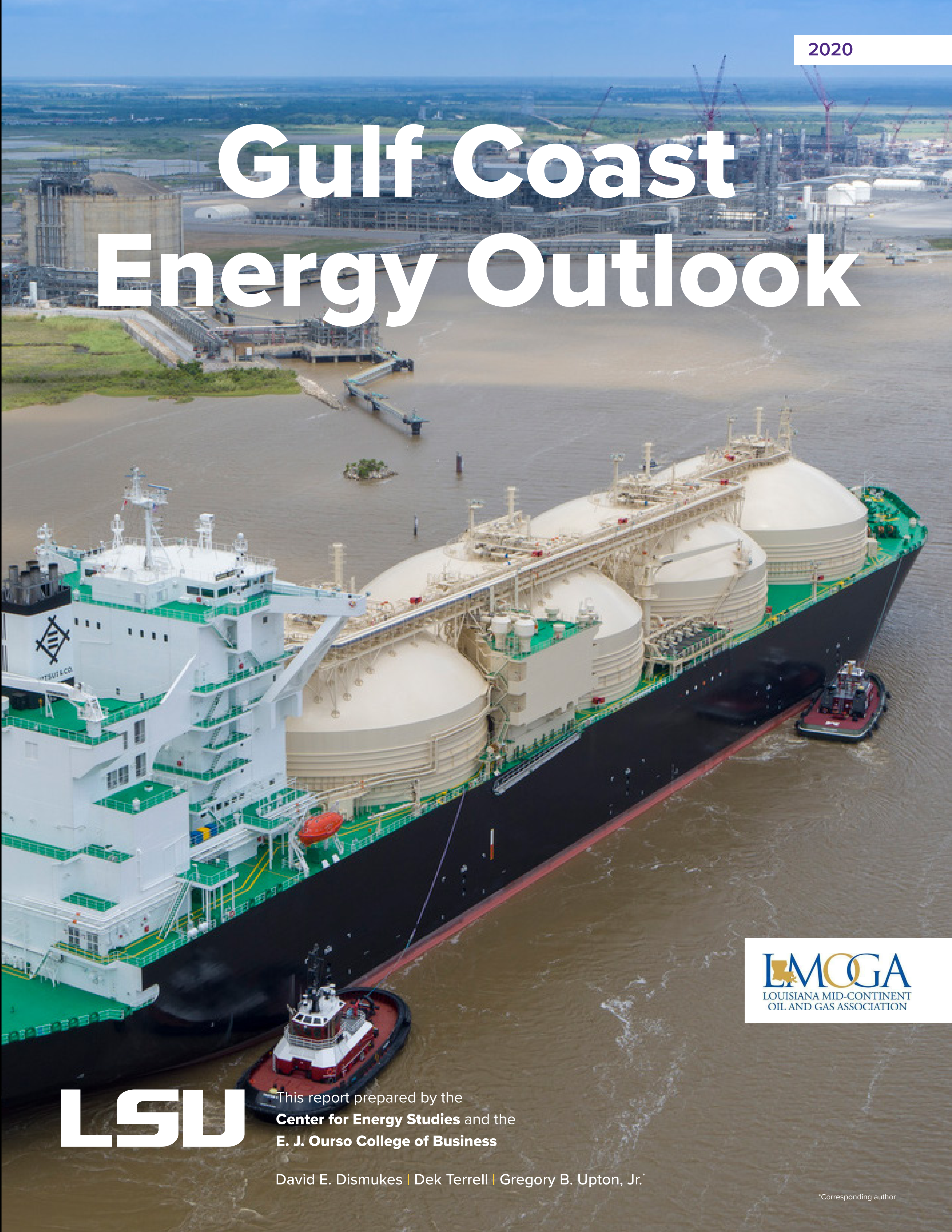

2020

Gulf Coast Energy Outlook

LOUISIANA MID-CONTINENT OIL AND GAS ASSOCIATION

LSU

This report prepared by the **Center for Energy Studies** and the **E. J. Ourso College of Business**

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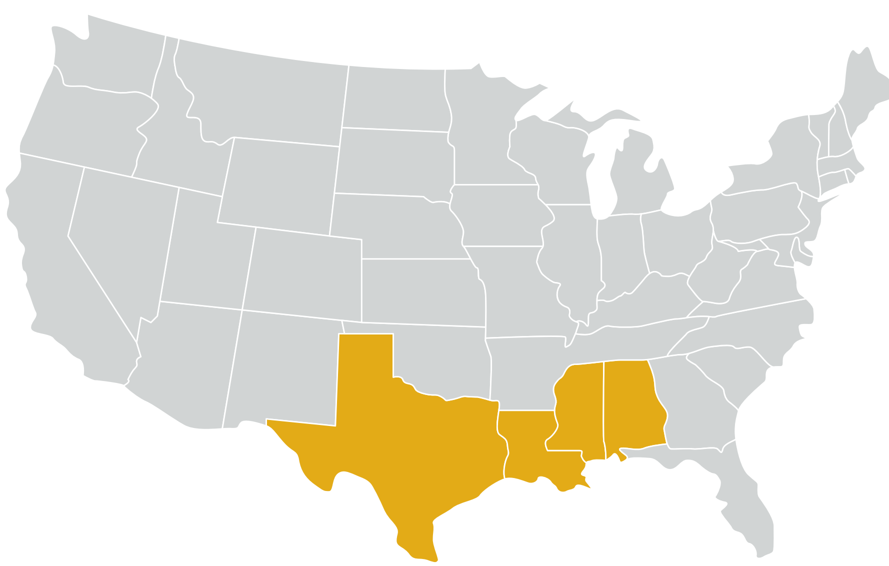
1 | Introduction

The GCEO is now in its third year and as in years past, is designed to provide stakeholders with a "one-stop" overview of the current trends and outlook for the region's energy industry and its various sectors. The GCEO is a collaborative effort of Louisiana State University's Center for Energy Studies and E.J. Ourso College of Business and has been sponsored by several corporations and institutions looking to assist LSU in disseminating timely and important information and analysis impacting the region's economy and citizenry.

The 2020 GCEO includes Gulf Coast-specific analyses that span across a wide range of regional energy sectors, starting with upstream crude oil and natural gas production and moving through to the downstream refining and petrochemicals (or energy manufacturing) sectors. The 2020 GCEO includes a new section highlighting crude oil and natural gas transportation trends and outlooks. This edition also continues last year's analysis focused on the growing importance of energy exports for the Gulf Coast region. The regional trends in energy manufacturing, particularly the continued capital investment in the region, or the "industrial renaissance" that has been facilitated by unconventional crude oil and natural gas development, is also figured prominently this year. The 2020 GCEO concludes with an analysis of the region's energy sector employment trends and a forecast for each sector's employment over the next several years.

Unless stated otherwise, the "Gulf Coast" region specifically refers to the states of Texas, Louisiana, Mississippi, and Alabama. In some instances, U.S. Department of Energy reporting conventions will require references to data collected at the Petroleum Administration for Defense District 3 (PADD 3) level, which includes Arkansas and New Mexico, in addition to the Gulf Coast states.



2 | Crude Oil and Natural Gas Production and Prices

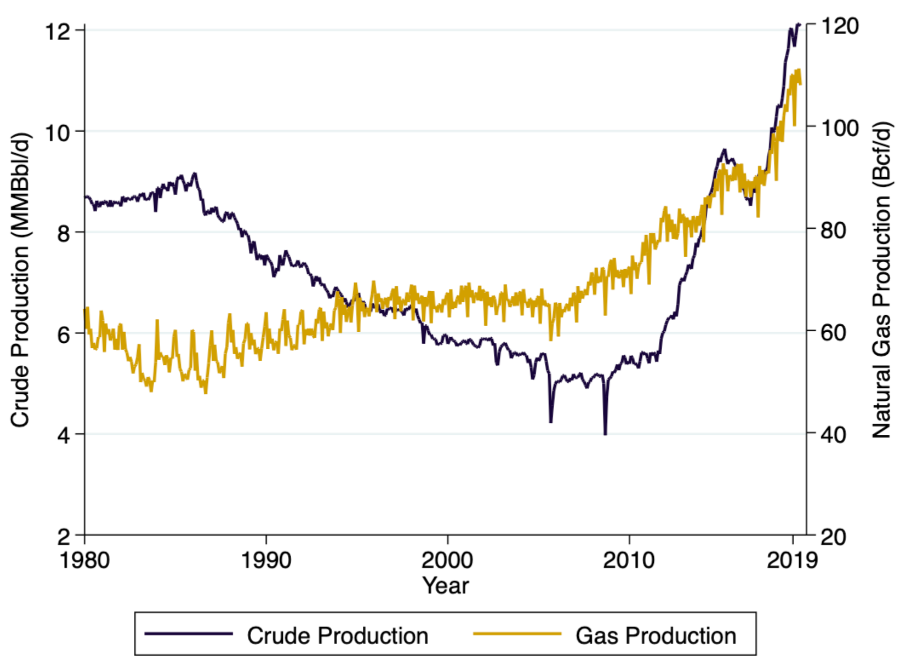
2.1. Recent Market Trends: Production

The upcoming year (2020) marks the beginning of a new decade as well as the 15th year of the shale revolution. This revolution started to manifest itself in U.S. natural gas supplies in 2005 and has dramatically changed the fortunes of U.S. energy across almost every sector. That revolution continues today in both crude oil and natural gas supplies, both of which continue to march upwards, breaking production records from decades long since passed.

Figure 1 shows that this past year (2019) marks the highest level of U.S. natural gas and crude oil production on record at around 111 billion cubic feet per day ("Bcf/d") and 12 million barrels per day ("MMBbl/d"), respectively. As will be shown later, a large share of this U.S. crude oil and natural gas production increase comes from the Gulf Coast region.

Recent trends in U.S. drilling, however, have begun to slow, given their tendency to closely follow prices, which have been down since early 2015. The cyclical nature of drilling and prices is being felt throughout the oil patch as major areas along the Gulf Coast cut back on activity.

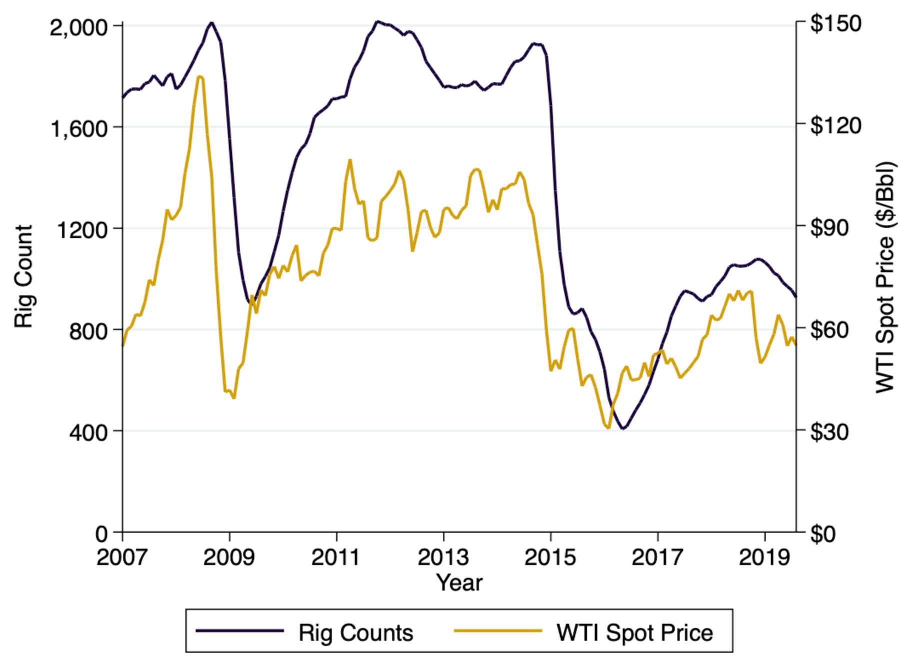
Figure 1: U.S. crude oil and natural gas production



Source: U.S. Energy Information Administration.

Figure 2 underscores that the few drilling rig gains made in early 2019 have long since expended themselves during the mid-year price correction. By year end 2019, drilling rigs were down by as much as 14 from the recent December 2018 peak. Unfortunately, the industry continues to be a victim of its own success. Higher drilling productivity has translated into higher crude oil and natural gas supplies, which in turn has damped prices, which itself curtails drilling activity. Today, the industry is no closer to reaching its prior 1,500 active rig peak than it was in the prior year.

Figure 2: U.S. crude oil prices and rig count



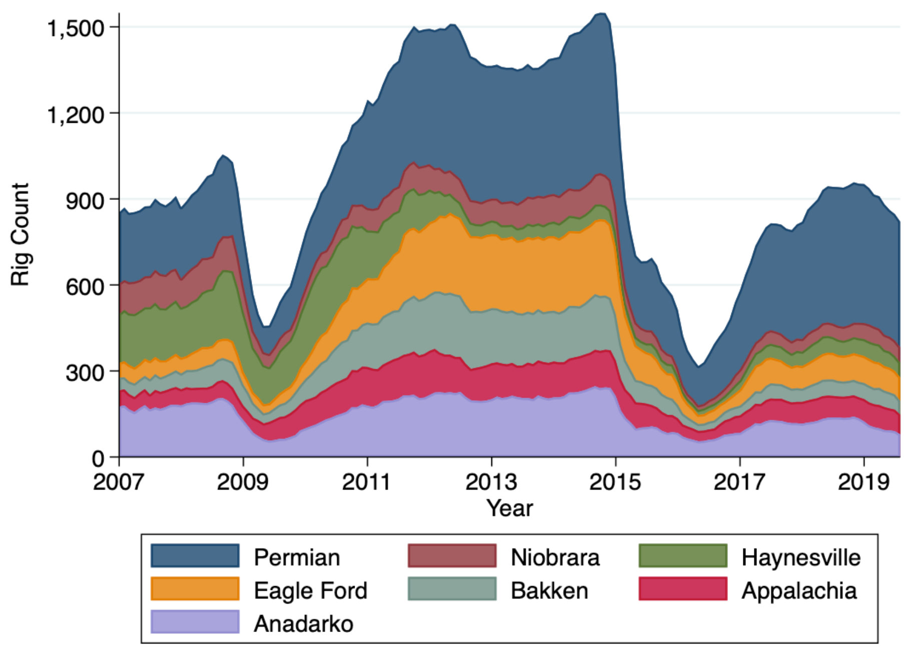
Source: U.S. Energy Information Administration.

Regionally, the Permian Basin continues to be the primary focus of drilling and production. Figure 3 illustrates the rig activity in the seven major U.S. shale plays. Since 2016, the Permian has been the predominant shale play in the U.S., accounting for more than half of drilling activity in shale plays during the first half of 2019.[1] Last years' regional constraints do not appear to have significantly dampened this interest. The 2019 GCEO anticipated that while regional export capabilities were tight, the development of new transportation alternatives would likely arrive just in time to prevent any significant basin migration. This appears to have been the correct call.

Last year, the U.S. became the unequivocal leader in world crude oil production. The movement to the top of the leader board is entirely attributable to U.S. unconventional shale production. Figure 4 shows that the U.S. share of total production continues to march forward and has leaped in the last four years alone from 12 percent of total world crude oil supplies to a current level in excess of 17 percent. Greater U.S. supplies, coupled with large production increases in Russia over the past several years, have significantly diversified

1 Based on EIA drilling productivity reports.

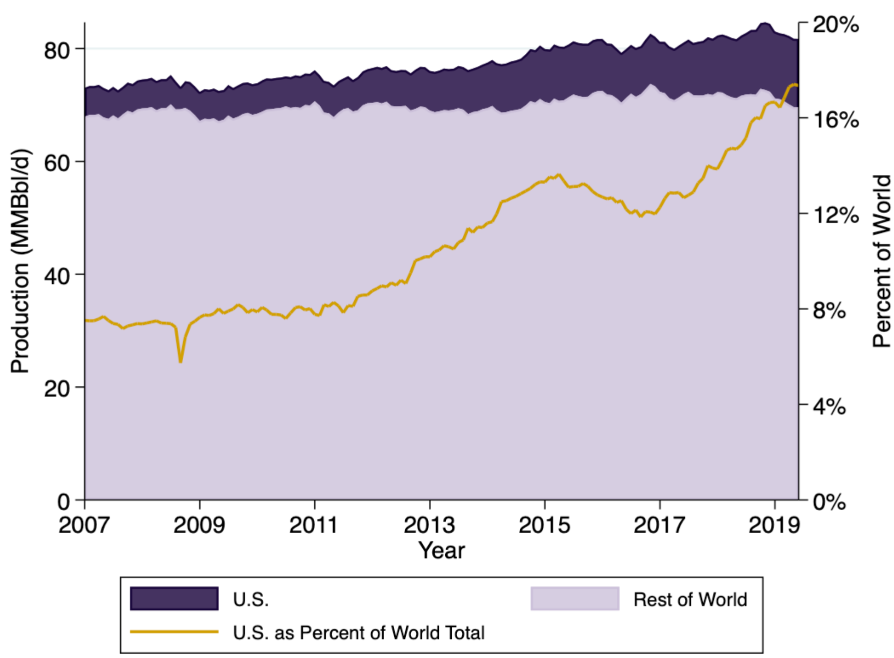
Figure 3: Rig counts in major shale basins



Source: U.S. Energy Information Administration.

non-OPEC world energy markets and helped to keep a lid on pricing volatility and minimize the impacts of sudden geopolitical events.

Figure 4: Global and U.S. crude oil production

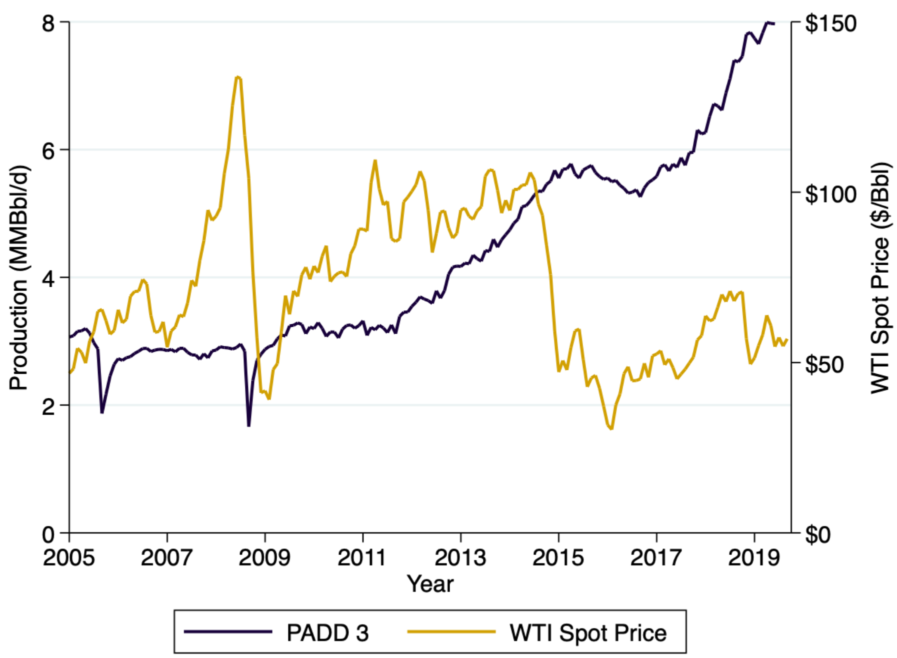


Source: U.S. Energy Information Administration.

