PPHB

ENERGY INVESTMENT BANKING

MUSINGS FROM THE OIL PATCH

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

Trials And Tribulations Of Wind Power Raise Economic Issues

Offshore wind, on the other hand, before any tax credit is 2½ times more expensive than the natural gas option

According to an Energy Information Administration (EIA) report prepared last spring, onshore wind power had a capacity-weighted estimated levelized cost of electricity (LCOE) for new generation resources entering service in 2022, based on 2017 dollars per megawatt-hour ($/MWh) and equal to that of combined-cycle natural gas plants on a full-system cost basis. After crediting wind with the value of the Production Tax Credit, it becomes approximately 23.5% cheaper than natural gas. Offshore wind, on the other hand, before any tax credit is 2½ times more expensive than the natural gas option. Even with the tax credit, offshore wind remains 2.2 times more expensive. So why the fascination and focus on offshore wind in the Northeast and Mid-Atlantic regions?

The simple answer of why offshore wind is so fascinating is that it is more abundant than onshore wind or solar power

The simple answer of why offshore wind is so fascinating is that it is more abundant than onshore wind or solar power for meeting the clean energy mandates of most of the states in these regions. Offshore wind can solve another stumbling block issue, which is that the turbines are far removed from people, so they find it a less-objectionable energy resource. Will they care about it being so expensive?

That sentiment seems to be evident in Virginia where Dominion Energy (D-NYSE), the state's largest utility, is planning to invest $300 million to build two wind turbines 27 miles off the coast, capable of producing 12 megawatts (MW). These turbines are part of a "demonstration" project that should lead to a planned offshore wind project with hundreds of turbines required to produce 2,000 MW of offshore power, commencing in 2024.

In response to a "prudency petition" by Dominion for the wind turbines, the Virginia State Corporation Commission (SCC)

The law revised the historical utility contracting and pricing review process and measuring sticks

reluctantly approved it based on the recently revised statutory review parameters contained in a massive energy bill passed by the state's legislature earlier this year and signed into law by the governor. The law revised the historical utility contracting and pricing review process and measuring sticks. As a result, after a hearing this fall, on November 2, the SCC issued an order approving the project. It also issued a press release setting forth its frustration with having its traditional regulatory powers revised to enable such a renewable energy project to be approved when it was detrimental to the interests of the ratepayers.

The SCC's press release stated:

> "The Commission concluded that the offshore wind project 'would not be deemed prudent [under this Commission's] long history of utility regulation or under any common application of the term.' However, the Commission ruled, as a matter of law, that recent amendments to Virginia laws that mandate that such a project be found to be 'in the public interest' make it clear that certain factual findings must be subordinated to the clear legislative intent expressed in the laws governing the petition."

The SCC also found that any "economic benefits specific to [the project] are speculative, whereas the risks and excessive costs are definite and will be borne by Dominion's customers"

The SCC's conclusion to approve the Dominion offshore wind project was reached despite them citing two specific conditions that would have doomed the project under historical regulatory approval rules. The SCC cited Dominion's proposal putting "essentially all" of the risk of the project, including cost overruns, production and performance failures, on the company's customers. It also pointed out the project was not the result of a competitive bidding process to purchase power from developers. Had the process been followed, the SCC believes all or some of the risks of the project would have been shifted to the developers, as exists in other offshore wind projects along the East Coast. The SCC also found that any "economic benefits specific to [the project] are speculative, whereas the risks and excessive costs are definite and will be borne by Dominion's customers."

While Rhode Island's General Assembly wrote the script, Virginia merely followed it

The Virginia SCC experience follows the script written in Rhode Island in 2010 (see article elsewhere). Politicians are more than willing to force the regulatory bodies in their state, who are responsible for protecting consumers against exploitation from monopoly utilities, to overturn their decades of successful historical regulatory analysis processes in order to promote "pet clean energy projects." While Rhode Island's General Assembly wrote the script, Virginia merely followed it. How many other states will also exercise the same script?

So why is the SCC so exercised about the restrictions on their review process? This wind power will cost Dominion customers 78-cents per kilowatt-hour (kWh) at a time when new onshore wind power can be secured for 9.4-cents/kWh, new solar power costs 5.6-cents and power purchased on the open market costs about 3-cents. Virginians will pay over 8-times the cost of expensive onshore wind, or 26-times what Dominion could purchase power for from other suppliers.

Dominion's expensive offshore wind power is even more egregious when one considers what the EIA says is the estimated LCOE of offshore wind, 12.5-cents/kWh

Dominion's expensive offshore wind power is even more egregious when one considers what the EIA says is the estimated LCOE of offshore wind, 12.5-cents/kWh. That figure is before the nearly 2-cents/kWh reduction that comes with the application of the Production Tax Credit. What's wrong with this picture? Is Dominion being snookered by its partner Ørsted over the cost of the project and what it will take to earn a reasonable return, or is Dominion just out to bilk its captive customers since the SCC isn't able to protect them? Remember, Dominion was supportive of the Virginia energy bill, so it was lobbying for this regulatory freedom. The other explanation is that the EIA's LCOE determination is woefully wrong, raising questions about the validity of this type of analysis.

We have yet to determine what the cost of a kilowatt-hour of solar power is at 3 am?

We considered the last explanation, as we have always been skeptical of the concept of LCOE as a true reflection of the cost of renewable energy. LCOE treats every kilowatt-hour of power as equal. We have yet to determine what the cost of a kilowatt-hour of solar power is at 3 am? However, to the credit of the EIA, in its LCOE report, it offers cautionary language about renewable power that is always overlooked by its proponents.

The first broad cautionary note from the EIA stated:

> "The direct comparison of LCOE across technologies is, therefore, often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives because projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed."

We should really only be comparing the LCOE's of power sources with a similar deliverability

To reflect some of these differences, the EIA pointed out that "LCOE values for wind and solar technologies are not directly comparable to the LCOE values for other technologies that may have a similar average annual capacity factor; therefore, they are shown separately as non-dispatchable technologies." So, we should really only be comparing the LCOE's of power sources with a similar deliverability. Instead, renewable energy promotors fail to point out that apples and oranges are not alike, even though they both contain juice.

