PPHB

ENERGY INVESTMENT BANKING

MUSINGS FROM THE OIL PATCH

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Note: *Musings from the Oil Patch reflects an eclectic collection of stories and analyses dealing with issues and developments within the energy industry that I feel have potentially significant implications for executives operating and planning for the future. The newsletter is published every two weeks, but periodically events and travel may alter that schedule. As always, I welcome your comments and observations.* Allen Brooks

History Doesn't Repeat, But Energy Market Rhymes – Part 1

The concept about history rhyming with its past appears to be truer than people often care to acknowledge

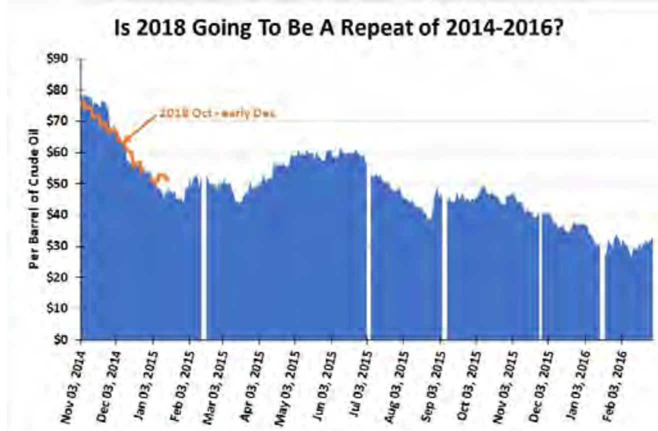
The idea that history doesn't repeat its past is inaccurately attributed to American humorist Mark Twain. The concept about history rhyming with its past appears to be truer than people often care to acknowledge. That thought grew more dominant in our thinking as we watched events of the global energy business unfold over recent weeks. Those events were reactions to fundamental trends emerging within the energy industry, giving rise to concerns over a repeat of the past. If our energy history is in the process of rhyming, those of us in the industry should be worried.

Fears mushroomed that without a global oil supply cut, prices were headed into the low $40s a barrel, a level at which few producers are capable of generating profits

The saga in Vienna a week ago that had energy markets on edge was the seeming inability of the OPEC member oil ministers and Russia energy officials to reach an agreement on a production cut to support oil prices. When the meeting seemed to be headed to an outcome of a minimal, at best, or possibly no output cut, global oil prices sank below $50 a barrel for West Texas Intermediate. Fears mushroomed that without a global oil supply cut, prices were headed into the low $40s a barrel, a level at which few producers are capable of generating profits. The concern was about the oil business repeating the 2014-2016 era that devastated the global oil industry. It is important to remember that in early 2015, in response to then-falling oil prices, BP plc's (BP-NYSE) CEO Robert Dudley said his company was planning its future with an expectation that oil prices would be "lower for longer." No one quite knew what that meant, but it sounded ominous for an industry built on optimism and ever-rising oil prices.

After oil prices rebounded from their February 2016 low of $28 a barrel to over $77 a few months ago, thoughts turned to when they would reach $100. Mr. Dudley's view of the future was dismissed, and optimism about living and working a $100 a barrel oil world dominated the thinking. Lower for longer was quickly resurrected as OPEC wrangled and oil prices collapsed.

Exhibit 1. Are We On The Road To A 2014-2016 Repeat?



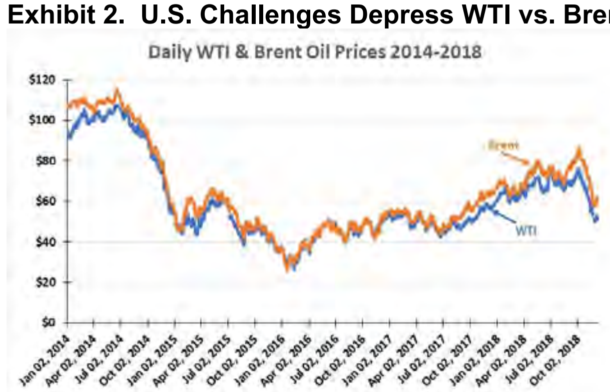
Source: EIA, PPHB

Although the oil market negotiations in Vienna made for dramatic market news and forced oil industry executives to start reordering their priorities for 2019, we need to step back and put all of the events unfolding around and within the oil market into a broader perspective. That may help us assess how the industry is likely to evolve over the next decade or so. This is where history provides some lessons.

The focus on short-termism may divert attention from the long-term trends underlying oil industry trends

The short-term oil price moves, influenced by daily geopolitical news, weekly storage and oil production estimates, coupled with instant analysis and predictions, receive intense scrutiny from the oil industry and oil traders. The focus on short-termism may divert attention from the long-term trends underlying oil industry trends that may, or could, reshape the business, such as we have seen at times in its history.

Exhibit 2. U.S. Challenges Depress WTI vs. Brent



Source: EIA, PPHB

In the short term, the question overhanging the oil market is whether oil prices are about to repeat the pattern of 2014-2016. Answering that question, however, is not as important as understanding the underlying trends that have forced the market to consider it. Moreover, it is important to understand that these trends are in the process of reshaping the oil industry's future.

Whether a new oil price cycle would dictate visiting price levels equal to, or lower than, the prior cycle-low is not clear, but another few years of wandering in the $40-$50 per barrel range would do little but further stress all segments of the oil industry

Exhibit 2 (prior page) shows oil prices over the past five years and suggests we have witnessed at least half of an oil price cycle. Oil prices fell from their 2014 mid-year peak north of $100 a barrel to a low in February 2016 in the high $20s, but had recovered nearly three-quarters of the old high before beginning their recent slide. As oil prices climbed back into the upper $70s a barrel, commodity market expectations called for the recovery to continue, eventually returning oil prices to the old high and above. The 33% price drop not only interrupted the completion of the oil price cycle, but the speed of the drop raised fears we were on the road to further price weakness as part of another cycle. Whether a new oil price cycle would dictate visiting price levels equal to, or lower than, the prior cycle-low is not clear, but another few years of wandering in the $40-$50 per barrel range would do little but further stress all segments of the oil industry.

What happens if we don't revisit those $100-plus oil price levels, but rather revisit the old lows?

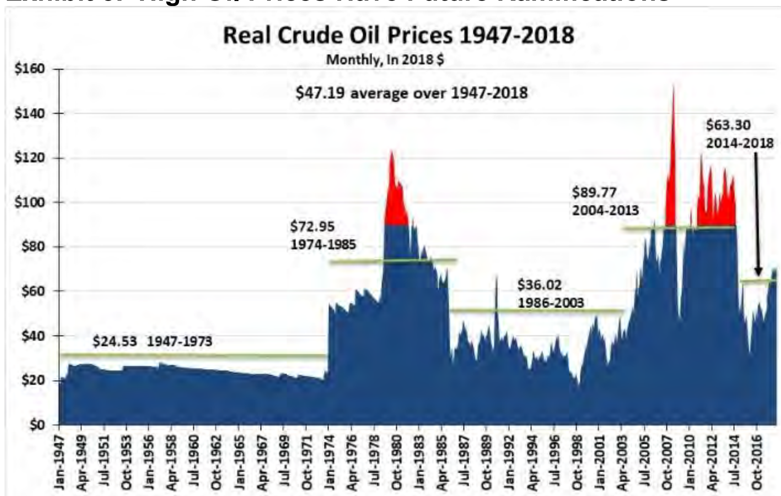
Many oil traders remain convinced oil prices must return to triple digit levels before the oil industry is able to restore its financial health to what existed during the halcyon years of 2010-2014. That period was dominated by extraordinarily high oil and gas prices, strong company cash flows, investors, especially those in private equity, willing to throw money at companies, high levels of oilfield activity, growing industry employment rolls, and booming local economies. What happens if we don't revisit those $100-plus oil price levels, but rather revisit the old lows? What is the fate of the industry?

