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

A Retrospective View Of A Restructured Energy Industry

Countries have become less fearful of oil shortages now that renewable fuels supply a significant share of the world's energy needs and electric power generation

Using our time machine, we ventured to 2025 where the global oil and gas industry is enjoying its fifth year of the "new normal" – crude oil prices were settled in the $95 a barrel range. Luckily for the industry, demand for its oil continued to grow, albeit ever so slowly. The steady growth since 2020 of 250,000 barrels a day represented an environment some are starting to call "boring." That may be a welcome respite for managers following the volatility of the first 20 years of this Century and the toll it took on companies, technology and investment. Countries have become less fearful of oil shortages now that renewable fuels supply a significant share of the world's energy needs and electric power generation. In developed economies, crude oil is essentially reserved for transportation fuels, but even then, the increased penetration of green fuels, electric vehicles and social attitude changes toward the use of vehicles and mobility in general have limited the growth of hydrocarbon-based transportation fuels.

The students of the industry understood that industrial sector restructurings usually don't occur until after the worst of an industry's downturn has passed

People contemplating this new petroleum industry environment have been reflecting on how dramatically the industry was restructured as it recovered following the oil price war of 2014-2017. The students of the industry understood that industrial sector restructurings usually don't occur until after the worst of an industry's downturn has passed and company management teams can begin to fathom how the underlying structure of the industry was altered by the forces that birthed the downturn. The last downturn was driven by the growth in crude oil and liquids output in response to the successes in harnessing horizontal drilling and hydraulic fracturing technologies to tap hydrocarbons trapped in shale formations all across the United States. The shale revolution slowly expanded from the United States to the rest of North America and then to Europe, Australia/Asia and South America. Global oil supply grew further

The high oil prices that existed during the decade of 2004-2014 were coupled with extraordinarily cheap capital in the last half of that period

when Russia embarked on drilling shale formation along with various Middle East countries. The high oil prices that existed during the decade of 2004-2014 were coupled with extraordinarily cheap capital in the last half of that period as central banks globally embarked on huge monetary easing campaigns in an attempt to boost economic growth in the central bank's countries. The need to flood local markets with cheap money was mandated by the tepid pace of economic recoveries following the 2008 global financial crisis and the recession that followed.

Those in the industry, however, assumed that 2008-2009 was merely an interruption in the long-term trend in oil prices that would soon take them back to and well above $100 a barrel

The speed with which oil prices recovered in 2009 after governments around the world injected essentially "free" money into their economies shocked many observers. Those in the industry, however, assumed that 2008-2009 was merely an interruption in the long-term trend in oil prices that would soon take them back to and well above $100 a barrel. Between 2010 and 2014, global oil prices traded within a range of $80 to $107 a barrel, which signaled that the world was desperately short of crude oil supply to meet the projected growth in demand. High oil prices provided the cash flow necessary to explore and develop new supply sources, especially the high-cost ones such as shale, oil sands and offshore/deepwater resources.

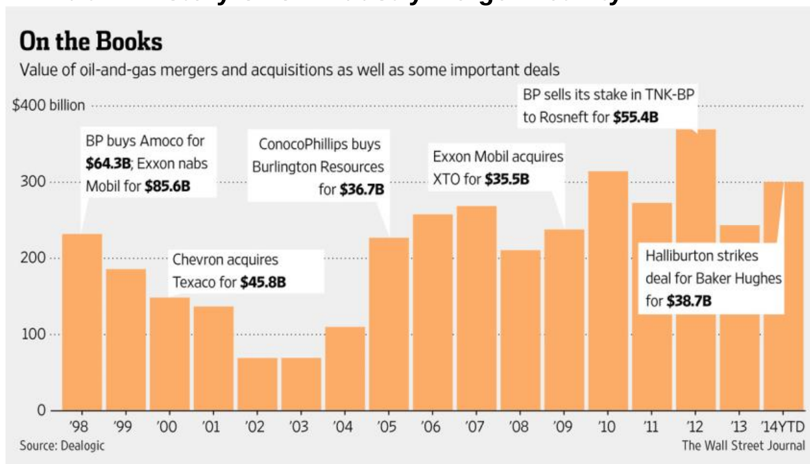
Forget the days of the Seven Sisters, now the members of the global oil industry could be counted on the fingers on one hand

One observer commented that if the industry had its own version of Rip Van Winkle who just happened to fall asleep in the summer of 2015 and awoke now in 2025, he wouldn't recognize the industry today. Forget the days of the Seven Sisters, now the members of the global oil industry could be counted on the fingers on one hand. The last major wave of oil industry consolidation occurred at the end of the 1990s and right after the turn of the current century. In 1998, Exxon bought Mobil Oil while BP plc purchased Amoco (formerly known as Standard Oil of Indiana). Early the following year, BP snapped up ARCO, the former Atlantic Richfield. In 2001, Chevron bought out Texaco following its bankruptcy fiasco fallout from losing its lawsuit with Pennzoil over Texaco's tortuous interference in merger negotiations between Pennzoil and Getty Oil. The following year, Oklahoma-based Phillips Petroleum merged with Houston's Conoco and then three years later the combined company acquired Burlington Resources in hopes of becoming the king of the domestic natural gas industry. Unfortunately, the timing of that transaction came as U.S. natural gas prices peaked and fell from double-digit price levels to mid- and then low-single digit prices. Later ExxonMobil became the largest U.S. natural gas producer when it acquired the large independent, XTO Energy, a company almost totally focused on gas.

ConocoPhillips was neatly tucked in under the ExxonMobil wing

Now, the international oil industry was finishing digesting its latest merger wave. Royal Dutch Shell had successfully integrated its 2015 purchase of BG Group; originally the UK government's British Gas Company that helped pioneer the development of the North Sea as a leading oil and gas basin. ConocoPhillips was neatly tucked in under the ExxonMobil wing helping keep its place as the

Exhibit 1. History Of Oil Industry Merger Activity



Source: ***The Wall Street Journal***

world's largest oil company. BP, the product of numerous major oil company acquisitions, after struggling for more than half a decade following the financial burdens from its Macando oil spill in the Gulf of Mexico in 2010, was finally absorbed by Chevron seeking to build its global presence, and especially seeking to enter the Russian market and keep pace with ExxonMobil.

The operational and social issues inherent in making these joint ventures work were significant, but they were slowly overcome as the pressures to make them work intensified

The merger wave wasn't confined to US-based oil companies as European-based companies Total and ENI forged a global merger. Possibly the strangest developments occurred in the national oil company universe as state oil companies succumbed to the pressure from escalating financial costs and the needs of their host governments for them to become more meaningful contributors to their local economies. Norway's Statoil, Brazil's Petrobras, Mexico's Pemex and Venezuela's PdVSA helped lead the global oil industry consolidation parade with creative joint venture structures that preserved the illusion that each of these national oil companies remained committed to their host governments while they were actually drifting closer to becoming full-fledged international oil companies. The operational and social issues inherent in making these joint ventures work were significant, but they were slowly overcome as the pressures to make them work intensified. Despite some of the political issues, there were even tie-ups between Asian producers including Chinese oil companies. The one region of the globe where the parade did stop was in the Middle East as the religious nature of the various host governments prevented any ties closer than those for the members of the Organization of Petroleum Exporting Countries (OPEC), which rapidly became an obsolete institution. What did remain and became even stronger, was the Organization of Arab Petroleum Exporting Countries (OAPEC) that provided closer coordination among those state oil companies confined to the Middle East region.

