ENERGY INVESTMENT BANKING

MUSINGS FROM THE OIL PATCH

September 18, 2018

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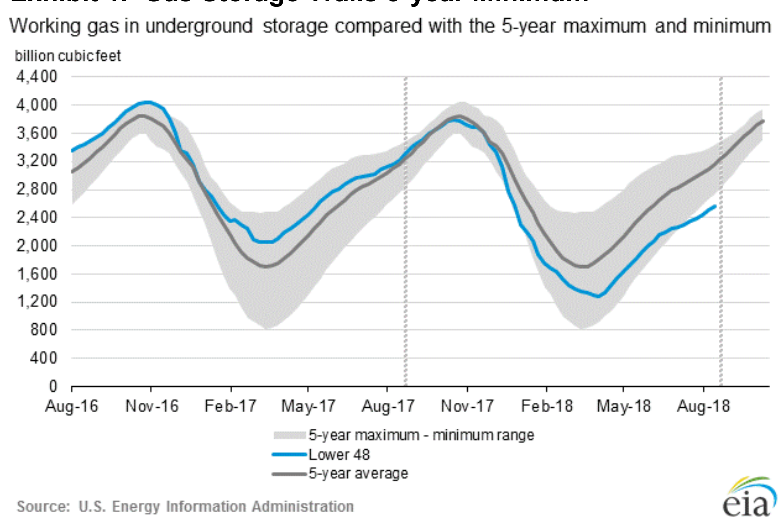
Note: *Musings from the Oil Patch reflects an eclectic collection of stories and analyses dealing with issues and developments within the energy industry that I feel have potentially significant implications for executives operating and planning for the future. The newsletter is published every two weeks,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

Natural Gas Storage And Possible Market Outlooks

The total volume of working gas in storage sits below the five-year historical range

With the Energy Information Administration's publication of its natural gas storage report for the week ending August 31, we gained an opportunity to assess where the gas storage stands relative to the soon-to-end injection season. For the last week of August, there was 2,568 billion cubic feet (Bcf) of natural gas in storage, an increase of 63 Bcf from the prior week. Storage was 643 Bcf less than last year at this time, and 590 Bcf below the five-year storage average of 3,158 Bcf. The total volume of working gas in storage sits below the five-year historical range.

Exhibit 1. Gas Storage Trails 5-year Minimum



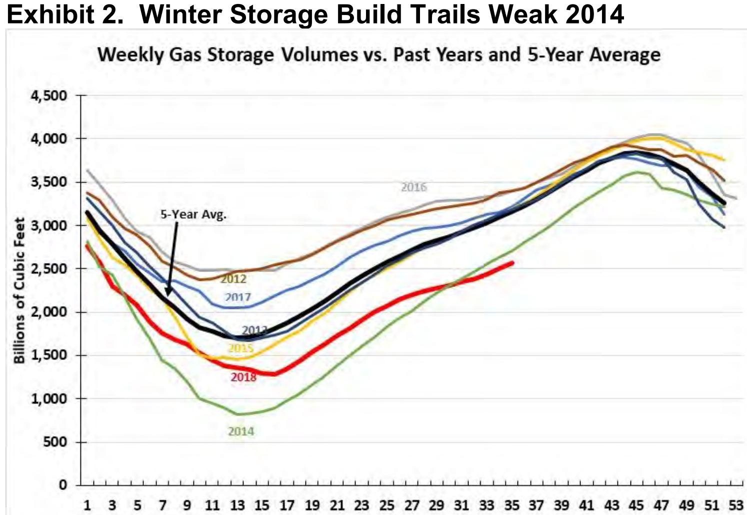
Source: EIA

A possibly more significant mark is that the current natural gas storage volumes are trailing the amount in 2014, the most recent

These prices are surprising given that during the final four weeks of August spot gas prices averaged $2.99/Mcf

lowest gas storage season. The current situation calls into question what is happening with natural gas futures prices, which should be reacting to the low storage to encourage producers to deliver more gas for storage. On Friday, September 7, the near-month natural gas futures price closed trading at $2.78 per thousand cubic feet (Mcf). Henry Hub spot gas prices are only 10-cents/Mcf higher. These prices are surprising given that during the final four weeks of August spot gas prices averaged $2.99/Mcf. That was up from the last half of July and first week of August during which the price averaged $2.79/Mcf.

Exhibit 2. Winter Storage Build Trails Weak 2014



Source: EIA, PPHB

Domestic dry natural gas production has grown by 15.5% over the past year

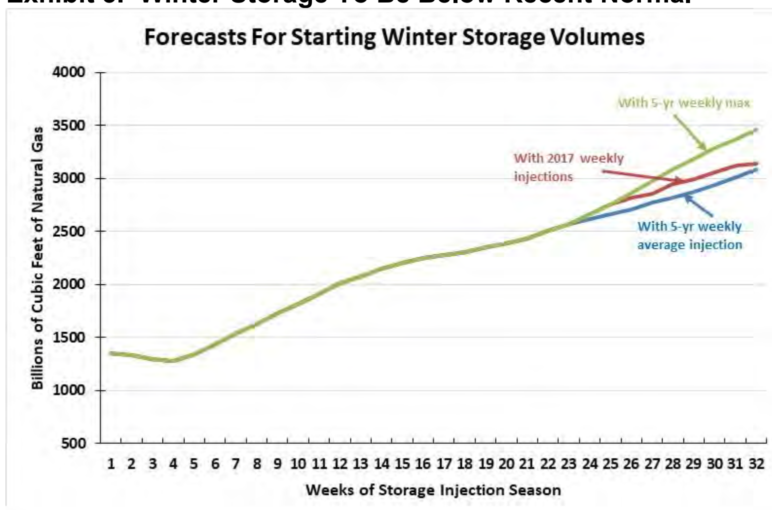
One has to wonder if gas prices seem to be signaling that the market believes gas storage volumes will reach adequate levels, given current gas production, to meet the market's needs for the upcoming winter. That conclusion is a function of understanding that natural gas production has grown dramatically this year. According to OPIS PointLogic Energy, domestic dry natural gas production has grown by 15.5% over the past year, increasing from an average of 71.7 Bcf/day to 82.8 Bcf/d. With stable gas import volumes from Canada and LNG sources, total gas supply grew 13.5% during the past 12 months.

Where will final storage volumes be when we end the injection season?

Possibly more encouraging for the gas market is that there has been 23 Bcf more gas injected into storage during the past four weeks as compared to the same weeks in 2017, a 12% increase. With gas production higher and storage injections up, the market may be taking solace that it doesn't need higher gas prices to boost storage injections. The question about storage that could change the trajectory of natural gas prices is where will final storage volumes be when we end the injection season? To understand what potential volumes might be in storage, we needed to project injections for the balance of the season.

There are roughly nine weeks of storage injection left in the season. If we project that the remaining weekly injection rates will equal the five-year average, the 2017 average or that every week matches the maximum injection during the past five years, the forecasts leave us with two very different conclusions.

