The remarkable resilience of US shale
Headwinds to rebalancing as a leaner industry emerges

Seismic shifts: energy security and instability
Will the end of oil insecurity bring new geopolitical risks?

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Low-carbon logic gains unstoppable momentum

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### December 2016

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“Apocalyptic...” That’s been a fairly standard reaction to this year’s cover, typically followed by acknowledgement that, yes, the concept probably is rather apt. It’s been quite a 12 months – the hottest on record, incidentally – and metaphorical wildfire does indeed seem to be sweeping across the world.

I’m not really here to comment on politics – that debate will continue to rage in other arenas and we at Platts remain neutral observers – but the political sphere and the energy sphere are always intertwined. The decisions that emanate from the former have a massive impact on the development of the latter; likewise energy issues can have huge feedback effects into the internal political life of nations as well as the geopolitics of regions and the entire world. These are issues that are touched on in many of the articles that follow, parts of which have had to be hastily revised to take into account recent events in the US after sparks from the fire started in the UK earlier in the year, somewhat carelessly many would argue, jumped across the Atlantic and set a torch to long-held assumptions.

The energy industry seems to be dealing with its own wildfire of sorts, and many are struggling to cope as the established order appears to melt away before their eyes. Some in the more traditional parts of the industry might take heart from recent political events, hoping that the fire can be quelled. Personally I wouldn’t bet on it, although some short-term relief might be forthcoming.

But is all of this so apocalyptic? I prefer to remain optimistic. Wildfire has traditionally been seen as a “bad thing”, an uncontrollable force of nature to be feared. There is no doubt that is true. In Canada earlier this year it certainly must have felt terrifying – and our sympathies for the losses and best wishes as the rebuilding continues are sincere. But in fact wildfire is recognized by ecologists as a natural and necessary process, one of renewal and even fundamental to the development of ecosystems.

A final thought. Incidences of wildfire are expected to become ever more common as global temperatures continue to rise – one suspects likely also of the metaphorical variety. Brace yourself for 2017.
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The remarkable resilience of shale

Contrary to expectations, the global price collapse has not halted the US shale oil revolution. Far from it: a leaner, more efficient industry is set to bounce back – creating serious headwinds to market rebalancing.

Throughout the history of the oil industry, it is difficult to find many examples of technologies that rapidly impacted global oil markets. With long lead times and slow turnover of capital, even important technology advances have typically taken decades to have a major impact on bottom-line supply and demand. But shale – or light tight oil – has been a major exception in this regard.

In well under a decade, global oil markets have been fundamentally changed by the shale revolution. The upstream impacts and changes in the geographic and quality mix of global liquids production are by far the most important. But the effects range far more broadly, touching refining economics, transport flows, petrochemical feed choice, and even global geopolitics.

The technologies of horizontal oil drilling and hydraulic fracturing were progressing steadily in the natural gas industry, but with the incentive of high oil prices the technology was rapidly adapted to oil, beginning with the Bakken and Eagle Ford. Very quickly, growth in shale caused US crude production to shift from over three decades of declines to showing significant growth of nearly 1 million b/d annually from 2012 to 2015.

Ten years ago, few would have predicted this shift. The EIA’s 2005 Annual Energy Outlook called for US crude production to decline to 5.5 million b/d by 2015. Instead, production came in nearly double that at 9.4 million b/d, and is about to surpass US peak annual production set back in 1970. The rapid shale-led growth in US production was the main reason prices collapsed in 2014, as global demand could not keep pace with the onslaught of supply.

Shale was initially expected to respond relatively quickly to the downturn in prices due to its short investment cycle and high decline rates. However, it has proven to be much more resilient. From peak production in March 2015, shale crude and condensate production has fallen by almost 500,000 b/d. This is a material price response and is a major contributor to total non-OPEC declines and global oil market rebalancing.

However, in the context of a more than 50% reduction in price since 2014, the...
response seems limited and highlights how shale operators have evolved to survive in this new environment. This resilience has been founded on four main factors: momentum, efficiency gains, accommodating financial markets, and decelerating base decline rates.

The 1 million b/d of growth observed through 2014 carries with it a significant momentum. The US horizontal oil rig count peaked in 2014 at just over 1,100 rigs. Soon after the collapse in prices, the rig count started falling precipitously, but by our estimates the rig count had to fall at least 35% just to eliminate growth. From the time prices fell below $80/b in November 2014, it took around three months for the rig count to fall enough to breach that 35% level and several more months for activity to fall to a point where production could start declining materially.

Offsetting this decrease in activity were huge gains in productivity. One horizontal oil rig today delivers 50% more oil compared to a rig back in 2014. The time it takes to drill a well has fallen around 20% due to increased multi-well pad drilling, higher-quality rigs, better understanding of the rock, more experienced drilling crews, and improved drilling techniques.

Well productivity has increased around 30% due to longer horizontal lateral lengths, better formation targeting, increased proppant concentration, and tighter frac spacing. At the same time, service price concessions and efficiency gains have reduced well costs by around 30%. Together, lower well costs and increased well productivity have caused well breakevens to fall by around 35%. Most shale play wells are now economic with WTI benchmark prices at between $40-50/b versus $60-70/b several years ago.

In addition, despite the sharp pullback in prices, financial markets did not close off to producers. Instead, capital markets were accommodating and producers were able to fund a $50 billion cash flow deficit in 2015. Operators issued over $18 billion in equity in 2015 and over $16 billion in equity so far this year, money that has been used to deleverage balance sheets, fund capex programs, and acquire more acreage.

Meanwhile, nearly $100 billion in private equity is sitting on the sidelines waiting...
to be put to work. Investors and operators repeatedly talk about financial conservatism, yet operators continue to outspend cash flows and investors are rewarding companies that show growth. The prized shale companies of today are not letting production roll off, they are growing production at double-digit rates.

Borrowing base redeterminations and other worries also turned out to be relatively immaterial. Although nearly 100 US producers have declared bankruptcy, so far no major E&P has done so. The largest oil producer to go bankrupt was Linn Energy with less than 50,000 b/d of oil production. In any case, the production of those operators that didn't survive did not get turned off. Instead, oil continued to flow in order to maximize value for creditors. For example, Linn Energy expects only a 2% drop in production between the second quarter and end of the year despite declaring bankruptcy in May 2016. Bankrupt companies may see ownership shift between equity and debt holders, but production remains largely unaffected.

Lastly, a slowing of shale's underlying base decline rates added to the resiliency. Individual shale wells decline very quickly in the early months and years of production. From month 1 to month 12 a typical well declines 60-70%. However, the average well is much more mature than a newly drilled well and the base decline rate for all wells at the play level is much lower. In 2015, the base decline rate was around 40%. As drilling slowed, the average age of wells increased and the base decline rate decelerated to around 30% today.

Lower base decline rates and increased productivity means as few as 350 horizontal oil rigs can hold shale production flat today compared with 700 horizontal oil rigs back in 2014, a 50% reduction in required rigs. Rather than hold production flat, 700 horizontal oil rigs today would be able to deliver nearly 1 million b/d of growth. Shale has evolved from a high-cost component of supply to a medium-cost component. Today with prices hovering in the $50/b range, the question shifts from “how much will shale decline?” to “how much will shale grow?” We’re quickly approaching an inflection point and it may have already passed. Operators are adding rigs and completion crews back, and guidance increasingly points to growth. We expect shale crude and condensate production to bottom shortly and quickly swing back to growth. We see sequential growth by the second quarter of next year and by the second half of 2017 we expect year-on-year growth of 300,000 b/d.

In the longer term, we expect US shale to be the largest contributor to global liquids growth for at least another decade, albeit at growth rates somewhat lower than those observed through 2014. While productivity will continue to rise service costs are expected to increase as activity picks up and the rate of drilling and completion efficiency gains is likely to slow.

Even under the most conservative assumptions, the threat of “peak oil” supply or an ever more powerful OPEC has been eliminated by the emergence of shale, first in the US but eventually around the world.
"Even under the most conservative assumptions, the threat of peak oil supply or an ever more powerful OPEC has been eliminated by the emergence of shale."
Seismic shifts: energy security and instability

Transport electrification could eliminate the insecurity of geography that has hung over oil supply chains for decades. But will it also bring new risks?

There have been three seismic shifts in the energy world in the last decade: the coming of age of US light tight oil production, the rise of renewables and the advent of electricity storage.

They are qualitatively different changes: LTO represents the extension of the oil and gas resource as the result of price-driven technological innovation, a practical example that the available oil and gas resource is not finite, but a product of technology and price.

The second, renewables, is just as fundamental. Renewables represent a variety of new sources of energy supply based primarily around the generation of electricity. They are a response to concerns about climate change and thus have a “social license” that provides a powerful regulatory tailwind.

Renewables’ unique characteristic – variability – has prompted a third phase of innovation based around electricity storage, which has cross-fertilized with other sources of demand for power storage in the area of personal electronic devices such as smart phones and laptops. The lead technology in this area is the lithium-ion battery.

These disruptive changes have, largely so far, been kept apart; LTO impacting the oil market and thus transport and petrochemicals; and the latter two electricity. But they are about to collide in ways that could fundamentally re-orientate global trade in energy, and with that the energy security of nations and the geopolitical considerations that drive foreign relations and diplomacy.

Chains of oil

LTO production to some degree rewrites the geography of global oil, rejuvenating and extending forward in time the production capacity of the US, potentially doing the same for Russia, and possibly bringing new countries
into the ranks of the major oil producers, for example Argentina. However, shale exploitation has not yet been replicated anywhere else in the world at scale. Even if it were, it would not significantly alter a world of long, insecure global supply chains, where the energy security of importing nations is dependent on events in countries far distant.

The growth of LTO has benefited the US most, as one would expect. US net crude oil imports have declined, lessening, to some extent, Washington’s interest in the Middle East and competition with Asian countries like China and India for access to international oil resources.

In addition, the US has moved from being a net importer of refined oil products to net exporter. Aided by plentiful, cheap feedstock, US refiners have been able to displace imports and expand their export markets. In particular, they have been able to capture market share in growing Latin American markets, where demand for oil products has outpaced refinery capacity.

Moreover, US oil producers have proven remarkably adept at reducing costs and improving efficiency, lowering the cost of shale oil extraction. The productivity of a rig drilling in the Permian basin is now five times what it was in 2012; rigs on the Bakken have seen a threefold increase in productivity. Well costs have almost halved and lead times are measured in months rather than years. US shale oil production now looks competitive with global oil prices at between $40-60/barrel.