Another aspect of the evaluation approach is based on the capacity factor of each technology. The EIA points out that "each technology is evaluated based on the associated capacity factor, which generally corresponds to the high end of its likely utilization range." This is another argument for why the power sources should be

The use of the high end of utilization is a convention "consistent with the use of LCOE to evaluate competing technologies in baseload operation such as coal and nuclear plants"

segregated based on dispatchable versus non-dispatchable power. The use of the high end of utilization is a convention "consistent with the use of LCOE to evaluate competing technologies in baseload operation such as coal and nuclear plants." Because both wind and solar power have limitations and cannot become baseload power supplies without significant storage capability that is not factored into the analysis, one has to wonder why their LCOE is based on their highest utilization factors?

Exhibit 1. An Onshore Wind Turbine's Early End

Source: ***PowerLine***

Another issue that impacts the LCOE calculation is that the values are based on a 30-year cost recovery period for the power plant, but wind turbines do not last that long

Another issue that impacts the LCOE calculation is that the values are based on a 30-year cost recovery period for the power plant, but wind turbines do not last that long. A recent article by the Center of the American Experiment pointed out that an industrial wind farm in Wisconsin was dismantled after 20 years, rather than the 30-year calculation period for LCOE. In the case of offshore wind farms, there have been situations when blades and turbine hubs have needed to be replaced within as few as two years, but many times in less than 10 years. Five years ago, a report prepared by Gordon Hughes, a Professor of Economics at the University of Edinburgh for the Renewable Energy Foundation (REF) in England, analyzed productivity data from wind farms in the UK and Denmark. A key finding from the study was:

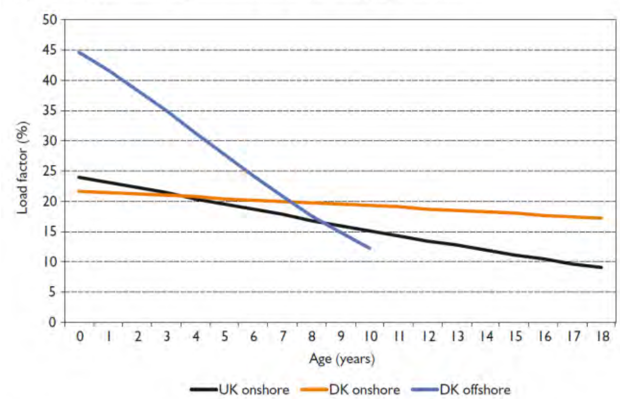
> "The normalized load factor for UK onshore wind farms declines from a peak of about 24% at age 1 to 15% at age 10 and 11% at age 15. The decline in the normalized load factor for Danish onshore wind farms is slower but still significant with a fall from a peak of 22% to 18% at age 15. On the other hand, for offshore wind farms in Denmark the normalized load factor falls from 39% at age 0 to 15% at age 10. The reasons for the observed declines in normalized load factors cannot be fully assessed using the data available but outages due to mechanical breakdowns appear to be a contributory factor."

This conclusion created a firestorm of disagreement from Professor David Mackay, Chief Scientific Advisor to the UK Department of Energy and Climate Change. Professor Mackay not only wrote online critical commentary, but also issued a draft paper refuting the claims and posted an extensive article on the topic on his blog site. The criticism resulted in the two authors being brought together by REF that led to Professor Mackay accepting the deterioration data conclusion. He then reversed his position, but without providing any new data. The critical difference between the two authors was the rate of decline. In essence, Professor Mackay believes the deterioration is only 2% per year rather than the 5% Dr. Hughes projects, based on actual performance data submitted to regulatory agencies in the UK and Denmark. Two charts show the deterioration based on equal weighting of the turbine performance versus capacity-weighted performance.

Professor Mackay believes the deterioration is only 2% per year rather than the 5% Dr. Hughes projects, based on actual performance data submitted to regulatory agencies in the UK and Denmark

Exhibit 2. How Wind Turbine Performance Deteriorates

Figure 1: Performance degradation due to age using equal weights

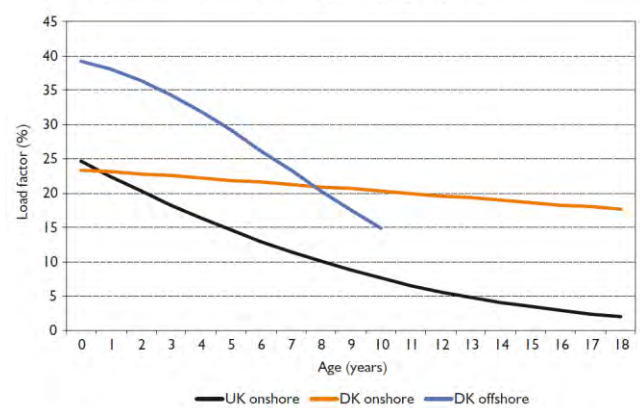


Note: Normalised load factors in %. Source: Author's estimates.

Source: Dr. Hughes

Exhibit 3. Wind Turbine Deterioration By Age

Figure 2: Performance degradation due to age using capacity weights



Note: Normalised load factors in %. Source: Author's estimates.

Source: Dr. Hughes

These time differences should be considered more prominently in the LCOE analyses

The deterioration of performance of wind turbines is similar to the deterioration of solar panels. While this deterioration will reduce the performance of wind farms that is not reflected in the LCOE analysis. Acknowledging that renewable power plants do not last as long as those of fossil fuel plants, which are known for lives of 40-50 years, is critical in the economic evaluations. These time differences should be considered more prominently in the LCOE analyses. Including the costs for rebuilding renewable power plants to match the lives of fossil fuel plants will cause LCOEs to increase significantly.