Exhibit 3. Winter Storage To Be Below Recent Normal



Source: EIA, PPHB

The highest storage total comes if the remaining weekly injections match the maximum weekly injection during each week of the 5-year average

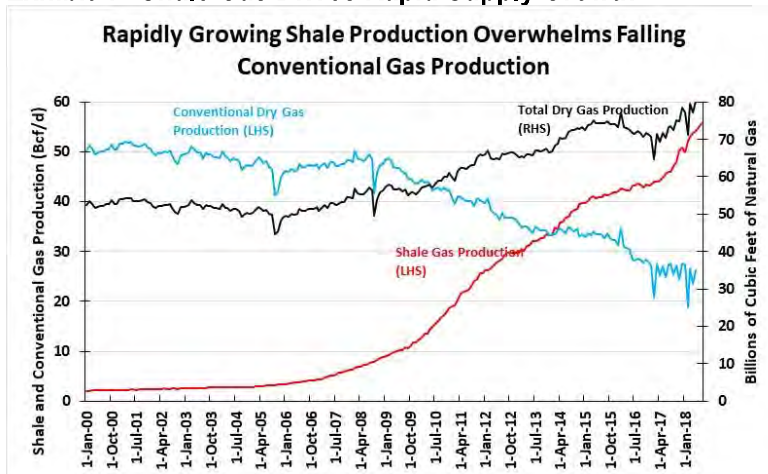
With the addition of the weekly average injection rate or the 2017 weekly injections, the ending range for storage volumes is 3,085-3,138 Bcf, only a 1.7% spread. The highest storage total comes if the remaining weekly injections match the maximum weekly injection during each week of the 5-year average. In that case, ending storage volumes reach 3,460 Bcf. That would still be roughly 300-500 Bcf below where storage volumes ended each year since 2009. However, the projected volume would be comparable to the storage volumes during the prior three years of 2006-2008.

Maybe the market will demand more gas than the low amounts projected by our forecasting model, but will 3,400 Bcf become the new acceptable norm?

What we found most interesting is that the low storage volume projections are consistent with the ending storage volumes for each year between 1999 and 2005. Is it possible the market is assuming that given the extremely sharp increase in shale gas production and renewables taking more of a share of the power generation fuel consumption that we do not need as much storage to start the winter withdrawal season as thought in recent years? Maybe the market will demand more gas than the low amounts projected by our forecasting model, but will 3,400 Bcf become the new acceptable norm?

Turning to the production question, when we examine how shale gas output has grown since 2009, we see it is growing at the fastest rate ever since the start of 2017. Couple fast shale output growth with a flattening in the decline rate of conventional gas production, as evident in the past two years, and we have the sharpest growth rate

Exhibit 4. Shale Gas Drives Rapid Supply Growth

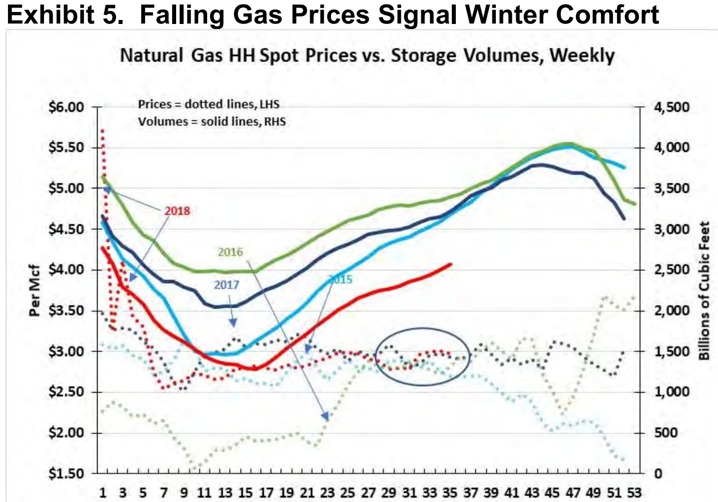


Source: EIA, PPHB

This oil pipeline issue is a challenge for gas output, leading to some gas production being flared

for domestic natural gas since 2000. The unanswered question about the continuation of rapid gas production growth is the impact on associated natural gas output coming from the Permian Basin where a shortage of oil pipeline capacity is capping the amount of oil production that can exit the basin. This oil pipeline issue is a challenge for gas output, leading to some gas production being flared. While it appears that the Texas Railroad Commission is working with producers in the basin to allow, while controlling, the burning of surplus gas, it will likely be hard to gain significant exemptions given the social pressure against flaring gas due to carbon emissions. With oil output being restricted due to the pipeline capacity problem, it may result in the TRC ordering producers to prioritize output from wells with less natural gas to prevent high volumes needing to be flared.

Exhibit 5. Falling Gas Prices Signal Winter Comfort



Source: EIA, PPHB

The market remains convinced there is adequate gas supplies available to meet winter needs

The fact that natural gas prices could not rise above $3.00/Mcf when weekly gas storage injections moderated causing total storage volumes to fall behind the recovery pace of 2014 suggests that the market remains convinced there is adequate gas supplies available to meet winter needs. Our chart showing gas storage in 2018 versus the most recent three years, as well as weekly spot gas prices, confirms that even though the pace of the 2018 storage rebuild remains weaker than anticipated, gas prices are actually in decline (inside the oval in Exhibit 5, prior page). The conundrum of the natural gas market continues to confound market analysts. With hurricane season reaching its peak activity, will that further complicate projecting winter natural gas storage levels?

Gun Smoke From Trans Mountain Decision Hasn't Cleared

The smoke from the gun used to shoot the Trudeau government in the foot has yet to clear. The National Energy Board's (NEB) approval of the Trans Mountain Pipeline Expansion in 2016 was rejected by the Federal Court of Appeal in response to a case brought by a number of indigenous populations, environmental groups and local governments. The unanimous decision was announced on the same day that Kinder Morgan Canada Ltd. (KML-TSX), a subsidiary of Kinder Morgan Inc. (KMI-NYSE), shareholders voted 99.98% in favor of selling the Trans Mountain Pipeline system and expansion project to the Canadian government.

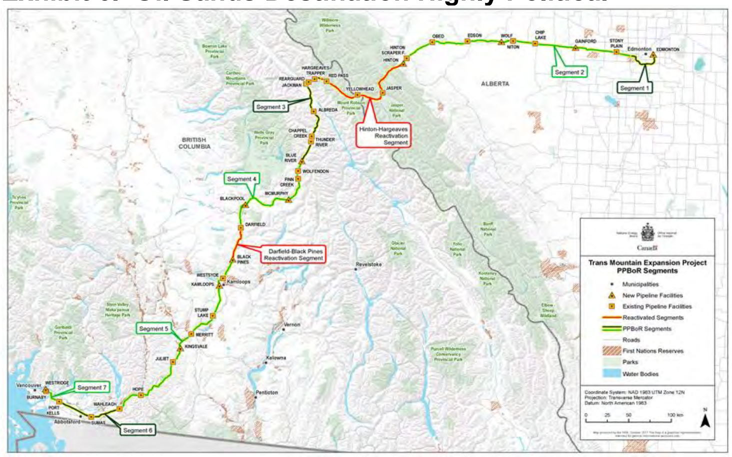
The sale was the "engineered" solution for keeping the project on track after continued legal challenges and protests imperiled the expansion construction

The system sale price was C$4.5 billion ($3.4 billion), less an estimated C$325 million ($245 million) in capital gains taxes owed to the Canadian government. The sale was the "engineered" solution for keeping the project on track after continued legal challenges and protests imperiled the expansion construction. KML delivered an ultimatum to the British Columbia and Alberta provinces, as well as the federal government to develop a solution to the legal and political morass stopping the pipeline expansion or the company would abandon the project. Recognizing the strategic and economic importance of creating alternative routes for Canadian oil and gas to global markets rather than having to pass through the United States, buying the pipeline became the most viable solution.