To answer those questions, it is appropriate to examine what has put the industry in its current state. Do the similarities of today with those of the 1970s-1980s offer lessons about what may be the oil industry's future? Let's explore that question.

Over the entire 71-year period, the real oil price per barrel averaged $47.19

We begin with the chart in Exhibit 3 (next page). It shows monthly real oil prices in 2018 dollars from 1947 through October 2018, or nearly 71 years. The oil prices in red represent months when the real price exceeded $90 a barrel, an extremely high price, the effects of which restructured the industry. Of note is that over the entire 71-year period, the real oil price per barrel averaged $47.19. Current oil prices, after the market digested the OPEC production cut announcement, are sitting about 10% above the long-term average price per barrel, which is actually a stunning revelation.

Exhibit 3. High Oil Prices Have Future Ramifications



Source: *WSJ*, EIA, BEA, PPHB

The average price nearly tripled to $72.95 a barrel during the boom years of 1974-1985, which demonstrated OPEC's pricing power

We calculated real oil price averages for selected periods. From 1947 through 1973, or from the start of the post-World War II years and U.S. dominance of the business up to the transferring of pricing power to OPEC, the oil price averaged $24.53 a barrel. The average price nearly tripled to $72.95 a barrel during the boom years of 1974-1985, which demonstrated OPEC's pricing power. The fallout from that boom in oil prices led to a 17-year period, 1986-2003, when oil prices averaged about half the average price during the boom years. During that extended period, real oil prices averaged $36.02 a barrel, even with the inclusion of high prices experienced during the months leading up to Operation Desert Storm in February 1991, when western powers ousted Saddam Hussein's military from its takeover of Kuwait during the Gulf War.

All this building activity required that China import huge volumes of steel, cement and other building materials, all of which necessitated a dramatic increase in energy consumption

The extended period of relatively low oil prices eventually led us into another period of extremely high oil prices, driven largely by explosive oil demand growth in China. As the country prepared to host the 2008 Summer Olympics, not only was it constructing the facilities for the games, but it was also building out China's infrastructure. China's leaders anticipated that many of the global visitors attending the Olympics would want to see other parts of the country, which necessitated building new airports, highways and other structures necessary to accommodate the increased tourism. All this building activity required that China import huge volumes of steel, cement and other building materials, all of which necessitated a dramatic increase in energy consumption. China's increased oil needs drove annual global oil consumption increases well above the long-term historical annual growth rate. Fears emerged that the world's oil industry would not be able to meet the high consumption growth. This was the time when oil investment banker Matt Simmons wrote a book questioning the size and productive capacity of Saudi Arabia's oil fields, the assumed unlimited oil supplier for meeting the projected growth rate. If Mr. Simmons' thesis was correct, the world was facing a stark future for its petroleum needs, and certainly much higher future oil prices.

With abundant, cheap capital, the shale technology unlocked huge new oil supplies, surprising even the most optimistic forecasters of the domestic oil business

At this time, China, itself, switched from being an oil exporter to becoming an oil importer. Since that fateful status switch, China has grown to become the world's largest oil importer, surpassing the United States who is experiencing a decline in oil imports due to the growth of its domestic oil production as a result of the success of its shale oil boom. When we calculate the oil price impact of this above trend demand growth rate, the 2004-2013 average real oil price was $89.77 a barrel. Little did the industry understand or appreciate the powers unleashed by the extended period of super-high oil prices. The promising shale oil technology was unlocking previously unrecognized petroleum resources. With abundant, cheap capital, the shale technology unlocked huge new oil supplies, surprising even the most optimistic forecasters of the domestic oil business.

The impact of extremely high oil prices on global oil demand, coupled with the supply growth from shale and traditional oil output sources driven by super-high oil prices, led to a supply/demand imbalance. Subsequently, the world's oil oversupply caused global inventories to build to levels that began to pressure oil prices. The peak in oil prices occurred in June 2014. The price slide due to the build-up in inventories lasted for nearly five months before Saudi Arabia told its fellow OPEC members that it would no longer support the organization's oil price target, but rather would increase its own production in order to attempt to reclaim its lost market share.

Saudi Arabia was also hoping to kill the growth of Canada's oil sands output, which was taking market share from Saudi's heavy oil

In particular, Saudi Arabia was targeting the new oil shale phenomenon, a little understood economic miracle. Saudi Arabia was also hoping to kill the growth of Canada's oil sands output, which was taking market share from Saudi's heavy oil. The final blow that forced Saudi Arabia to act was the declaration by the European Union that it would not ban the use of oil sands bitumen after holding out for nearly a year that the use of that oil would be prohibited. That approval ensured that Saudi Arabia's heavy oil market in the EU would be under attack, further increasing the pressure on the kingdom to regain market share elsewhere in the world. Hence its willingness to accept a lower oil price in an attempt to undercut higher oil producers – shale and oil sands being two primary targets.

Although oil prices remained very high for the first half of 2014, if we calculate the average real price per barrel for oil for 2014-2018, it comes to $63.30. This average seems to fit into the thinking about what is an acceptable price for oil globally that ensures oil producers can earn positive returns, but is not so high that it cripples global economies, the ultimate driver of oil consumption. For us, this average oil price calculation sets the stage for analyzing the future of the oil business, in light of the lessons from its history.

Should we focus on the high or the low end of these averages as being indicative of what the long-term average price will be during this recovery period?

An enlightening analysis of this post high-oil period is determining the average real oil price if it is calculated from the peak in oil prices in June 2014 through 2018. That average was $59.16. If we only include the three years of October 2014 to October 2018, the real oil price average was only $55.31. This shows how sensitive the average price is to those few months of super-high oil prices. The spread in the three calculated averages is $8 a barrel, or 12.6%. That is a pretty wide spread, but importantly, each time we eliminate the remnants of the high oil price months, the average real oil price drops considerably. Should we focus on the high or the low end of these averages as being indicative of what the long-term average price will be during this recovery period?

Focus on the months with red oil prices in Exhibit 3 (page 4). Those periods marked crude oil prices at or above $90 in real terms. In our view, they unleashed forces that dramatically changed the oil market as both demand and supply reacted to the high oil prices.

During 1979-1982, the industry enjoyed a total of 34 months of above $90 a barrel oil prices

During 1979-1982, the industry enjoyed a total of 34 months of above $90 a barrel oil prices. During that time, there was a run of 30 consecutive months between August 1979 to January 1982 with those super-high prices, which acted as a strong driver for increased oilfield activity and investment. That high oil price era was the direct result of events in Iran when Mohammad Reza Shah Pahlavi, the Shah of Iran, left for exile in January 1979 and was replaced by a regency council and an opposition-based prime minister. Grand Ayatollah Ruhollah Khomeini was invited back and arrived on February 1, as the military loyal to the Shah was defeated by guerrillas and rebel troops. In April 1979, the public voted in a theocratic regime headed by Khomeini who became the Supreme Leader of the country in December 1979. The prior month, Iranian students supporting the regime stormed the American Embassy in Tehran and captured 52 American diplomats and citizens who were then held captive for 444 days, only being released after negotiations that provided for their release immediately following the inauguration of President Ronald Reagan (R) on January 20, 1981.