If the turbine lives are much shorter – 15-20 years, rather than 30 years – then the impact on the LCOE will be greater

Another consideration for offshore wind is the cost of abandonment. All offshore energy structures are required by international law to be removed, usually within five years after they cease productive/profitable output. The seabed is supposed to be restored to its initial state. A study about the 37 offshore wind farms either in operation or under construction in United Kingdom waters shows that the reclamation costs will be between £1.28 ($1.63) bn and £3.64 ($4.64) bn. Because these expenditures will be spread over the 30-year forecast life of the wind farms, the impact is to increase the LCOE by only 1%. Of course, if the turbine lives are much shorter – 15-20 years, rather than 30 years – then the impact on the LCOE will be greater.

If the LCOEs are wrong, as possibly suggested by the Virginia offshore wind project, or they are being misread relative to dispatchable energy, then quite possibly many communities will find they are facing exploding power costs down the road

LCOE is the preferred metric for promoting the growth in renewable energy. The proponents claim that the dramatic declines over the past half dozen years in LCOE's for renewable energy, coupled with expectations for further declines, makes them the cheapest sources of energy, besides being the cleanest. The latter is an important consideration because of the growing number of government entities mandating significant portions of future energy supply come from renewable energy. Based on the LCOE arguments, politicians are pushing for higher mandates. If the LCOEs are wrong, as possibly suggested by the Virginia offshore wind project, or they are being misread relative to dispatchable energy, then quite possibly many communities will find they are facing exploding power costs down the road. Mandates enacted without consideration for constituents' pocketbooks is a grave disservice.

Deepwater Wind Sale: A Sign Of Offshore Wind's Arrival?

On November 7, hedge fund investor David E Shaw sold his funds', D.E. Shaw's, ownership in Deepwater Wind for $510 million to Ørsted (DOEGF-Nasdaq), an international energy company and formerly Dong Energy, the Danish oil company. Deepwater Wind is the developer of the Block Island Wind Farm, the first offshore wind farm to successfully navigate, after eight years, the regulatory approval and construction processes and actually begin operation. The five wind turbines, with a total electricity generating capacity of

30 megawatts (MWe), began spinning and delivering power to Block Island and Rhode Island electricity customers in December 2016.

The 130-turbine project was conceived in 2001 and battled local opposition from a strange collection of locals including the Kennedy family and the billionaire industrialist William Koch

The wind farm, located 3.8 miles off the coast of Block Island in Rhode Island state waters, was not the first offshore wind project proposed, but it was the first to clear all hurdles. Cape Wind, a 468 MWe wind farm to be located on Horseshoe Shoal in Nantucket Sound off the coast of Massachusetts was the first offshore wind farm proposed. The 130-turbine project was conceived in 2001 and battled local opposition from a strange collection of locals including the Kennedy family and the billionaire industrialist William Koch. Even with a federal lease secured in 2010 and $400 million of initial financing, the project could not overcome every legal and regulatory battle it encountered. As a result, the delays and cost escalations pushed the total estimated project cost to $2.6 billion and eventually forced the electric utilities to cancel their power purchase agreements in 2015, killing the project.

Rhode Island was ideally positioned geographically, as well as being blessed with port facilities that could support the nascent wind industry and create new jobs for the Ocean State

While the road to operation was equally rocky in Rhode Island, the project had the political support of the state's governor and key members of the state's legislature. The offshore wind project was conceived in 2005, when Rhode Island Governor Donald Carcieri pushed the idea of offshore wind as a way to provide clean energy and reinvigorate the state's struggling economy. His vision, supported by "green energy" proponents, was that the entire offshore East Coast would eventually become a sea of wind farms, which needed construction and maintenance support. Rhode Island was ideally positioned geographically, as well as being blessed with port facilities that could support the nascent wind industry and create new jobs for the Ocean State.

Exhibit 4. The First U.S. Offshore Wind Farm

Source: Deepwater Wind

After securing the Rhode Island lease to construct the Block Island wind farm, Deepwater Wind began pursuing other offshore wind

Offshore wind has been promoted as the optimal renewable power solution for the New England and Middle Atlantic regions

projects, based on the belief that offshore wind would become the preferred renewable power source for the region. Offshore wind has been promoted as the optimal renewable power solution for the New England and Middle Atlantic regions because of its abundance and the need for more clean energy to meet renewable energy mandates enacted by the states.

Offshore wind's abundance is demonstrated by the wind speed map from the National Renewable Energy Laboratory in Exhibit 5. Given that most of the regions' states lack attractive onshore renewable energy sources, offshore wind offers the best alternative. Additionally, every one of the coastal states contemplating offshore wind farms sees itself as becoming the center of the burgeoning industry, adding economic benefits to bolster justification for the project approvals.

Exhibit 5. Why Offshore Wind Is Favored

Source: NREL

Although D.E. Shaw was involved for 13 years, its actual Block Island wind farm investment was made in 2015

As mentioned above, the latest news about Deepwater Wind is its sale. We are not surprised it is being sold, given the approach behind private equity-type investments. We thought it would be interesting to see how D.E. Shaw came out on its investment, given the long-time involvement with Deepwater Wind. Although D.E. Shaw was involved for 13 years, its actual Block Island wind farm investment was made in 2015, once it received final approvals and was to begin construction.

The PPA called for National Grid to pay 24.4-cents per kilowatt-hour (kWh), or $244 per megawatt-hour (MWh) in the first year of commercial operation, with a guaranteed 3.5% annual escalation

To determine D.E. Shaw's return, we need to consider how much money was invested, how much it received from the sale, and the investment time frame. In the 2009 filing with the Rhode Island Public Utility Commission (PUC) seeking approval of the Power Purchase Agreement (PPA) with National Grid (NNG-NYSE), Deepwater Wind's project was estimated to cost $219 million. The PPA called for National Grid to pay 24.4-cents per kilowatt-hour (kWh), or $244 per megawatt-hour (MWh) in the first year of commercial operation, with a guaranteed 3.5% annual escalation. The increase guaranteed the PPA price in year 20 of the contract to be $479/MWh, or 47.9-cents/kWh. This pricing scheme became a key point in the battle over the approval of the PPA.