The Trans Mountain expansion was to deliver an additional 590,000 barrels per day of oil to the Pacific Coast terminal

Following the KML shareholder vote, the sale was completed. Involved were 2.9 million barrels of regulated oil storage tanks, as well as the Puget Sound Pipeline, Kamloops/Sumas/Burnaby Terminals and the Westridge Marine Terminal. Trans Mountain Pipe Line Company was created on March 21, 1951, and the first shipment of oil from Alberta to reach the Trans Mountain Burnaby Terminal arrived on October 17, 1953. The Trans Mountain expansion was to deliver an additional 590,000 barrels per day of oil to the Pacific Coast terminal. The project's total estimated cost had risen to C$7.4 billion ($5.6 billion), but with the possibility of further delays due to the legal challenges and protests that would extend the pipeline's in-service date to 2021 and was projected to potentially increase the cost to C$9.3 billion ($7.0 billion). It was the fear of the cost escalation and in-service date delay that drove KML to deliver its ultimatum.

Exhibit 6. Oil Sands Destination Highly Political



Source: NEB

The Trudeau government's approval of the pipeline expansion came with 157 conditions, something Mr. Trudeau loudly proclaimed was a victory for his line-walking effort

The Trans Mountain Pipeline Expansion project commenced in 2012 and ultimately was approved in 2016. This was during the first year of Prime Minister Justin Trudeau's Liberal government reign. An avowed environmentalist, Mr. Trudeau tried to walk a fine line between approving pipeline projects that would help lift the fortunes of the oil and gas industry, which is crucial for the economic health of the western provinces and the country overall, while satisfying his environmental supporters focused on mounting an anti-fossil fuel campaign. The Trudeau government's approval of the pipeline expansion came with 157 conditions, something Mr. Trudeau loudly proclaimed was a victory for his line-walking effort.

The most interesting aspect of the protests over the Trans Mountain Pipeline Expansion is that the local governments who attacked the project lost every case. The courts even established a protest-free zone to allow the construction work to proceed. Protesters who entered into that zone were arrested, convicted of trespassing, and fined or jailed. But, in the most important legal case involving the pipeline expansion, the plaintiffs were victorious.

Ms. Notley also removed Alberta from the federal government's national climate change program, potentially wrecking a prize accomplishment of Mr. Trudeau

Their victory has created chaos in Canadian political circles. Rachel Notley, premier of Alberta, was so angered by the court rejection that she not only demanded the federal government appeal the decision to the Supreme Court, but she also demanded that Mr. Trudeau call Parliament back into session to devise a solution and begin consultations with the First Nation's leaders. Immediately following the court ruling, Ms. Notley also removed Alberta from the federal government's national climate change program, potentially wrecking a prize accomplishment of Mr. Trudeau.

Getting Parliament to legislate the pipeline project into existence, overruling the court, doesn't appear to be a viable option

Natural Resource Minister Amarjeet Sohi commented that "all options are on the table," but Prime Minister Trudeau told a radio audience in Edmonton that "[u]sing a legislative trick might be satisfying in the short term, but it would set up fights and uncertainty for investors over the coming years on any other project, because you can't have a government keep invoking those sorts of things on every given project." Getting Parliament to legislate the pipeline project into existence, overruling the court, doesn't appear to be a viable option. Will appealing the ruling to the Supreme Court be the intermediate step? Analysts say this could take upwards of a year to resolve. Moreover, there is no guarantee that the ruling would be overturned. No progress on the expansion can proceed during the appeal process, putting the Canadian oil and gas industry under pressure to step up riskier rail transport of its increasing oil output.

While the court ruling rested on two key points – the failure to consider the impact of increased project-related tanker traffic on the Southern resident killer whales from the project's definition and to not adequately and appropriately consult with impacted Indigenous populations – the media coverage seemed to focus on only one – the consultation. We are sure this is a response to concern over the government's dealings with Indigenous populations.

Having waded through the 266-page written decision, we see that the court went to great pains to document its belief that the Phase III consultation process with the First Nations was not conducted properly

Having waded through the 266-page written decision, we see that the court went to great pains to document its belief that the Phase III consultation process with the First Nations was not conducted properly. In the court hearing, the NEB relied on demonstrating that the consulting process was conducted properly, but failed to demonstrate that the discussions resulted in any concrete responses that led to adjustments of the project. At times, the recitation of the back and forth during the hearings almost seemed like the script of a marital therapist counseling a couple. Both sides were saying the right things from their perspective, but the other side failed to hear and understand what it was being told, which meant that little progress was made. Thus, the court demonstrated that it was unpersuaded there were "real" consultations involving the six First Nations plaintiffs. The court felt the government listened to what it was being told but failed to hear and make any adjustments. This outcome is not completely surprising as the pendulum of rights and power of Indigenous people has swung very far away from the day when the federal government extended the colonial policies of its founders – France and Britain.

Starting in the 1940s, Canadian policies toward Indigenous people began to shift away from the colonial view that these people had no rights, only what the government allowed, to one based on assimilation. Since the late 1960s, Canadian policy has gradually moved to accept greater degrees of self-determination, achieved through modern-day treaties and self-government agreements. In July 2014, the Trudeau government, partly in response to the United Nations Declaration on the Rights of Indigenous Peoples, set forth ten principles to help achieve reconciliation with Indigenous peoples through a "renewed, nation to nation, government to government, and Inuit-Crown relationship based on recognition of rights, respect, co-operation and partnership."

Those discussions cannot begin until the NEB report on the project is revised

What seems to be missed by the media and other observers who suggest that a "better" consultation process will resolve the Trans Mountain legal battle quickly is that those discussions cannot begin until the NEB report on the project is revised. That means incorporating new research on the increased tanker activity on the Southern resident killer whales. The Federal Court of Appeals decision authored by Madame Justice J.A. Dawson concluded:

> "[766] This finding—that the Project was not likely to cause significant adverse environmental effects—was central to its report. The unjustified failure to assess the effects of Project-related shipping under the Canadian Environmental Assessment Act, 2012 and the resulting flawed conclusion about the environmental effects of the Project was critical to the decision of the Governor in Council. With such a flawed report before it, the Governor in Council could not legally make the kind of assessment of the Project's environmental effects and the public interest that the legislation requires."