2.2 Recent Regional Trends: Crude Oil and Natural Gas Production

Regional (PADD 3) crude oil production activity mirrors, and in fact, dominates the overall U.S. production trends discussed earlier. Regional crude oil and natural gas production continues to progress to higher levels notwithstanding recent price contractions (Figure 5). Overall, regional 2019 crude oil production was up by 19 percent (1.2 MMBbl/d) relative to 2018. To illustrate this resiliency, consider that in the first half of 2019, PADD 3 oil production was 14 percent higher than the first six months of 2014. But the price over the first half of 2019 was more than $40 per barrel lower than in the pre-crash time period. Amazingly, the Gulf Coast region (PADD 3) has been able to maintain this high degree of well productivity even in the face of low prices.

Figure 5: PADD 3 crude oil production and crude oil price

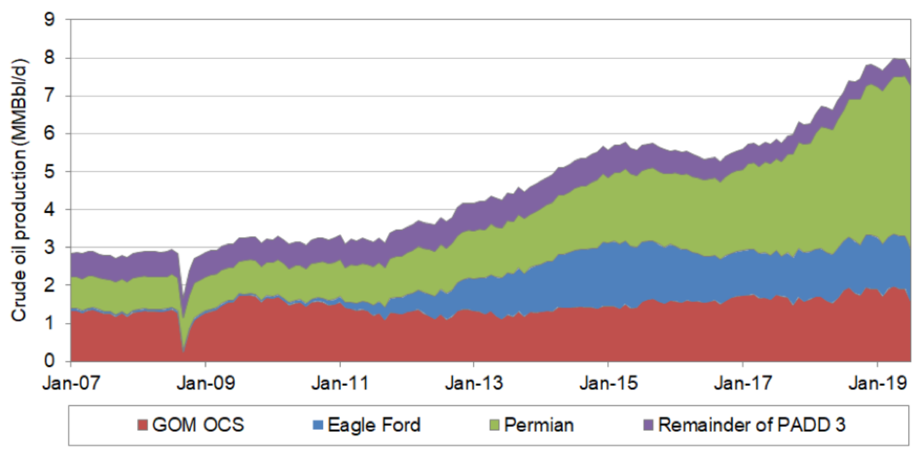


Source: U.S. Energy Information Administration.

Figure 6 breaks out PADD 3 crude oil production by major play within the region. The Permian Basin dominates regional crude oil production at 4.2 MMBbl/d followed closely by the offshore outer continental shelf (OCS) at 1.9 MMBbl/d. Eagle Ford follows closely behind these two predominate regional plays at 1.3 MMBbl/d. While unconventional crude oil production gains tend to dominate the national media and financial press, the OCS continues to be a major workhorse for regional crude oil production.

Regional natural gas production continues to rise to record levels, with 2019 production on course to be the highest producing year in recorded history at close to 45 Bcf/d, or 40

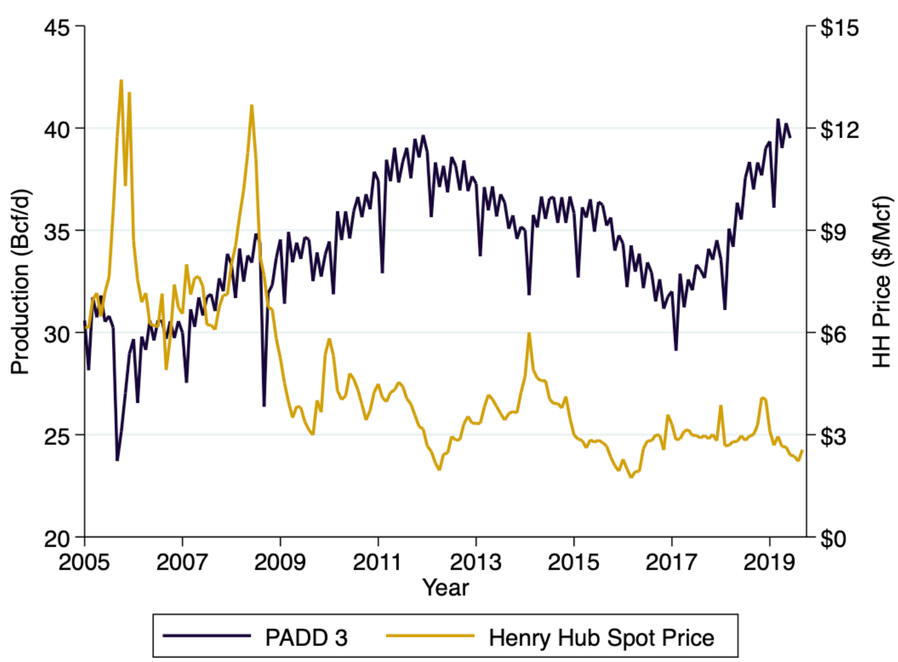
Figure 6: Regional crude oil production by major area/play



Source: U.S. Energy Information Administration.

percent of total U.S. natural gas production (see Figure 7). This regional surge in natural gas production reflects a short term rebound from an earlier production contraction that ran from mid-year 2011 to about early 2017. Regional monthly natural gas production has been growing at a rapid clip of about 10 percent per year since 2017.

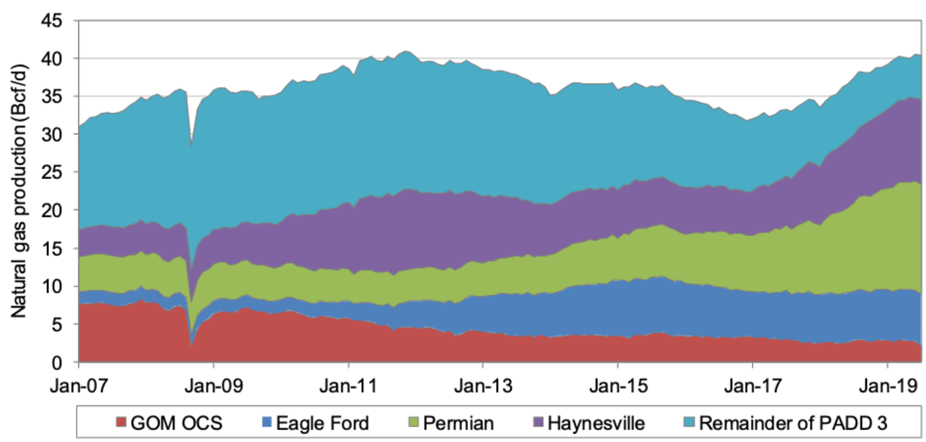
Figure 7: PADD 3 natural gas production and natural gas price



Source: U.S. Energy Information Administration.

Figure 8 shows the decomposition of regional natural gas production, which is dominated by the Permian as well as "other" collective regional sources like Haynesville. The Permian is now producing as much as 14.5 Bcf/d, while Haynesville is up to about 11 Bcf/d. Recent Eagle Ford natural gas production, while significant, has been flat over the last two years at around 6.5 Bcf/d. This leaves about 5 Bcf/d being produced in the remainder of the region.

Figure 8: Regional natural gas production by major area/play



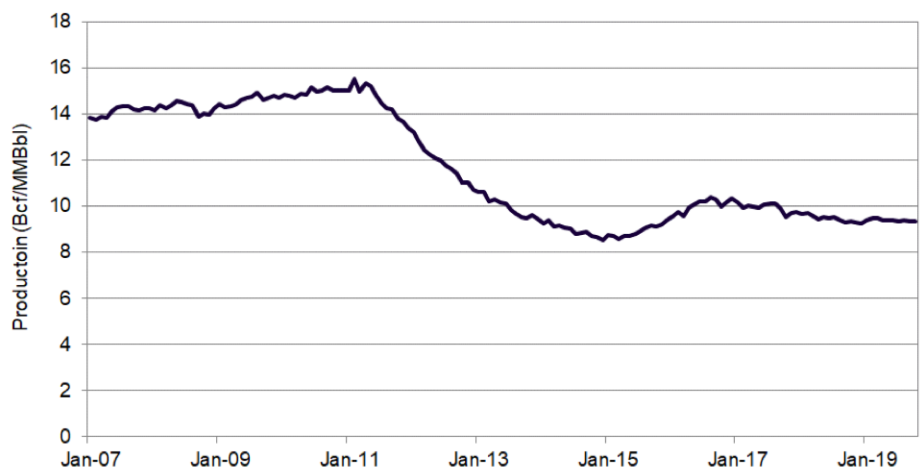
Note: Alabama and Mississippi are included in Remainder of PADD 3 however production estimates are only available through 2017. Values for 2018 and 2019 are estimated using average monthly trends from 2017.

Source: U.S. Energy Information Administration.

Recent regional natural gas supplies have been driven, in large part, by considerable associated (co-produced) production. Figure 9 presents the overall national trends in associated gas production, which are driven by the seven major shale plays. From 2007 to 2011, major U.S. shale plays were extracting as much as 15 Bcf/d of natural gas for every one MMBbl/d of crude oil production. That trend started to fall in 2011 and was down to just 8.5 Bcf/d per MMBbl/d in early 2015. The associated gas production rate has been rebounding since and has stabilized at a relatively constant rate of 9 to 10 Bcf/d for every MMBbl/d of crude oil production.

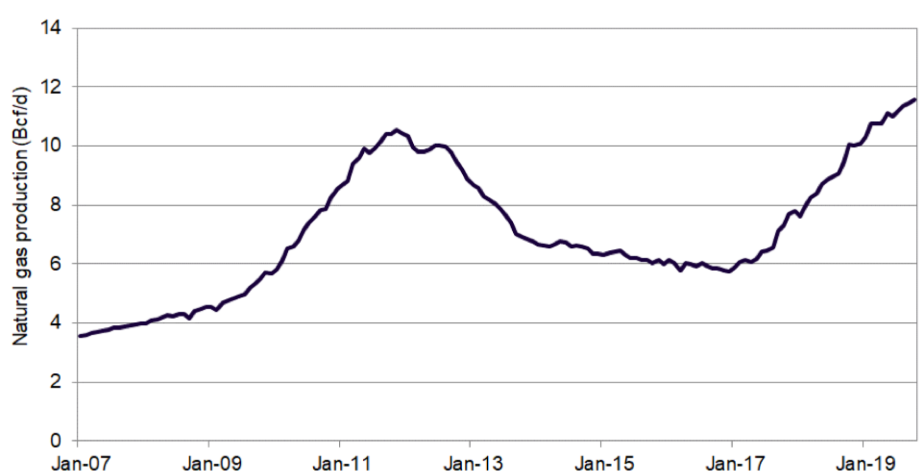
Lastly, recent trends in the Haynesville Shale have had a positive, albeit modest impact on regional natural gas supplies. Over the past three years, the Haynesville Shale has seen a relatively quiet revival, at least in natural gas production. Figure 10 shows that current natural gas production trends have increased the play's overall production from a low of 5.8 (December 2016) to a current level of 11.5 Bcf/d.

Figure 9: Associated natural gas production (seven major shale plays only)



Source: U.S. Energy Information Administration.

Figure 10: Haynesville natural gas production



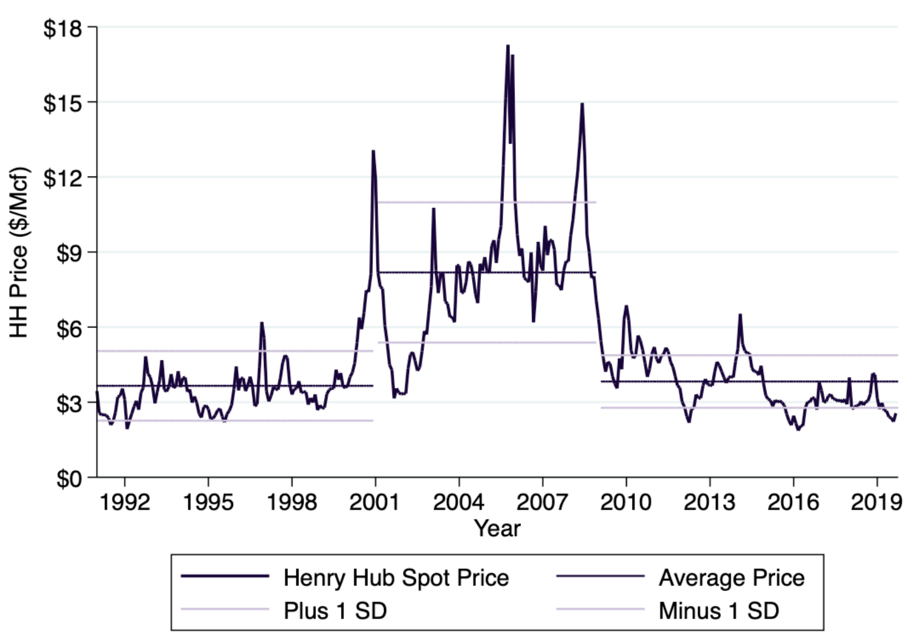
Source: U.S. Energy Information Administration.

2.3 Recent Trends: Commodity Pricing

One of the less appreciated aspects of shale production has been its impacts on pricing. Figure 11 highlights three different natural gas pricing epochs: (1) the period spanning the 1990s; (2) the period starting with the natural gas supply/pricing crisis of the 2000s; and (3) post-recession period to current. As the chart clearly shows, the current epoch's prices are not only competitive relative to historic trends, but the volatility, as measured by the standard deviation in those prices (or the standard movement about the average) has been exceptionally low and will continue to be low.

Figure 12 provides a comparable analysis for crude oil pricing, underscoring again the dramatically reduced volatility that current period prices are experiencing relative to past pricing epochs. On a year-to-date basis, 2019 crude oil prices have averaged $57/Bbl. As with natural gas prices, the 2019 GCEO used futures prices to inform the crude oil pricing forecast. To date, those crude oil pricing expectations (embedded in the prior futures prices) have been mostly correct; however, actual events, particularly geopolitical and political events that have arisen over the summer and fall of 2019, have created uncertainty that will likely extend into 2020 and perhaps even into 2021.

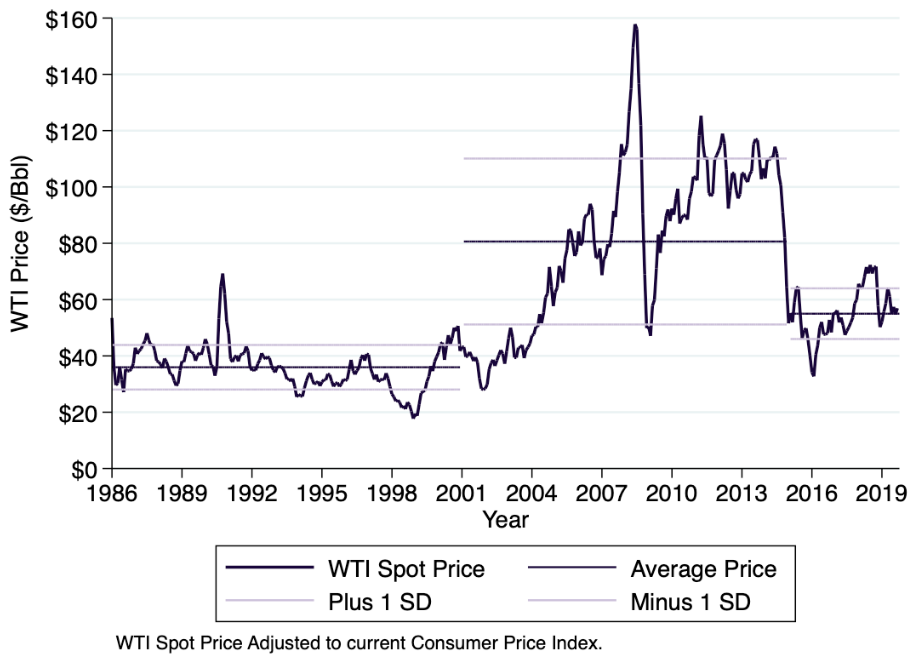
Figure 11: Historic inflation-adjusted natural gas prices



Henry Hub Spot Price adjusted to current Consumer Price Index.

Source: U.S. Energy Information Administration and Louisiana DNR.

Figure 12: Historic inflation-adjusted crude oil prices



Source: U.S. Energy Information Administration.

2.4 Recent Trends: Uncertainties Created by Geopolitical and Policy Tensions

The past year has seen two important uncertainties hang over energy markets: (a) the trade tensions between the U.S. and China, which have been pervasive over the better part of the current administration's tenure; and (b) more recent geopolitical tensions that have arisen in the Middle East that include the ongoing U.S.-Iranian disagreements regarding Iran's nuclear and regional hegemony goals.

Last year's GCEO clearly articulated the significant economic and energy market changes occurring along the Gulf Coast. Increasingly, the region is transforming itself into an exporter of energy products and supplies, as well as one that will likely serve as a transfer point or hub for global energy transactions. The U.S., for instance, is exporting about five million barrels per day of petroleum products, most of which are leaving a Gulf Coast port. The escalating trade disputes with China, the world's most populous country and second largest economy, have resulted in increased tariffs on natural gas and petroleum products, which could have significant implications for the Gulf Coast region's ability to sell basic energy commodities, refined products, and commodity chemicals overseas.

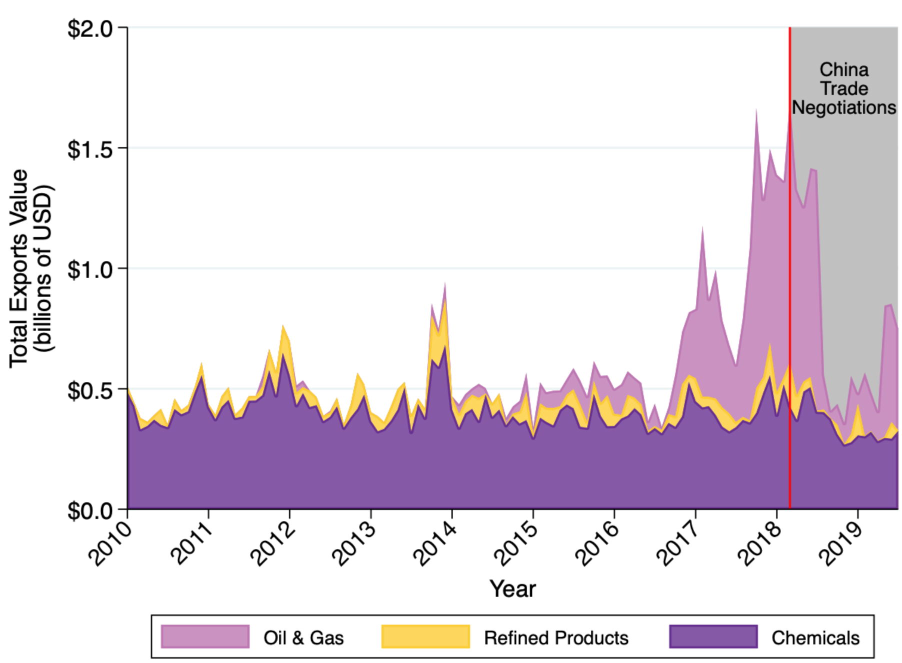
On June 1, 2019, China increased its tariff on natural gas coming from the United States in the form of liquified natural gas (LNG) from 10 percent to 25 percent, in response to recently implemented U.S. tariffs on other Chinese goods and products. This is already having impacts on LNG export facility development along the Gulf Coast and changing the economics and opportunities for overall development. To date, at least one announced LNG project has been postponed, with others seriously considering their development potentials and postponing their final investment decisions.