The higher price for the wind power translated into an estimated $440 million overcharge on electricity over the life of the contract

At the time the PPA was signed, the average electricity price in Rhode Island was 14.25-cents/kWh, according to the Energy Information Administration's (EIA) web site. As a result, the higher price for the wind power translated into an estimated $440 million overcharge on electricity over the life of the contract. As the price for natural gas, the principal source of electricity generation, fell in the interim, the overcharge expanded to an estimated $500 million, and now potentially may be as much as $650 million. That overcharge is income going to the developer at the expense of rate-paying customers.

When the 2009 PPA was presented to the PUC for approval, it was rejected. The PUC wrote:

> "The fundamental question of this case is whether the PPA between Deepwater Wind and Grid is commercially reasonable, and if so, does this Project provide other direct economic benefits to Rhode Island such as job creation. Based on the evidence, upon which this Commission is legally bound to render all its decisions, the Commission must unanimously, but regrettably, respond in the negative based on the pricing contained in the PPA."

"The Commission found that Deepwater's pricing failed to meet either prong of the analysis"

The entire review process had been conducted in four months, which is quick for such an undertaking. The PUC described the review process in the subsequent hearing, writing: "In reaching its decision, the Commission adopted a two-prong analysis in which it compared the pricing of the proposed Project to other renewable energy projects and compared the internal rate of return ("IRR") to what an investor would expect to see for other newly developed energy resources. The Commission found that Deepwater's pricing failed to meet either prong of the analysis. Furthermore, the Commission found that the Project would not lead to other economic benefits such as net job creation."

The outcome was not what the governor and the legislature desired. Rather than filing for a review of the decision by the Rhode Island Supreme Court as provided for in the general laws, the next move was political. As the Commission described the next events, it wrote:

> "Instead, apparently dissatisfied with the Commission's findings, on June 10, 2010, both chambers of the General Assembly passed amendments to R.I. Gen. Laws § 39-26.1-7 and on June 15, 2010, the amendments were signed into law by the Governor. The 2010 R.I. Pub. Laws 31 and 32 authorized Grid to enter into a new PPA with Deepwater "changing dates and deadlines" and amending pricing terms such that the PPA price in 2013 could still be the 24.4 cents per kWh contained in the 2009 PPA with a 3.5% annual escalator intact, but that would contain a provision that

> would allow the first-year price to be reduced if Deepwater realizes certain cost savings in the development and construction of the Project. The amendments also included a change in the definition of "commercially reasonable" for purposes of the Commission's review of the new PPA."

Under the newly revised rules, the PUC was afforded a 45-day review timetable for rendering a decision

The original submission for the 2009 PPA occurred in early December 2009. After conducting a review of the legal issues and the desire of affected parties to be heard, accepting testimony and reviewing documents and expert testimony, the decision to reject the PPA was rendered on March 30, 2010. As seen in the PUC's writing about the reaction to its disapproval of the PPA, two and a half months elapsed from the decision to the enactment of revisions to the PUC rules for dealing with such an offshore wind project. Under the newly revised rules, the PUC was afforded a 45-day review timetable for rendering a decision.

Besides a dramatically shortened time frame for ruling on the revised PPA, the ground rules for its evaluation were changed

Besides a dramatically shortened time frame for ruling on the revised PPA, the ground rules for its evaluation were changed. As the PUC articulated in its approval decision, it was mindful of the state's mandate for the Commission to take into account the state's policy intent on clean energy, and offshore wind, in particular. In approving the PPA, the PUC wrote:

> "The General Assembly has mandated that:
>
> "The [C]omission shall review the amended power purchase agreement taking into account the state's policy intention to facilitate the development of a small offshore wind project in Rhode Island waters, while at the same time interconnecting Block Island to the mainland. The Commission shall review the amended power purchase agreement and shall approve if… [the Amended PPA meets each of the findings articulated above]."

The PUC was mandated to only determine that the Deepwater Wind contract included economic benefits

Another aspect of the PUC's normal consideration that was changed was the ability to evaluate long-term utility contracts by weighing the benefits of the contract against its cost. In this case, the PUC was mandated to only determine that the Deepwater Wind contract included economic benefits. The Rhode Island Economic Development Commission provided testimony from a consultant showing that the structure of the PPA would provide for rate payers to benefit from lower construction costs of the wind farm, ensuring an economic benefit.

The PUC's conclusion clearly reflected its frustration. The PUC wrote:

> "Stated another way, the General Assembly has instructed this Commission to accept the high cost of offshore wind

> technology for a project with limited economies of scale, so long as the slated costs, and concomitant PPA pricing, terms and conditions, duly reflect those costs."

The estimated $440 million of above-market costs for the power could not be considered

The end result of the hearings and testimony was that there was an economic benefit in the revised PPA, but the estimated $440 million of above-market costs for the power could not be considered. The modified PUC law only provided for project benefits to be considered, as there was no mention of "costs."

What is interesting is that the PPA was not really revised. As an article in *Block Island Times* pointed out:

> "In an email, National Grid spokesman David Graves said, 'This is the same contract as the first one. The only exception is a statement that the cost of the power may be lower if Deepwater is able to achieve cost savings.'"

