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

Rhode Island Electricity Rate Hike Battle Ends In Whimper

The news media, public officials and the public focused on its magnitude – a 53% increase!

Last week, the Rhode Island Public Utility Commission approved the electric rate hike requested by the state's primary electric utility, National Grid (NGG- NYSE). Currently, National Grid serves 486,000 customers and accounts for over two-thirds of the electricity usage in the state. In 2014, it had 473,000 customers while competitor suppliers served another nearly 20,000 customers, but over half of them were commercial and industrial users. When the higher rate was proposed several weeks ago, the news media, public officials and the public focused on its magnitude – a 53% increase! That hike applies only to the Supply Services portion of a customer's bill, or the cost of power. The rate increase is only for the upcoming winter period, as the utility is required to divide its annual billing cycle into halves – the summer months, April 1 to September 30, and the winter months, October 1 to March 31.

Natural gas is the primary fuel for generating electricity in Rhode Island

There are several aspects of the rate hike request that should be understood. First, natural gas is the primary fuel for generating electricity in Rhode Island, and it is more expensive during the winter months as electricity generators compete with home heating for the limited gas supplies coming into the region. Secondly, electricity bills in the state are divided between the fuel supply cost and the cost to operate the electricity distribution system, with National Grid only able to profit from the distribution component.

The cost of supply will go from 6.2/kWh to 9.5 cents/kWh

The proposed rate hike made for a great headline, but it wasn't the whole story. The 53% figure impacted only the cost of supply, which will go from 6.2 cents per kilowatt hour (kWh) to 9.5 cents/kWh. Given the outrage, National Grid's president and chief operating officer wrote an op-ed in *The Providence Journal* responding to the criticisms and to educate the public why the increase in its monthly bill was required and why it won't be as large as suggested.

National Grid has used the 500 kWh "typical monthly usage" since the 1990s

According to National Grid, the typical monthly residential electric bill for a homeowner using 500 kWh of power will only rise by 18%, or $16 per month. That monthly increase includes the higher cost for the supply component along with a stable delivery component cost. *The Energy Miser* blog wrote about the rate increase and made an interesting point. The blog, referencing the newspaper op-ed, pointed out that National Grid has used the 500 kWh "typical monthly usage" since the 1990s. The blog wondered if anyone was still at that low usage number. It believes the average household is now using 800-1,000 kWh a month due to the use of computers and other electronic devices, especially the instant-on feature of televisions and computers. It estimates that a household using 800 kWh of electricity a month likely has a bill of about $142. With the supply component rate hike, that bill is likely to jump to about $170 per month, or a $28 increase. The nearly 20% increase will impact many households in Rhode Island, which helps to explain why the people were outraged by the announced hike.

The second point Mr. Horan made in his op-ed was that the supply cost hike magnitude was due to the low level it has been at for the past couple of years. If one compares the proposed 9.5 cents/kWh rate with the winter rate for 2016-2017 of 8.2 cents/kWh, the hike is only about 16%. Again, the percentage increase is based on that "typical" monthly usage figure of 500 kWh.

It is due to the greening of the New England power market

The most telling point in Mr. Horan's defense of the proposed rate hike was why it was necessary. It is due to the greening of the New England power market. To meet the power needs of residents, ISO-New England (ISO-NE), the non-profit operator of the region's power grid, holds a Forward Capacity Auction (FCA) annually to meet the supply needs of customers three years in the future. When the auction for the upcoming rate season was held three years ago, several major power-generating plants in New England had just announced their retirement. At that point, 2014, the outlook for the region went from having a capacity surplus to a capacity shortfall, driving up the future capacity (supply) cost.

National Grid management also commented on their plans for rate hikes, which was to become more aggressive following the company's SAP computer system upgrade

Critics of the proposed rate hike attacked National Grid for gouging the public. They point to the company's overall financial performance, which, according to the commentary during company earnings conference calls with investment analysts, has demonstrated a healthy performance for its Rhode Island operation. National Grid management also commented on their plans for rate hikes, which was to become more aggressive following the company's SAP computer system upgrade. Now the company can detail its costs better and quicker, so Rhode Island customers should be prepared for future rate hikes covering the distribution component given the low returns National Grid is earning.

What is the health of the New England and Rhode Island power markets, and how does it play into the effort to expand the natural gas pipeline network supplying the region? It is important to understand how the region's electricity grid works. Once a year, ISO-NE holds its FCA for a one-year period of time three years in the future. The FCA's purpose is to ensure there will be adequate electricity supply to meet the region's expected demand.

ISO-NE runs both New England's electricity market and New England's capacity market. Although the two markets are related in the sense that electricity generators can participate in both, the two markets are not identical. Electricity generators include both conventional generators such as natural gas, coal and nuclear, as well as all renewable generators such as wind, solar and small hydropower plants, and they all compete in the electricity market.

The capacity market is designed to ensure that sufficient electricity supply will be available in New England in the future

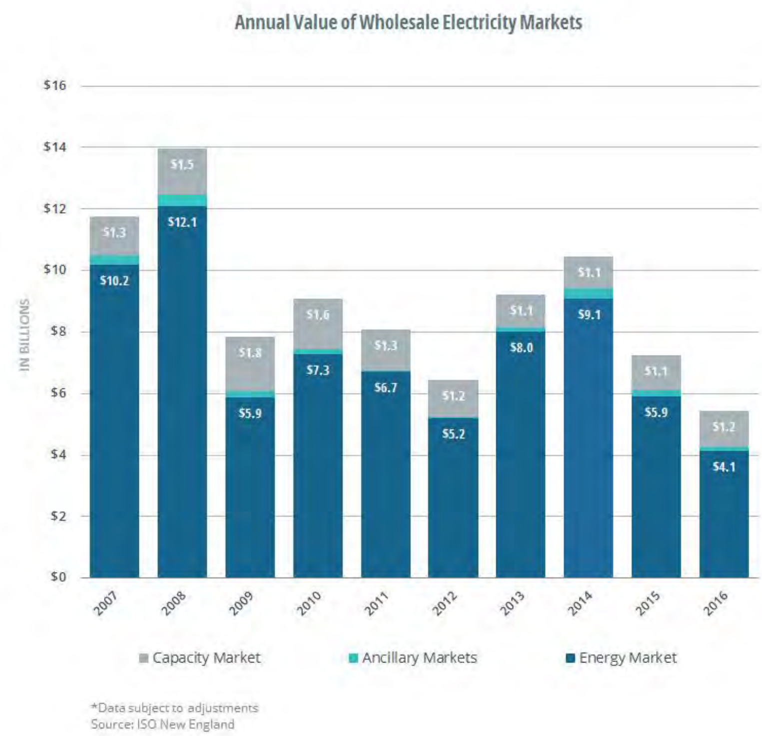
The capacity market is designed to ensure that sufficient electricity supply will be available in New England in the future. In the FCA, electricity generators compete for what is called a "Capacity Supply Obligation" (CSO). Generators who bid successfully in an auction acquire a CSO for a future period, essentially for a one-year period, three years in the future. The CSO creates a future stream of income, in the form of "capacity payments" that the owner can use to collateralize a loan now, in order to finance the construction of a new power plant that will deliver power in three years when their obligation begins. The CSO requires the generator to produce electricity if and when it is called on to do so by ISO-NE during the relevant one-year period.