Nonetheless, global oil supply chains are still inescapably dominated by geology and geography. Shale partially reorders rather than resolves them. The largest conventional resources are located mainly in the Middle East; the largest unconventional resources in Canada’s oil sands and Venezuela’s Orinoco Belt. If governed by competition alone, the cheapest oil will be produced first. Unfettered Middle Eastern output from giant onshore fields implies that the expansion of more expensive forms of oil production – Venezuelan heavy oil, Canadian oil sands, and deepwater – must await a more fundamental upturn in prices.

That leaves Asia dependent on primarily Middle Eastern oil imports, and in the context of less US interest in the stability of that region. Moreover,
These disruptive changes are about to collide in ways that could fundamentally re-orientate global trade in energy, and with that the energy security of nations.
A renewable to electric transport supply chain would hugely enhance the energy security of oil-importing nations, but would also destabilize those economies dependent on oil for revenue.
instability in the Middle East appears almost endemic. The past decade has been particularly dramatic, with the Arab Spring, the disintegration of Syria and the rise of militant Islam, but there is considerable historical continuity in this instability that goes back more than a thousand years.

Oil, as a fairly cheap bulk commodity, is expensive to store and its use is so widespread that it depends on continual daily supply with stocks providing only a short buffer between disruption and genuine scarcity. For oil importers this represents not just a drain on the balance of payments, but perpetual vulnerability both in terms of adverse price swings and physical availability.

Renewables, in contrast, point towards the full-scale electrification of energy systems, including transport. As electricity is delivered by wire, its production and consumption has an inherently local bias.

Although the level of renewables penetration varies, the shape of expansion is similar across the world and often exponential in its early stages. There is also a clear correlation between net oil importers and the general enthusiasm for renewables. Uptake has been minimal in the former Soviet Union, the Middle East and Africa, but significant in the US, oil-importing South America, Europe and Asia.

The impact in Europe has been most spectacular, with renewables, not including hydro, accounting for 7.7% of total primary energy consumption in 2015, up from just 1.8% in 2005. What has been most dramatic is the sustained fall in renewable energy costs so that both Levelized Cost of Electricity studies and real-life pricing points, such as recent electricity capacity tenders in Chile, Mexico, Peru and most recently in September in the UAE, show that onshore wind and utility-scale solar are cheaper than natural gas. This despite oil and gas prices more than halving in value since 2014.

Self-generating security

The supply chain for renewables is fundamentally different to that of oil. Wind and solar power are essentially manufacturing industries that can be replicated anywhere in the world. The input costs are the cost of labor, land, power and key raw materials.

A wind turbine or solar panel, once made, does not require any fuel. Supply chain insecurity exists in the procurement of raw materials for manufacturing not for operation. A solar panel might contain gallium and a battery lithium, but these units will not stop generating or storing electricity if there is a shortage of these elements in the way that an SUV would shudder to a halt on an empty tank.

To take a step into one possible, but perhaps not too distant future, a business or individual generating their own electricity from solar and wind, with battery storage, would create a completely new energy consumer. Rather than continual, regular payments for fuel and grid-supplied electricity, they would make long-term capital investments, financed on the back of what they would have been paying for power and fuel. The self-generator, either as an individual or as a country, would have broken all connection with the large fuel and electricity supply chains that dominate energy provision today.

The supply chain for electrified transport based on renewables runs direct from the consumer to the sales department or marketing outlet of an Original Equipment Manufacturer. Their supply chain, in turn, runs to the procurement of the necessary raw materials for manufacture.

These materials are either abundant, in the case of steel or silicon, or used in relatively small quantities, for example...
rare earth metals, which are easy and cheap to store. Their short-term availability has no impact on the operational performance of existing assets. Any commercial operation that is electrified based on renewables is thus fundamentally more secure than one dependent on imported energy commodities.

Oil displacement as a result of transport electrification would also serve to reduce oil and gas prices more broadly, bringing down the cost of oil and petrochemical feedstocks for a wide range of industries. A renewables-to-transport electricity chain thus reduces the cost of wider economic oil dependency and has a more beneficial local multiplier effect than the balance of payments drain represented by imports.

There are neither middle men nor foreign originators between electricity supplier and consumer. But there is the risk that one commodity dependency is simply swapped for another.

**New dependencies?**

Demand for lithium comes not just from traditional uses of the element, but from batteries in cars, buses, smart phones, laptops and a variety of other consumer goods, as well as for home storage and megawatt-scale battery storage for grid applications. A mobile phone uses 3 grams of lithium carbonate, but an electric vehicle uses only just begun.

Analyses by a number of banks suggest lithium carbonate prices will remain elevated until 2017/18, but then moderate afterwards as a new wave of projects enter the market. According to Citigroup, lithium carbonate prices are likely to rise to about $7,000/mt by mid-2017, but their marker for the period through 2020 is $6,000/mt, above current levels of about $5,000/mt.

The bank lists 15 potential new projects that could come on stream by 2020, which would add 332,000 tons of lithium carbonate equivalent (LCE) production. In its demand-supply balance analysis, Citigroup sees total demand rising from 188,000 tons of LCE in 2015 to 308,000 tons by 2020 and supply rising from 189,000 tons to 318,000 tons, which assumes 129,000 tons – 38.8% in terms of capacity of the pipeline projects – actually starting production.

Lithium supply and reserves are quite narrowly concentrated, more so than oil. The US Geological Survey estimates global reserves at 14.4 million tons of lithium (not LCE) and resources at about 35 million tons, as against production in 2015 of 32,460 tons. Chile holds the largest reserves followed by China, Argentina and Australia. Bolivia, currently a non-producer, is thought to hold the largest resource.

However, geologists rarely know how much there is of an element until they really start to look for it. In addition, lithium exists in very low concentrations, for example in seawater, which means it is abundant if not immediately economically recoverable. There is a clear parallel with oil and gas. After decades of mass use and exploitation, proved oil and gas reserves have risen rather than fallen and a serious search for lithium has only just begun.

Moreover, in terms of physical volume, lithium use is small compared with oil or gas. That means it is easy and cheap to store. Copper or nickel are more analogous markets than oil or gas. In addition, lithium is a manufacturing raw material not a fuel. Batteries will not stop storing and releasing electricity if
there is a shortage of lithium upstream, just as wind turbines and solar panels will keep on generating electricity, even if there is a shortage of the raw materials required to expand capacity. As a result, there is probably little to fear in terms of energy security from even greatly expanded use of imported lithium.

**Uncertain variables**

Concern over climate change has heavily weighted regulatory environments in favor of renewables, but there is no certainty that they can expand fast enough to meet decarbonization targets, let alone meet the additional demand that would be created by large-scale uptake of electric vehicles (EVs).

Estimating the additional power demand from EV penetration depends on the number of EVs sold, the technological mix of adoption between plug-in electric vehicles (PHEVs) compared to pure battery electric vehicles (BEVs) and the number of miles that these cars travel in the future; all are uncertain variables.

A recent survey from Norway’s Institute of Transport Economics, the first of its kind, showed that PHEVs are driven on electricity from the grid 55% of the time, implying that they burn gasoline for the remaining 45%. So a high proportion of PHEVs to BEVs would mean much less additional power demand and less oil displaced because fewer miles would be driven powered by electricity.

Assuming a 50:50 PHEV/BEV mix, a high-growth scenario, consistent with the current rate of EV sales growth could lead to an additional 1,000 TWh of electricity demand by 2028, which would represent a 4.1% increase in global electricity generation in 2015. Additional demand increases fast thereafter as the number of EVs continues to grow, but it suggests that even in a fast-growth scenario electricity provision will not be a major break on EV adoption.

US oil major ExxonMobil, in its most recent outlook to 2040, provides a very low EV penetration scenario. The company sees non-plug-in hybrids and conventional internal combustion engines as dominant. EVs – PHEVs, BEVs and fuel cell vehicles – account for less than 10% of new car sales globally in 2040. It is just one possible future, but it highlights three important uncertainties:

- It is entirely plausible that oil demand growth from the heavy-duty vehicle segment outweighs the oil demand displaced by EVs, particularly in low-EV penetration scenarios.
- Equally, ExxonMobil sees global oil demand rising by an annual average of 0.7% between 2014 and 2040. This suggests fairly weak demand growth even with low EV penetration, a view which could therefore be upset, if EVs prove more successful.
- Finally, another potential development which could derail ExxonMobil’s outlook is the prospects for electrification in the HDV sector.

According to consultancy Research and Markets, the global market for electric & hybrid electric buses is projected to grow at a compound annual growth rate of 17% from 2016-2021, driven by concerns over urban air quality, as well as more general climate change. Another consultancy, IDTechEx

**Lithium production, reserves and resources**

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<th>Mine production 2015 (mt)</th>
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Source: USGS
estimates that the market for medium and large hybrid and pure electric buses will be over $132 billion in 2026.

**Security and instability**

A renewable to electric transport supply chain would hugely enhance the energy security of oil-importing nations, but would also have serious negative effects. It would destabilize those economies dependent on oil for revenue.

According to the US Energy Information Administration, OPEC members earned $404 billion in net oil export revenues in 2015. In many cases, these revenues make up the primary share of state earnings. And, again in many cases, these funds underpin authoritarian regimes. There is arguably a negative correlation between oil income dependency and democracy, although equally there are examples where oil income dependency is no barrier to democracy.

OPEC’s oil earnings in 2015 were 46% down from 2014 and the financial strains are already showing, extending beyond OPEC to other major oil producers such as Russia. Many oil producing nations are characterized by a lack of economic diversification. Oil dominates the state’s finances and non-oil revenue is weak. Their low uptake of renewables is a case in point.

The current malaise is the result of oversupply in the oil market, a situation from which oil producers can expect relief at some point when supply and demand rebalances. But, in the future, transport electrification means they could suffer a more sustained and structural reduction in their incomes, not from excess supply but from a lack of demand.

Oil income dependency is and always has been a much greater weakness than dependence on oil imports. The destabilization of these countries could present a host of new problems in terms of militant ideologies taking advantage of economic dislocation and mass migration. Peak oil demand may prove much more of a problem than even the worst imaginings of the peak supply theorists.

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Unbridgeable gulf at the heart of OPEC

The historic Saudi-Iranian rivalry seemed to enter a new, more dangerous phase this year

A consensus is developing among political analysts that Saudi Arabia and Iran, the regional oil powers on either side of the Persian Gulf, have arrived at an intractable state of cold war that is exacerbating political instability throughout the Middle East while threatening to roil the international oil market further, and that tensions between the two are unlikely to ease.

Indeed, the two arch rivals for regional hegemony, which also find themselves on opposite sides of the historic religious divide between mainstream Sunni and heterodox Shia Islam and an equally fraught ideological divide over clerical involvement in government, in January severed diplomatic relations and have made no significant move since then to repair them.