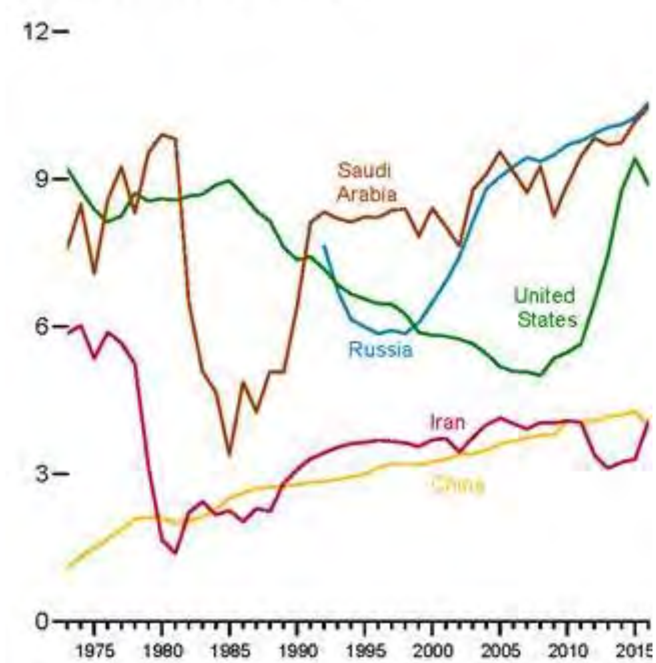
A year earlier, seeing the deterioration of U.S.-Iran relations, an emboldened Iraq leader Saddam Hussein tried to capitalize on the situation in an attempt to replace Iran as the dominant Persian Gulf state. He was worried that the Iranian Revolution would lead Iraq's Shi'ite majority to rebel against the Ba'athist government and possibly depose him. Border skirmishes between Iran and Iraq were a long-standing issue, often fomented by reported plans of Iraq to annex the oil-rich Khuzestan Province.

One outcome of the Iranian Revolution was the sanctioning of the country's oil by the United States

One outcome of the Iranian Revolution was the sanctioning of the country's oil by the United States following the capture of the 52 American hostages. This move came despite President Jimmy Carter's policy moves to deregulate oil prices, which had been regulated in 1973 by President Richard Nixon following the first Arab oil embargo and subsequent tripling of oil prices. President Carter agreed to remove the price controls in stages beginning in 1979 and eventually being totally deregulated in 1981. He instituted a windfall profits tax to capture for the government the huge price increase that would occur as domestic oil prices jumped from $6 a barrel to the then-world price of $30.

Domestic oil prices jumped from $6 a barrel to the then-world price of $30

Exhibit 4. See Iran's Change Supply Role After 1979
Selected Producers, 1973–2016



Source: ***Wikipedia***

The public watched the Iranian Revolution and the eventual removal of the country's oil from the market, and envisioned a repeat of the gasoline lines and rationing that occurred in 1973. Certain states implemented rationing – odd/even license plate and calendar day gasoline purchases – and the federal government even printed up gasoline ration coupons, but they were never used. The increased government involvement in the oil business expanded worldwide. Electric utilities were pushed to switch from oil to coal, natural gas or nuclear power. Governments initiated multibillion-dollar energy research programs such as the Synthetic Fuels Corporation in the United States to produce an alternative to imported oil. The role of nuclear power was expanded.

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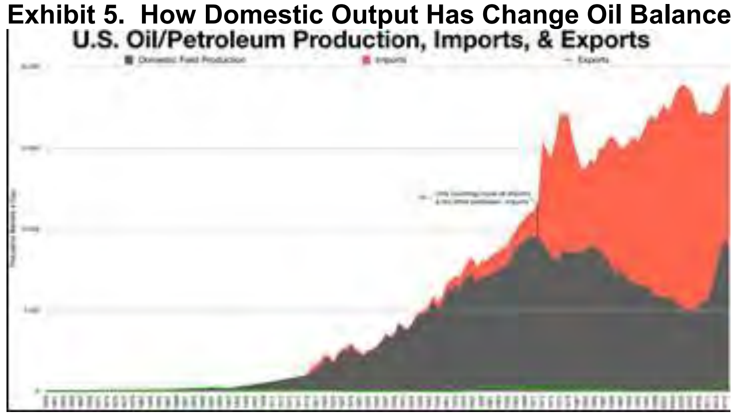
The 1970s saw both the U.S. and Europe establish energy data collection organizations – the Energy Information Administration in the U.S. and the International Energy Agency in Europe – to help assess trends underway their implications, as well as to recommend strategies for dealing with suddenly expensive and possibly less-

Between 1979 and 1986, worldwide demand for oil dropped by five million barrels per day, while non-OPEC production grew by an even greater amount

available oil and gas supplies. This development was funny as the high oil prices of the 1970s had actually put into motion the self-corrective forces of increased supply and decreased consumption. The net effect of those trends was to significantly diminish the pricing power of OPEC, which ultimately led to its internal war that caused oil prices to collapse in the mid-1980s. Between 1979 and 1986, worldwide demand for oil dropped by five million barrels per day, while non-OPEC production grew by an even greater amount as Alaska's Prudhoe Bay, the UK's and Norway's North Sea production and West African oil supplies all arrived in the market. OPEC's share of world oil output fell from 50% in 1979 to only 29% by 1985.

What this didn't help was U.S. oil production, even with the start-up of Alaskan oil, which continued to falling from its historical peak of 1971. As U.S. energy demand continued to grow, the nation's oil imports steadily rose until the oil shale revolution changed the industry dynamics.

Exhibit 5. How Domestic Output Has Change Oil Balance



Source: ***Wikipedia***

This high level of government involvement in the energy business is likely why the industry continued to struggle through the 1990s to recover from the busting of the 1970s boom

These supply and demand dynamics destroyed the global oil boom of the 1970s. The industry was littered with bankrupt companies, if they weren't liquidated, thousands of unemployed workers, and significant losses among financial institutions that forced a restructuring of that industry, also. The decade of the 1980s was dominated by high levels of government intervention in the oil and gas industries that made managing businesses and planning corporate strategies impossible without considering the rules of operation being set forth, and constantly subject to revision. This high level of government involvement in the energy business is likely why the industry continued to struggle through the 1990s to recover from the busting of the 1970s boom.

What do we see today? While maybe not appreciated as much, government involvement in the energy industry is creating just as much angst as oil and gas company executives experienced in the 1980s and 1990s. Fossil fuels are under attack for their carbon emissions as never before. These attacks are across the board: legislation mandating the use of increased renewable energy at the expense of fossil fuels; attacking the construction of energy infrastructure necessary to support the development of new oil and gas supplies; litigation against energy companies for supposed failures to warn (defrauding) shareholders of the dangers from the use of hydrocarbons; and attempting to restrict investment in energy companies who do not declare that fossil fuels are harmful and embrace renewable energy development corporate strategies.

The revolutionary success of exploiting oil and gas shale resources has turned the United States from an also-ran oil producer into the world's leader

All of these actions are working to destroy growth for fossil fuels. The revolutionary success of exploiting oil and gas shale resources has turned the United States from an also-ran oil producer into the world's leader. This dramatic change in about a decade's time, has shaken up the global oil industry, and forced more government intervention. Whether it is Russia's sudden willingness to cooperate with OPEC to set production quotas to help support global oil prices, or Canada's move to cut production in an attempt to shrink its wellhead price differentials that have diminished both the industry's cashflow and the provinces' revenues, government involvement in the energy business is growing and threatens the energy industry's future.

