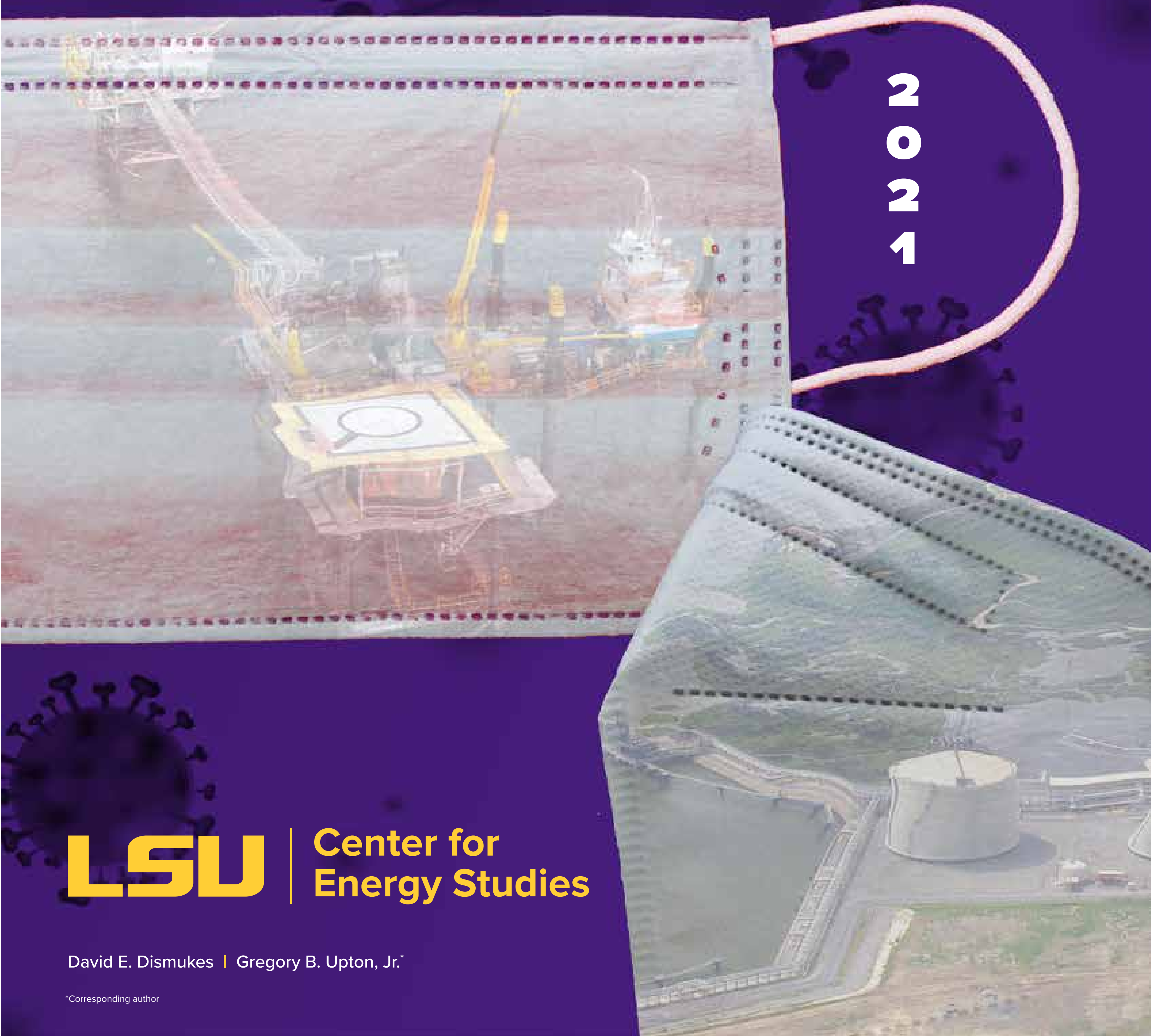
Gulf Coast Energy Outlook

2021



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Release Date: Fall 2020

Acknowledgments

The *Gulf Coast Energy Outlook* (*GCEO*) would not have been possible without the help of many who contributed both time and financial resources. First, the input from dozens of industrial, governmental, civic, and trade organizations that requested having the 2020 *GCEO* presented to their organizations is much appreciated. The feedback that was provided during these conferences and individual meetings was instrumental in preparing the current 2021 *GCEO*. While "crunching the numbers" is an important aspect of any forecasting process, the input provided by stakeholders who have an "on-the-ground" view of what is occurring in real time is equally valuable.

Special thanks are owed to Marybeth Pinsonneault and Ric Pincomb (Center for Energy Studies) and Stephen Radcliffe (E.J. Ourso College of Business), for their media, editorial, and production expertise. Drew Smith (Center for Energy Studies) also contributed to data collection and analysis included in this report.

Last, but certainly not least, a special thanks and appreciation is extended to our sponsors. We know this has been a difficult year across all facets of the energy sector, so this year, in particular, we are extremely grateful for this financial support:

- Gold: **Louisiana Mid-Continent Oil & Gas Association (LMOGA) and Phillips 66**
- Silver: **Entergy, Enverus, and Koch**
- Bronze: **Bristow Group**

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1. Introduction

The annual GCEO 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 work product of Louisiana State University's Center for Energy Studies and has been sponsored by several companies and institutions looking to assist LSU in disseminating timely information and analysis impacting the region's economy and citizenry. The GCEO is also supported by the Center's general state appropriation, which represents a generous commitment by the Louisiana Legislature to support energy-related research. It would be difficult to produce the GCEO without both sources of support.

Unless stated otherwise, the "Gulf Coast" region specifically refers to the states of Texas, Louisiana, Mississippi, and Alabama. In some instances, the U.S. Department of Energy reporting conventions will require references to data collected at the Petroleum Administration Defense District 3 (PADD 3) level, which includes Arkansas and New Mexico, in addition to the Gulf Coast states. Employment forecasts will focus on Louisiana and Texas. Where not specified, the forecast horizon extends to the end of 2024, or approximately three years.

The remainder of this introduction will highlight the big picture considerations and assumptions made in subsequent analysis and forecasting.

1.1 COVID-19

Forecasting is difficult under normal circumstances; this year there is perhaps more uncertainty than ever. In January of 2020, the U.S. economy was in its 126th month of economic growth, the longest in modern history. Demand growth in Asia, the source of demand for energy products produced in the Gulf Coast, was strong and, while slowing was expected to continue, was well above growth rates in the developed world. President Trump and Chinese President Xi Jingping had just signed Phase I of a trade deal, at least temporarily alleviating some of the source of risk highlighted in last year's GCEO. Oil prices were about $60 per barrel, a level that is a good balance and high enough to support continued exploration and production and sustain a profitable refining sector. According to last year's GCEO, there were more than $190 billion of investment announcements in the energy sector, and a number of important pipeline investments were underway to deliver the hydrocarbons to the Gulf Coast for processing and delivery all over the world. The 2020 GCEO was forecasting that, barring an unforeseen external shock, oil and natural gas production was projected to continue to set records in coming years, and employment in the refining and chemical manufacturing sector would experience growth.

In March of 2020, everything changed rapidly when the COVID-19 pandemic essentially shut down the global economy. Oil markets were rocked by (1) a historic decline in demand due to COVID-19 and (2) a failed OPEC+ deal to curtail output and sustain prices. These combined factors created the perfect storm for a complete collapse in energy prices to a low that at one point touched on an unheard-of negative daily price for West Texas Intermediate (WTI) oil. U.S. production immediately fell in response to these price signals from a record high of 12.86 million barrels per day in November of 2019 to 10.0 million barrels per day by May 2020. This is an over 20 percent drop in U.S. oil production in just seven months—the largest percent change in any seven-month period in modern history.

The question GCEO will be addressing this year is, where does the energy industry go from here? How have companies responded operationally to a global pandemic? How quickly will the global, national and regional economies recover? The speed of recovery will play a major role in how quickly demand for transportation—and therefore energy products—will rebound. But to further complicate matters, has the COVID-19 pandemic also changed *long-term* behavior? Therefore, while specific long-term forecasts are not presented, the GCEO will also be tasked with considering whether the fundamental relationships between energy consumption and economic activity has changed more broadly.

> **For purposes of economic modeling, COVID-19 is assumed to attenuate globally and the world is slowly able to return to some level of normalcy over the next two years. Another wave of COVID-19 leading to cascading shutdowns would certainly make our forecasts less optimistic. In the long run, transportation demand will rebound, but not to its pre-COVID-19 trajectory, especially in the developed world.**

1.2 Phase One of China Trade Deal Reached

Perhaps the largest risk to the Gulf Coast energy industry, and in particular to the continued industrial construction, highlighted in last year's GCEO, was the trade negotiations with China. For the past two years, the GCEO has articulated the significant economic and energy market changes occurring along the Gulf Coast. Increasingly, the region is transforming itself into an exporter of energy and chemical products (that are derived from hydrocarbons), as well as one that will likely serve as a transfer point or hub for global energy transactions. The U.S. for instance, was exporting about five million barrels per day pre-COVID-19 of petroleum products, most of which were leaving a Gulf Coast port. Last year, the 2020 GCEO highlighted how the escalating trade disputes with China, the world's most populous country and second largest economy, had resulted in increased tariffs on natural gas and petroleum products.

Specifically, in response to U.S. tariffs meant to bring China to the negotiating table, on June 1, 2019, China increased its tariff on natural gas coming from the U.S. in the form of liquefied natural gas (LNG) from 10 percent to 25 percent. The 2020 GCEO reported that at least one announced LNG project had been postponed, with others seriously considering their development potential if these tariffs continued. Estimates suggest that in total, the U.S. applied $550 billion in tariffs exclusively to China, with China responding in applying $185 billion in tariffs exclusively to U.S. goods.[1]

After months of negotiations, in January of 2020, the U.S. and China signed Phase 1 of a trade deal that went into effect on February 14.[2] The 91-page agreement includes six chapters covering topics such as intellectual property, technology transfer, trade in food and agricultural, financial services, and macroeconomic policies.

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[1] Dean Shira & Associates. China Briefing. The US-China Trade War: A Timeline. < https://www.china-briefing.com/news/the-us-china-trade-war-a-timeline/> Accessed September 2020.

[2] Economic and trade agreement between the government of the United States of America and the government of the People's Republic of China.

Table 1: China import commitments in perspective. Phase I China Trade Deal

	Manufacturing	Agriculture	Energy	Other	Total
Panel A: U.S. Exports (Billions USD)*					
	(1)	(2)	(3)	(4)	(5)
China					
2017	$50.4	$20.9	$7.6	$51.0	$130.0
2018	$49.0	$10.4	$8.0	$52.8	$120.3
2019	$49.3	$14.8	$3.6	$38.8	$106.4
World					
2017	$627.8	$153.5	$59.2	$706.7	$1,547.2
2018	$648.3	$155.5	$95.6	$766.3	$1,665.7
2019	$646.5	$151.3	$108.4	$736.9	$1,643.2
Panel B: Phase I China Import Increase Committment (Billions USD)**					
2020	$32.9	$12.5	$18.5	$12.8	$76.7
2021	$44.8	$19.5	$33.9	$25.1	$123.3
Panel C: China Import Commitment Percent 2017-2019 Exports***					
China					
2020	66.3%	81.2%	288.8%	26.9%	64.5%
2021	90.3%	126.7%	529.1%	52.8%	103.7%
World					
2020	5.1%	8.1%	21.1%	1.7%	4.7%
2021	7.0%	12.7%	38.6%	3.4%	7.6%

Sources: * U.S. Census Bureau: Economic Indicators Division USA Trade Online. ** China Phase I Trade Deal. Chapter 6. ***Authors' calculatons

As summarized in Table 1, Chapter 6 of the Phase I trade deal focused on expanding trade and perhaps has received the most attention. It requires that in 2020 and 2021, China will increase purchases and imports, into China from the United States, of manufactured goods, agricultural products, energy products and services, exceeding the 2017 baseline amount by no less than $200 billion. A specific carve-out of $52.4 billion for energy products is included.[3]

To put the energy carve-out into perspective, this is equivalent to 21 percent of the U.S.'s historical (as measured by the average of 2017-19) total energy exports in 2020, and 38 percent in 2021. These are large numbers, and China is currently not on track to meet these commitments.[4] There is significant uncertainty as to what might happen in these trade talks if China does indeed not meet these commitments. At the time that this document is being finalized, the U.S. is still waiting for the result of

[3] Specifically, $18.5 billion in 2020 and $33.9 billion in 2021.

[4] The Peterson Institute for International Economics (PIIE) is actively tracking China's purchases of U.S. goods. At the time of this writing, China is significantly below its agreed targets in all areas, including agriculture, manufactured goods, and energy. < https://www.piie.com/research/piie-charts/us-china-phase-one-tracker-chinas-purchases-us-goods>

the recent presidential election. The outcome could have significant implications for how and if these negotiations continue. Would a Biden presidency revert to a pre-Trump trade policy with China? Would an emboldened Trump, with an election behind him, increase pressure on China? Is another round of tariffs to come? Or perhaps negotiations could be successful in reducing trade barriers without imposing addition tariffs?

> **For purposes of economic modeling, the GCEO will work under the assumption that trade talks with China do not deteriorate, that new tariffs will not be implemented, and that these export commitments on net do not impact demand for Gulf Coast energy products.**

1.3 2020 Hurricane Season

As if a global pandemic were not enough, 12 major hurricanes were recorded, with five reaching Category 3 status or higher. For the first time in recorded history, five named storms made landfall in Louisiana. Most notably, on August 15, Hurricane Laura, the strongest hurricane on record in the state's history, made landfall in Cameron Parish, Louisiana. Hurricane Laura made landfall as a Category 4 and caused billions of dollars of damage across many sectors of the economy, including damage to electricity infrastructure, agricultural products such as forestry[5], and of course damage to residential homes and local businesses. Fewer than three weeks later, Hurricane Sally made landfall as a Category 2 hurricane near Gulf Shores, Alabama. Hurricane Delta made landfall on October 9 as a Category 2 also near Lake Charles. Finally, on October 28, Hurricane Zeta made landfall in southeast Louisiana.

Perhaps most notably for our purposes, the Lake Charles area in southwest Louisiana has been ground zero for billions in infrastructural investments in the refining, chemical manufacturing, and export of natural gas in the form of liquefied natural gas. In fact, over 40 percent of the energy infrastructure investment made in Louisiana over the past decade has been in the Lake Charles area.

Workers in the energy processing and export industry in the region have confirmed that the industry was incredibly resilient through these hurricanes. Perhaps most notably, news reports have confirmed that neither Cheniere's Sabine Pass nor the Cameron LNG facility experienced major damage during Hurricane Laura and are now back up and running.[6] Industry insiders reported that this was an important litmus test for other LNG export facilities that are weighing the risk of hurricane damage. The most notable damage to an individual plant was a fire at BioLab in Westlake Chemical's Lake Charles Complex.

In terms of electricity infrastructure, while final numbers are not yet released, Entergy alone has reported $1.4 billion in damage associated with Laura, with the plurality of this damage on transmission infrastructure. Entergy reported 1,285 transmission structures destroyed, with another 492 damaged, and 297 substations out.[7] Both SWEPCO and Cleco have also reported significant damage, but at the time of this writing specific public damage estimates have not yet been released. At the peak over 600,000 customers had power outages.[8]

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[5]According to the LSU Ag Center, approximately $1.1 billion dollars of timber was lost due to Hurricane Laura.

[6]Sabine pass was up and running more quickly than Cameron LNG due to quicker access to both electricity and natural gas supply. Nonetheless, Cameron LNG is now up and running with no permanent damage of which we are aware. Source: LNG exports resume for Sabine Pass and Cameron terminals as another hurricane approaches. U.S. Energy Information Administration. Today in Energy. October 8, 2020.

[7]Hurricane Laura Restoration Update – 9/9/20 @9:30 AM. Entergy Newsroom.

[8]Source: U.S. Department of Energy. Office of Cybersecurity, Energy Security, and Energy Response. Hurricane Sally & Laura Situation Reports.

For purposes of economic modeling, effects of the 2020 hurricanes are short lived and have not materially affected companies' decisions to make infrastructural investments in the Gulf Coast region. Electricity infrastructure has largely been restored.

1.4 What a Biden Presidency Could Mean for the Energy Industry

At the time of this writing, the U.S. has undergone a presidential election, but the final outcome is not yet known. This election was particularly unique in that presidential candidate Biden made history as the first nominee for president from a major party in modern U.S. history to propose the ban of new oil and gas permitting on public lands and waters.[9] Further, he proposed modifying royalties to account for climate costs. The Gulf Coast region will perhaps be the most impacted if these policies are enacted.

What could this mean for the industry? Consider the two regulatory steps taken to drill for oil and gas in federal waters in the Gulf of Mexico.

Leasing: When a company wants to drill for oil or natural gas in the federal waters of the Gulf of Mexico, it must first obtain a lease. Federal waters are beyond three miles from the Louisiana, Mississippi, and Alabama shorelines and nine miles from the Texas shoreline. The Bureau of Ocean Energy Management (BOEM), part of the U.S. Department of the Interior, conducts lease sales. Companies bid on lease tracts and the winner of those bids is awarded the lease in exchange for a payment that is determined by the result of the auction. This payment is called a "bonus" payment.

Permitting: Once a lease is obtained, the private company will next have to obtain a permit to drill a well from the Bureau of Safety and Environmental Enforcement (BSEE). The permit to drill gives the operator approval to begin the process of drilling the well and requires the operator to show that they will meet environmental and safety regulations. Once the well is drilled and oil and natural gas is sold to the market, the operator will then pay the federal government royalties.

According to Joe Biden's plan for climate change, there are two changes to this process. First, his plan calls to ban new oil and gas permitting on public lands and waters, which would include the Gulf of Mexico. Second, the plan calls for the modification of royalties to account for climate costs. For perspective, royalties currently range from about 12 to 20 percent, depending on a number of factors.

While modification of royalties could impact the economics of offshore drilling, because companies bid based on the expected economics, this would likely cost the federal government money in up-front bonus payments. The net effect of this is an empirical question that the GCEO will not address directly.

But, the effect of an outright ban on new permitting would have a clear negative effect on the offshore industry. A few things would likely occur if this policy were enacted as stated. First, there would likely be some drilling over the next several years, as companies that have already received permits would presumably be able to drill these wells. But nonetheless, this would slow drilling. A recent Wood Mackenzie report considers four scenarios of what the Biden policy could entail. It is simply not possible to know which, if any, of these scenarios will actually be enacted.[10]

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[9] The Biden Plan for a Clean Energy Revolution and Environmental Justice. <https://joebiden.com/climate-plan/>

[10] What could a Biden administration mean for the U.S. GoM and Alaska? July 2020. Wood Mackenzie.

Therefore, for modeling purposes, GCEO will assume that a Biden policy of banning permits offshore will not go into effect, at least over the forecast horizon.

Incorporating such information into the forecast modeling would require specifics of the policy change and timing of these changes. Consistent with forecasting methodology in prior year GCEOs, proposed policy changes will not be incorporated into forecasts until the policy change is actually enacted. In other words, a business-as-usual assumption with regard to offshore leasing will be considered. In the event that a ban is swiftly implemented, forecasts are likely to be too optimistic.

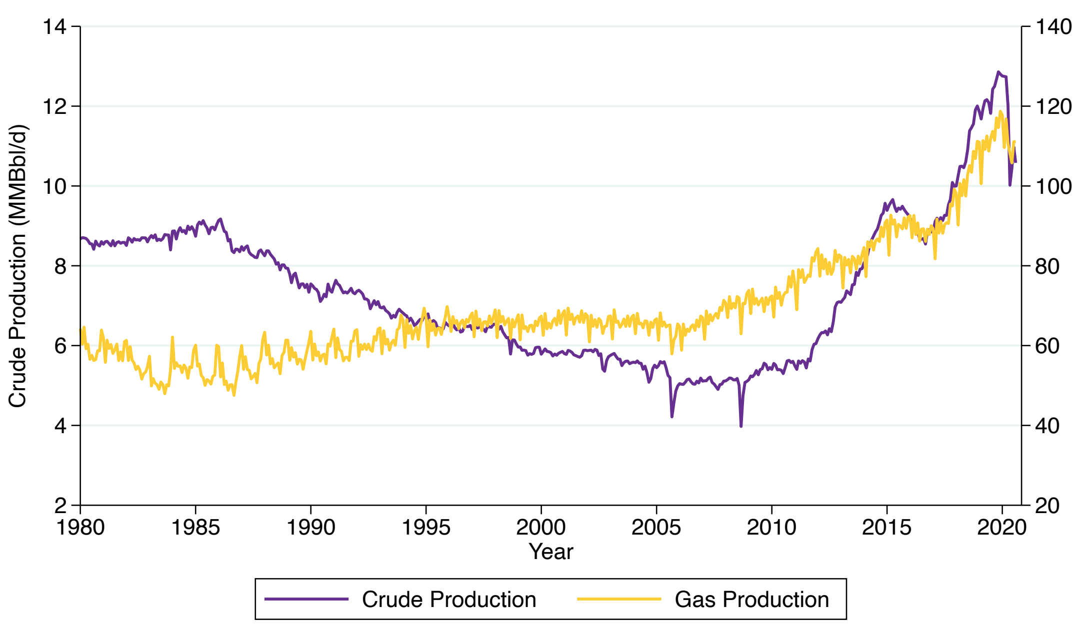
2. Crude Oil and Natural Gas Production and Prices

2.1 Recent Market Trends: Production

The Shale revolution started to manifest itself in U.S. natural gas supplies in 2005 and has dramatically changed the fortunes of U.S. energy companies across almost every sector. That revolution continues in both crude oil and natural gas supplies, both of which continued to march upwards, breaking production records from decades long since passed, until growth was abruptly interrupted with the outbreak of COVID-19 globally.

Figure 1 shows that 2019 marked the highest level of U.S. crude oil and natural gas production on record, averaging 12.3 million barrels per day (MMBbl/d) of oil and 112 billion cubic feet per day (Bcf/d) of natural gas. As we will show later, a large share of this U.S. crude oil and natural gas production increase comes from the Gulf Coast region. But, also highlighted in Figure 1, both oil and natural gas production declined precipitously in response to COVID-19.

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



Source: U.S. Energy Information Administration. Petroleum & Other Liquids. Crude Oil Production. Natural Gas Gross Withdrawals.

For perspective, Table 2 shows U.S. crude oil and natural gas production alongside the percent change from the same month in the prior year for each month post the COVID-19-induced slowdown. In March, U.S. oil production was at 12.7 MMBbl/d, or 6.7 percent above the level of production in March of 2019. By May of 2020, production fell to 10.0 MMBbl/d, a drop of 17.6 percent relative to the May of 2019.[11] U.S. oil production reached its bottom in May, and as of July has rebounded to 11 MMBbl/d, but still 7.1 percent below production in the same month the prior year. Recently released August data shows that production once again fell in August to 10.6 MMBbl/d, almost 15 percent below the prior year's August. On an annualized basis, U.S. oil production is currently down 4 percent from 2019.

Natural gas production, also shown in Table 2, experienced a similar pattern. In March of 2020, U.S. natural gas production was at 116.9 Bcf/d, or 5 percent above its March 2019 level. Natural gas production bottomed out in June at 106.0 Bcf/d, or 2.5 percent below the same month in the prior year. In the most recent month, August, production is 2.2 percent below its August 2019 level. On an annualized basis, natural gas production is still up 1.5 percent relative to 2019. Thus, while both oil and natural gas production have been impacted, COVID-19's impact on oil has been larger on a percentage basis.

In preparation for the GCEO, one of the questions asked to many across the upstream industry was the extent to which these production reductions were due to (1) operational issues directly related to safely operating with COVID-19 and/or (2) market price and demand reductions.

In terms of operational response, industry representatives have told us that rapid testing has been key, especially for offshore oil operations, where workers are confined to relatively close quarters while offshore. Companies servicing offshore operations revealed they would test workers for COVID-19 before going offshore, temporarily quarantine while waiting for test results, and then keep workers offshore for 28 days, in lieu of the standard 14 days.[12] With proper planning, test results could be received within approximately three to four hours. With these precautions in place, we are aware of no offshore platforms that were shut down due to COVID-19.

As compared to offshore operations, onshore oil and gas operations by their very nature have been able to implement social distancing more easily. Thus, GCEO will take the broad view that reductions in oil and natural gas production have been, in essence entirely, due to a demand shock and the resulting price reduction. Any effects of COVID-19 on the operations themselves, while costly for companies financially, have been manageable logistically.

[11] Production numbers monthly averages. Where not specified, all references to production will be monthly averages.

[12] Instead of working 14 days on with 14 days off, now workers are working 28 days on with the subsequent 28 days off.