The fluctuations in the value of the electricity market reflects the impact of weather and economic performance in the region

The electricity market is the real-time market of actually producing electricity for real-time use throughout New England. The money generators earn from the capacity market can be used to finance new electricity generating power plants, while the money that goes to the generators from the electricity market is used to run those plants, which is mostly fuel cost. The history of how these two market segments have performed from 2007 to 2016 is shown in Exhibit 1 on the next page. As shown, during the early years of that time period, the capacity market received significantly more funding than in later years, which enabled the region to develop new generating capacity to meet growing power needs, or at least as they were projected. The fluctuations in the value of the electricity market reflects the impact of weather and economic performance in the region, which was hurt by the 2008 financial crisis and subsequent recession.

The high system-wide prices, along with the even higher new-capacity prices, reflected expectations that only high prices would encourage the construction of new generating capacity, including renewable energy, as well as demand reduction programs

Exhibit 1. How The Power Market Has Moved Over Time



Source: ISO New England

To better understand how the electricity market in New England and Rhode Island has changed and is expected to change in 2010-2021, we turn to the results from the annual FCAs.

As shown on the next page, between 2010/2011 and 2016/2017, the capacity floor price ranged from $2.95 to $4.50 per kilowatt hour per month. In FCA #8 (2017/2018), the price jumped to $15.00/KW/M for new capacity and $7.025/KW/M for existing capacity, more than double the prior year's floor price. In 2016/2017, new capacity for a sub-region including Boston jumped to $14.99/KW/M. The price jump coincided with announcements of several large fossil fuel power plant closures, as well as the largest nuclear power plant in New England. That impact was seen in FCA #9 (2018/2019) when system-wide capacity's clearing price reached $9.55/KW/M, up threefold from two years prior. More importantly for the sub-region that includes Rhode Island, new capacity was paid $17.73/KW/M and existing capacity earned $11.08/KW/M. The high system-wide prices, along with the even higher new-capacity prices, reflected expectations that only high prices would encourage the construction of new generating capacity, including renewable energy, as well as demand reduction programs. With the prospect of significant new capacity entering the region – much of it from Canada and New York – the new price for the capacity market fell to $7.03/KW/M for

2019/2020 and further declined to $5.30/KW/M for 2020/2021. The results of the recent FCAs confirm Mr. Hogan's point about why Rhode Island's power supply cost has increased.

Exhibit 2. FCA Auction Results Reflect Power Price Changes

Results for ISO-NE Annual Forward Capacity Auctions				
Auction Commitment Period	Total Capacity Acquired (MW)	New Demand Resources (MW)	New Generation (MW)	Clearing Price ($/KW-Month)
FCA #1 2010/2011	34,077	1,188	626	$4.50 (Floor Price)
FCA #2 2011/2012	37,283	448	1,157	$3.60 (Floor Price)
FCA #3 2012/2013	36,996	309	1,670	$2.95 (Floor Price)
FCA #4 2013/2014	37,501	515	144	$2.95 (Floor Price)
FCA #5 2014/2015	36,918	263	42	$3.21 (Floor Price)
FCA #6 2015/2016	36,309	313	79	$3.43 (Floor Price)
FCA #7 2016/2017	36,220	245	800	$3.15 (Floor Price) NEMA/Boston $14.99
FCA #8 2017/2018	33,712	394	30	$15.00/new & $7.025/existing
FCA #9 2018/2019	34,695	367	1,060	System-wide: $9.55 SEMA/RI: $17.73/new & $11.08/existing
FCA #10 2019/2020	35,567	371	1,459	$7.03
FCA #11 2020/2021	35,835	640	264	$5.30

Source: ISO-NE, PPHB

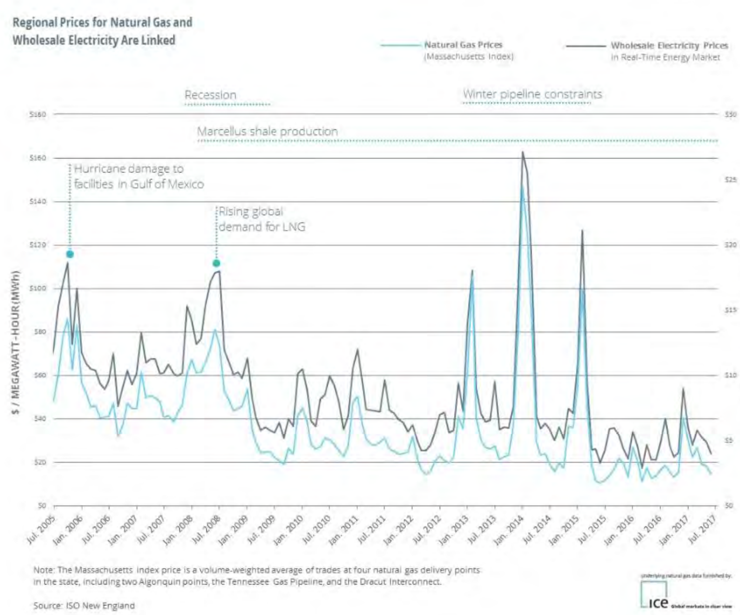
For Rhode Island, where natural gas provided 93.4% of the power in May, the linkage between gas prices and electricity is tight

For Rhode Island, where natural gas provided 93.4% of the power in May, the linkage between gas prices and electricity is tight. ISO-NE demonstrated the linkage in Exhibit 3 (next page) covering 2005 to July 2017. The chart highlights how the Gulf of Mexico hurricanes in 2005 and rising LNG demand in 2008 impacted gas prices. What was more dramatic were the price spikes of 2013-2015 due to pipeline constraints and cold weather. Those spikes stand out from the overall declining gas price trend exhibited since 2008 due to the emergence of Marcellus gas supply. ISO-NE commented on the period following those price spikes: "…by June 2015, the average monthly wholesale power price had plummeted, due to mild weather, low demand, and the lowest average natural gas price since 2003." They went on to say, "In 2016, extremely low natural gas prices, aided by the 2015/2016 'winter that wasn't' kept wholesale electricity prices low."

The pipeline opponents point to the sharp fall in FCA capacity prices for 2019/2020 and 2020/2021 as a sign that the region doesn't need more gas pipeline supply, but maybe they are being shortsighted

Those gas supply-constrained price spikes prompted the major natural gas transmission companies to propose new and expanded pipeline projects to expand supply during super-cold winter periods. These projects have been fought by environmentalists and anti-fossil fuel activists. In most cases, these efforts have been successful, largely because weather and low natural gas prices have cooperated. The pipeline opponents point to the sharp fall in FCA capacity prices for 2019/2020 and 2020/2021 as a sign that the region doesn't need more gas pipeline supply, but maybe they are being shortsighted. They would rather see more Canadian hydro power imported and greater regional wind and solar power sources developed, hence the effort to increase renewable power mandates. It is interesting that in May in Rhode Island, the same amount of power came from biomass (burning wood chips) as from wind and solar power combined.