The ongoing trade disputes with China could have a negative effect on Louisiana's economy in two ways. First, a negative demand shock associated with reduced U.S.-based energy exports could negatively impact regional refiners and petrochemical companies that have made billions in local investments to serve these international markets. Lower exports, resulting from unnecessary trade restrictions, make the region's recent energy manufacturing investments less profitable relative to management's original expectations and reduce these firms' incentive to make additional capacity investments until this uncertainty plays itself out.

Further, the negative demand shock arising from continued U.S.-Chinese trade tensions could reduce U.S. crude oil prices relative to international prices, thereby negatively impacting domestic upstream oil and gas producers due to reduced drilling activity, and ultimately U.S. production.

Figure 13 explores these impacts in greater detail by examining U.S. exports of oil and natural gas, refined products, and chemicals to China (collectively, "energy products"). The first round of U.S. tariffs was announced in March 2018 at a time when the Gulf Coast was exporting more than $1.5 billion monthly in energy products to China. Within several

Figure 13: Gulf Coast exports to China



Source: U.S. Census Bureau, Economic Indicators Division, USA Trade Online.

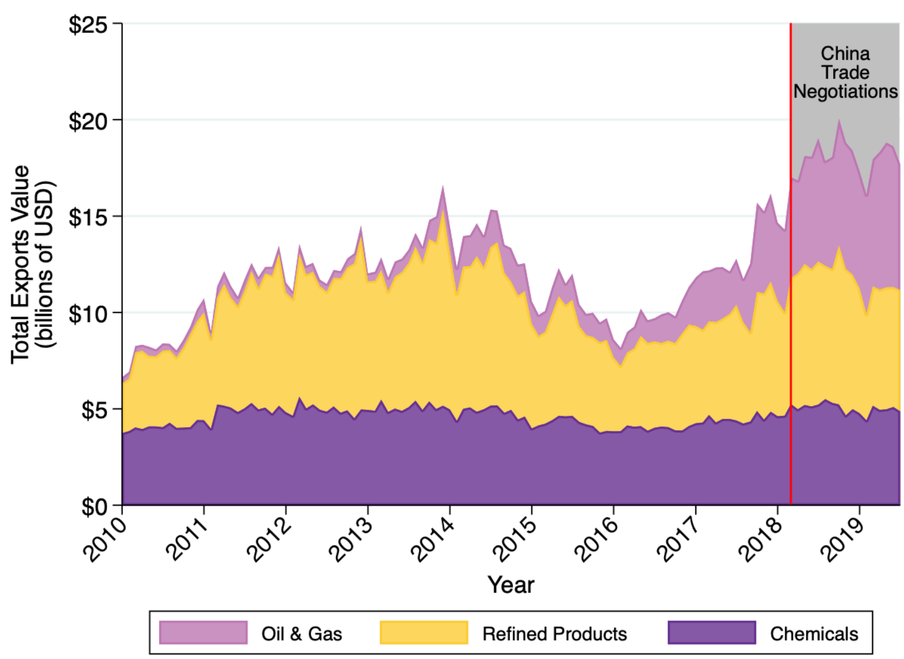
months, exports dropped to less than a third.[2] In more recent months, exports to China have rebounded but clearly not to pre-tariff levels.

Figure 13 underscores Gulf Coast trade tension vulnerabilities. This vulnerability was recently verified by a Federal Reserve Bank of Dallas analysis that estimates Louisiana could lose an astounding seven percent of gross state product (GSP) if a trade war were to escalate, ranking Louisiana as the third most vulnerable state to a U.S.-Chinese trade war.[3]

Figure 14 examines the trends in Gulf Coast energy product exports to the rest of the world in order to assess whether some of these displaced energy products are finding a home elsewhere during this trying period. Fortunately, Gulf Coast energy exports have been relatively strong since the tariff announcements, and there is even a slightly upward bump in the balance of energy trade after these announcements were made; however, more recent trends clearly show a downward movement, albeit not as significant as the downward trend shown earlier for China-bound energy exports.

It is very likely that the more recent export decreases to the rest of the world shown in Figure 14 are attributable to the weakening of the global economy that itself is at least partially a function of the ongoing U.S.-China trade dispute. If the Chinese economy starts to contract from this trade dispute, its ability to purchase goods and products from its other trading

Figure 14: Gulf Coast exports to world



Source: U.S. Census Bureau: Economic Indicators Division USA Trade Online.

2 Agricultural products also experienced a large decrease in exports to China over this time period but are not shown in this figure.

3 Sposi, Michael and Kelvinder Virdi. Steeling the U.S. Economy for the Impacts of Tariffs. Federal Reserve Bank of Dallas. Economic Letter. Vol. 13, No. 5. April 2018.

partners will start to deteriorate as well, even if they are not directly embroiled in this problem. The Eurozone, Japan, and other economies around the world are also experiencing slow growth, thereby reducing trade opportunities for Gulf Coast energy manufacturing.

The second, and potentially more dangerous uncertainty that has arisen in 2019 has been the geopolitical tensions in the Middle East. On September 14, 2019, Houthi rebels in Yemen claimed to have launched coordinated drone attacks against neighboring Saudi Arabia, directly into the heart of its Abquiq and Khurais oil fields. These fields, collectively accounting for five MMBbl/d of production, and the important oil field equipment that processes the lower quality crude oil into a more suitable intermediate crude oil grade for western refining, were immediately damaged. This event followed closely behind summer maritime tensions in the Straits of Hormuz, over which 21 percent of world's petroleum liquids consumption flows and re-energized concerns about how geopolitics, energy supplies, energy prices, and economics interact.

While energy markets responded quickly and meaningfully to the attack on Saudi Arabian production, this market reaction ultimately proved to be short-lived. International oil spot prices (Brent exchange) surged on the day of the event, increasing by 20 percent, or $12 per barrel (Bbl). But futures prices, reflecting trades contracted for closure 12 months later, only increased by about $4.50/Bbl or eight percent. This pricing outcome suggests that markets were banking that the longer-run impact of the attacks would not be that deleterious to world energy supplies.

Three days after the event, spot prices had fallen to around $4/Bbl to $5/Bbl above pre-attack prices. The increase in 12-month futures prices was down to just three percent, indicating that the markets were doubling down on the belief that there would be no significant long-run impacts. The market's optimism was seemingly proven correct on October 3, 2019, when the Saudis reported that 100 percent of all production damaged by the earlier attacks was back online.

While world crude oil prices appear to have stabilized, this is likely not the end of the story. There are considerable continued geopolitical tensions that could have important ramifications for the U.S. energy sector, particularly, and perhaps most importantly, along the Gulf Coast. As will be discussed later, current futures prices likely factor in a good part of this uncertainty, and what appears to be clear from these futures prices is that the market continues to be relatively well supplied.

2.5 Outlook: Commodity Pricing

Futures markets are indicating that both crude oil and natural gas prices will be relatively flat in real terms over the forecast horizon primarily because: (a) the global economy is weakening, and the demand for energy will clearly follow this weakness in the near term; (b) non-OPEC energy resources, including unconventional U.S. supplies, continue to be prolific; and (c) Saudi Arabia is likely to be accommodative on crude oil supplies given the precariousness of tensions in the Persian Gulf region, and increasing throughout the Middle East, particularly in Syria. This should come as no surprise, as futures markets are at least pricing in the same considerations.

In fact, an examination of Figure 15 and Figure 16, which chart respective futures market prices for crude oil and natural gas, show continued pricing moderation. November 2019 futures markets are predicting that prices will remain below $55 per barrel for the foreseeable future. In other words, futures markets are predicting that this new era of lower prices for oil is here to stay.

Figure 16 shows the corollary for natural gas futures prices. Natural gas prices are forecasted to bottom out in 2020 yet stay well below $3.00/MMBtu for the foreseeable future. This is

Figure 15: Crude oil price outlook

Source: S&P Global Market Intelligence.

a positive price outlook for most of the Gulf Coast energy complex, since regional energy manufacturing and export investments rely so heavily on an affordable and amply supplied natural gas feedstock.

2.6 Outlook: Crude Oil and Natural Gas Production

As noted earlier, an important issue arising in the development of the 2019 GCEO crude oil

Figure 16: Natural gas price outlook

Source: S&P Global Market Intelligence.

and natural gas production forecasts was the extent to which the region's unconventional basins would continue to expand production. At the time of the 2019 GCEO development, there was a considerable debate, particularly among various industry analysts, as to whether the region could maintain its unparalleled productivity improvements, with some analysts going so far as to suggest that the region had topped out in terms of well productivity, particularly for crude oil, and would start to see flat-to-declining daily crude oil production rates over the next several years.

For the past three years, the GCEO has utilized the Enverus ProdCast model for production forecasts.[4] The 2019 production forecasts did not take this position and, as shown in the earlier section of this outlook, the past year's production trends underscore the likelihood of continued strong production growth. This year, the ProdCast model continues to take the position that it is simply too early in the unconventional revolution to discount the ingenuity of U.S. producers and their ability to extract copious levels of hydrocarbons from these reserves. Ultimately, the law of diminishing returns will kick-in, but the GCEO takes the position that this is not in the very immediate future (to 2030).

The GCEO crude oil and natural gas production forecasts, to 2030, are provided in Figure 17 and Figure 18.[5] The forecast for U.S. production and Gulf Coast production are provided

4 Enverus was formerly DrillingInfo.

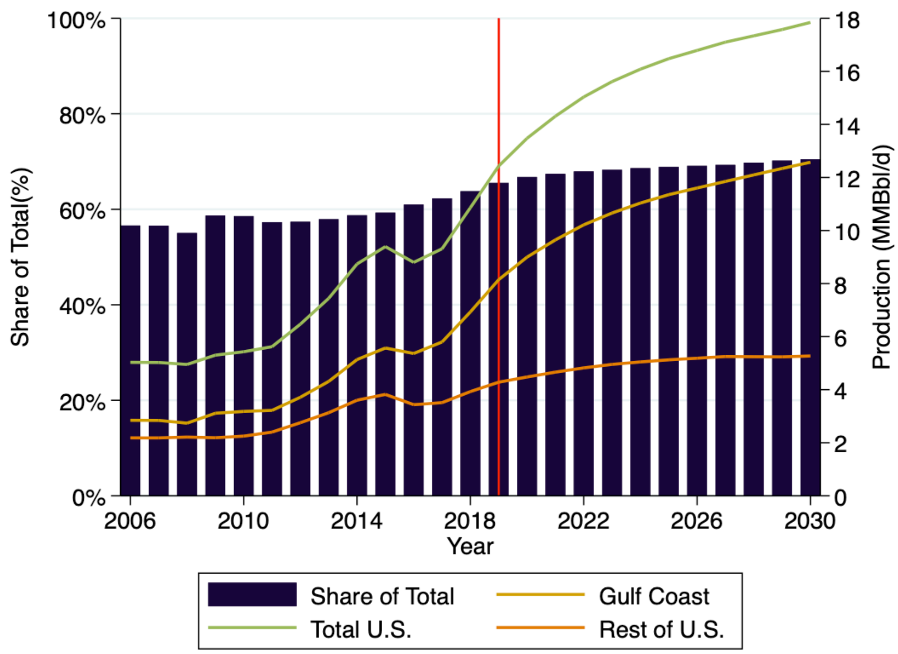
5 Crude oil and natural gas production forecasts for the 2020 GCEO are based on market observations and the *Enverus Prodcast* software formerly known and branded as *DrillingInfo*. Despite the name change, this is the same forecasting tool utilized by the 2018 and 2019 GCEO.

as separate series in each of these outlooks, along with the Gulf Coast's anticipated share of total U.S. crude oil and natural gas production, respectively.

Total U.S. crude oil production is projected to increase to approximately 18 million barrels per day by 2030, with more than 12 million barrels a day of that production coming from the Gulf Coast region. This will lead to a modest increase in the share of oil production coming from the Gulf Coast region from about 66 percent in 2019 to 70 percent by 2030.

Figure 18 shows the forecast for U.S. and regional natural gas production through 2030. The 2020 GCEO U.S. natural gas production forecast anticipates an increase from 100 Bcf/d in 2019 to 131 Bcf/d by 2030. While Gulf Coast natural gas production is anticipated to increase from 42 Bcf/d in 2019 to 56 Bcf/d in 2030, the region's share of U.S. natural gas production is forecast to flatline after 2027.[6]

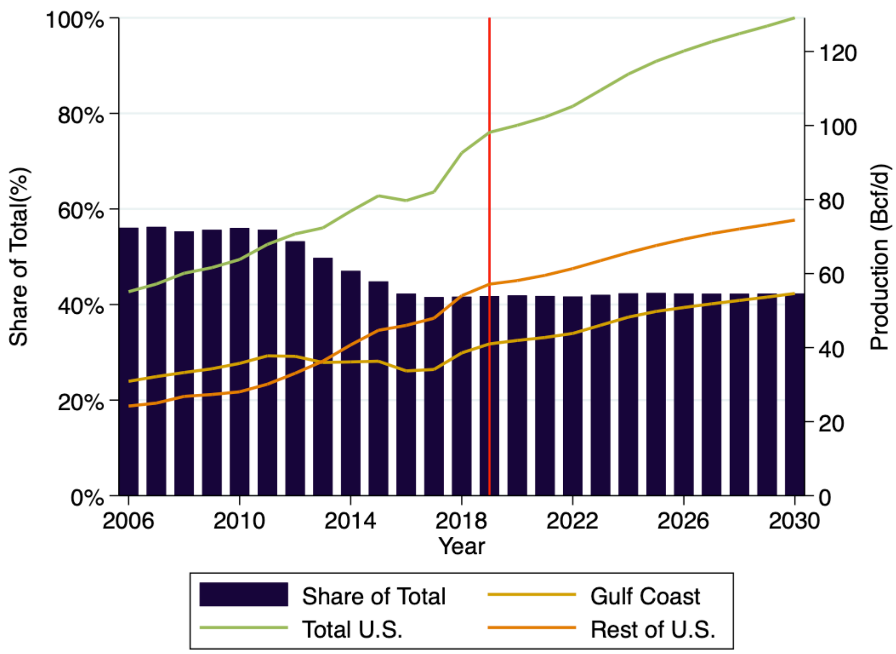
Figure 17: Crude oil production forecast and Gulf Coast share of US. production



Source: Enverus ProdCast.

6 Note that the ProdCast model is based on specific reservoirs, some of which cross state lines. For this reason, these do not match the specific state level production shown in above historical production figures.

Figure 18: Forecast for natural gas production and Gulf Coast share of U.S. production



Source: Enverus. DI ProdCast.

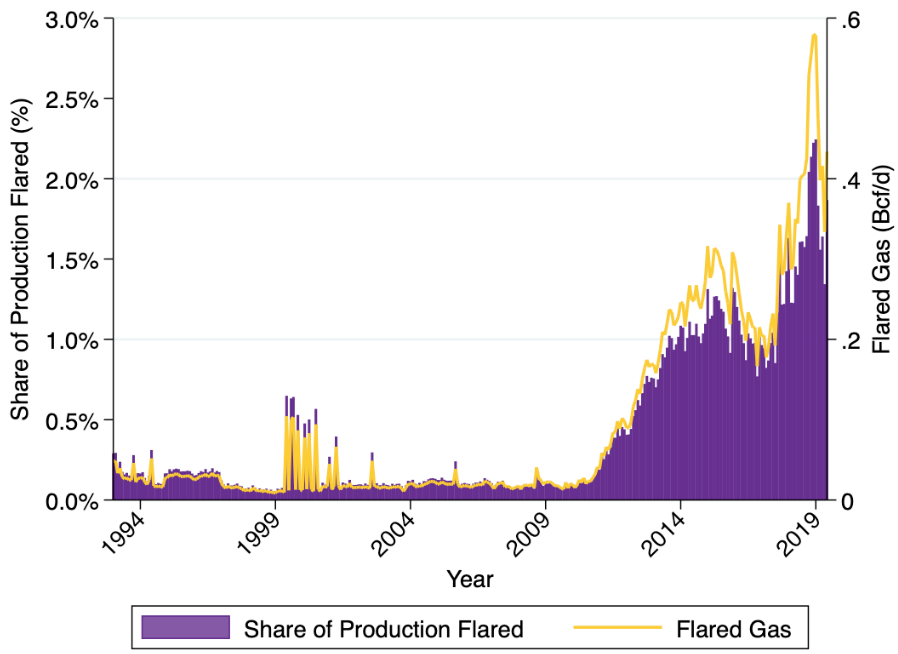
3 | Pipeline Activity

3.1 Recent Trends

While both crude oil and natural gas production forecasts are strong, there are however, a number of challenges to PADD 3 production, and those have less to do with geology than they do the physical transportation constraints of moving crude oil out of the Permian Basin and to the Gulf Coast. Recent financial and trade press articles have continued to emphasize the challenges that the Permian Basin has in getting commodity out of the region and into consuming and/or export areas.

An examination of the current level of natural gas flaring that is occurring in East Texas is a good indicator of this transportation constraint (see Figure 19). Between November 2018 and January 2019, East Texas natural gas flaring peaked at 500 million cubic feet per day ("MMcf/d"), primarily driven by associated natural gas production in the Permian Basin, exceeding two percent of Texas total natural gas production. In the Permian itself, flaring has exceeded five percent of total natural gas production in some months. For some producers, these natural gas transportation constraints are becoming so significant that

Figure 19: Natural gas flaring in Texas



Source: Texas Railroad Commission.

they have made decisions to simply not bring wells online because they would be forced to flare the gas, even if bringing the well online could be profitable just from a crude oil production perspective alone.

There are three types of transportation-oriented constraints arising in the Permian region. The first constraint rests with the limited in-field gathering system capabilities in some areas. The second constraint rests with limited gas processing, while the third constraint rests with the need for additional longer-haul transmission pipeline capacity to move natural gas out of the Permian to Gulf Coast markets.

Collectively, these constraints are leading to high in-region natural gas pricing discounts, as seen in the Henry Hub/Waha pricing comparison provided in Figure 20. Over the past several years, these two hubs traded at very similar prices, with Henry Hub receiving a small premium, on average, due to its proximity to many large sources of natural gas demand. However, early 2008 saw the emergence of significant Waha price discounts relative to Henry Hub, and on some days, natural gas at Waha has traded at negative prices.

However, price signals do appear to be doing the trick of motivating regional infrastructure development that includes the recently operational Gulf Coast Express Pipeline (Waha Hub to Corpus Christi) that has two Bcf/d of capacity and should help to alleviate these growing flaring challenges, as well as their corresponding negative impacts on prices.

Figure 20: Henry Hub and Waha natural gas prices

Source: S&P Global Market Intelligence.