Since February they have been deeply at odds during intense negotiations on how and whether to participate in a proposed agreement between key international oil producers from within and outside OPEC to freeze or cut production in the face of the current slump in oil prices that stretched from H2 2014. In April, they jointly scuppered a Russian-sponsored deal when Iran stayed away from a meeting in Doha at which the agreement was to be signed, while Saudi Arabia at the last minute pulled its support over Iran’s refusal to participate.

‘The good old days’

Riyadh and Tehran have for years hurled insults at each other, peppered by periodic shows of military might, intermittent Iranian threats to close the Strait of Hormuz chokepoint at the mouth of the Persian Gulf, and repeated Saudi demands that Tehran stop “meddling” in Arab affairs. For the most part, political analysts based in the Middle East have dismissed such behavior as saber rattling.

Moreover, it was clear in the “good old days” of triple-digit crude prices that political rhetoric enhancing global perceptions of a geopolitical threat to Persian Gulf oil supplies served both sides well. When the Iranian Revolutionary Guard Corps in mid-2008 helped push oil prices to record levels near $150/b by holding exercises in the Strait of Hormuz and threatening to close its shipping lanes, windfall oil export revenues swelled
the state treasuries of all the region's oil producers.

That was then and this is now. In the current low oil price environment, the market responds sluggishly, if at all, to political threats to oil supply, even those affecting key producing regions such as the Persian Gulf. Even so, Saudi-Iran relations have continued to deteriorate as each increased their embroilment on opposite sides of regional conflicts outside their own borders. Those civil conflicts, in Iraq, Syria, Lebanon and Yemen, although they may have sprung from local political or inter-tribal disputes, are now being kept on the boil largely by animosities between the external actors who stepped in on pretexts of seeking to end the conflict or protecting an oppressed minority. Hence they are widely regarded as proxy wars.

In the Levant, Tehran has consistently sought to prop up the regimes of Arab Shiite leaders it regards as allies, including that of Syrian President Bashar al-Assad, while Riyadh helped finance and eventually joined regional and international military efforts to topple those regimes. For Saudi Arabia, the embroilment took a Byzantine twist with the emergence of the Islamic State group, comprised of ultra fundamentalist Sunni insurgents and terrorists as virulently opposed to the Saudi regime as they are to regional Shia strongmen.

Another convoluted scenario is being played out in Yemen, where Saudi Arabia was part of the Arab regional alliance that installed Abdrabbuh-Mansur Hadi as president in a 2012 deal aimed at ending a civil war in the country. Riyadh is now leading a regional alliance against Iranian-supported Houthi rebels from a Yemeni Shiite tribe that backed the country’s former president, Ali Saleh. The Houthis seized Yemen's capital of Sanaa in 2014, driving Hadi into exile in Aden.

**Beyond saber rattling**

Involvement in such regional conflagrations, which have directly caused hundreds of thousands of civilian casualties, displaced millions of refugees and have recently led to oil wells being torched in northern Iraq, goes well beyond saber rattling. It is also a huge drain on state finances, particularly during the current oil-price slump.

Iran, with its economy still reeling from the international sanctions over Tehran’s nuclear program that were lifted only in January 2015, now has an extremely low per capita GDP compared with Saudi Arabia and most other Gulf oil producers from the region. The World Bank estimated it at under $6,000 for 2014. Nonetheless, Tehran has seen fit to maintain its long-term financing to Shiite militia groups it considers allies, including Lebanon's Hezbollah.

Riyadh, for its part, has been paying for increasing numbers of air strikes on Houthi strongholds in Yemen as well as Syrian government and ISIS-held positions further north. Evidently, both regimes considered those costs worth paying in January and continue to do so now.

The diplomatic split came after Saudi authorities in January executed Nimr al-Nimr, a prominent Shiite cleric from Saudi Arabia’s oil-rich Eastern Province, along with 46 others convicted of “terrorist” crimes. Until his arrest in 2012, Nimr had led Arab Spring anti-government protests that erupted in 2011, and Iranian Supreme Leader Ali Khamenei was quick to condemn the execution as political while hailing Nimr as a “martyr” and man of peace.

After Khamenei warned via Twitter that Saudi Arabia would face “divine revenge” for “unjustly spilled blood,” Iranian protesters stormed and set fire to the Saudi embassy in Tehran. That prompted Riyadh to sever diplomatic ties with Tehran, and a standoff has prevailed ever since.

The research program manager at Qatar University’s Social and Economic Survey Research Institute, Justin Gengler, has a compelling theory to explain this, and it has more to do with economics than political hubris. In an August paper published by the Carnegie Endowment for International Peace, he argued that by “sowing communal distrust, highlighting threats and emphasizing their ability to guarantee security,” Arab Gulf regimes “can reinforce domestic backing and dampen pressure for reform more cheaply than by distributing welfare benefits,” the tactic previously employed by Saudi authorities to defuse Arab Spring uprisings.

Results from surveys Gengler conducted in the region showed that security-minded Gulf citizens were willing to accept lower levels of economic performance from their government in return for stability, so that the state’s provision of security represented for those citizens a substitute for the financial benefits citizens of oil-rich states had traditionally come to expect.

“In this way, Gulf governments can capitalize on the security concerns of
citizens to purchase popular political support more cheaply than through the standard distribution of material benefits,” Gengler concluded.

“Gulf regimes thus have economic and political incentives to embellish or manufacture domestic and external threats in order to heighten popular concerns over security and so lower the cost of accruing political support,” he added.

This applies directly to Saudi-Iranian hostilities in the current low oil-price environment. Both countries have been seeking to push through ambitious economic reforms, including large cuts to entrenched fuel and power subsidies, which might normally prompt widespread popular protests. With civil conflicts raging in bordering states, it is a matter of mutual convenience for Riyadh and Tehran to portray each other to their respective domestic constituencies as real and imminent threats to national security. Even large military spending budgets can be justified under the security banner if they do not exceed the expected gains to be reaped from economic reform.

The strategy is somewhat new for Riyadh but has been deployed successfully by Tehran for decades. The clerics who hold real power in Iran have, ever since the country’s 1979 Islamic Revolution, burnished and strengthened their political carapaces through skillfully crafted domestic propaganda campaigns in which a trio of far, regional and near external threats are personified by the US, Israel and Saudi Arabia.

In a nutshell, that is why, even during an oil price slump, Saudi Arabia and Iran will remain the best and most neighborly of enemies.

Near-term, that could mean further failures to reach agreement on freezing or cutting oil output. Longer-term, Saudi-Iranian rivalry could conceivably contribute to the successful implementation of needed economic reform and wealth creating. However, there are many opportunities for complex economic plans to misfire.

Gengler has additional words of caution that market-watchers might do well to heed: “Gulf rulers are often unable to manage social tensions once unleashed, and some have ended up stoking the very dissent they wished to suppress. This is a precarious strategy that carries serious risks to citizen welfare and the long-term survival of regimes.”

**SAUDI ARABIA, IRAN: KEY INDICATORS**

<table>
<thead>
<tr>
<th></th>
<th>Saudi Arabia</th>
<th>Iran</th>
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<tbody>
<tr>
<td>Population (July 2016 est.)</td>
<td>28,160,273*</td>
<td>82,801,633</td>
</tr>
<tr>
<td>Religion</td>
<td>Muslim (official; citizens are 85-90% Sunni and 10-15% Shia)</td>
<td>Muslim (official) 99.4% (Shia 90-95%, Sunni 5-10%)</td>
</tr>
<tr>
<td>Median age</td>
<td>27.2 years</td>
<td>29.4 years</td>
</tr>
<tr>
<td>GDP (official fx rate, 2015 est.)</td>
<td>$646 billion</td>
<td>$390 billion</td>
</tr>
<tr>
<td>GDP per capita</td>
<td>$53,800</td>
<td>$17,300</td>
</tr>
<tr>
<td>Oil production 2015 (inc NGLs)</td>
<td>12.014 million b/d</td>
<td>3.92 million b/d</td>
</tr>
<tr>
<td>Proved oil reserves</td>
<td>266.6 billion barrels</td>
<td>157.8 billion barrels</td>
</tr>
<tr>
<td>WEC trilemma index**</td>
<td>B-A-D (world rank 47)</td>
<td>B-B-D (world rank 78)</td>
</tr>
<tr>
<td>TI Corruption Index</td>
<td>52 (48th out of 168 countries)</td>
<td>27 (130th/168)</td>
</tr>
<tr>
<td>Military spending 2015</td>
<td>$87.12 bll (13.7% of GDP)</td>
<td>$10.27 bll (2.5% of GDP)</td>
</tr>
<tr>
<td>Global Firepower Index</td>
<td>0.4335 (world rank 24)</td>
<td>0.4071 (world rank 21)</td>
</tr>
</tbody>
</table>

*Immigrants make up more than 30% of the total population, according to UN data.

**(energy security - energy equity - environmental sustainability)

Sources: CIA Factbook, BP WEC, Transparency International, Stockholm International Peace Research Institute, Global Firepower
“It is a matter of mutual convenience for Riyadh and Tehran to portray each other to their respective domestic constituencies as real and imminent threats to national security.”
Specter of regulation

Two relatively new environmental issues have emerged to confront the US upstream oil and gas industry in the last few years – wastewaster disposal and methane emissions. Discerning the impact of regulations so far introduced is difficult, but they’re not going away and the actions of the next administration will be closely watched.

A few weeks ago while randomly changing channels, I came across “A View to a Kill,” the James Bond movie from 1985. Things particularly notable about that film:

- It was Roger Moore's last spin as 007, at the age of 58, which resulted in Bond aficionados screaming bloody murder that such an “old guy” should be playing the dashing James
- It featured Tanya Roberts as the “good” Bond girl (Grace Jones as her “bad” counterpart). She turned in what is generally considered just about the worst Bond girl acting performance in the history of the series, awful enough that she was nominated for a Razzie, a sort of anti-Oscar
- It serves as a 30-year advance notice of what can happen if you shoot a lot of water into a seismic fault, which people in Oklahoma are learning about on a fairly regular basis these days.

In the movie, the evil Zorin, played by Christopher Walken, is seeking to...oh, heck, it doesn't matter. You don’t watch Bond movies for the plot. It’s enough to know that it’s a terrible thing he wants to do, and to reach his goal, Zorin needs to flood California's San Andreas fault with seawater, thereby causing a really big earthquake.

Earthquakes and methane emissions: two relatively new environmental issues that have moved to the forefront for the US upstream oil and gas industry in the last few years. Taken individually, each of them has a unique set of characteristics that separate them from the usual tension between extractive industries and environmental regulation.