Government involvement is more pervasive, meaning it is coming at all levels of domestic government, as well as worldwide

If one reads the daily energy news, virtually every story incorporates discussions about government involvement. While the involvement may range from high-level geopolitical events to court battles over pipeline construction permits, the involvement of governments appears to be at a level equal to what the industry had to deal with in the 1980s. One difference between those two eras is that Wall Street energy investment analysts no longer need to spend as much time in Washington, D.C. as they did in the 1980s. There are several reasons why. First, government involvement is more pervasive, meaning it is coming at all levels of domestic government, as well as worldwide. That means the scope of government involvement is wide, minimizing the focus on any particular level of government. Secondly, access to legislative and regulatory developments are more open, with documents much more readily available from public sources. That means analysts no longer have to travel to Washington to obtain copies of draft legislation or regulatory reports, as they are now mostly posted on government and non-government web sites.

We perceive that we are spending more time now trying to follow and understand the impact of energy legislation and government policy moves on the future of the business

While we may be proven wrong, we perceive that we are spending more time now trying to follow and understand the impact of energy legislation and government policy moves on the future of the business than in recent years. If feels to us that we are back in the 1980s, when we spent much of our time trying to figure out the implications on our energy companies of 'old' oil versus 'new' oil, windfall profits taxes, take-or-pay requirements, and the myriad of other rule changes that forced corporate strategies to be altered.

Today, our focus increasingly is on pipeline protests and court rulings, OPEC developments, clean energy mandates, and the push for electric vehicles, among other issues.

In the recent high oil price era, we spent exactly twice as many months (68 versus 34) with prices at or above $90 a barrel than we did in the 1970s and 1980s

If our perception is correct, we return to Exhibit 3 (page 4). The high oil prices of the 1970s set in motion, what turned out to be earth-shattering changes for the energy industry. Those boom years led to nearly 17 years of sub-optimal performance for the energy business. While we acknowledge that history doesn't repeat, the recently-experienced high-oil years, 2004-2014, may be setting us on an extended era of sub-optimal performance. This is not a popular message, or a happy one. In the recent high oil price era, we spent exactly twice as many months (68 versus 34) with prices at or above $90 a barrel than we did in the 1970s and 1980s. Are the current struggles of the global oil industry to rebalance supply and demand reflective of the inability of the industry to manage the forces unleashed by the 68 months of $90-plus oil prices? Does twice as many high-oil price months translate into twice as many sub-optimal months of recovery? Or, has the oil-price-cycle accelerated, so it will only be half as many sub-optimal months in recovery? The power to determine that outcome lies in the hands of government leaders, and what they do to restrict and ultimately to destroy fossil fuel markets, whether intentionally or unintentionally by their actions. Always lurking in the background is the power of technology to alter the industry's cost structure.

Bankruptcies, consolidation and investor shunning the industry are having, and will continue to have, an impact on the future structure of the oil and gas, as well as the overall energy business

One cannot answer our questions about the future recovery years without also understanding the impact of the shale revolution, and how its evolution from version 1.0 to 2.0 is changing the industry. How the companies in the industry are adjusting to the new era is also impacting how the industry evolves. Bankruptcies, consolidation and investor shunning the industry are having, and will continue to have, an impact on the future structure of the oil and gas, as well as the overall energy business. All of these issues need to be examined, but that is for another day. Suffice it to say that we believe these trends are rhymes with the restructuring that went on in the 1980s and 1990s. Learning your industry's history may be time well spent in seeking a path to the future.

Oh Canada, Oh OPEC, Eh!

Canadian Prime Minister Justin Trudeau is fortunate that his citizens don't feel as pressured by their financial situation and government taxes as those in France do

Canadian Prime Minister Justin Trudeau is fortunate that his citizens don't feel as pressured by their financial situation and government taxes as those in France do. Otherwise, there might be people protesting in the streets against the Trudeau government's energy and economic policies. As we are seeing in numerous locations around the world, not just in Paris, governments adopting "green energy" agendas are creating a backlash from those forced to fund the programs as they struggle to put food on their tables and gasoline in their cars. These people just don't understand how much they are being asked to sacrifice today so their great-great-grandchildren may enjoy a less-warm world. We guess someone needs to explain to them the science behind climate change, as we all know it is settled.

The issue is that no new pipelines have been built to haul away the growing output the Canadian oil industry is diligently working to produce

Across the pond from France, parts of Canada's economy are struggling with extremely low oil prices due to a lack of egress options for the country's crude oil and bitumen output. The issue is that no new pipelines have been built to haul away the growing output the Canadian oil industry is diligently working to produce. The industry's efforts represent the backbone of Western Canada's natural resource industry that supplies lots of jobs, healthy incomes to be spent in the local economy, and substantial tax revenues for governments at multiple levels. When one part of that chain breaks down, everyone involved suffers, and that has happened.

"Canadians want their government to do different things, and to do things differently"

When Justin Trudeau's Liberal Party won the federal election in October 2015 and elevated him to the position of Prime Minister, he presented an aggressive governing agenda, delivered via the traditional "speech from the throne" given by the country's governor general, David Johnston, the representative of Queen Elizabeth II. In Mr. Johnston's speech, prepared by Mr. Trudeau, a claim was made that "Canadians want their government to do different things, and to do things differently." Today, many might say that is exactly what is happening.

Mr. Trudeau's major proposals included a national climate change plan and a new national health care accord, but they required the cooperation of the nation's ten provinces

Mr. Trudeau's agenda included many traditional Liberal policies such as middle-class tax cuts and pension improvements, but there were other actions proposed such as the admission of 25,000 Syrian refugees and the legalization of marijuana. He proposed rolling back many of the measures instituted under the prior Conservative leader, Stephen Harper. Mr. Trudeau's major proposals included a national climate change plan and a new national health care accord, but they required the cooperation of the nation's ten provinces. The acting Conservative Party leader, Rona Ambrose, representing the opposition to the Liberal government, declared to the media that Mr. Trudeau's speech contained "no mention of the private sector." She went on to point out that the speech was all about "big government, big taxes." The taxes, in this case, are carbon taxes, which are not popular in a number of provinces, and are known to be regressive since they fall disproportionately on lower-income residents.

The energy plan was based on imposing a carbon tax equal to C$20 (US$14.94) per ton of emissions beginning in January 2019, and increasing it by C$10 (US$7.47) each year until 2022

The national climate change plan, which began with the support of a number of provincial governments headed by liberals, is losing that support as conservative leaders are replacing those liberal leaders. The energy plan was based on imposing a carbon tax equal to C$20 (US$14.94) per ton of emissions beginning in January 2019, and increasing it by C$10 (US$7.47) each year until 2022. Half the provinces have now announced they will not support the federal plan, as most believe their actions on reducing carbon emissions are sufficient for meeting the national goal of CO_2 reductions. The federal plan requires that any province that does not institute a sufficient carbon emissions tax may face a "backup" tax installed by the federal government.