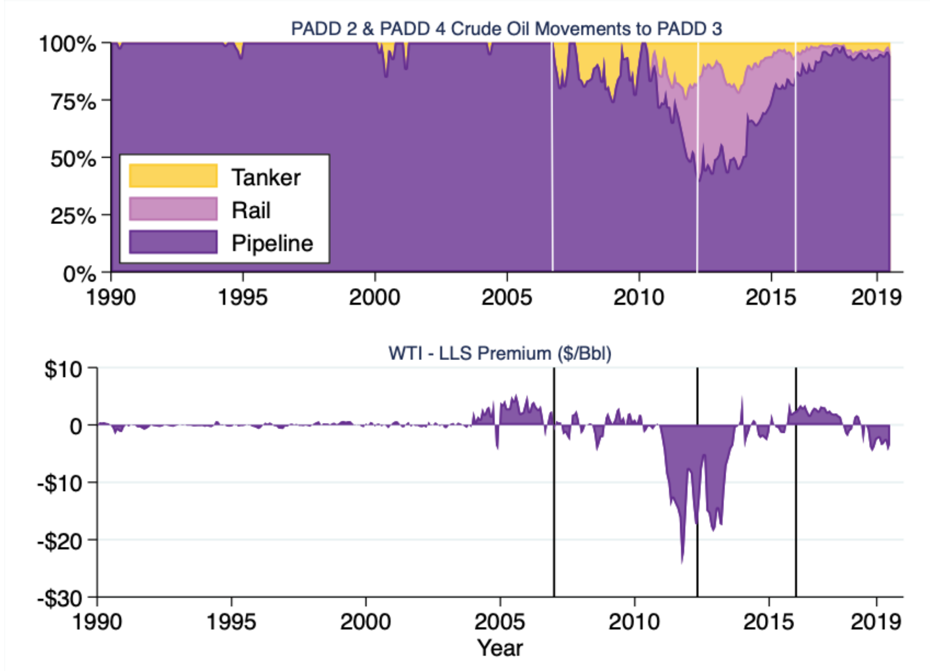
These transportation constraints are not limited to natural gas. Last year's GCEO noted that one of the more watched issues for the region was the degree to which new takeaway crude oil transportation capacity could be developed. Figure 21 highlights the extent to which these transportation constraints can influence crude oil pricing discounts.[7]

Specifically, Figure 21 investigates the extent to which shipping constraints can explain the discount of West Texas Intermediate (WTI) relative to Louisiana Light Sweet (LLS). Three vertical lines are drawn. The first vertical line is January 2007, the date at which EIA began tracking crude oil and natural gas unconventional production in its Drilling Productivity Reports. The second line is May 2012, when the Seaway pipeline was reversed. Seaway initially moved crude from Freeport, Texas, on the Gulf Coast, to Cushing, Oklahoma, where WTI is priced. After Seaway was reversed, the pipeline carried crude produced in the mid-continent to Gulf Coast refineries. This line divides a regime of increasing internal shipping constraints from a regime where those constraints were relieved. The third line is December 2015, when the U.S. government lifted the export ban that constrained the sale of crude oil overseas.

The top panel of Figure 21 shows the share of crude oil transported from PADD 2 and PADD 4 in the mid-continent (states in the Rocky Mountain and Midwestern regions) to PADD 3 in

7 For more detailed analysis see: Agerton, Mark and Gregory B. Upton Jr. " Decomposing crude price differentials: Domestic shipping constraint or the crude oil export ban?" The Energy Journal 40 (3) 155-172; Upton, Gregory B. Crude Oil Exports and the Louisiana Economy. A discussion of U.S. policy of restricting crude oil exports and its implications for Louisiana. LSU Center for Energy Studies. November 2015.

Figure 21: PADD 3 crude oil movements by transportation type



Source: U.S. Energy Information Administration and Bloomberg.

the Gulf Coast. From 1990 to 2007, almost all crude was transported from the mid-continent to the Gulf Coast via pipeline. Shippers used pipelines because rail and tanker were more expensive on the margin. During this time WTI and LLS moved in lockstep. In fact, by April 2012, more than half of the crude shipped from the mid-continent to the Gulf Coast went via high-cost barge and rail. Almost immediately after the reversal of the Seaway pipeline, this trend stopped, and the share of crude shipped via pipeline began to recover.

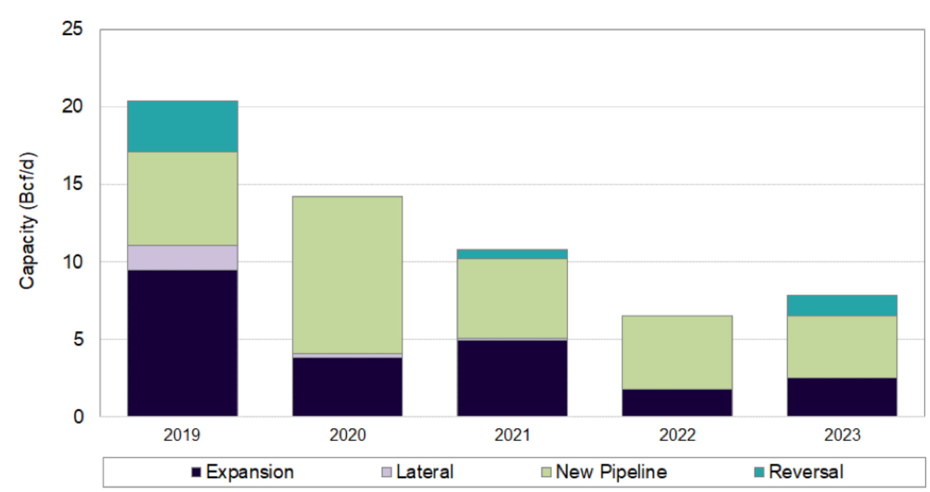
The LLS-WTI premium closely mirrors changes in the mode of transport over the 2007-2015 time period. This close correlation between shipping and prices can explain between half and three-quarters of the movement in relative prices. Empirical research has investigated whether changes in the composition of refining as captured by API gravity of crude inputs can explain these differentials. Evidence of shipping constraints, but not refining constraints, is observed.

This analysis provides strong evidence that shipping constraints between the mid-continent and Gulf Coast were the culprit for the price discount. Since the beginning of 2019, LLS has once again began trading at a small premium to WTI. There are currently nine crude oil pipeline projects in the Gulf Coast region, either under construction or announced, that are expected to be completed by the end of 2021. We anticipate that this premium will be temporary and relieved as additional pipeline infrastructure is built.

3.2 Pipeline Outlook

Figure 22 shows the pipeline transmission capacity additions anticipated over the next five years. These capacity additions are restricted to just larger, interstate transmission pipelines and do not include intrastate or gathering pipeline additions that may arise over the same time period. The chart shows a decreasing level of interstate natural gas development activity. Year end 2019 should see some relief to these regional constraints with about 34 percent of the announced natural gas transportation capacity coming on-line: The remaining 66 percent will come online in subsequent years.

Figure 22: U.S. interstate natural gas pipeline capacity expansions by project type



Source: U.S. Energy Information Administration.

Table 1 provides the underlying natural gas pipeline projects that are under construction or have been announced for development. This table includes the 42 largest projects, and focuses only on major interstate natural gas pipelines, not the other corresponding pipeline infrastructure (like intrastate lines and gathering system lines) that could be developed over the same time period.

There are 15 major interstate natural gas pipeline projects currently under construction or identified for development in the Northeast region. These are all new pipelines or expansions of existing systems, representing 12 Bcf/d, and are being developed to alleviate regional export constraints, particularly in the Permian and Appalachian Basins. For instance, Mountain Valley Pipeline is a natural gas pipeline project that will run 304 miles from northwestern West Virginia to southern Virginia, and transport natural gas produced in the Marcellus and Utica shale to markets in the Mid and South Atlantic regions of the U.S. (Mountain Valley

Table 1: Major U.S. interstate natural gas pipeline projects

Project Name	Pipeline Operator Name	Project Type	Status	In Service	State(s)	Region(s)	Cost (million $)	Miles	Additional Capacity (MMcf/d)
Equitrans Expansion Project	Equitrans LP	Expansion	Construction	2019	PA,WV	Northeast		8	600
Mountain Valley Pipeline	Mountain Valley Pipeline, LLC	New Pipeline	Construction	2020	WV,VA	Northeast	$5,000	304	2,000
Supply Header Project	Dominion Transmission	Expansion	Construction	2019	PA,WV	Northeast	$500	38	1,500
Empire North Expansion Project	Empire Pipeline	Expansion	Construction	2019	PA,NY,ON	Northeast, Canada	$141	25	300
Atlantic Coast Pipeline	Atlantic Coast Pipeline	New Pipeline	Construction	2020	WV,VA,NC	Northeast, Southeast	$5,100	600	1,500
Northeast Supply Enhancement Project	Transcontinental Gas Pipeline	New Pipeline	Approved	2019	PA,NJ,NY	Northeast	$927	37	400
PennEast Pipeline Co	PennEast Pipeline Co	New Pipeline	Approved	2019	PA,NJ	Northeast	$1,000	118	1,107
Constitution Pipeline	Constitution Pipeline Co	New Pipeline	Approved/On Hold	2020	PA,NY	Northeast	$683	121	650
Northern Access 2016 Project (PA to NY)	National Fuel Gas Supply Corp	Expansion	Approved/On Hold		PA,NY	Northeast	$455	101	497
FM 100 Project	National Fuel Gas Supply Corp	Expansion	Applied	2021	PA	Northeast		31	330
Leidy South Project	Transcontinental Gas Pipeline	Expansion	Applied	2021	PA,MD,DE	Northeast		12	580
Buckeye Xpress	Columbia Gas Transmission	Expansion	Applied	2020	OH,WV,KY	Northeast, Midwest	$709	64	275
MVP Southgate Project	Mountain Valley Pipeline, LLC	New Pipeline	Applied	2020	VA,NC	Northeast, Southeast	$440	73	300
Diamond East Project	Transcontinental Gas Pipeline	Expansion	Announced	2020	PA,NY	Northeast	$800	50	1,000
Regional Energy Access Project (I and II)	Transcontinental Gas Pipeline	Expansion	Announced	2022	PA,NJ	Northeast		34	1,050
Cheniere MIDSHIP Pipeline Project	Cheniere MIDSHIP Pipeline	New Pipeline	Construction	2019	OK,TX	South Central	$1,025	233	1,440
Creole Trail Expansion Project 2	Cheniere Creole Trail Pipeline	Reversal	Approved	2019	LA	South Central	$610	104	1,500
Port Arthur Pipeline- Texas Connector	Port Arthur Pipeline LLC	New Pipeline	Approved	2022	TX	South Central		34	2,000
Golden Pass LNG Bidirectional Pipeline	Golden Pass Pipeline LLC	Expansion	Approved/On Hold	2023	LA,TX	South Central	$383	69	2,500
Lake Charles Expansion (Magnolia LNG)	Kinder Morgan Louisiana PL Co	Reversal	Approved/On Hold	2023	LA	South Central	$202		1,362
Corpus Christi Stage III Pipeline	Cheniere Energy Corpus Christi	Expansion	Applied	2021	TX	South Central		21	1,530
Index 99 Expansion Project	Gulf South Pipeline	New Pipeline	Applied	2020	LA, TX	South Central		22	500
Port Arthur Pipeline- Louisiana Connector	Port Arthur Pipeline LLC	New Pipeline	Applied	2023	LA,TX	South Central	$1,207	131	2,000
Rio Bravo Pipeline Project	Rio Bravo Pipeline Company	New Pipeline	Applied	2020	TX	South Central	$2,173	138	4,500
TransCameron Pipeline	Venture Global Calcasieu Pass	New Pipeline	Applied	2021	LA	South Central	$345	24	1,900
Delta Express Pipeline Project	Venture Global	New Plpeline	Pre-applied		LA	South Central		281	
Gulf Run Pipeline	Enable Gas Transmission	New Pipeline	Pre-applied	2022	LA	South Central		165	2,750
Permian Global Access Pipeline	Tellurian	New Pipeline	Announced	2023	TX,LA	South Central			2,000
Spire St. Louis Pipeline (Laclede Lateral)	Spire STL Pipeline LLC	Lateral	Construction	2019	IL,MO	Midwest	$220	65	400
Louisiana XPress Project	Columbia Gulf Transmission	Expansion	Applied	2022	KY,TN,MS,LA	Midwest, South Central	$472		493
NGPL Gulf Coast Southbound Project (Ph. II)	Nat Gas P L Co of America	Reversal	Applied	2021	IL,MO,AR,TX	Midwest, South Central	$145		300
NGPL Gulf Coast Southbound Project (Ph. III)	Nat Gas P L Co of America	Reversal	Announced	2021	IA,IL,MO,AR,TX	Midwest, South Central	$145		260
NGPL Waha Deliverability Expansion Project	Nat Gas P L Co of America	Reversal	Announced	2019	IL,IA,NE,KS,OK,TX	Midwest, South Central			465
Sierrita Pima Expansion	Sierrita Gas Pipeline LLC	Expansion	Construction	2020	AZ,MX	Mountain, Mexico	$56	61	323
Cheyenne Connector Pipeline	Tallgrass Energy Partners LP	Expansion	Applied	2019	CO	Mountain	$213	70	600
Sendero Gateway Project	Sendero Midstream	New Pipeline	Applied	2019	NM,TX	Mountain, South Central	$45	23	400
Cheyenne Hub Enhancement Project	Rockies Express Pipeline LLC	Expansion	Applied	2019	CO,WY,NE,KS,MO,IL	Mountain, S.Central, Midwest	$133		1,000
Double E Pipeline	Summit Midstream Partners	Expansion	Pre-applied	2021	NM,TX	Mountain, South Central	$450	134	1,400
Western Energy Storage and Transportation	Magnum Gas Storage LLC	New Pipeline	Announced	2021	UT,NV,AZ,MX	Mountain, Mexico		650	2,000
Trail West/N-MAX	Northwest Pipeline Co	Expansion	Announced	2021	OR	Pacific	$800	106	450
Pacific Connector Gas Pipeline	Pacific Connector Gas Pipeline LP	New Pipeline	Applied	2021	OR	Pacific	$1,700	229	1,200
Island Gas Connector	Island Gas	New Pipeline	Announced	2020	WA,BC	Pacific, Canada		81	700

Source: U.S. Energy Information Administration.

Pipeline, 2019). Similarly, the Atlantic Coast Pipeline is a 600-mile interstate natural gas pipeline project that will originate in West Virginia and move gas through Virginia and into eastern North Carolina. This project is anticipated to come online in 2020 with a capacity of 1.5 Bcf/d (Atlantic Coast Pipeline, 2019).

Several other projects are being developed primarily to move U.S. natural gas production volumes to the Gulf of Mexico (GOM) region for industrial consumption and the Gulf Coast for LNG exports. For instance, Cheniere's Midship Pipeline is being developed "to deliver a reliable supply of domestic natural gas from Oklahoma's rapidly growing production areas to consumers predominantly in the Gulf Coast and Southeast U.S. markets. Natural gas will be delivered through the pipeline to industrial facilities, natural-gas-fired power generators, liquefaction terminals, and downstream users such as local distribution companies" (Midship Pipeline, 2019). Enable's Gulf Run Pipeline is a proposed interstate transmission line designed to bring natural gas from the Haynesville, Marcellus, Utica and Barnett shales, as well as the Mid-Continent region to the Gulf Coast. It is designed to provide a critical link between increased domestic natural gas production and increasing demand from Gulf Coast and international markets.

In total, the larger projects listed in Table 1 amount to 46 Bcf/d of new or expanded transmission capacity. About 12 Bcf/d are in the Northeast region and are being developed to alleviate regional constraints, as well as to transport production from prolific Appalachian shale. More than half of the new capacity in Table 1, almost 24 Bcf/d, is in the South Central region, being developed to bring natural gas toward the GOM. And another 2 Bcf/d will originate in the Midwest and also bring natural gas toward the GOM. Much of this capacity will be a reversal of pipeline flow.

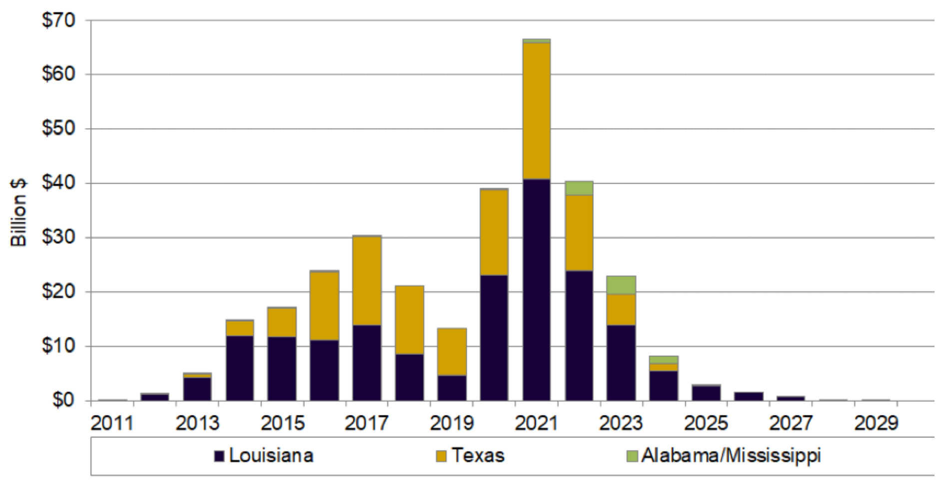
4 | Energy Manufacturing Activity

4.1 Recent Trends

The Gulf Coast has some of the highest concentration of energy manufacturing activities in the U.S. The level of capital development in the region has been phenomenal, but there are warning signs that these capital investments may be starting to slow. The political and geopolitical challenges discussed earlier, which create considerable investment uncertainty, do not bode well for potential projects that typically run in the hundreds of millions of dollars, if not billions.

Figure 23 highlights the recent Gulf Coast industrial capital investments that have been leveraged by lower cost and more available unconventional hydrocarbons. In total, across the entire period examined, the Gulf Coast region is anticipated to potentially experience as much as $308 billion in new capital investments. This investment averages to about $15

Figure 23: GOM energy manufacturing investments by state



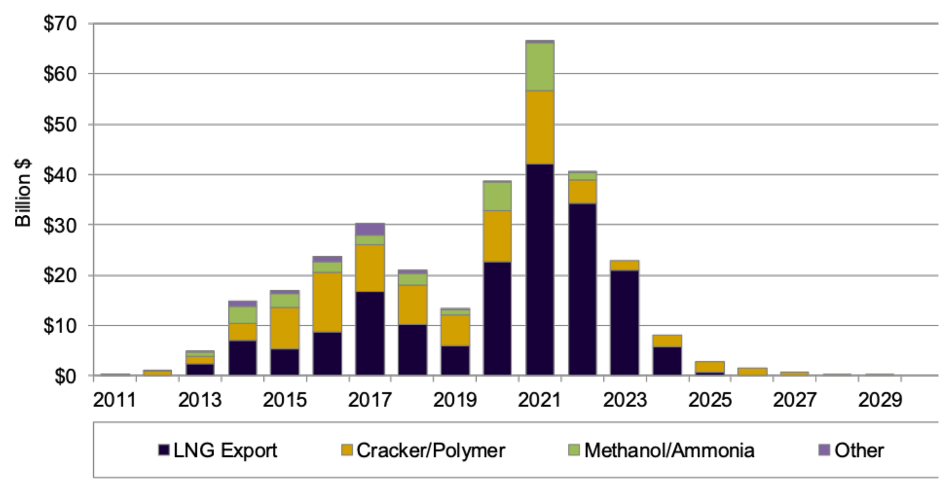
Source: LSU Center for Energy Studies.

billion per year along the GOM over a 20-year period. Through 2018, all GOM states, mostly Texas and Louisiana, have experienced as much as $113 billion (or about $14 billion per year). Louisiana has received the larger share of this investment ($62 billion or 55 percent) while Texas has received as much as $50 billion (or 44 percent).