In Oklahoma, there’s a geological formation called the Arbuckle. As one geology professor said of it, quoted in a news article: “It’s very thick. It’s porous, it’s permeable so it can accommodate very large injection rates.” And it appears that the combination of the Arbuckle’s geology, the rise in oil and gas output, and its concurrent rise in disposal water being injected into the Arbuckle, is why Oklahoma is rattling at far greater rates than other states that have seen disposal rates increase with the rise in upstream activity. It’s sort of like what Zorin was doing in “A View to a Kill.” But in the Sooner State, the quakes haven’t been intentional.
The Arbuckle has been doing plenty of shaking in recent years. It’s not new; “induced seismicity,” or earthquakes created by the disposal of wastewater from oil and gas drilling, has been observed in Oklahoma for many years. But with Oklahoma rig counts having risen from a recent low in 2009 in the mid-70’s range, to peak at about 215 in November 2014 before falling back to less than 60 earlier this year, that’s still a lot of water that rose up through the borehole that needed to be disposed.

It is largely agreed upon by all but the most close-minded opponent of hydrocarbon production that the earthquakes are not being caused by fracking but instead by wastewater disposal. Such disposal is not new, but when laid up against rising output and drilling, it means a lot more wastewater needs to disappear.

Different feel

What makes this environmental issue facing the industry different from so many others is that it is one that is very much in the face of – or under the feet of – the average resident of Oklahoma. That rang particularly true in early September, when the biggest quake in Oklahoma history – a 5.8 on the Richter scale – shook the state.

The irony is that just before that, news stories had been touting the decline in quakes. For example, the US Geological Survey reported that in the first half of 2016, Oklahoma had just fewer than 1,100 earthquakes of 2.5 or higher. A year earlier, that figure totaled 1,400. Breaking that down further, other USGS data quoted by USA Today in August said the number of 3.0-plus quakes had dropped to 448 from 558 during that time. But to anybody who
“What makes this environmental issue facing the industry different from so many others is that it is one that is very much in the face of – or under the feet of – the average resident.”
went through the 5.8 that was of small comfort.

Then in early November, a smaller quake – but still a 5.0 – hit the state. The smaller severity from the September temblor was offset in part by it being centered in Cushing, home of the gigantic tank storage facilities and the delivery point of the NYMEX light crude contract. Assurances were given that the tanks there could withstand such a quake, but it created concerns nonetheless.

Kansas and Texas have disposal-related earthquake issues as well. But the US Geological Survey’s forecast for 2016 had Oklahoma well out in front of those two states in seismic activity created by wastewater disposal.

Kansas has implemented tougher limits on the amount of water that can be disposed of at one time, and the data so far shows a clear decline in seismic activity. But the question always lingers: is that because of the new rules, or because of less drilling due to weaker prices?

In Texas, the industry regulator, the Texas Railroad Commission, has been under fire for – in some eyes – being reluctant to tie earthquakes in that state to wastewater disposal. The Environmental Protection Agency filed a report with the Railroad Commission in August, noting a link in that state between seismic activity and disposal wells.

But it’s Oklahoma where the problems have been most severe. After the early September quake near Pawnee, Oklahoma Governor Mary Fallin ordered that 37 wastewater disposal wells be shut, and the Oklahoma Corporation Commission took action on top of that soon after, closing wells or modifying their operations. This comes on top of wells ordered shut in by the state after earlier big temblors. The OCC said that the steps it had taken would cut total “disposed volume” in earthquake areas by approximately 1 million b/d over 2014 levels.” The OCC also noted that in this particular “area of interest,” disposal well operators needed to report disposal activity to the commission at least once per week.

And finally: “New applications for Arbuckle disposal wells in the (area of interest) are not given administrative approval.”

After the early November quake, the OCC passed a further set of restrictions. It’s a series of rules that ordered more wells to be shut in within a six-mile radius from the quake’s center, and imposed reduced flows at other wells further out from the center. The count: seven disposal wells would be shut, and 16 would have their flows reduced further, on top of the earlier required reductions in wastewater disposal. This isn’t a long-range requirement; by the time you are reading this, all those rules will be in place.

What’s been the impact on production? It’s too hard to discern from the data. There isn’t even a clear rule of thumb on the amount of disposal water that is produced/b of oil produced.

An Argonne National Laboratory estimate a few years ago put it at 7.5 barrels of water for a barrel of oil, and 260 barrels of water for every million cubic feet of natural gas.

An overly simplistic calculation that takes the 1 million b/d of water reduced, at a ratio of 7.5 barrels of water for each barrel of oil produced, cuts oil output by more than 130,000 b/d. But that assumes zero reduction in water as a result of gas output, and also isn’t backed up by any data showing a decrease in Oklahoma of that magnitude. And how much of the decline that was recorded was the result of weak prices, as opposed to disposal well shutdowns that ended up closing producing wells?

Still, shutting in wells, by definition, will have some impact on production. Kim Hatfield, CEO of Crawley Petroleum who is also on Gov. Fallin’s Coordinating Council on Seismic Activity, said in mid-September the steps taken by the state have had a noticeable impact on production. “Oil and gas companies are shutting rigs, cutting jobs or turning to new locations inside and outside the state,” said Hatfield in a widely circulated news story. “Property owners who allow drilling are watching royalty checks dry up.”

Given the normal lag in output data, it’s hard to check now the validity of that statement. Still, some fresh data seems to undercut the Hatfield thesis; while total rigs at work in Oklahoma is well off its 200+ number from late November, by mid-October the Baker Hughes rig count for the state had climbed above the 70 level from lows a little less than 60 over the summer. But maybe it would have been higher had it not been for the disposal well shutdowns.

Bottom line: discerning the disposal well shutdown impact is difficult to find in the data, but it isn’t zero.

The federal role here is minimal. There is legislation governing activity that was passed in the 1970’s, but a lot of the powers in it have been transferred to
the states. But the EPA still has regulatory oversight. E&E News reported in early October that the EPA recommended to Oklahoma that it should “consider a moratorium” on wastewater disposal in certain parts of the state, particularly in the Arbuckle disposal. The EPA could take back the authority it gave to Oklahoma, but is not expected to do. So the suggestion remains that: a suggestion.

So for Oklahoma, this is in the hands of the OCC and for purposes of providing advice, the joint government & industry Coordinating Council on Seismic Activity. Unique to regulatory issues, the average resident who sees a small crack develop in their wall after another shaker understands this one in a way that they might just tune out if they hear something about the regulation of drilling muds; even in Oklahoma, most people won’t know what they are. But they know what an earthquake is.

**Capturing value**

Methane emissions from upstream and midstream activities are also beginning to take an increasing prominence on the regulatory landscape. Just as the earthquake issue is unique because the general public is quite aware of it, methane emissions differ from standard environmental issues because they’re an externality that has economic value. An externality, as they teach you in Econ 101, is a byproduct of an economic action that foists part of the process’ cost on an unwilling – or unwitting – third party. Mercury emissions from a coal-burning power plant are a classic externality.

Methane emissions from upstream or midstream activities are different.

Capturing mercury emissions involves scrubbers and other expensive facilities, but there’s a question of the cost of capturing methane. The issue is comparing the cost of capturing those emissions and keeping them in the supply stream, against the price of natural gas – which is mostly made up of methane – and whether the costs to capture it are less than the value of the methane retained.

The issue of methane emissions has risen as a regulatory point of contention as natural gas (and to a lesser degree, oil) output has risen; attention has been brought on the fact that methane is a “powerful” greenhouse gas (it’s almost always described that way); and the now-blocked Clean Power Plan of the Obama administration focuses concerns on ways companies will try to meet its standards, if it is ever revived. But the methane issue is unique because it has the rather odd specter of environmentalists giving what they consider to be sound economic advice to upstream and midstream companies: Hey...this is good stuff! You can capture it and sell it! You’re welcome!

In August, a new set of rules regulating methane emissions was implemented by the Environmental Protection Agency. The rules are complex, but impact a large range of activities where there is a potential for methane leakage. The final rule was considered stronger than the rule that was first proposed back in 2015, and only impacts new or modified wells. The Obama administration in November formally began an information collection request for regulations on existing wells, which generally would be is expected to be a regulation that has more impact. But with the election of Donald Trump, implementation of a rule regulating emissions from existing wells can fairly said to be in doubt.

The outgoing Obama administration in mid-November threw up a new rule, governed by the Bureau of Land Management (rather than the EPA) that would regulate methane emissions on all wells on federal and Indian lands. It was immediately challenged in court by industry groups, so its fate is in doubt on two fronts. First, when the challenges go to court, the rule could be stayed; second, the new Trump administration may choose not to fight the industry’s challenges. And for all three of these...
rules, implemented and proposed, Congress or the Trump administration could seek to overturn them.

That’s why the implementation of the Obama methane capture rules did not quell the debate. On the environmentalists’ side, the Environmental Defense Fund – generally considered the most moderate of key environmental groups – said cutting methane emissions has a cost on average of about 1 cent per 1,000 cubic feet of gas. (That’s against a price that in mid-October was anywhere from $3.25-$3.50 for the Henry Hub benchmark). “And of course, one of the benefits of the EPA regulation is that it is already driving innovation in the private sector, which promises to bring those costs down even more,” the EDF said in a statement prior to a hearing in Congress on the issue.

The industry, primarily through the public affairs group Energy in Depth, funded by the Independent Petroleum Association of America, has been pushing back against the idea of the need to significantly clamp down on methane emissions. Its argument was fueled by a report released by the EPA this fall showing methane emissions from the US petroleum sector falling to 70.3 million mt of CO₂ equivalent in 2015 from 83.8 tons in 2011. But the EPA’s assumption is that methane emissions are going to increase by 25% by 2025, making it difficult to reach the broader goal of cutting methane emissions by 40-45% by 2025. The industry’s response is that the EPA’s own figures already show significant progress on that front, so what is the basis for the belief in rising methane emissions, and are regulatory actions needed when the trend is already clear?

Just like the quake data, it’s difficult to figure out how much of the decline in methane emissions has been created by less drilling and production due to lower prices, versus steps taken by the industry to capture the value. But the industry’s answer to that is that petroleum industry CO₂ emissions rose during the 2011-2015 period, while methane fell. That, they say, is proof that the value of the externality is being captured. (Another response: agriculture produces far more methane and it has not been singled out the way the petroleum industry has. An anti-hydrocarbon push is clearly feared.)

Although there now is a Donald Trump presidency looming, the Obama administration regulations on methane are in place. Trump may have talked about eliminating many Obama era executive orders, but the methane rule doesn’t fall under that category. A process to change it would not happen overnight, and even a new rule almost certainly wouldn’t eliminate all restrictions. And the change in the White House occupant has no impact on any state regulations. Methane emissions will continue to be a regulatory concern for the industry.
Battleground Europe

With European gas production falling rapidly, the continent is a key market for the growing ranks of global gas suppliers – notably US LNG. The incumbents are not likely to give up their share of the market lightly, with defense strategies already taking shape.