Exhibit 3. The Linkage Between Gas And Electricity Prices



Source: ISO-NE

Because National Grid complied with the regulatory rules and does not make any profit from the supply component, the Rhode Island PUC had no choice but to grant National Grid's rate hike request. It will also be interesting to see if all the new non-fossil fuel power that contributed to lower future capacity prices arrives as promised, since some of it is keyed to proposed large offshore wind facilities, among the most expensive renewable power available. The development of new export outlets for Marcellus natural gas may also raise gas prices in New England, which could disrupt the region's power market, and keep electricity prices higher than during the 2010 – 2016 period.

Australia Green Folly Beats Germany: Warning For The U.S.?

Australia has been following the German model of shutting down fossil fuel power plants and pushing renewable power with a healthy subsidy scheme

Australia is experiencing very high electricity prices, which some have attributed to its push for increased renewable power. Australia has been following the German model of shutting down fossil fuel power plants and pushing renewable power with a healthy subsidy scheme. The difference is that Australia has been rapidly expanding its natural gas exports. This has led to power outages due to a lack of gas supply. Should Australia's energy market problems be a warning to the United States about its current energy course?

Households in South Australia are paying the highest prices in the world at 47.13¢ per kilowatt hour

A new report from *Australia Financial Review* shows that customers in many of Australia's states are paying the highest electricity costs in the world. More importantly, the report states that when the National Energy Market was formed in 1998, Australia's power costs were among the lowest in the world. According to data from *Carbon + Energy Markets*, households in South Australia are paying the highest prices in the world at 47.13¢ per kilowatt hour (kWh). That price is higher than residents in Germany, Denmark or Italy are currently paying. Those other high-cost countries heavily tax energy and have promoted the rapid expansion of renewable energy sources. The United States came in last in the price compilation, thanks to its cheap coal and natural gas supplies. But some of the energy policies being pursued in the U.S. might be setting the country on a course with an outcome possibly ending up mirroring that of Australia.

Australia went from fourth most expensive to first, an increase of over 62%

Based on electricity prices for countries in 2011, compiled by OVO Energy, Australia went from fourth most expensive to first, an increase of over 62%. Denmark and Germany had the first and second most expensive electricity costs in 2011, but both now trail Australia, even after posting increases of 9% and 24%, respectively. Not surprisingly, Great Britain, which has embraced renewables and shut down its coal-fired power plants, saw its power price jump 56% between 2011 and 2017, from 20¢ to 31.3¢ per kilowatt hour.

Exhibit 4. From Low To Highest Electricity Prices In Five Years

Source: ***Australia Financial Review***

What caused this explosion in electricity costs in Australia?

What caused this explosion in electricity costs in Australia: is it due to more renewable power or higher domestic natural gas prices due to the increase in the nation's liquefied natural gas (LNG) business? Proponents on all sides of the debate are weighing in, which makes it a challenge to sort out which of the arguments carries the greater weight. The debate began a year ago when power prices in Australia began soaring. As a result, in early October 2016, the Council of Australian Government (COAG) Energy Ministers agreed to an independent review of the national electricity market, in order to assess its current security and reliability, and to provide advice to the governments on a coordinated, national reform blueprint. A preliminary report was delivered in December 2016, and the final report was completed in June 2017. The report team was headed by Australia's Chief Scientist Dr. Alan Finkel, and the report seems to arrive with a bias in favor of renewables, while ignoring some of the key factors behind why residents' electricity bills have soared. According to the release announcing the final report, "The report uses three pillars to achieve these outcomes: orderly transition measures, system planning and stronger governance."

As often comes from studies done in response to government perceived problems, the report recommends more government

Clean energy was chosen as the most effective mechanism to reduce carbon emissions, while supporting security and reliability. The question of carbon emissions was not part of the COAG request when agreeing to the preparation of the report. As often comes from studies done in response to government perceived problems, the report recommends more government. The report recommends the creation of a new Energy Security Board to drive the implementation of the blueprint and to deliver an annual report on the state of the electricity system. The blueprint assumes there will be an agreement among the federal, state and territorial governments to a national emissions reduction trajectory, again something that was not part of the original study mandate.

Plants closing employ more workers than what will replace them

As part of the report's blueprint, existing large electricity generators will be required to give a 3-year notice of plant closures, in order to signal new generation investment opportunities, as well as giving communities a heads up in planning for the loss of a large employer. This appears to be an acknowledgement that the plants closing employ more workers than what will replace them, making regional economies worse off.

The blueprint further requires that new generators be required to guarantee electricity supply when needed

The blueprint further requires that new generators be required to guarantee electricity supply when needed at a level determined following regional assessments by the market operator. There is also a need to develop a system-wide grid plan to help promote renewable energy projects, while preserving electricity security. As Dr. Finkel put it in a speech discussing the report, "The National Electricity Market is 5,000 kilometers (3,100 miles) long, spans five states and one territory and has more than nine million metered customers. It's essential that we get it right."

His greatest criticism was leveled at the report's promotion of "intermittent electricity devices" (IED), meaning renewable power, to the exclusion of on-demand power sources – fossil fuel plants

Within two weeks after delivery of the report, Dr. Finkel's study was hit with a blistering critique by Dr. Michael Crawford, a professor of management and a consultant with a focus on government failings. He attacked the Finkel report for promoting clean energy, which was not the issue the report was asked to address. His greatest criticism was leveled at the report's promotion of "intermittent electricity devices" (IED), meaning renewable power, to the exclusion of on-demand power sources – fossil fuel plants. He pointed out that the IED subsidy scheme nearly doubles the value of a kilowatt hour of power produced by such a generator compared to that from a fossil fuel plant. "Under the RET [renewable energy trading] scheme,

IED earns more than twice what a traditional power generator would earn

fossil-fuel generators have a single source of income, which is the money paid for the electricity they sell into the grid. IEDs have two sources, money paid for electricity sold into the grid and money paid (ultimately by electricity consumers) for the RECs [renewable energy certificates] the federal government authorizes them to print and which electricity distributors are compelled to buy." With the spot price for electricity at $80 per megawatt hour and $85 per megawatt hour being paid for RECs, an IED earns more than twice what a traditional power generator would earn - $165 versus $80 per megawatt hour.

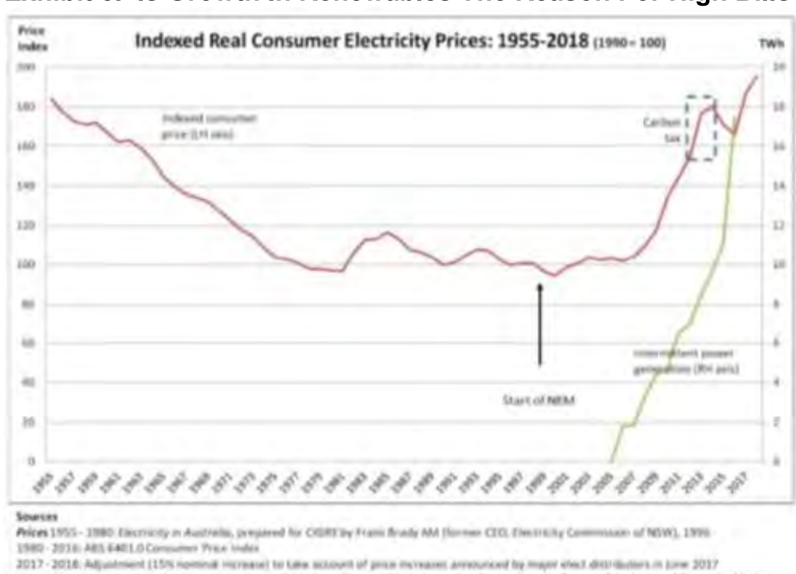
The fossil fuel plant becomes the backup supply for IEDs when the wind fails to blow and the sun doesn't shine

An additional problem for traditional power providers is that under the rules for supplying electricity into the grid, IEDs are guaranteed to be able to sell into the grid all the electricity they produce, while fossil fuel plants are allowed to supply only the balance needed to meet demand. Theoretically, the fossil fuel plant becomes the backup supply for IEDs when the wind fails to blow and the sun doesn't shine.