Unless the data conclusively shows that there will be no impact, any impact will necessitate remedies, which will involve the maritime and coastal regulatory agencies to develop alternative solutions

The result of this decision, if not overturned through an appeal to the Supreme Court, is that the NEB must extend its analysis beyond the coastline and into the waters in which tankers will travel hauling the additional crude oil flowing through the Trans Mountain Pipeline Expansion project. We assume data on the issue already exists, but we have no idea how recent it is and whether it covers all the areas impacted by the additional tanker traffic. Unless the data conclusively shows that there will be no impact, any impact will necessitate remedies, which will involve the maritime and coastal regulatory agencies to develop alternative solutions. From the set of possible solutions, the best alternative would be selected, and if that involves altering shipping channels, or some similar modification, there would likely be a process to make that happen. How long that process might take is unknown.

In taking stock of the status of the Trans Mountain Pipeline Expansion project, we sense it is dead in the water for the time being. With no clear path to a quick resolution of the roadblock, there will be much speculation on what is the best path for moving forward. At the same time, this singular victory by the opponents of the pipeline expansion will boost their resistance efforts. Moreover, the regulatory stumble comes just as the Canadian government has spent billions of dollars to purchase the Trans Mountain Pipeline assets. It has recruited the former CEO of Trans Mountain to run the newly established Crown subsidiary to hold and operate the system, and he is working to hire 5-6 executives who worked with him to join the new company. Now KML is considering liquidating.

There are three options available to the Trudeau government: 1) appeal the court decision to the Supreme Court; 2) legislate a solution that end-runs the court ruling; and 3) follow through on the two remedies the court stipulated. Based on Prime Minister Trudeau's comments, option No. 2 seems off the table. He doesn't want any legislative tricks.

Option No. 1 seems to have the shorter time horizon – one year – but it carries the risk of failure

Option No. 1 seems to have the shorter time horizon – one year – but it carries the risk of failure, which would force turning to option No. 3, or potentially reverting to option No. 2 and seek legislative approval. That scenario assumes the time up to starting the process was utilized to prepare the populace for the need to take such an action. Without that preparation, the public reaction might create additional problems for the Trudeau government.

Option No. 3 likely has the longest time horizon because a revised report needs to be completed before consultations with the protesting First Nations can be conducted

Option No. 3 likely has the longest time horizon because a revised report needs to be completed before consultations with the protesting First Nations can be conducted. With elections upcoming in Alberta and at the federal level next year, it is impossible to know what the political and economic, landscape might look like when option No. 3 is completed. One might expect the recently-emboldened First Nations groups to be more demanding during the consultation phase, forcing further concessions and extending the consultation phase beyond the assumed quick process. Remember that delay has been proven to be a powerful weapon in the anti-fossil fuel battle.

While the gun smoke from the court decision might be clearing soon, the cloud overhanging the Canadian oil industry, due to its access to world oil markets, will remain. Faced with the prospect of an extended delay in the availability of additional oil export capacity, producers will need to make strategic decisions about their future. Will this involve committing to greater oil-by-rail shipments? Or, possibly producers will decide to hold up more exploration and development activity until the pipeline battle outcome is resolved and a future timetable for its in-service operation is determined. According to NEB data, in July oil-by-rail shipments rose by over 200,000 barrels per day, but still not sufficiently high enough to help reduce the growing inventory volumes.

Restricted egress to world oil markets will continue to depress wellhead prices and sap the Canadian industry's capital

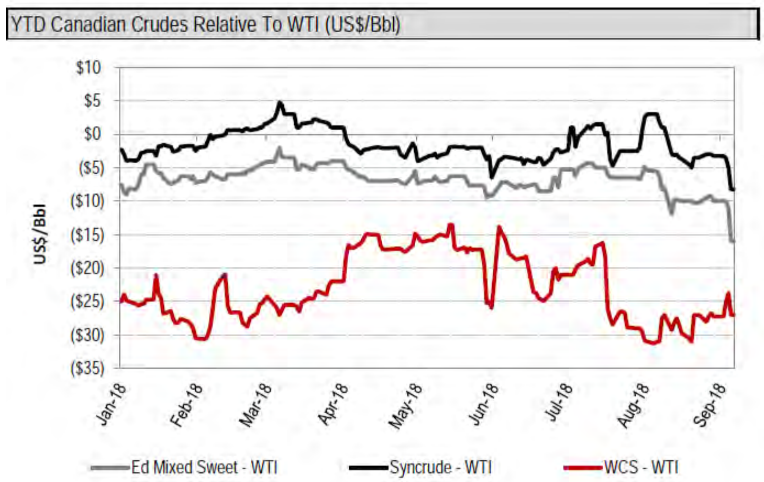
In the meantime, restricted egress to world oil markets will continue to depress wellhead prices and sap the Canadian industry's capital. In turn, it will limit future oilfield activity growth. Not only will employees suffer, but investors will be deprived of increased earnings and dividends that would lift the value of company shares. Provinces and the federal government will suffer from lower income and corporate tax revenues, royalty payments, plus the benefits from greater economic activity.

At the same time the court ruling was announced, the CEO of oil sands producer Syncrude announced that its operations were

For the week ended August 31, Canadian oil inventories increased by 4.3 million barrels to a record high of 36.3 million barrels

approaching 100% following the power failure earlier this summer that shut down production. He also told an investment conference that his company's Ft. Hills facility was ramping up production. In the United States, refiners are starting plant maintenance and turnarounds to handle winter fuel needs, which means less demand for crude oil supply from Canada. For the week ended August 31, Canadian oil inventories increased by 4.3 million barrels to a record high of 36.3 million barrels. As a result of these events, there was a sharp drop in Canadian output prices and widening discounts from U.S. oil prices. Western Canadian Select, a heavy oil blend, saw its discount to U.S. crudes rise to $27 per barrel, the widest discount since July. Edmonton Par, a light oil blend, fell to a $16 discount to West Texas Intermediate, the steepest discount since 2014.

Exhibit 7. Canadian Oil Prices Trade At U.S. Discount



Source: CIBC

Canada continues to struggle with its internal war between the western provinces' oil and gas economic machine and the liberal anti-fossil fuel movement

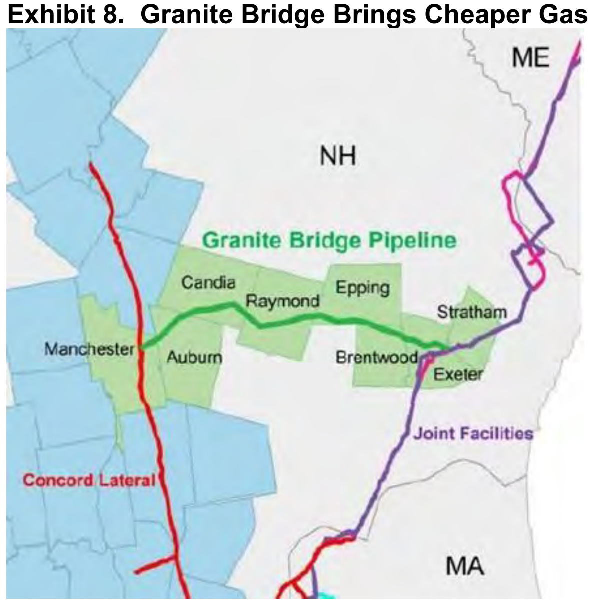
Weak Canadian oil prices are facing an extended period of above-normal discounts. Every day these discounts remain, the Canadian oil industry is losing billions of dollars of revenues. This likely future is why Ms. Notley of Alberta reacted so violently after the Federal Court of Appeals decision was rendered. The health of the Alberta oil and gas industry will be severely impacted by this decision and the delay in constructing the Trans Mountain Pipeline Expansion. In turn, this will hurt the health of Alberta's economy, and likely dooms Ms. Notley's upcoming re-election chances. Canada continues to struggle with its internal war between the western provinces' oil and gas economic machine and the liberal anti-fossil fuel movement. Until the nation settles on a game plan to resolve this conflict, the country will continue bouncing from one political/economic extreme to the other. That is not a confidence builder for energy investors.