Without a steady supply of new petroleum engineers and scientists, the lure of the security of working for the behemoths sapped the strength of the small, independents

One trend that had become more pronounced in 2020-2025 was how these new mega-oil companies were sucking up many small, independent producers around the globe as the ability for these smaller companies to operate in an industry dominated by giants was limited. Personnel emerged as a managerial challenge. The reality is that the oil and gas industry was starting to confront its early sunset days as the dominant fuel source became an impediment for students to seek to earn degrees in petroleum sciences. Without a steady supply of new petroleum engineers and scientists, the lure of the security of working for the behemoths sapped the strength of the small, independents. In addition, a growing and severe shortage of "grey-haired" oil and gas professionals developed limiting the formation of new independents and even for staffing existing ones. The small producers were further hampered by the explosion in regulations that were the weapon of politicians to punish the industry for past environmental accidents. The attacks by the anti-fossil fuel movement led to some erosion in financial and investment support for the industry. Not only had this regulatory onslaught raised the cost of doing business, but the constant political and social battles had worn down the energy of those managers running the independent companies. It was much easier for large, politically savvy and important petroleum companies to overcome these hurdles, so they devoted a greater share of their cash flows to buying up small producers as an effective way to build reserves and augment production.

Those desires were part of the rationale for the Halliburton-Baker Hughes merger as the combined company became a true competitor to industry kingpin Schlumberger

Recognizing the impact from the consolidation of the oil and gas producing sector, the oilfield service industry also found it more profitable to become bigger. Back in 2015, the industry was tracking the maneuvers that brought Halliburton Companies and Baker Hughes together and then their saga in seeking approval for the merger from the U.S. and other governments. Once that deal was done, the combined company was forced to sell off a handful of divisions in which the two previously competed, which enabled smaller service companies to not only become larger, but also more diversified. Those desires were part of the rationale for the Halliburton-Baker Hughes merger as the combined company became a true competitor to industry kingpin Schlumberger.

That broad portfolio had prompted the new Schlumberger CEO to propose modifying the company's business model

While most observers were fascinated by the Halliburton-Baker Hughes transaction, Schlumberger was further broadening its portfolio enabling it to provide an even more complete range of services to its customers. That broad portfolio had prompted the new Schlumberger CEO to propose modifying the company's business model in order to not only gain additional market share through providing a true value-added service to customers but also as a way to increase Schlumberger's profitability.

When Schlumberger introduced the new business approach to investors in 2014, they called it "transformation." The management said that this new business approach "leverages the drivers of

"Schlumberger was also targeting a 10-fold reduction in customer non-productive time, a doubling in asset utilization, a 25% reduction in inventory days, a 20% increase in workforce productivity and a 10% lowering of unit support costs"

technology innovation, equipment reliability, process efficiency, and system integration, all together delivering better management of costs, better quality of products and service delivery, and better generation of free cash flow." For the clients and Schlumberger, it meant that while setting "goals for new technologies and increasing elements of service integration, they were also targeting a 10-fold reduction in customer non-productive time, a doubling in asset utilization, a 25% reduction in inventory days, a 20% increase in workforce productivity and a 10% lowering of unit support costs." The net result of Schlumberger's new approach to conducting its business and how that approach impacted customers' work flows was to slowly create a new mindset for operating in the oil patch.

That deal kicked off a service industry merger wave with French service giant Technip picking off FMC Technologies

Part of Schlumberger's long-term business strategy that drove its "transformation" was the formation of a joint venture in a market sector where it had never operated. That was the formation of OneSubsea, a joint venture company Schlumberger formed with Cameron International that focused on providing equipment and services for developing offshore oil and gas fields totally subsea. After the initial successes of the joint venture, to further Schlumberger's new business model, it used its OneSubsea interest to acquire Cameron. That deal kicked off a service industry merger wave with French service giant Technip picking off FMC Technologies. It had previously tried to acquire French seismic industry leader CGG, which would put it firmly in competition with Schlumberger who has a major seismic player in its WesternGeco subsidiary. The CGG deal was resurrected and eventually completed. Technip and Schlumberger would also battle in the subsea area as Cameron and FMC Technologies have been long-time competitors.

GE felt compelled to acquire businesses in order to broaden its well completion and subsea equipment portfolio, and subsea service provider Oceaneering became its latest acquisition target

In 2015, GE made the strategic corporate move to exit its financial services businesses, which had propelled the company's outstanding stock market performance under legendary leader Jack Welch in the late 1990s and early 2000s. That business became an albatross around the neck of GE when the 2008 financial crisis emerged. GE's strategic move drove the company to emphasize oil and gas equipment that it continued growing through a series of acquisitions. With that new focus, GE felt compelled to acquire businesses in order to broaden its well completion and subsea equipment portfolio, and subsea service provider Oceaneering became its latest acquisition target. The deal was brutal and expensive as the new Halliburton Company battled GE to the end. The two other large oilfield service companies, National Oilwell Varco and Weatherford International, both built by serial acquisitive managements, battled over the Halliburton-Baker Hughes assets that they were forced to sell to complete their merger. As always in the oilfield service industry, the big boys are continually wrestle with the buy/grow decision, especially over unique product lines.

In the new normal world of the petroleum industry, despite moderate

So, while many observers had expected a "V-shaped" recovery in 2015, much like what occurred in 2009, that didn't happen

and consistent demand growth, oil prices continue to lag where they had been trading before the last collapse in 2014-2015. That price collapse forced oil and gas operators to cut their exploration and production spending and begin aggressively axing staff and overhead in order to lower E&P costs. The oilfield technologies that were critical for opening shale basins around the world proved capable of enabling operators to increasingly increase their production by extracting a greater percentage of hydrocarbons from shale reservoirs than initially. So, while many observers had expected a "V-shaped" recovery in 2015, much like what occurred in 2009, that didn't happen. As the resiliency of shale output coupled with healthy volume growth from low-cost conventional reservoirs around the world battled low oil demand growth due to the continuation of the era of historically low economic growth, oil prices failed to rebound quickly.

Based on history, no one was surprised that the petroleum industry would go through another consolidation phase - the surprise was the speed and magnitude once the effort began

At the start of the oil price collapse, the debate within the industry was whether companies were looking at a "V-shaped," "U-shaped" or "L-shaped" recovery. Having quickly dismissed the first choice, the debate then shifted to the remaining options. The problem was that the length of the bottom of the "U" can easily transition into an "L," and in this case it did, much like what happened in the late 1980s and 1990s. One could say that it was the lack of any oil price improvement for an extended period of time that contributed to the petroleum industry's merger wave at the end of the 1990s and early 2000s. Based on history, no one was surprised that the petroleum industry would go through another consolidation phase - the surprise was the speed and magnitude once the effort began.