If the PPA rate was tied to the $219 million cost estimate, the $14 million savings should produce a lower power rate and benefit Rhode Island ratepayers

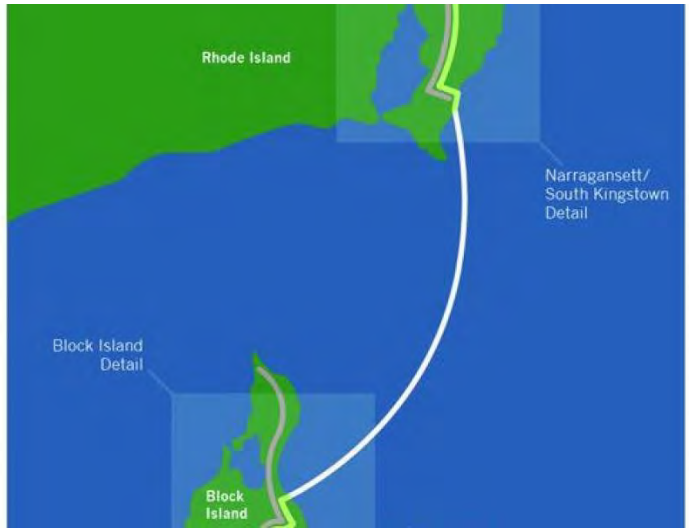
What became a point of contention in the second hearing was the cost of the wind farm. In the 2009 PPA application and hearing, the cost of the wind farm was estimated at $219 million. The second application put the estimated project cost at $205 million. At issue was which cost figure should be used for calculating savings for customers. In effect, if the PPA rate was tied to the $219 million cost estimate, the $14 million savings should produce a lower power rate and benefit Rhode Island ratepayers. Despite the logic of this calculation, it was not the outcome of the PUC decision.

If the Deepwater Wind project was only going to cost $205 million, why did it secure $290 million in financing? This is especially curious given that D. E. Shaw and its partners provided approximately $70 million in equity. Combined, the $360 million invested in the Block Island wind farm is 175% of the project's final construction cost estimate. This investment plays into the return that D.E. Shaw earned when it sold Deepwater Wind.

Interestingly, the cost of the cable was originally estimated to be $43 million

A recent article about Deepwater Wind offered that the total investment in the Block Island wind farm was $451 million. Included in that cost was the $107 million for the cable to bring power from Block Island to the Rhode Island mainland. That investment was the responsibility of National Grid. Interestingly, the cost of the cable was originally estimated to be $43 million. Some of the cost inflation may have come from the cable having to travel further to shore since the most direct route to Charlestown was rejected, and the first proposed landing at the Narragansett Town Beach was objected to by the citizens and the town council. Rhode Island finally approved a cable landing at the Scarborough State Beach in Narragansett.

Exhibit 6. Where The Block Island Power Cable Goes



Source: Deepwater Wind

Developing a solution, or relocating the cable's landing point, will take time and cost money

Presently, Deepwater Wind, National Grid and the Rhode Island Coastal Resources Management Council (CRMC) are dealing with the cable landing on Block Island being uncovered by shifting beach sands. The initial solution to that problem was viewed as short-term and the Town of New Shoreham, where the cable lands, wants a long-term solution. Developing a solution, or relocating the cable's landing point, will take time and cost money.

If we exclude the $107 million cost of the cable, it leaves a total cost estimate for the wind farm of $344 million. It has been reported that the final cost of the wind turbines and infield cable system was $225 million. The $119 million difference reflects the development, legal and permitting costs expended by Deepwater Wind.

If the full project cost was eligible for the ITC, then D.E. Shaw received a tax credit of $67.5 million

To estimate D. E. Shaw's net investment, we need to factor in the wind farm's 30% investment tax credit (ITC). Deepwater Wind elected that credit rather than the production tax credit in which the money is returned over a ten-year period based on the number of kilowatt-hours of wind power produced. In other words, the hedge fund wanted money back faster. If the full project cost was eligible for the ITC, then D.E. Shaw received a tax credit of $67.5 million, reducing the investment cost to $276.5 million. That tax credit could be used to reduce the hedge fund's tax bill, or monetized by selling the credit.

We have assumed that the $290 million loan Deepwater Wind secured was amortized evenly over its 20-year life, thus $14.5 million would be repaid each year. The loan's two-year life would be reduced from $290 million to $261 million. If we subtract that debt from the $510 million purchase price, D.E. Shaw and its partners received $249 million net, or 3.6 times its $70 million equity investment. This gives no value to the other offshore wind permits and projects Deepwater Wind retains, but since most are in the development stage, they will become the responsibility of Ørsted. We assign them a nominal value.

A 3.6-times return on investment after two-years is an attractive return for a hedge fund or private equity investor

A 3.6-times return on investment after two-years is an attractive return for a hedge fund or private equity investor. Admittedly, we are using a number of estimates and assumptions, but our guess is that a return in this range was the motivation for the sale of Deepwater Wind, but it is consistent with private equity-type returns. Why else would investors seeking high returns on risky investments be willing to sell? A more interesting question is why D. E. Shaw was willing to sell so quickly if offshore wind is the growth industry everyone projects it to be. Maybe the 'bird in a hand' return beats waiting for future wind farms to be developed. Maybe David Shaw is to offshore wind as Robert Preston was to 'The Music Man.'

Why Is General Motors Pushing For EV Tax Credits?

This move comes at the same time GM is pushing deeper into the electric vehicle and autonomous vehicle markets

Last week, General Motors (GM-NYSE) announced plans to downsize its North America manufacturing capacity, essentially eliminating the production of sedan vehicles. The move will see five assembly plants shut, costing over 6,000 workers their jobs, plus cutting 8,000 staff, bringing the total job losses to over 14,000. This move comes at the same time GM is pushing deeper into the electric vehicle and autonomous vehicle markets and backing a plan for the federal government to begin a Zero Emissions Vehicle (ZEV) effort, much like that in California.

One of the GM models to be ended is its hybrid Volt, which was started in 2010 as the company emerged from bankruptcy and wanted to quickly demonstrate its alignment with the Obama administration's push into clean autos

One of the GM models to be ended is its hybrid Volt, which was started in 2010 as the company emerged from bankruptcy and wanted to quickly demonstrate its alignment with the Obama administration's push into clean autos. This move seems strange in light of GM's arguing for a ZEV program and backing Senator Dean Heller's (R-NV) bill to undo the cap of 200,000 EVs sold that are eligible for the full $7,500 federal tax credit for electric vehicle (EV) purchases. Sen. Heller's bill also includes an ending of the tax credit scheme after 2022. A competing bill, introduced by Senator John Barrasso (R-WY) who chairs the Senate Environment and Public Works Committee, proposes to immediately end the EV tax credit entirely and impose a new tax on EVs to fund highway repairs. This legislation is opposed by a number of Senate Democrats.