Is New England Waking Up To Future Energy Problems?

New Hampshire's Senate recently endorsed the Granite Bridge natural gas pipeline project

A recent op-ed in *The Providence Journal* by Craig Stevens with Grow America's Infrastructure Now, a national coalition focused on promoting infrastructure investments, pointed out that New Hampshire's Senate recently endorsed the Granite Bridge natural gas pipeline project. This 27-mile, $340 million natural gas pipeline project planned by Liberty Utilities will connect a newly constructed two-billion-cubic-foot liquefied natural gas (LNG) storage facility to be built in Epping with two larger existing pipelines flowing north-south. Besides providing a diversity of gas supply sources, the storage project will take advantage of weak gas demand during summer months to build storage to be used to meet customer demand during the winter. The project must still be approved by the New Hampshire Public Utility Commission (PUC) and the Site Evaluation Committee (SEC), which are hoped to be done by the end of 2018, or in the first half of 2019. That would facilitate construction to be completed in 2021, with the storage tank finished in 2022. Does this approval mark the beginning of the tide turning with regards to opposition to gas pipelines? Certainly, Mr. Stevens believes it, but the war is not over.

Exhibit 8. Granite Bridge Brings Cheaper Gas



Source: Liberty Utilities

The Granite Bridge pipeline would run east-west between two existing north-south flowing natural gas pipelines

The Granite Bridge pipeline would run east-west between two existing north-south flowing natural gas pipelines. The 16-inch pipeline would be buried completely within the New Hampshire Department of Transportation's right-of-way along Route 101 in one of the recently designated Energy Infrastructure Corridors. In addition, in Epping, Liberty Utilities plans to purchase 140 acres for the storage tank that would utilize only 15 acres of the site. The company has asked the town for suggestions for how the remaining property might be best used. No eminent domain claims will be involved in this project, diffusing an often highly emotional issue.

Consumers are suffering from double-digit electricity rate increases due to the weaknesses in the structure and operation of utility systems throughout New England

The battle over how to fuel the New England power grid continues as activists fight new and expanded pipelines after being emboldened by their recent victories. And this project is not immune from that warfare. Unfortunately, consumers are suffering from double-digit electricity rate increases due to the weaknesses in the structure and operation of utility systems throughout New England. These rate increases are coming on top of some of the highest power prices in the nation. In fact, the six states comprising New England all rank among the 10 states with the highest electricity prices in the nation.

More than 50% of the electricity generated in New England is derived from power plants fueled by natural gas. Due to limited pipeline capacity into the region, plus the inability of electric utilities to sign long-term natural gas supply contracts, when winter arrives, these companies are often confronted with huge gas price increases, and/or have to turn to other fossil fuel sources – coal and oil - to generate the needed power. While this is the reality of operating the electricity grid in New England, the closing of older fossil fuel and nuclear generators is making the region's system increasingly more dependent on gas. Low natural gas prices due to the success of fracturing technology have contributed to holding marginal electricity prices down, which, in turn, is impacting the more expensive power coming from the older fossil fuel plants. As a result, these plants are being closed as they become economically uncompetitive. Companies, as well as the Trump administration, have asked the Federal Energy Regulatory Commission (FERC) to consider restructuring rate-setting to help keep these expensive, dispatchable fossil fuel generating plants in service. So far, FERC has refused to embrace that argument, and environmentalists are fighting the concept as they see the suggested plan as a way to undercut the growth in renewable power sources. The problem is that renewable power is not dispatchable, plus it often is not available or highly restricted during winter months, and especially at peak demand times, which occurs at night when the sun doesn't shine, and the wind is often low. To offset this lack of deliverability, the utilities must either keep fossil fuel plants running regardless of their economic profitability or build battery storage facilities, which are highly expensive.

The company aggressively worked to gain as much political and business support for the Granite Bridge Project as possible before announcing it

Recognizing some of these issues, especially how they could impact the future desirability of locating in the region of New Hampshire served by Liberty Utilities, the company aggressively worked to gain as much political and business support for the Granite Bridge Project as possible before announcing it. The company gained the support of 22 of 24 state senators and the backing of Governor Chris Sununu (R). Liberty Utilities worked out an agreement with the New

Hampshire Building Trades Union aimed at maximizing the number of local workers who would construct the project. The proposed project is expected to create 330 construction jobs.

"Natural gas is consistently 40% to 60% less expensive than alternative heating fuels"

Granite Bridge was endorsed by the New Hampshire Business and Industry Association (BIA), which described the project as critical to the state's economy. In a statement by BIA President Jim Roche, "Natural gas is consistently 40% to 60% less expensive than alternative heating fuels. Without Granite Bridge, some businesses looking to expand or relocate in New Hampshire will choose not to bear the higher cost of alternative fuels and will choose to grow elsewhere." The project also won the support of the Greater Nashua, Manchester and Concord chambers of commerce because of its positive impact on economic growth in the region, especially as they see households and businesses seeking to switch from heating oil to more environmentally-friendly natural gas.

Opposition to the Granite Bridge Project is coming from the same groups that successfully opposed earlier pipeline projects proposed for bringing additional natural gas into New England

Opposition to the Granite Bridge Project is coming from the same groups that successfully opposed earlier pipeline projects proposed for bringing additional natural gas into New England. These groups have yet to fully mobilize to object to the Granite Bridge Project. The one concrete accusation came from attorney Donald Kreis, the state-appointed consumer advocate on utility issues, who believes the project could raise consumer rates for natural gas as the cost of the new project is built into future rates. He acknowledged that this is an issue the PUC will have to sort out.

Mr. Kreis did suggest that Liberty Utilities has less formidable hurdles than other recent pipelines that were defeated, but there are still substantial issues to be addressed. In that context, he made an interesting point. "It's interesting and noteworthy that 22 of 24 senators have endorsed the project, but it's the PUC and then the SEC that decide, not the New Hampshire Senate." Obviously, Mr. Kreis is not familiar with the Deepwater Wind saga in Rhode Island. In that case, the Rhode Island PUC rejected the offshore wind project, only to have the state legislature re-write utility regulations to force the approval of the project. With New Hampshire political support, a similar scenario could unfold.