If supply exceeded demand, you just stopped drilling and waited for production to fall-off

One of the outcomes from the petroleum industry restructuring was the rationalization of E&P activity. Lower oil prices forced the newly combined E&P companies to re-prioritize their exploration prospects and, importantly, their development activity. Managers seemed less troubled with cutting back exploration due to the emergence of shale production as they were able to rapidly respond to changes in supply and demand dynamics by quickly adjusting capital spending. When you needed to boost production you went out and drilled a few more wells. If supply exceeded demand, you just stopped drilling and waited for production to fall-off. Companies with substantial shale operations were blessed with the flexibility to grow their reserves and potentially their production despite the rapid production decline of shale wells. This flexibility was rewarded with investors clamoring to own their shares. The problem was that there weren't many of these companies.

For those companies that operated primarily in the offshore arena, they found that its cost structure proved to be higher than the breakeven point for most of the shale basins, meaning that offshore, and especially the very high cost deepwater and ultra-deepwater production was a victim of economics. To respond to the growing

uneconomic arena producers reacted by embracing greater

Offshore exploration wasn't something that allowed standardized actions, but development presented many opportunities to standardize

standardization of field development. Offshore exploration wasn't something that allowed standardized actions, but development presented many opportunities to standardize, especially well production equipment and even platforms and floating production facilities. Rejecting the not-invented-here phenomenon was difficult but changing the culture of how to develop offshore fields was critical for the success of their owners.

The price for these producers delaying projects was the realization that there would be a delay in a substantial volume of future oil and gas production

Re-ordering development work proved more difficult to achieve than anticipated. Many development projects, especially those offshore, were already underway when the oil downturn arrived at the end of 2014. Management teams historically have been reluctant to delay or shut down already approved development projects. But, as one of the petroleum industry's leading consultants pointed out in mid-2015, the industry at that point had already delayed $200 billion of development projects, which represented about 30% of annual industry spending during the good times. The price for these producers delaying projects was the realization that there would be a delay in a substantial volume of future oil and gas production. For companies worried about their cash flow and profits, enduring these cutbacks was a tough decision.

The increased efficiencies within the service sector translated into lower service and equipment costs that further helped lower the oil companies' production break-even costs

The industry's consolidation effort has led to reduced overhead at the oil companies enabling them to lower their well breakeven costs, especially with their onshore properties. At the same time, the consolidation within the oilfield service sector has contributed to improved efficiencies across the range of products and services that are needed to develop new hydrocarbon reserves. The increased efficiencies within the service sector translated into lower service and equipment costs that further helped lower the oil companies' production break-even costs. But the efficiencies also meant that not as many drilling rigs and other oilfield services were needed to achieve the same level of oil and gas output. That reduced activity became a meaningful hurdle for the service industry to overcome in order to restore the sector's profitability.

Fewer service providers and a more stable and predictable business level has enabled the service companies to become more efficient, helping to offset some of the downward profit margin pressure

Maybe the petroleum industry has finally arrived at nirvana – a world in which oil price volatility is eliminated, the ability to grow production modestly is assured and the profitability of that output has been stabilized by the reduction in breakeven finding and development costs. In the interim the service industry struggled with reduced profitability due to the increased bargaining power of the larger producing companies. Fewer service providers and a more stable and predictable business level has enabled the service companies to become more efficient, helping to offset some of the downward profit margin pressure. It is too bad these industry developments have arrived as petroleum companies look toward their sunset.

We intend to return to 2025 to explore how the energy business evolved and the challenges faced during that decade-long journey.

Renewables Role Boosted By EPA Climate Plan – A Mistake?

The EPA plan, when it is fully implemented in 2030, is projected to reduce U.S. carbon emissions from the power sector to levels 32% below 2005's levels

Last week, President Barack Obama announced his plan to implement the Environmental Protection Agency's (EPA) final rule for its Clean Energy Plan. The plan is designed to reduce carbon emissions from two subcategories of existing fossil fuel-fired electric generating plants. Those subcategories include those electric-generating plants fueled by fossil fuels, generally, coal-fired power plants, while the other subcategory includes combined cycle electric-generating units fueled, generally, by natural gas. The EPA plan, when it is fully implemented in 2030, is projected to reduce U.S. carbon emissions from the power sector to levels 32% below 2005's levels. One analysis we read of the impact of the plan questions whether, when the data is analyzed, most of the targeted reduction has already been achieved. The question focuses on the selection of 2005 as the base year for measuring the carbon emissions reduction along with current trends in emissions. We comment on this analysis later.

The EPA sets the standards and the states and tribes choose how they will be met

The plan's authority is based on section 111 of the Clean Air Act that authorizes the EPA to set emission standards for air pollutants emitted by new and existing industrial sources. Section 111d creates a partnership between the EPA, the states and tribes in America for regulating these existing sources. The EPA sets the standards and the states and tribes choose how they will be met. In the newly announced plan, the EPA established final statewide targets for emissions in three forms measured in: 1) pounds per megawatt-hour (lb/MWh) power generated; 2) total short tons of CO_2; and 3) a state goal including a new source (power plant) complement measured in total short tons of CO_2.

Once a target is selected by a state, it then develops and implements a plan that ensures that the power plants in their state either, individually, together or in combination with other measures, would achieve the interim CO_2 emissions performance reduction rates programmed for attainment over the period 2022 to 2029 along with meeting the final CO_2 emissions targets in 2030.

As the plan represents part of President Obama's legacy, it is not likely that he nor the EPA will delay or alter the plan even if the courts accept the states' lawsuits

As expected, immediately following the announcement, 16 bipartisan state Attorneys General asked the EPA to defer implementing the new plan until litigation over the plan could be heard by the courts. As the state Attorneys General didn't expect a sympathetic response from the EPA, several states including Ohio and Nebraska, are moving forward to sue to block the plan's implementation. Several governors also indicated that they would simply ignore the EPA plan. As the plan represents part of President Obama's legacy, it is not likely that neither he nor the EPA will delay or alter the plan even if the courts accept the states' lawsuits.

The EPA claims in its supporting documents outlining the details and background information for the plan that it will contribute important

The costs for the plan will be somewhere in the $8-$9 billion range

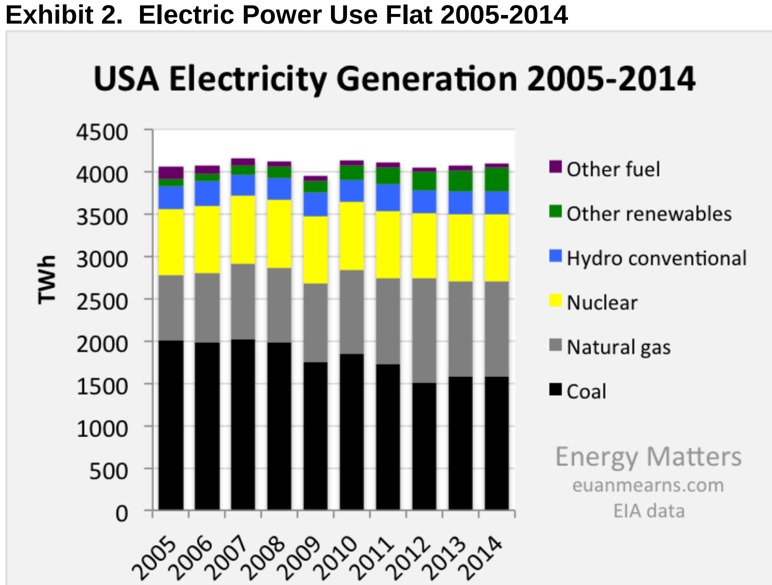
benefits. The EPA suggested that the plan will produce climate benefits of $20 billion along with health benefits of $14-$34 billion, suggesting combined benefits totaling $34-$54 billion. However, the EPA also listed the net benefits at $26-$45 billion, meaning the costs for the plan will be somewhere in the $8-$9 billion range. We don't know what those costs are, and we question the health benefits.