With IED generating capacity entering the market in 2005, and then growing rapidly, real electricity prices began rising sharply

Dr. Crawford produced a chart showing an index of real consumer electricity prices in Australia since 1955, along with the growth in IED generation. With IED generating capacity entering the market in 2005, and then growing rapidly, real electricity prices began rising sharply. Dr. Crawford chastised Dr. Frankel for not examining the correlation and examining if the growth in renewable energy bears any responsibility for the rise in Australian consumer electricity bills.

Exhibit 5. Is Growth In Renewables The Reason For High Bills?



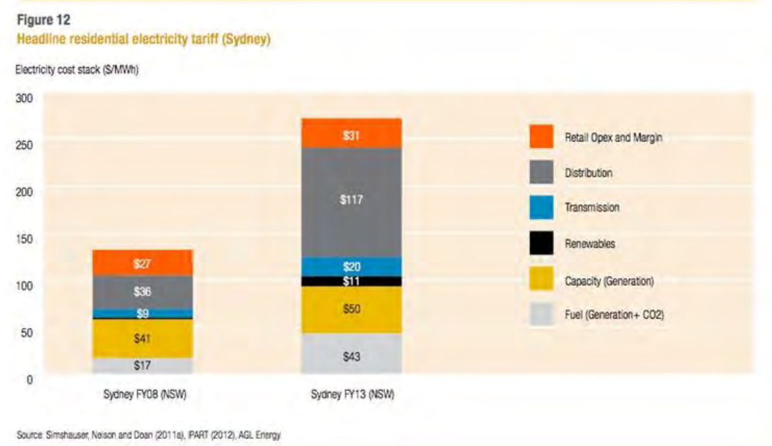
Source: Dr. Michael Crawford

An alternative explanation for the increase in consumer power bills is the rising cost of operating the transmission and distribution system.

"The charge for transporting electricity and the charge for selling it is much more significant than the charge for its production"

Bruce Mountain, Director of Carbon and Energy Markets, writing in the *Australia Financial Review* said, "…the main part of Australia's electricity pricing problems do not lie in the costs of producing electricity. For all but the very biggest electricity users, the charge for transporting electricity and the charge for selling it is much more significant than the charge for its production. It is expansion in these network and retailers' charges that explains Australia's precipitate decline from the top to the bottom ranking in international electricity price league tables. The issue underlying such dismal failure – political economy – remains completely untouched [in the report]."

Exhibit 6. Moving & Distributing Gas Have Hit Customer Bills



Source: AGL Energy

The distribution and transmission's share of the total bill rose from 34.6% to 50.4%

An examination of this issue shows that from 2008 to 2014, the rising cost of distribution and transmission was the primary generator of higher consumer electricity bills. A breakdown of monthly residential power bills in Sydney shows that between FY2008 and FY2013 the distribution and transmission's share of the total bill rose from 34.6% to 50.4%. At the same time, the fuel component's share rose from just 13.1% to 15.8%. Now, according to analysts, the rise in electricity bills is coming from the higher cost of fuel, which has meant higher natural gas prices. That conclusion seems to be supported by a study of the typical bill breakdown for July that showed the fuel component share is now up to nearly 37%, or more than twice what is was in 2013. This is why the debate has shifted to whether consumers are being abused by renewables or natural gas exports.

A July article in *The Wall Street Journal* focused on the power blackout for 90,000 residents of Adelaide, which was instituted to prevent a larger power blackout due to a shortage of natural gas. That event occurred one night this past February during a summer heatwave. The electricity grid regulators requested a gas-powered generating plant to ramp up from half capacity to full capacity to help meet the increased air conditioning load, but the plant was unable to secure the necessary gas supply. This has raised the fear that there will not be enough natural gas to meet domestic needs while Australia is stepping up to become the largest global exporter of liquefied natural gas (LNG), surpassing Qatar.

Exhibit 7. Australia's Natural Gas Basins Are Not Connected

Source: Geoscience Australia

At the center of these issues is the emergence of the Asian LNG market

The problems Australia's natural gas business have include the geographic location of reserves, the rapid exploitation of eastern region marginal gas resources, and the lack of pipeline interconnections that could move gas supplies from Australia's west coast deposits to the country's population centers in the southeastern region. At the center of these issues is the emergence of the Asian LNG market and the realization that Australia had substantial coal seam gas resources on the east coast that could supply this market. The rush to tap this resource began in 2008 and accelerated in 2010. The development of coal seam gas requires an extensive drilling and dewatering effort before trapped natural gas is released. It also requires a sustained drilling effort to keep gas supply up.

From about 2014 onward, nearly all new east coast gas production was diverted offshore

The growth of the Asian LNG market offered coal seam gas producers the opportunity to export more-costly-to-produce Australian gas that could not be marketed at home. The higher price, and the long-term contracts, enabled companies to finance the development of the gas fields, the pipelines, and LNG export plants and terminals needed to tap this new supply source. The result was that from about 2014 onward, nearly all new east coast gas production was diverted offshore. At the same time, mature east coast natural gas output has declined as domestic gas prices were not sufficient to attract new domestic supply.

That test has been a hallmark of U.S. petroleum export contracts, and in particular those contracts for the new LNG export terminal

Further compounding the problem in Australia was that LNG export contracts did not include a provision to defer the exports in situations where domestic gas supply became inadequate. This issue has become a political football. In an email to the *WSJ* for its article, Australian Prime Minister Malcolm Turnbull (Liberal) said, "gas export licenses were issued without regard to the consequences for the domestic market." He went on to write, "as a result, at the time of record gas production we have had the prospect of a shortage of domestic gas on the east coast." In response, the representative of the Labor Party responsible for energy acknowledged that when the LNG export plants were being approved, the government was assured by the industry that the overseas sales wouldn't affect domestic gas supplies because it was developing new sources of gas. He said that if the party was issuing licenses now, they would include a "national interest test." That test has been a hallmark of U.S. petroleum export contracts, and in particular those contracts for the new LNG export terminals.