Although "pleased" with the outcome, she acknowledged that "as of yet" there were no concrete plans to revive Alberta's economy

On the first ministers' meeting (the premier of each province and the prime minister) agenda for December 7th was a request to address the oil "crisis" in Alberta and Saskatchewan. Reportedly, the outcome of the meeting pleased Alberta Premier Rachel Notley, as she received support for short-term help for oil patch workers, medium-term support to increase oil-by-rail capacity, and long-term support to get major export pipeline projects moving. Although "pleased" with the outcome, she acknowledged that "as of yet" there were no concrete plans to revive Alberta's economy.

As we have written before, Premier Notley's idea of buying 80 locomotives and upwards of 7,000 tank cars to boost Alberta's oil shipments by 100,000 barrels per day will not have much impact before the Keystone XL and Trans Mountain pipeline projects might be under construction, or possibly close to starting up. With global oil prices under pressure from the perceived worldwide oil glut, and OPEC and Russia wrestling to design a production cut that would relieve the downward price pressure, Premier Notley finally embraced the traditional OPEC step of mandating a production cutback.

Alberta is planning an 8.7% production cut effective January 1, 2019

Alberta is planning an 8.7% production cut effective January 1, 2019. The cut, an estimated 325,000 barrels a day reduction in output is designed for the short-term. Once Canadian oil inventories are reduced, the production cut will be scaled back to only 95,000 barrels per day through the balance of 2019.

The cut is based on a company's highest six-month average oil production during 2018, after a 10,000 barrels per day output exclusion

The January 2019 start date allows the Alberta Energy Board to review individual company well data, as well as to complete writing of the plan's implementation rules. The cut is based on a company's highest six-month average oil production during 2018, after a 10,000 barrels per day output exclusion. This provides significant protection for the many very small oil producers in the province. It also means the larger oil producers, who have already cut back their production, will theoretically contribute a greater volume to the reduction, and possibly help reach the inventory decline target quicker.

The combined market reaction to the agreed-upon-cut of 1.2 million barrels per day from October 2018's output level by OPEC and Russia and its partners, as well as the Alberta oil production reduction caused the Western Canadian Select (WCS) oil price to jump. On July 6, 2018, WTI traded at $73.80 a barrel, while WCS was at $53.30, or a $20.50 per barrel discount. When the oil discounts reached their highs in November, we had WTI at $60.19, but WCS fell to $16.58, boosting the per-barrel discount to as much as $43.61. With all the favorable Canadian and OPEC news, on

December 7, 2018, WTI traded at $52.61 as WCS rose to $32.66, narrowing the discount to only $19.95 a barrel. It has continued to move higher.

Ultimately, the Trudeau government will need to address its energy policy, and especially its posture toward new pipelines

As Canadian oil producers as well as the Alberta's government push for increased rail export volumes, the environmentally safer and less costly transportation option is expanded pipeline egress. Recently, Enbridge Inc. (ENB-NYSE) announced it is working to be able to carry an additional 100,000 barrels per day in its pipeline systems to help relieve the glut and boost producer prices. Ultimately, the Trudeau government will need to address its energy policy, and especially its posture toward new pipelines that will allow Canadian oil exports to reach world markets without having to traverse the United States to reach Gulf Coast export facilities. To employ OPEC-like tactics to manage wellhead prices in Canada may become problematic for the Alberta government. Extracting itself from this regulatory role may prove more challenging than Premier Notley currently anticipates.

Another Sign Of How Shale Is Changing The Energy World

The total of 9.0 million b/d of petroleum exports exceeded our total imports of 7.2 million b/d of crude oil and 1.6 million b/d of refined petroleum products by 200,000 b/d

Last week the web site of the Energy Information Administration (EIA) carried a story about the United States becoming a new oil exporter for the first time in weekly data back to 1991. This doesn't mean that we stopped importing crude oil and petroleum products because we were self-sufficient, but rather that our exports exceeded our imports. According to the EIA, for the week of November 24-30, the U.S. exported 3.2 million barrels per day (b/d) of crude oil, along with 5.8 million b/d of refined petroleum products, such as gasoline, heating oil and propane. The total of 9.0 million b/d of petroleum exports exceeded our total imports of 7.2 million b/d of crude oil and 1.6 million b/d of refined petroleum products by 200,000 b/d.

Exhibit 6. Celebrating U.S. Net Oil Export Status

Source: EIA

Starting in mid-2016, the EIA began improving its weekly petroleum data series. It began using near real-time petroleum export data collected by the U.S. Customs and Border Protection agency that provides the data to the U.S. Census Bureau. The monthly export data certified by the Census Bureau is used in the monthly data series, as it was judged to be more reliable than the weekly data estimates. That said, this recent report should be viewed in the context of the longer-term trends in the U.S. energy market and less a celebration of a new status.

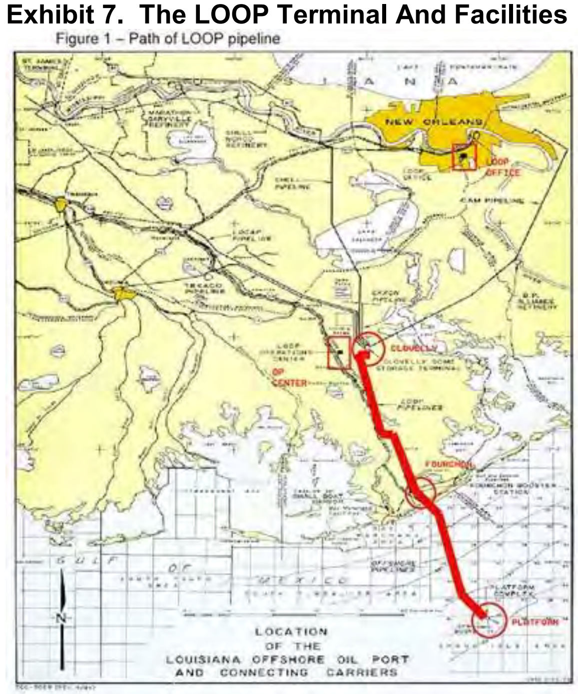
Most of our imports are heavier oil needed to run our refineries more efficiently, while our exports are primarily light shale oil

The U.S. remains a net crude oil importer. The latest official monthly data for September 2018, shows that the U.S. imported 7.6 million b/d and exported 2.1 million b/d of crude oil. Most of our imports are heavier oil needed to run our refineries more efficiently, while our exports are primarily light shale oil. However, the U.S. has been a net exporter of various refined petroleum products, including motor gasoline, distillate, hydrocarbon gas liquids, and jet fuel for a while. This refining surplus has been driven by long-term trends showing significantly slower growth in the consumption of these petroleum products compared to the industry's capacity to produce them.

The late November petroleum product export surge was helped by very high refinery utilization

The late November petroleum product export surge was helped by very high refinery utilization as the industry continues its recovery from Hurricane Harvey, which forced the shutdown of approximately 30% of the nation's refining capacity located along the Gulf Coast. The high refinery utilization is helping the industry to rebuild product inventory levels that had been drawn down sharply by the hurricane shutdowns and damage to various refineries.

