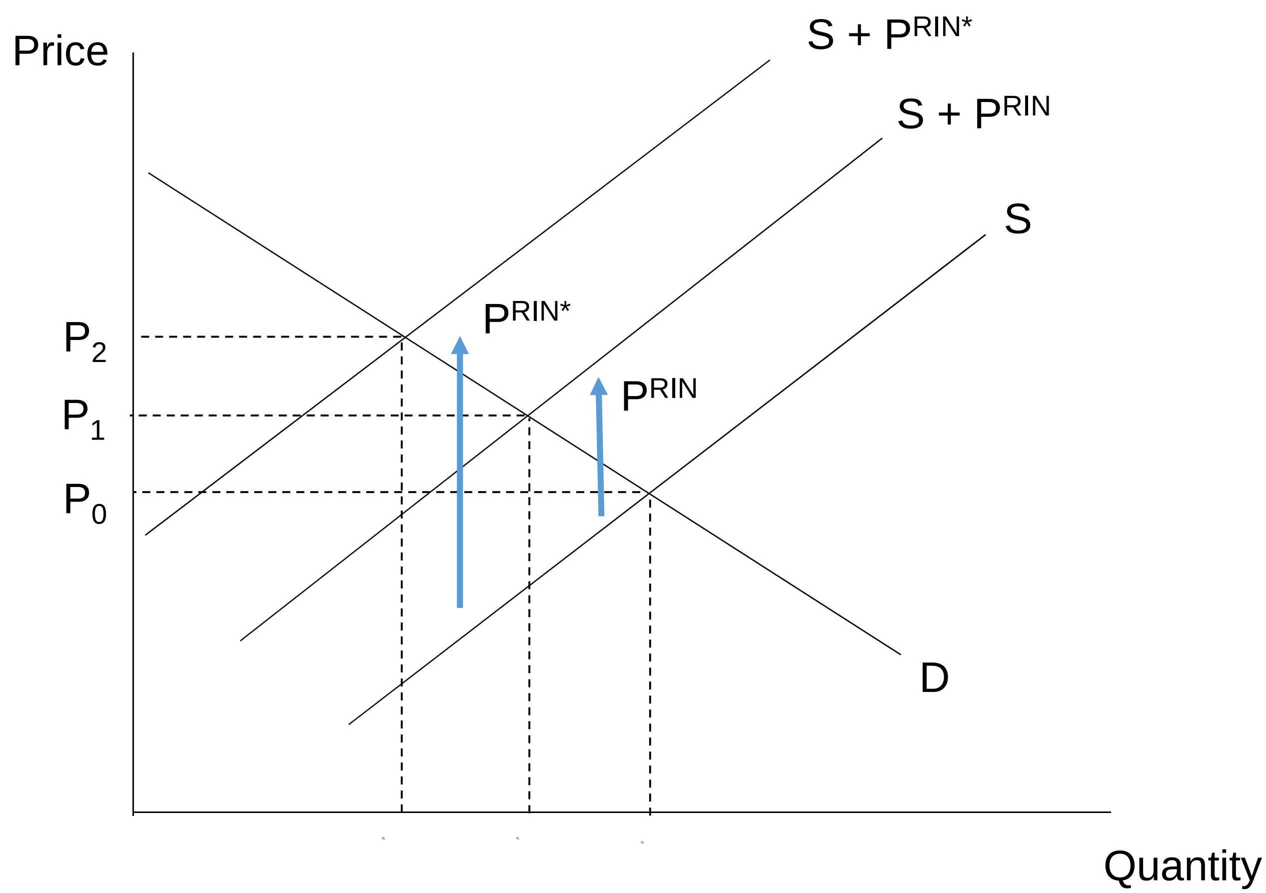
Source: "Reemployment Assessment and Economic Impact of ConocoPhillips and Sunoco Closings" ("ConocoPhillips and Sunoco Report"), Center for Workforce Information & Analysis, January 9, 2012, at pp. 54–56; EIA.