The EPA suggested that carbon emissions also come "packaged" with other air pollutants, so the agency believes that the Clean Power Plan will protect public health, avoiding 3,600 premature deaths, 1,700 heart attacks, 90,000 asthma attacks and 300,000 missed workdays and schooldays. So how much of these health benefits come from reduced carbon emissions or is the EPA's estimate an attempt to piggyback on the health benefits from reduction of non-carbon emissions. We don't know the answer.

Mr. Mearns utilized a series of charts attempting to show that much of the targeted carbon emissions reduction has already been achieved

The objective of the Clean Power Plan is to cut the CO2 emissions of existing fossil fuel-fired power plants, which currently make up 31% of U.S. total greenhouse gas emissions. A blog written by Euan Mearns, *Energy Matters*, carried an article last week entitled "Obama's CO2 Deception." In the article, Mr. Mearns utilized a series of charts attempting to show that much of the targeted carbon emissions reduction has already been achieved. His analysis started with the fact that power consumption has remained essentially flat between 2005 and 2014.

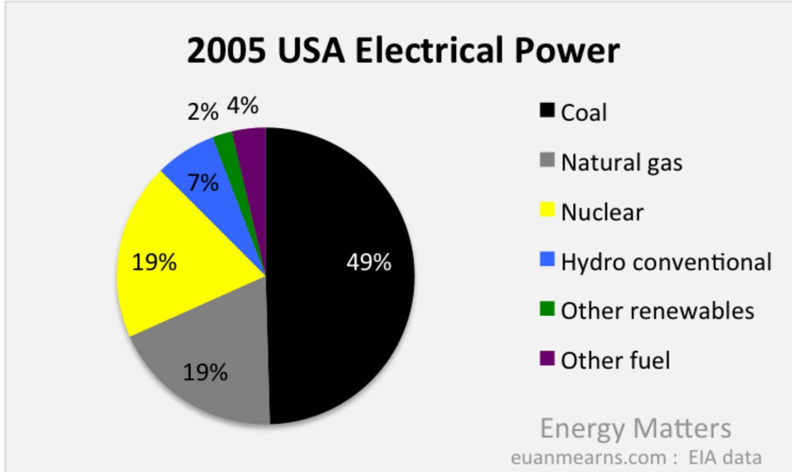
Exhibit 2. Electric Power Use Flat 2005-2014



Source: ***euanmearns.com***

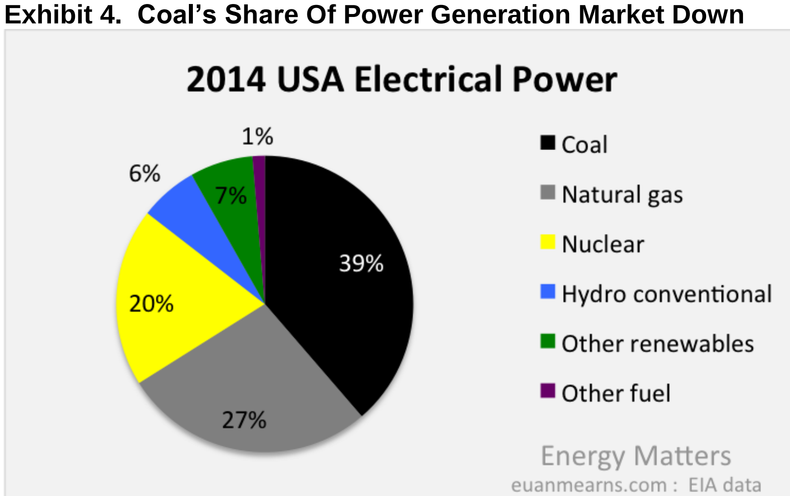
He then looked at the percentage of power generation by fuel type for each of 2005 and 2014. What those two charts showed was that coal-fired power generation accounted for 49% in 2005. In 2014, the coal-fired power generation was down to 39%.

Exhibit 3. Coal Most Important Power Fuel Source



Source: *euanmearns.com*

Exhibit 4. Coal's Share Of Power Generation Market Down



Source: *euanmearns.com*

Natural gas emits roughly half the carbon per unit of power that coal does

One also notes that the percentage of power generated by natural gas has increased from 19% to 27% between 2005 and 2014. The carbon emissions intensity of coal is 2.13 pounds of CO_2 per kilowatt hour (KWh) of electricity generated, but natural gas emissions intensity is only 1.21 pounds of CO_2 per KWh. That means natural gas emits roughly half the carbon per unit of power that coal does. Carbon emissions will also be reduced by the increase in the percentage of power generated from other renewables besides hydro and nuclear power. Collectively, as Mr. Mearns demonstrates, the government's own numbers show the following impact from the shifts in the fuels generating power in this country:

"2005 electric power emissions = 2417 million tons (Mt)
"2005-2013 lower demand = 402 Mt reduction (16.6% reduction)
"2005-2013 substitution of coal with gas = 212 Mt reduction (8.8% reduction)
"2005-2013 addition of low carbon sources i.e. other renewables = 150 Mt reduction (6.2% reduction)"

Based on this set of numbers, Mr. Mearns concludes that total emissions reductions since 2005 due to reduced power consumption and fuel substitution have already reached 31.6% of the targeted 32% reduction. Therefore, he asks: Has the Clean Power Plan already been achieved?"

A little known research paper published last month in *Nature* attempted to show what factors actually drove the recent decline in carbon emissions and implicitly why further emission restrictions are needed

While the math would suggest that the U.S. power industry has already achieved the objective of the EPA's Clean Power Plan, a little known research paper published last month in *Nature* attempted to show what factors actually drove the recent decline in carbon emissions and implicitly why further emission restrictions are needed. The paper was titled, "Drivers of the U.S. CO2 Emissions 1997-2013" and it was authored by a team of five professors from institutions located around the world – Maryland, California, London, China and Austria. The paper's abstract states the following:

After 2007, decreasing emissions were largely a result of economic recession with changes in fuel mix (for example, substitution of natural gas for coal) playing a comparatively minor role

"Fossil fuel CO2 emissions in the United States decreased by ~11% between 2007 and 2013, from 6,023 to 5,377 Mt [millions of tons]. This decline has been widely attributed to a shift from the use of coal to natural gas in US electricity production. However, the factors driving the decline have not been quantitatively evaluated; the role of natural gas in the decline therefore remains speculative. Here we analyze the factors affecting US emissions from 1997 to 2013. Before 2007, rising emissions were primarily driven by economic growth. After 2007, decreasing emissions were largely a result of economic recession with changes in fuel mix (for example, substitution of natural gas for coal) playing a comparatively minor role. Energy–climate policies may, therefore, be necessary to lock-in the recent emissions reductions and drive further decarbonization of the energy system as the US economy recovers and grows."