Exhibit 7. The LOOP Terminal And Facilities



Source: LOOP

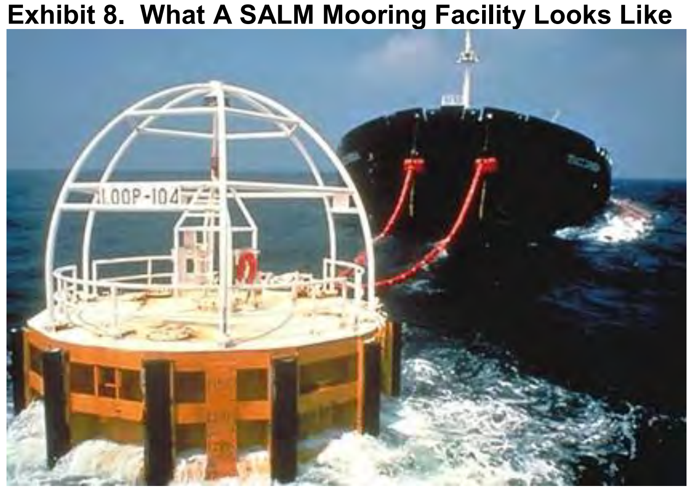
It meant the ships did not have to wait to enter ports along the Gulf Coast, speeding up the import process

There is another industry development of significance behind the crude oil export surge, which may have been responsible for the recent record. The development will lift the U.S. into its new role as a leading global oil exporter. It is the Louisiana Offshore Oil Port LLC, or LOOP. Founded in 1972, shortly after the United States oil industry reached peak production and began to decline, LOOP was designed as an offshore oil unloading facility to ease importing of crude oil arriving by tanker. It meant the ships did not have to wait to enter ports along the Gulf Coast, speeding up the import process. It also helps that LOOP's terminal is located 18 miles off the Louisiana coast, reducing the impact of coastal fog that often impacts marine activity. For those living along the Gulf Coast, we are very familiar with the coastal fog that often plays havoc with the weekly oil import statistics. When it is foggy, ships cannot enter ports and unload crude oil, reducing imports and forcing inventory drawdowns. On the refined product side, fog prevents ships from leaving ports, so product inventories might be higher than otherwise.

The solution is to unload them offshore, either fully, as at LOOP, for example, or partially, called "lightering," in which a portion of the cargo is transferred to a smaller ship that eliminates the water depth requirements for large ship in order to enter the port

Now, we have almost the reverse situation, which may have contributed to November's weekly net export achievement. The LOOP facilities consist of an offshore Marine Terminal with three SALMs (Single Anchor Leg Mooring) located 8,000 feet from the platform. Each SALM is 21-ft. in diameter and 46-ft. in length. It sits in water 115-ft. deep, which provides sufficient depth for Ultra Large Crude Carriers (ULCC), Very Large Crude Carriers (VLCC), and Medium Range tankers that can have drafts of up to 85-ft. and carry 1,000,000-2,000,000 barrels of oil. When fully loaded, many of these ships require greater water depths for maneuvering than exists in many ports, preventing them from being used. The solution is to unload them offshore, either fully, as at LOOP, for example, or partially, called "lightering," in which a portion of the cargo is transferred to a smaller ship that eliminates the water depth requirements for large ship in order to enter the port.

Exhibit 8. What A SALM Mooring Facility Looks Like



Source: LOOP

The SALMs provide 3600 movement, enabling the ship to rotate (weathervane) to maintain a stable and safe platform with a minimum of effort while it is unloading its cargo

The LOOP facilities were constructed in 1979 and provide for the unloading of crude oil cargoes in the Gulf of Mexico, Each SALM provides an anchoring point, along with hoses for unloading the crude oil. The SALMs provide 360^0 movement, enabling the ship to rotate (weathervane) to maintain a stable and safe platform with a minimum of effort while it is unloading its cargo. With the 2015 overturning of the ban on exporting domestic crude oil, LOOP began working to make its terminal a bi-lateral shipping facility. In February, LOOP began to load large tankers with crude oil for export besides unloading arriving cargoes.

LOOP is the first U.S. crude oil export facility that can load the largest tankers in the world, reducing the transportation cost for delivering cargoes to international markets. There are plans for an additional nine deepwater export terminals along the Gulf Coast – some to be in Texas ports and others located offshore as single-point mooring facilities similar to LOOP. Those additional export terminals will not be up and running until the second half of 2019, and after.

LOOP was able to reduce the time necessary to load a VLCC to two days

The key point about LOOP, with respect to the recent net oil export achievement, was its announcement of last week. The announcement was that in the prior week, LOOP was able to reduce the time necessary to load a VLCC to two days. As a result, LOOP loaded three VLCCs in the first week of December. This achievement was facilitated by the lack of tankers arriving with cargoes to be unloaded. That enabled LOOP to move empty tankers to the terminal easier and faster, facilitating the three VLCC loadings. So, how many fewer tankers arrived to offload their cargoes at LOOP, which helped reduce the November weekly oil imports, while boosting export cargoes?

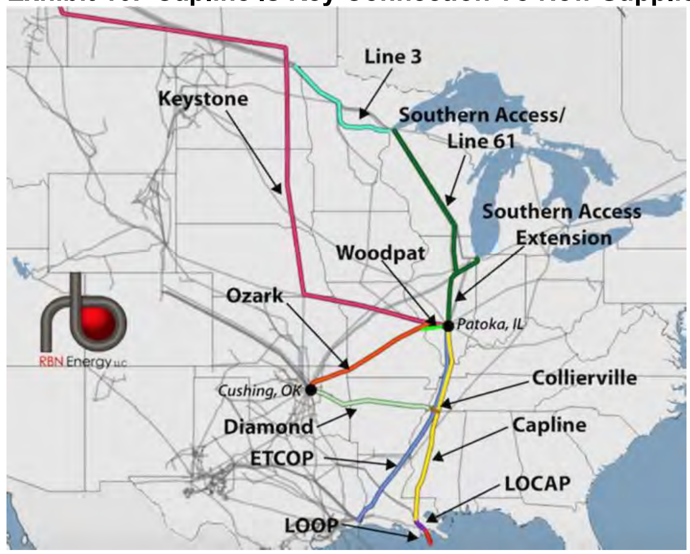
Exhibit 9. Tanker Unloading At LOOP Terminal

Source: LOOP

That reversal would add possibly 300,000 b/d of supply for export from LOOP

The November achievement should not be treated as merely a step towards much greater export volumes. That will only happen after certain infrastructure steps are taken. First is the start-up of other export terminals. Secondly is reversing the Capline pipeline that moves oil from the Gulf Coast north. That reversal would add possibly 300,000 b/d of supply for export from LOOP. However, most of the additional oil available for export is likely coming from the Eagle Ford and Permian basins. That oil will head to closer Texas ports for export. That means LOOP cannot increase its export volumes materially without a Capline reversal, and that won't happen quickly.

Exhibit 10. Capline Is Key Connection To New Supplies



Source: RBN Energy

Assuming the owners agree, the reversed pipeline would be operating in 2022, hauling 300,000 b/d of oil to the Gulf Coast for export

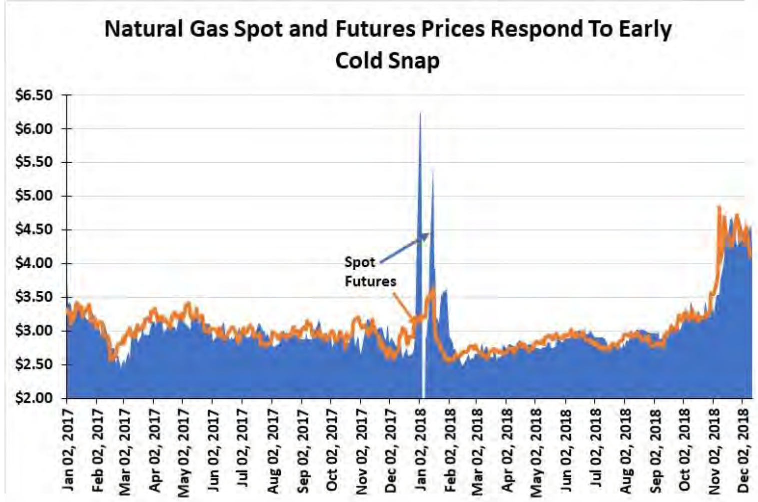
In late 2017, the owners of Capline, Marathon Pipe Line LLC, a unit of MPLX LP (MPLX-NYSE), and Plains All American Pipeline, L.P. (PAA-NYSE), and BP Oil Pipeline Co. (BP-NYSE) held a non-binding open season to determine the interest of oil shippers for reversing the pipeline's direction. There was support for such a move, as Capline is only utilizing about one-third of its capacity. Reversing the flow would allow Capline to tap oil from Appalachian and Canadian sources. Assuming the owners agree, the reversed pipeline would be operating in 2022, hauling 300,000 b/d of oil to the Gulf Coast for export. That will be a key infrastructure move that will further enable the United States to become a dominant global oil exporter, further changing the dynamics of the worldwide oil industry.