Europe is increasingly becoming a battleground for global gas and LNG suppliers as the current supply glut leaves producers scrambling for market share in key European consuming countries. As Fatih Birol, the head of the International Energy Agency, put it in June this year: “Intense competition will develop among producers to retain or gain access to European customers.”

Exports of US LNG – produced from dirt-cheap shale gas production – started up in February this year to much fanfare, with Europe seen as a likely destination. But the response from Europe's traditional pipeline suppliers – Russia, Norway and Algeria – has been clear: we're ready for the fight.

In mid-October, the amount of gas imported by Europe via pipeline rose above the 800 million cu m/d mark for the first time since at least 2011, according to data from Platts Analytics’ Eclipse Energy. This compares with much lower flows of around 700 million cu m/d a year ago.

Are state gas companies Gazprom, Sonatrach and Statoil following the Saudi Arabian model in the oil market?
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and producing at full blast, despite low prices, to retain market share?

Publicly they have played down the prospect of a market share war between US LNG and pipeline gas in Europe, but some of the evidence at least suggests that Europe’s traditional suppliers are loathe to lose ground to US LNG supplies. The surge in pipeline flows into Europe has extended the supply advantage seen for pipeline gas over LNG imports – not just those from the US but even LNG kingpin Qatar.

Pricing has had a lot to do with the rise of pipeline gas to Europe so far in 2016 too – with oil prices so low, gas indexed to oil has been relatively cheap. Russia, Algeria and Libya still sell oil-indexed gas into Europe. In addition, hub prices in Europe since the start of 2016 have been low, too low some would argue to incentivize large-scale US LNG imports despite the corresponding low price at the Henry Hub. European prices have also been lower than the netback to newer demand centers such as Dubai, Kuwait and Jordan in the Middle East, which have both taken cargoes of US LNG since its startup.

Whether the pricing elements of long-term contracts with the likes of Gazprom and Sonatrach have been tinkered with to incentivize buyers to take more pipeline gas into Europe is unclear. Equally unclear is how much seller-nominated gas is flowing to European hubs.

But Russia clearly does have the option to undercut the US LNG price to ensure it keeps its share of its key European markets and could flood the market with cheap gas, maximizing revenues and cash flow at a time when producers worldwide are suffering from the impact of such low prices. S&P Global Ratings in a July credit update said it expected Gazprom to cut prices to its European customers. “We assume Gazprom will have to provide discounts to its European customers to compete with supplies from other geographies,” it said.

Russian pipeline gas deliveries to Europe so far in 2016 remain comfortably above previous levels for the time of year. Between January and September, flows totaled 85.6 Bcm, 13% higher than the cumulative total for the same period last year.

Algeria has also proven a number of naysayers wrong so far in 2016, boosting its gas exports despite concern over whether it would be able to amid crushingly low prices and rampant domestic demand growth. Algeria’s gas exports via pipeline to Europe in the first six months were a whopping 5.1 Bcm higher than they were in the same period of 2015, according to Platts Analytics data. Algeria has been able to boost gas output as new fields came on stream and the country has looked to stem its domestic gas demand growth.

The amount of gas exported from Norway via pipelines to Europe is also booming and for the first seven months
of the year stood at 63.64 Bcm, 9% higher year on year and 12% up on the five-year average. That comes off the back of all-time record high exports of 115 Bcm in 2015 and growing Norwegian gas production so far in 2016.

Norway’s state oil and gas company Statoil has – on more than one occasion – distanced itself from the idea of a market share defense strategy in Europe. In October, the company said it was sticking to a strategy of “value over volume” – withholding supply during periods of low prices and boosting output when prices are high.

And Statoil’s vice president for marketing and trading, Tor Martin Anfinnsen, said in May that the company followed the market and had no strategy on volume or price with regard to other suppliers. “We produce what is available to be produced at any given time. We don’t look to the left or to the right to see what the Americans or Russians are doing,” Anfinnsen said.

**Russia’s dual flexibility**

Industry observers believe Gazprom is almost certainly headed down the market share defense route in a bid to stave off US competition. A recent report from two energy think-tanks – ewi Energy Research & Scenarios and the European Centre for Energy and Resource Security – concluded that Gazprom would follow a “competitive” pricing strategy, which will see Russia increase its market share in the EU to 33% by 2035 from 27% in 2014.

Russia – like Saudi Arabia in oil – is the only country with significant spare production capacity, estimated at 170 Bcm/year, so Moscow can take a strategic view. It has flexibility on the volumes it can export, and also flexibility on the prices it charges its customers given how low its production costs are. This dual flexibility puts Gazprom in an enviable position.

Forecasts from Platts Analytics certainly suggest that Russia is in the best position to ramp up supplies to Europe as domestic European production declines quickly into the next decade. Other than a slight lull in supplies in 2017 and 2018 due to the extremely well supplied European market and the glut of global LNG, Russian supplies to Northwest Europe are expected to rise strongly in the 2020s, according to Platts Analytics.

In what may be a signal of its ambition to protect European market share, Gazprom has also been looking over the past year to find ways to tempt new customers with bargain deals and new sales techniques – including through auctions – or keep hold of existing buyers by agreeing to better supply terms and more contract flexibility.

So with Europe firmly in Russian sights, the key question is how Gazprom’s response to the startup of US LNG develops. Its reaction to Lithuania’s move to import LNG at the end of 2014 – offering a discount of 23% on pipeline gas supplies – is evidence that Russia does not want to give up its market share. And Russia has also discounted supplies to Ukraine in the recent past to try to make its price competitive with European gas now that Kiev can import gas from the west.

Clearly there is much to gain by having the optionality that Lithuania, Ukraine and now Poland – with its brand new LNG import facility – have. For Russia, the key is that it can afford to cut prices to its European customers. It can maintain supply to Europe and make money even if gas prices continue to stay so low or fall yet further. Even with low Henry Hub prices, US LNG is unlikely to be able to compete with Russian gas at the margins.

But with Russia looking increasingly likely to build on its European market share in the coming decade, there is the risk that Brussels could look to intervene to prevent Russian market dominance. EU President Donald Tusk said in December that one of the key

![US LNG EXPORTS: 2016-2020](chart.png)
Gazprom undeterred on European gas pipelines

European gas production is falling – fast – which can mean only one thing: increased dependence on imports. Gazprom is well aware of that, and wants to retain its dominance over the lucrative European market by making its gas readily available. That means more pipelines, and specifically pipelines that bypass troublesome neighbor Ukraine.

The Russian company is moving forward, full speed ahead, with two new pipeline systems that would all but eliminate the need for transit via Ukraine, adding 86.5 Bcm/year of new export capacity. Given that Ukraine expects to transit some 75 Bcm/year of Russian gas to Europe in 2016, it doesn’t take a genius to work out what is at stake.

The names are familiar – Nord Stream 2 and TurkStream – and despite geopolitical hiccups and regulatory headaches, both projects could well be operational by the end of 2019. That date is key because it is when the 10-year Russian gas supply and transit deal with Ukraine expires.

The deal on TurkStream in mid-2016 completed a remarkable turnaround for Ankara-Moscow relations which had soured immeasurably when Turkey shot down a Russian fighter jet in November 2015. An intergovernmental agreement was sealed in Istanbul in October, just two months after an apology from Turkish President Recep Tayyip Erdogan for the fighter jet incident, paving the way for construction of two 15.75 Bcm/year pipelines from Russia to Turkey.

Clearly, the finalization of the political accord on TurkStream is a signal to Europe and competing suppliers that Russia still means business in the region.

As part of the deal, Moscow and Ankara also reached an agreement on price. It was not immediately clear if it would be equivalent to the 10.25% discount on the existing price structure agreed last year but never implemented. Sources suggested it was lower, at between 5% and 7%. Of course, a lot has changed since the discount was first agreed back in February 2015. The main thing is that gas prices in Europe have plummeted, making it less urgent for Ankara to secure itself a discount.

Russia also has an incentive to lock Turkey in — new possible suppliers are emerging all the time. It comes as Azerbaijan and Turkey continue to work on the TANAP/TAP pipeline network to bring Azeri gas from Shah Deniz to southern Europe and as LNG suppliers eye reverse flows via Greece into Bulgaria and other southeast European countries. The timing of the October accord was also notable for coming just weeks after Turkey imported a cargo of US LNG — the first time a European market traditionally supplied by Russia brought in US LNG.

Russia last year sent 27 Bcm of gas to Turkey — more than half of the country’s overall consumption — so the market remains critical to Gazprom. Gazprom also supplied some 11 Bcm to southeast Europe — the likes of Greece, Bulgaria, Romania, Moldova and the countries of the former Yugoslavia. The region represents a not insignificant chunk of market share that Gazprom wants to retain. And with Russian gas production costs among the cheapest in the world, Gazprom would likely be able to compete on price versus LNG and more expensive offshore Azeri gas.

Gazprom is also still committed to Nord Stream 2, which would add another 55 Bcm/year of capacity to the existing 55 Bcm/year Nord Stream system to Germany. It was dealt a blow in August when the five European companies that had hoped to partner Gazprom to build the link abandoned the plan due to Polish objections. But the five — BASF, Uniper, Engie, OMV and Shell — are still planning to support the project without falling foul of the kind of opposition that derailed the original venture.

Nord Stream 2 has provoked unprecedented opposition from some Eastern European countries and from Brussels, while the US government has also criticized the project as having an “adverse effect” on Eastern Europe. Shell earlier in the year had appeared to distance itself from the political controversy, its CEO Ben van Beurden stressing that the company’s involvement in Nord Stream 2 was purely as an investor.

Gazprom as sole shareholder of the Nord Stream 2 operating company says work continues as planned and the implementation schedule is unchanged. Analysts believe Nord Stream 2 will still be built, one way or another. “We believe that the break-up of the joint venture is unlikely to result in the project being terminated, but we do think it could create higher political risks for the project and for Gazprom,” S&P Global Ratings credit analyst Alexander Griaznov said.
objectives of the EU’s energy union is to reduce its dependency on individual suppliers and diversify suppliers, sources and routes.

Therefore Russia’s growing market share in Europe could potentially trigger some new policy-making in Brussels. Any barriers put up to increased market dominance by Gazprom would, of course, favor US LNG.

Gazprom, meanwhile, has looked to play down the likelihood of a European gas price war. Gazprom deputy CEO Alexander Medvedev said in the spring there was “no need” for a price war, suggesting that US LNG would struggle to ever be competitive with Russian gas because of how low Russia’s gas production costs can go. And on October 21, Gazprom’s board concluded that “in the European market US LNG was losing against Gazprom’s pipeline gas.”