Last month, seven Democratic senators introduced legislation to lift the EV cap and extend it for 10 years. It would also allow buyers to use the tax credit as a "point of sale rebate," a potentially significant change if the tax credit structure is to remain in place.

Tesla (TSLA-Nasdaq), GM's only significant EV competitor, said this summer it had hit the 200,000 EV cap and that future tax credits

GM is on the cusp of reaching its cap, so the company is obviously focused on what a reduced tax credit means for its EV sales, given plans to expand its model lineup in the coming years

would be reduced as required under the law. We questioned whether that event actually happened because it appears Tesla delivered a number of cars to Canadian buyers, holding its U.S. sales below the cap. That would seem to have been the case as the company announced in early October that orders placed over the few days would be eligible for the full tax credit. By law, once the cap is reached, the tax credit is reduced by 50% for the following six months and then to $1,875 for an additional six months before ending entirely. GM is on the cusp of reaching its cap, so the company is obviously focused on what a reduced tax credit means for its EV sales, given plans to expand its model lineup in the coming years.

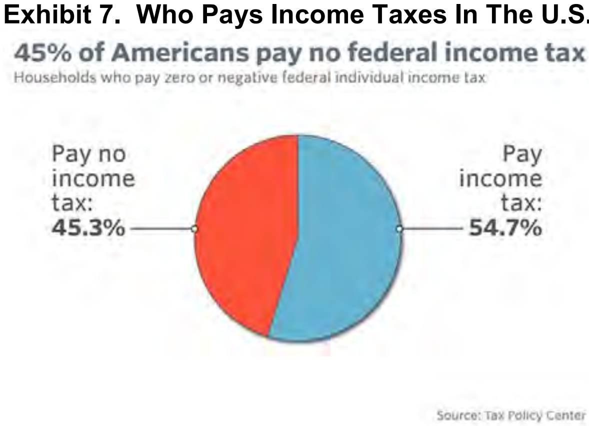
Given the high cost of EVs, reducing the down payment may help people finance the purchase

Without seeing the language of any legislation that would make the tax credit a "point of sale rebate," we cannot tell whether the shift will actually accomplish much, other than to likely reduce the down payment necessary for buying an EV. Given the high cost of EVs, reducing the down payment may help people finance the purchase. That could potentially expand the EV market, but the bigger issue is just how much power the tax credit scheme will deliver to the EV market.

The program calls for a 7% ZEV fleet requirement starting in 2021 and increasing by two percentage points each year until 2030 when the 25% share would be reached

GM's ZEV plan, submitted to the Environmental Protection Agency and National Highway Traffic Safety Administration, would require 25% of fleets to be composed of zero emissions vehicles by 2030. That could mean more than seven million long-range EVs on the road by 2030. GM's CEO Mary Barra is also calling for the government to invest in charging infrastructure, renewing and expanding federal tax credit incentives, and providing regulatory incentives for US battery suppliers. The program calls for a 7% ZEV fleet requirement starting in 2021 and increasing by two percentage points each year until 2030 when the 25% share would be reached. The expanded tax credit program might be the Achilles heel of the scheme. It makes expensive EVs more affordable for the affluent, and not the middle class.

Exhibit 7. Who Pays Income Taxes In The U.S.?



Source: Tax Policy Center

According to data from the Tax Policy Center, over 45% of families pay no federal income tax

According to data from the Tax Policy Center, over 45% of families pay no federal income tax. That is different from paying Social Security payroll taxes, as that is not an income tax liability. Based on the latest federal income tax data released by the Internal Revenue Systems, only people in the very upper end of the Middle-income category and above have a sufficient income tax liability to be able to fully utilize the EV tax credit. Remember, this credit is only available in the year the EV is purchased, so buyers need to know that their federal income tax liability that year will be at least $7,500 for maximum value to the EV buyer. This ignores any state tax credits available for EV purchasers.

Families in the Second richest group have a tax liability of nearly $12,600, so likely everyone in this income strata, as well as the Richest 20%, would be able to fully utilize the EV tax credit

In examining the average income tax bill per person by income level, we are assuming that the average family is composed of two people filing jointly. The Tax Policy Center analysis shows the average per capita tax bill for the Middle-income groups is $1,743, or roughly $3,500 per family. Since it is an average, we know some people in that income strata will have a much greater tax liability. Families in the Second richest group have a tax liability of nearly $12,600, so likely everyone in this income strata, as well as the Richest 20%, would be able to fully utilize the EV tax credit.

Exhibit 8. How Income Tax Liability Is Shared By Income

Income level	Share of total federal individual income tax paid	Average income tax bill per person
Lowest 20%	-2.2%	-$643
Second lowest 20%	-1.7%	-$621
Middle income	4.2%	$1,743
Second richest 20%	12.9%	$6,285
Richest 20%	86.8%	$50,176

Source: Tax Policy Center

Our guess is that the number of families that can fully utilize the EV tax credit may shrink, leaving manufacturers struggling to still figure out how to reduce the final cost of their models

Roberton Williams, a senior fellow at the Tax Policy Center, explains that roughly half the people paying no federal income tax is due to them having no taxable income, while the other roughly half get sufficient tax breaks to erase their tax liability. This tax landscape will change beginning this year due to the impact of the tax cuts put in place at the end of 2017. Our guess is that the number of families that can fully utilize the EV tax credit may shrink, leaving manufacturers struggling to still figure out how to reduce the final cost of their models.

EV manufacturers continue to promise that battery costs will fall and range-anxiety will be erased. If the nation invests in enough charging points, then EVs should see their popularity grow beyond urban centers. What if those assumptions prove wrong? A mandate for ZEV sales is the hammer! Once again we may be witnessing a “green energy” program being promoted without any consideration of our citizens’ pocketbooks. Who has the pitchfork concession?