Has The Natural Gas Market Embraced Global Warming?

Gas prices struggled to return to the $3/Mcf level in the face of waning demand and robust production growth

Coming out of the Arctic cold that enveloped the U.S. in December 2017 and January 2018, natural gas prices slumped to $2.50 per thousand cubic feet (Mcf). The "early" spring abruptly ended the heating season and, as natural gas production continued growing rapidly, the gas market – real and paper – reflected the conventional view that we had too much of the stuff! Gas prices struggled to return to the $3/Mcf level in the face of waning demand and robust production growth. As producers couldn't slow the growth in associated gas from Permian basin oil wells, they worked to find other outlets for gas – exports – and to choke back gas-directed drilling.

Exhibit 11. Mother Nature Scared The Gas Market Into Rally



Source: EIA, PPHB

Volatility was low with fluctuations ranging in the pennies to maybe a dime a day

The net result of these actions was to limit the growth of natural gas in storage. But there was little concern about any supply shortage, at least as measured by the pattern of gas prices. Volatility was low with fluctuations ranging in the pennies to maybe a dime a day. That all changed when cold weather arrived in early November. Thanksgiving Day turned out to be the coldest day ever in portions of New England. The records were not merely passed, they were shattered by double-digit amounts.

The short-term solution to an undersupplied, but overly consuming gas market is to raise prices

The shock of early cold and snow, seemed to jump-start the natural gas futures trading scene, although spot prices also picked up commensurately. It was as if gas traders and gas buyers suddenly realized that if November's weather was the start of a long, cold winter, we were woefully short of gas storage. The short-term solution to an undersupplied, but overly consuming gas market is to raise prices. That is exactly what the market did.

An explanation for the explosion in gas price volatility was that commodity traders had made pair trades – going long crude oil futures and short natural gas futures

Volatility during this repricing phase was violent, with daily moves of as much as 60- and 80-cents at a time. An explanation for the explosion in gas price volatility was that commodity traders had made pair trades – going long crude oil futures and short natural gas futures. For a long time that trade has been profitable, as crude oil prices rallied into the upper $70s a barrel, while natural gas prices struggled to sustain a $3/Mcf level. When crude oil prices began crashing in November, and the early cold and snow caused natural gas prices to blast off, these commodity funds were forced to cover their short positions, further adding to the rising price. Exactly how much of the dramatic gas price rise was due to short-covering is difficult to know, but it certainly had to have been a major factor.

As with every winter, there are a range of issues impacting supply and demand. This winter is no different, so analysts are beginning to look at the performance of the natural gas market so far this year. They are considering current gas storage volumes, natural gas import and export volumes, competitive fuel prices, and the every-present winter weather forecasts. The trends impacting every one of these factors not only are changing, in some cases they may be working against other trends, at least until the market has a better understanding of the dynamic for each factor.

Despite cheap natural gas, coal has been even cheaper, helping to put a temporary lid on coal-to-gas fuel switching in the power generation market

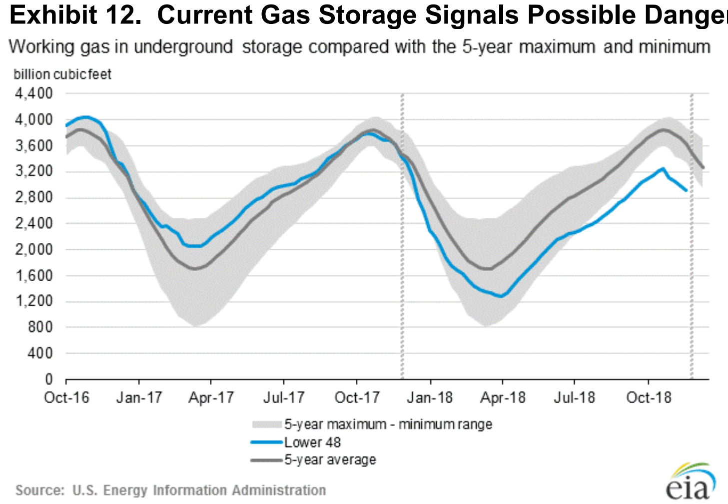
Despite cheap natural gas, coal has been even cheaper, helping to put a temporary lid on coal-to-gas fuel switching in the power generation market. In certain cold climates, primarily New England, the lack of adequate gas transportation and storage capacity helps coal demand, which has become the primary backup fuel for electric utilities in the winter.

Cheap natural gas nationally, was even cheaper at times in the Marcellus/Utica region, forcing producers to aggressively pursue market opportunities in Eastern Canada

Cheap natural gas nationally, was even cheaper at times in the Marcellus/Utica region, forcing producers to aggressively pursue market opportunities in Eastern Canada. At the same time U.S. gas moved across the border undercutting Canadian gas sales, Canadian gas exports to the U.S. fell. On the southern border, the completion of new pipelines into Mexico boosted gas export volumes there, helping to prevent storage volumes from building. And, the United States is enjoying growing liquefied natural gas (LNG) exports, with last week seeing the first shipment from a new facility in Corpus Christi, Texas, marking the third export terminal in operation in the U.S.

Even though gas production has continued growing, the increasing bottleneck for crude oil shipments from the Permian is leading to fewer new wells being drilling and completed. That means there will be less associated natural gas, at least as long as the pipeline congestion exists, which is not projected to ease until about the middle of 2019.

Exhibit 12. Current Gas Storage Signals Possible Danger



Source: EIA

Last week's natural gas storage report shows total volumes down 20% from both last year and the 5-year average

Last week's natural gas storage report shows total volumes down 20% from both last year and the 5-year average. That means we have 722/723 Bcf less gas in storage than in the past. That is not a particularly good position to be in, given that we are only in mid-December. Just how cold might the rest of winter be? That becomes the biggest question for the market, assuming that natural gas exports – both via pipelines and LNG ships – do not change materially. It also assumes that competitive fuel pricing in the power generation market doesn't shift, and that gas production grows, or at least doesn't fall.

"Projected end-of-March natural gas storage at Wednesday's [Dec. 12] strip prices: 1,179 Bcf | Coal displacement: 0.0 Bcf/day"

Different analysts have developed models for predicting the amount of natural gas that may be in storage at the end of the winter withdrawal season, which will impact where gas prices may be as we move into the annual gas injection season. One model we watch, produced by EBW AnalyticsGroup and Weather Decision Technologies, predicted the following last week: "Projected end-of-March natural gas storage at Wednesday's *[Dec. 12]* strip prices: 1,179 Bcf | Coal displacement: 0.0 Bcf/day."