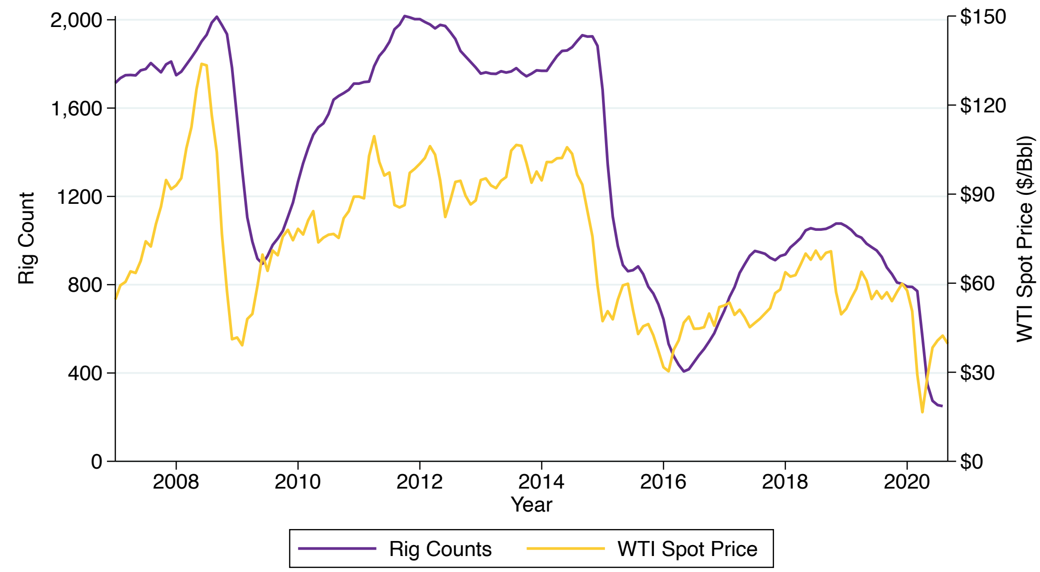
Table 2: COVID-19 impacts on U.S. crude oil and natural gas production

	United States		Gulf Coast		
	Prod.	Percent Change	Prod.	Percent Change	Gulf Coast % of US.
Panel A: Crude Oil (MMBbl/d)					
March	12.7	6.7%	7.5	8.0%	59.2%
April	12.0	-1.0	7.2	1.8	60.2%
May	10.0	-17.6	6.1	-13.7	61.1%
June	10.4	-13.6	6.3	-10.5	60.6%
July	11.0	-7.1	6.5	-3.7	59.5%
August	10.6	-14.9	6.0	-18.4	56.9%
Year to Date	11.5	-4.0%	6.9	-2.3%	59.4%
Panel B: Natural Gas (Bcf/d)					
March	116.9	5.0%	41.9	5.0%	35.9%
April	110.7	1.4	39.4	1.2	35.6%
May	108.2	-3.8	37.9	-7.1	35.0%
June	106.0	-2.5	37.5	-5.5	35.3%
July	111.3	-0.5	39.0	-4.7	35.1%
August	111.2	-2.2	38.7	-8.5	34.9%
Year to Date	111.5	1.5%	39.5	-0.6%	35.4%

Source: U.S. Energy Information Adminstration. Petroleum & Other Liquids. Crude Oil Production. Natural Gas Gross Withdrawals.
Note: Percent change represents a percent change from the same month in the prior year

Figure 2 underscores the drilling reduction associated with the global pandemic. In December, Baker Hughes reported 804 rigs running in the U.S. Consistent with what was reported and forecasted in last year's GCEO, rig counts were declining modestly throughout 2019 and through the pre-COVID-19 beginning of 2020. But what was not predicted in last year's GCEO was the precipitous drop associated with the COVID-19 pandemic. In August of 2020, the most recent month of data available at the time of this writing, rig counts as reported by Baker Hughes are at 250, a 73 percent decline relative to August of 2019. Unsurprisingly, this rig count drop has mirrored the drop in the West Texas Intermediate Spot price. Notably, though, while the oil price has rebounded from its low of $17 in April, rig counts have continued to decline each month.

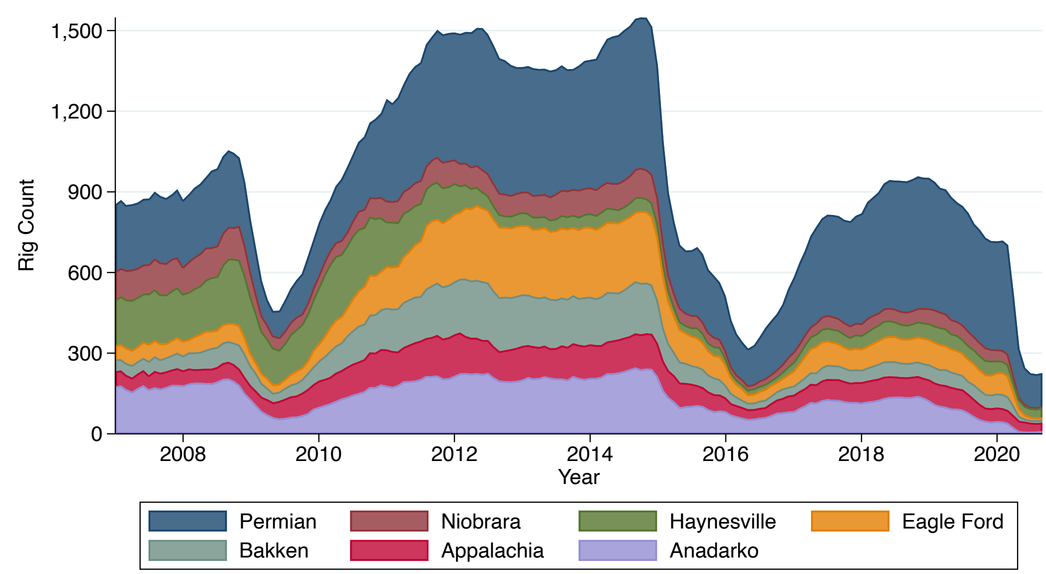
Figure 2: U.S. crude oil prices and rig count



Source: U.S. Energy Information Administration. West Texas Intermediate Spot Price. Baker Hughes Rotary Rig Counts.

Figure 3 illustrates the rig activity in the seven major U.S. shale plays, as defined by EIA's Drilling Productivity Reports. As reported in last year's GCEO, the Permian basin has been the predominant shale play in the U.S., accounting for approximately 46 percent of the rig counts in the U.S. in 2019. But the Permian basin has also seen the largest reduction in rig counts, losing almost 315 rigs (72 percent) in August of 2020 compared to August of 2019. Remarkably, over half of the reduction in rig counts nationally have come from the Permian Basin. While rig counts have likely reached near their bottom, GCEO is not anticipating a significant increase in drilling activity over the next year.

Figure 3: Rig counts in major shale basins

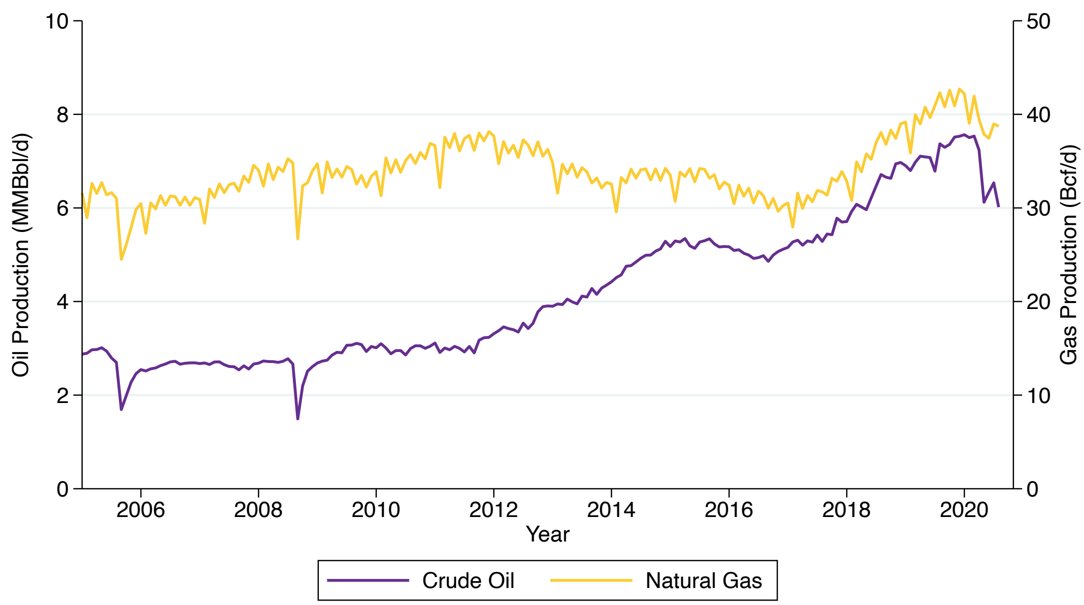


Source: U.S. Energy Information Administration. Drilling Productivity Reports

2.2 Recent Regional Trends: Crude Oil and Natural Gas Production

As a corollary to Figure 1, Figure 4 illustrate regional (PADD 3) crude oil and natural gas production in response to COVID-19. Referring to Table 2, a comparison of total U.S. oil and natural gas production changes in response to COVID-19 to the Gulf Coast region is provided. A few notable observations are as follows.

Figure 4: Gulf Coast crude oil and natural gas production



Source: U.S. Energy Information Administration. Petroleum & Other Liquids. Crude Oil Production. Natural Gas Gross Withdrawals.

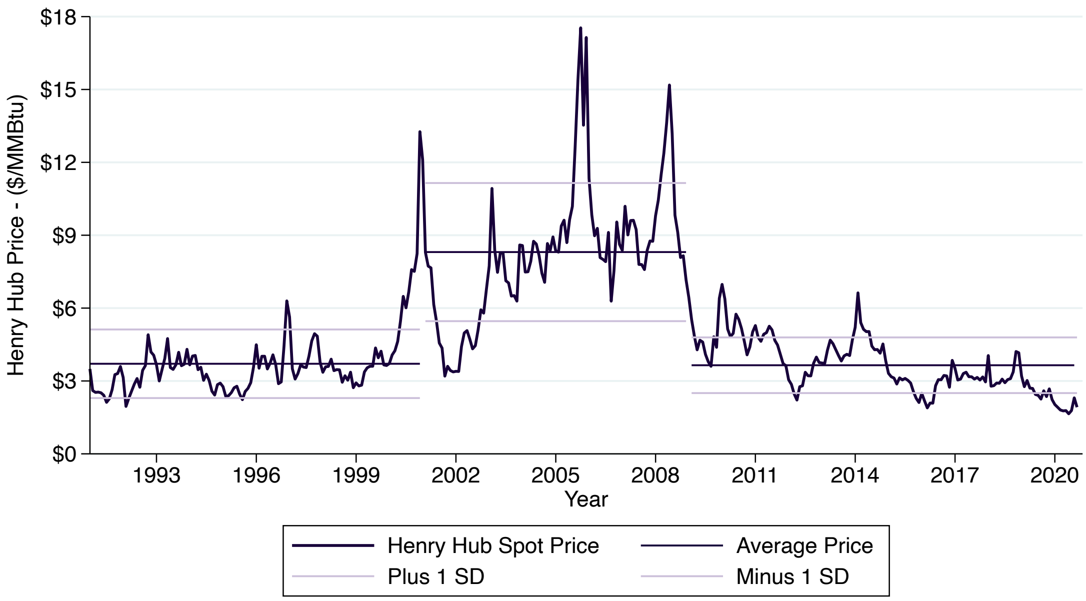
First, examining oil production, the Gulf Coast region, on a percentage basis, experienced both a slower and shallower response compared to the U.S. percentage change. While Gulf Coast oil production declined between March and April, the region's production was still 1.8 percent above April of 2019. By May of 2020, Gulf Coast oil production was down 13.7 percent from the prior May, compared to 17.6 percent for the entire U.S. As a result, the share of U.S. oil production from the Gulf Coast region increased from approximately 59.2 percent to 61.1 percent in just two months during the pandemic. In the most recent month of data, August, Gulf Coast crude oil production was down 18.4 percent from the prior August, compared to 14.9 percent for the U.S. On an annualized basis, Gulf Coast crude oil production is down 2.3 percent compared to 2019.

Interestingly, comparison of natural gas production nationally to the Gulf Coast region reveals a different story. Gulf Coast natural gas production declined by 7.1 percent in May of 2020 relative to May of 2019, compared to 3.8 percent for the U.S. In the most recent month of data available, August, Gulf Coast natural gas production is still 8.5 percent below August 2019 production, compared to 2.2 percent for the U.S. as a whole. On an annualized basis, Gulf Coast natural gas production has been down 0.6 percent compared to up 1.5 percent nationally. Notably, the winter heating season has yet to come.

2.3 Recent Trends: Commodity Pricing

Figure 5, like prior year GCEOs, highlights three different natural gas pricing epochs: (1) the period spanning the 1990s; (2) the period starting with natural gas supply/pricing crisis of the 2000s; and (3) post-recession period to current. These epochs differ in both the level of prices and the variability in prices.[13] Unsurprisingly, the effect of COVID-19 has been prices that are on the lower range of even this lower price epoch. As will be highlighted throughout the report, GCEO believes that as the COVID-19 pandemic gradually subsides, natural gas prices will continue within this third epoch of relatively low prices and low variability.

Figure 5: Historical inflation-adjusted natural gas price

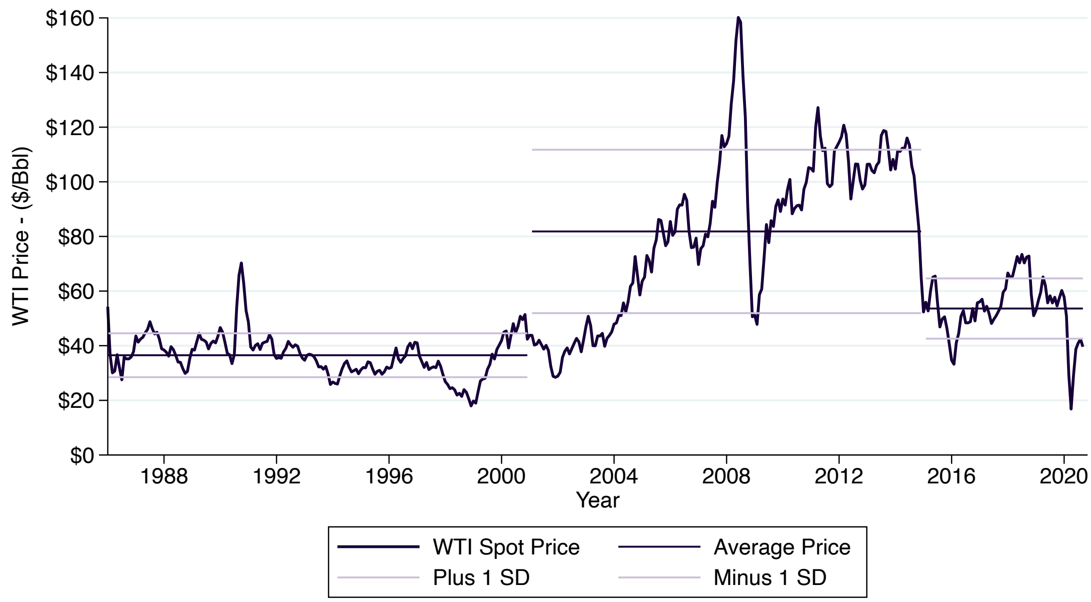


: U.S. Energy Information Administration. Henry Hub Natural Gas Spot Price. Inflation adjustment based on U.S. Consumer Price Index sources from the Bureau of Labor Statistics.

Figure 6 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. Pre COVID-19, oil prices were in the middle of the range of this third epoch and consistent with the outlook provided in last year's GCEO. In response to COVID-19, oil prices plummeted precipitously, bottoming out at a monthly average of less than $17 per barrel in April.

[13] Variability is shown as the standard deviation in the change in average monthly prices.

Figure 6: Historic inflation-adjusted oil prices



Source: U.S. Energy Information Administration. West Texas Intermediate Spot Price. Inflation adjustment based on U.S. Consumer Price Index sources from the Bureau of Labor Statistics.

2.3.1 COVID-19 impacts on oil prices

On April 20, 2020, the WTI spot prices closed at -36.98 per barrel. A timeline of relevant dates and events describing oil markets since the beginning of 2020 is shown in Table 3. Two pieces of information are given for each date; (1) the relevant event; and (2) the West Texas Intermediate (WTI) spot price per barrel as reported by the EIA on that date. As will be shown, it was a convergence of both supply (OPEC) and demand (COVID-19) shocks and unfortunate timing that created such unprecedented short-lived price swings.

Table 3: Oil prices and relevant events

Date	Event	WTI Price
Thursday, Jan. 2	First trading day of 2020	$61.17
Wednesday, March 4	The day before OEPC+ meeting	$46.78
Monday, March, 9	OPEC+ fails to reach agreement on March 5-6 meeting	$31.05
Wednesday, March 11	COVID-19 declared a pandemic by World Health Organization. U.S. Presidential Proclamation 9993 bans entry into US from over 25 countries	$33.13
Friday, March 13	National emergency declared in the United States	$31.72
Saturday, March 14	Presidential Proclamation 9994: Bans entry from Britain or Ireland.	$28.96
Thursday, April 9	OPEC+ agrees to 10mbd production cuts to begin on May 1st	$22.90
Monday, April 20	Day before May WTI NYMEX close	-$36.98
Friday, May 1	OPEC+ production cuts begin	$19.72
Monday May 18	WTI reaches $30 for first time since crash	$31.83
Monday, June 22	WTI reaches $40 for first time since crash	$40.60

Source: Authors' research. All dates in 2020. For weekend dates, the WTI prices on the following Monday is listed.

On the first trading day of the year, oil was trading at $61 per barrel; a level that was about $10 per barrel higher than what futures markets were forecasting at the time of the GCEO's release last year (September 2019). Supply and demand were approximately in balance and futures markets were anticipating prices to remain steady into the foreseeable future. A growing global economy and other generally bullish factors at the time were moving oil demand on a steady upward trajectory. U.S. oil production was at an all-time high of 12.8 million barrels per day in December of 2019. Market signals were displaying confidence that production would be capable of meeting the demand growth at current prices.

But beginning in the first two months of 2020, concerns of COVID-19 spreading to countries outside of China began to translate into forecasts that oil demand would weaken, putting downward pressure on prices. By March 4, the day before an OPEC+ meeting the price of oil was at $47 per barrel. While lower than the onset of the year, supply and demand were approximately in balance at this price point.

In response to the pandemic-induced global slowdown, OPEC+ was considering output reductions. Specifically, Saudi Arabia was recommending reducing output by 1.5 million barrels per day with the hopes of raising prices closer to those observed in the earlier part of the year. But Russia was not on board—and by the time the meeting ended on Friday March 6, there was no agreement in place. Upon a deal not materializing, by April 1, all OPEC countries (and Russia) were free to produce as much oil as they chose. The following Monday (March 9), oil prices plummeted to $31 per barrel, a reduction of 33 percent.

Further exacerbating these factors, the COVID-19 pandemic began to spread rapidly. On March 11, the World Health Organization (WHO) declared COVID-19 as a pandemic. On the same day, President

Trump signed a presidential proclamation (9993) banning entry into the U.S. from more than 25 countries. On March 13, a national emergency was declared in the U.S., and the next day (March 14) President Trump signed another presidential proclamation (9994) banning entry into the United States from Britain and Ireland. Over the next few weeks, individual U.S. states and many countries around the world began implementing stay-at-home orders and other similar policies, significantly reducing economic activity and therefore transportation. For perspective, on March 22, Governor John Bel Edwards issued a stay-at-home order for Louisiana. By the time Louisiana's stay-at-home order was implemented, oil prices were already below $25 per barrel.

OPEC was under enormous pressure to make a deal happen; what started with a price drop in response to a failed OPEC agreement quickly spiraled out of control as the global pandemic began to rapidly accelerate. So, on April 9, just one month after the failed agreement, OPEC agreed to historic production cuts by an unprecedented 10 million barrels per day. Recall, the initial agreement that fell through just one month earlier was for just 1.5 million barrels per day. But in some ways, the damage was already done. As global demand received a sudden and dramatic reduction, oil production cuts could not happen fast enough, and on April 20, the WTI NYMEX futures closed at a negative price for the first time in history: -$37 per barrel.

It is important to note that this negative price was a hub price in Cushing, Oklahoma, where physical deliverability was required, and a relatively small volume of oil traded at this price. For comparison, the Brent price that does not have a physical deliverability requirement bottomed at about $9 per barrel. This is more indicative of the actual prices received at the wellhead. Nonetheless, these low prices were unprecedented.

By May 1, the OPEC+ production cuts hit the market (that were agreed to in the April meeting) and by that time prices had risen to about $20 per barrel. By mid-May prices exceeded $30 per barrel for the first time since the crash, and by mid-June exceeded the $40 threshold, where prices have more or less held steady since.

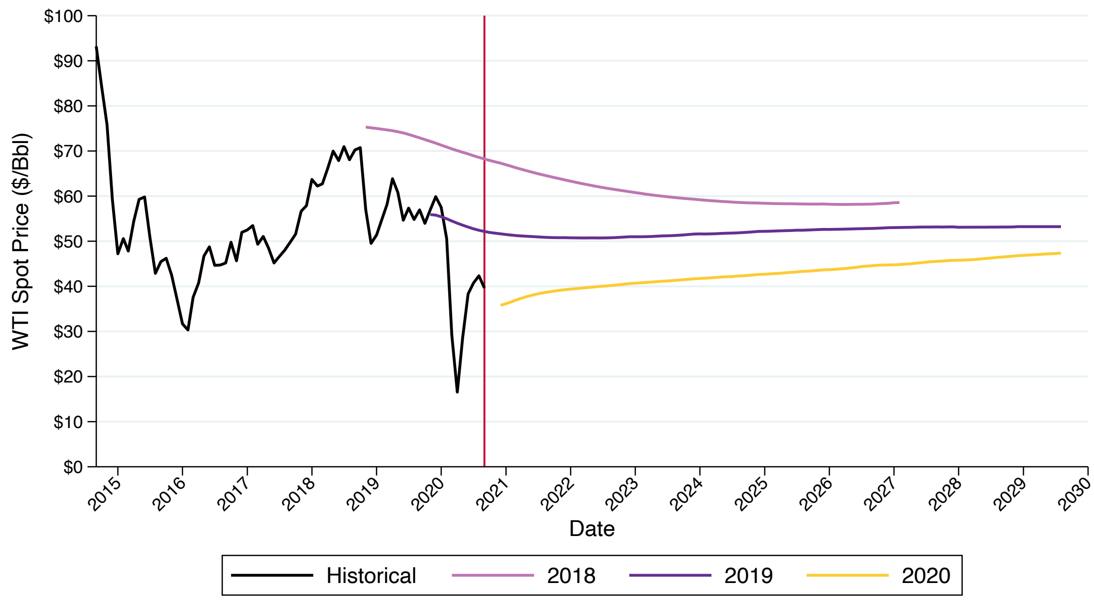
2.4 Outlook: Commodity Pricing

Futures markets are indicating upward pressure on both crude oil and natural gas prices as global demand rebounds from COVID-19, followed by years of relatively flat prices in real terms (i.e. inflation adjusted) over the remainder of the forecast horizon. Figure 7 and Figure 8 show current futures prices for oil and natural gas alongside the futures prices from the last two year's GCEOs. Examination of not only the current futures price but also how expectation has changed is instructive for understanding market trends.

Figure 7 shows the crude oil futures prices. For the past two years, GCEO has shown oil futures in *backwardation*—meaning that prices were expected to fall in the future. And in both years, the futures markets were successful in predicting declining prices, but in both instances the magnitude of decline was larger than what markets were anticipating. In contrast, today the futures market for oil is in *contango*—meaning that prices are expected to increase in the future. This is logical, given the precipitous demand reduction for transportation, and therefore oil, in light of the global pandemic. As transportation returns (and therefore demand), prices are expected to increase. What is perhaps more interesting is that prices are not anticipated to reach pre-COVID-19 predicted levels until 2030.

In other words, futures markets are anticipating that there will be enough supply to meet global demand at between $40 and $55 per barrel for the next decade.

Figure 7: Crude oil price outlook

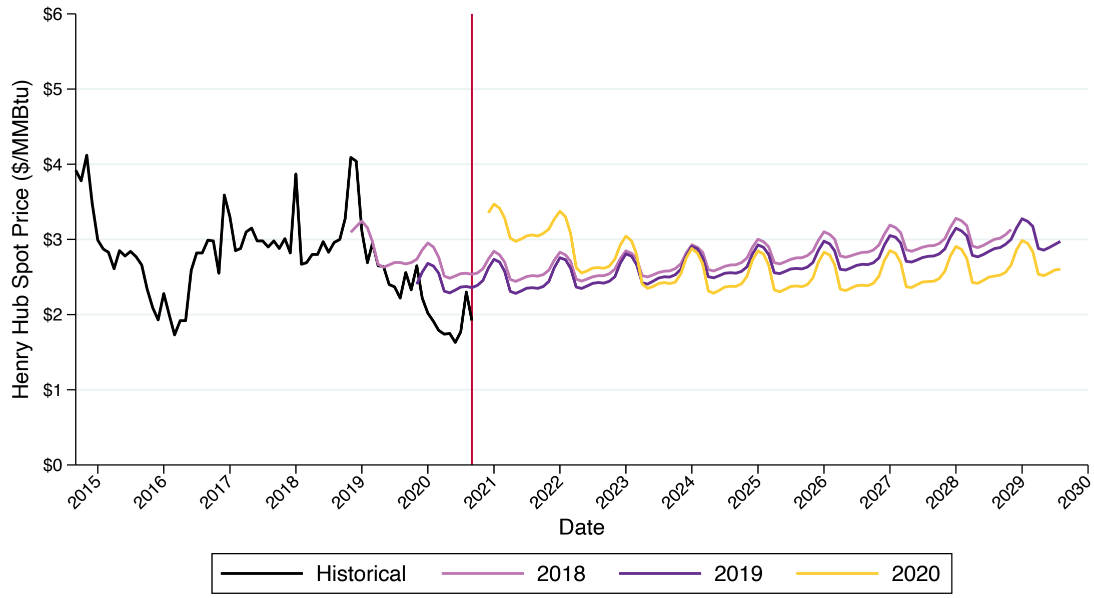


Source: New York Mercantile Exchanged West Texas Intermediate Futures Price. Sources from S&P Global Market Intelligence. Most recent future price as of October 30, 2020.

Figure 8 shows the corollary for natural gas futures prices. Interestingly, while natural gas prices are currently lower than markets predicted this time last year, natural gas prices are expected to be higher in 2021 and 2022 than futures market suggested over the past two years. This is likely due to at least two factors. First, as will be highlighted later, demand for natural gas has been less impacted by COVID-19 than oil due to the simple fact that oil is primarily a transportation fuel. But second, on the supply side, natural gas produced from oil wells (i.e. associated natural gas) production also has declined. This is expected to put upward pressure on natural gas prices over the next two years. Nonetheless, comparisons to Figure 5 reveal that natural gas prices are anticipated to continue in the third low price and low variability epoch.

Although low oil and natural gas prices can create challenges for the upstream oil and gas extraction and services sectors, the longer-term trajectory that these prices remain low is relatively good news for the continued investment in refining, chemical manufacturing, and energy export in the Gulf Coast region, as will be discussed in Section 5.