It went on to paint a fairly negative picture of the evolution of US gas production. “Pressured by low hydrocarbon prices, US operators have had to cut considerably their investments in shale projects,” Gazprom said. “Well drilling operations have been essentially frozen at a number of well-known US shale fields in 2016, with aggregate shale gas production showing negative growth since this March.”

It added that some 170 US-based production and servicing companies had gone bankrupt since early 2015.

All this is true, with US gas output falling below 70 Bcf/d in October for the first time since December

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**US LNG EXPORT DESTINATIONS AS OF NOVEMBER 16 (cargoes)**

- **Chile**: 9
- **Brazil**: 4
- **Argentina**: 4
- **India**: 4
- **Mexico**: 3
- **Jordan**: 2
- **Kuwait**: 2
- **Spain**: 1
- **UAE**: 1
- **China**: 1
- **Dom Rep**: 1
- **Portugal**: 1
- **Turkey**: 1

Source: Platts trade flow software cFlow
last year, according to data from Platts Analytics’ Bentek Energy. But US LNG should not be ruled out – it is here to stay.

While Sabine Pass on the US Gulf Coast for now only has two operational trains, the ramp-up in capacity is set to accelerate in the coming years – a total of some 70 million mt/year of US LNG export capacity is expected to be online by 2020.

At the start of the decade, US LNG looked like a way to print money. The US realized that it could transform its underused LNG import plants into export facilities to make the most of cheap and abundant US shale gas. But following the precipitous commodity price collapse since 2014, the economics of US LNG exports look considerably more fragile than the industry would have ever imagined.

With the core LNG markets in northeast Asia seemingly off-limits to US LNG in the near term as prices move closer to global levels, there was always one market that, it was hoped, would take the gas – the European sink market. But even in Europe – with its massively underused LNG import capacity and liquid gas markets – it seems that so far there is very little room for US LNG penetration under current market conditions.

As of mid-November, Cheniere Energy’s Sabine Pass export facility had loaded just short of 40 cargoes, with the majority headed to South America. Only three cargos had landed in Europe – one in Portugal, one in Spain and one in Turkey – meaning the European gas landscape is yet to see any meaningful shift. However, as Henry Hub/NBP spreads widened quickly in November, the economics of US LNG coming to Northwest Europe have improved.

Cheniere has said it sees some 50% of its total LNG exports coming to Europe in the future. It has plans for seven 4.5 million mt/year trains at Sabine Pass and Corpus Christi – so half of that would be as much as 15.8 million mt/year or almost 22 Bcm/year. But so far, the key Northwest European markets – where import demand is growing fastest due to declining indigenous production – have not attracted any US LNG.

Iberian isolation

Indeed, the fact that Portugal and Spain were the first European countries to import LNG from the US is telling. And Turkey’s import of a US LNG cargo has its own geopolitical implications (see box). The Iberian Peninsula is considered an “island market” with poor interconnection to the rest of Europe, so the delivery of US LNG into the region is not likely to be seen as a sign that it will take hold in the wider European market.

Spain has an annual LNG regasification capacity of 43 million mt/year (59 Bcm/year) at its six LNG terminals, plus 28 Bcm/year of pipeline import capacity, including interconnectors with France and Portugal. That gives Spain a gas import capacity of some 87 Bcm/year despite only having consumption of around 30 Bcm/year. Its import capacity is more than eight times higher than its current export capacity to France and Portugal of just 10.6 Bcm/year.

Spain may well take the lion’s share of US LNG in Europe in the future – Gas Natural is expected to begin taking more regular cargoes in 2017, though it is a portfolio player so could easily send US LNG anywhere in the world. But the biggest supplier to Europe – Russia – does not supply the Iberian market with pipeline gas so it is unlikely to be concerned about US LNG headed to southwestern Europe.

And US LNG could face problems of its own – the current low prices are forcing ever growing numbers of US producers into bankruptcy. According to a recent report by Haynes and Boone, 90 gas and oil producers in the US and Canada have filed for bankruptcy between January 2015 and the start of August 2016.

Competitive advantage

Russia could face greater competition from other new sources of gas in the near future, albeit mostly targeting markets in southeast Europe. The huge volumes of gas discovered in the East Mediterranean could find their way to Europe, and then there are Iran and Iraq – two countries with vast gas reserves but not much in the way of export infrastructure yet.

Iran has plans to send 30-35 Bcm/year to Europe and Turkey after 2020, while a pipeline with 20 Bcm/year capacity will link the northern Iraqi region of Kurdistan to Turkey and Europe by around the same time. And Azerbaijan can also offer optionality to southern Europe once the Shah Deniz 2/TANAP/TAP integrated gas projects come on stream toward the end of the decade.

But for now, Russia seems to have the competitive advantage to see off all-comers, including the expected influx of LNG from across the Atlantic.
With more than 75 years at the forefront of the energy industry, our collaborative approach, extensive resources and critical knowledge of trends keep us focused on what’s next. And we don’t just manage risk, we create strategic solutions because we know the industry inside out.
Defying gravity

Global energy markets continue to question Canada’s enigmatic oil sands and the 305,000 b/d of supply growth since the price collapse of 2014. How is it that the heavy, viscous bitumen that is amongst the most expensive in the world to extract continues to grow in this low-price environment? Though it is the world’s sixth-largest producer of petroleum liquids according to the International Energy Agency and world’s largest producer of heavy crude (gravity of less than 28 API), Canada is home to the world’s least understood oil reserves and production.

How the oil sands work

For those familiar with the complex technology and extraction techniques used in Alberta’s oil sands, feel free to read on to the next section, but if you are like most of the world, a quick explanation of the workings of the oil sands is important to understanding the fundamentals driving production in the region.

Bitumen, the viscous tar-like crude produced mostly in northeast Alberta, can be extracted either by mining the bitumen or through a process similar to enhanced oil recovery. Bitumen reserves that lie within 200 feet of the surface can be produced using traditional mining techniques, bulldozers, shovels, etc. The resulting bitumen, rock and soil is processed to isolate the bitumen and then is typically processed at an upgrader on site. These facilities turn the heavy raw bitumen into a “synthetic” crude called syncrude. With the exception of Imperial’s Kearl mine and new mines, crude produced from mining reaches market as this highly desired light, sweet crude.

Though there are multiple ways to recover bitumen in situ — a term defined as “in place,” but more used in Canada to refer to bitumen produced through enhanced oil recovery — the most common such recovery method is steam injection. Water and natural gas are injected into the bitumen reservoir in order to heat the bitumen and allow it to flow freely to the surface. The raw bitumen is typically very heavy and must be diluted with light hydrocarbons, such as butane, pentanes, naphtha or light crude oil, in order for the bitumen to flow onto a pipeline to a refinery configured to process very heavy crude. Though some in situ bitumen is processed on site, the bulk of it reaches market as diluted bitumen, or dilbit, a heavy sour crude with a gravity of about 20 API.

Both recovery methods require specialized infrastructure, labor and technology, and are in fact extremely expensive projects. However, unlike
large projects underway globally, such as ultra-deep offshore or projects in Siberia, the midstream infrastructure and much of the technology already exists in northeast Alberta. Unlike shale production, oil sands production does not decline within a year, but is designed to produce at near capacity for, in many cases, over 30 years.

The future of oil sands

Platts Analytics expects production from Canada’s oil sands to grow 45% in the next five years from an average 2.852 million b/d in 2016 to 4.124 million b/d in 2021. By next year alone, Platts Analytics expects 388,000 b/d of incremental production despite a bearish $53.13/b global price forecast in 2017.

Since 2014, the global energy market has expected Canadian oil production to fall rather than grow. Of the 39 projects operational at the start of the price collapse, only 12 small projects have halted operations as of 2016 due to poor economics. At its peak the total shut-in capacity only amounted to 44,500 b/d, and in fact just 11,000 b/d of actual oil production as the projects had been running well below capacity anyway. Meanwhile, the remaining 27 oil sands facilities actually increased production, some in excess of project capacity as producers focused on optimization and taking advantage of economies of scale, as well as the low cost of labor and natural gas.

The key to understanding persistent production in the oil sands in a low-price environment is producer sentiment and operating costs. Producers in the oil sands value oil sands projects as long-term, low-decline assets, in which returns from large up-front investments are realized over the 30-year life of the project.

Platts Analytics estimates that the average large-scale existing oil sands project needs Western Canadian Select (WCS), the heavy oil benchmark in Alberta, to average $36/b over the next 30 years in order to break even. Platts Analytics currently expects WCS to average $53/b between 2017 and 2021, resulting in profit for the oil sands producer despite a period of low prices.

In addition, two of the most significant operating costs for oil sands producers are the cost of natural gas to generate steam and the cost of condensate to blend for pipeline transportation. Natural gas prices in Western Canada have been under pressure from increasing supplies of natural gas across North America, falling from

![Western Canada Oil Sands Production Forecast by Type](chart1.png)

![Oil Sands Average Breakeven Price (WCS) by Project Type](chart2.png)
$4.68/MMBtu in the first half of 2014 to just $1.21/MMBtu in the first half of 2016.

Similarly, the price of condensate has trended with the price of crude, falling from $101/b in the first half of 2014 to just $40/b in the first half of 2016. Therefore, in this low price environment, oil sands producers are benefiting from substantially lower costs, essentially reducing the price needed to break even. Meanwhile, the Canadian dollar lost 25% in value relative to the US dollar, at which most Canadian crude is sold, inflating the selling price of Canadian crude and deflating domestic costs.

Much of the growth in production expected over the next five years stems from brownfield expansions to existing large oil sands projects. In 2017 alone, Platts Analytics expects an additional 300,000 b/d of production capacity from project expansions. Much of the infrastructure associated with these expansions, such as central processing facilities, pipelines, roads, etc., is already in place. So aside from the cost of drilling additional wells and the increase in cost for steam generation, power and diluent, there is significantly less upfront capital needed to accommodate expansions. Platts Analytics estimates that the 30-year WCS breakeven price for brownfield expansions is in a range of $39-47/b, remaining profitable at the price forecast of $53/b.

The downside risk to the five-year oil sands production forecast is greenfield and pilot oil sands projects. An entirely new facility, or any project that would come along with significantly higher labor costs or other sustaining capital costs, is more likely to face delay or cancellations due to economics. Platts Analytics currently includes 13 greenfield projects in its five-year forecast. Though most of these face significant uncertainty about their construction and production timelines, these are primarily the projects that have not been explicitly deferred or canceled to this point, though it also includes some high priority projects from established oil sands producers.