This conclusion set the stage – at least from an academic point of view – for the more stringent emission reduction targets in the Clean Power Plan

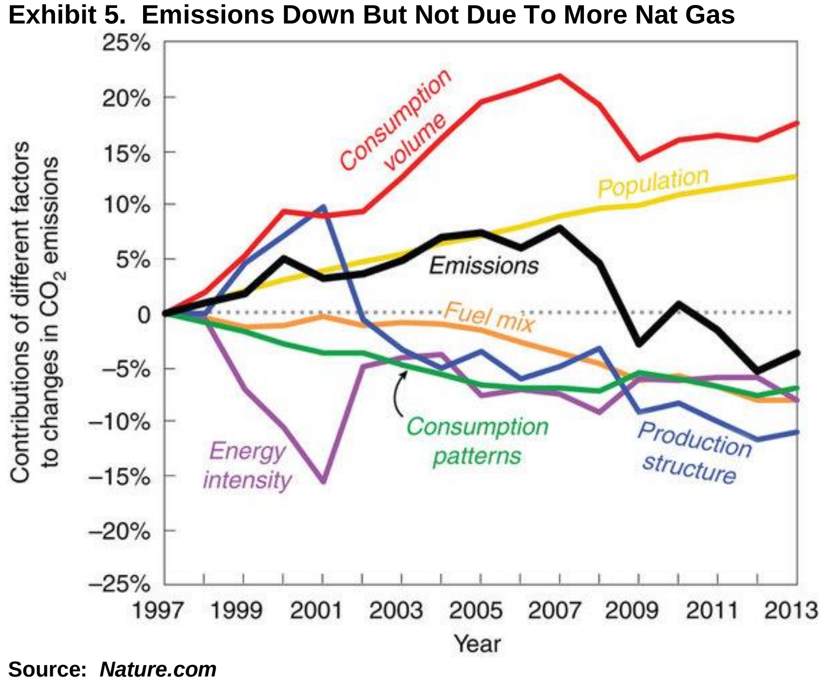
While this paper was prepared and published before the EPA released its final Clean Power Plan rules, the paper based its analysis on the existing carbon emission restrictions that were already in place in 2013. The paper's conclusion was "Assuming no change in emissions outside the power sector, the new rules proposed by the US Environmental Protection Agency in June 2014 to limit CO2 emissions from [new] power plants will require US emissions to decrease to 4,200 Mt CO2 in 2030—a further 20% reduction from 2013 levels. This conclusion set the stage – at least from an academic point of view – for the more stringent emission reduction targets in the Clean Power Plan. So how can Mr. Mearns analysis and these academics reach such different conclusions about the need for greater carbon emissions restrictions? Maybe it has to do with interpretation of the emission numbers, or different base years for measuring the amount of reductions already achieved, or possibly the analytical methodology employed.

SDA enables the researchers to assess the sources of change in U.S. CO2 emissions and their relative importance

The paper's research is based on the use of input–output structural decomposition analysis (SDA) that enables the researchers to assess the sources of change in U.S. CO2 emissions and their relative importance. The focus was to utilize SDA to assess the role of various forces during the period of rising carbon emissions (1997-2007) and then the period of falling emissions (2007-2013).

The researchers explored "six different factors to changes in US emissions. These factors are: population growth; changes in consumption volume caused exclusively by changes in per capita consumption of goods and services; shifts in consumption patterns or the types of goods and services being consumed; adjustments in production structure or the mix of inputs (for example, labor, domestic and imported materials) required to produce US goods and services; changes in fuel mix as reflected by the CO2 emitted per unit of energy used; and changes in energy intensity or the energy used per inflation-adjusted unit of economic output."

Exhibit 5. Emissions Down But Not Due To More Nat Gas



Source: ***Nature.com***

In Exhibit 5, the black line shows the trend in carbon emissions while the colored lines show the contribution to emissions from the respective six factors studied. The researchers concluded the following from their analysis:

"We conclude that substitution of gas for coal has had a relatively minor role in the emissions reduction of US CO2 emissions since 2007

"We find that before 2007, rising emissions were driven by economic growth: 71% of the increase between 1997 and 2007 was due to increases in US consumption of goods and services, with the remainder of the increase due to population growth. Concurrent with the global economic recession, 83% of the decrease during 2007–2009 was due to decreased consumption and changes in the production structure of the US economy, with just 17% related to changes in the fuel mix. During the economic recovery, 2009–2013, the decrease in US emissions has been small (<1%), with nearly equal contributions from changes in the fuel mix, decreases in energy use per unit of GDP, changes in US production structure, and changes in consumption patterns. We conclude that substitution of gas for coal has had a relatively minor role in the emissions reduction of US CO2 emissions since 2007."

This effort by the administration should please the environmental wing of the Democratic Party

The final sentence in their conclusion that natural gas played a "relatively minor role" in the reduction in emissions in recent years was used to "discredit" the linkage of the growth and success of hydraulic fracturing, along with the growth in natural gas reserves and output, in reducing carbon emissions. That conclusion teed up President Obama and the EPA to argue that the decarbonization of the U.S. economy must be driven by renewables and not natural gas. This effort by the administration should please the environmental wing of the Democratic Party. The most interesting reaction other than the predictable reaction of state Attorneys General and various state governors is the opposition from leading minority groups who see that their members will be subjected to higher utility costs and other energy-related costs that will push more of their people into poverty, along with likely reducing employment opportunities as economic growth is restrained further. The Clean Power Plan must also be interpreted as a precursor to a rejection of the Keystone XL pipeline application. The war over carbon will become a key political issue in the upcoming 2016 presidential election, so expect to see and hear considerable debate about our energy future and the need to change it. We now know that all fossil fuels will be under attack. As they say: Let the games begin!

July Ended With Low Oil Prices And Poor E&P Earnings

For the past seven months all the gyrations in crude oil prices in the interim did little to establish any clear direction

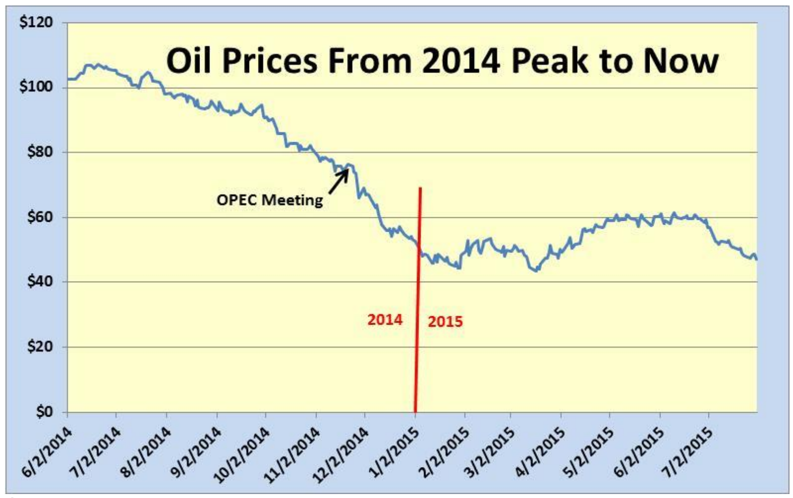
The month of July witnessed the worst monthly decline since the 2008 financial crisis. The futures price for the near month of West Texas Intermediate (WTI) crude oil closed on July 31st at $47.12 a barrel, down 21.2% for the month. Interestingly, the price decline for the year through July was only 10.6%, suggesting that for the past seven months all the gyrations in crude oil prices in the interim did little to establish any clear direction. At the market close that Friday, sentiment was that oil prices would continue to fall. In fact, a week later, WTI closed at $43.87 a barrel.