Figure 8: Natural gas price outlook



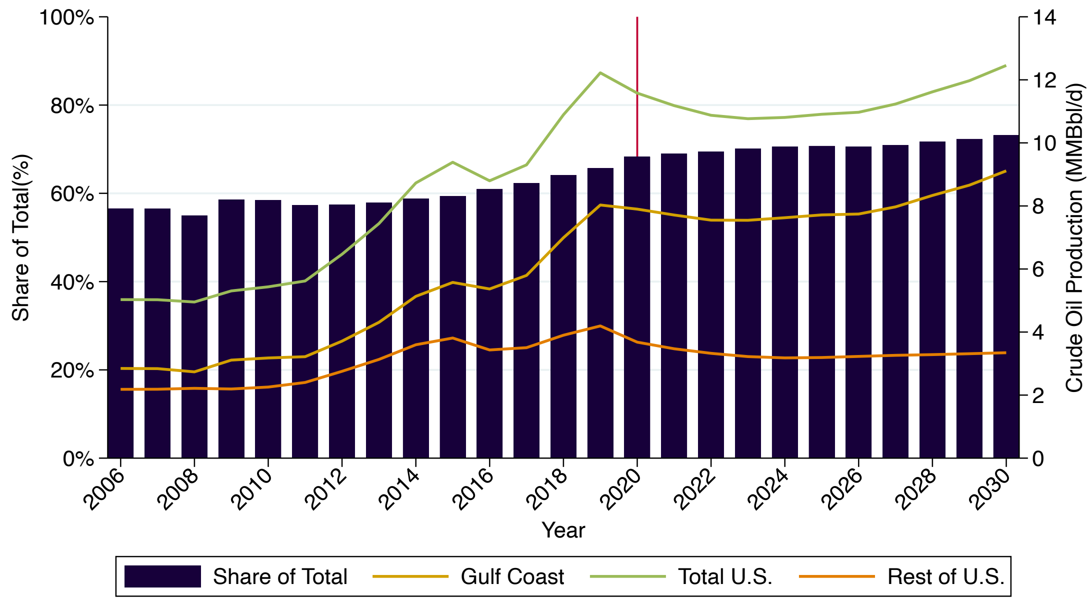
Source: New York Mercantile Exchanged Henry Hub Futures Price. Sources from S&P Global Market Intelligence. Most recent future price as of October 30, 2020.

2.5 Outlook: Crude Oil and Natural Gas Production

Next, Figure 9 and Figure 10 show oil and natural gas production forecasts based on the Enverus ProdCast model. This is the same model used in production forecasting in past GCEOs. Prior year GCEO readers will recall that each year U.S. oil and natural gas production have come in higher than expected, and the ProdCast model has upgraded its production forecasts in response each year. In last year's GCEO, ProdCast was forecasting that total U.S. oil production would increase to approximately 18 million barrels per day by 2030, with more than 12 million barrels a day coming from the Gulf Coast region. Natural gas production was forecast to increase to 131 Bcf/d by 2030.

ProdCast's outlook has changed dramatically this year in light of COVID-19. On an annualized basis, U.S. oil production is anticipated to fall from its 2019 peak of 12.2 million barrels per day to 10.71 million barrels per day in 2023. Thus, ProdCast is estimating that U.S. oil production will continue to decline over the next approximately three years, as oil prices are anticipated to rebound slowly. Gulf Coast oil production is anticipated to decline from its high of 8.0 million barrels per day in 2019 to 7.6 million barrels per day in 2023. Thus, both U.S. and Gulf Coast oil production are anticipated to decline over the next three years.

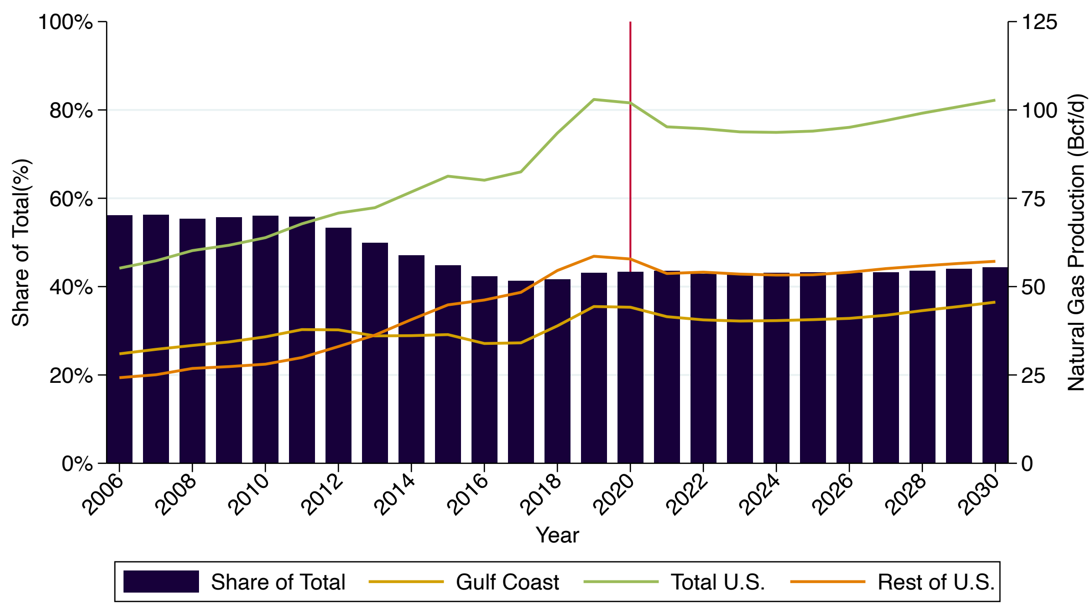
Figure 9: Crude oil production forecast and Gulf Coast share of U.S. production



Source: Enverus ProdCast

ProdCast has similar predictions for natural gas production, as shown in Figure 10. U.S. natural gas production is anticipated to drop from its 2019 high annualized average of 102.9 Bcf/d to 93.5 Bcf/d in 2023. Gulf Coast natural gas production is anticipated to decline from 44.3 Bcf/d to 40.4 Bcf/d over this same time horizon (2019 to 2023). The ProdCast model production forecasts will be one of the inputs used to forecast upstream oil and gas employment presented in Section 8.

Figure 10: Natural gas production forecast and Gulf Coast share of U.S. production



Source: Enverus ProdCast

3 Pipeline Activity

3.1 Recent Trends

Spatial differences in prices of hydrocarbons between areas is the market signal that drives pipeline development. If prices at “Point A” are higher than “Point B” at a given time, this provides an opportunity for a firm to move hydrocarbons from “Point A” to “Point B” and earn a profit doing so. Economists and traders call this phenomenon spatial arbitrage. As in prior year GCEOs, we highlight price differentials that represent pipeline constraints in both oil and natural gas markets.

First, Figure 11 investigates the extent to which shipping constraints can explain the difference in prices between West Texas Intermediate (WTI) relative to Louisiana Light Sweet (LLS). Three vertical lines are drawn. The first vertical line is January of 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 11 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 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.

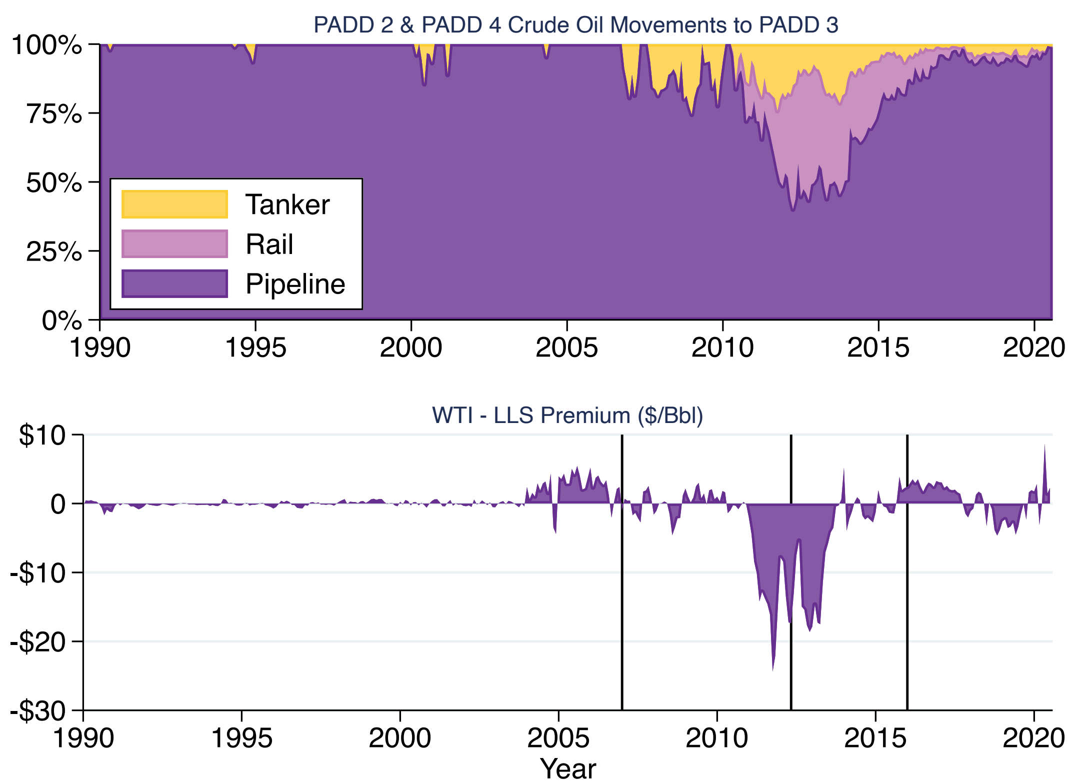
The LLS-WTI premium closely mirrors changes in the mode of transport over the 2007-2015 time period. This close correlation between shipping and prices can explain between half and three-quarters of the movement in relative prices. Empirical research has investigated whether changes in the composition of refining as captured by API gravity of crude inputs can explain these differentials.[14] 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. Last year, GCEO identified nine crude oil pipeline projects in the Gulf Coast region, either under construction or announced, that were expected to be completed by the end of 2021. Based on conversations with industry, pipelines that are currently not under construction likely will not begin construction, due to the precipitous drop in oil production associated with COVID-19. The good news is that at the time of this writing, crude markets are approximately in balance, with a slight premium for LLS. We anticipate this few dollar premium will persist over the forecast horizon and approximately 95 percent of crude shipped from the mid-continent

[14] Agerton & Upton, 2019. Decomposing Crude Price Differentials: Domestic Shipping Constraints or the Crude Oil Export Ban? The Energy Journal, Vol. 40, No. 3.

to the Gulf Coast will continue to come from pipelines. Due to the current oil price environment, sudden increases in oil production from new areas creating the need for barge and rail shipments are unlikely.

Figure 11: PADD 3 crude oil movements by transportation type



Source: U.S. Energy Information Administration, West Texas Intermediate Spot Price and Light Louisiana Sweet First Purchase Price. Movements between PADD Districts, by pipeline, by tanker & barge, and by rail

Shifting focus to natural gas midstream constraints, the relevant constraint is not between the mid-continent and the Gulf Coast region (as has been the case for oil), but instead moving natural gas out of the Permian Basin. Specifically, 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.[15]

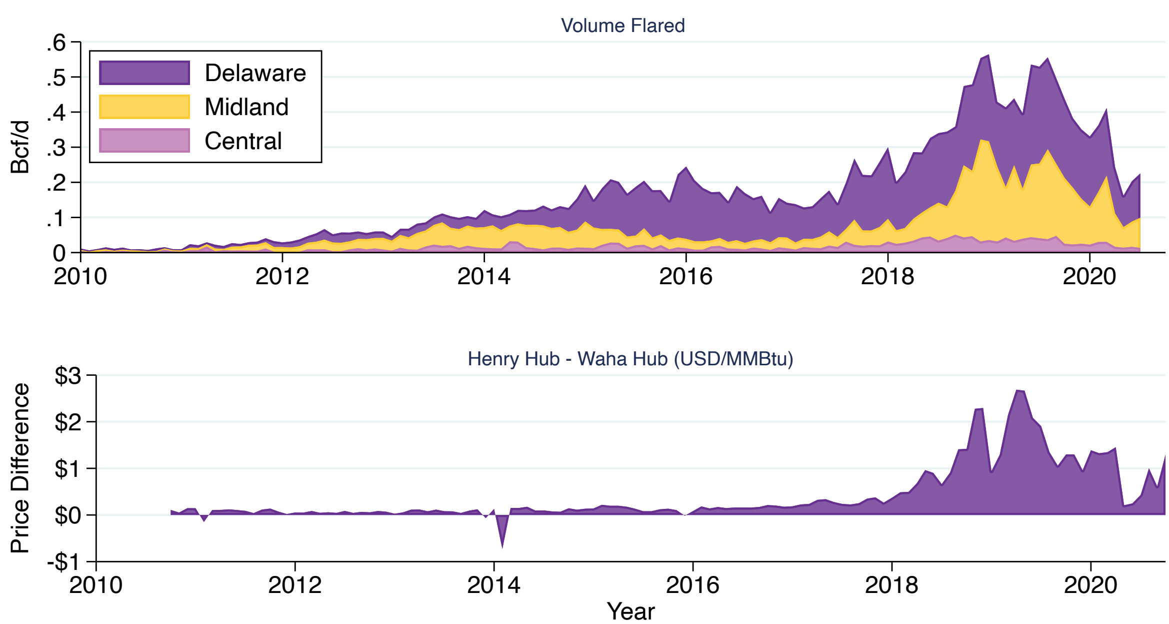
Collectively, these constraints can lead to two phenomena (1) wellhead flaring of natural gas and (2) inter-region natural gas pricing discounts, as seen in the Henry Hub/Waha pricing. Figure 12 illustrates both of these trends focusing on the Permian basin and comparing Henry Hub and Waha natural gas prices. Pre-2018 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. Also, flaring in the Permian basin was consistently less than 0.1 bcf/d; however, as Permian basin production

[15]For a detailed discussion of the value chain moving natural gas from wellhead to market, see recent research. Agerton, Gilbert & Upton, 2020. The Economics of Natural Gas Flaring in U.S. Shale: An Agenda for Research and Policy. Rice University's Baker Institute for Public Policy Working Paper. USAEE Working Paper No. 20-460.

ramped up, markets began to experience the emergence of significant Waha price discounts relative to Henry Hub. On some days, natural gas at Waha has traded at negative prices. These price discounts moved in lock step with flaring in the Permian, and at its peak the Permian basin was flaring more than one half billion cubic feet of natural gas per day. According to EIA, in 2019 over 538 billion cubic feet of natural gas was flared or vented in the United States. To put this into perspective, that represented about 1.3 percent of U.S. gas production.[16] If the flared volume of natural gas was instead used to generate electricity, it would have been enough to power 6.1 million households for a year.[17]

Last year's GCEO predicted that pipeline investments would alleviate much of this constraint, and over the coming year Waha was likely to converge to Henry Hub. Interestingly, while this has begun, it has not yet fully materialized. As also shown in Figure 12, Waha prices have continued to be volatile relative to Henry Hub and have had significant discounts on average.

Figure 12: Henry Hub and Waha natural gas prices



Source: Texas Railroad Commission.

3.2 Pipeline Outlook

Figure 13 shows the natural gas pipeline transmission capacity additions scheduled in 2020 and then over the next three years.[18] These capacity additions are restricted to just larger transmission pipelines and do not include local gathering pipeline additions that may arise over the same time period. In 2020, to date there have been 1.7 billion cubic feet (bcf) of new pipelines completed, with an additional 4 bcf announced to be completed by the end of the year. In total, there are currently 12.6 bcf/d of pipelines currently under construction, with another 40 bcf of projects included in the list.

[16]Source: Natural Gas Gross Withdrawals and Production. Gross Withdrawals compared to Vented and Flared in Annual-Million Cubic Feet. Accessed Oct 2020.

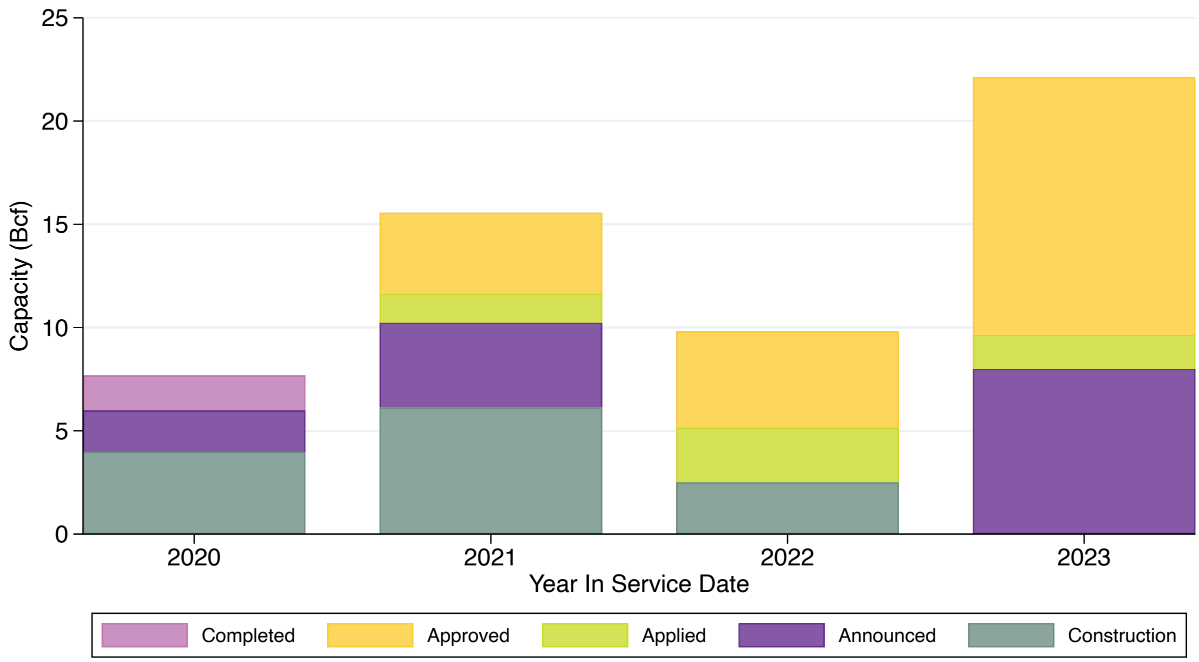
[17]See Agerton, Gilbert & Upton (2020) for more discussion and calculations.

[18]These include laterals, expansions, reversals and new pipelines.

Discussions with industry have suggested that many of these projects are likely to be delayed while the effects of COVID-19 on natural gas production bear out.

Nonetheless, recent reports have suggested that the completion of these pipelines that are currently under construction will improve natural gas pricing at the Waha hub dramatically and create an influx of supply to the Texas Gulf Coast.[19] Thus, while both the Waha discount to Henry Hub and flaring have been subdued over this past year, as shown in Figure 12, GCEO expects for this trend to continue. Over the next two years, Waha will likely be trading in lock step with Henry Hub, barring another unexpected event.

Figure 13: Gulf Coast natural gas pipeline capacity outlook



Source: U.S. Energy Information Administration. U.S. natural gas pipeline projects.

Note: Includes laterals, expansions, reversals and new pipelines.

4. Power Sector

4.1 Recent Trends: Load Growth

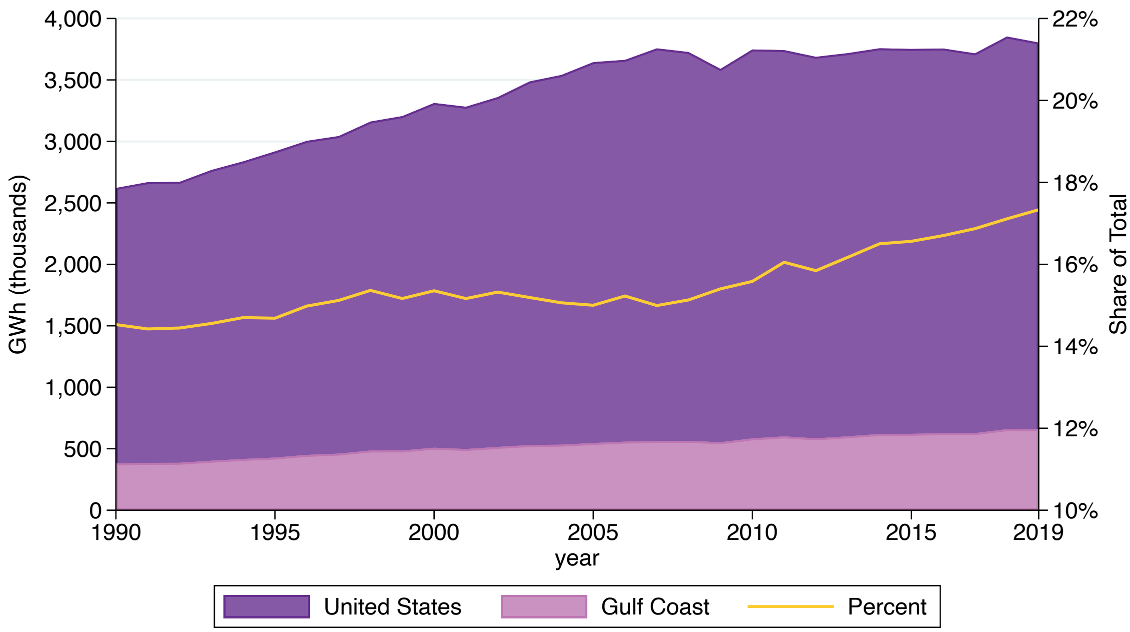
This novel section of the GCEO will focus on the electricity sector. Note that short-term impacts of COVID-19 on electricity usage will be discussed in Section 7. This section focuses on longer trends.

Figure 14 shows total electricity usage in the United States and the Gulf Coast Region. Analysis reveals a few notable items. First, electricity demand has been relatively flat in the United States over the past decade. For instance, comparing total sales in MWhs to all customers in the United States

[19] Some Beach – New Permian-to-Gulf Gas Pipelines to Shake up Regional Flows and Basis. 10/11/2020. Jason Ferguson. RBN Energy LLC.

in 2007, (the highest load year before the Great Recession) to the most recent full year available (2019) shows that load was actually slightly lower in 2019 than 2007. Analyzing the same time frame (i.e. 2007 to 2019) for the Gulf Coast reveals a different trend, namely increasing load over this time period. Specifically, electricity demand increased by 13.2 percent. As a result, the share of electricity usage from Gulf Coast states increased from 15 percent to 17 percent over this time period.

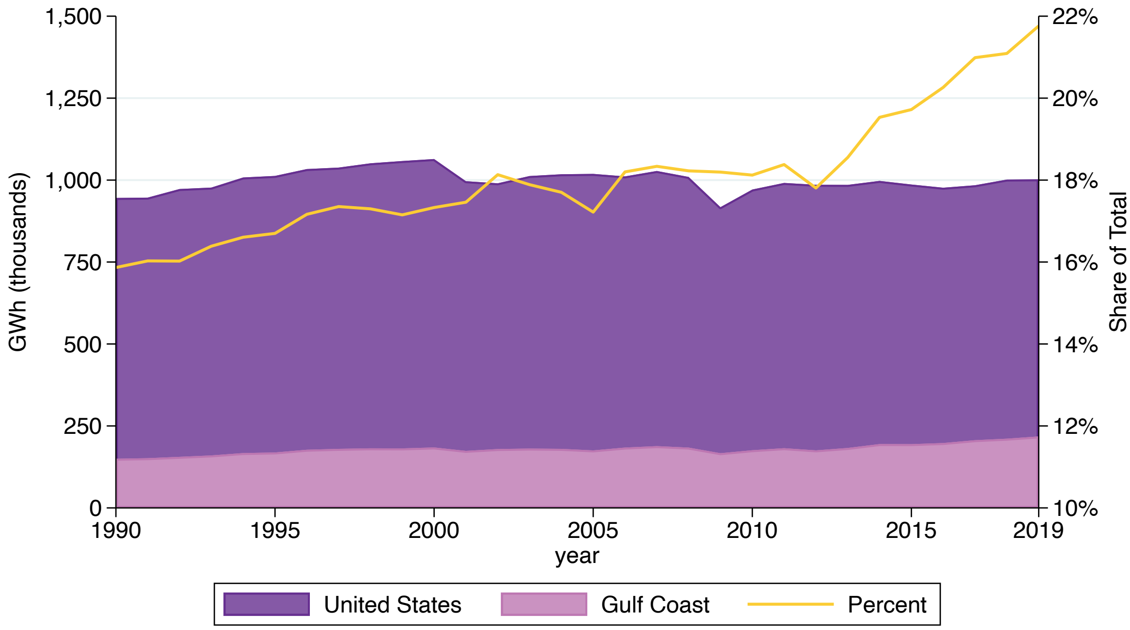
Figure 14: U.S. and Gulf Coast electricity sales



Source: U.S. Energy Information Administration. Retail sales of electricity to ultimate consumers.

Next, Figure 15 focuses on electricity sales to industrial customers, again comparing the U.S. and Gulf Coast region. Similar to total U.S. electricity demand, industrial demand was down about 7 percent over the 2007 to 2019 time period, while Gulf Coast industrial demand was up 6.7 percent. As a result, the share of national industrial demand coming from the Gulf Coast region has increased over this time period. This has especially been apparent since 2013 as industrial construction projects came online utilizing the prolific natural gas resources available from shale production discussed in Section 2.