IMO 2020 May Not Be As Disruptive As Some Have Thought

The ominous forecasts projected oil prices might soar to $150-$200 a barrel as refiners scrambled to purchase low-sulfur crude oil

A recent analysis by consultant Baker & O’Brien shows how the energy and shipping industries business are likely to deal with the impact of IMO 2020. That is the International Maritime Organization’s, a unit of the United Nations, rule that all marine transportation switches its fuel from oil with a 3.5% sulfur content, to fuel with no more than 0.5% sulfur, effective January 1, 2020. This switch is projected to create havoc in the crude oil refining business, as well as inflate shipping costs. As the fuel rule was finalized earlier this year, forecasts of doom for the oil business were presented as there exists an imbalance between the amount of high-sulfur bunker fuel consumed and the capacity for the industry to produce low-sulfur oil. The ominous forecasts projected oil prices might soar to $150-$200 a barrel as refiners scrambled to purchase low-sulfur crude oil to process in order to meet the sudden low-sulfur fuel oil consumption explosion.

As the months have passed, the disastrous forecasts have begun to moderate as researchers better understand the various ways the shipping and refining industries can work together to meet the new mandate with less market disruption. That does not mean the transition will not create problems for both industries with oil prices forcing some shifts among fuels in the transportation sector leading to higher demand for low-sulfur crude oil supplies.

The demand increase results from the combination of shipping growth and increased fuel needed due to the lower energy density of low-sulfur fuel

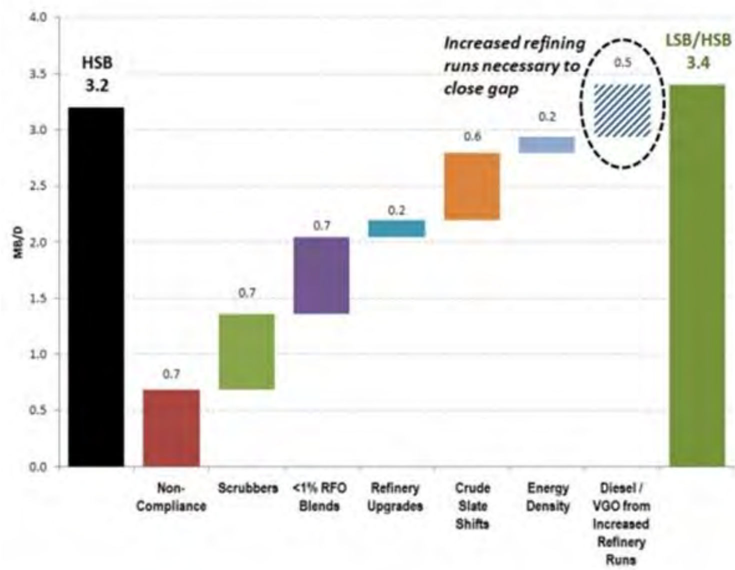
The Baker & O’Brien presented its view of the various methods with which IMO 2020 compliance will unfold, and how these methods might impact the refining business. To start, the forecast begins with the current 3.2 million barrels per day (mmb/d) of high-sulfur bunker fuel, which is projected to rise to 3.4 mmb/d of a combined high-sulfur and low-sulfur fuel pool to power ships. The demand increase results from the combination of shipping growth and increased fuel needed due to the lower energy density of low-sulfur fuel. The options for meeting the demand growth and fuel switching were listed as:

- Non-compliance
- Scrubbers
- Alternative fuels
- Blending of existing low-sulfur fuel oil with distillate
- Refinery upgrades
- Shifts in crude slates and crude oil flows
- Increased global refining throughputs

The study states that various market forecasts project non-compliance ranging from a low of 10% to a high of 30% of demand

Some of these options require more time for meaningful impacts on consumption than others. Non-compliance is expected to be just as significant a factor on the fuel market as does the installation of exhaust gas scrubbers on ships. The study's authors point to a "loophole" in the rules that enables a shipper who can show that there was no compliant fuel (low-sulfur) available can continue to burn high-sulfur oil. The study states that various market forecasts project non-compliance ranging from a low of 10% to a high of 30% of demand. Baker & O'Brien assume a 20% non-compliance rate, or 700,000 barrels per day (b/d). The non-compliance rate, whatever it is initially, presumably will shrink as we move further into the 2020s, but it is a significant safety valve for shippers and refiners to help prevent an explosion in prices.

Exhibit 9. How IMO 2020 May Be Met By Refiners



Source: Baker & O'Brien

If the non-compliance rate is 30% rather than 20%, the increase shrinks by 350,000 b/d, or 65% of the projected refinery runs increase

As the chart in Exhibit 9 shows the various options for meeting the fuel switch, assuming the non-compliance factor is 20%, to close the gap between current consumption and projected fuel needs. The gap necessitating more refinery runs to produce more low-sulfur fuel is 500,000 b/d. With a few minor assumption switches that increase could be eliminated. For example, if the non-compliance rate is 30% rather than 20%, the increase shrinks by 350,000 b/d, or 65% of the projected refinery runs increase. Add in the potential that the current tariff war continues and global trade shrinks, the remaining 200,000 b/d projected consumption gas would be eliminated. Suddenly, the entire 500,000 b/d refinery runs increase disappears. That would remove the significant upward pressure on fuel oil and low-sulfur crude oil prices currently envisioned. It would also provide the refinery industry with additional time to add to its low-sulfur fuel oil output capacity.

We were interested to read about a fine recently levied on the captain of a P&O cruise ship for burning non-compliant fuel in the EU

On another note about the shipping fuel market, we were interested to read about a fine recently levied on the captain of a P&O cruise ship for burning non-compliant fuel in the EU. The incident occurred last March when inspectors boarded the Azura in Marseille, France and sampled her fuel tanks and determined it was using fuel with a sulfur content of 1.68%, which is higher than the European Union's 1.5% limit for "passenger ships providing regular services to destinations or from ports of the European Union."