Most investments made in the region over the past decade originally began as expansions to existing facilities, including LNG facilities, which at the time were dedicated primarily to facilitating natural gas imports, not exports. While some greenfield investments have been made, these too have been to leverage existing low-cost, abundant hydrocarbons and the existing regional infrastructure that can be used to process and move those hydrocarbons from point A to point B.

Figure 24 provides a breakdown of these GOM investment trends by sector and shows that LNG export facility investments dominate the historic trend, and clearly dominate the outlook from 2019 to 2023. Prior to 2019, LNG investments accounted for $55 billion (45 percent) of all capital investments along the Gulf Coast. Olefins (cracker) and other petrochemical-based investments accounted for the second highest share at $43 billion (38 percent). The high investment shares in LNG facilities should come as no surprise given the high individual investment cost per train, which can run as much as $8 billion to $12 billion.

Figure 24: GOM energy manufacturing investments by sector



Source: LSU Center for Energy Studies.

4.2 Energy Manufacturing Outlook

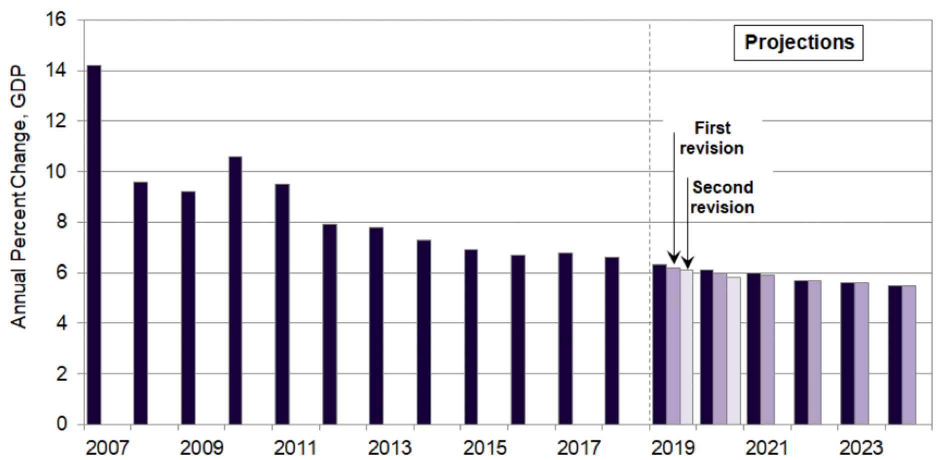
As noted earlier, there are strong headwinds negatively impacting industrial development in the region. Ongoing trade tensions impact industrial projects in the region in numerous and different ways, from raising their cost of development, to lower utilization of existing capital/capacity investments, to creating a degree of uncertainty that is never conducive for large capital investments. To date, there is at least one major Gulf Coast project (Wanhua Chemical in Convent, Louisiana) that has been cancelled due in large part (but not exclusively) to the ongoing trade tensions between the U.S. and China.

One of the more important ramifications of the current U.S.-China trade tensions is the resulting negative implications they have for continued economic growth around the world. The International Monetary Fund (IMF) has already revised its outlook for Chinese economic growth downward (Figure 25) and has revised its outlook for world growth downward at least twice this year from 3.3 percent in April 2019 to 3.2 percent July 2019 and 3.0 in October 2019.

The Organization for Economic Co-operation and Development (OECD) and International Energy Agency (IEA) have expressed the same expectations by downgrading world economic growth outlooks this year.

Furthermore, overall industrial weakness is starting to become more and more visible in the overall U.S. manufacturing numbers. Figure 26, for instance, shows the trend in the Federal Reserve's Industrial Production Index and the Institute for Supply Management (ISM) Purchasing Managers' Index (PMI). The Industrial Production Index can be thought of as a barometer of current industrial activity, whereas the PMI is often thought of as a barometer of future industrial activity and investment sentiment.

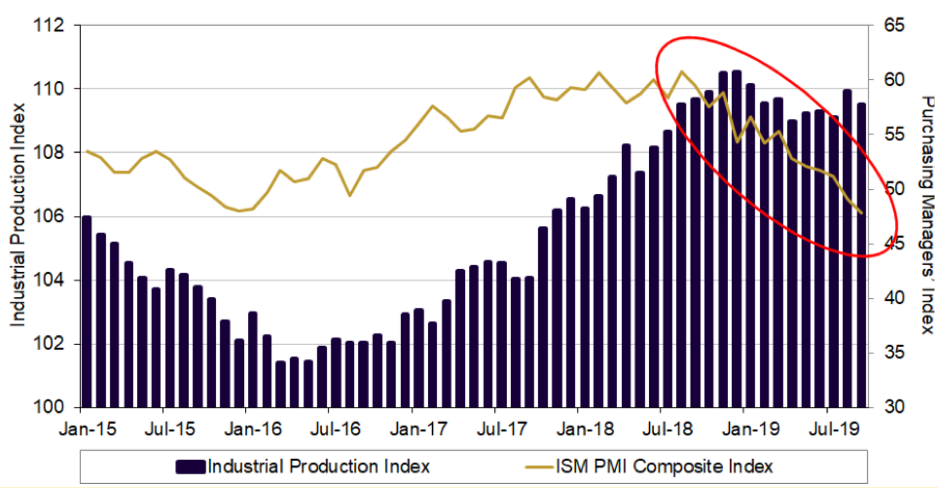
Figure 25: Changes in Chinese GDP



Source: International Monetary Fund.

Unfortunately, both the Industrial Production Index and the PMI have been falling throughout the better part of 2019 to the point where, by August 2019, the PMI registered a number well below 50, indicating potential contraction of the U.S. manufacturing sector. This does not bode well for future U.S. economic activity since (a) manufacturing activities in the oil and gas sector have carried the U.S. economy for the better part of the decade, and (b) overall, manufacturing has surged since mid-year 2016 and has proven to be an important source of economic growth pushing the U.S. economy beyond its prior two percent per year GDP doldrums.

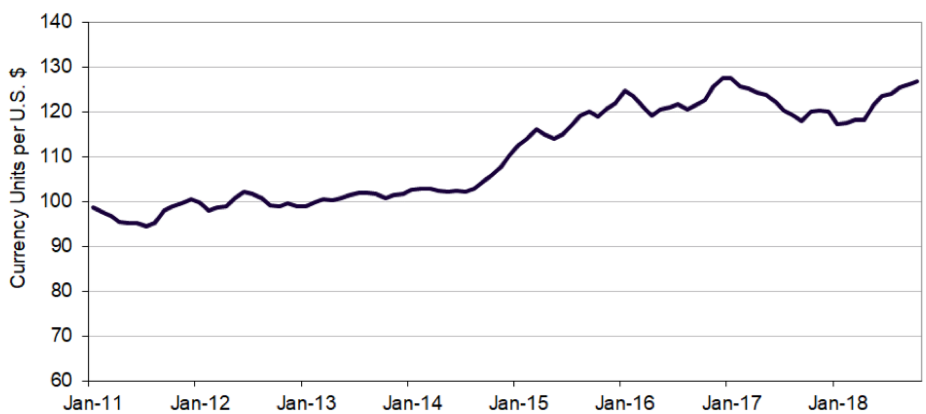
Figure 26: U.S. industrial production index



Source: Federal Reserve Bank of St. Louis.

Lastly, economic and geopolitical uncertainty, as is often the case, has created a flight to quality in capital and foreign exchange markets over the past year. Dollar valuations, as a result, continue to be high, returning to previous exchange levels that peaked in January 2017. High dollar valuations make U.S. goods and products, including energy manufacturing goods (refined product, commodity chemicals, etc.) and energy exports, increasingly more expensive. Figure 27 highlights recent dollar valuation shifts using the Federal Reserve Board's "Broad Index," which is a weighted average of foreign exchange values for the U.S. dollar versus its major trading partners.

Figure 27: U.S. dollar valuation, Federal Reserve Broad Index



Source: Federal Reserve Bank of St. Louis.

Table 2 provides an overview of total investment dollars associated with all the project announcements in the major parts of the Gulf Coast (Texas, Louisiana, and other GOM). The total investment dollars for each GOM state is broken down in the table by LNG-related investments and non-LNG-related investments. Overall, for the time period 2019 to 2029, the 2020 GCEO anticipates a maximum level of investments, based on current project announcements of $195 billion. A large share, 68 percent ($133 billion), of these potential investments are related to LNG facilities. Louisiana, at this point, is likely to receive as much as $116 billion of this investment (60 percent); however, it is very heavily weighted to LNG export facilities (76 percent of total Louisiana investment). Texas could receive as much as $71 billion of this investment; however, the totals are slightly more balanced between LNG facility investments, several olefins investments ($36 billion), and several other methanol facility investments ($35 billion).

Table 2: Total GOM investment, all project announcements

Year	Texas LNG	Texas Non-LNG	Louisiana LNG	Louisiana Non-LNG	Other GOM LNG	Other GOM Non-LNG	Total GOM LNG	Total GOM Non-LNG
	(million $)							
2019	$ 3,503	$ 5,126	$ 2,466	$ 2,075	$ –	$ –	$ 5,969	$ 7,201
2020	5,374	10,387	17,337	5,688	11	–	22,723	16,075
2021	9,817	15,352	31,773	9,001	561	–	42,150	24,352
2022	10,419	3,502	21,291	2,560	2,665	–	34,375	6,062
2023	5,448	151	12,167	1,699	3,327	–	20,941	1,850
2024	1,421	–	3,033	2,279	1,332	–	5,786	2,279
2025	99	–	476	2,159	104	–	679	2,159
2026	–	–	29	1,442	–	–	29	1,442
2027	–	–	–	648	–	–	–	648
2028	–	–	–	162	–	–	–	162
2029	$ –	$ –	$ –	$ 11	$ –	$ –	$ –	$ 11
Total	**$ 36,082**	**$ 34,518**	**$ 88,511**	**$ 21,124**	**$8,000**	**$ –**	**$ 132,653**	**$ 62,241**

Table 3 presents the 2020 GCEO baseline outlook for energy manufacturing in the region. This baseline discounts certain projects based upon their likelihood of development in the 2019-2029 time period. Most of the adjustment in this baseline comes from LNG facility development, which is now forecast to occur much later in the time horizon that current announcements suggest. As a result, the 2020 GCEO sees near- term energy manufacturing and export investment reduced during the 2019-2029 time period from an announced level of $195 billion to $131 billion. This forecast, however, is highly dependent upon the ongoing

Table 3: Total GOM investment, new baseline outlook

Year	Texas LNG	Texas Non-LNG	Louisiana LNG	Louisiana Non-LNG	Other GOM LNG	Other GOM Non-LNG	Total GOM LNG	Total GOM Non-LNG
	(million $)							
2019	$ 3,417	$ 4,975	$ 2,205	$ 1,991	$ –	$ –	$ 5,622	$ 6,966
2020	3,660	7,207	8,686	5,683	–	–	12,346	12,891
2021	4,667	9,655	11,830	9,001	–	–	16,497	18,655
2022	5,885	4,908	11,760	2,560	–	–	17,644	7,468
2023	3,037	491	11,642	1,699	–	–	14,679	2,191
2024	578	–	6,925	2,279	–	–	7,503	2,279
2025	34	–	1,891	2,159	–	–	1,924	2,159
2026	–	–	132	1,442	–	–	132	1,442
2027	–	–	–	648	–	–	–	648
2028	–	–	–	162	–	–	–	162
2029	$ –	$ –	$ –	$ 11	$ –	$ –	$ –	$ 11
Total	**$ 21,277**	**$ 27,237**	**$ 55,071**	**$ 27,635**	**$ –**	**$ –**	**$ 76,348**	**$ 54,872**

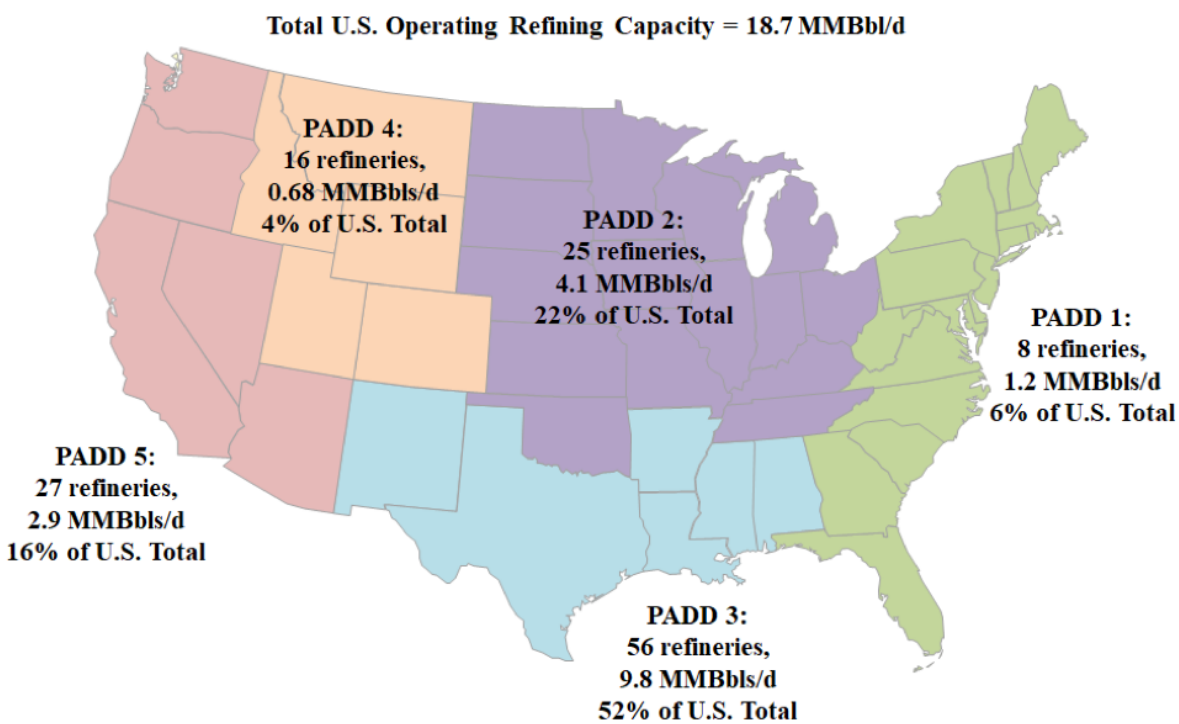
trade and geopolitical uncertainties discussed earlier. An exacerbation of these uncertainties could reduce this near-term capital expenditure profile considerably.

5 | Energy Exports

5.1 Recent Trends: Refined Product Exports

The Gulf Coast region is the largest concentrated area of petroleum refining in the U.S. Figure 28 shows the concentration for PADD 3 relative to other regions of the U.S. There are 56 refineries operating on the Gulf Coast that can process up to 9.8 MMBbl/d of refined product. The region's refineries account for 52 percent of all U.S. operating refinery capacity.

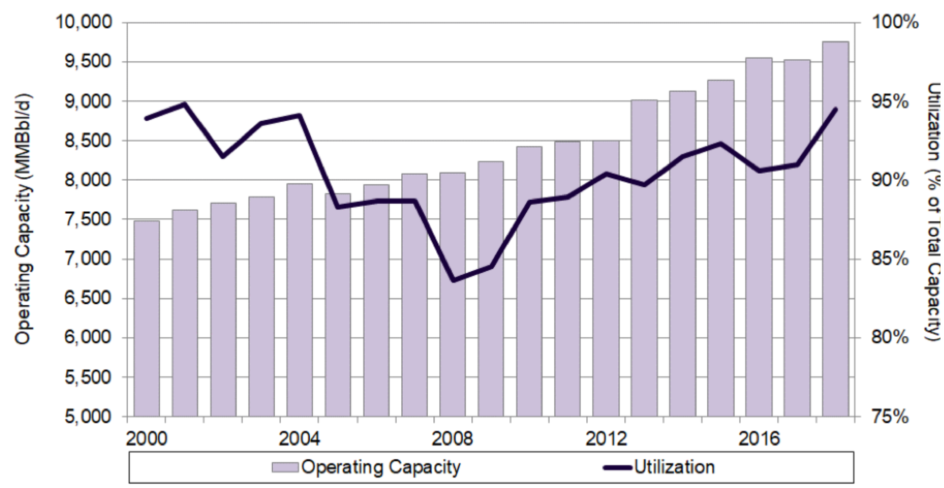
Figure 28: Number and capacity of U.S. refineries



Source: International Monetary Fund.

Operable capacity in the region has grown considerably over the past 30 years, primarily due to capacity creep at existing facilities. No new greenfield refinery has been built since 1976 in Garyville, Louisiana (the Marathon refinery). The last several years have seen considerable growth in PADD 3 refining capacity in order to meet new opportunities for the export of refined product to other places of the world (Figure 29). The operating utilization of that capacity has increased considerably since the contractions of the earlier part of the last decade. Over the past several years, the region's refineries have been operating at around 90 percent, a level comparable to, and likely driving, the national average.

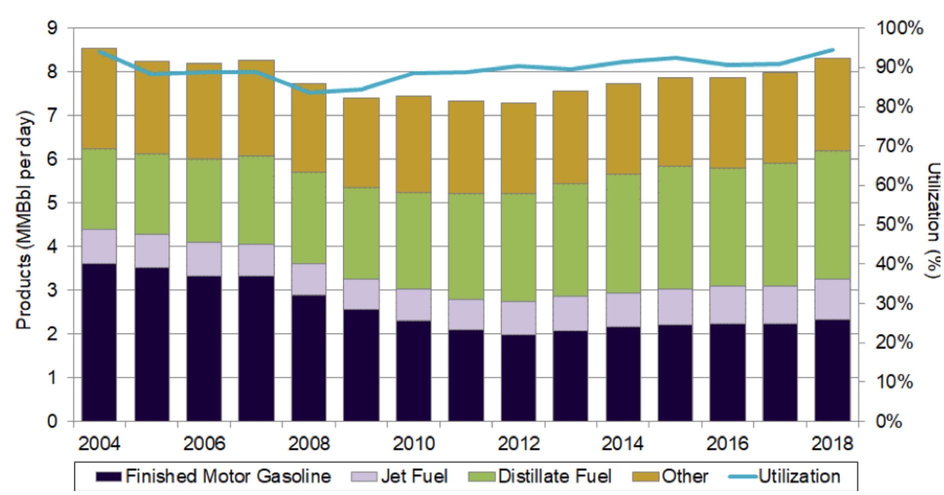
Figure 29: PADD 3 refining capacity and utilization



Source: U.S. Energy Information Administration.