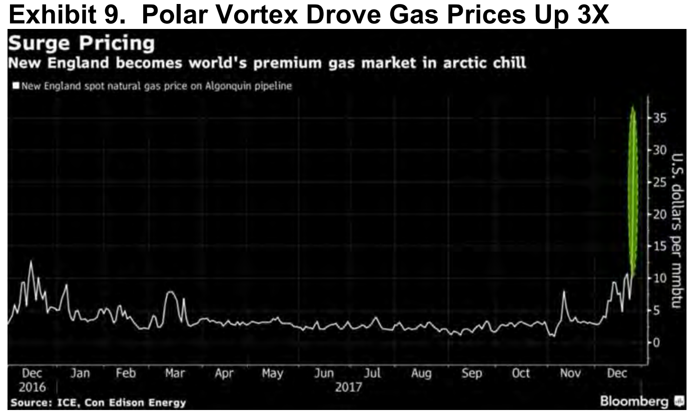
Opposition to fossil fuels is high, but consumers are weighted down by the large electricity rate increases being imposed

If the tide of opposition to gas pipelines in New England is changing, it will be a tough fight. Opposition to fossil fuels is high, but consumers are weighted down by the large electricity rate increases being imposed. Politicians are fighting these rate increases, but they are also forcing them with their mandates and programs to inject "green" energy into the grid. What we are also seeing, especially recently, is the argument that there is no need for increased natural gas supply because the growth of renewable capacity and the push for increased energy efficiency will meet future power needs. These arguments are highly questionable. One cannot expect solar power to help in the winter when the coldest temperatures are registered at night, unless the grid has substantial battery power backup. Who will build this storage and at what cost? There is not much sunlight during snow storms, which can last for days.

The lack of natural gas supplies, even beyond the LNG in the region, actually forced power companies to turn to burning more oil and coal

The New England independent power grid operator warned earlier this year of the prospect of rolling electricity blackouts for the region by 2024-2025 because of the closure of fossil fuel power plants and the lack of expanded natural gas deliverability. To better understand the problems facing the grid is to see what happened late last December when a polar vortex hit the northeast and frigid temperatures caused natural gas prices in New England to triple in just one day. The lack of natural gas supplies, even beyond the liquefied natural gas (LNG) in the region, actually forced power companies to turn to burning more oil and coal.

Exhibit 9. Polar Vortex Drove Gas Prices Up 3X

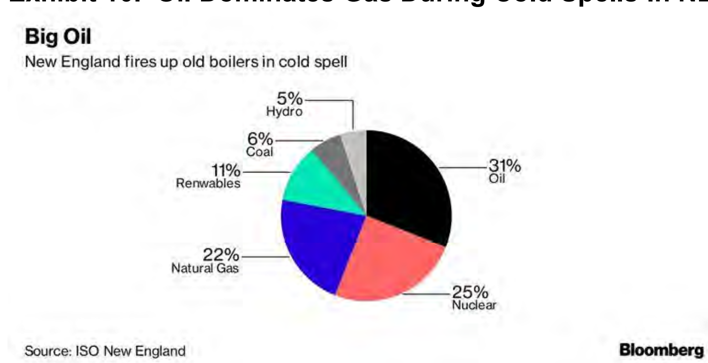


Source: ***Bloomberg***

Oil went from its traditional 1% market share to 31%

When the polar vortex hit, over the course of one day, December 27, 2017, oil use went from generating 500 megawatts (MW) of power to nearly 4,000 MW. The impact was that oil went from its traditional 1% market share to 31%, surpassing nuclear at 25% and natural gas at 22%. Renewables were able to contribute 11% and hydropower provided 5% of power supply.

Exhibit 10. Oil Dominates Gas During Cold Spells In NE

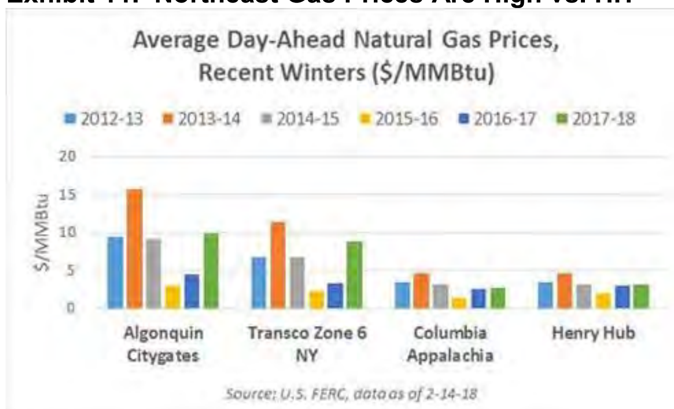


Source: ISO-New England

Coal's contribution to the power market was at 6%, up from its traditional 3% role

Coal's contribution to the power market was at 6%, up from its traditional 3% role. However, since 2000, New England has seen coal's power contribution fall from 18%. With more coal power plants closing, that 3% share will fall further, but coal will likely remain a crucial backup power supply source during cold spells.

Exhibit 11. Northeast Gas Prices Are High vs. HH



Source: Northeast Gas Association

The average day-ahead gas prices during recent winters demonstrates the challenge for the New England energy market. For New England utilities, they are mostly subject to Algonquin Citygate prices. New York and Pennsylvania utilities look toward the Transco Zone 6 prices, while utilities in the Mid-Atlantic region watch the Columbia Appalachia prices, which reflects the abundance of Marcellus and Utica gas and the recent lack of pipeline export options. As new pipeline capacity opens, it is likely this gas price may become more volatile. But notice how the Algonquin and Transco prices compare with Henry Hub prices, which is what sets gas prices nationally.

Almost every New England state is designing plans to address the high cost of their solar power mandates and incentives

Almost every New England state is designing plans to address the high cost of their solar power mandates and incentives. These adjustments reflect the recognition of what solar programs have and are doing to electricity bills, something that is unacceptable for politicians, especially those facing elections this fall. Addressing this issue is also a recognition that the New England power grid situation is increasingly at risk. Dan Dolan, the president of the New England Power Generators Association, called on policy-makers to bring back market competition into the region's electricity generation industry, warning that rampant government regulations and subsidies will ultimately affect grid reliability and consumer bills. He wrote in an early September op-ed for *Utility Dive*:

> "On the current trajectory, the state of the New England electricity market will rapidly worsen, requiring further out-of-market actions to adequately compensate generators in order to preserve grid reliability. State subsidies will beget

> reliability subsidies, driving consumer costs ever higher and doing away with future market-based investments for new or existing power generation."

Rising electricity prices and the prospect of rolling blackouts in the region were "like a horror story"

This warning follows that of Gordon van Welie, president of ISO New England, the region's grid operator, who warned last February of rolling blackouts due to growing fuel security issues. Robert Powelson, a FERC member at the time, said in April that rising electricity prices and the prospect of rolling blackouts in the region were "like a horror story."

Mr. Dolan's op-ed emphasized that "the choice is straight-forward: maintain reliability through a game of chicken — with plants announcing retirement only to be handed cost-of-service contracts to keep them around — or ensure opportunities for facilities to competitively bid against each other to supply needed electricity services." These warnings over the workings of the grid and the ability of subsidized power prices to disrupt the natural functioning of the region's power market are growing. These warnings come as energy consultants promote increased energy efficiency and more renewables as the best option for meeting the "adequate" power challenge.