The market optimism that greeted the initial oil price rebound that began in late January was dashed when the recovery ended in early

The initial decline in the second half of June didn't prompt much concern, but July's sharp drop has many questioning both the extent of the damage done to the global petroleum industry and the duration of low oil prices

March. Investors had been hoping that oil prices were going to repeat the "V-shaped" recovery of late 2008 and early 2009. The quick reversal in oil prices ended that hope. Optimism soon returned to the market when oil prices began climbing again later in March, reaching $60 a barrel in late April and then staying at about that level through mid-June. The initial decline in the second half of June didn't prompt much concern, but July's sharp drop has many questioning both the extent of the damage done to the global petroleum industry and the duration of low oil prices. Concern over these issues has ramped up due to fear that the oil price slide will continue along with uncertainty about how low prices might fall.

Exhibit 6. Oil Price Setback Means Bottom Still Not Here



Source: EIA, PPHB

Last week's Baker Hughes rig count showed another six more oil-directed rigs went back to work, further adding to the pressure for lower oil prices

Concern that the oil price decline is not over, was intensified by the pace of the oil price decline in the last few days of July, but also by the downward move in prices in response to industry news released mid-day on July 31st. In the aftermarket trading that day, oil prices fell from their $47.12 a barrel close to a low of $46.84 a barrel. Ostensibly, the aftermarket fall was in response to Baker Hughes (BHI-NYSE) reporting that afternoon in its weekly drilling rig count that it declined by two rigs while the oil-focused rig count had added five but was offset by a seven-rig drop in gas-oriented rigs. The concern among the sellers of crude oil futures is that the increase in the number of working oil-directed drilling rigs will lead to higher U.S. oil production in the future. Higher U.S. oil output would work counter to the desires of the petroleum industry and crude oil speculators who want to see lower oil production in order for oil prices to rise. Last week's Baker Hughes rig count showed another six more oil-directed rigs went back to work, further adding to the pressure for lower oil prices.

Analysts' myopic focus on weekly movements in the components of the drilling rig count has become almost absurd. We have been

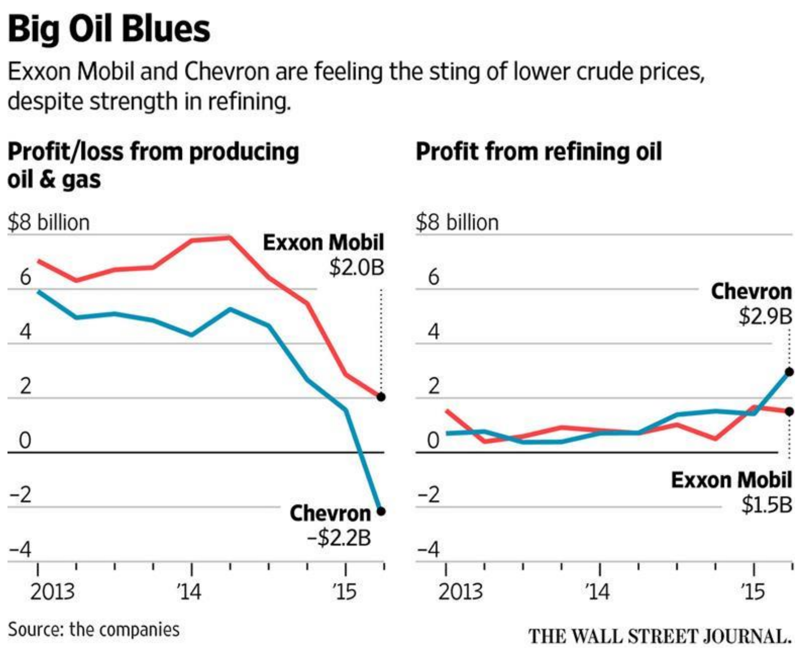
Thus, the incremental rig drilling the incremental well that produces the incremental barrel of oil is sufficient to drive oil prices lower

through previous periods marked by the relentless pursuit by analysts to gain insight into the future of the global oil business based on knowledge of whether five additional rigs go to work or stop working. Remember, we are talking about five rigs out of an operationally-ready drilling rig fleet of nearly 2,000 rigs. The thought process is that oil prices are set by the incremental barrel of output, especially when it adds to the current glut of production. Thus, the incremental rig drilling the incremental well that produces the incremental barrel of oil is sufficient to drive oil prices lower. On the flip side, one less rig working means fewer wells and less production, the conditions necessary for crude oil prices to recover.

This increase in the oil rig count is coming just when it appeared that domestic oil output may have peaked in March and was now heading lower

What truly spooked the analysts on July 31st was the fact that this marked two consecutive weeks of the drilling rig count rising. Maybe what also concerned the analysts was that the oil-rig count had now increased in four of the five weeks of July. This increase in the oil rig count is coming just when it appeared that domestic oil output may have peaked in March and was now heading lower, the critical event for the recovery of the oil business.

Exhibit 7. How Low Oil Prices Have Hurt E&P Earnings



Source: *The Wall Street Journal*

That Friday was also marked by the second quarter earnings releases by ExxonMobil (XOM-NYSE) and Chevron Corp. (CVX-NYSE). Both companies' reported results missed Wall Street analyst estimates due to the impact of low oil prices on their oil and gas drilling and production operations. An article in *The Wall Street Journal* discussing the companies' earnings results contained a chart (Exhibit 7) that highlighted the impact low oil prices had on the

The chart also showed how the companies' refining and chemical operations earnings had prospered with the advent of low oil prices

companies' quarterly upstream earnings since oil prices peaked at the end of 2014's second quarter. The chart also showed how the companies' refining and chemical operations earnings had prospered with the advent of low oil prices since late last year and that had become a much more important source of total company earnings. The chart exemplified why the integrated oil company model has certain advantages over the upstream-only focused business model.

…which appears to signal that the company believes low oil prices will last much longer and it needs to conserve cash

Despite the implied strength of the integrated oil company business model, the results of ExxonMobil and Chevron were questioned by investors due to other aspects of the companies' strategies, in particular their high dividend payouts and their share buybacks. In the case of ExxonMobil, since its merger with Mobil Corp. in 1998, the company has bought back 40% of its then outstanding shares while continuing to boost its dividend. Up until this year, the company had been repurchasing about $3 billion worth of shares each quarter. In each of the first two quarters of this year it repurchased $1 billion in shares. ExxonMobil announced it was now planning to repurchase only $500 million worth of shares per quarter, which appears to signal that the company believes low oil prices will last much longer and it needs to conserve cash. As a result, the company has cut its capital spending.

Chevron has ceased buying back shares in order to protect its dividend and to conserve cash

Chevron reported that its profit in the second quarter tumbled to the lowest level since 2002. Part of the profit decline was due to more than $2 billion in impairments and charges for suspended projects due to low crude oil prices. Chevron has ceased buying back shares in order to protect its dividend and to conserve cash, plus it announced plans to lay-off 1,500 workers as part of further cost-cutting efforts.