Figure 15: U.S. and Gulf Coast industrial electricity sales

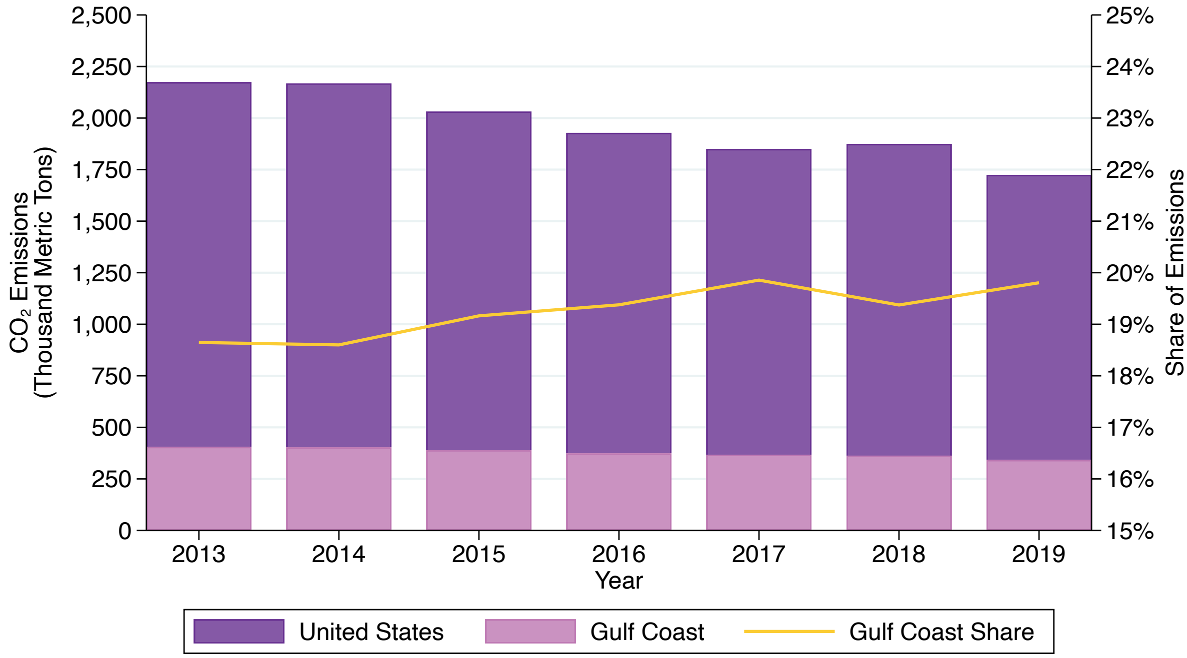


Source: U.S. Energy Information Administration. Retail sales of electricity to ultimate consumers.

4.2 Recent Trends: Carbon Emissions

Next, carbon dioxide emissions for the United States and Gulf Coast region are shown in Figure 16. Since 2013, U.S. and Gulf Coast total carbon dioxide emissions from power generation have been down 13.8 percent and 10.4 percent, respectively. As a result, the Gulf Coast's share of total U.S. carbon emissions has remained at approximately 19 percent. While both U.S. and Gulf Coast emissions have trended downward in total, as shown in Figure 14, Gulf Coast electricity generation has increased its share of total U.S. electricity generation over this time period. Thus, while not shown here, the carbon dioxide emissions per MWh of electricity produced has declined by almost exactly 16 percent in both the U.S. and Gulf Coast region. In 2018, the most recent year shown, the Gulf Coast carbon intensity of electricity generation was about 2.7 percent higher than the U.S.

Figure 16: U.S. and Gulf Coast carbon dioxide emissions from electricity generation



Source: U.S. Energy Information Administration. Electricity. Emissions by plant and by Region.

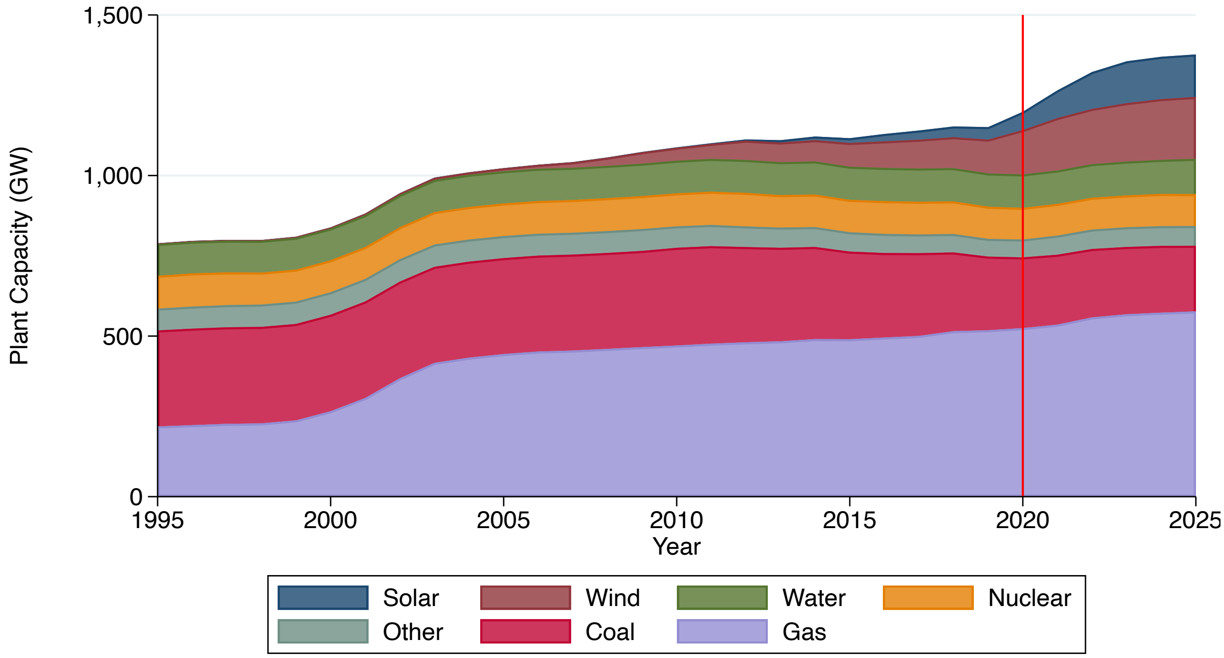
4.3 Outlook: Capacity Investment

Next, Figure 17 and Figure 18 show power generation capacity by fuel source for the U.S. and Gulf Coast region, respectively. Comparison of these figures reveals a few important insights.

First, comparing the U.S. and Gulf Coast region, the generation mix is very different. The Gulf Coast has a higher concentration of natural gas capacity. In the most recent full year of data, 2019, natural gas accounts for 58.9 percent and 45.0 percent in the Gulf Coast and U.S. regions, respectively. But second, natural gas capacity has grown in both the U.S. and Gulf Coast over the past decade. Since 2009, over 52 thousand GWs of natural gas capacity have been added to the grid nationally, with only 4.31 GWs of natural gas capacity added in the Gulf Coast. Third, renewable energy capacity (including hydro, solar and wind), accounts for 21.5 percent of capacity nationally in 2019, and 17.9 percent in the Gulf Coast.[20] Finally, for both the U.S. and Gulf Coast, over 90 percent of the capacity growth over the next five years is anticipated to come from natural gas, solar and wind.

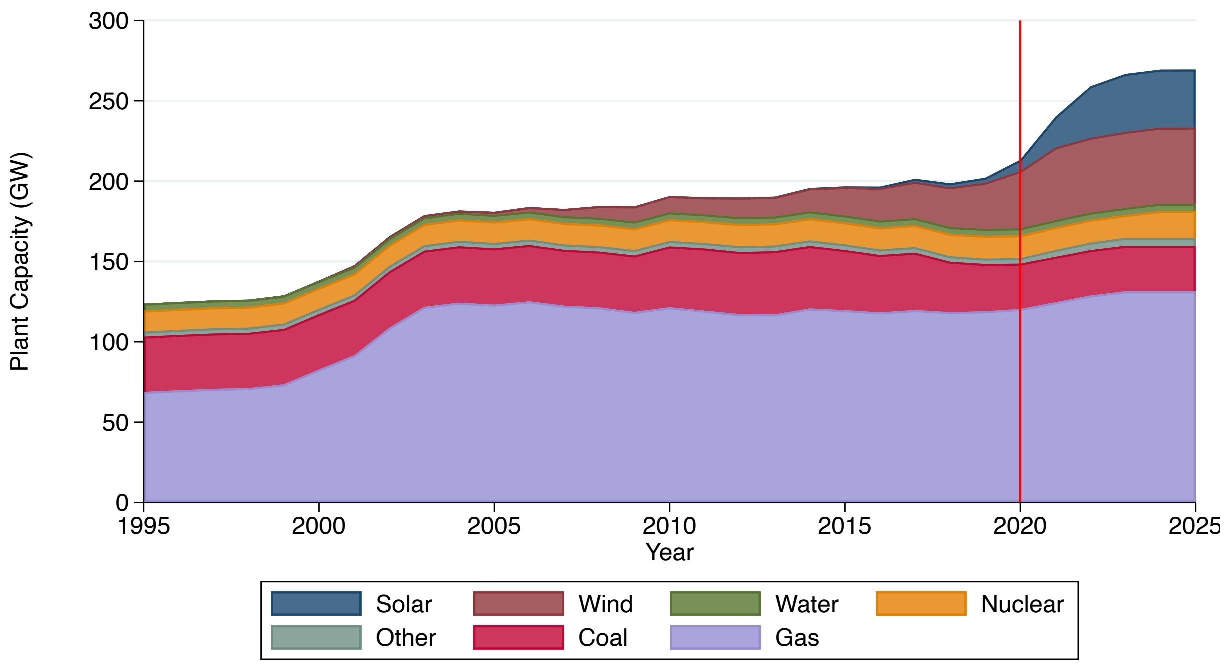
[20]Importantly, this is referring to renewable capacity, not energy. According to EIA, in 2019 15.7% of generation came from hydro, solar and wind.

Figure 17: U.S. power generation capacity and outlook



Source: S&P Global Market Intelligence, Historical and Future Power Plant Capacity

Figure 18: Gulf Coast power generation capacity and outlook



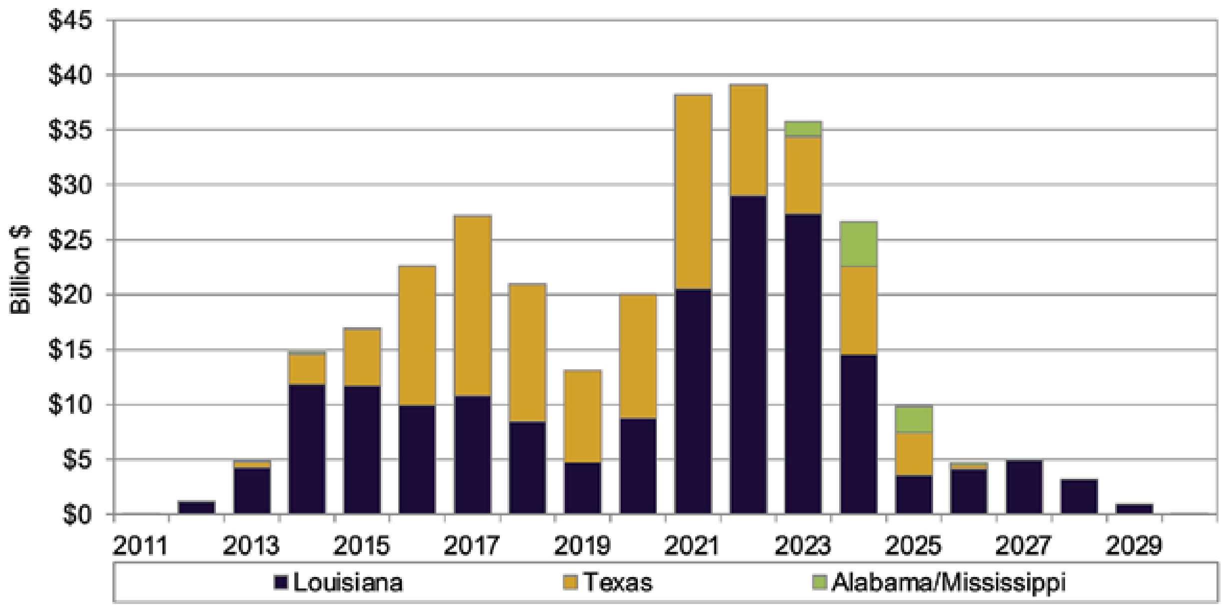
Source: S&P Global Market Intelligence, Historical and Future Power Plant Capacity

5. Energy Manufacturing Activity

5.1 Recent Trends

The Gulf Coast has been a major beneficiary of an exceptionally long, large, and sustained level of capital investment dedicated to energy manufacturing activities and energy export infrastructure. These energy manufacturing investments assist in refining and transforming hydrocarbons into a variety of intermediate and final goods. Energy export infrastructure investments, on the other hand, facilitate the movement of hydrocarbons produced in the prolific unconventional basins in the U.S. to various destinations around the world. Through commodity exports or final chemical products, these investments have propelled the U.S., and particularly the Gulf Coast, into a leadership position in global energy markets.

Figure 19: GOM energy manufacturing investments by state

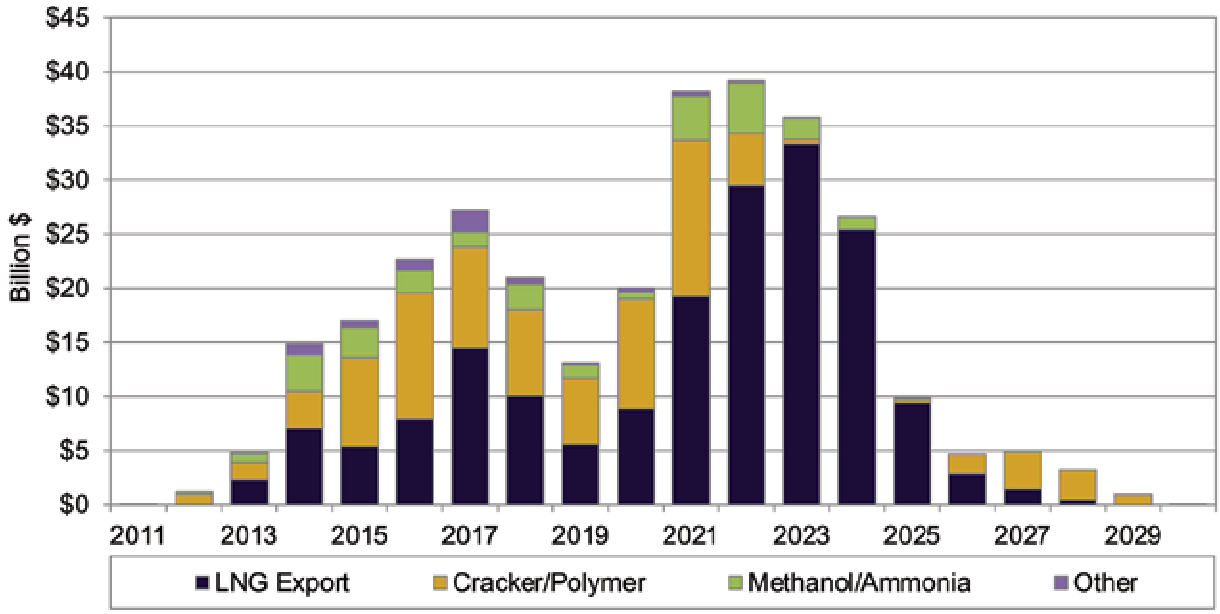


Source: Center for Energy Studies (2020), authors' construct from publicly reported data.

As shown in Figure 19, since 2011, regional investment in both commodity and product exports has led to regional investment of $142 billion (through 2020), or over $14 billion per year. The expected total through 2030 sums to $305 billion. The distribution of these capital investments across the Gulf Coast is almost exclusively weighted towards Louisiana and Texas, with historic investment split evenly between Louisiana ($71.6 billion, 51 percent) with the balance occurring in Texas ($69.8 billion, 49 percent).

As shown in Figure 20, in terms of investment composition in dollar terms, most energy manufacturing and infrastructure investment has been concentrated in LNG export facilities. In fact, 60 percent of all regional capital investment comes from LNG facility development. The dominance of LNG facilities as a share of total regional capital investment should come as no surprise given its relatively high per unit investment cost. A typical Gulf Coast energy manufacturing investment runs around $45 million, whereas a typical LNG export facility investment has been $8-10 billion, on an average facility basis (since 2011).

Figure 20: GOM energy manufacturing investments by sector

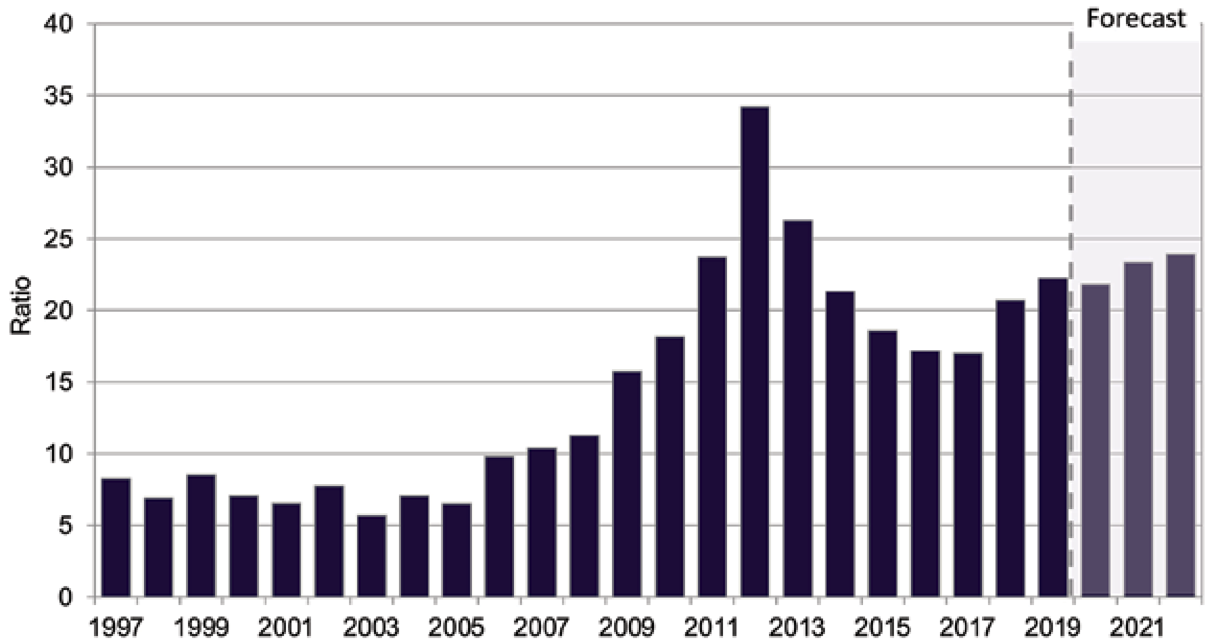


Source: Center for Energy Studies (2020), authors' construct from publicly available information.

Both energy manufacturing and LNG facility investment have been enabled by a number of positive factors that have aligned over the past decade: (1) low natural gas prices relative to crude oil prices; (2) low interest rates and low borrowing costs to finance capital intensive projects; (3) generally favorable exchange rates that have helped keep U.S. exports competitive; and (4) strong global economic growth, particularly in emerging markets in Asia.

The trend in declining energy prices and their role in stimulating U.S. investment opportunities in energy manufacturing cannot be emphasized enough. Chemical industry production in the U.S., and particularly along the Gulf Coast, utilizes natural gas-based feedstocks, particularly ethane, as their primary inputs. Chemical production in Europe and Asia, on the other hand, utilize crude-based feedstocks, particularly naphtha. U.S. and Gulf Coast chemical production (as does most regional energy manufacturing) becomes considerably more competitive when natural gas prices fall relative to crude oil prices, which has been the case for the better part of the past decade. Thus, it should come as no surprise that the bulk of all regional energy manufacturing investments arose and were completed during a time when the oil-to-gas price ratio (Figure 21) was in excess of 10.

Figure 21: Oil-to-gas price ratio



Source: U.S. Energy Information Administration. Ratio of West Texas Intermediate Crude Oil Spot Price ($/bbl) and Henry Hub Natural Gas Price ($/MMBtu). Forecast based on Annual Energy Outlook 2020.

Last year, the 2020 GCEO forecast anticipated a slower capex growth in energy manufacturing and infrastructure. The slow-down was largely attributed to: (a) simple exhaustion from a decade's worth of record investment growth; and (b) considerable economic uncertainties due to trade related challenges that were beginning to slow overall global economic growth, particularly economic growth in China. For instance, the 2020 GCEO anticipated total 2020 capex of $25.2 billion, with $12.3 billion being dedicated to LNG investments and $12.9 in energy manufacturing. Further, the 2020 GCEO forecast that most of this regional investment would occur in Louisiana and of this amount, some 60 percent ($8.7 billion) would be dedicated to LNG export capacity, with the balance ($5.7 billion) being dedicated to energy manufacturing.

However, the unanticipated COVID-19 pandemic of the past year has considerably changed the capital investment profile of the region. Table 4 compares 2019 capital investment to that forecast in the 2020 GCEO and actual 2020 investment. Actual 2020 capital investment was down by as much as 21 percent ($5.2 billion) relative to the prior GCEO forecast.

Table 4: GOM energy manufacturing investment, GCEO comparison

Period	Texas LNG	Texas Non-LNG	Louisiana LNG	Louisiana Non-LNG	Total GOM LNG	Total GOM Non-LNG	Total GOM Total
	(million $)						
2019	$ 3,503	$ 5,126	$ $2,466	$ 2,075	$ 5,969	$ 7,201	$ 13,170
GCEO 2020	$ 3,660	$ 7,207	$ 8,686	$ 5,683	$ 12,346	$ 12,890	$ 25,236
2020 Actual	$ 3,416	$ 7,910	$ 5,445	$ 3,270	$ 8,861	$ 11,180	$ 20,041

These investment decreases should come as no surprise given the change in global economic performance, particularly after mandated stay-at-home orders throughout a good part of the industrialized world in early 2020. Most publicly traded companies, including large integrated energy and chemical companies, began to restrict cash flow and cancel/delay projects as the significance of the COVID-19-related downturn became apparent. Table 5 summarizes a survey conducted by international consultancy Wood Mackenzie, examining capital budget revisions as a result of COVID-19.

Table 5: Chemical industry, revised capex

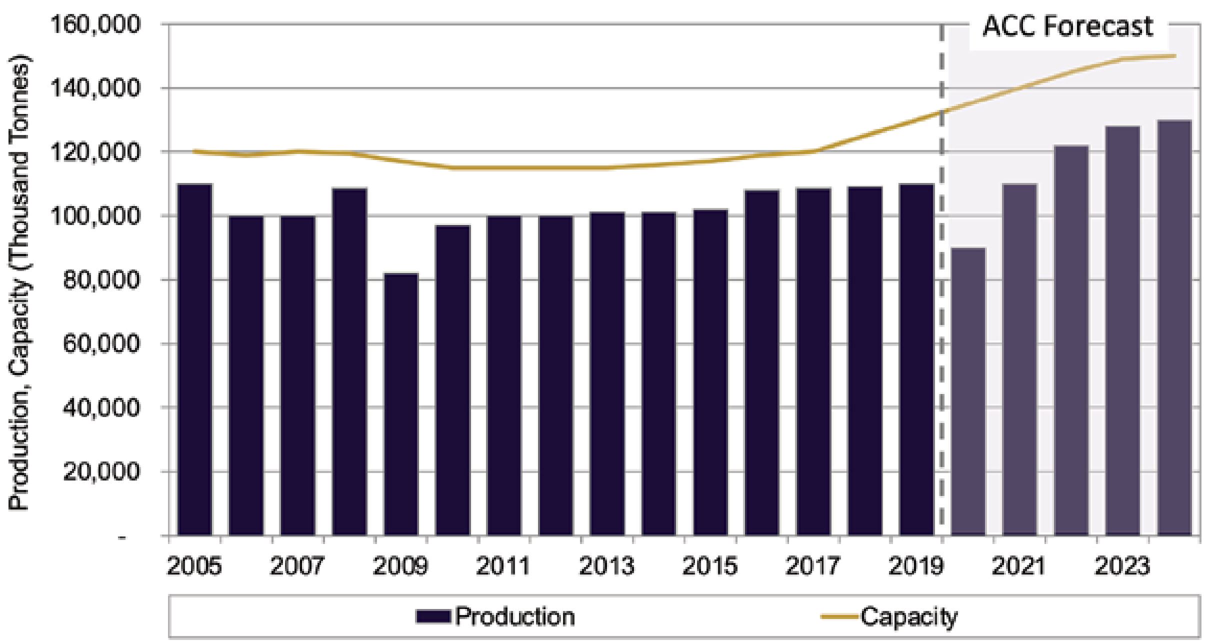
Company	Capex 2020	Capex 2020 Revised	% Capex Δ
	(billion $)		
ConocoPhillips	6.5-6.7	5.9	-11%
Dow Inc	1.5	1.3	-17%
Total S.A.	18.0	15.0	-17%
Royal Dutch Shell	25.0	20.0	-20%
Chevron Corporation	20.0	16.0	-20%
Lyondell Bassell Industries N.V.	2.4	1.9	-21%
Eastman Chemical Company	0.450-0.475	0.350-0.375	-22%
Westlake Chemical Corp	0.675	0.525	-22%
Dupont de Nemours	1.3	1.0	-23%
Eni	8.0	6.0	-25%
Enterprise Product Partners LP	3.75	2.5-3.0	-27%
Eastman Chemical Company	0.450	0.325	-28%
Targa Resources Corp	1.2	800-900	-29%
Exxon Mobil Corp	33.0	23.0	-30%
The Chemours Company	0.400	0.275	-31%
EOG Resources	6.5	4.3-4.5	-32%
Pembina Pipeline Corp	2.3	1.2	-43%

Source: Galindo, Enrique. How are chemicals companies responding to the coronavirus blow? Wood Mackenzie. May 2020. <https://www.woodmac.com/news/opinion/how-are-chemicals-companies-responding-to-the-economic-blow-from-coronavirus/>

Many of the companies surveyed by Wood Mackenzie reported reducing 2020 capital expenditures by between 11 percent to 43 percent, with an average 2020 reduction, across all surveyed firms, of 25 percent.

The industry contraction has been strongly visible in the utilization of facilities that have seen extensive capacity expansion over the past decade. Figure 22, for instance, shows historic and recent trends in U.S. annual basic chemical production. Sector output in 2019, the year proceeding the pandemic, saw output rivaling the prior recent peaks set in 2018: Q2 of 115 million tons; however, the pandemic saw chemical sector output plummet to slightly over 80 million tons, a level not seen since the 2008-2009 recession.