Note:
[1] The multiplier is calculated using Total Employment divided by Direct Employment from p. 55 of the ConocoPhillips and Sunoco Report, *i.e.* -1,831 / -100. Total Employment includes direct, indirect, and induced impact employment figures.
[2] The state level multiplier is from p. 54 of the ConocoPhillips and Sunoco Report. The ConocoPhillips and Sunoco report did not include labor income losses at the state level. Scaling up from the regional level is not possible because state job losses include a different mix of industries from the regional job losses.
[3] Multiplied current total employees by mutipliers to calculate direct, indirect, and induced job losses in each scenario.
[4] Calculated using Total Labor Income based on the direct, indirect, and induced impact divided by Total Employment based on the direct, indirect, and induced impact from the ConocoPhillips and Sunoco Report.

Supply and Demand Diagram



Gas Supply and Demand with Different RIN Prices



RIN Supply and Demand

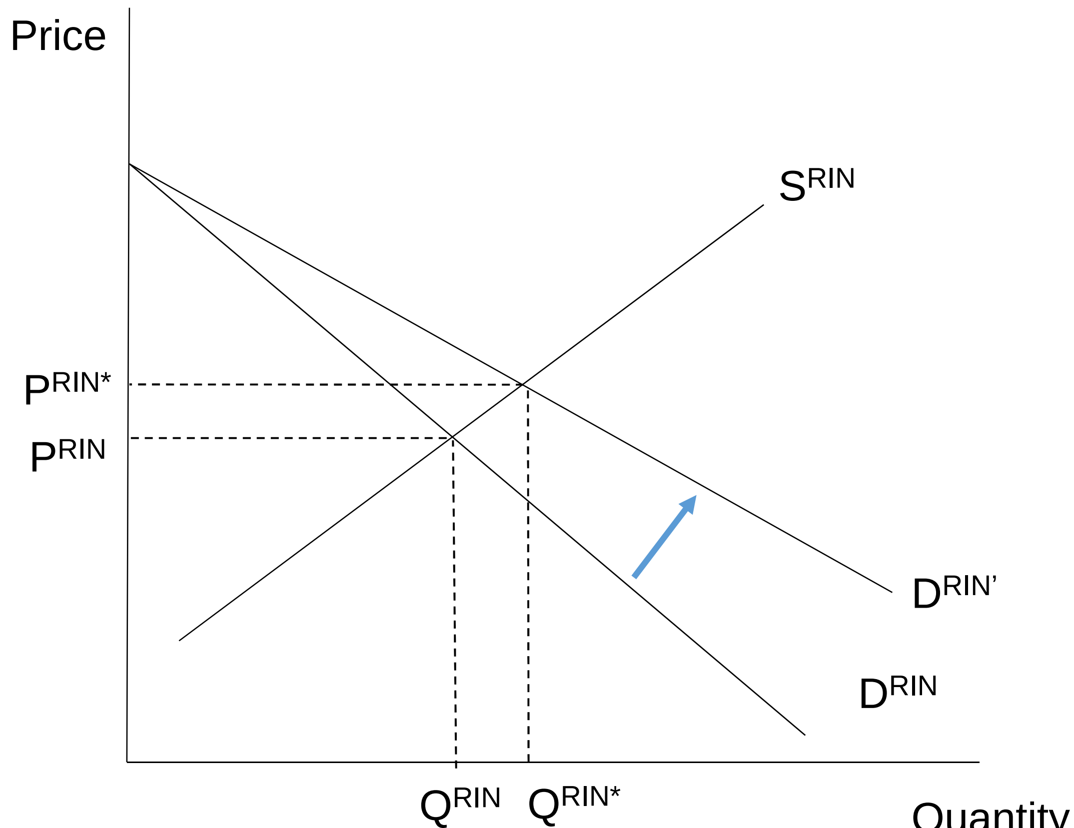


Exhibit 32

Gas Supply and Demand with Different RIN Obligations