Natural Gas Matters

Oil and Gas in the Age of COVID-19 —Where Do They Go From Here?

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FINANCIAL IMPACTS ON INDUSTRY EMERGE

Within the global financial chaos caused by the impacts of COVID-19, the oil and natural gas production industry has been hit unusually hard. At the onset of the pandemic, oil was already experiencing severe market distress, as global supply exceeded global demand. OPEC had tried to craft a cutback in production, which then turned into a price war between Russia and Saudi Arabia, driving a dramatic decline in global crude oil prices. Then, as the global pandemic emerged and the response of almost all major consuming nations was to bring travel, industry, and workplace commuting to a screeching full stop, the resulting collapse in demand allowed the oil industry to give an object lesson in supply-demand economics. The bottom fell out of the crude oil price both internationally and domestically for the United States. Figure 1 charts the price of US crude oil at the West Texas Intermediate (WTI) index at Cushing, Oklahoma, from 2007, when the shale era began, to the current situation (the chart presents the data on a rolling-monthly-average basis, to smooth out the high level of daily volatility experienced over that entire 13-year period).

As shown, the current price in the mid-$20s is lower than the price WTI crude has been at any time in recent history. As is also shown, this is the third major crash in prices over the 13 years covered, the first being the result of the Great Recession in 2009 and the second being the major market correction in 2014–16, when the widespread emergence of shale oil swamped the market. Note that this third crash, while smaller in dollars than the other two—perhaps because there just weren’t nearly as many dollars to be affected in the first place—is the largest percentage decline, at 77 percent. Thus, the normal operation of a free market was simply to reflect that there was far more oil supply globally than demand, affecting all major indexes, including WTI in the United States.

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Natural gas was similarly affected by loss of demand, and had similarly been affected by oversupply in the prior period, before COVID-19 took hold. Figure 2 is a depiction of the Henry Hub price per million Btu (MMBtu), again on a rolling-monthly basis.

Note that with the exception of the original plunge when the Great Recession coincided with the shale boom hitting the market, the only time...
natural gas has seen a 65 percent decline was when the Polar Vortex of 2013–14 gave way to more normal weather, and the 62 percent drop that has occurred from winter to spring this year—in part the normal winter-spring weather change, and in part loss of demand from industry shutdowns and lack of electricity use in office buildings, restaurants, movie theaters, malls, and all the other facilities that have been closed and empty—added to the loss of demand in industrial applications. The natural gas losses have been nothing like the losses experienced in oil demand.

**LNG SUPPLIES WITHSTAND IMPACTS**

Oddly, despite the global nature of lockdowns and supply-demand loss, the most important
new element of natural gas demand in the United States, liquefied natural gas (LNG) export feed gas, has not been seriously affected. This is largely because the existing terminals already in service are heavily supported by long-term, firm take-or-pay contracts, so that they are part of their customers’ baseload. There has recently been a trend toward more canceled cargoes, and it may become a major source of concern if a margin does not develop between Henry Hub prices and LNG sales prices. But in the words of the guy who jumped off a 10-story building, “So far, so good.” That is true for the existing in-service terminals and for those who are far enough along and sufficiently anchored by firm contracts, but the next wave of LNG terminals is having a lot of trouble—no one seems interested in signing long-term contracts for $6 or $7 dollars per MMBtu, when spot LNG prices are in the $2s. Thus, a great deal of the nation’s planned expansion in LNG export activity may be in jeopardy of at least significant delays before things start moving again.

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**DO FUTURES TELL US ANYTHING ABOUT THE FUTURE?**

Where do things go from here? What can the future hold? Will oil producers survive, and what effect will the answer to that question have on natural gas supply? The best way to answer the survival question is to observe how producers reacted this time as compared with prior market crashes. In the 30 years since natural gas wellhead prices were deregulated (oil was already unregulated), there have been three major examples of such price collapse, in 2009, 2014–16, and now. In the first crash, only natural gas was becoming heavily dependent on shale production, and thus on horizontal drilling. In the second and third, oil had become a fast-growing industry due to the application of shale technology (including horizontal drilling) to its production. Figure 3 shows how producers reacted during all three crises, in terms of horizontal rig count, the key parameter in its effect on shale oil or shale gas production.

In 2009, horizontal rig count experienced only a modest drop—the fledgling shale gas industry continued its drilling activity for the most part. However, this was a result of the industry structure at the time, whereby many of the shale gas producers (the primary users of horizontal drilling then) had hedged their prices so that they were not immediately affected by current prices, and many of their lease agreements required drilling within a limited time in order to hold the leases. The 2014–16 decline did not enjoy the same level of safeguards. A 72 percent decline in oil prices (the new target of horizontal drilling), combined with a somewhat larger than normal 65 percent decline in natural gas prices, resulted in a virtual shutdown of shale drilling, deactivating (“laying down”) 76 percent of the horizontal rig fleet in the course of a year. Producers had learned from prior crashes to act quickly or risk extinction. As a result, there were far fewer bankruptcies than anticipated, and an essentially healthy industry emerged over the 2016–17 period, to become the developers of the “new” Permian basin and thus bring forth one of the largest oil supplies in the world. Along with that oil came enormous quantities of “free” associated gas, thus flooding natural gas markets and requiring massive expansions of natural gas pipelines out of the Permian. The industry was back on a boom track. There was a flattening and some decline in rig count over

Figure 3. Total US Horizontal Rig Count, 2007–20
the course of 2019, for various reasons, including a perception of declining prices and a lack of pipeline capacity out of the Permian, continuing into early 2020.