Figure 22: U.S. chemical industry production and capacity

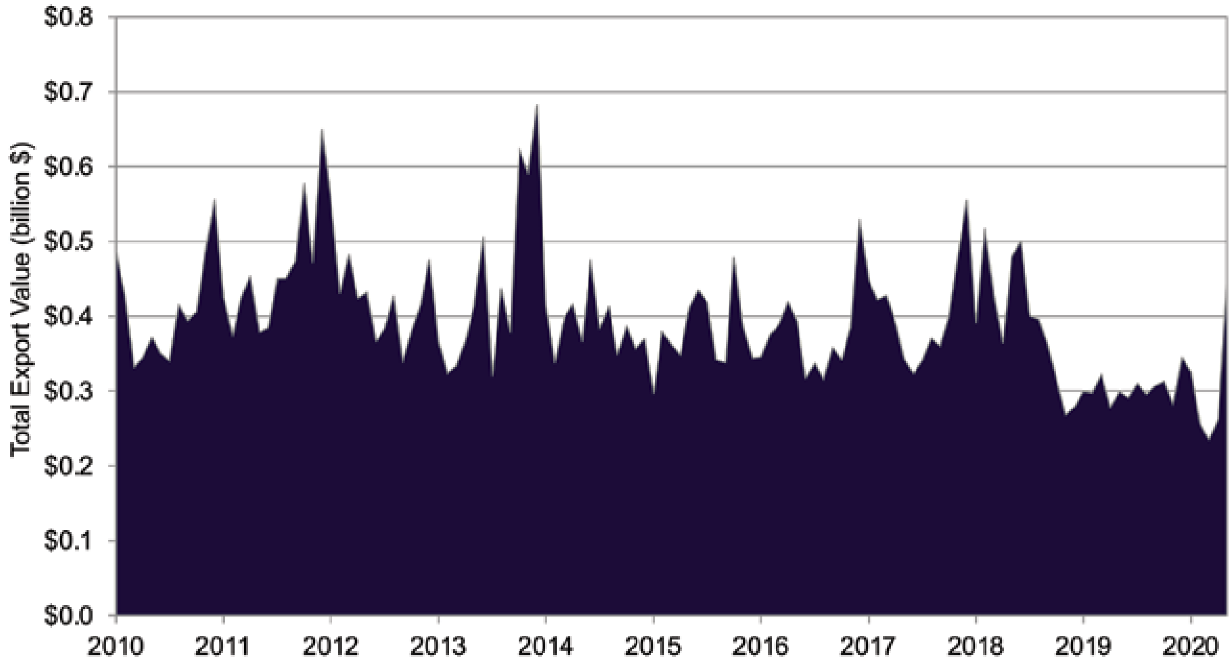


Source: Swift, K. U.S. Chemical Outlook. The Future of South Louisiana Industry 2020 Business Report Power Breakfast. June 9, 2020.
Note: Author's estimate from source. ACC is American Chemistry Council.

An additional important takeaway from the above chart is the degree to which excess U.S. chemical industry capacity is burnt off as the world's economy attempts to claw back from the considerable economic contraction of 2020. Just in the U.S. alone, statistics suggest as much as 50 million tons of excess capacity, a level not seen since the last recession; however, interestingly, the excess U.S. chemical production capacity of 2008-2009 itself quickly evaporated as Asia and other developing economies recovered from the last recession. Thus, there is some optimism this trend could occur over the next year.

The pandemic was not the only challenge faced by the U.S. chemical sector. The 2020 GCEO highlighted the considerable uncertainty created by Sino-U.S. trade disputes. Figure 23 underscores the anticipated weakness that these trade imbroglios have had on U.S. chemical industry exports. For instance, 2019 Gulf Coast chemical industry exports to China were down by as much as 25 percent relative to 2018. Gulf Coast chemical industry exports fell another 23 percent in early 2020 as the pandemic and the associated economic lock downs arose. While regional chemical industry exports to China have rebounded, they have only recovered to pre-pandemic levels, not those seen in 2018 before the trade disputes arose.

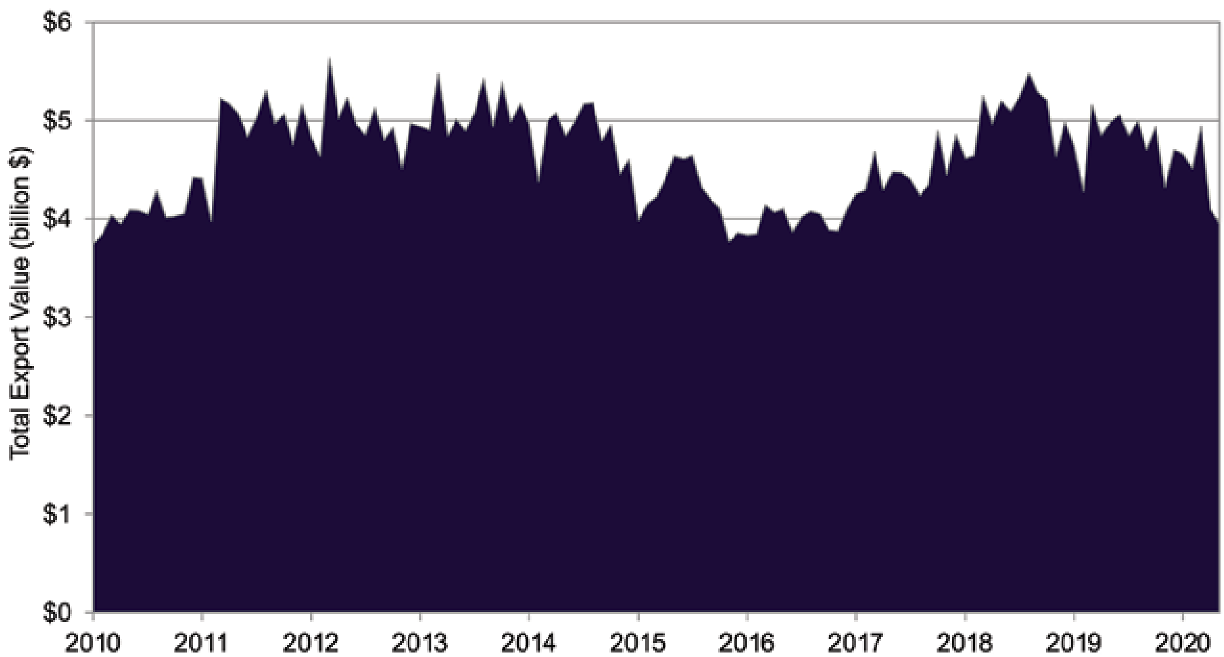
Figure 23: Gulf Coast chemical exports to China



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

Figure 24 provides additional evidence that the China-U.S. specific trade disputes undermined trade between the two countries, but that had limited impacts on Gulf Coast chemical industry trade elsewhere. Regional chemical industry exports to the rest of the world, for instance, appear to have remained relatively constant, and at generally high levels, throughout 2019. Export volumes to the rest of the world, however, have fallen precipitously during the early part of 2020 and are yet to rebound.

Figure 24: Gulf Coast chemical exports to rest of world



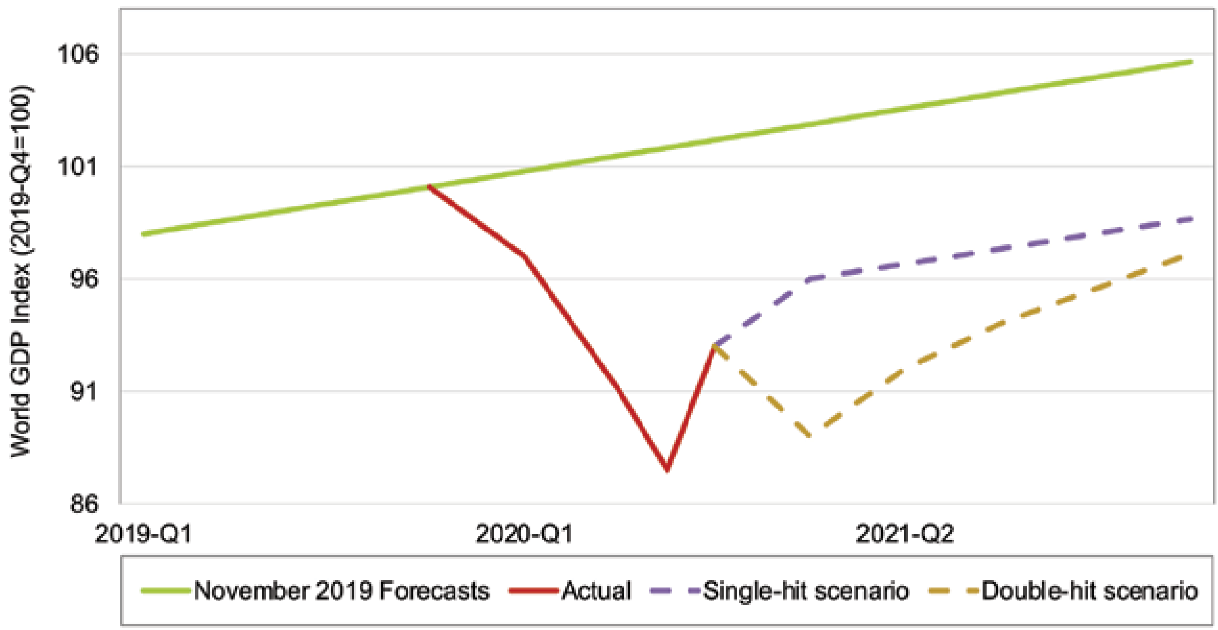
Source: U.S. Census Bureau, Economic Indicators Division, USA Trade Online.

5.2 Energy Manufacturing Outlook

The outlook for energy manufacturing over the next 24 months will be largely dependent upon the degree to which the global economy rebounds from the current pandemic. At year's end 2020, there still remains a considerable degree of uncertainty about the staying power of the current pandemic and its lagging impacts on global economic activity.

For instance, Figure 25 provides recent economic growth projections for major world economies through 2024. The projections, developed by the Organization for Economic Co-operation and Development (OECD), show last year's projected GDP growth compared to a very different picture today. The path to recovery is highly uncertain. Should a second wave of shutdowns be avoided, the OECD anticipates a six percent decrease in global GDP. A second wave however, with renewed lock-downs, would mean a further decline in world GDP of 7.6 percent. In either scenario, recovery will be slow. This does not bode well, at least in the near term, for regional chemical industry growth that is highly dependent upon global trade as an engine of economic growth.

Figure 25: Collapse in output followed by a slow recovery



Source: OECD Economic Outlook No.107, October 6, 2020.

Second, as seen earlier in Figure 22, there is a considerable excess capacity overhang that the American Chemistry Council (ACC) believes will not be worked off until 2022. However, this forecast assumes a relatively quick "v-shaped" type of global economic recovery that is becoming increasingly more questionable. While the ACC anticipates a relatively quick convergence between production and capacity, the excess even in 2022 is larger than past years. For instance, the excess chemical production capacity for the 2015-to-2019 time period was around 12 percent (14.7 million tons), whereas excess capacity for the 2022-to-2024 time period is forecast to be around 20 percent (27.8 million tons).

Table 6 presents the 2021 GCEO baseline outlook for energy manufacturing and LNG facility development in the region. This baseline outlook, like the one included in last year's GCEO, is based upon total investment announcements in the region and is broken down by investment type (LNG, non-LNG) and Gulf Coast state. None of these project announcements have been "scrubbed" or discounted in any way relative to their original announcements. In some instances, commercial operation dates (CODs) have been moved to accommodate continued development on a time horizon consistent with the original announcement. Thus, this baseline can be thought of as a "book-end" of total energy related capex that could arise in the region through 2029.

Table 6: Total GOM investment, all project announcements

Year	Texas		Louisiana		Other GOM		Total GOM	
	LNG	Non-LNG	LNG	Non-LNG	LNG	Non-LNG	LNG	Non-LNG
	(million $)							
2020	3,416	7,910	5,445	3,270	-	-	8,861	11,180
2021	4,234	13,407	15,016	5,545	-	-	19,250	18,953
2022	6,024	4,081	23,429	5,555	33	-	29,486	9,636
2023	6,755	253	25,255	2,142	1,321	-	33,331	2,395
2024	8,040	-	13,303	1,241	4,038	-	25,380	1,241
2025	3,905	-	3,126	434	2,394	-	9,425	434
2026	336	-	2,305	1,835	213	-	2,855	1,835
2027	-	-	1,421	3,506	-	-	1,421	3,506
2028	-	-	412	2,785	-	-	412	2,785
2029	$ -	$ -	$ 29	$ 908	$ -	$ -	$ 29	$ 908
Total	**$ 32,710**	**$ 25,652**	**$ 89,741**	**$ 27,220**	**$ 8,000**	**$ -**	**$ 130,451**	**$ 52,872**

The current baseline of energy manufacturing and LNG export facility investments is $183 billion or $18.3 million per year, on average. This total period investment is down relative to last year's 2020 GCEO baseline of $195 billion. Most of the investment is tied to LNG export facilities (71 percent) with the balance in a variety of energy manufacturing projects. Most of the currently announced projects are anticipated to occur in Louisiana ($117 billion or 64 percent) relative to Texas ($58 billion or 32 percent) and the rest of the GOM states ($8 billion or 4 percent).

Table 7 presents the 2021 GCEO outlook for energy manufacturing and LNG export facility development. This outlook differs from the "baseline" capital investment announcement provided above in that it removes projects that are unlikely to be developed in the near future given: (a) their already long development profile or failure over multiple development years to attain a final investment decision (FID); or (b) their unlikelihood to be developed given near term economic conditions.

Table 7: Total GOM investment, new baseline outlook

Year	Texas		Louisiana		Other GOM		Total GOM	
	LNG	Non-LNG	LNG	Non-LNG	LNG	Non-LNG	LNG	Non-LNG
	(million $)							
2020	3,372	7,131	3,628	2,550	-	-	6,950	9,682
2021	3,631	7,716	9,262	1,169	-	-	12,893	8,884
2022	4,159	2,912	14,303	2,411	-	-	18,462	5,323
2023	1,665	5,491	10,577	3,242	-	-	12,241	8,733
2024	130	1,298	3,692	2,594	-	-	3,822	3,892
2025	214	899	293	506	-	-	508	1,404
2026	2,247	215	-	687	-	-	2,247	903
2027	538	-	-	3,132	-	-	538	3,132
2028	-	-	-	3,909	-	-	-	3,909
2029	$ -	$ -	$ -	$ 1,565	$ -	$ -	$ -	$ 1,565
Total	**$ 15,905**	**$ 25,663**	**$ 41,755**	**$ 21,764**	**$ -**	**$ -**	**$ 57,660**	**$ 47,427**

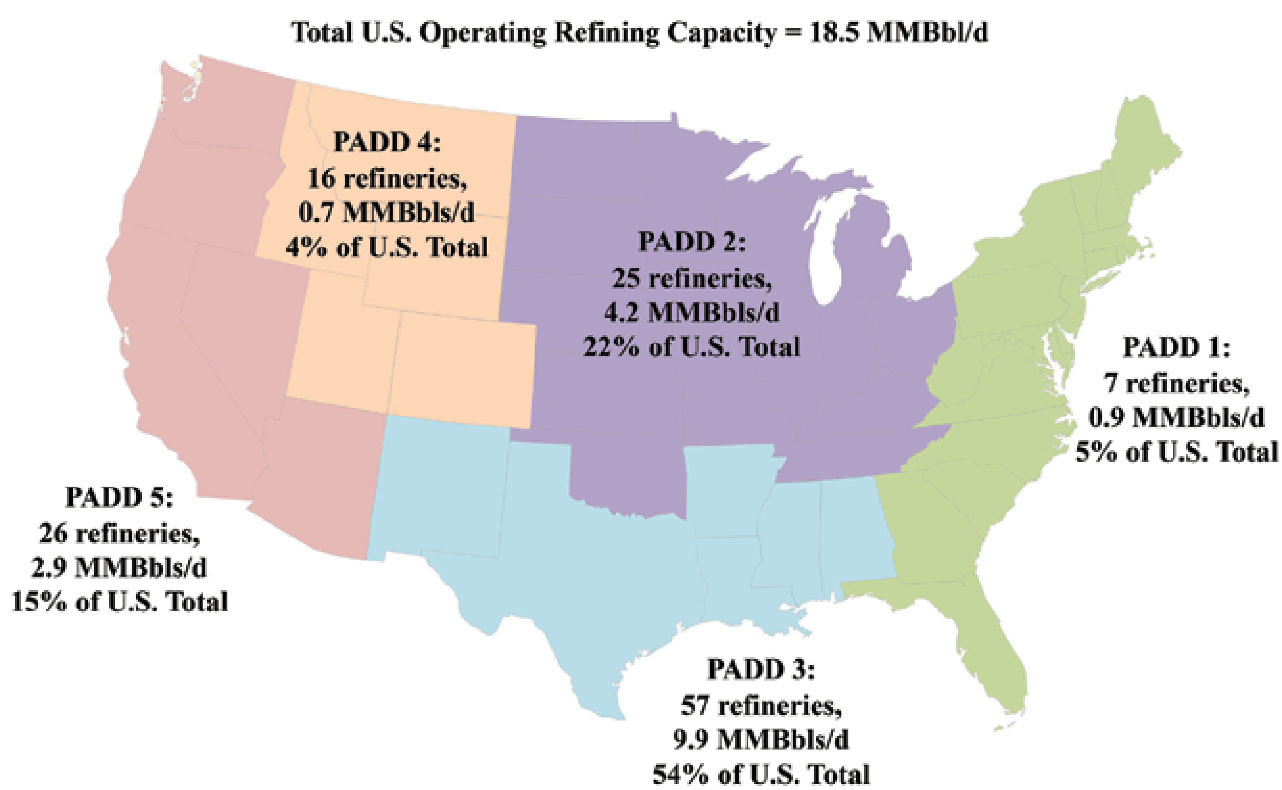
The 2021 GCEO energy manufacturing investment outlook, until the year 2029, totals $105 billion. This investment is comprised of $58 billion in LNG investments (55 percent) and $47 billion (45 percent) in energy manufacturing investments (non-LNG). Most of the total investment will be in Louisiana ($63.5 billion or 60 percent), followed by Texas ($41.5 billion or 40 percent).

6. Energy Exports

6.1 Recent Trends: Refined Product Export

The Gulf Coast region is the single largest region in the U.S. for refined product capacity and output. As shown in Figure 26, the region accounts for 54 percent of all refining capacity and is interconnected into a variety of input and refined product pipelines. In addition, these refineries are integrated either directly or indirectly with various hydrocarbon pipelines (such as liquefied petroleum gas or LPG) that move these commodities to chemical plants where they are converted into a number of intermediate commodity chemicals that, in turn, are shipped all around the world. Hence, the refineries in the Gulf Coast region are some of the most efficient and profitable in the U.S. and in some instances around the world.

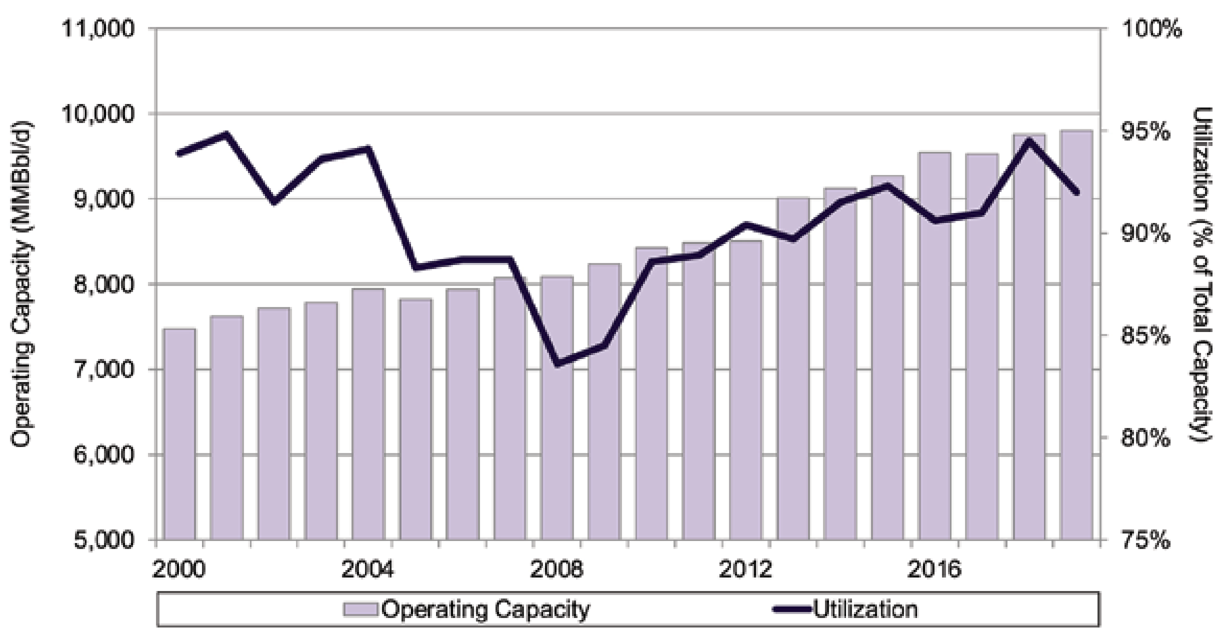
Figure 26: Number and capacity of U.S. refineries



Source: U.S. Energy Information Administration. Author's calculations from Form EIA-820.

The last year has been particularly hard on U.S., refineries including those located along the Gulf Coast. The year started out with growing capacity and high utilization rates. The 2020 GCEO expected continued, but slower, capacity creep and efficiency gains. The slow-down in efficiency was attributed to a slowing economy in Asia and the need for middle-distillate exports; however, despite this anticipated slowing, refineries were expected to maintain high capacity and utilization levels. The pandemic, however, changed expectations dramatically. Figure 27 shows capacity growth and utilization for the Gulf Coast regional refineries on an annual basis that reflects the 2020 GCEO projections.

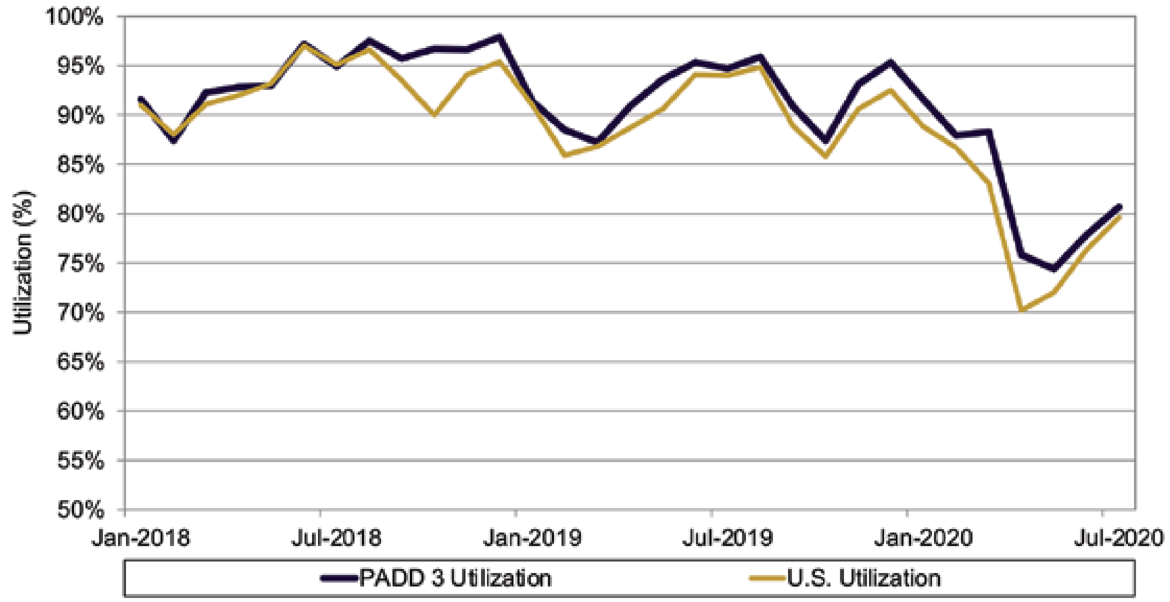
Figure 27: PADD 3 refining capacity and utilization



Source: U.S. Energy Information Administration. Petroleum & Other Liquids. Refinery Utilization and Capacity.

Figure 28 provides a more granular analysis of refinery utilization over the past 24 months for PADD 3 (Gulf Coast) and the U.S. overall. The chart offers a number of important take-aways about the pandemic's impact on refined product markets. First, the impacts of the pandemic were tremendous on regional and U.S. refined product output. Output peaked for both the U.S. and PADD 3 in February 2020, only to fall precipitously in the spring months as the U.S. and global economy went into a shut down. U.S. refinery utilization fell to 70 percent in April 2020 which was an all-time low. Similarly, PADD 3 refinery utilization fell to 74 percent in May 2020. PADD 3 output, however, was much more resilient than other regions and the U.S. average. And, U.S. refinery utilization even in the last available month of information (July 2020) still lags PADD 3. But, both U.S. and PADD 3 utilization levels still far lag their pre-pandemic levels.