Figure 30 underscores the changing composition of the Gulf Coast energy economy and the greater emphasis toward export-oriented projects. This chart shows the overall refined product trends for PADD 3 refineries. Overall, refined product output is up from the lows

Figure 30: PADD 3 petroleum products supplied

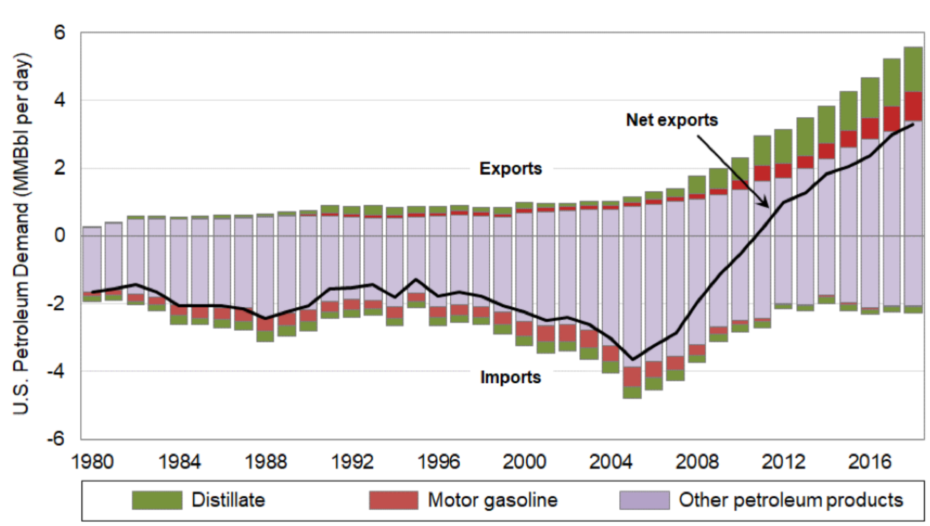


Source: U.S. Energy Information Administration.

experienced after the 2008-2009 recession. Further, the shares of finished motor gasoline, produced predominately for the U.S. market, have begun to contract in each year in the series. More profitable distillates and jet fuel are taking their place. These products, in large part, are consumed abroad and are designed for international markets.

Lastly, Figure 31 shows the trends in overall petroleum imports and exports for the U.S. Prior to 2011, the U.S. was a net importer of all refined petroleum products. After that year, the U.S. shifted to becoming a net exporter, and that position has continued to increase on a year-over-year basis since 2011. As noted earlier, increasingly, the U.S., and PADD 3, are leveraging distillation capacity to produce higher value distillates to sell in international commerce.

Figure 31: U.S. petroleum product imports and exports



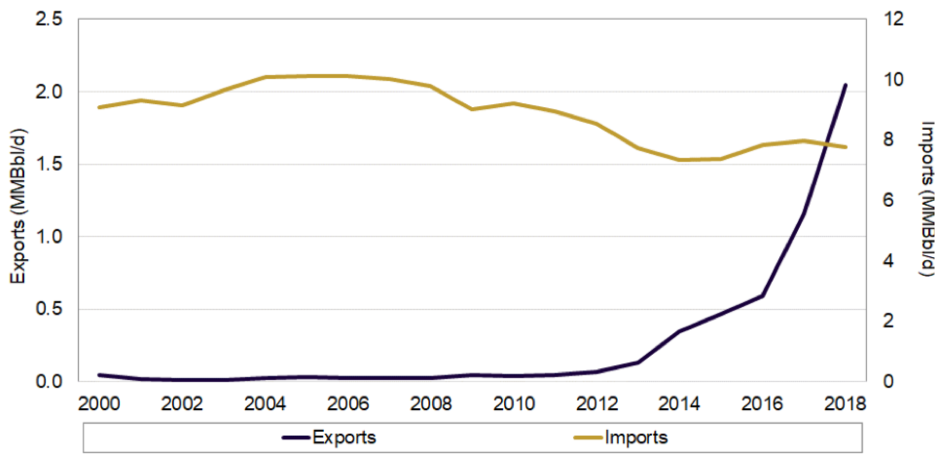
Source: U.S. Energy Information Administration.

5.2 Recent Trends: Crude Oil Exports

U.S. energy exports continue to grow, as does the continued progress and productivity of most unconventional plays along the GOM. While crude oil, like any commodity, is fungible, a large amount of in-region (PADD 3) crude oil production is finding its way to GOM ports and into international commerce. Over 80 percent of all U.S. crude oil exports exit the country from a GOM port, most of which are export facilities around Houston and Corpus Christi, and through the new export investments at the Louisiana Offshore Oil Port (LOOP).

U.S. crude oil exports continue to grow at a rapid pace, by as much as 20 percent since 2016. The past year (2019) has been no different. Figure 32 shows how these exports have dramatically changed the U.S.' balance of crude oil trade. Crude oil imports into the U.S., while still substantial, continue to fall. This decrease, however, appears to be flattening, in large part due to qualitative requirements that many refineries have in the U.S., particularly those on the West Coast.

Figure 32: U.S. crude oil exports and imports



Source: U.S. Energy Information Administration.

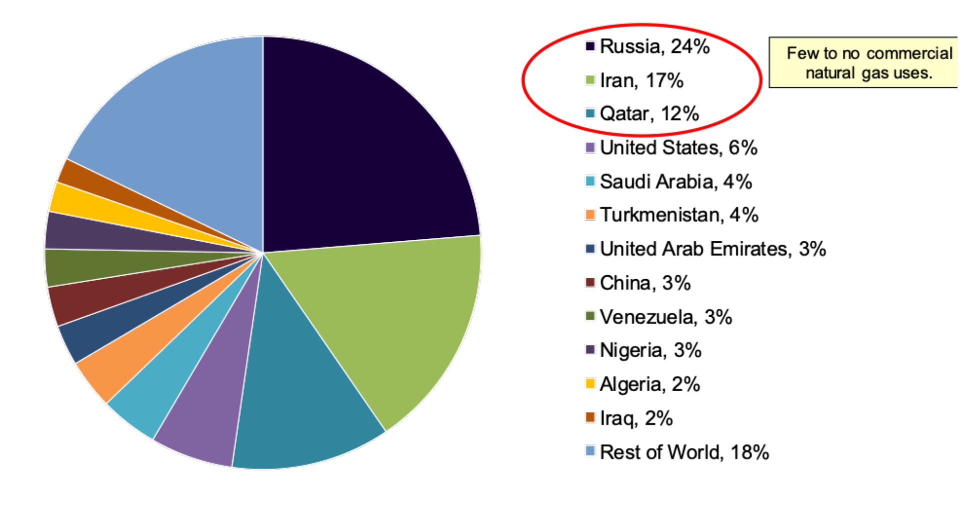
5.3 Recent Trends: LNG Exports

LNG exports are driven by trends in domestic production costs as well as world markets, particularly the price of crude oil, since crude, and its refined products, are often substitutes for natural gas. The U.S. is not the only source of abundant low-cost natural gas supply, and any LNG that leaves domestic markets must compete with natural gas produced by other countries from both conventional and unconventional plays.

Figure 33 shows there are several countries with robust natural gas reserves totaling close to 7,100 trillion cubic feet (Tcf). While U.S. unconventional development has greatly enhanced domestic supplies, these recent domestic resource developments pale in comparison to the size of natural gas reserves in other countries, such as Russia, Iran and Qatar. Each of these three countries has reserves that are two- to four-times that of the U.S. and, collectively, the three countries control over half of estimated global natural gas reserves. The U.S., by contrast, reports six percent of global natural gas reserves.

Cost is also an important factor in determining global natural gas (LNG) market share; however, relative cost, which is the cost of natural gas relative to crude oil, is often just as important as any individual country's overall cost advantage. Figure 34 shows the cost differential between crude oil and natural gas, standardized on a barrel of oil equivalent (BOE) basis. Here, crude oil prices are those associated with the Brent index, and natural gas is the domestic U.S. price at the Henry Hub. The relative difference in these two energy commodity prices drives the market, since LNG prices in these markets are often pegged to crude oil prices.

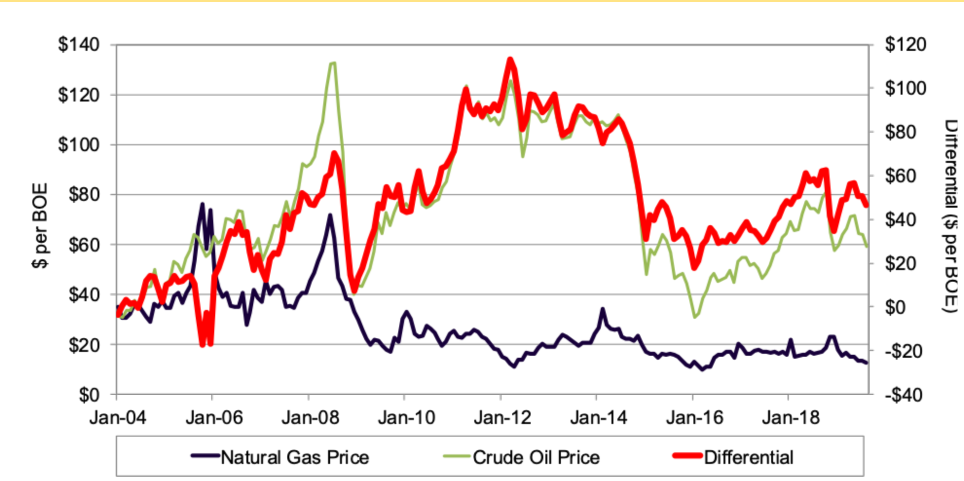
Figure 33: Natural gas reserves by country, 2019



Source: U.S. Energy Information Administration.

Figure 34 shows that crude oil and natural gas prices follow similar trends until about mid-year 2006. Afterward, the gap in the two prices began to increase substantially. This was also the time period during which many LNG export facility announcements were being made. Prices re-adjusted during the Great Recession to only “decouple” once again after 2009. The period from 2009 to 2015 marks the highest differential between crude oil and natural gas prices over the past three decades. The relative pricing differential soared to levels ranging between $80/BOE and $100/BOE. This high differential created a considerable opportunity for U.S. natural gas exports.

Figure 34: Natural gas and crude oil prices

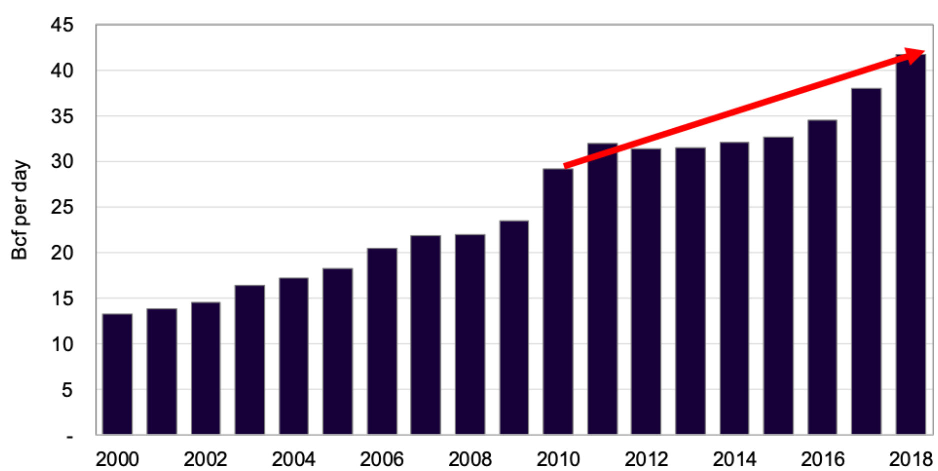


Source: U.S. Energy Information Administration.

Since 2015 the differential has fallen (ranging between $30/BOE and $60/BOE) but is still relatively strong compared to historical norms. Over the last decade, crude oil prices have been the primary if not sole determinant of this differential since natural gas prices, as seen from the chart, have been relatively constant since the last recession (2008-2009).

Figure 35 shows that world LNG growth has boomed over the last two decades, increasing from levels that were around 10 Bcf/d to over 35 Bcf/d in 2017. On average, the growth of LNG trade volumes around the world has increased at an annual rate of seven percent, and in the last 10 years, trade volumes have increased 77 percent. There was a significant leap in 2010 and LNG trade shifted upward, in the post-global economic recession period, by over five Bcf/d.

Figure 35: World LNG trade volumes

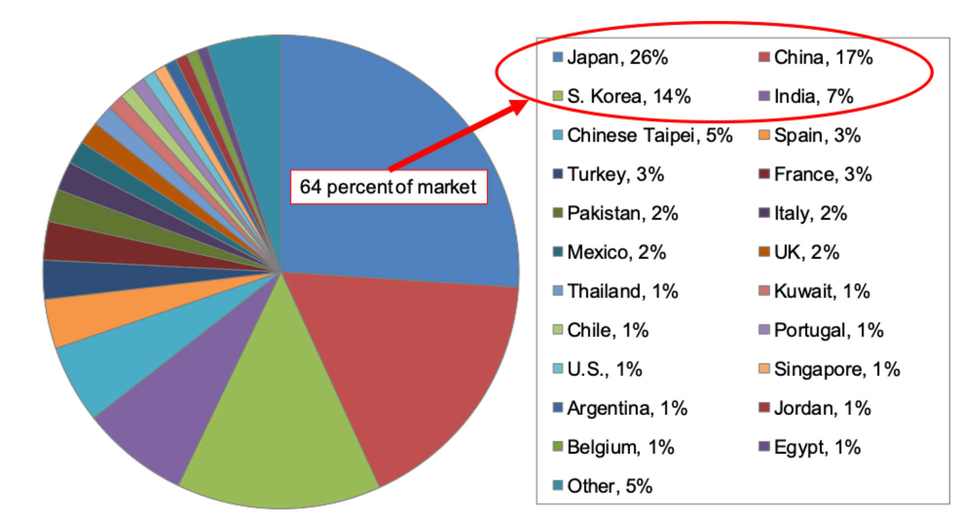


Source: BP, 2018.

Not surprisingly, a amount of LNG that is being traded is ultimately bound for Asia. Figure 36 shows that Japan, China, South Korea, and India are all leading LNG importing countries. Collectively, these four countries account for over 60 percent of world LNG importers and are likely to remain significant importers of LNG for the next decade.

Figure 37 examines the growth in LNG imports, by region, over the 2016-2017 time period. The chart shows that Japan dominates global LNG markets in terms of overall imports, but not necessarily in terms of annual growth. For instance, Japan imports as much as 11.0 Bcf/d of LNG in both 2016 and 2017, clearly indicating no growth in overall natural gas usage in that year. China and other Pacific Rim countries have seen recent growth of 47 percent and 23 percent, respectively. On an individual region basis, China and the Pacific Rim countries' annual usage is about half that of Japan's. Europe has recently posted some relatively

Figure 36: LNG imports and market share by country, 2018

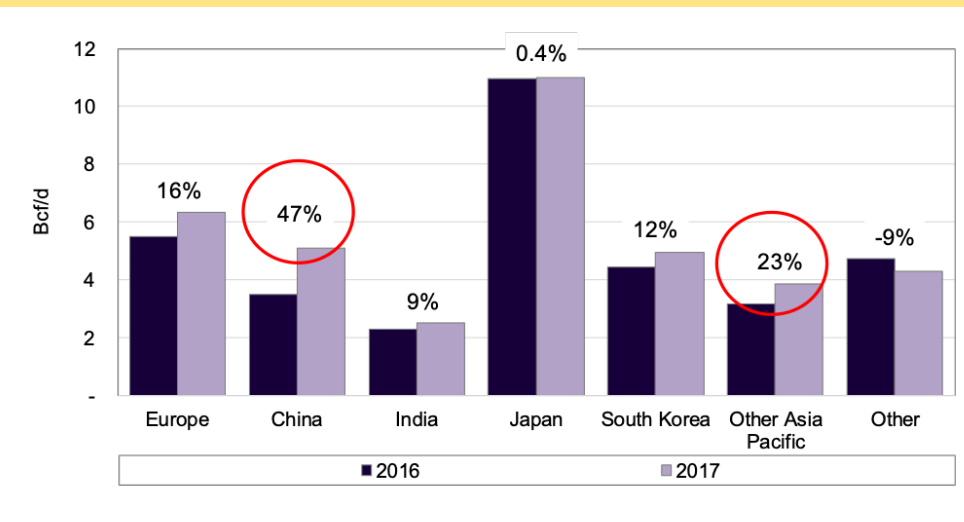


Source: International Gas Union, 2018.

strong LNG import growth at 16 percent in 2016 to 2017; however, much of this growth arose to displace Russian sources of natural gas with those from other places around the world, including the U.S.

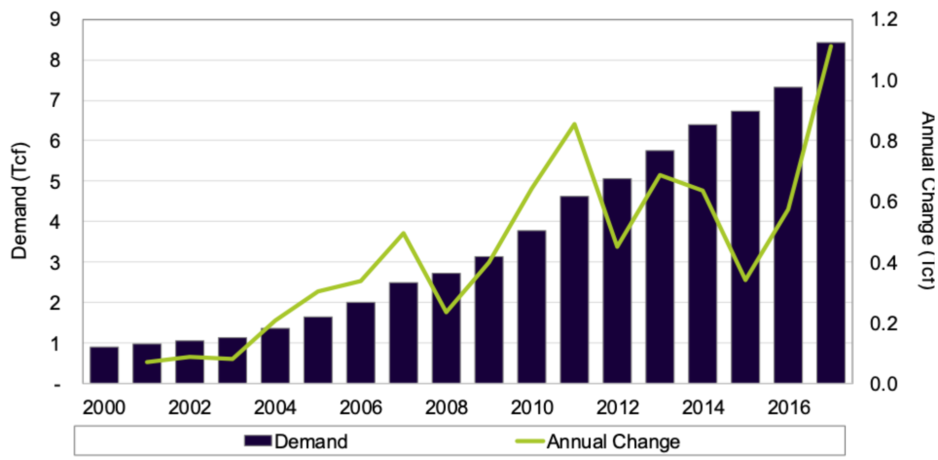
The primary growth market for most LNG developers, particularly those along the GOM, has been and will continue to be in China. Figure 38 shows the exceptional annual natural gas demand growth in China over the past decade. Chinese natural gas demand has grown by as much as 66 percent over the past five years alone, and between 2016 and 2017, Chinese natural gas demand was up by almost a full Tcf.

Figure 37: LNG imports, 2016 vs. 2017



Source: BP, 2018.

Figure 38: China's natural gas demand

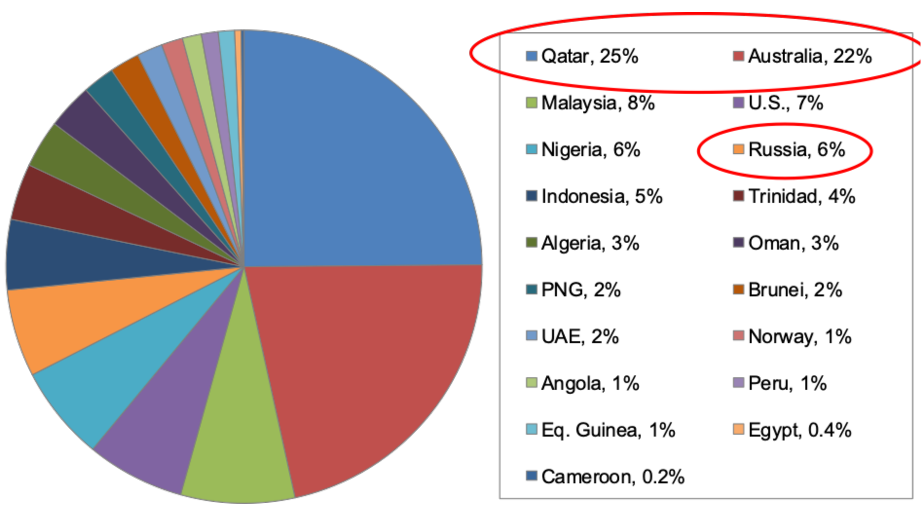


Source: U.S. Energy Information Administration.