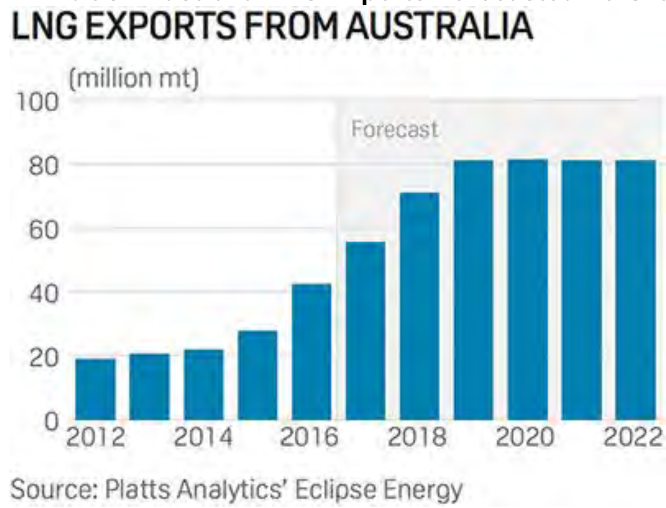
The government can, beginning on January 1, 2018, force LNG exporters to limit their shipments or seek new gas supply sources to prevent a domestic gas shortage

In late July, the Australian government began the formal process to determine whether 2018 will be a "gas shortfall year" and whether the country's LNG exports will be restricted as a result. Under the Australian Domestic Gas Security Mechanism, which was announced in June, the government can, beginning on January 1, 2018, force LNG exporters to limit their shipments or seek new gas supply sources to prevent a domestic gas shortage. The determination window is September 1st to November 1st, and if export controls are invoked for the year, each LNG exporter will be granted either unlimited or restricted volume permissions. Ultimately, rather than restricting LNG exports, the Australian government is more interested in expanding natural gas supplies.

DIIS revised down its forecast for fiscal 2017-2018 (July-June) LNG exports by 3.8 million metric tons

In its latest quarterly forecast, The Australian Department of Industry, Innovation and Science (DIIS) revised down its forecast for fiscal 2017-2018 (July-June) LNG exports by 3.8 million metric tons (mt) to 63.8 million mt from its March forecast of 67.6 million mt. The reduction reflected a later-than-expected startup of the Ichthys LNG project, which will not start up until March 2018. There are two additional LNG projects scheduled to begin production in the current fiscal year - the 8.9 million mt per year Wheatstone LNG project and 3.6 million mt per year Prelude floating LNG facility. The government also pointed out that intensifying global completion in the LNG market and the federal government's potential LNG export restriction are adding to uncertainty about the outlook for the LNG business.

Exhibit 8. Australia LNG Exports Forecasted To Grow



Source: *Platts*

DIIS expects the average capacity utilization of Australian plants to be lower in the future

Due to the more competitive global LNG market, DIIS expects the average capacity utilization of Australian plants to be lower in the future, but how much lower will depend on the cost competitiveness and the amount of flexibility existing in LNG contracts. "LNG contracts often include clauses which allow buyers to reduce purchases to minimum 'take-or-pay' levels. It is possible buyers may utilize these provisions if oil-linked contract prices remain higher than spot prices, or if they become over-contracted for LNG," said DIIS.

It is possible, given these reductions in LNG exports that the Australian energy crisis may ease without restrictions on exports

The government has also lowered its estimate for the value of Australia's LNG exports for fiscal 2017-2018 to $7.30 per million British thermal units (MMBtu) from $7.70/MMBtu. It also initiated a forecast for fiscal 2018-2019 LNG export volumes and prices of 73.8 million mt and $7.50/MMBtu, respectively. The forecast has been impacted by expected movements in oil-linked contract prices. It is possible, given these reductions in LNG exports, which the Australian energy crisis may ease without restrictions on exports. If that happens, we will then begin to see whether the green power movement has jeopardized the stability of Australia's electricity business, ensuring further increases in customer monthly bills.

All the U.S. LNG projects include a "public interest" clause

The important thing about the Australian situation is to see how it may differ from the U.S. market. First, all the U.S. LNG projects include a "public interest" clause, which is designed to enable the government to curtail natural gas exports should market conditions – a significant supply shortfall, for example – dictate. To understand this issue better, we turned to our old friend and LNG expert, James Jensen, who sent us some language from his contribution to an Oxford book on LNG that dealt with this clause. He wrote: "In the US, the Natural Gas Act of 1938 establishes two responsibilities that are relevant to LNG exports. First, exports of natural gas must obtain specific authorization from the DOE. Second, it requires a 'certificate of convenience and necessity' from the FERC before a project sponsor can construct facilities. The relevant passage of the export authorization states that: 'The Commission shall grant such application, unless … it finds that the proposed importation or exportation will not be consistent with the public interest'. This effectively places the burden of proof that the export is not in the public interest on those who object to it."

Should a supply shortage develop in the United States, one would expect Henry Hub gas prices would be signaling that possibility through sharply higher prices

Mr. Jensen described the process that companies need to go through to obtain the respective approvals, with those involving "free trade area" countries being much easier than those without such a designation. What neither Mr. Jensen nor we understand is how such an approval would be rescinded. The more relevant point is that U.S. LNG exports are based on gas supplies tied to Henry Hub prices, either directly because the recipient buys the gas directly and has it liquefied and shipped, or it purchases the LNG directly from the exporter who prices it off the hub price. In either case, should a supply shortage develop in the United States, one would expect Henry Hub gas prices would be signaling that possibility through sharply higher prices. As a result, U.S. LNG would become uncompetitive in the global market, thereby curtailing shipments and contributing to an increase in available domestic gas supplies that would presumably help relieve the supply crisis.

The U.S. is not likely to fall into a natural gas supply crisis as Australia has due to its LNG exports

While the U.S. is not likely to fall into a natural gas supply crisis as Australia has due to its LNG exports, it doesn't mean that we can't experience a similar explosion in residential electricity bills from an aggressive green energy mandate. We know that Denmark, the country with the highest electricity costs until Australia overtook it, is backing off its green energy push due to the pain inflicted on its citizens. A similar situation exists in Germany, where not only do its citizens pay the highest residential electricity costs in Europe, but the policy has thrown a significant portion of its citizens into 'energy poverty' while the country's carbon emissions rise due to the need to burn greater amounts of coal and lignite to keep the power on. We will be watching Australia's electricity costs once its greater control over LNG exports goes into effect in order to see if consumer utility bills continue rising or begin moderating.

No Future For Internal Combustion Engine Say Futurists

"The internal combustion engine had a good run. But the end is in sight for the machine that changed the world."

A recent cover of *The Economist* magazine featured the internal combustion engine (ICE) as "Roadkill," as the magazine's editors predicted the engine's upcoming demise. As the byline on its lead story put it: "The internal combustion engine had a good run. But the end is in sight for the machine that changed the world." We were a little surprised there wasn't a tombstone with 'R.I.P.' inscribed on it in the background. This is a bold forecast, especially given the magazine's history of treating extreme industry conditions as having become the new norm, often with dire consequences. In researching the predictions of the magazine's covers, we enjoyed perusing the online archives since the early 1970s to now. We could point to other oil industry covers that coincided with major industry turning points in its history, often with incorrect conclusions.

Exhibit 9. Bye, Bye Internal Combustion Engines

Source: ***The Economist***

Remarkably, from then to the end of the year, Brent oil prices rose by two and a half times

Who can forget the iconic March 6, 1999, cover (next page) - "Drowning in oil" - that marked the bottom of the oil price decline. We obtained a copy of the magazine, at that time, as we checked into a hotel at Charles De Gaulle Airport the evening before our flight home from Paris that March. Brent oil prices at that time were in the $10 per barrel range, up from about $9.50 a barrel at the end of December 1998, and a lot of our energy investor clients were unhappy and frustrated. Remarkably, from then to the end of the year, Brent oil prices rose by two and a half times, providing a significant lift to energy security prices and industry activity.