If this projection is realized, it would put storage about 175 Bcf below where we were at March 31, 2018

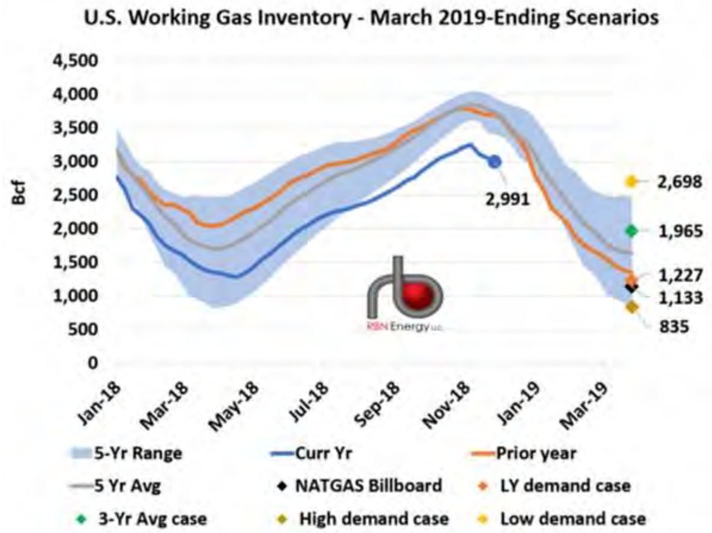
Their comment on natural gas not displacing more coal consumption in the power generation market is not surprising given current natural gas prices that are in the $4.40-$4.50/Mcf range, depending on whether one looks at the near-month futures contract or the Henry Hub spot price. The more interesting figure is the estimate for gas storage at the end of March 2019's withdrawal season. If this projection is realized, it would put storage about 175 Bcf below where we were at March 31, 2018. It would be almost 360 Bcf above the lowest end-of-winter storage level (2013) in the last 15 years. That is not a particularly comforting consideration, because there are a number of factors that could alter the final amount significantly.

Another model run by RBN NATGAS Billboard the middle of last week arrives at a projected storage volume at the end of March 2019 of 1,133 Bcf, or virtually at the same level as the EBW model. This suggests the two models are considering the same variables, but possibly weighting estimates slightly differently.

They have outcomes both above and below the 5-year range, with three forecasts falling within that historical range, but with two of them in the lower end of the range

RBN published an article detailing various scenarios for the natural gas market, with a similar aim as we are doing: trying to answer the question of how the gas market this winter may deal with the current low storage volume. They examine all the variables – LNG exports, pipeline exports to Canada and Mexico, gas imports from Canada, domestic gas production, coal-to-gas fuel switching and the weather. Without going through all the various assumptions, the chart in Exhibit 13 (next page) shows their forecast outcomes. They have outcomes both above and below the 5-year range, with three forecasts falling within that historical range, but with two of them in the lower end of the range.

Exhibit 13. How One Forecaster Sees Gas Market Ending

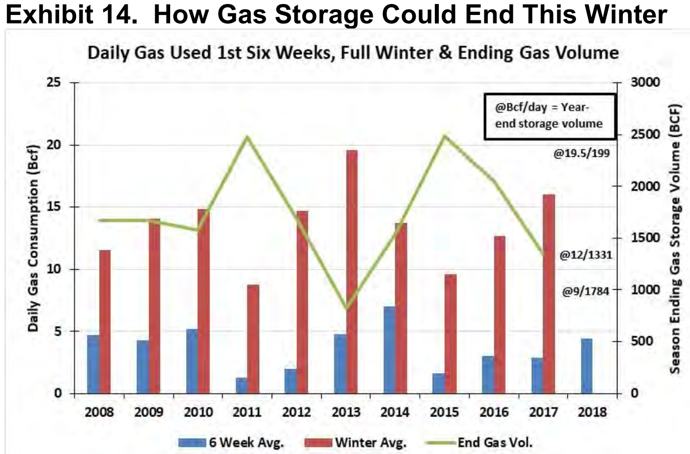


Source: RBN Energy LLC

Our model is relatively simple and only focuses on the amount of natural gas withdrawn from storage, not imports or exports or even production

We have been developing our own model for predicting winter gas storage withdrawal, as this is what will determine the trajectory of gas prices for the balance of the winter, but more importantly, the spring and summer of 2019. Our model is relatively simple and only focuses on the amount of natural gas withdrawn from storage, not imports or exports or even production. We have looked at gas storage from 2008 to now. We have calculated the average daily withdrawal for the first six weeks of each winter (blue bar) and for the entire winter season (red bar). The green line represents the amount of natural gas that remained in storage at the end of the winter withdrawal season. The level of the green line is a reflection of the degree of harshness of the winter, but also gas production growth and beginning storage levels.

Exhibit 14. How Gas Storage Could End This Winter



Source: EIA, PPHB

If we have a cold winter and use 19.5 Bcf/d, as in 2013, we will barely escape winter with any gas in storage (199 Bcf)

What we see at the moment is that the daily withdrawal rate for the first six weeks is 4.4 Bcf/d, which is substantially higher than for the past three winters. Since it is impossible to know what this withdrawal rate will be for the entire 2018-2019 winter season, we have estimated three possible outcomes based on past experience. If we have a cold winter and use 19.5 Bcf/d, as in 2013, we will barely escape winter with any gas in storage (199 Bcf). On the other hand, if we have a very mild winter and only use 9 Bcf/d as in 2011, we will end up with nearly 1,800 Bcf left in storage, or slightly over 400 Bcf more than we ended with last winter. An intermediate forecast using 12 Bcf/d produces an ending storage volume of 1,331 Bcf. What we found most interesting was when we calculated the average withdrawal over the entire 2008-2017 period of 13.5 Bcf/d, we arrive at a season-ending volume of 1,105 Bcf. While lower than either the RBN or EBW forecasts, ours is in the same ballpark.

The first winter forecast we saw this year suggesting that the meteorology variables that drive our weather have established a pattern that leads to the conclusion that over half the United States will be cooler than normal

The key variable for the forecast is likely the weather. A recent winter forecast from our friends at *StormGeo* shows a colder-than-normal south and east regions of the country. The firm produced the first winter forecast we saw this year suggesting that the meteorology variables that drive our weather have established a pattern that leads to the conclusion that over half the United States will be cooler than normal. Certain areas within these broad regions are likely to experience greater precipitation, often in the form of snow, but it is not likely that this will be a winter with broad snow storms. We show a couple of screen shots of their forecast slides from the webinar we attended. We have found their weather forecasts, and especially their hurricane forecasts, to be very accurate.

Exhibit 15. Near-Term Colder Winter Is Expected

Source: *StormGeo*

Exhibit 16. Cool Late Winter And Spring Helps Gas Demand

Source: ***StormGeo***

If *StormGeo* is correct, then the first two months of this winter will be much colder than normal, which could easily spook the gas market, sending gas prices to $5/Mcf or above. For portions of the Northeast where gas supplies are not readily available, we could see competition for the limited volumes soaring to well over $100/Mcf as has happened at times in the past. This could be a winter where weather conditions defy the global warming thesis and send gas prices soaring. Hold on for what may be an interesting next few months for natural gas.

This could be a winter where weather conditions defy the global warming thesis and send gas prices soaring

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