Figure 39 highlights the nations that compete with the U.S. for global LNG export market share. The market is expansive, with numerous participants. The largest two, however, are Qatar and Australia, which collectively account for close to half the LNG export market. The other market participants are more evenly distributed in terms of market share. For instance, Malaysia and the U.S. rank third and fourth, respectively, in market share but are followed by other countries that deviate from one another by a full percentage only.

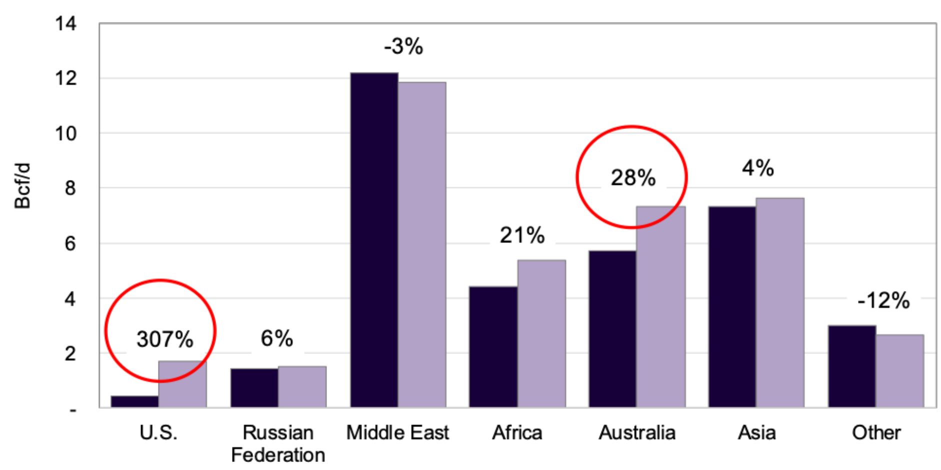
While the absolute level of LNG exports is concentrated in two countries (Australia, Qatar), the recent growth in the LNG export market has come from many other places of the world (Figure 40). For instance, the highest percentage growth in LNG exports has actually arisen

Figure 39: LNG exports and market share by country, 2018



Source: International Gas Union, 2018.

Figure 40: LNG exports, 2016 vs. 2017



Source: BP, 2018.

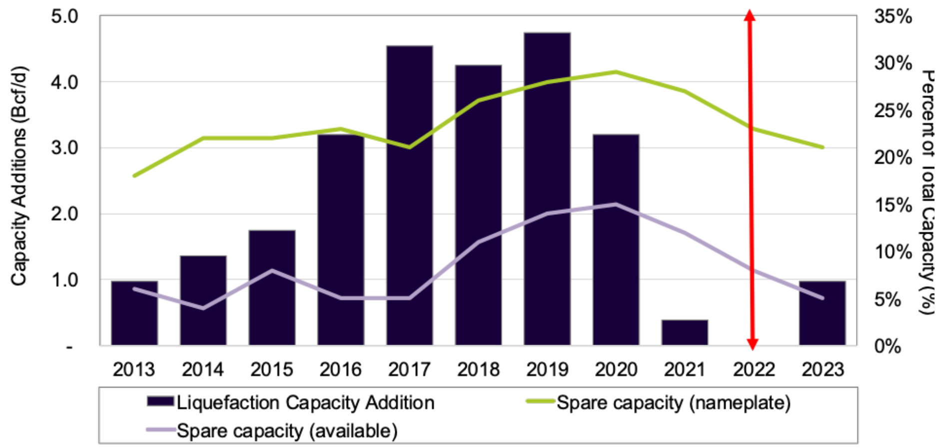
in the U.S. at over 300 percent, followed by Australia and Africa. Russian exports have been moderate (at six percent) and Middle Eastern LNG exports, driven almost exclusively by Qatar, are down by three percent during the 2016-2017 time period.

The last several years have seen rapid global LNG liquefaction (export) capacity development. Figure 41 shows that this development was particularly extensive between 2016 and 2020. Currently, there is over 50 Bcf/d of total active liquefaction capacity around the globe (IGU, 2018; IEA, 2018). This capacity is expected to grow by 22 percent by 2020 (IEA, 2018). The IEA anticipates that new capacity will account for 30 percent of existing capacity in the market, well in excess of what is needed to meet global natural gas demand. This excess capacity, however, is anticipated to dampen in the 2021-2023 time period based on current expectations.

Excess liquefaction capacity has resulted in a buyers' market for LNG exports. This is particularly evident in looking at annual LNG contract durations. Long term contracting is important for a large, expensive liquefaction facility. These longer-term contracts serve as the financial underpinning or support for an asset that has a tax life of around 30 to 40 years, the same time period in which the project's economics and estimated financial returns are based. The longer the contract duration, the more certain an LNG liquefaction facility will be that it will earn a return on investment. The shorter the contract duration, the more risk an LNG developer will bear, since additional contracts will need to be signed in the future, at the termination date of the original contracts, in order to continue the financial support for the export facilities.

Figure 42 shows that long term contract durations have been falling rapidly over the last several years as the LNG export market grew into a surplus situation. In 2008, for instance,

Figure 41: LNG liquefaction capacity additions

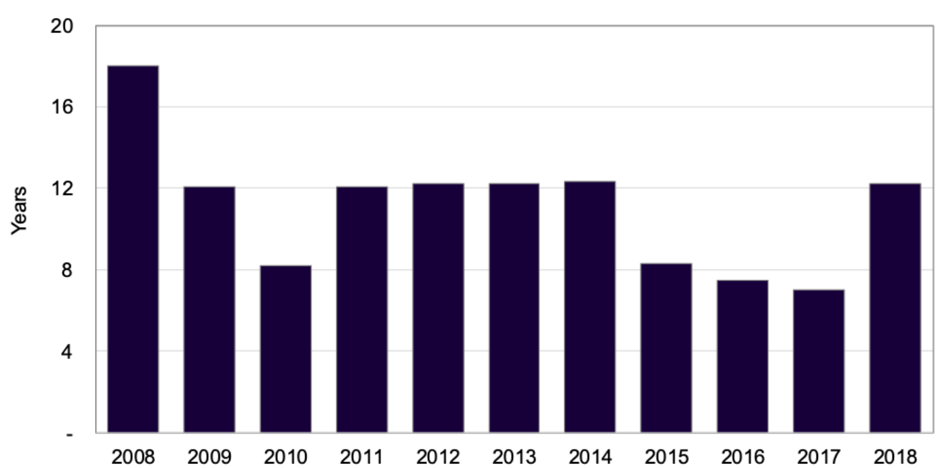


Source: International Energy Agency, 2018.

LNG export contracts signed in that year averaged around 17 years in duration. These contract durations fell to 12 years throughout the 2011-2014 time period and fell to as low as seven years by 2017. Durations have recently rebounded to 12 years but are still short of duration that helps to financially secure a typical $9 billion to $12 billion liquefaction investment.

Volumes moving under longer-term LNG export contracts have also been falling over the past several years in tandem with the shorter-term contract durations discussed above. Fewer volumes under long-term contract, like shortened contract durations, can also lead

Figure 42: Average LNG contract durations



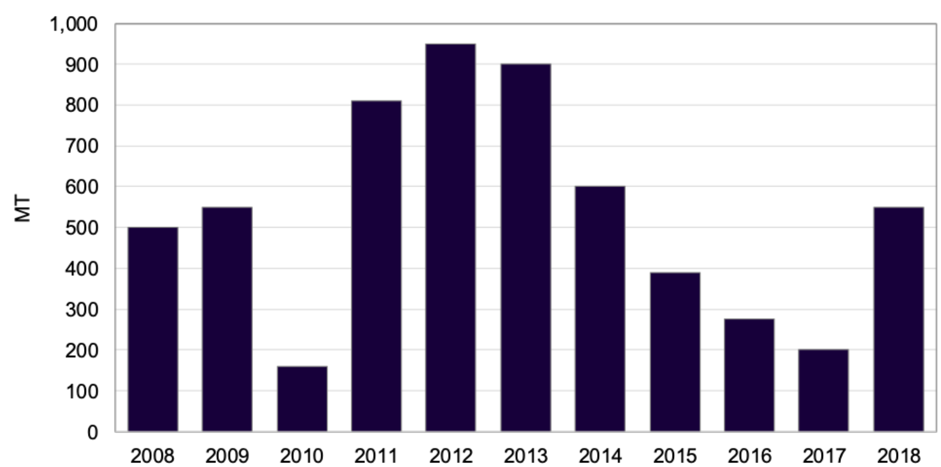
Note: Author's estimate from source.

Source: Shell, 2019.

to financial risks for LNG exporters. Figure 43 shows that LNG contract volumes peaked in the 2011-2013 time period despite that, as seen earlier, contract durations had fallen, on average, to 12 years. Contract volumes have continued to fall since 2013 to a low of 200 million tons (mt) in 2017. Contract volumes are up in 2018 to 500 mt but are still below the 800 mt to 900 mt seen in the 2011-2013 time period.

One of the larger concerns about U.S. involvement in international LNG markets was the impact that this would have on domestic natural gas prices for U.S. consumers. Concerns during the early part of this decade, as several projects were seeking their FERC certifications and approvals, were that the "law of one price" would govern in competitive commodity markets: Already low U.S. prices (as reported at the Henry Hub) would rise to high global prices benefiting U.S. producers and energy marketers, but harm American consumers, particularly the "renaissance" of industrial development that was arising during the same time period. Figure 11 shows that, at least to date, those fears have been misplaced.

Figure 43: Total contract volumes



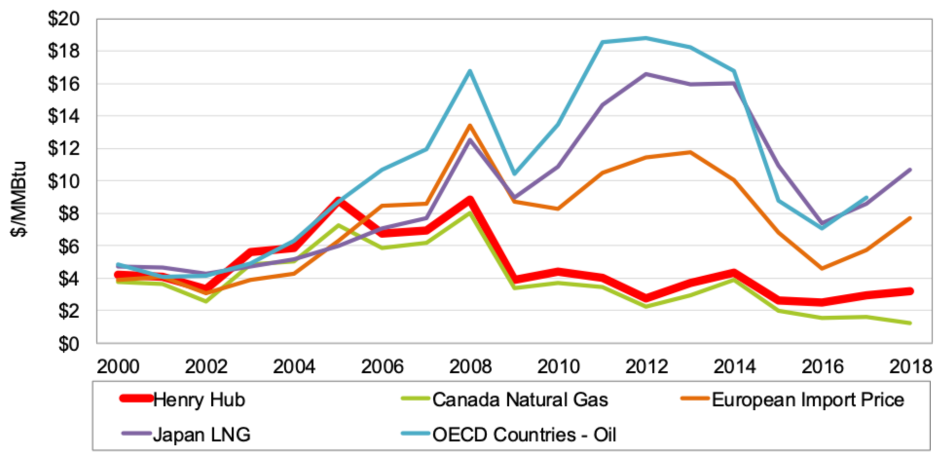
Note: Author's estimate from source.

Source: Shell, 2019.

Figure 44 provides another illustration of how increased U.S. natural gas trade in LNG has followed trends that were not entirely consistent with fears of some during the early part of this decade. If anything, world natural gas (LNG hub) prices have fallen to meet U.S. domestic natural gas prices, not vice versa. While global LNG prices were high during the 2010-2014 time period, these spikes were likely a function of high crude oil prices and the fact that during this time, world LNG prices were tied very closely, if not contractually indexed, to crude oil prices (like those on the Brent index). Since the recalibration of world crude oil prices, brought about in large part due to U.S. shale oil production, overall global

LNG hub prices have fallen. Regardless of the ups and downs of global prices, one thing is certain from these trends: U.S., and even Canadian, natural gas prices never rose to follow these global trends. They have been low, and have remained low since the advent of the shale revolution.

Figure 44: World energy prices



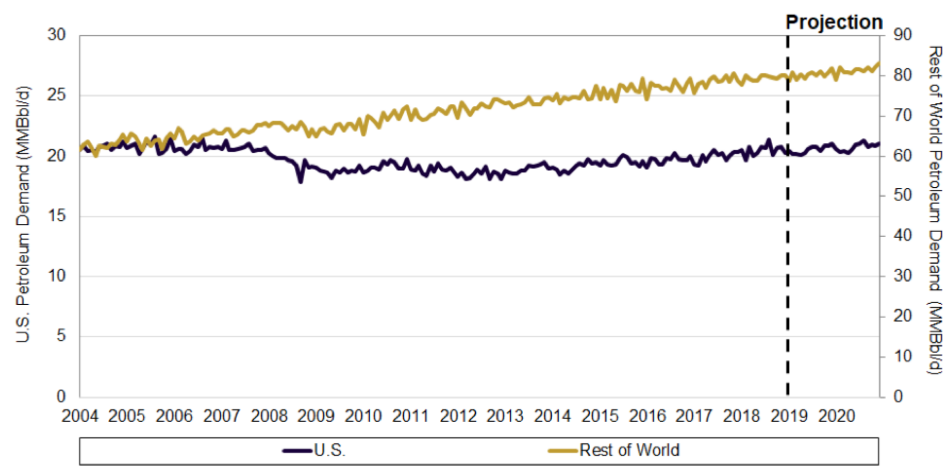
Source: World Bank, 2018.

5.4 Outlook: Refined Product Exports

The outlook for Gulf Coast refined products will largely be driven by what is going on around the world, not the U.S. Figure 45, for instance, examines U.S. versus world petroleum demand. U.S. petroleum demand is flat: As a mature economy, the U.S. continues to adopt transportation fuel efficiency standards and continues to promote fuel switching (primarily electricity use in transportation) which dampens near term and longer run refined product demand. Growth in the rest of the world, primarily the developing world, continues to move at a rapid pace. Growth in refined product output will likely be driven by refined product export opportunities. This has been true for the last several years and will continue to be true in the future.

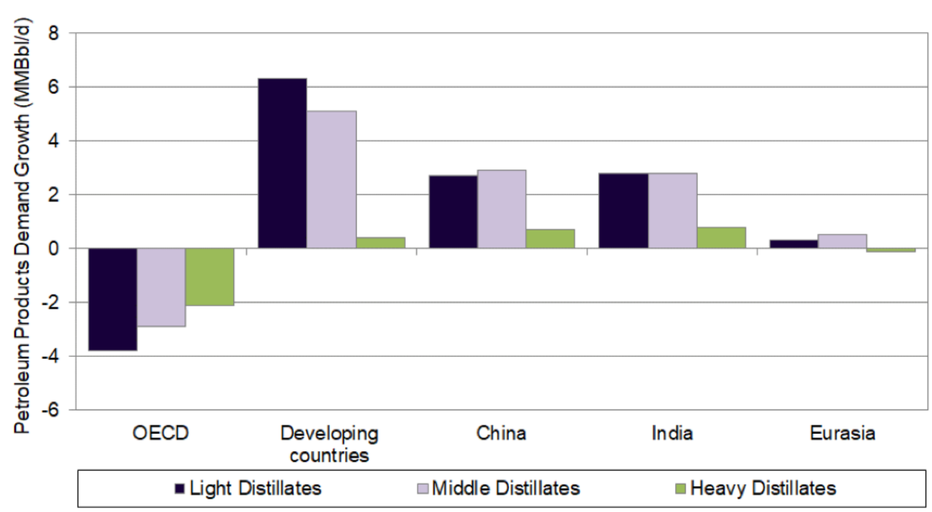
Figure 46 highlights composition of refined product demand through 2040 by major refined product type. The chart confirms that the trends already becoming apparent in the existing refined product export and demand numbers will continue, if not grow, into the future. The first trend is that the growth in refined product demand will not be in the developing world. OECD refined product growth for all major product types is expected to decrease over the next several decades. The second trend is that the developing world, including China and India (presented in this chart separately) will continue to consume most of the refined product produced along the Gulf Coast and throughout the world. Lastly, light distillates will be heavily used, primarily for transportation purposes. In these growth economies, so much of the increased distillation capacity arising along the GOM will likely be oriented in a fashion to serve those specific product needs.

Figure 45: U.S. and world petroleum demand



Source: U.S. Energy Information Administration.

Figure 46: Petroleum product demand growth by destination and product type

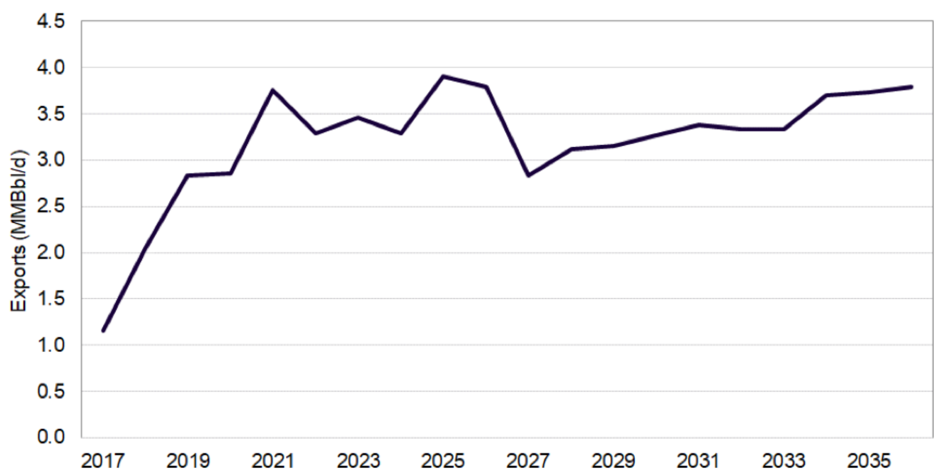


Source: OPEC World Oil Outlook.

5.5 Outlook: Crude Oil Exports

Figure 47 highlights the most recent EIA AEO that projects U.S. crude oil exports for the next several decades. The 2020 GCEO does not dispute this outlook and believes it represents a good consensus outlook for U.S. crude oil exports, which are anticipated to grow to 2.8 MMBbl/d by the end of 2019 and over 3 MMBbl/d by 2021. The important aspect of these exports for the Gulf Coast region is that the overwhelming majority will originate and leave the Gulf Coast ports of either Corpus Christi or LOOP.