Exhibit 10. *The Economist* Iconic Oil Industry Cover

Source: ***The Economist***

It turned out that the world was not drowning in oil at March 1999, as the cycle's low price had actually been passed, energy demand was growing and activity was on the way up. The story the magazine told, however, was a reflection of how much the industry had been hurt by the low oil price (no mistake) and the likelihood that the pain would continue far into the future, which did not happen.

Equally as telling was the October 25, 2003, cover calling for the 'End of oil.' Last we checked, the oil industry was still pumping away, although maybe not as actively as it was doing during the period of 2010 to 2014 when oil prices traded at $100 a barrel. The industry has lived through likely the worst downturn in its history, but it is recovering, while still producing nearly 95 million barrels a day of oil. Of course, now it is the favorite target of energy forecasters who are predicting when the industry will reach peak oil demand, i.e., no further overall growth, but markedly different regional growth trends. Expectations are that once peak oil is reached, the industry will begin a downward trajectory, the pace of which will accelerate over time. That pace of decline will be tied to how quickly the world develops its next energy source, or system, such as envisioned by

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environmentalists. Rather than a more powerful and concentrated energy source, their view is that renewable fuels – wind, solar, hydro and biomass – with battery backup and time-of-use energy pricing will be sufficient to meet the world's energy needs. We will see.

Exhibit 11. Another Dire Oil Outlook Prediction

Source: ***The Economist***

The editors highlight all the forces working to reshape the oil market

The point *The Economist* made in its current article chronicling the oil industry's eventual end is that the forces causing it are already in place. Therefore, industry executives and investors should be preparing for this eventuality, which *The Economist* believes is accelerating faster than generally assumed. In barely over a page in the magazine, the editors highlight all the forces working to reshape the oil market – electric vehicles, industrial batteries, people who will no longer want to own cars, and the growing role policymakers are playing in transitioning the world to one populated with zero-emission vehicles. We are sure that if the editors had other forces in mind, those would have been listed, too.

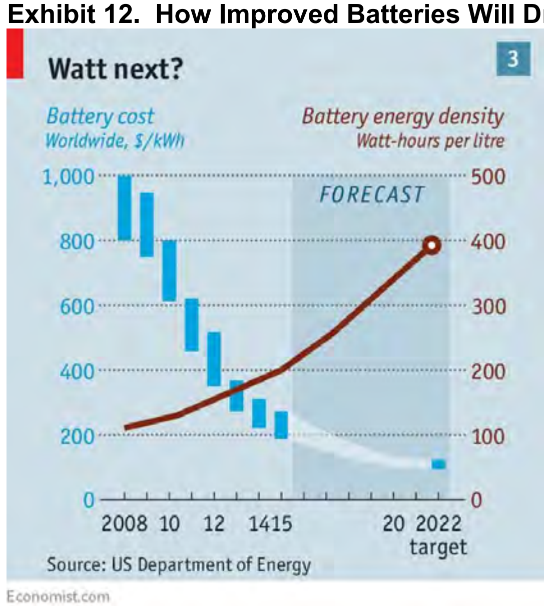
According to Jeff Siegel of the *Energy & Capital* newsletter, "While the internal combustion engine still has a good 10 to 12 years left before being archived along with the typewriter, the rotary phone, and the Betamax machine, its usefulness is rapidly being phased out as new transportation technologies begin to take hold. And when it comes to personal transportation, the electric vehicle is, without a shadow of a doubt, the final deathblow for internal combustion." He contrasted his view of the future with a news report that Russian President Vladimir Putin, who was pictured with Russian oilfield workers, is touting new oil extraction technology that is more efficient and would boost the country's output and sustain it for longer. For Mr. Siegel, this is unnecessary technology because electric vehicles will make oil superfluous.

This is unnecessary technology because electric vehicles will make oil superfluous

Mr. Siegel also discussed another technology being researched that could revolutionize the electric vehicle industry. He reported that "researchers in the UK and Israel are now running tests on roadways that are wired to charge electric cars as they ride over them. One in particular, developed by Qualcomm, has metal coils embedded into the asphalt. These coils create an electromagnetic field that transmits energy to a receiver to supply the vehicle's battery." Mr. Siegel suggests that investors should be thinking about this technology for a moment, and we agree. What happens to people crossing the street, especially those with pacemakers? If one thinks about the time needed and cost to map our existing road system to allow self-driving cars to operate, how long and at what cost are involved in repaving our highways with electric wires imbedded? These realities are what often trips up the optimistic forecasts for the impact of such new technologies.

"Researchers in the UK and Israel are now running tests on roadways that are wired to charge electric cars as they ride over them"

Exhibit 12. How Improved Batteries Will Drive EVs



Source: ***The Economist***

The electric vehicle business will be driven by improved battery economics

As far as *The Economist* is concerned, as well as many other optimistic forecasters, the electric vehicle business will be driven by improved battery economics, both reduced cost and increased power density. In its article, the magazine included a chart from the U.S. Department of Energy showing how battery costs have fallen since 2008, along with its projected target for 2022. There was also included a forecast for battery energy density, which, we noted, shows an acceleration during the forecast period, at the same time the battery cost decline slows.

Chile and Argentina are centers for lithium brine, an important supply source, but adding new capacity requires upwards of seven years

One question about lithium-ion batteries is whether there will be adequate raw material capacity to produce sufficient batteries to support the aggressive growth projected for electric vehicles. The issue is not necessarily the amount of raw materials, it is more a question of refined material volumes. According to *Benchmark Mineral Intelligence*, there is an estimated 210 million tons of lithium supply against annual consumption of 180,000 tons. Major hard rock lithium deposits are found in Australia, but it takes upwards of three years to bring new battery-ready supply into production. Chile and Argentina are centers for lithium brine, an important supply source, but adding new capacity requires upwards of seven years.

Exhibit 13. A Major Lithium Brine Supply Plant

Source: ***amusingplanet.com***

By 2025 the battery industry will need 750,000 tons of lithium carbonate equivalent to meet electric vehicle demand forecasts

According to Consultants Roskill, by 2025 the battery industry will need 750,000 tons of lithium carbonate equivalent to meet electric vehicle demand forecasts, but this will leave the industry about 26,000 tons short. That compares with a current market of 217,000 tons of demand versus 227,000 tons of supply. There are also questions about where the final 200,000 tons of supply will come from in order to meet the 2025 forecast.

We assume the lithium carbonate forecast is tied to the electric vehicle forecast from Morgan Stanley Inc. (MS-NYSE) as they were

By 2050, Morgan Stanley believes electric vehicles will account for 81% of 132 million new vehicles

presented together in an article. Morgan Stanley's forecast calls for electric vehicles, which accounted for 1.1% of 86.5 million new vehicle sales last year, to grow to 2.9% of 99 million new vehicles in 2020, and then to 9.4% of 102 million vehicles in 2025. By 2050, Morgan Stanley believes electric vehicles will account for 81% of 132 million new vehicles, not 100% as in other forecasts.