Platts Analytics estimates that greenfield oil sands projects break even at around $53/b WCS over the next 30 years. Given the average forecast for WCS over the next five years, only the most cost-effective greenfield projects are likely to begin production. However, in the longer term, sustained higher prices are likely to incentivize a return by producers and investors to the other 38 greenfield projects that have been proposed, but are not included in our five-year forecast, as well as multiple new expansions on existing projects.
**Shale and conventional production**

Unlike the oil sands, which are long-term, low-decline assets that require little in the way of maintenance costs, shale and conventional production in Canada has been drastically affected by low oil and gas prices and the resulting decline in drilling activity in Western Canada. Without additional investment and resumption in drilling activity, shale and conventional oil production in Canada is expected to fall by 15%, or 183,000 b/d, in the next five years.

The oil sands are operated by, for the most part, large integrated companies with strong cash flow and unique expertise. With the exploitation of shale, smaller producers in Canada were able to capitalize on the new exploration and production environment. Foreign investors, too, were enticed to produce from Canada's massive shale reserves, resulting in a deluge of investment in the Western Canadian E&P market. One of the biggest drivers behind investment in shale was the production mix of shale plays. The Montney, for example, produces 70% natural gas, 13% natural gas liquids (NGLs), and 17% light oil. In 2014, all hydrocarbons produced in Western Canada were extremely valuable.

Natural gas prices in North America were the first to collapse as new shale gas reserves were discovered across North America, most of which were much closer than Western Canada to premium natural gas markets in the US Northeast and Gulf Coast. However, shale production maintained its value through liquids production – the heavy NGLs, such as butanes and pentanes plus, condensate, and ultra-light crude that are used as diluent in the oil sands. Diluent prices garnered a premium of up to $17/b to benchmark WTI until 2014 when rampant drilling activity in the US and Canada led to the fall in liquids prices.

However, the trend of capital fleeing from Canadian shale after the price collapse could be reversed with persistent growth in oil sands production and, consequently, diluent demand. Natural gas prices are still expected to stay under pressure as Canadian liquefied natural gas (LNG) terminals remain in limbo and the US continues to grow domestic production. The premium sources of diluent, domestic and imported NGLs, will not be sufficient to meet diluent demand over the next five years, which will likely lead to a diluent premium sufficient to attract new drilling and investment in Canada’s shale plays.

**Risks and opportunities**

Demand for Canada’s heavy oil sands production remains strong, particularly in the US Gulf Coast, home to 50% of the world’s coking capacity and the largest demand center for heavy crude,
Canada and new and expanding pipelines have facilitated greater access to the US Gulf Coast. Meanwhile, global exporters of heavy crude such as Venezuela, Ecuador and Colombia face declining supply and foreign investment, increasing demand for Canadian crude.

Other regions around the world, such as India and China, are increasing their capacity to consume heavy crude, but one of the largest risks to Canadian production growth is the absence of export pipelines. Nearly all Canadian crude flows by pipeline to refineries in the US and there remains little capacity for Canadian crude to reach its own coast.

Like the infamous Keystone XL pipeline that would bring oil sands crude to the US Gulf Coast, Canada’s domestic pipelines to the Canadian west coast (Kinder Morgan’s TransMountain Expansion and Enbridge’s Northern Gateway) and east coast (TransCanada’s Energy East) face powerful environmental dissent.

Without export pipelines, Canadian oil producers will not be able to take advantage of demand growth outside North America. Rather, Canadian producers will have to move incremental production via rail to the US and export ports, incurring further transportation costs and affecting the economics of oil sands production.

Meanwhile, export facilities for natural gas and propane are also facing opposition from environmentalists and First Nations groups, hindering Canada’s ability to take advantage of its massive shale reserves and access to prime demand centers in Asia.

Geography and geology lend Canada the potential to be a much more influential player in the global energy market and a recovery in prices could drive renewed investment in Western Canadian oil and gas and the Canadian economy. Such a rise to significance, however, will depend on Canada’s midstream infrastructure, overcoming environmental and indigenous dissent, and the country’s ability to reach growing demand markets outside of North America.
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Transition tipping point

The low-carbon transition appears to have gained its own logic and with it an unstoppable momentum

The lightning fast entry into force in November of the Paris Agreement on climate change, barely 11 months after it was agreed following years of fraught negotiations, gave unambiguous backing to the view the world had entered a new era and was heading inexorably towards a low-carbon future.

Hailed as probably the fastest entry into force of a major international treaty, Paris is in sharp contrast to its very one-sided predecessor the Kyoto Protocol, which took more than seven years to make the transition from paper to practice and was unceremoniously dumped by the US Senate despite being signed by then President Bill Clinton. This time around Barack Obama was among the first to ratify Paris, one of his last, and probably most meaningful, acts as president.

Then suddenly on November 10, with COP22 underway in Marrakesh attempting to hammer out the “how” of what was agreed in Paris, the world woke up to the fact that, against the odds, Donald Trump would be the next US president. The news shook the world but not least the global environmental lobby. After all Trump has vowed to rip up the Paris Agreement, along with many other multilateral agreements.

It could also set back the US environmental movement – with undoubted repercussions across the globe – as Trump has promised support to the ailing domestic coal industry and to roll back much of the current administration’s more far-reaching environmental legislation including on air quality. With a Republican president in the White House and Republicans in control of both Houses, the much-vaulted checks and balances of the American governmental system are also in some doubt, and the bitter campaigning on both sides has split the country and could have even more far-reaching consequences for future climate action in the US.

Epitomizing the joy of the US coal industry at Trump’s victory, Murray Energy CEO Robert Murray applauded the result saying it was a great day for America. Murray Energy is the largest
The key thing in all of this is that the economics have changed so much.
underground coal mining company in the country and has repeatedly attacked Obama’s climate actions. “This is also a great day for coal miners and their families, and for all Americans who depend on reliable, low-cost electricity, which coal provides, particularly those who are poor or on fixed incomes and those manufacturers who create products which must compete in the global marketplace,” he said.

But even before the dust was beginning to settle, the less pessimistic environmentalists were starting to reason that much of the more histrionic Trump campaign rhetoric will undergo something of a metamorphosis as he gets inducted into the daily presidential briefings giving him an insight into what lies behind government policies – including on foreign policy, climate and security.

In a post-election briefing, General Stephen Cheney of the American Security Project think-tank said several US bases around the world – including Norfolk, Virginia and Diego Garcia in the Indian Ocean – were under threat of flooding from rising sea levels due to climate change. He also noted that more than 70% of countries around the world have climate change written into their national security strategies.

There is also a feeling that Donald Trump will have so much on his plate that climate change, which was not an election issue, may be relegated to something of a lesser priority for reaction. And while Trump’s election will certainly hinder Paris and give succor to its opponents, there is a strong belief it will not alter the fundamental shift, perhaps just the speed – although speed is of the essence if the world is to stave off fundamental climate change.

“Averting climate catastrophe has just become harder, but not impossible,” Greenpeace International directors Jennifer Morgan and Bunny McDiarmid said in a joint statement. “The renewable energy transformation is unstoppable. China, India, and others are racing to be the global clean energy superpowers, and the US, as Donald Trump will learn, does not want to be left behind.”

Despite the changed picture there remains an undoubted momentum carrying Paris forward, although still faces an uphill struggle converting its stated volitions and ambitions into concrete actions as it is based on an aggregation of nearly 200 national plans, the so-called Nationally Determined Contributions, which are universally acknowledged to fall well short of the two-degree Celsius goal, with no coercion measures internationally to enforce or strengthen them.

Nonetheless, while the political winds will inevitably continue to shift, a consensus seems to have emerged among analysts, investors and decision makers that the direction of travel is now irrevocably set, with only the pace of change still to be determined. Having opened the door, politics can now take something of a back seat again.

Tom Burke, chairman of the influential sustainability-focused think-tank E3G, is sanguine. “Paris currently has baby teeth, and there will be a very complex and long negotiation over the next four years to put some real teeth into it. Those will come from the ‘ratchet
mechanism’ [designed to steadily increase ambition over time], the reporting and the money built into Paris. Getting public money leverages lots more private money,” he said.

“We expect most countries will exceed their NDCs. The low-carbon transition is only partly being driven by climate policy. It is now being driven by its own momentum. It is a business opportunity. Investors are beginning to understand that if they are not investing in the low-carbon economy they are running the risk that climate policy fails and with it comes systemic risk,” he added.

The conviction that the die is cast is founded on two fundamental differences between the near-catastrophic failure in Copenhagen in 2009 to achieve what was finally sealed in Paris. Firstly, the Paris Agreement was built from the bottom up with crucial input from across the financial and business sectors globally – and that engagement is getting progressively stronger – and secondly the technology behind the low-carbon economy has undergone a cost revolution, with prices tumbling.

“The key thing in all of this is that the economics have changed so much since Copenhagen," said Seb Beloe, head of research at WHEB, a specialist sustainable investment company. “Prices are coming down very quickly, so going low-carbon is not the costly thing it was. In fact, in some cases it is now cheaper than to do the traditional thing.”

“The economics have changed dramatically in its favor and will continue to do so. Policy therefore gets less important – at least in terms of power generation,” he added.

The US aside, Europe too is not without its dilemmas and difficulties. The UK’s referendum decision in June to quit the European Union had climate skeptics rubbing their hands in glee at the prospect of abandoning wholesale a plethora of EU climate policies and regulations. The departure of the UK, formerly one of the bloc’s leading actors on climate change, might well give more leeway to those aiming to slow climate action. National elections next year in key players France and Germany could give an indication of future developments.

“Obviously there will be some rowback and cycling down, but ultimately there are other factors now coming into play that are extremely important in determining how the politics plays out, and that is totally different from where we were even five years ago,” Beloe said.

The fact that major financial institutions and businesses are now keenly involved is bringing a whole new aspect to the issue. The Bank of England’s governor, Mark Carney, who is heading up the G20’s Financial Stability Board looking at the potential risk of climate change to the world’s financial system, warned recently whole swathes of national economies could become uninsurable without government support due to climate change.

“The more we invest with foresight, the less we will regret in hindsight,” he told a meeting in Berlin in September. “Financial stability risks will be minimized if the transition begins early and follows a predictable path, thereby helping the market anticipate the transition to a two-degree world.”

A special taskforce set up by Carney’s FSB late last year under former New York mayor Mike Bloomberg is developing stress tests to set out clear, albeit initially voluntary, rules companies should follow to declare their own and their supply chains’ carbon footprints – an area the Carbon Disclosure Project pressure group says is woefully under-reported. Bloomberg’s Task Force on Climate-Related Financial Disclosures published its initial report earlier this year and is due to make its final recommendations in the first quarter next year.

“It is developing recommendations for voluntary, consistent, comparable, reliable and clear disclosures around climate-related financial risks for companies to provide information to lenders, insurers, investors and other stakeholders,” Carney said in Berlin. “Disclosure is currently incomplete and fragmented with, for example, only around a third of the top 1,000 US companies producing broadly comparable information on the financial risks posed by climate change.”