"We have to make sure the company is resilient in a world where oil prices remain low for some time while keeping an eye on a recovery we believe will come."

Earlier that week, Royal Dutch Shell (RDS.A-NYSE) reported its second quarter earnings and later in the week announced plans to let 6,500 employees and contractors go, or approximately 7% of its work force. While earnings declined by 33% compared to the same quarter a year before, Shell is continuing to focus on its Arctic drilling efforts and other long-term projects while still working to conclude its purchase of BP Group (BG-NYSE), which may be its most transformative move in decades. That deal, however, continues to be viewed critically due to the huge implied bet on the future of the liquefied natural gas (LNG) business and the significant presence it brings in deepwater oil exploration efforts offshore Brazil. As part of the earnings release, Mr. Ben van Beurden, Shell's CEO, said, "Our results today show we are successfully reducing spending and costs. We have to make sure the company is resilient in a world where oil prices remain low for some time while keeping an eye on a recovery we believe will come."

It has been assumed by the investment community that for the Brazilian offshore assets to be profitable and provide positive returns

That motto is: "Grow to simplify"

for the money spent in the BG deal, oil prices need to be much higher. As a result of this perception, Mr. van Beurden commented, "Perhaps we left the impression that we're waiting for the cavalry in the form of high oil prices." He went on to admit that management had failed to adequately explain how it planned to manage the company through this lower price environment when it reported the company's earnings earlier in the week. He announced that the strategic thrust of Shell's new plan has been captured in a new motto. That motto is: "Grow to simplify."

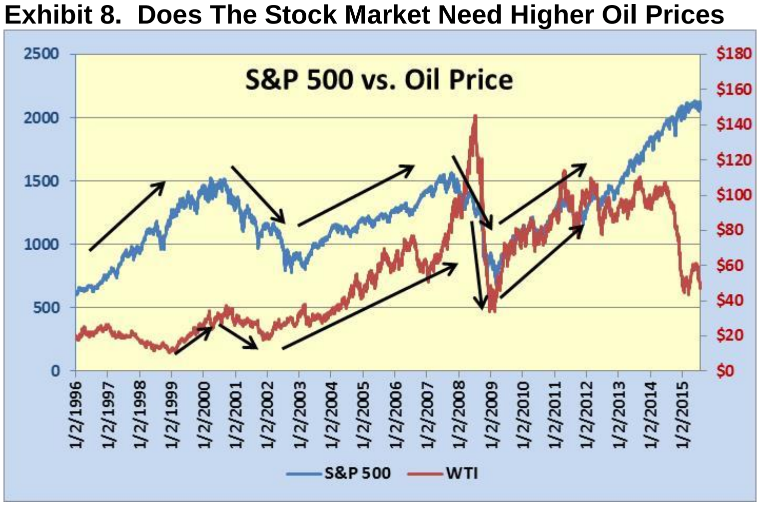
Some investors question whether the overall stock market needs crude oil and commodities in general, to be doing better in order for stock prices to rise

With crude oil, petroleum company earnings and energy share prices crashing, the overall stock market so far this year has struggled to stay even for the year. The only stock market sectors that have performed well this year to date have been technology and biotechnology. That outcome has prompted some investors to question whether the overall stock market needs crude oil and commodities in general, to be doing better in order for stock prices to rise. One analyst suggested that in the past month, 68% of the time, share prices and oil prices have moved in the same direction.

Despite oil prices having stopped rising in 2010, they did stay high and the stock market continued climbing

To see how often the stock market and oil prices have moved in concert, we plotted the movement of Standard & Poor's 500 stock index prices against West Texas Intermediate (WTI) crude oil prices since 1996. Throughout most of that period, the two data series moved in tandem, at least until late 2010. Since then, oil prices fluctuated, but essentially moved sideways until 2014 when they began to slide. Despite oil prices having stopped rising in 2010, they did stay high and the stock market continued climbing. This pattern has led some investment professionals to suggest that the best thing for the stock market, in other words for it to stay high and possibly go higher, would be for crude oil, and maybe commodity prices in general, to start going back up. Rising commodity prices would signal acceleration in global economic growth.

Exhibit 8. Does The Stock Market Need Higher Oil Prices



Source: EIA, Yahoo Finance, PPHB

In our view, the shift in the direction of commodity prices since 2010 reflects a transfer of the benefits of higher commodity production from producers to consumers

We are not convinced that the stock market needs higher commodity and oil prices in order to continue to rise. In our view, the shift in the direction of commodity prices since 2010 reflects a transfer of the benefits of higher commodity production from producers to consumers. That means basic industries and consumers should be the beneficiaries of falling commodity prices. Long-term, commodity prices should climb in response to increased consumption, which will drive up corporate earnings that are necessary to support higher share prices. A higher stock market can come without oil prices reaching new all-time highs, but they need to be higher than current levels for energy company earnings to rebound, that is unless substantial operating costs can be removed from the energy business. The energy business may get both, and investors will benefit from increased share prices. Unfortunately, this isn't likely until sometime in 2016.

Rhode Island And U.S. Enter Offshore Wind Era – Good News?

The local Rhode Island media is fascinated by the mechanics of constructing and installing offshore structures to support the five wind turbines that will form the 30-megawatt wind farm located offshore Block Island

The local Rhode Island media is fascinated by the mechanics of constructing and installing offshore structures to support the five wind turbines that will form the 30-megawatt wind farm located offshore Block Island. As we have written about before, the local press sent reporters and photographers to Louisiana to learn about the construction of the offshore steel jackets and deck sections that will support the French-made wind turbines due to be installed next year. After the first barge with two jackets, the piles to anchor them and a deck section arrived at Deepwater Wind's assembly base in Quonset, Rhode Island, the media shifted to covering the mechanics of the installation process that involved a large crane barge. We have been treated to schematics in the *Providence Journal* showing how the jackets are built and assembled, loaded on the transportation barge for the trip from the Gulf Coast to Rhode Island, and how the floating crane barge lifts and positions the jacket on the seafloor and then hammers the piles in the jacket's legs to anchor the structure. Later the deck will be lifted onto the jacket and next year the wind turbine will be mounted on the deck.

We learned that a barge involved in the installation process had dented one of the legs of the jacket after it was positioned in the water

Just after the first jacket was installed, Deepwater Wind's CEO Jeff Grybowski announced "steel in the water," which marks a major milestone. A day later the company organized an offshore tour for federal and state government officials and others involved in the wind farm's development to see the first jacket positioned in the water. We soon learned that due to rough water, the second jacket installation was to be delayed for a week. At about the same time, we learned that a barge involved in the installation process had dented one of the legs of the jacket after it was positioned in the water. Reportedly the damage was not serious and will not impact the project's development.