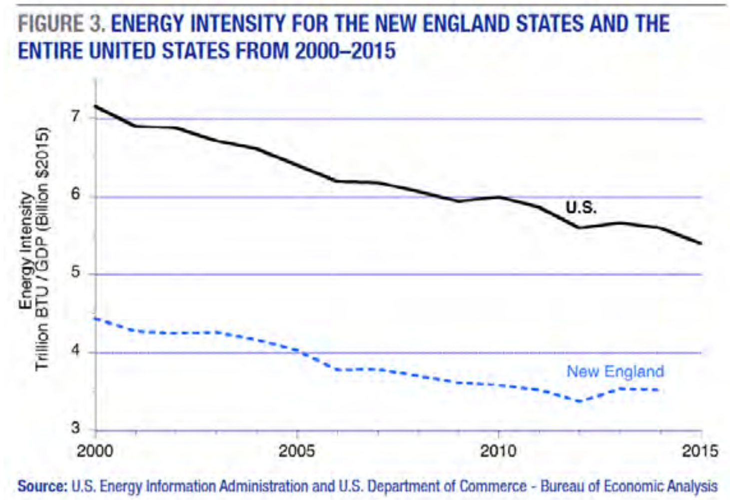
It cited the prospect that the region's power needs would be declining by 0.2% per year for the next decade, although the base case for New Hampshire's power projections suggests a 4% increase over 2017-2025

An updated May 2017 report from the Carsey School of Public Policy at the University of New Hampshire focused on the best way to meet the region's future electricity needs. It cited the prospect that the region's power needs would be declining by 0.2% per year for the next decade, although the base case for New Hampshire's power projections suggests a 4% increase over 2017-2025. For New Hampshire, power bills for residential and commercial users are equal to, or lower than, the national average despite electricity rates being 50% higher than the U.S. average. The report also showed that New England's energy intensity was below that of the United States. Taking all of this into consideration, the report questioned ISO-New England's concerns about the reliability of the region's grid after 2021.

Since the report's publication, the New Hampshire PUC has killed one hydropower from Canada option

Included in the report's argument against the need to expand natural gas pipelines to provide additional power generating capacity was the analysis that by increasing energy efficiency, boosting renewable power plus importing more hydroelectric power from Canada through New Hampshire and across Vermont, the region's power needs would be satisfied without risking stranded assets for no longer necessary pipeline expansions. Since the report's publication, the New Hampshire PUC has killed one hydropower from Canada option. That shocking announcement torpedoed Massachusetts' clean energy plans, sending state planning people scurrying to find immediate alternatives, but having to acknowledge that the options will be more expensive than the imported power from Canada. They didn't say, but it is true, that the likely options will add to the instability of the ISO-New England grid.

Exhibit 12. New England Bests US In Efficiency



Source: Carsey Perspectives, UNH

The LNG contracting option had the lowest annual cost ($18 million), but the highest return on investment (150%)

In attempting to bolster the argument that energy efficiency and renewable energy was a better course, the report highlighted the results from another report that analyzed three power scenarios, in which their cost and return on investment were calculated. The three scenarios included additional LNG contracting, expanded natural gas pipelines and increased energy efficiency and demand reduction investments. The LNG contracting option had the lowest annual cost ($18 million), but the highest return on investment (150%). The energy efficiency case produced the highest annual cost ($101 million), but had a return on investment close to that of the LNG scenario (145%). The pipeline expansion case annual cost fell between the other two scenarios ($66 million), but it had a respectable return on investment of 92%.

The energy efficiency option also sees a reduction in power consumption of 10% between 2017 and 2030, which helps its case

One would think that the better return on investment option would be the best choice. That wasn't the case when the focus was on the dollar returns from the investments. The efficiency case, which also included a solar power component, generated the highest annual dollar return on investment of $146 million versus $61 million for the pipeline expansion, and only $27 million for the LNG contracting option. The energy efficiency option also sees a reduction in power consumption of 10% between 2017 and 2030, which helps its case. The use of solar as part of the plan also means that new clean energy meets 15.8% of the power load by 2030, which is acknowledged to provide environmental benefits.

Because these results come from another report, and rely on the work of still an additional report that we did not have access to, there may have been assumptions made that distort the conclusions or underestimate the costs of the efficiency and solar option. A lot of the work in the base report was prepared during the battle over the construction of a new major gas pipelines for New England, and

The line is being drawn in this battle between more natural gas or taking steps to cut power use and meeting more of electricity demand through investment in renewable power supplies

certainly doesn't relate to the economics of the Granite Bridge Project. Regardless, the line is being drawn in this battle between more natural gas or taking steps to cut power use and meeting more of electricity demand through investment in renewable power supplies. That battle may be more difficult in this case because the political and business leaders are supporting the pipeline and storage tank investment since they see it helping the local economy, something the theoretical spreadsheet analyses are unable to fully reconcile. Stay tuned as we watch to see if this project actually marks an inflection point in the New England war over natural gas.

Transocean/Ocean Rig Deal Sends Us To The History Books

Combined, the 57-rig fleet will possess a third of the top ultra-deepwater drillships in the global fleet, a segment of the industry that is likely to see more demand

Labor Day weekend must have been a busy time in the offices of Transocean Ltd. (RIG-NYSE) and Ocean Rig UDW Inc. (ORIG-Nasdaq). All those meetings and negotiations led to an agreement for Ocean Rig to be acquired by Transocean in a $2.7 billion cash and stock deal. The press release highlighted the impact on Transocean's financial position by adding Ocean Rig's existing nine high-spec, ultra-deepwater drillships and two harsh environment semisubmersibles, plus the two under-construction high-spec, ultra-deepwater drillships to the company's fleet. Combined, the 57-rig fleet will possess a third of the top ultra-deepwater drillships in the global fleet, a segment of the industry that is likely to see more demand as the world's oil business seeks additional reserves and high output wells, conditions associated with more remote, and under-explored regions.

While this deal is not the largest transaction Transocean has ever done, it is significant in the message it sends to its oil and gas company customers. The message is simply: The offshore recovery is happening, will gather strength and the quality drilling equipment in the industry is moving into stronger hands who will demand better contracts than have been available in recent years. That means higher day rates for these rigs, and ultimately all rigs. The struggle between operators and contractors over who dictates contract pricing terms will become more balanced in the future. This is important and welcomed news for contractors.

We were further reminded of the offshore industry's history with the company's announcement that it was retiring the C.R. Luigs drillship

As we are deeply immersed in the history of the offshore service industry at the present time, Transocean's announcement started us thinking about the company's colorful history. The history is a recitation of some of the most famous names in the offshore drilling industry. We were further reminded of the offshore industry's history with the company's announcement that it was retiring the C.R. Luigs drillship. That rig, originally a premier unit in the Global Marine Inc.'s fleet, was named after the second chairman and CEO of that company, and its head during the offshore drilling boom of the late 1970s. In fact, he almost single-handedly created that boom with his 17-rig, $400 million order in 1979. Mr. Luigs told the author that the mistake he made was not ordering more rigs and filling up every

The boom was turned upside down into a bust in the mid-1980s when Saudi Arabia elected to open its production valves and flooded the market with oil

shipyard so no one else could be a rig. The boom was turned upside down into a bust in the mid-1980s when Saudi Arabia elected to open its production valves and flooded the market with oil, driving the price below $10 a barrel. Saudi Arabia's action was to punish its partners in OPEC for cheating on production quotas designed to help manage the integration of the huge new oil supplies, many of them from newly opened offshore basins such as the North Sea and West Africa, in a world that was cutting its oil consumption growth drastically.