The problem is that cobalt supplies are smaller and about 60% comes from the Democratic Republic of Congo, which is controlled by war lords and relies on child labor for mining the ore

We don't know the details behind the Morgan Stanley electric vehicle forecast, but we know there are both more and less aggressive forecasts. We wonder if those forecasters have considered the potential constraints from lithium carbonate supply. There is a greater issue with cobalt, which accounts for 58% of a battery by weight, more than the lithium in a battery, and consumes 42% of all cobalt output. The problem is that cobalt supplies are smaller and about 60% comes from the Democratic Republic of Congo, which is controlled by war lords and relies on child labor for mining the ore. The governments we will have to deal with to meet the demand for rare minerals to meet electric vehicle forecasts present many moral and financial question marks. In fact, when we were in Tibet earlier this summer, we followed Chinese trucks hauling bags of lithium carbonate from mines to shipping depots. That supply is likely committed to the Chinese electric vehicle industry, which needs it to meet its anticipated growth outlook.

Since 2015, lithium prices have quadrupled, while cobalt prices have doubled

As a result of the growing demand for lithium and other rare minerals, their prices are climbing, and in some cases at alarming rates. Since 2015, lithium prices have quadrupled, while cobalt prices have doubled. What will rising prices and limited availability mean for the forecasts of ever cheaper batteries?

Batteries are only one issue. We haven't even begun to provide a sufficient public charging network with an equivalent charging time to an ICE-car fill-up. There are fast charging stations, but not all electric vehicles can use them, and we still don't know if the nation's electricity grid can handle the number necessary. Charging usually is assumed to be done at the electric vehicle owner's home, and at night, but that doesn't address the issue for urban dwellers with access to only curbside parking. Where do they plug in?

We agree with the magazine that there will be "profound and unexpected" outcomes from the coming transition in the transportation sector

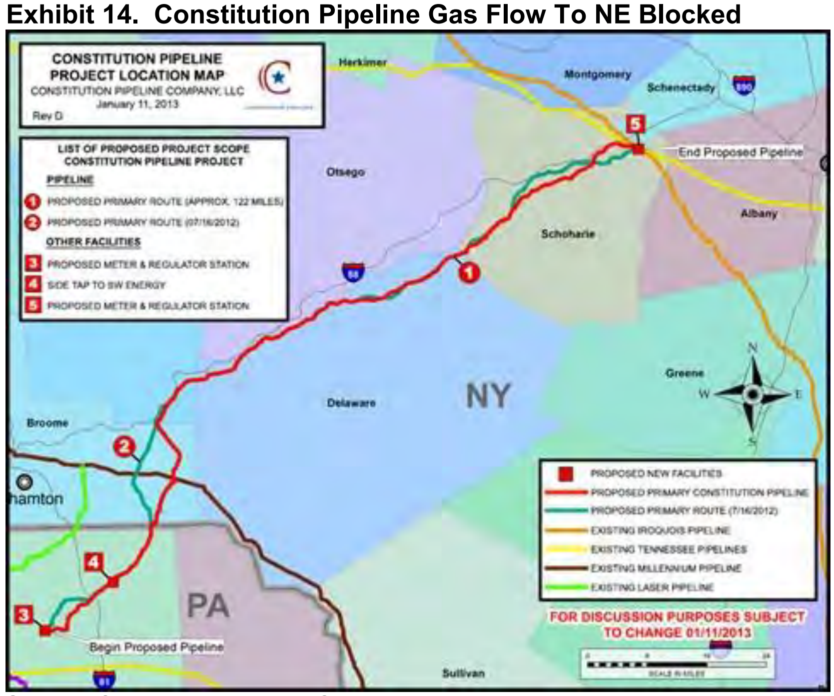
We think it is early to be writing the obituary for ICE cars as *The Economist* has done. We agree with the magazine that there will be "profound and unexpected" outcomes from the coming transition in the transportation sector. We also agree with the magazine's conclusion that the transition "…will be a bumpy road. Buckle up." Every energy executive needs to be thinking about the transition, the possible scenarios for its shape and speed, and what they may mean for their corporate strategies, no matter how outrageous the conclusions may appear on the surface. Without going through such a rigorous thought process, executives will be less prepared for how the future may challenge their companies. Preparing for the future is a better strategy than merely reacting to events as they unfold.

Natural Gas Pipelines A Victim Of Anti-Fossil Fuel Movement

The Second Circuit Court of Appeals ruling that the New York Department of Environmental Conservation acted properly in 2016 when it denied Constitution Pipeline a Section 401 certificate under the U.S. Clean Water Act

Recent days have not been kind to the natural gas pipeline industry, as it has found itself on the losing end of regulatory battles that landed in federal courts sympathetic to the anti-fossil fuel movement. First was the Second Circuit Court of Appeals ruling that the New York Department of Environmental Conservation (DEC) acted properly in 2016 when it denied Constitution Pipeline a Section 401 certificate under the U.S. Clean Water Act, effectively killing the project. The Constitution Pipeline is a joint venture project led by Williams Companies (WMB-NYSE) to build a 124-mile, $750 million pipeline from Pennsylvania into New York State. The nearly 100 miles traversing New York will cross 251 water bodies, including 87 trout streams. I

Exhibit 14. Constitution Pipeline Gas Flow To NE Blocked



Source: Constitution Pipeline Company

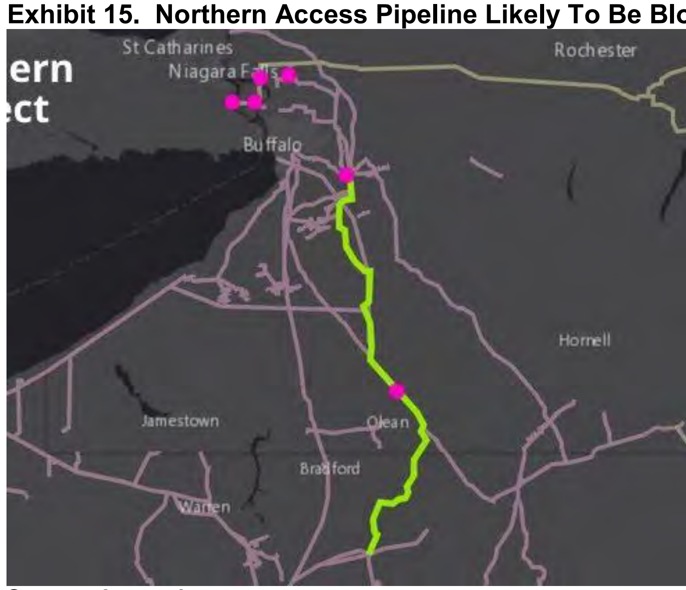
Section 401 of the Clean Water Act requires that certain federally-licensed projects must also secure state-issued permits

Section 401 of the Clean Water Act requires that certain federally-licensed projects must also secure state-issued permits. According to the opinion, the court said that Congress intended the states to "retain the power to block, for environmental reasons, local water projects that might otherwise win federal approval." At issue for the Constitution Pipeline was that it only supplied minimal information in response to the DEC requests, arguing that the Federal Energy Regulatory Commission (FERC) had primary jurisdiction, with which the company had complied. We expect Constitution Pipeline will appeal the ruling to the U.S. Supreme Court. In the meantime, its fate is uncertain.