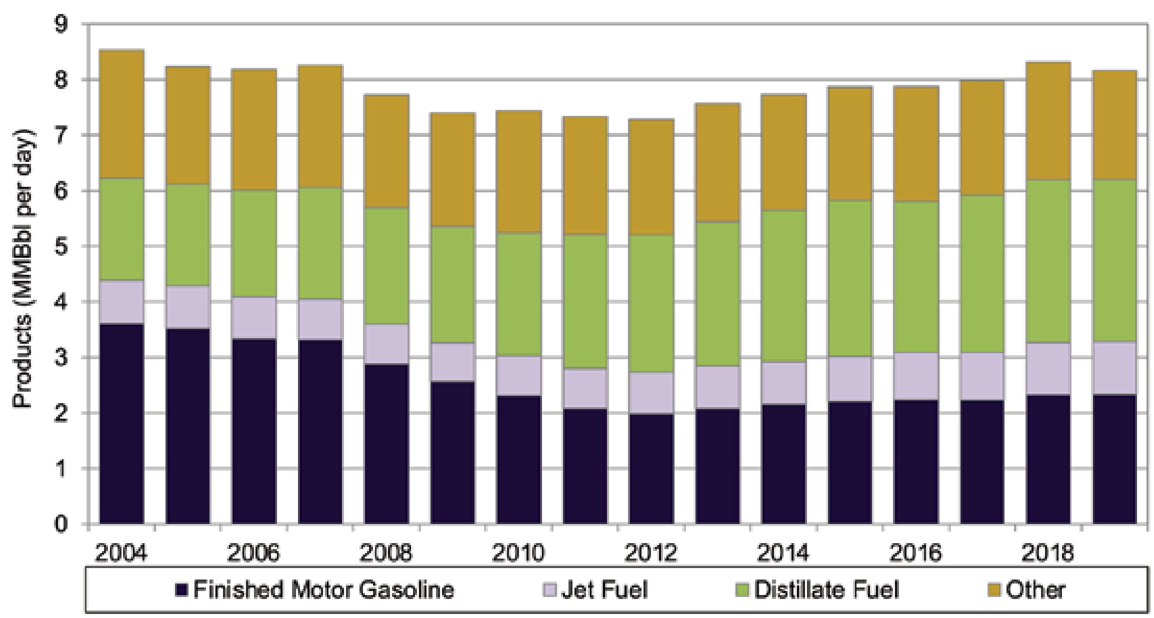
Figure 28: Monthly PADD 3 and U.S. refining utilization



Source: U.S. Energy Information Administration. Petroleum & Other Liquids. Refinery Utilization and Capacity. Percent Utilization of Refinery Operable Capacity.

The 2020 GCEO noted the changes occurring in Gulf Coast refinery output over the past several years. Since the last recession, the Gulf Cost refinery output slate, on average, has seen an increasing concentration of output being dedicated to middle distillates (such as diesel and heating oil) and increasingly less on finished motor gasoline. Further, much of this middle distillate output has been dedicated to increasing exports. The 2020 GCEO anticipated that these trends would continue into the short-term forecast period (2020 to 2022). Figure 29 shows these annual trends and their continuation into 2019.

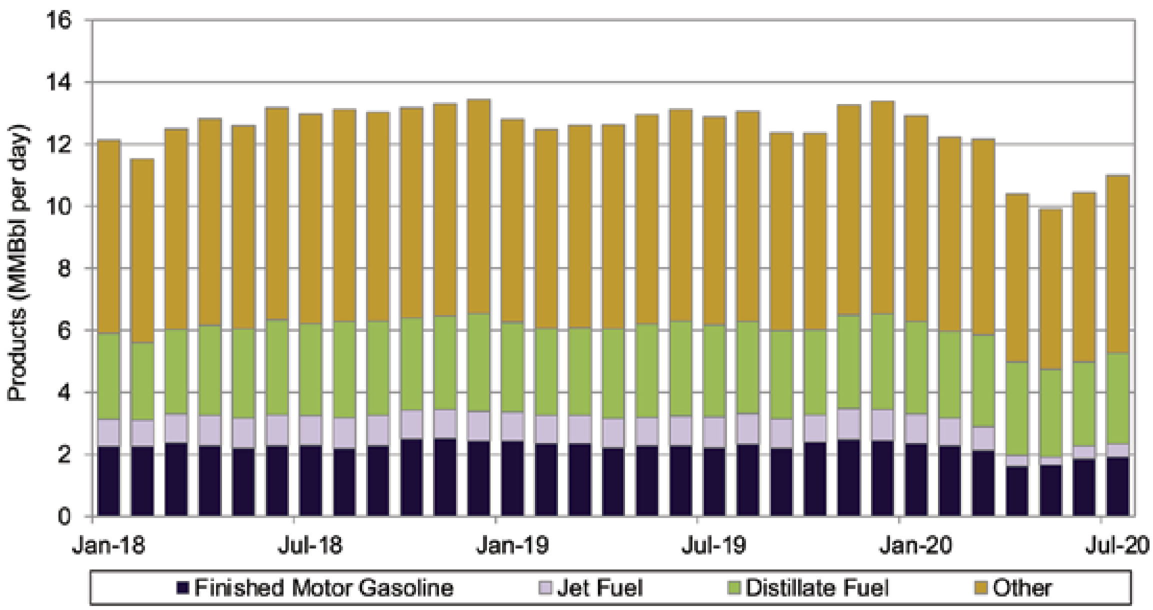
Figure 29: PADD 3 petroleum product supplied



Source: U.S. Energy Information Administration. Petroleum & Other Liquids. PADD 3 Refinery & Blender Net Production.

The COVID-19 pandemic has had equally important impacts on the shift in PADD 3 output slate. Figure 30 shows the monthly output for the Gulf Coast region over the most recent 24 months of available data. First, as noted earlier, overall output is down precipitously, and down across all refined product types. Second, middle distillates have taken an exceptionally large hit due to the pandemic, including the separately reported jet fuel slate that is virtually non-existent in the more recent months of data. Third, all output types are still far below their pre-pandemic levels. While finished motor gasoline has recovered the most (82 percent of pre-pandemic levels), distillates of all types are down considerably.

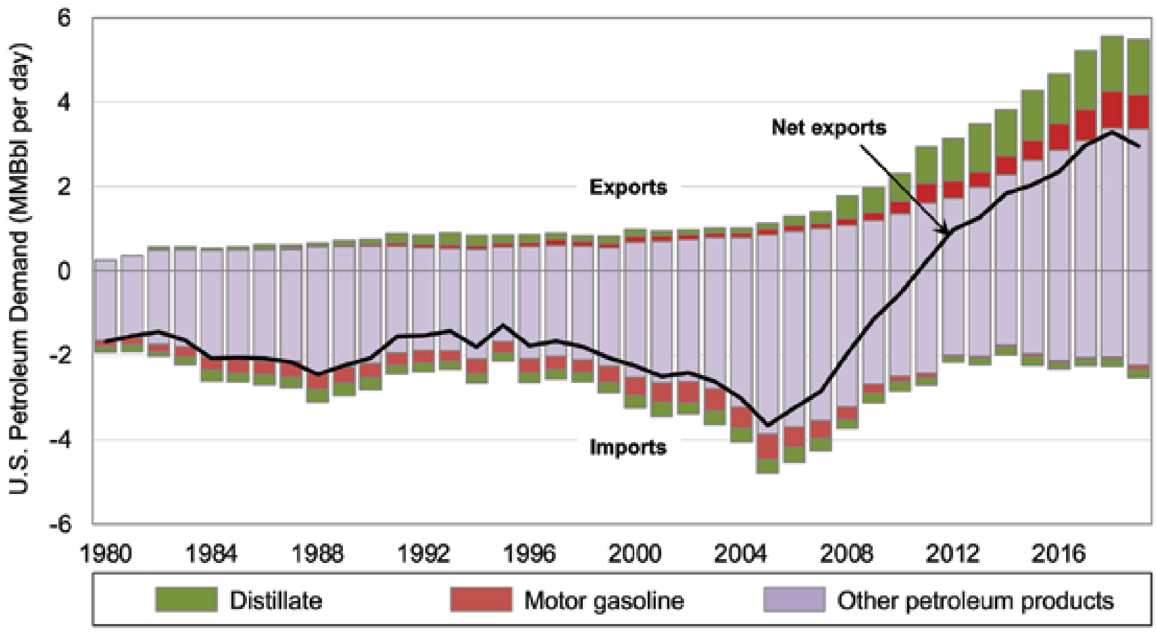
Figure 30: Monthly PADD 3 petroleum product supplied



Source: U.S. Energy Information Administration. Petroleum & Other Liquids. PADD 3 Refinery & Blender Net Production.

The 2020 GCEO also noted continued strength in refined product exports, mostly attributable to growth in middle distillates and other petroleum products. Shown in Figure 31, U.S. refined product exports have been growing rapidly since the U.S. became net exporter. These trends continued through 2017 and 2018 but began to slow in 2018 as trade pressures with China began. This slowdown in refined product exports continued into 2019, even though overall exports were still at records levels of around three MMBBl/d.

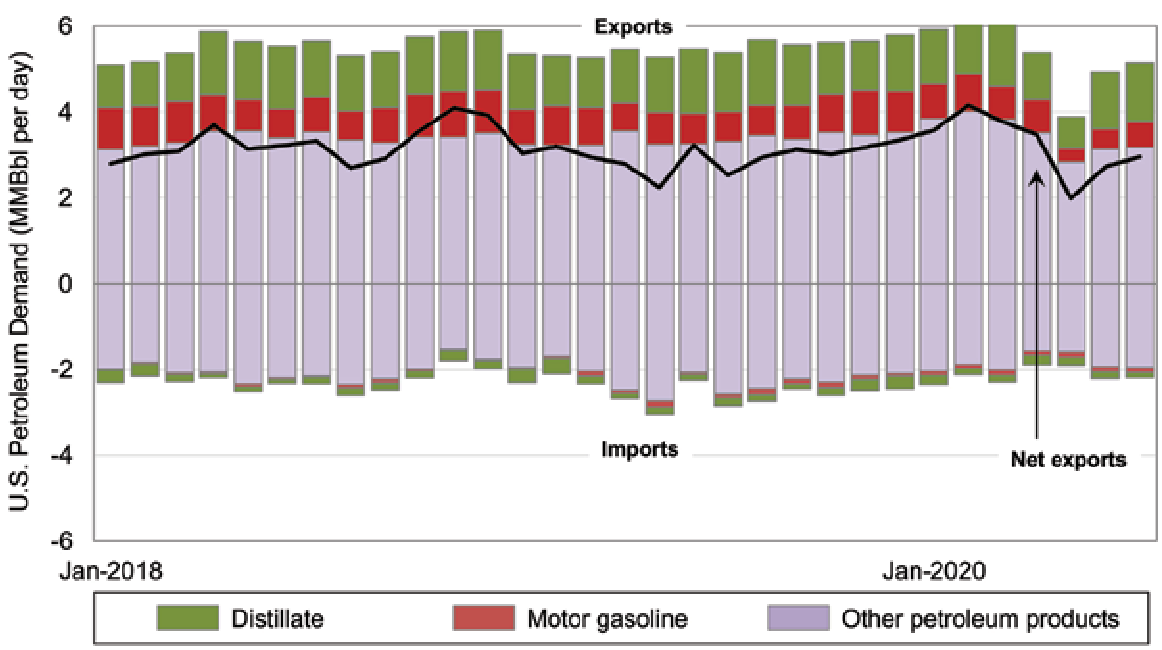
Figure 31: U.S. petroleum product imports and exports



Source: U.S. Energy Information Administration. Petroleum & Other Liquids. U.S. Imports and Exports of Crude Oil and Petroleum Products.

The pandemic, however, has had a considerable impact on U.S. refined product exports. Figure 32 provides more contemporaneous monthly data on total U.S. refined product volumes. Overall, the U.S. is still a net refined product exporter. Those exports, however, have fallen by as much as 47 percent and, in the most recently-reported month, stood at 2.9 MMBbl/d.

Figure 32: Monthly U.S. petroleum product imports and exports

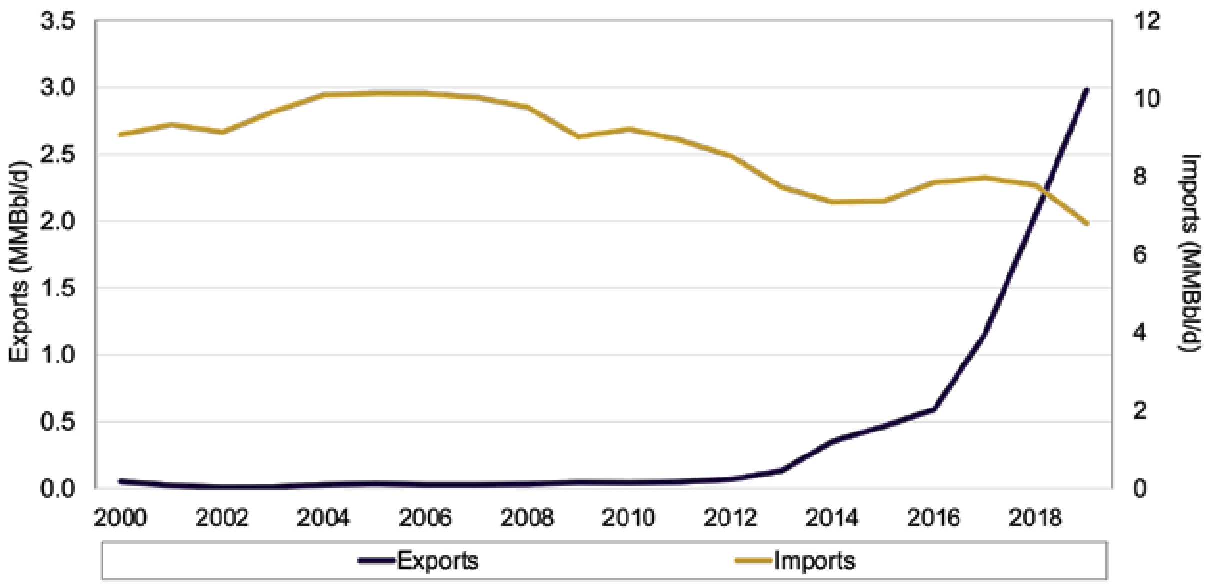


Source: U.S. Energy Information Administration. Petroleum & Other Liquids. U.S. Imports and Exports of Crude Oil and Petroleum Products.

6.2 Recent Trends: Crude Oil Exports

The Gulf Coast has become a leading export center in the U.S. ever since the 40-year ban on crude oil was lifted at the end of 2016. Prior to the pandemic, close to 85 percent of all U.S. crude oil exports left a GOM port, primarily Corpus Christi, Houston, and the Louisiana Offshore Oil Port (LOOP). The 2020 GCEO anticipated continued strength in this sector of the region's energy economy with 2020 exports growing to around 3.0 MMBbl/d and 2021 crude oil exports growing rapidly, and peaking at around 3.5 MMBBl/d. As Figure 33 shows, the 2019 export figures are close to the 3.0 MMBbl/d mark.

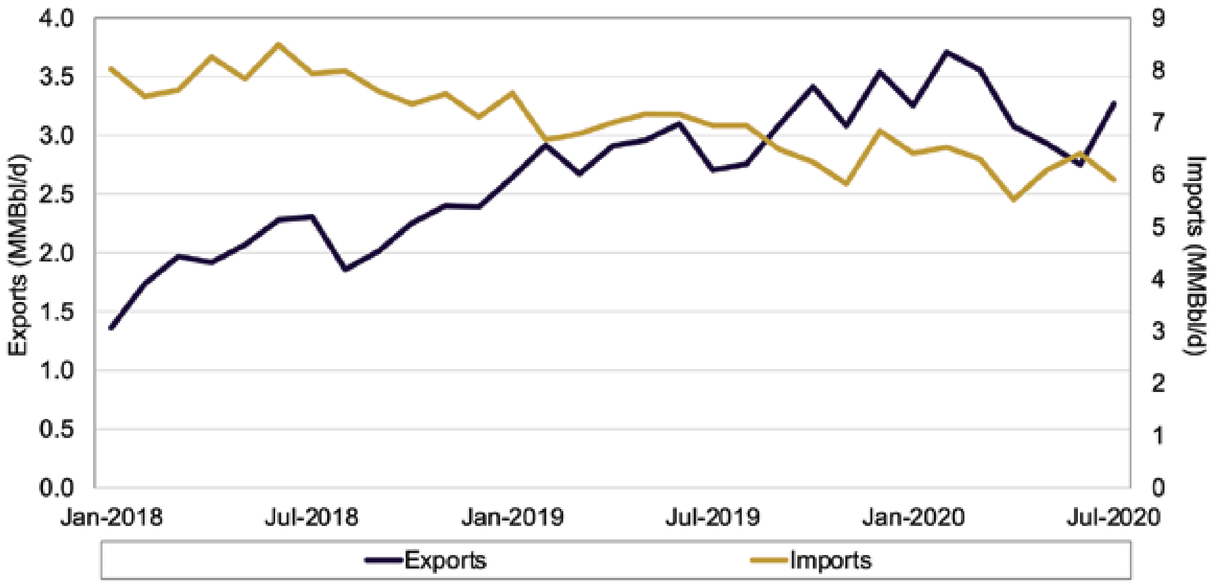
Figure 33: U.S. crude oil exports and imports



Source: U.S. Energy Information Administration. Petroleum & Other Liquids. U.S. Imports and Exports of Crude Oil.

While the global pandemic has negatively impacted U.S. exports, overall volumes have been somewhat resilient over the past several months. For instance, year-end and early 2020 export numbers were in line with the prior GCEO forecast, if not slightly greater. Shown in Figure 33, export volumes, however, fell with the global economic shut down and corresponding lock downs that reduced overall refined product, and ultimately crude oil demand. To date, exports have rebounded from their summer lows, but are still only 85 percent of their February 2020 high volumes.

Figure 34: Monthly U.S. crude oil exports and imports



Source: U.S. Energy Information Administration. Petroleum & Other Liquids. U.S. Imports and Exports of Crude Oil.

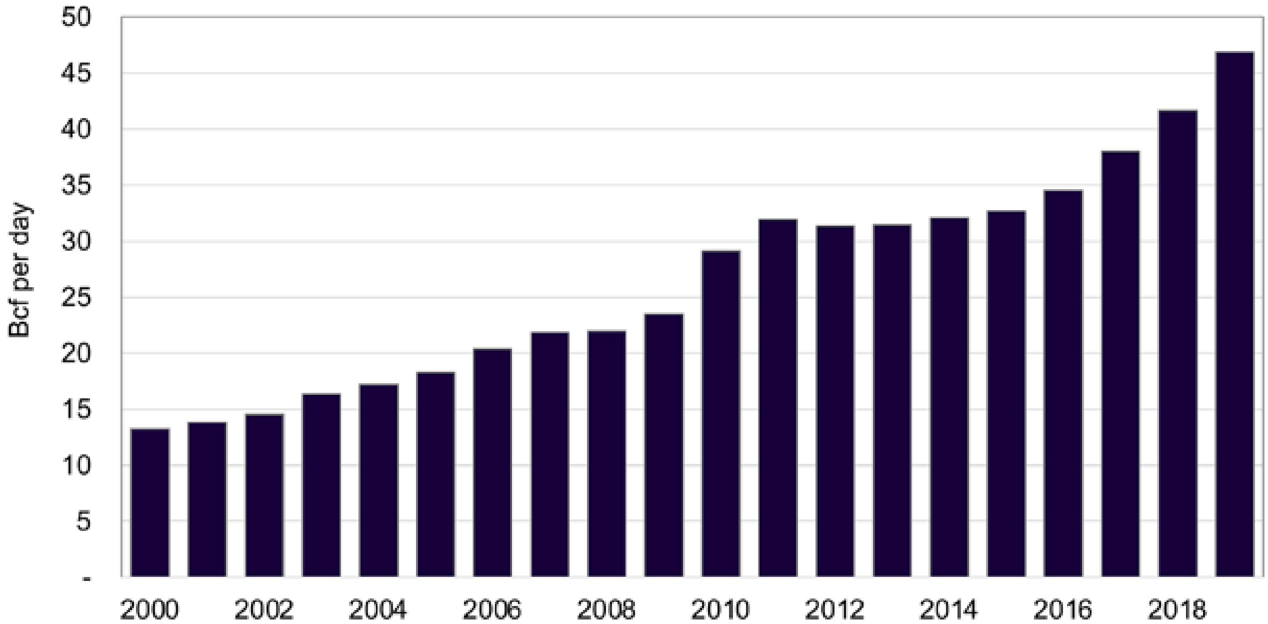
6.3 Recent Trends: LNG Exports

In 2005, high natural gas prices put a good part of the region's manufacturing industries in an existential crisis. Natural gas, as noted earlier, is a key feedstock for the Gulf Coast's petrochemical industry. Increasing costs after Hurricane Katrina forced a considerable amount of petrochemical production to be relocated to other parts of the world that relied more heavily on what was then relatively lower priced crude oil-based feedstocks. Capital investments in the U.S. during this period hit all-time lows. The saving grace for the industry during this time appeared to rest with the development of a number of very capital intensive LNG import facilities that were designed to vaporize (or "re-gas") liquid fuel and inject it into the Gulf South natural gas pipeline network.

Years later, the unconventional revolution and the production of abundant, low cost natural gas, completely turned around these challenging conditions to a point where the U.S. has become a net exporter of natural gas. All of the GOM facilities that were originally designed to import natural gas have now all been converted through expansive investments to export facilities. This is usually done through the addition of expensive liquefaction investments that cool natural gas to -260 degrees Fahrenheit. Over the past eight years, export volumes from these GOM facilities, as well as many others around the world, have grown considerably.

Figure 35 highlights the considerable growth of the LNG market since the last global economic recession. LNG trade volumes for 2010, for instance, show a considerable "shift change" in export volume trends that have continued over the past decade. In fact, LNG trade volumes have grown at a healthy clip of 6 percent per year over the past decade alone with 2019 reporting a record level of over 45 Bcf/d.

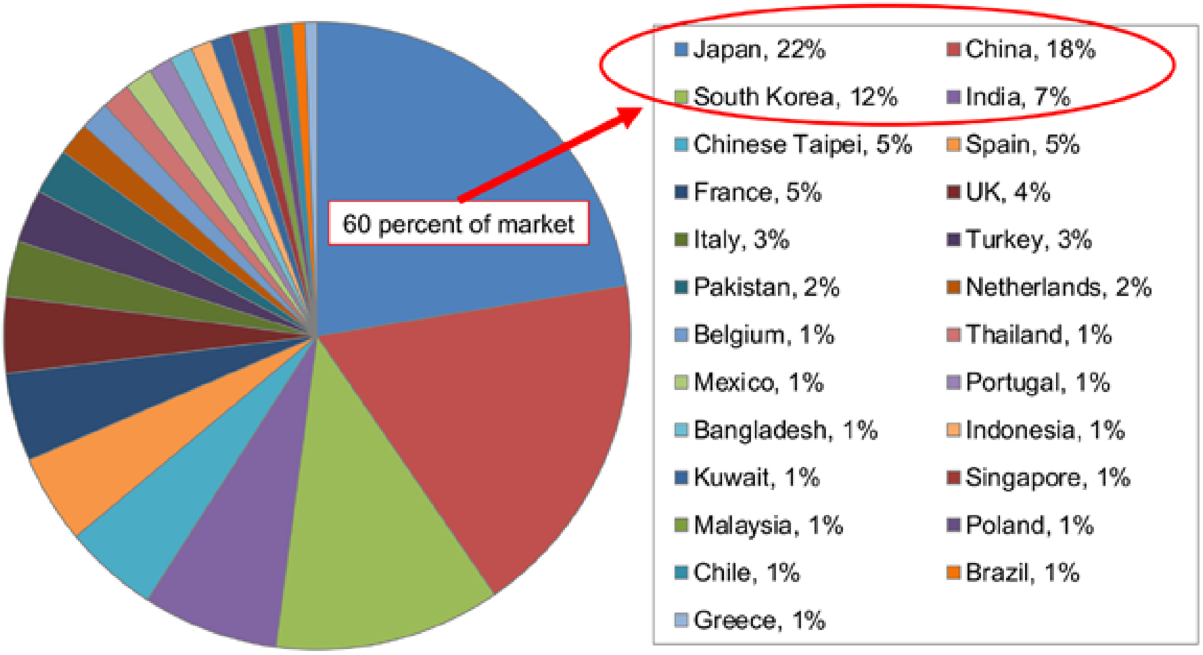
Figure 35: World LNG trade volumes



Source: BP Statistical Review of World Energy.

As shown in Figure 36, currently, the market share for LNG imports is dominated by Asian countries. Japan, is currently the largest global LNG importer and has a long historic relationship with LNG trading that dates back to early imports from the Kenai LNG facility in Alaska that provided natural gas volumes to the Tokyo Electrical Power Company (TEPCO) and Tokyo Gas Company. China follows closely as the second largest importer followed closely by South Korea and India. These four countries, collectively, account for 60 percent of all currently traded LNG volumes.

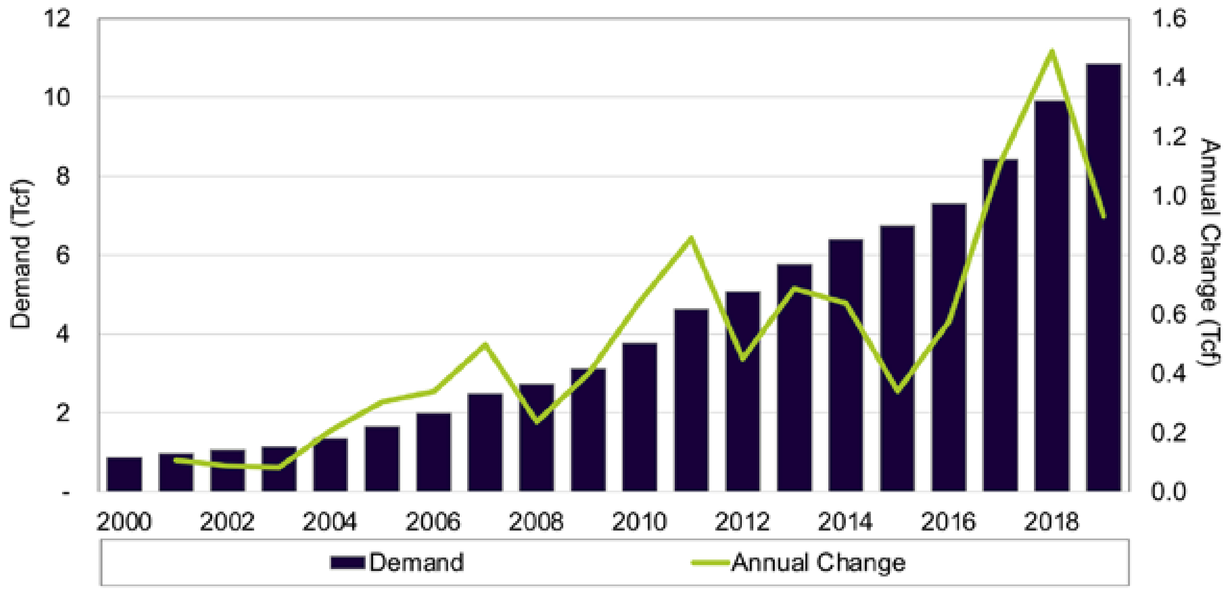
Figure 36: LNG imports and market share by country, 2019



Source: International Gas Union, 2019 World LNG Report.