The governments of France and Spain have previously determined that it does not apply to cruise ships

The issue is that the rule does not cover all passenger vessels, and is interpreted differently in different EU nations. The governments of France and Spain have previously determined that it does not apply to cruise ships. The French prosecutors contend that the EU's passenger ship sulfur cap applies to vessels fitting the Azura's description. They further alleged that P&O had used the slightly higher sulfur fuel illegally in order to save money. As a result, P&O was required to pay $90,000 of the $110,000 fine levied on the captain. The company is appealing the rule based on its understanding of the French rule for cruise ships.

Even members of the EU don't agree on what fuel restrictions apply to classes of ships calling in its ports

This is a lesson in the complexity of understanding the shipping industry fuel rules. The EU is, like the United States, a region where 0.5% sulfur fuel is supposed to be used by ships. We guess that blanket assumption doesn't apply to all ships in the region. Here we see that even members of the EU don't agree on what fuel restrictions apply to classes of ships calling in its ports. Will this 1.5% sulfur fuel rule be replaced by the 0.5% switch? It is supposed to be. However, the new fuel rule is well-above the supposed 0.1% sulfur fuel oil rule that we understood was applicable throughout the EU, but clearly not, as demonstrated by this case. This shows that analyses with assumptions about a complete fuel switch and its impact on the oil market need to be questioned. Many forecasters have also totally ignored the non-compliance option. We also don't know what other exemptions may exist after 2020. Be skeptical of the forecasts assuming a complete fuel switch driving up demand for low-sulfur fuel oil with catastrophic price impacts.

Alberta To Buy Rail Cars, But Then Moves To Cut Oil Output

Within the province, there is a full-scale battle between fully-integrated producers whose downstream refining operations are benefitting from the extremely depressed wellhead prices for Canadian oil trapped in the country by the lack of pipeline export capacity

We wrote last issue of the challenge for the Canadian oil industry for increasing crude oil exports from Alberta by rail. That option is receiving increased attention due to the roadblocks stopping construction of new pipeline export routes. Within the province, there is a full-scale battle between fully-integrated producers whose downstream refining operations are benefitting from the extremely depressed wellhead prices for Canadian oil trapped in the country by the lack of pipeline export capacity. Less-integrated, or non-integrated producers are advocating that the Alberta government invoke its power under current laws to limit oil production and help reduce the present over-supply that is depressing wellhead prices.

She is asking the federal government to kick-in some of the money necessary for the purchase

Alberta Premier Rachel Notley announced last week that the province will begin buying tank rail cars in order to ship 120,000 barrels per day of oil to the United States. She is asking the federal government to kick-in some of the money necessary for the purchase. She may be missing some important details about the challenges of shipping more oil by rail in her announcement.

It requires two unit-trains per day, each needing three locomotives and 100 tanker cars carrying 600 barrels of oil apiece

As we wrote, Cenovus (CVE-NYSE) has already committed to purchasing the necessary rail equipment to ship a similar volume of crude oil. It requires two unit-trains per day, each needing three locomotives and 100 tanker cars carrying 600 barrels of oil apiece. With a 25-day roundtrip between Alberta and the U.S. Gulf Coast refining market, Cenovus is buying equipment for 50 trains, or 150 locomotives and 5,000 rail cars. The two major rail operators – Canadian National Railway Company (CNI-NYSE) and Canadian Pacific Railway Ltd. (CP-NYSE) – will be hiring and training 450 crews to man the trains.

CN and CP say they do not have capacity to add additional unit-trains before 2020

So where does Alberta stand in the rail equipment market? It is behind Cenovus, meaning it will be the end of 2019, or possibly not until well into 2020 before it receives this equipment and can begin shipping oil. Moreover, CN and CP say they do not have capacity to add additional unit-trains before 2020. If the legal roadblocks preventing construction of the Keystone XL and Trans Mountain oil export pipelines were removed, they could be in operation by the time Alberta gets its rail assets. In other words, there is little gained from Premier Notley's move, other than from a public relations perspective of her working hard for the interests of the province's leading industry.

Political drama over energy policy in Canada continues to roil the industry, which is rapidly sinking into a depression due to the huge oil price discounts from U.S. oil prices

Political drama over energy policy in Canada continues to roil the industry, which is rapidly sinking into a depression due to the huge oil price discounts from U.S. oil prices. Those discounts are sapping huge sums from the oil producers, forcing them to scale back their activity, and negatively impacting the Alberta government's royalty and income tax collections. Scaling back oilfield activity will hurt service companies, and employment. This will make the battle between the province and the federal government increasingly contentious, which could be highly significant as next year sees elections in both Alberta and at the federal level.

Premier Notley announced plans to impose an 8.7% production cutback for Alberta oil

Over the weekend, Premier Notley announced plans to impose an 8.7% production cutback for Alberta oil, a policy that had been promoted by Alex Pourbaix, CEO of Cenovus, but opposed by other major integrated producers. They reportedly remain opposed to the policy, at least as of Friday, but before Premier Notley's Sunday afternoon announcement. They continue to benefit in their downstream operations from very low wellhead prices, resulting in expanded refining margins.

The cut will reduce production, effective January 1, 2019, by 325,000 b/d and remain in place until a meaningful reduction in storage volumes occurs

The cutback, consistent with Sec. 85 of the Mines and Minerals Act, will provide a 10,000 barrels per day (b/d) exemption for producers, meaning that only about 25 producers will be forced to reduce output. The cut will reduce production, effective January 1, 2019, by 325,000 b/d and remain in place until a meaningful reduction in storage volumes occurs. At that point, the cut will be reduced to only 95,000 b/d, lasting through the end of 2019. At the moment there are 35 million barrels of oil in storage, or roughly twice the normal level. The projection calls for the cut to shrink the oil price differential with West Texas intermediate by C$4 (US$3) per barrel, and add roughly C$1.1 billion (US$830 million) to Alberta's royalty income for 2019-2020.

While we cannot be sure, we suspect that the government recognized the futility of their 'oil-by-rail' plan to impact oil price differentials in the immediate term. That realization forced Premier Notley to embrace the more drastic action of mandating a production cut, making Alberta look like a member of OPEC. We will see how this plan works out.

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