The permit denial appeal is sitting at the Second Circuit Court, likely facing a similar fate as the Constitution Pipeline

The Northern Access Pipeline, a $455 million project to build a natural gas pipeline from Sergeant Township in southern McKean County, Pennsylvania, up into Erie County of New York, also had its water permits denied by the DEC. Some 96 miles of that pipeline would be in New York, crossing 180 streams, 270 wetlands and 17 ponds. The pipeline's owner, National Fuel Gas (NFG-NYSE), proposed horizontal drilling under only six of the streams with the remainder "dry-cut," in which the pipeline is located six feet below the water. The permit denial appeal is sitting at the Second Circuit Court, likely facing a similar fate as the Constitution Pipeline.

Exhibit 15. Northern Access Pipeline Likely To Be Blocked



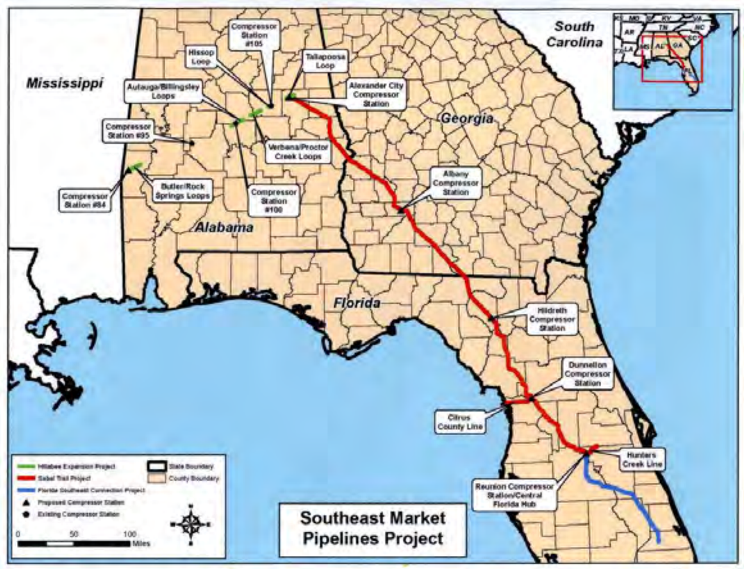
Source: ***fractracker.com***

By 2-1 the Circuit Court for the District of Columbia vacated the project's approval because FERC did not sufficiently analyze the downstream greenhouse gases emitted from the power plants supplied by the pipeline

While many in the pipeline business were watching these cases, another industry defeat signaled potentially greater future regulatory problems. This case involved a suit against FERC by the Sierra Club over the scope of FERC's Environmental Impact Statement (EIS) for the $3.5 billion Southeast Market Pipelines Project, with its centerpiece 515-mile Sabal Trail pipeline from Alabama to Florida, providing increased natural gas supplies to power plants. By 2-1 the Circuit Court for the District of Columbia vacated the project's approval because FERC did not sufficiently analyze the downstream greenhouse gases emitted from the power plants supplied by the pipeline. Since the pipeline is already in service, the decision raises questions about FERC's next move – to redo the EIS to address the issue or appeal the decision to the Supreme Court? In the interim, is the operation of the pipeline in jeopardy? We don't know.

While the Sierra Club is claiming victory and suggesting this approach is an effective way to fight new infrastructure projects, the ruling actually left room for FERC to address the issue. Complying with this new requirement would add time and additional analysis for

Exhibit 16. The Sabal Trail Pipeline In Legal Limbo



Source: ***investorvillage.com***

future EIS reports. The court acknowledged that FERC may have a problem preparing these analyses, so it left open the option for the agency to explain its inability to perform the analysis, fulfilling its requirement.

The lack of clarity may lead to more Marcellus natural gas being exported rather than flowing to the energy constrained New England region

For the natural gas industry, the water permit issue has the greatest near-term impact, as Virginia is also looking at permit rejections. Because this raises states' right, commerce and environmental questions, clarity is likely needed from the Supreme Court. However, any effort in this regard will likely be at least a year away, or longer. What happens in the mean time? The lack of clarity may lead to more Marcellus natural gas being exported rather than flowing to the energy constrained New England region. Keep in mind that the Cove Point LNG terminal is now open, enabling gas supply to head overseas. These pipeline cases will bring additional disruption to the domestic gas market, something it doesn't need.

Message From The Great Crew Change In Oil Company CEOs

"Chevron Seeks CEO for New Era," which suggested that the company might be reassessing its corporate strategy in light of the disruption underway in the energy business

The Wall Street Journal published a report last Tuesday that Chevron Corp. (CVX-NYSE) Chief Executive Officer John Watson would be announcing in September that he was stepping down from his post prior to his mandatory retirement age. He led the company since 2010. The *WSJ* story was headlined "Chevron Seeks CEO for New Era," which suggested that the company might be reassessing its corporate strategy in light of the disruption underway in the energy business. The reality is that the company already has a successor candidate onboard who has been an active participant in the development of the current strategy driving Chevron, given his long tenure with the company. While there was no official response to the succession rumor, there is also no evidence that the board of directors is looking outside of the company for a new leader. That would send a signal that the directors thought the company might need to address its strategy.

We expect his experience in managing the cyclical and thin-margin downstream businesses is the capability the board is seeking in its next CEO, as the oil industry confronts an extended period of lower oil prices

The likely reported successor to Mr. Watson is Michael Wirth, currently vice chairman of the board of directors and in charge of the company's midstream and development activities, including supply and trading, and the midstream operating units engaged in transportation and power, as well as corporate strategy, business development, and policy, government and public affairs. Given Mr. Wirth's background, it is unlikely that Chevron will make any major strategy shift. Rather, we expect his experience in managing the cyclical and thin-margin downstream businesses is the capability the board is seeking in its next CEO, as the oil industry confronts an extended period of lower oil prices.

If Mr. Wirth does step up, he will join several other executives with downstream backgrounds running major oil companies

The key takeaway from this announcement is not a strategy change, but rather an increased focus on cost control, which will be increasingly important for future earnings and return on investment metrics. If Mr. Wirth does step up, he will join several other executives with downstream backgrounds running major oil companies: Darren Woods at Exxon Mobil Corp. (XOM-NYSE); Ben van Buerden at Royal Dutch Shell (RDS.A-NYSE), and Patrick Pouyanné at Total S.A. (TOT-NYSE), although the latter only spent five years overseeing this business segment, rather than a career as the other two did.

"Big oil is turning toward very disciplined, returns-centric leaders who can manage razor-thin margins in disruptive, volatile markets"

As we have written previously, tracking the educational background and career paths of CEOs at Exxon Mobil since the early 1960s has proven enlightening in understanding what issues the company's board of directors considered most challenging for the company and industry, and they usually were accurate. As Les Csorba of executive recruiter Heidrick & Struggles told the *WSJ*, "Big oil is turning toward very disciplined, returns-centric leaders who can manage razor-thin margins in disruptive, volatile markets." That is an excellent assessment of the energy business' future. It also suggests that industry leaders need to understand the importance of these qualities given that the 'salad days' of the last boom are gone, likely forever.

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