Exhibit 9. First Offshore Wind Turbine Platform In RI Waters

Source: ***Reuters***

However, due to the mandatory annual escalation, after five years, the wind power cost will surpass that of the solar project, and then continue rising for another 15 years

As the media focused on the Block Island project, a reporter wrote about the cost of electricity generated by the wind farm. Deepwater Wind has a contract to supply power to the 1,000 residents of Block Island and then shipping surplus power by an underwater cable to shore. National Grid (NGG-NYSE), Rhode Island's primary utility provider, has a contract to buy this electricity starting at 24.4 cents per kilowatt-hour (kWh) that will escalate by 3.5% per year for each of the 20 years of the contract. National Grid charges customers 10.4 cents per kWh, which includes a charge for alternative renewable fuels. The price and contract terms of the wind power agreement are considerably different from those of a solar project where National Grid is paying 28 cents per kWh, but without any price escalation. However, due to the mandatory annual escalation, after five years, the wind power cost will surpass that of the solar project, and then continue rising for another 15 years.

Over the past decade, wind power capacity grew by a factor of 7.7 times while solar PV capacity expanded by nearly 50 fold

A recent analysis of solar and wind renewables by Robert Rapier showed that global solar photovoltaics (PV) installed capacity grew by 28.7% in 2014 bringing the total amount to 177 gigawatts (GW). Global wind power grew its installed capacity by 16.2% in 2014 to 370 GW. Over the past decade, wind power capacity grew by a factor of 7.7 times while solar PV capacity expanded by nearly 50 fold. If those growth rates continue, solar PV will overtake global wind capacity within the next ten years. The problem is that installed capacity does not equate to electricity output due to the intermittent nature of these renewable fuels. This is both a problem for utility companies but also can be used to mislead the public about how significant solar PV and wind are for helping decarbonizing the U.S. power industry.

In 2014, for wind power, it was 21.6%, while it was only 11.8% for solar PV

Mr. Rapier utilized data from the latest BP Statistical Review (BP-NYSE) to determine what the performance of solar PV and wind power really was. By multiplying 24 hours by 365 days and the total number of GWs of power capacity it is possible to determine the theoretical output from the industry's installed capacity for any particular fuel. Dividing the actual consumption number by the theoretical output shows the capacity utilization rate. In 2014, for wind power, it was 21.6%, while it was only 11.8% for solar PV.

Based on its utilization rate, in order to replace all the U.S. coal-fired capacity, it would require 1,542 GW of solar PV

If these renewables are to replace U.S. coal-fired power plants, it would be interested to see how much additional capacity would be needed. According to Mr. Rapier, the U.S. has 303 GW of coal-fired capacity with an average capacity utilization of 60%. At 100% of theoretical usage, there would be only 183 GW of coal-fired capacity needed. Based on its utilization rate, in order to replace all the U.S. coal-fired capacity, it would require 1,542 GW of solar PV. As current U.S. solar PV capacity is 18.3 GW, it represents only 1.2% of the theoretical capacity necessary to replace all the coal-fired capacity.

The U.S. installed wind power capacity in 2014 was 66 GW, or 7.8% of the theoretical capacity needed to replace all coal-fired capacity

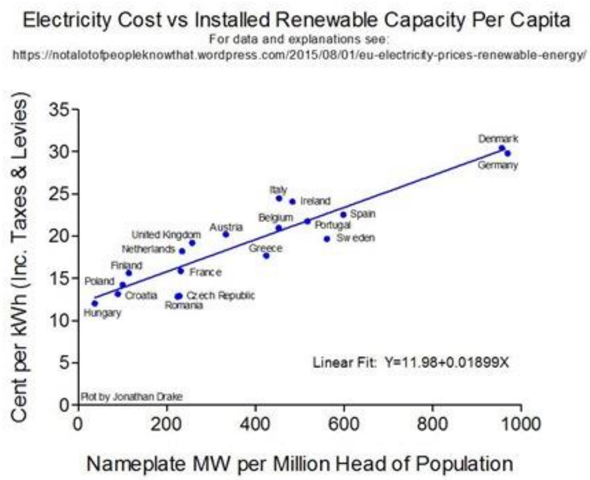
Performing the same analysis for wind power, the U.S. would need 843 GW of wind power to replace all the coal-fired capacity. The U.S. installed wind power capacity in 2014 was 66 GW, or 7.8% of the theoretical capacity needed to replace all coal-fired capacity. The status of U.S. installed solar PV and wind capacity suggests it is completely unrealistic to expect them to replace even a substantial amount of our coal-fired power capacity anytime soon. The other problem is that we are constantly treated to projections of how quickly the cost to install solar PV and wind capacity are falling and that this will translate into sharply reduced electricity costs, especially compared to their current costs. We wonder whether that is true, or even possible given the unknown impact of the intermittency of these renewables on the cost to operate the electricity grid.

"It will look fine. It will still be beautiful. Besides, I think it is about time America starts catching up with Europe on wind anyway."

We were reminded of the impact these intermittent power sources have had on European countries' cost of electricity by a media story about Deepwater Wind. The article quoted a German tourist, Britta Schulte, who was visiting Block Island's Southeast Light House on a bluff overlooking the Deepwater Wind work site. She said she did not expect the wind turbines there to create an eyesore for vacationers. "It will look fine. It will still be beautiful. Besides, I think it is about time America starts catching up with Europe on wind anyway." A chart prepared by Jonathan Drake and posted on the blog notalotofpeopleknowthat.com shows the relationship among countries measured by their installed renewable-capacity per capita versus the cost of electricity in the country.

As Exhibit 10 on the next page shows (we have not verified the numbers), the two European countries with the highest penetration of renewable fuels, Denmark and Germany, also have the highest

Exhibit 10. More Renewables; Higher Power Costs



Source: ***notalotofpeopleknowthat.com***

As politicians push for a renewables-only power industry, consumers can expect an explosion in their power costs

electricity costs. In the case of Rhode Island's 30 MW offshore wind project, given that the state has slightly over one million residents, the state would be located about where Hungary is positioned but with a cost closer to Italy's, so about 85% of the way to the cost of Denmark's and Germany's cost of electricity. As a result of the renewables cost data and its trend, consumers should be alarmed about their future electricity costs. As politicians push for a renewables-only power industry, consumers can expect an explosion in their power costs.

The wind investment would represent about 9% of our current national debt while solar would be 50%

Based on the most recent data from the American Wind Energy Association, the capacity-weighted average installed cost for wind energy is $1,940 per kilowatt (kW). Based on our earlier analysis of the amount of new wind power capacity that would be needed to replace all our coal-fired power plants, the cost would total $1.4 trillion. Likewise, for solar power, based on data from the solar industry, the average cost of installed solar panel projects (roof-top and not solar power farms), a 5 kW installation costs $25,000-$35,000. Using the average cost per kW, we calculate that to build the 1,524 GW of solar power needed to replace our coal plants would cost the nation $9.14 trillion. To put those cost numbers into perspective, the U.S. government debt totals $19 trillion. The wind investment would represent about 9% of our current national debt while solar would be 50%. We can now begin to appreciate how the Obama Clean Power Plan will reshape America as we know it today.

In 2008, then-presidential-candidate Barack Obama told the editorial board of the *San Francisco Chronicle* that "If somebody wants to

"Under my plan … electricity rates would necessarily skyrocket."

build a coal-fired power plant, they can. It's just that it will bankrupt them." Mr. Obama was discussing his cap-and-trade plan to regulate carbon emissions; something that is no longer operational. He then went on to add, "Under my plan … electricity rates would necessarily skyrocket." The mandate for solar PV and wind to replace coal- and natural gas-fired electricity generation will fulfill Mr. Obama's dream of transforming the American economy.

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