The offshore drilling boom, as well as the onshore one, was in response to the explosion in global oil prices from the 1973 oil embargo and the subsequent 1978 loss of Iranian oil supplies following that country's ruler being overthrown. Over 1971-1981, oil prices increased nearly 11-fold, rising from $3.56 to $38 per barrel. What many people forget about that period was that oil prices didn't rise steadily. Rather, oil prices jumped in response to each of the two political events. A quadrupling of oil prices followed the Arab oil embargo of 1973, and a further tripling following the Iranian Revolution in 1979. The decade's price explosion, coupled with the easy capital available through accelerated depreciation to reduce high personal tax rates and limited liability partnerships, accelerated the rig fleet building boom that became the gargantuan weight that held down the industry's recovery for over a decade following the 1985 bust. It was industry consolidation during the recovery phase that provided the acquisitions that Transocean used to build itself into today's dominant offshore driller.

Transocean's roots go back to the Southern Natural Gas Company's move to acquire the joint drilling operations of DeLong-McDermott

Transocean's roots go back to the Southern Natural Gas Company's move to acquire the joint drilling operations of DeLong-McDermott from DeLong Engineering and J. Ray McDermott in 1953. To house that acquisition, a subsidiary, The Offshore Company, was created. That operation launched the industry's first mobile jackup rig, Rig 51, in 1954. By 1993, Sonat Offshore Drilling Company had grown, gone public and was spun off to shareholders, creating an independent offshore drilling company.

In 1996, just as the offshore industry recovery was accelerating, Transocean ASA was acquired for $1.5 billion. Transocean had begun in the 1970s as a whaling company in Norway before moving into the offshore drilling business. It was at this point that Transocean Offshore, the newly formed company, dedicated itself to pioneering the deepwater drilling segment of the industry. It began building a deepwater drilling ship capable of working in 10,000-feet of water depth, vastly exceeding the typical deepwater rig with only 3,000-5,000-foot depth capability. To address the challenges of operating in such ultradeep water depths, the rig was equipped with dual drilling capability to improve drilling efficiency.

Transocean Offshore's deepwater focus led to the 1999 acquisition of the Sedco Forex offshore drilling subsidiary from Schlumberger

This was a huge premium at a time when other offshore drillers and oilfield service stocks were under pressure due to the collapsing oil price

Ltd. (SLB-NYSE) in a $3.2 billion transaction. That subsidiary had been created through the 1985 acquisition of Sedco, a pioneer in floating drilling technology, by Schlumberger, which it merged with its subsidiary Forex Neptune Drilling Company. Schlumberger gained a foothold in the French driller, Forages et Exploitations Pétrolières, founded in 1942 in German-occupied France for drilling in North Africa, in 1959, and assumed total control in 1964. Sedco, founded by William "Bill" Clements in 1947 as a land driller, Southeast Drilling Company. Schlumberger paid $1 billion for Sedco in a cash/stock transaction subject to the desire of shareholders. The $48 a share purchase price was roughly a 40% premium to Sedco's share price immediately before the news of the deal was leaked. This was a huge premium at a time when other offshore drillers and oilfield service stocks were under pressure due to the collapsing oil price. In 1986, Schlumberger wrote down the value of its Sedco purchase by $800 million.

With the Schlumberger acquisition, the company's name changed to Transocean Sedco Forex. It was the world's largest offshore drilling company. But the hunt for more deepwater drilling rigs continued. The next move occurred in 2000 when Transocean acquired another storied offshore driller, R&B Falcon Corporation, formed in 1997. At the time of the merger, R&B Falcon was the largest offshore drilling company with a combined fleet including 12 drillships (seven under construction), 11 semisubmersible rigs, two tender rigs and 55 barge drilling and workover rigs.

The two key components of this company were the offshore drilling business of Reading & Bates, which had been founded in Houston in 1955, 20 years after its parent had started business in Oklahoma City. Falcon Drilling was created in 1988 to capitalize on the recovery in the Gulf of Mexico. Cliffs Drilling Company had been acquired by R&B Falcon in 1998. This deal brought 115 drilling rigs into the Transocean stable, making it clearly the world's largest offshore drilling company, with a dominant position in deepwater drilling.

The purchase of Global Santa Fe Corporation in 2007 for $15 billion in cash and shares brought two famous drilling companies, both founded in California with roots extending back to the same West Coast oil company – Union Oil Company of California

While R&B Falcon brought critical mass to Transocean Offshore, as well as several semisubmersibles and drillships, a key deepwater rig deal was on the horizon. The purchase of Global Santa Fe Corporation in 2007 for $15 billion in cash and shares brought two famous drilling companies, both founded in California with roots extending back to the same West Coast oil company – Union Oil Company of California. Santa Fe Drilling Company had started as the land drilling arm of Union Oil in 1946. Global Marine Drilling Company was the heir to the offshore drilling assets of the CUSS group. CUSS was a company established in 1946 by four oil companies – Continental Oil, Union Oil, Shell Oil and Superior Oil – to build and operate a floating drilling rig and supporting assets in order to explore for oil and gas offshore California. Following the resolution of the ownership of offshore lands, and the assets on them, between the coastal states and the federal government in the Tidelands Act of 1953, the CUSS assets were transferred to a company formed in 1955 by CUSS drilling superintendent Louis N. Waterfall. Global Marine Drilling was established as a subsidiary of the company to hold title to the assets and operate them.

These rigs were an important addition to the Transocean fleet as they arrived as oil prices were returning to the $100 a barrel range

Four years following the Global Santa Fe Corporation deal, Transocean purchased for $1.43 billion the four harsh-environment 6th generation semisubmersible drilling rigs in the fleet of Norwegian driller, Aker Drilling, a subsidiary of the Aker Group. These rigs were an important addition to the Transocean fleet as they arrived as oil prices were returning to the $100 a barrel range, which was key to boosting offshore drilling, especially deepwater drilling.

This year has been a busy one for the management of Transocean as it purchased Songa Offshore for $1.2 billion and the assumption of $2.2 billion of debt. Songa, which had operations in both the North Sea and Southeast Asia, was restructured several years ago to become a focused mid-water semisubmersible drilling rig company targeting the Norwegian shelf and working for Norwegian national oil company, Statoil.

The Ocean Rig deal signals that Transocean's management firmly believe the next industry upcycle is underway

The history of the offshore drilling business has been one of pushing frontiers – deeper waters and harsher environments – while dealing with the oil industry's cycles driven by the interaction of supply and demand on global oil prices. The Ocean Rig deal signals that Transocean's management firmly believe the next industry upcycle is underway. That cycle will likely further challenge the offshore industry's ability to work in these deepwater and harsh environments. Transocean will be an important player in this cycle. But the announcement stirred memories for this author of the people and companies that built the offshore business to where it is today.

The Next Musings Will Not Appear For A Month Due To Travel

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