While China ranks “second” in terms of imported LNG volumes, it is one of the fastest growing countries for LNG volumes and will likely outpace, and then substantially exceed, Japanese volumes within the next few years. Figure 37, for instance, shows the annual changes in Chinese natural gas demand, a large part of which is met through international LNG imports. That demand, totaling 10 Tcf per year, is growing at rates that over the past three years have been at or above 1 Tcf per year. The growth rate over the past five years alone is around 70 percent.

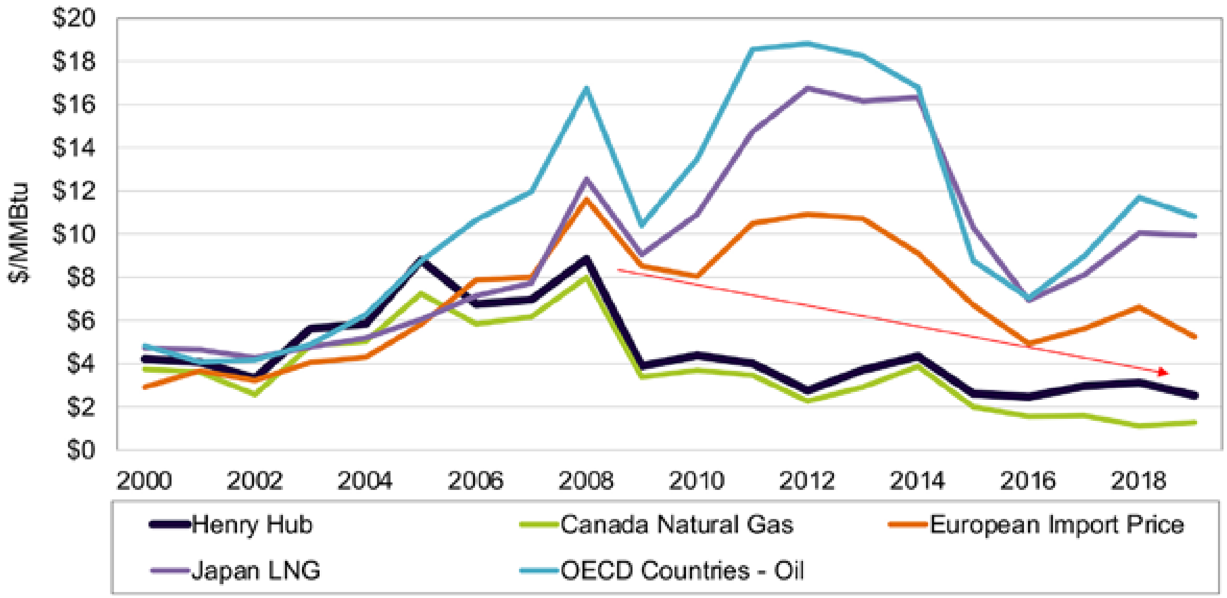
Figure 37: China's natural gas demand



Source: U.S. Energy Information Administration. Country Analysis: China. September 2020. Figure 4. China's dry natural gas production and consumption, 2000-2019. And author's calculations.

Some concerns have been expressed about U.S. natural gas commodity prices increasing to meet global prices as international natural gas markets become more integrated through LNG trade. Figure 38, for instance, shows the trends in global natural gas prices over the past two decades. The Henry Hub price, the primary benchmark used for natural gas pricing in the U.S., has remained relatively low and flat since the past recession (2008-2009). Interestingly, the high prices seen in places like Western Europe (OECD countries) or Japan have fallen to levels closer to the Henry Hub price, not vice versa. So, while the "law of one price" may appear to be working, it has been working in a direction that has seen world prices fall to levels more comparable to those in the U.S.

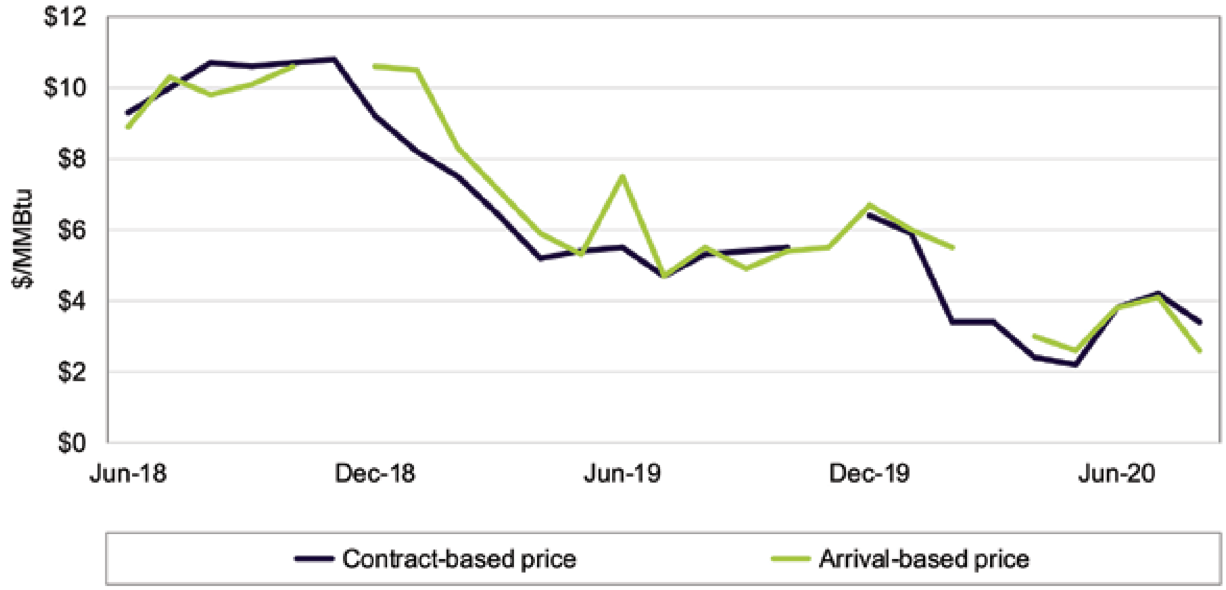
Figure 38: World energy prices



Source: World Bank Commodity Price Data.

LNG markets have been impacted by the recent pandemic and these negative impacts are likely to continue for the next several years. Like spot crude oil prices over the past spring, Asian spot prices for natural gas cargoes have fallen to levels that are almost unbelievable. Figure 39 provides the recent trends on the Japan Korean Marker (JKM) price that plummeted to a record low of around $2.00 per MMBtu in May 2020. JKM prices have tried to rebound since that time, moving up to around $4.00 per MMBtu during the summer, but are moving their way back down to $2.00 as the year ends. Prices this low make it difficult to justify moving cargoes from the U.S. to Asian economies, where natural gas priced at the Henry Hub is higher.

Figure 39: Japan spot LNG price



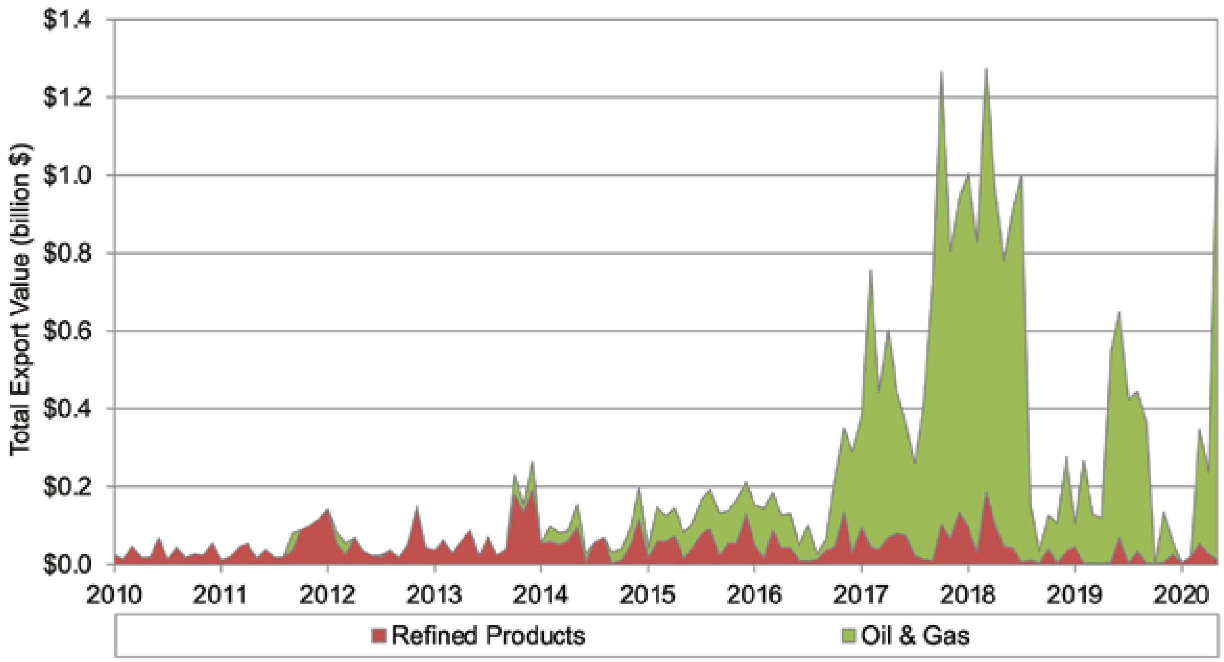
Note: "Spot-LNG" refers to LNG that are traded on a cargo-to-cargo basis and does not mean term contracts of LNG (so-called "long," "medium," "short-term" contracts). In addition, spot-LNG, the price of which is linked to a particular price index (for example the Henry Hub link, and the JKM link), is excluded from these statistics. Objects of these statistics are spot-LNGs, the prices of which are determined at the time of contract (so-called "fixed price").

Source: Japanese Ministry to Economy, Trade and Industry. Spot LNG Price Statistics. Commodity Market Office. Commerce and Service Industry Policy Group, METI.

6.4 Outlook: Refined Product Exports

The refined product outlook for the next several years will be highly dependent upon the gradual winding down of the current pandemic threat and the economic recovery from the 2020 economic shutdowns. At year-end 2020, China's economy appears to be recovering strongly from its prior COVID-19-related contraction. In fact, China has seen a considerable level of crude oil and refined product imports over the past several months. Those increased crude oil and refined product imports from the GOM alone are clearly visible in Figure 40.

Figure 40: Gulf Coast exports to China



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

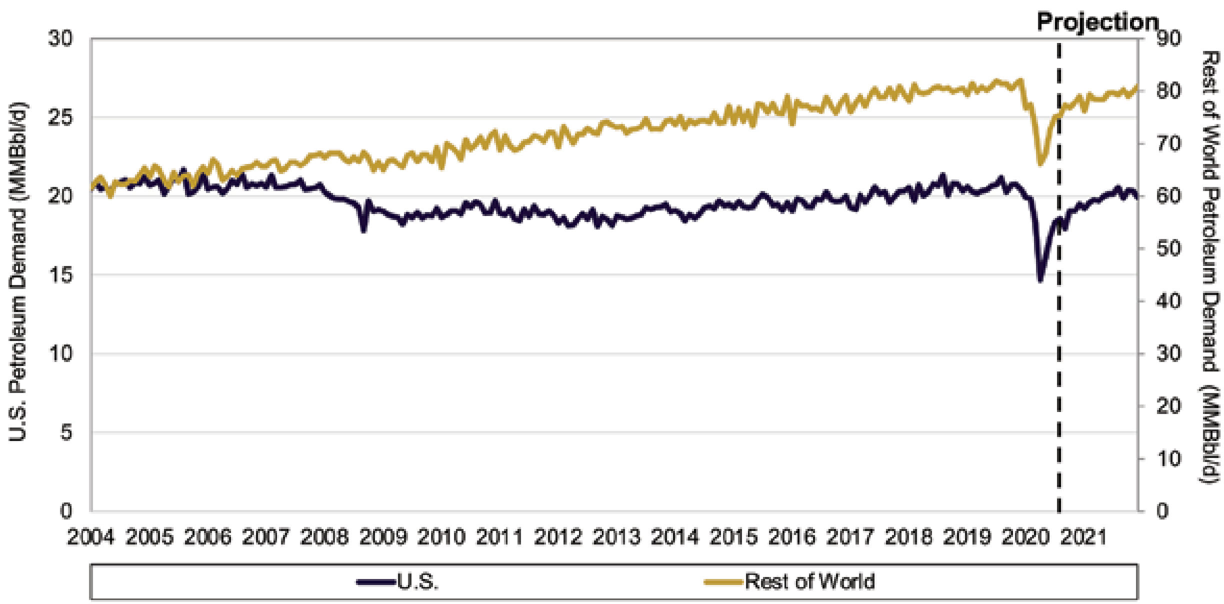
The 2020 GCEO anticipated relatively stable refined product growth over the 2020-2022 time period. Liquid fuel demand at that time was still anticipated to rise, but at slower rates than prior years. Most of this growth was anticipated to be generated by Asian and other developing economies with little arising from OECD countries and the U.S. The outlook for liquid fuel demand, however, has become much more difficult to gauge given the massive disruptions in economic activity and traveling habits of countries all around the globe.

Some of the COVID-19-related impacts on liquid fuel demand have been unambiguous. Consider that the demand for jet fuel has suffered tremendously since a virtual cessation of most air travel around the globe. While air travel has picked up from lows during the earlier part of the year, most airlines anticipate exceptionally low travel volumes for at least the next two years. This will clearly result in considerably lower jet fuel demand for the foreseeable future.

The impacts of the pandemic on future motor gasoline demand are a little more ambiguous. During the initial months of the pandemic in early 2020, motor gasoline demand was clearly lower: however, as economies around the globe started to return to work and economic activity, gasoline demand in some applications started to increase. Passenger vehicle demand for motor gasoline started to increase as individuals chose to use their own vehicles instead of public transportation. Further, in the early summer months of 2020, households opted for vacations that were drivable and within a day's travel, leading to some optimism that gasoline demand would make a comeback that ultimately stalled by Labor Day.

Thus, understanding where and how liquid fuel demand will go is difficult. What is likely is that the outlook for refined products will continue to be challenging for the next 24 months. Figure 41 below provides recent trends and outlook for liquid fuels prepared by the EIA. The chart shows the precipitous decline in petroleum demand due to the pandemic: as much as 6 MMBBl/d for the U.S. compared to a decrease of as much as 16 MMBBl/d for the rest of the world. While the EIA anticipates a recovery, both U.S. and global liquid fuel demand is anticipated to remain below 2019 levels through at least 2021.

Figure 41: U.S. and world petroleum demand

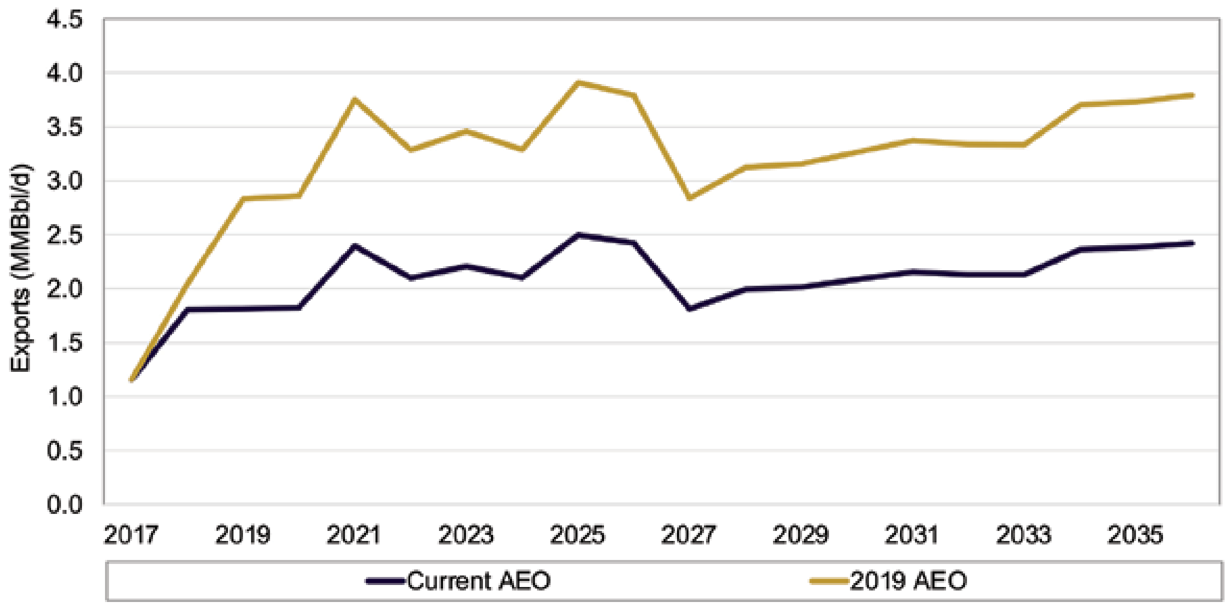


Source: U.S. Energy Information Administration. Short-Term Energy Outlook. October 2020.

6.5 Outlook: Crude Oil Exports

Figure 42 provides the most recent EIA Annual Energy Outlook (AEO) that forecasts likely U.S. crude oil exports over the next several decades. This forecast, which was completed in January 2020 prior to the pandemic, itself shows a considerable revision from the prior year outlook, which formed the basis for the 2020 GCEO. For instance, near term crude oil exports, even under the pre-pandemic AEO, are anticipated to be about 1 MMBBl/d lower in the 2020-to-2022 period relative to the prior year AEO. Additional weakening is likely due to carry-over impacts of the earlier pandemic-induced economic contractions, as well as any additional contractions that may arise due to the winter 2020-2021 and its corresponding flu season.

Figure 42: U.S. crude oil exports

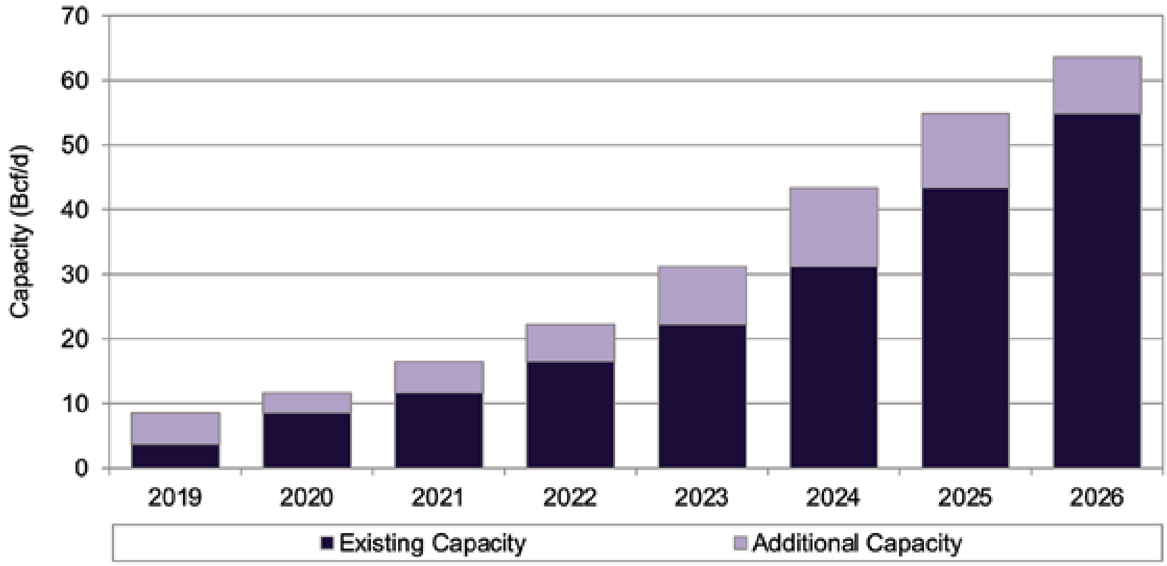


Source: U.S. Energy Information Administration. Annual Energy Outlook 2019 and 2020. Petroleum and Other Liquids Supply and Disposition. Liquid Fuels: Crude Oil: Domestic Production.

6.6 Outlook: LNG Exports

As noted earlier, the outlook for LNG exports is bleak. While Asian demand is making a resurgence, and China appears to be the bright spot in the overall global economy, there are simply too many molecules of natural gas chasing too little demand. Figure 43 presents an outlook of the potential U.S. LNG export capacity that could be developed based on current announcements about construction and commercial operation dates (CODs). This chart represents the "book-end" of potential regional LNG export facility development: the maximum amount that could arise based on currently projected timelines. This level of development, which sums to as much as 50 Bcf/d, or one-half of the total current U.S. natural gas market, is unlikely to arise, but it does put some perspective on the magnitude of LNG project announcements that is considerably higher than market needs, particularly in a post-pandemic world.

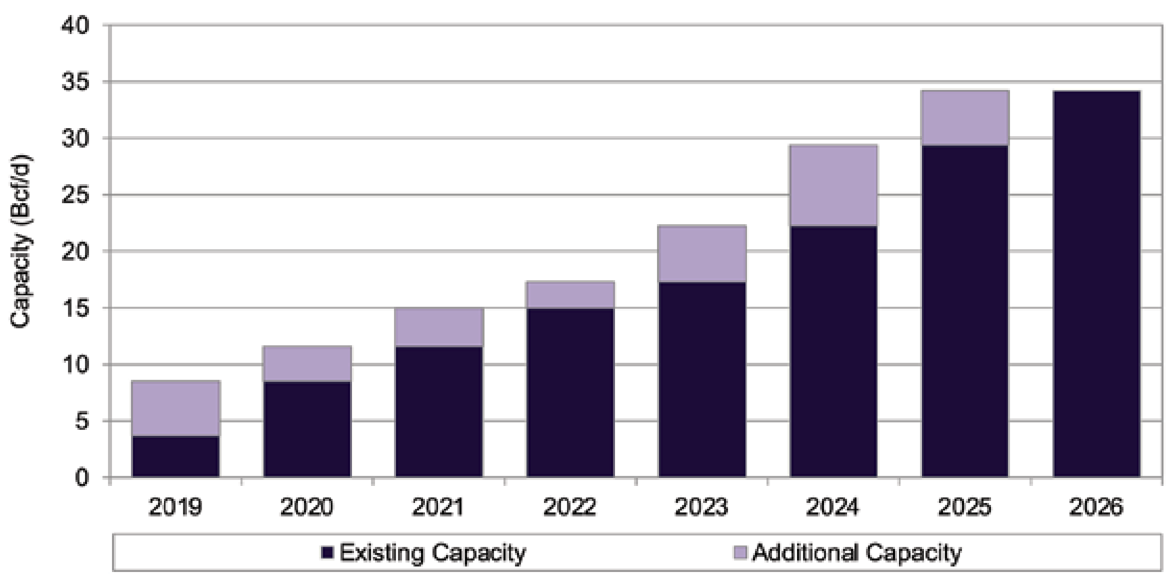
Figure 43: Existing and proposed U.S. LNG capacity development



Source: U.S. Energy Information Administration. Natural Gas. U.S. Liquefaction Capacity. Existing, under construction, and FID large scale U.S. liquefaction facilities.

Figure 44 provides a more likely scenario for LNG export facility development. This chart is based on the revised baseline analysis discussed earlier and is tied to the energy manufacturing investment outlook. This chart removes projects that have not reached FID or have been in the project development pipeline for a long time, with little to no physical or contractual development activity. Other projects, announced by large companies with some degree of financial commitment or prior LNG development experience, are moved out in their respective development timelines to accommodate the current glut of global LNG export capacity.

Figure 44: Revised existing and proposed U.S. LNG capacity development



Source: U.S. Energy Information Administration. Natural Gas. U.S. Liquefaction Capacity. Existing, under construction, and FID large scale U.S. liquefaction facilities and author's calculations.

The 2021 GCEO capacity forecast anticipates total LNG facility development of 34 Bcf/d an amount that is 46 percent lower than the "book-end" tally based on total project announcements. The 2021 GCEO anticipates as much as 8.5 Bcf/d of new capacity in 2021 and 11.6 Bcf/d of new capacity in 2022.

7. COVID-19 Impacts on Domestic Energy Demand

There are two sources of demand for energy and chemical products; exports and domestic demand. Exports were highlighted in Section 6. Next, three categories of domestic energy demand are highlighted. Specific focus will be given to short-term COVID-19 demand impacts. For each of these categories of energy demand, the percent change in monthly demand in 2020 relative to the same month in 2019 is presented. This will be instructive in understanding how demand reductions have impacted demand differently across the energy sector. Consistent with Table 2, these tables will show percent change by month in 2020 compared to the same month in the prior year (i.e. 2019) for apples-to-apples comparisons across energy sources. It is important to note that revisions to monthly data are common, and therefore these are likely not final. Nonetheless these comparisons are constructive for broadly understanding COVID-19 impacts on energy markets.

7.1 Electricity Demand

Table 8 shows electricity demand both for the entire United States and for the Gulf Coast region. Electricity demand is also broken out by customer class, including residential, commercial, and industrial customers.[21] Analysis of Table 8 reveals several insights.

First, electricity demand was initially negatively impacted due to COVID-19. Specifically, U.S. electricity demand was down 5.5 percent in March relative to the prior year, and Gulf Coast demand was down 1.3 percent in the same month. Thus, initially U.S. electricity demand was impacted more than the Gulf Coast. On a monthly percent basis relative to the prior year, May was the lowest demand for both the U.S. and Gulf Coast at 8.8 percent and 8.9 percent down respectively. But since the bottom in May, the U.S. has bounced back more quickly than the Gulf Coast, and on an annualized basis, Gulf Coast demand is down 4.3 percent relative to 2019, as compared to 3.8 percent for the U.S.