However, when the effect of COVID-19 became clear in March, between March 20 and May 15—less than two months—the industry laid down 56 percent of the active horizontal drilling rigs in the nation. In other words, the industry reaction was swifter and stronger than had ever been the case. This meant tremendous hardships, with many job losses and economic uncertainty within the industry, but the swift, severe action should mean survival and an industry that comes back strong if prices should recover to the necessary levels.

What are those levels and what will determine whether they are reached? It requires a WTI crude oil price of somewhere in the $30–$40 range per barrel for production to be relatively flat. At the $50 to $60 levels experienced before the crash, substantial growth would resume, but one has to question whether those levels are possible. Even if demand comes back to pre-COVID-19 levels, the global industry was already oversupplied, causing downward pressure on prices. The futures market is currently optimistic that a comeback will be quick and sustained. Figure 4 shows the NYMEX futures prices as of May 14, 2020.

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Futures prices are rarely predictive of anything, particularly beyond about a year. They are retraded every day, resulting in a continuous modification of prices as the actual contract months approach. Predictions beyond four or five years are so lightly traded that their prices are just estimated continuations of trends, not real deals. However, the latest data as of this column’s drafting has the price increasing to almost $30 by June, reaching $35 by the end of next year, and

Figure 4. WTI Crude Oil Through December 2030 at May 14, 2020
Oddly, if that were to happen, it would most likely have the effect of making natural gas prices go up, rather than down. The reason is that with less oil production, there is less free-associated gas driving prices down, while gas-directed drilling actually requires fairly decent natural gas prices, enough above break-even to make the trip worthwhile. Aside from domestic consumer impact and competitiveness with other power generation fuels, what would higher natural gas prices (higher than the $2.35 assumed by the futures market) mean for the gas market? Quite simply, higher Henry Hub natural gas prices would affect the United States’ competitive position in world LNG markets. Figure 6 demonstrates the futures market’s view of the relationship between domestic natural gas prices and the most important world benchmark price for LNG, the “JKM Index” (the price per MMBtu for LNG delivered to the Japan-Korea market).

Like the Henry Hub futures, the JKM futures are seasonal, so a trendline has been added. Note that at the beginning, in June, Henry Hub and JKM are extremely close together. In fact, spot LNG has been trading in Tokyo Harbor at $2.00 per MMBtu. For a US LNG export terminal, the variable costs of liquefying and shipping, with continuing to increase into very supportive prices for further development. It takes 10 years to reach the levels enjoyed last year, suggesting that rapid growth will be the exception rather than the rule, but that supplies will remain stable with the ability to support the existing oil export levels.

What does the futures market think of natural gas prices? Not much in either direction. Figure 5 shows the futures prices for Henry Hub in their seasonal format, which we have converted to a steady trendline. The natural gas price has been juxtaposed with the futures market’s oil expectation, converted to price per MMBtu to allow comparability with natural gas.

The first observation is that natural gas prices are expected to increase to an annual level of approximately $2.35 per MMBtu and stay there for the next decade. Oil is expected to restore (slowly) to its historic premium per MMBtu over natural gas—at current cash prices, the two are actually at parity, while for many decades oil prices tended to average three times the natural gas price per MMBtu. That level is not restored in the futures prices until 2024.

What this could mean is that for several years, drilling for natural gas could once again be more economically attractive than drilling for oil.
no recovery of terminal fixed costs, can amount to $2.00 per MMBtu or so. Thus, a Henry Hub price of $1.78 would be added to variable costs of $2.00, for a marginal cost into Tokyo of $3.78. There was a fellow in Joseph Heller’s *Catch-22*, Milo Minderbinder, who bought eggs for a nickel and sold them for three cents—he said he “made it up in volume.” It is hard to see how LNG that costs $3.78 in out-of-pocket costs can be sold for $2.00 and “make it up in volume.” If the futures market is correct and the JKM price does jump and then ramp up to $6.00 per MMBtu, the expected Henry Hub price of $2.35 plus $2.00 for variable costs would see an ability to generate new sales by next year and could provide some margin to cover fixed costs by 2025. However, if natural gas prices do go up significantly because of the interaction with oil decisions, the available margins would shrink, and the actual level of LNG export shipments could be reduced. In particular, the demonstrable economics of the next wave of terminals could be threatened even more than they already are.

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At the current expected prices, for existing terminals and those on a glide path to entering service with firm customer commitments, between their current long-term contracts, spot business, and creative deals, the next few years should be successful. However, for terminals that do not yet have customer commitments, regulatory approvals, or funding, which generally have target dates in the 2024–25 range for going into service, it’s hard to see why potential customers would make new firm commitments until their spot options are no longer much less expensive. Presumably they eventually will, but time tends to be on their side, not on the terminal developers’ side. Thus, the next wave of major LNG export terminals could take a while.

**BALANCING ACT AND THE PATH FORWARD**

Lastly, with the already very complex Rubik’s Cube of oil economics, gas interaction with those economics, gas economics, and their interaction with international markets through LNG, there has to be a consideration of the many political forces weighing on both oil and gas. Those forces involve both consumption and development. If the global use of oil goes down because of environmental considerations but domestic development is impaired by opposition to hydraulic fracturing, etc., there could well be no net change in oil prices. However, the prospect of a balance between the two is speculative. The same is true of natural gas, but there is the additional variable of the value of natural gas in enabling intermittent renewables growth, and the value of LNG in world markets that are burning much dirtier fuels such as coal. Basically, the success of the oil and gas industries will depend on understanding the dancing elephants of global demand, global environmental concerns, domestic development, and infrastructure with its highly political polarization, and successfully identifying and navigating the sliver of light between those dancing elephants. The next decade will be fascinating to see play out, but the two major constants are that we have enormous oil and gas resources that are already located and that our oil and gas industry has proven remarkably adaptable and resilient. We will see.