Figure 47: U.S. crude oil exports



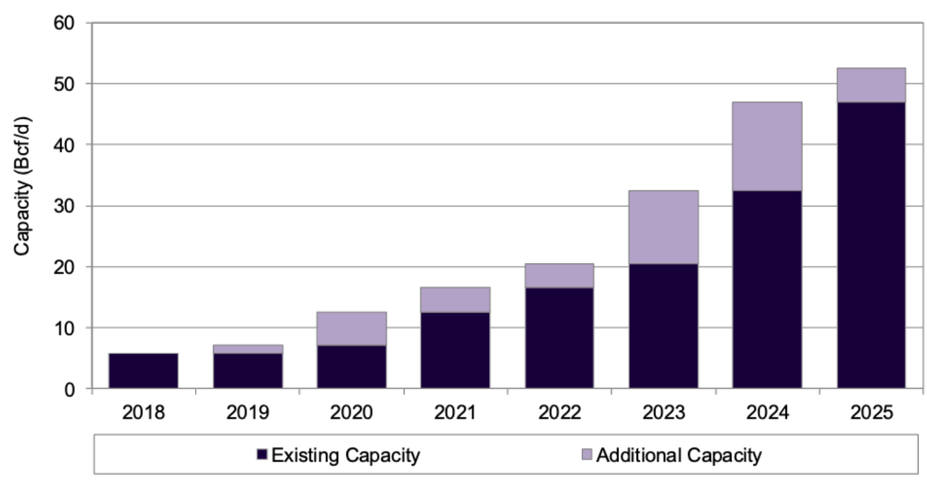
Source: U.S. Energy Information Administration.

5.6 Outlook: LNG Exports

Figure 48 charts the potential build-out on U.S. LNG liquefaction capacity if all announced U.S. projects are developed. Currently, the U.S. has 5.7 Bcf/d of active LNG export capacity. There is a possibility of as much as 52.5 Bcf/d of total U.S. liquefaction capacity development by 2025 based on current project announcements. The likelihood of all this capacity being developed is very low, since all require longer-term contracts that secure as much as two-thirds of the total project capacity in order to get to a final investment decision.

The current slow-down in global economic conditions makes the near-term realization of this capacity development low. However, it is important to understand that (a) there is a healthy degree of interest in developing this capacity should the underlying market conditions justify the development and (b) a large share of this capacity, if not almost all of this LNG export capacity development (47.5 Bcf/d out of 52.5 Bcf/d) will be located along the GOM. Thus, future U.S. LNG capacity development and GOM capacity development trends and outlooks are almost synonymous.

Figure 48: Existing and proposed U.S. LNG export capacity development



Source: FERC, 2019.

As noted earlier, the LNG export capacity outlook provided in Figure 29 above represents all announced capacity with development timelines consistent with its announcement. This will likely not be the case as discussed earlier in the energy manufacturing/industrial section of the 2020 GCEO. The baseline GCEO, as noted earlier, anticipates that a large share of LNG export capacity will be pushed well out into the 2025-2026 time period and will not be developed in the near term consistent with original announcements. The rationale for this position is that: (a) trade conflicts with the U.S. and China will likely continue in the near future, although there is an opportunity for a slight abatement of these tensions (yet they will still exist); (b) the damage from these uncertainties, coupled with other international economic conditions, has resulted in a significant slowing in economic output that will reduce energy demand and the need for LNG in the near term; and (c) current dollar valuations simply compound the primary problems created by both (a) and (b).

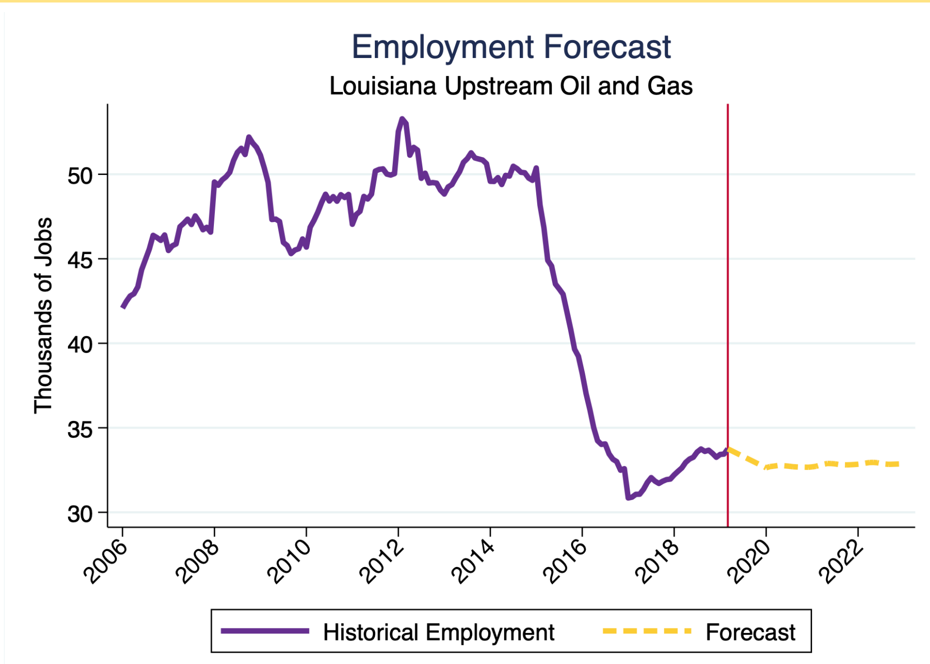
6 | Employment Outlook

Upstream oil and gas employment for both Louisiana and Texas exhibit two key patterns in historical data in Figures 49 and 50. The first is growth prior to 2015, modest in Louisiana and very rapid in Texas. This is followed by a collapse in upstream employment in both states in 2015. The explanation is simple and abundantly clear from our earlier discussion. The collapse in oil prices led to a dramatic reduction in rigs counts. With fewer rigs, there is less demand for workers. Texas lost more than 100,000 up-stream jobs from peak to trough. Louisiana lost about 18,000.

Upstream employment forecasts for Louisiana and Texas are also present in Figures 49 and 50, respectively. The Louisiana upstream outlook is flat for two reasons. First, with anticipated flat oil prices it will be difficult for Louisiana's employment to come back in a meaningful way. But second, after discussions with upstream producers, particularly focused on offshore production, we are consistently told that while employment in shale formations nationwide is expected to decline over the next year, deep offshore production is expected to remain resilient. If anything, the rig count in the Gulf might even pick up in the coming year. Thus, the flat forecast is a balance of difficult times for onshore producers and continued investment in offshore production.

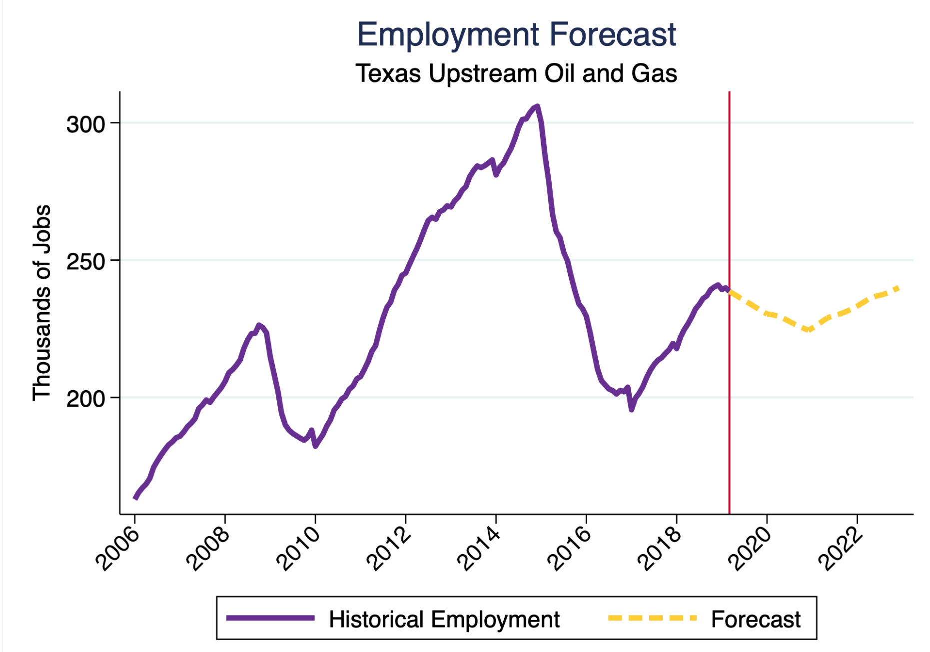
The Texas upstream outlook looks very different over the next year. The forecasting model estimates that Texas will shed about 16,000 upstream jobs by the end of 2020. This forecast is a result of (1) discussions with companies that are already announcing layoffs, (2) preliminary

Figure 49: Louisiana Upstream Oil and Gas Employment Forecast



Source: U.S. Bureau of Labor Statistics – Quarterly Census of Employment and Wages and authors' computations.

Figure 50: Texas Upstream Oil and Gas Employment Forecast



Source: U.S. Bureau of Labor Statistics - Quarterly Census of Employment and Wages and authors' computations.

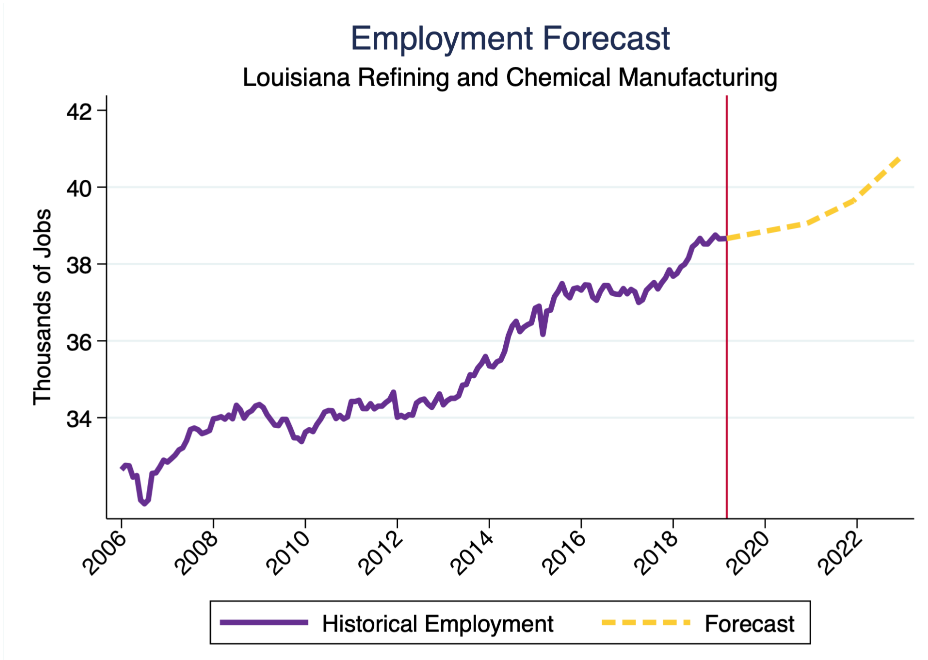
government data already showing employment declines, and (3) the rig count reductions observed over the past year. This anticipated employment decline is also corroborated by the Dallas Fed Energy Survey that shows Texas firms with a negative outlook for employment. The good news is that GCEO takes the position that this employment drop will be somewhat short lived. As the less efficient producers and areas are dropped over the next year, supply and demand will balance to support stable employment over the medium-term horizon.

For both Texas and Louisiana, we do not see upstream employment returning to pre-2014 price drop levels any time in the foreseeable future. Instead, GCEO takes the position that both states have entered into a new equilibrium at permanently lower levels of employment compared to the 2014 peak.

The forecasts of refining and chemical manufacturing employment are shown in Figures 51 and 52. For both Louisiana and Texas, the GCEO forecast is based on lagged capital expenditures in refining, chemical manufacturing, and LNG export presented in the industrial outlook.

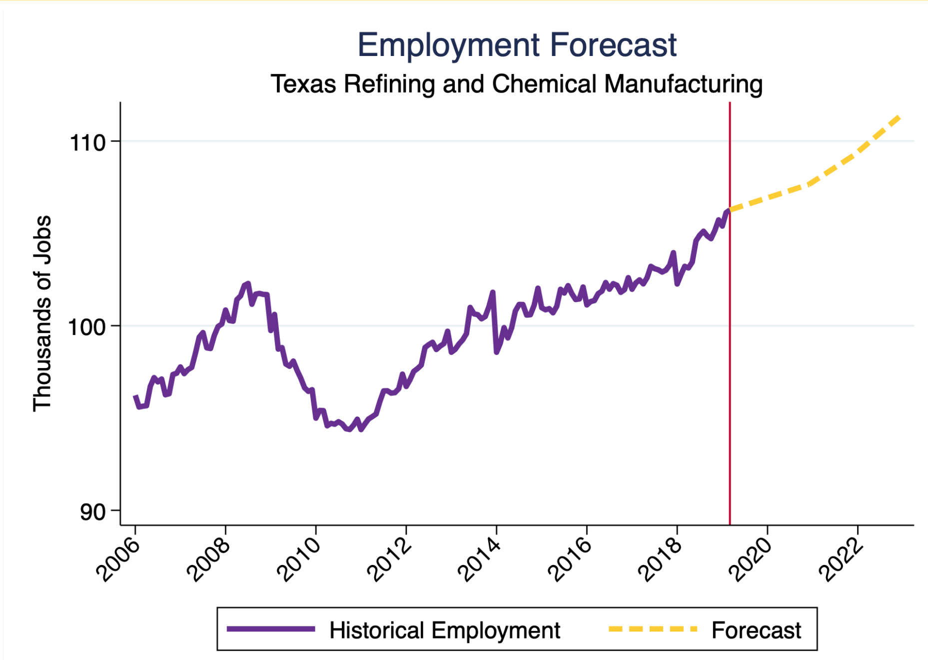
For Louisiana, we anticipate modest employment growth through the end of 2020 given the current lull in construction expenditures. But, over the next year, we anticipate construction to pick up followed by a lagged increase in employment in the sector. In total, we anticipate Louisiana and Texas will gain about 2,500 and 7,000 jobs respectively in refining and chemical manufacturing over the forecast horizon (to the end of 2022). This is approximately a 7 percent increase over the next three years.

Figure 51: Louisiana Refining and Chemical Manufacturing Employment Forecast



Source: U.S. Bureau of Labor Statistics – Quarterly Census of Employment and Wages and authors' computations.

Figure 52: Texas Refining and Chemical Manufacturing Employment Forecast



Source: U.S. Bureau of Labor Statistics – Quarterly Census of Employment and Wages and authors' computations.

7 | Conclusions

Overall, the 2020 GCEO sees a cloudy future for global, national, and regional energy markets. This uncertainty is not good for capital formation and could have longer run implications if the uncertainty continues throughout 2020. The sources of uncertainty are multi-faceted and range from the U.S.-China trade imbroglio, to the recent attacks in Saudi Arabia (and any looming responses to those attacks), to the continued Middle Eastern uncertainties in Syria and along the Turkish border, interest rate changes and dollar valuations, to impeachment proceedings for the U.S. President. Cumulatively, these uncertainties create negative incentives for capital investment and economic activity, which, in turn, reduce energy demand at a time when the industry (in the U.S. and along the Gulf Coast) has been making considerable levels of capital investment to keep up with the changing composition of U.S. energy production and the changing nature of world energy requirements.

Despite these uncertainties, the near-term outlook for U.S. and Gulf Coast energy production continues to be strong given the ongoing strong productivity gains that will continue in the near term, particularly in the Permian Basin and offshore GOM. An extended period of low crude oil prices, however, could wear on these gains, as drilling activity contracts and the rapid production decline of existing wells outpaces the productivity gains of the newer ones. This is primarily true for the Permian: The offshore GOM, which tends to be much more price resilient, should likely continue to maintain its steady and sustained production gains through deepwater and ultra-deepwater developments.

The *Enverus Prodcast* model utilized by GCEO estimates U.S. crude oil production rates of 13.5 MMBBl/d in 2020, 14.3 MMBBl/d in 2021 and 15.0 MMBBl/d in 2022. Closer to home, Gulf Coast crude oil production numbers are forecast at 9.0 MMBBl/d in 2020, 9.6 MMBBl/d in 2021 and 10.2 MMBBl/d in 2022.

This model also anticipates near-term natural gas production to be strong at both the national and regional level, with estimates of U.S. natural gas production rates of 100 Bcf/d in 2020, 102 Bcf/d in 2021, and 105 Bcf/d in 2022. Regionally, Prodcast sees Gulf Coast natural gas production rates at 42.0 Bcf/d in 2020, 42.7 Bcf/d in 2021, and 43.8 Bcf/d in 2022. This indicates the potential for a very well supplied regional market to support existing industrial and power generation requirements, as well as a very healthy level of exports from the region's growing LNG export facilities.

The transportation sector of the industry continues to see growth opportunities linking the region's growing hydrocarbon supplies to both domestic and world demand centers. This past year (2019) saw transportation infrastructure constraints for crude oil rear their head once again, but nowhere near the extent observed from 2009 to 2015. Natural gas transportation infrastructure in the Permian Basin has developed more slowly than production has come online, leading to steep price discounts and flaring. But there are a number of new projects that, like their crude oil counterparts in 2019, will likely hit the market in time to alleviate some of the abnormal prices and basis differentials that have arisen over the past year between Waha and Henry Hub.

The outlook for energy manufacturing (petrochemical and refining), as well as LNG exports, is tied to the global economy and, as discussed earlier, there are considerable headwinds that will push against (a) the capacity investments that have been made in the region over the past several years and (b) any opportunities for new capital investments over the next three years. The 2020 GCEO forecasts that some recently announced industrial projects will not likely make it to development because of these global economic headwinds. Other projects, while likely to be developed at some point, are expected to develop along a slower time horizon, particularly several larger LNG facilities.

As a result, the 2020 GCEO sees near term energy manufacturing and export investment reduced during the 2019-2029 time period from an announced level of $195 billion to $131 billion. Near term capital investment during the 2019-2023 window has been reduced from an announced level of $182 billion to $115 billion. This capital investment forecast, however, is highly dependent upon ongoing trade and geopolitical uncertainties discussed earlier. An exacerbation of these uncertainties could reduce this near-term capital expenditure profile considerably.

Finally, the 2020 GCEO forecasts a decrease in upstream employment by about 16,000 jobs by the end of 2020 in Texas. The forecast is flat for Louisiana. This is due to (1) the slowing drilling activity, especially in the Permian and Eagle Ford basins, and (2) resilient and potentially picking-up offshore activity. These two trends are anticipated to impact Texas and Louisiana differently.

While investments in refining, chemical manufacturing, and energy export have slowed this past year, as projects are completed, the 2020 GCEO anticipates modest increases in employment in both Louisiana and Texas in coming years. In total, the 2020 GCEO forecasts that Louisiana and Texas will gain about 2,500 and 7,000 jobs, respectively, in refining and chemical manufacturing over the forecast horizon (to the end of 2022). This is approximately a seven percent increase over the next three years.

The Center for Energy Studies

The Center for Energy Studies conducts, encourages, and facilitates research and analysis to address energy-related problems or issues affecting Louisiana's economy, environment, and citizenry. The Center's goal is to provide a balanced, objective, and timely treatment of issues with potentially important consequences for Louisiana.

The Center for Energy Studies was created by the Louisiana Legislature in 1982 as the embodiment of recommendations made by an independent group of experts and at the urging of Louisiana business and public interest groups, as well as the University.

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The Energy Program

The Energy Program at the LSU E. J. Ourso College of Business is designed to provide the skills and knowledge needed by the next generation of energy professionals. Not only do students take classes that are specific to the energy sector, but they are also provided a wide range of learning opportunities, including site visits, access to speakers in the industry, case competitions, energy conferences and expos, and industry-related internships.

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