Second, though, there has been a compositional change in electricity demand. Perhaps unsurprisingly, residential demand has been up during COVID-19. On an annualized basis U.S and Gulf Coast residential electricity demand are up by 2.4 percent and 1.5 percent, respectively. Industrial demand has been impacted the most on a percent basis, with U.S. commercial electricity demand down 15.9 percent in its worse month (May). Commercial demand is also down on an annualized basis by 6.4 percent for the U.S. and 3.9 percent in the Gulf Coast.

Important to note related to our industrial outlook (see Section 5), Gulf Coast industrial electricity usage has seen the most persistent reduction of all. GCEO takes the view that the return of this industrial demand will be driven by demand for products globally that are exported from the Gulf Coast region, and less so by industrial facilities' ability to operate efficiently during COVID-19.

[21] Note that the sum of customer classes does not equal total demand due to smaller customer classes, such as transportation.

Table 8: Electricity demand

	Residential		Commercial		Industrial		Total Demand	
	Thousand GWh	Percent Change	Thousand GWh	Percent Change	Thousand GWh	Percent Change	Thousand GWh	Percent Change
Panel A: United States								
March	104.0	-7.6%	102.9	-4.2%	77.6	-4.4%	284.5	-5.5%
April	97.5	7.8	90.6	-11.5	69.6	-13.5	257.7	-5.7
May	105.4	5.1	93.4	-16.0	71.2	-15.9	270.0	-8.8
June	131.2	9.3	108.7	-6.1	75.2	-11.5	315.1	-1.8
July	166.9	8.5	126.0	-3.8	81.3	-10.4	374.2	-0.3
August	158.8	5.8	122.0	-6.7	82.6	-9.3	363.4	-2.3
Year to Date	1,000.2	2.4%	854.4	-6.4%	610.5	-9.2%	2,465.2	-3.8%
Panel B: Gulf Coast								
March	15.6	-4.2%	15.4	3.8%	16.9	-2.9%	47.9	-1.3%
April	14.9	9.4	14.1	-4.0	15.7	-10.5	44.7	-2.5
May	17.4	4.0	14.3	-14.0	15.4	-16.0	47.1	-8.9
June	22.7	3.8	17.2	-4.6	16.0	-15.6	55.9	-5.1
July	27.8	7.6	19.3	-3.1	16.6	-15.2	63.8	-2.5
August	27.8	1.8	19.1	-7.1	16.9	-13.9	63.8	-5.5
Year to Date	161.0	1.5%	129.4	-3.9%	130.3	-10.9%	420.8	-4.3%

Note: Percent change represents a percent change from the same month in the prior year.
Source: U.S. Energy Information Administration. Sales of Electricity to Ultimiate Cusomters by End-Use Sector.

7.2 Transportation Fuels Demand

Table 9 shows COVID-19 impacts of domestic transportation fuel demand. The three largest transportation fuels (in total volumes) include (1) motor gasoline, (2) diesel fuel, and (3) jet fuel. Unsurprisingly, demand is down in all three of the categories presented, but the level of demand reduction is very different.

Specifically, and perhaps unsurprisingly, jet fuel has experienced the largest reduction on a percentage basis. In its worse month, April, domestic jet fuel demand was down 65 percent relative to the same month in the prior year. In the most recent month available, August, jet fuel demand is still down 43 percent. On an annualized basis, jet fuel demand is down 35 percent in 2020 relative to 2019. These are staggering numbers on a percentage basis. GCEO anticipates that jet fuel will continue to experience the slowest recovery.

Motor gasoline was also negatively impacted but has recovered at a faster rate. In April, motor gasoline demand was down 38 percent from the prior April; as of August this has bounced back but is still 10.8 percent below 2019 levels. Part of this recovery likely comes from travelers substituting away from plane travel toward vehicles. But discussions with industry suggest that most people are still working from home to avoid the commute to work. GCEO takes the view that this motor gasoline demand will continue to recover into mid-2021. At that point, it will be interesting to see how companies respond long term to an already shifting dynamic toward working at home. Some companies, in particular outside of the energy sector, have revealed that they are permanently reducing office space with the intention of increasing the share of work conducted at home into perpetuity.

On a percent basis, diesel fuel was the least impacted. It was down 12.3 percent in May but recovered quickly in June to just 5.2 percent below the level observed in June of 2019. On an annualized basis, diesel fuel is down 5.1 percent compared to 2019, and these numbers are likely to improve through the end of the year, although, improvement has flatlined in the most recent two months of data.

Table 9: Transportation fuel demand

	Motor Gasoline		Diesel Fuel		Jet Fuel	
	Million Gallons per Day	Percent Change	Million Gallons per Day	Percent Change	Million Gallons per Day	Percent Change
March	309.1	-13.7%	159.2	2.5%	55.0	-12.8%
April	228.2	-38.1	143.5	-10.1	23.9	-62.8
May	284.6	-24.6	140.3	-12.3	23.6	-64.8
June	332.3	-12.0	153.4	-5.2	32.8	-51.6
July	345.0	-9.2	151.3	-6.1	37.8	-43.3
August	345.4	-10.8	154.1	-6.1	38.4	-42.7
Year to Date	318.5	-13.3%	151.5	-5.1%	42.2	-34.9%

Note: Percent change represents a percent change from the same month in the prior year
Source: U.S. Energy Information Administration, Petroleum & Other Liquids Prime Supplier Sales Volumes

7.3 Natural Gas Demand

Table 10 shows domestic natural gas demand. Four categories of demand are highlighted: final sales of natural gas to residential, commercial, and industrial customers as well as natural gas consumption for power generation. On an annualized basis, natural gas demand from residential, commercial, and industrial customers is down 8.4 percent, 10.9 percent, and 3 percent, respectively. Interestingly, while residential natural gas demand was down in March by 23.7 percent, in all subsequent months, residential natural gas demand has been higher compared to 2019. This is consistent with observed residential demand for electricity shown in Table 8.

Commercial and industrial demand have been down each month since the pandemic began. But natural gas consumption used for electricity generation has been up since in each month relative to 2019, with the exception of August where it was down just slightly. This is likely due to a number of factors, including increased natural gas capacity (discussed in Section 4) alongside low natural gas prices (discussed in Section 2.3) increasing the economics of natural gas generation in dispatching decisions. With all of these factors taken into account, domestic natural gas demand is down only 1.3 percent on an annualized basis, and by the end of 2020 (depending on the weather this winter), domestic natural gas usage will likely be relatively flat compared to 2019. This will of course be impacted greatly by the weather as the heating season begins.

Table 10: Domestic natural gas demand

	Residential		Commercial		Industrial		Electric Power		Total Demand	
	Bcf/d	Percent Change	Bcf/d	Percent Change	Bcf/d	Percent Change	Bcf/d	Percent Change	Bcf/d	Percent Change
March	16.93	-23.7%	10.87	-20.5%	23.24	-4.0%	28.35	10.1%	80.85	-7.5%
April	12.51	14.3	7.90	-3.9	21.47	-4.7	25.47	3.8	66.40	1.8
May	7.58	10.7	5.20	-12.8	20.16	-7.5	26.89	0.3	60.97	-2.5
June	4.53	5.2	4.39	-9.0	20.24	-4.3	34.85	5.2	63.11	1.0
July	3.81	5.7	4.15	-9.2	20.69	-1.3	44.29	7.8	74.29	3.9
August	3.54	7.7	4.24	-6.6	21.08	-2.8	41.31	-0.6	71.48	-1.2
Year to Date	12.56	-8.4%	8.46	-10.9%	22.28	-3.0%	32.86	6.0%	76.33	-1.3%

Note: Percent change represents a percent change from the same month in the prior year
Source: U.S. Energy Information Administration

8. Employment Outlook

8.1 Employment Forecasts

In this final section of the GCEO, all prior sections are synthesized into employment forecasts for the regional energy industry. Specifically, employment is forecast within two broad sectors: (1) upstream oil and gas extraction and services and (2) refining and chemical manufacturing. Sectors are identified based on the North American Industry Classification System (NAICS). Upstream oil and gas is defined as including oil and gas extraction (NAICS sector 211) and support activities for mining (NAICS sector 213). Refining and chemical manufacturing employment includes petroleum and coal products manufacturing (NAICS sector 324) and chemical manufacturing (NAICS sector 325).[22] Employment forecasts are produced for each of these aggregated sectors for Texas and Louisiana.

Upstream oil and gas employment for both Louisiana and Texas exhibit three key patterns in historical data in Figure 45 and Figure 46. The first is growth prior to 2015, modest in Louisiana and 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 that led to a dramatic reduction in rig counts (see Figure 2 in Section 2.1). During the 2015 crash, Texas lost more than 100,000 upstream jobs from peak to trough. Louisiana lost about 18,000. Post-2015 crash, Texas employment climbed back slowly through approximately the end of 2018 before beginning a modest decline. Louisiana upstream employment was approximately flat over this period.

[22]Chemical manufacturing includes many product types, including resins, pesticides, pharmaceuticals, paints, soaps, and others.

The third shock began in early 2020 in response to the COVID-induced economic downturn. According to the most recent estimates, Texas has lost 52,000 jobs, and Louisiana has lost 7,100 jobs.[23] On a percentage basis, Texas and Louisiana lost 23.6 percent and 21.3 percent, respectively. Thus, not only did Texas lose more jobs, but it also experienced a larger percentage drop relative to Louisiana.

Figure 45 and Figure 46 also show the forecast employment in the upstream oil and gas sectors for Louisiana and Texas, respectively. Econometric forecasts are based on a combination of both the futures markets for oil and natural gas shown in Figure 7 and Figure 8, alongside the Enverus ProdCast model outputs shown in Figure 9 and Figure 10.

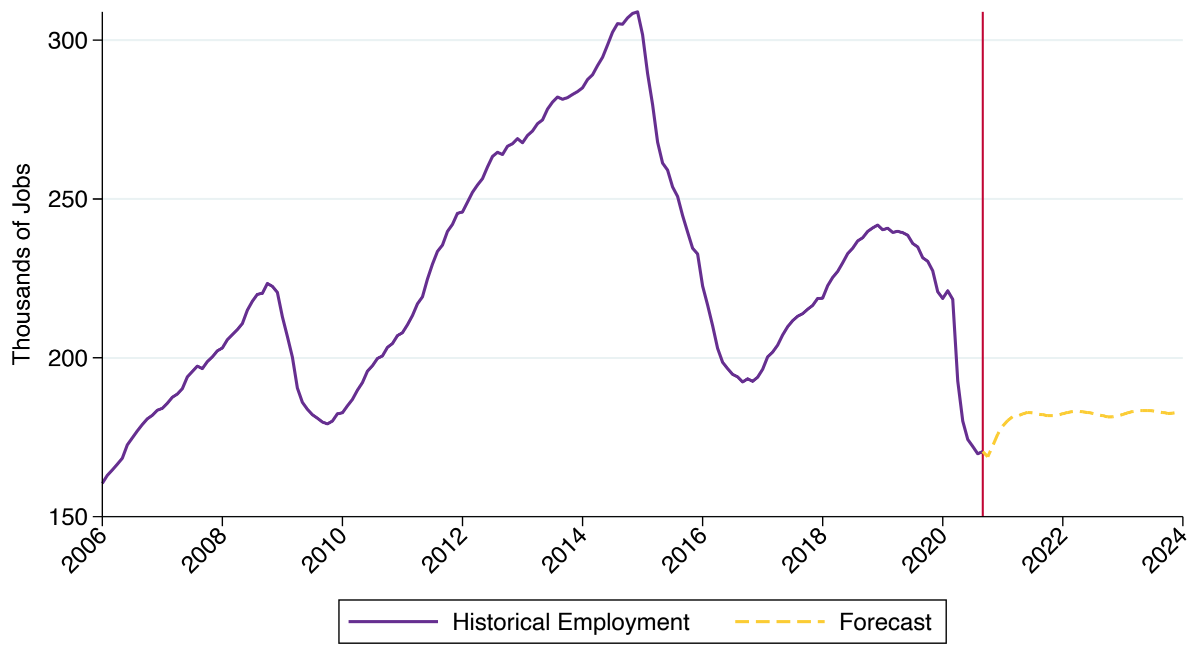
Model results suggest that Louisiana "bottomed out" upstream employment in September of 2020, while Texas reached its lowest level with a one-month lag (i.e. in October). So, at the time of this writing, we anticipate that the bottom is behind us in both states. Over the next year, we anticipate both states to gain back some of these COVID-19 induced job losses. By the end of 2021, Louisiana is expected to gain about 2,600 jobs back relative to the trough in September of 2020. Texas is forecast to gain 13,150 upstream jobs back. It is important to note that although employment is expected to increase over the forecast horizon, these model results are not anticipating employment in either state to reach pre-COVID-19 levels over the forecast horizon.

Figure 45: Louisiana upstream employment forecast

Source: U.S. Bureau of Labor Statistics, Current Employment Statistics. Authors' forecast.

[23]Comparison of employment in December of 2019 to the current estimated employment in August of 2020.

Figure 46: Texas upstream employment forecast



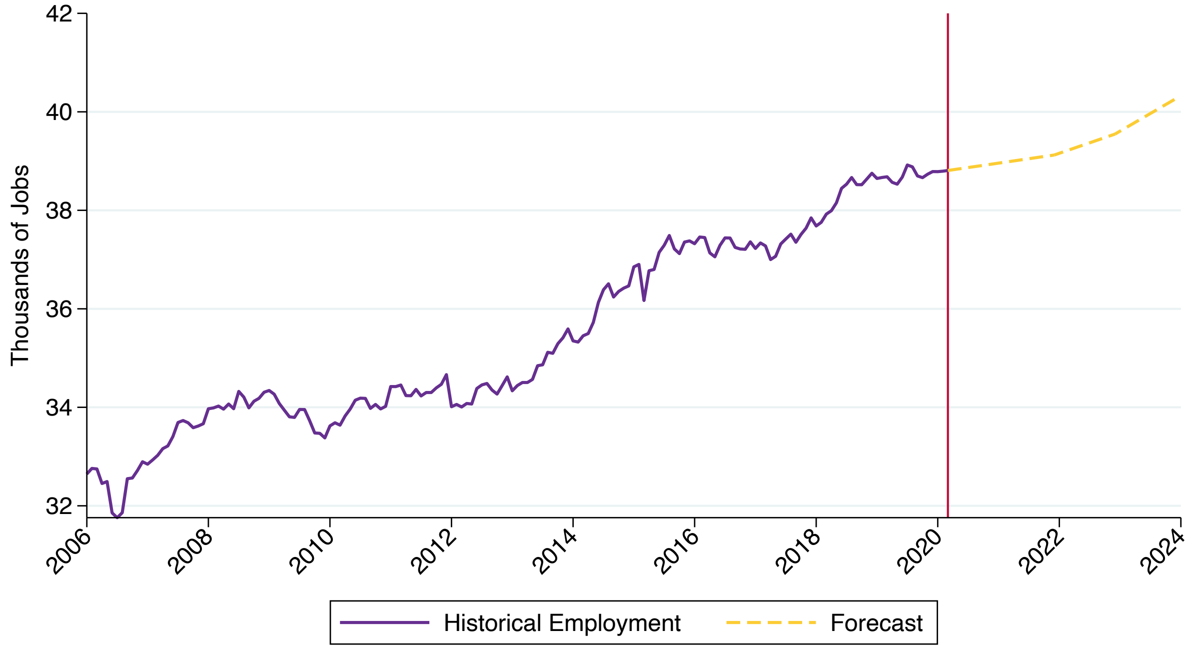
Source: U.S. Bureau of Labor Statistics, Current Employment Statistics. Authors' forecast.

The forecasts of refining and chemical manufacturing employment are shown in Figure 47 and Figure 48. For both Louisiana and Texas, the GCEO forecast is based on the historical relationship between capital expenditures and employment growth alongside our baseline capital expenditures presented in Table 7.

Unlike the upstream oil and gas employment that has seen significant reductions since the 2015 price crash, refining and chemical manufacturing employment has increased in both Texas and Louisiana over this time horizon, for reasons discussed in Section 5. This employment growth has been facilitated due to a combined $120 billion in manufacturing investments since 2011 in these two states. As new plants are built and expansions are completed, this creates jobs that can persist for decades into the future.

For Louisiana, we anticipate employment to grow modestly over the forecast horizon. Specifically, we anticipate employment to increase by about 300 jobs by the end of 2021, or about 0.8 percent increase. Employment growth is expected to expand its pace in 2022 and 2023 by 1.1 percent and 1.8 percent, respectively. This is driven by the current lull in capital expenditures that are expected to accelerate in the post COVID-19 era as global demand is anticipated to return.

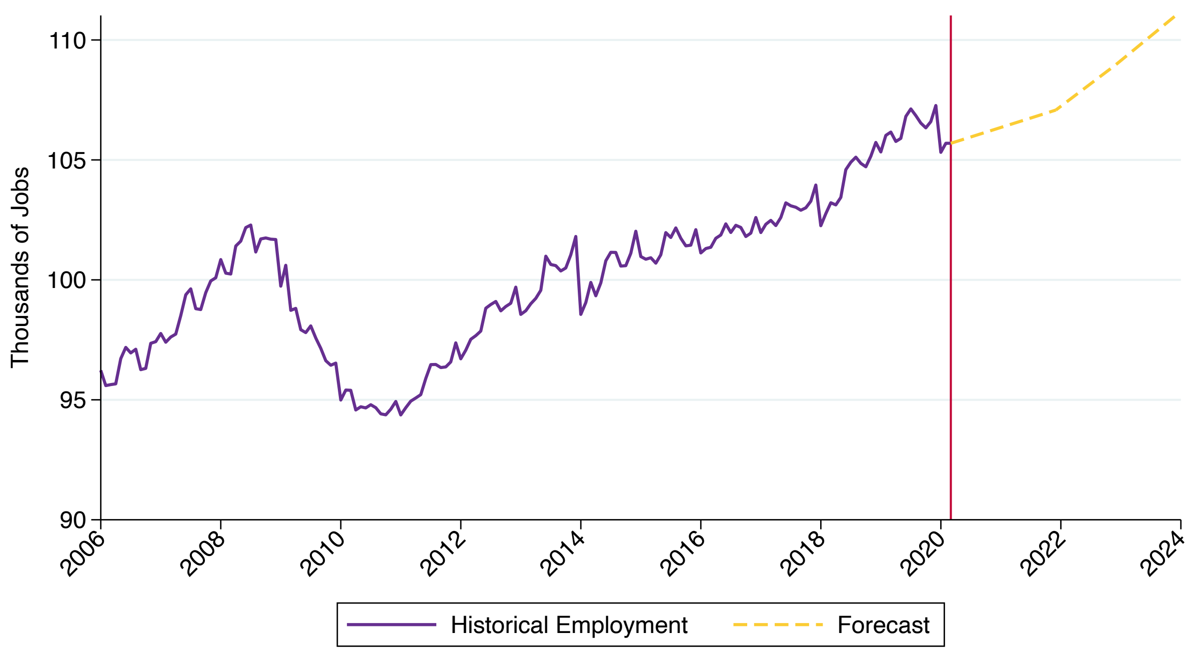
Figure 47: Louisiana refining and Chemical manufacturing employment forecast



Source: U.S. Bureau of Labor Statistics, Quarter Census of Employment and Wages. Authors' forecast.

As shown in Figure 48, Texas refining and chemical manufacturing employment is expected to increase through 2021 but still be at slightly below the employment level experienced in the peak in December of 2019. In 2022 and 2023, we expect an increase in refining and chemical manufacturing employment by 1.8 percent and 1.9 percent, respectively, as capital projects are completed.

Figure 48: Texas refining and chemical manufacturing employment forecast



Source: U.S. Bureau of Labor Statistics, Quarter Census of Employment and Wages. Authors' forecast.

9. Conclusions

This has been a difficult year for the energy industry along the Gulf Coast and globally. Energy demand has been reduced due to COVID-19 across energy types, including electricity, liquid fuels, and natural gas. These demand reductions have cascaded through the economy, reducing employment by tens of thousands of jobs in the select sectors highlighted here, alone. But in addition to the short-term impacts of COVID-19, there is significant longer-term uncertainty in energy markets. Increasingly, countries across the world and individual companies are making commitments to decarbonize the global economy. Thus, while energy will still be very much needed, the very structure of the energy industry has the potential to change.

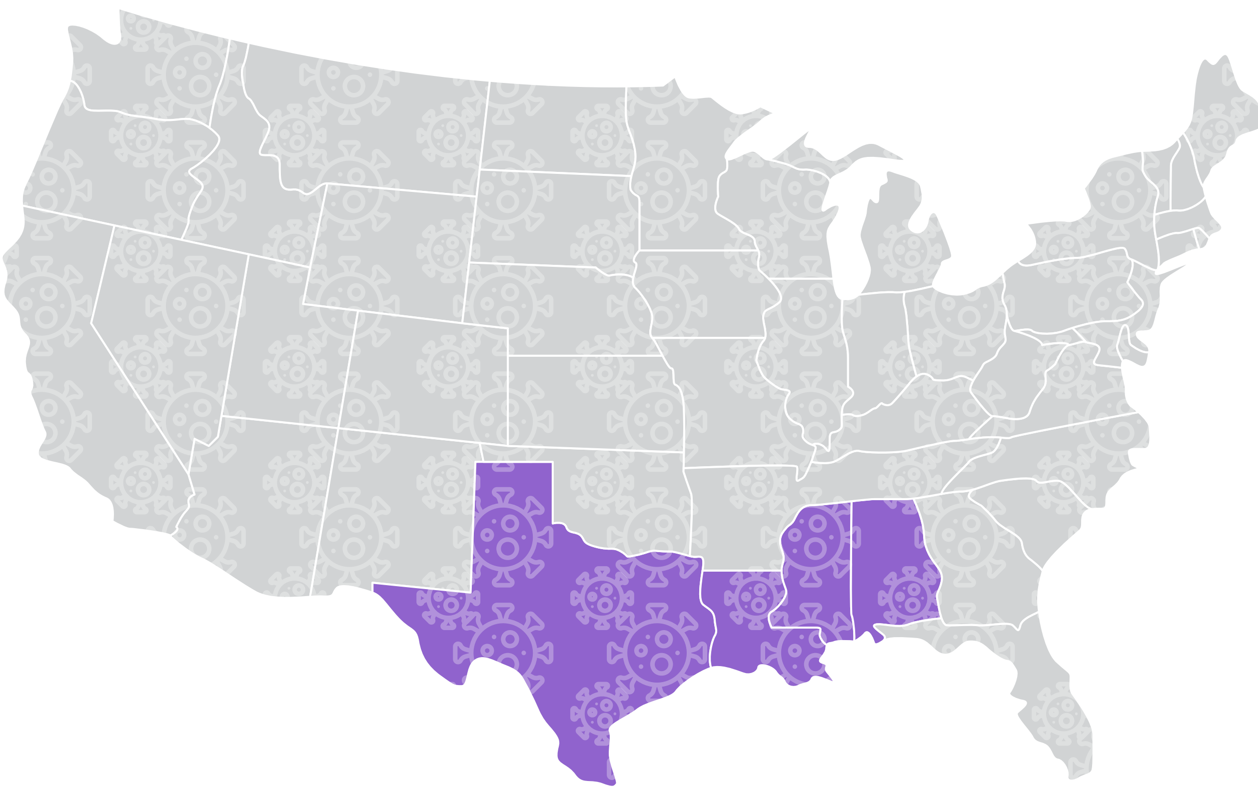
As mentioned previously, at the time that this document is being finalized, the U.S. has completed its presidential election, but the final result has still not been determined. The outcome of this election has the potential to impact the energy outlook in two major ways.

First, the Biden campaign has promised to ban new oil and gas permitting on federal lands and waters while investing 1.7 trillion of taxpayer dollars into "clean energy" over the next 10 years. Supply side effects of a Biden policy, ironically, could increase oil and natural gas prices, leading to improved economics in areas not directly impacted by regulatory changes. But also, higher prices for fossil-based energy alongside subsidies can improve the comparative economics of renewables. Potential Biden policies that could work against higher domestic prices include the emergence of potential energy trading barriers, particularly barriers to energy infrastructure development (e.g., storage, pipelines, export facilities) needed to move energy commodities of all types from their various producing areas to export centers along the GOM. Further, diplomatic re-engagement with Iran, including a rehabilitation of the Iranian nuclear deal, could have considerable implications for world crude oil supplies at a crucial time when many GOM energy companies are simply trying to survive. While predicting specifics of a Biden energy policy are beyond the scope of this outlook, these policy changes if implemented could have important implications for the Gulf Coast energy industry.

Also impacted by the outcome of the election are the trade negotiations with China. As part of this year's outlook preparation, input was gathered from international trade experts with regard to the status of trade negotiations. One recurring theme of these discussions was uncertainty as to how and if a Biden presidency would continue these negotiations. Would a Biden administration return to a pre-Trump trade policy with China, or would he continue negotiations? Further, how would a re-elected President Trump approach Phase II negotiations? Because energy demand growth over the coming decade is anticipated to come from Asian markets, these negotiations can impact the viability of projects on the Gulf Coast. The future of U.S.-China trade relations has the potential to impact industrial developments along the Gulf Coast.

But perhaps more important than governmental policies, the speed of recovery from the pandemic will be the main determinate of employment recovery in the energy sector over the next year. At the time of this writing, the U.S. is experiencing increases in COVID-19 daily cases, even surpassing the daily rate for cases in July. The U.K., Germany, and France have re-entered country-level shutdowns due to cases spiking in Europe. Embedded in this outlook is the assumption that COVID-19 will gradually subside, and that a second wave of shutdowns will be avoided. Yet, within days of sending this off to print, the likelihood of a second wave of infections and associated reduced economic activity has increased substantially.

Looking into the future, the 2021 GCEO suggests that Louisiana will continue to play an increasingly important role in the manufacturing of energy and chemical products, while Texas will continue to be at the forefront of the upstream oil and gas extraction industry. While upstream employment is anticipated to rebound in both Texas and Louisiana, forecasts do not suggest returning to levels seen before the 2015 oil price crash, or even back to pre-COVID-19 levels over the forecast horizon.



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