As the response to the Task Force’s appeal for evidence illustrates, engagement across the sectors is very lop-sided. The financial sector was the most engaged with 59% of the inputs while the energy sector – on the front line as far as carbon exposure is concerned – had among the lowest input at just 3.9%.

The pressure is rising, though – not just for exposure disclosure but also risk planning – as major investor groups turn up the heat. A consortium of investor groups from Europe, North America and Australia and New Zealand – the Institutional Investors Group on Climate Change, the Ceres Investors
Low-Carbon Economy

Network on Climate Risk and the Investor Group on Climate Change whose 304 members have between them $30 trillion under management – told Bloomberg’s Task Force climate risk exposure and planning needs a backbone.

"The fact that major financial institutions and businesses are now keenly involved is bringing a whole new aspect to the issue,” they said.

Exposure

For Bob Ward of the London-based Grantham Centre on Climate Change, the question is both deeper and wider. “It is much broader than stranded assets. It is about understanding to what extent you are exposed to any kind of carbon risk," he said. “If you are a company you have to be explicit about the assumptions you are making about the future – on climate particularly.”

“If you are betting against international policy, you should be making that explicit so everybody knows – and you yourself know – that is what you are doing. Otherwise it is not always clear that companies are recognizing exactly what they are doing. If it is not explicitly written then it is not always clear the company is operating on the assumption international climate policy fails. If that is your strategy, then everybody investing in you should be aware of it so they can make a decision about whether it is a smart thing to do,” said Ward.

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“There is also the broader risk to the market itself. If you suddenly get a sector that is particularly exposed, it can pose a systemic risk,” he added.

Some $2 trillion of assets are at risk of becoming stranded in a low-carbon world, according to analysis by the Carbon Tracker Initiative, a think-tank. But it also argues that if the big oil companies align their production with the two-degree climate target they could even add up to $140 billion to their value.

There are growing signs that the leadership at the big oil and gas companies are coming round to this viewpoint. Even ExxonMobil, the nemesis of environmentalists and currently facing multiple legal actions over its alleged “climate deceit,” has come out to support “serious action” on climate change. And ten of the world’s largest oil companies - Shell, CNPC, Total, Pemex, BP, Statoil, Eni, Repsol, Reliance Industries and Saudi Aramco - chose November 4, the day Paris entered into force, to announce the creation of a $1 billion fund to promote development of renewable energy sources.

Critics said the focus of the fund on improvements in efficiency and emissions reductions from the internal combustion engine as well as the largely untried technology of carbon capture and storage hardly indicated a major switch of direction. But change is bound to be gradual. While the writing would appear to be on the wall for the fossil fuel industry, the transition to low-carbon will still take decades.

“This is a 30-year transition. We have got to get to net zero emissions by 2050, but that is still a very steep trajectory so oil is still very big business in that period," said Anthony Hobley, CEO of the Carbon Tracker Initiative. “But the oil majors have to change radically. There can be no more pouring trillions into exploring, finding and developing yet more reserves and resources, although the current reserves that are being used are probably fine.”

“The danger is that these companies completely ignore that and... continue to say ‘we can keep on growing’. They can’t. They have lost their monopoly. Many of the emerging technologies are at, or in only a few years will be, at cost parity if not cheaper," he added.

Investors have also fired a warning shot across the bows of the car industry, which is responsible for around one-third of greenhouse gas emissions and a key end-user for oil companies.

“Escalating risks arising from climate change mean the automotive industry is likely to undergo a significant transformation in the short to medium term,” a group including Ceres and the IIGCC said in a new report called Investor Expectations of Automotive Companies. “To remain competitive and successful in the long run, automotive companies must develop more resilient business models that adapt to the
challenges imposed by climate change and stricter environmental regulations.”

The report particularly highlights the crucial role to be played by electrification of the global vehicle fleet which, after a slow start, is starting to pick up steam albeit from a very low level, with just 1.5 million vehicles worldwide. According to the IEA, this figure needs to surge to 100 million by 2030 to meet the Paris goals, although that is generally accepted to be a very tall order.

Nevertheless, battery costs are falling and endurance rising sharply, and there are moves to boost charging infrastructure, the lack of which has been a significant hindrance to greater uptake, with China leading the way in the recent sharp growth. And in early November, in a move explicitly designed to “help reduce our dependence on oil,” the White House announced plans to massively accelerate the development of US charging infrastructure, including the designation of 48 national electric vehicle charging corridors on US highways, as well as two studies to evaluate how best to set up EV charging throughout the country.

“We have been living through a technological revolution, and it looks like we will be going through another one in the next 10–20 years with electric vehicles,” said Jill Duggan, director of the UK’s Prince of Wales Corporate Leaders Group. “This is relentlessly driving in one direction, not just because of the climate but simply because it makes sense. While one of the key motivations for the electrification of vehicles will be air quality, the impact will also be felt in reduced emissions.”

There are also moves to use old electric vehicle batteries to help meet a crucial failing of the intermittent wind and solar energy sector, with banks of used batteries to act in a similar manner to pumped storage – storing power at peak generation and releasing it again when output eases thereby smoothing the peaks and troughs. This could help the wind energy industry achieve its stated hope of being able to supply 20% of global electricity as early as 2030.

“The transition has developed a momentum of its own and is unstoppable. As surely as we transitioned from horse and buggy to steam locomotives and then to automobiles, as surely as we transitioned from Kodak film to digital, we will transition to clean energy and low-carbon technology,” said CTI’s Hobley. “But the critical question is, will it be fast enough?”

What was agreed in Paris

Under the Paris Agreement, signed by 195 countries, nations put forward Nationally Determined Contributions – voluntary pledges to curb greenhouse gas emissions according to their respective capabilities, in a coordinated global effort to limit global warming to well below 2 degrees Celsius from pre-industrial levels by 2100.

The Paris Agreement included pledges from the big industrialized countries and economic blocs, fast-growing emerging economies and small developing countries alike. Under the deal, the EU agreed a target to reduce GHG emissions by at least 40% by 2030 from 1990 levels, and the EU is already overachieving on its 20% emissions target by 2020.

The US target is to cut emissions by 26–28% below its 2005 level by 2025 and to make “best efforts to reduce its emissions by 28%” by that date. China is targeting a peak in its CO2 emissions by around 2030 but agreed to make “best efforts” to achieve the peak ahead of that date. China also aims to cut CO2 emissions intensity (emissions per unit of GDP) by 60–65% from the 2005 level by 2030 and increase the share of non-fossil fuels in primary energy consumption to about 20% by the same date.

Article 6 of the Paris Agreement set out the conditions for the use of market-based mechanisms so countries that want to can trade emissions units to help meet their national targets at the lowest possible cost.

Critically, developed countries reaffirmed a previous pledge to set up a fund of at least $100 billion a year from 2020 until 2025 to help developing countries reduce their emissions and adapt to climate change. This money is seen as a crucial catalyst to unleash many times more investment.
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Striving for energy harmony at the center of the world

Pratyek achchaa karya pahalay asambhav najar aataa hai
Indian saying, translated as “In the beginning, every good work looks impossible...”

Indian legend has it that Brahmavart Ghat on the banks of River Ganges in Uttar Pradesh is the exact center point of the Earth – a most holy of places where Lord Brahma, the creator god in Hindu mythology, used to live. It is also said that a temple some 1,400 miles away at Chidambaram in Tamil Nadu is the center of Earth, being one of the principal abodes of Lord Shiva, the destroyer – the second of the three gods that make up the Trimurti. (Lord Vishnu, the preserver, is the third).

Whether you believe either is true, clearly they couldn’t both be. But the existence of two global center points is a classic contradiction in a country that has often, typically with affection, been referred to as a land of contradictions quite unlike any other. Perhaps nowhere is the description more true than in the country’s energy sector, which is developing at breakneck speed as a huge, multi-faceted and unprecedented experiment.

It is clear that India – with its low per capita energy consumption and huge potential for economic growth – will be a crucial focal point for global energy over the coming years and decades. The International Energy Agency estimates that India – which is expected to overtake China to become the most populous country in the world by 2022 – will account for around a quarter of the rise in global energy use over the period to 2040. Oil, natural gas and coal exporters all view India as a key growth market, while nuclear, solar and wind developers are also queuing up to get in on the action. But just how India’s role plays out is still very much up for grabs, and will have repercussions across all energy-related markets.

For a start, on the one hand the south Asian giant is attempting to achieve probably the most ambitious renewable energy construction program in the world, as it strives to address rising concerns about pollution levels and

Alisdair Bowles
Senior Editor, Central Editing Desk
S&P Global Platts
meet greenhouse gas emissions commitments. But on the other it is pushing to nearly double its thermal coal production in the next four years, as it struggles to meet rampant electricity demand expansion while controlling – even eliminating within a matter of years – its reliance on coal imports.

The two aims, both extremely ambitious, are key planks of India’s energy policy as laid out in its INDC, or Intended Nationally Determined Contributions, submitted to the UN Framework Convention on Climate Change COP21 meeting in Paris in December 2015. This year, on the highly symbolic date of October 2 – the birthday of the country’s spiritual father Mahatma Gandhi – the INDC became an NDC, losing the “intended” as India ratified the Paris treaty.

The ratification came almost exactly a month after the much heralded formal joining of the treaty by the US and China, a pivotal moment because they are the world’s two largest economies and emitters. Arguably, however, India’s ratification was the more important of the two milestones on the road to the treaty’s unprecedentedly rapid adoption. As Charles K Ebinger of the Brookings Institution put it in a June 2016 policy briefing: “India’s success or failure in meeting its future energy needs is not only of concern to India but to the entire world, since if India fails, Paris fails.”

India’s INDC is unlike any other in various ways, not least the staggering $2.5 trillion estimated cost of implementing it, but one of the most striking stylistic differences is how it embraces the country’s spiritual heritage. It is presented as a statement of philosophical intent, opening with a quote in ancient Sanskrit from the Vajurveda (translated as “Unto Heaven be Peace, Unto the Sky and the Earth be Peace, Peace be unto the Water, Unto the Herbs and Trees be Peace”, if you were wondering), then moves on to mention yoga before variously citing Gandhi. One famous quote from the great man that it doesn’t reference though, which seems in some way especially relevant to India’s energy sector, runs so: “Happiness is when what you think, what you say, and what you do are in harmony.”

The question is, can India – which saw the largest increase in energy-related CO₂ emissions in the world in 2015 –
– plot a harmonious path, matching its actions and intentions while achieving the rapid economic development it sees as its inalienable right? The challenge is immense: according to the IEA, India needs to quadruple the size of its power system, already the world’s third largest, by 2040 to keep pace with an almost 5% a year increase in electricity demand growth.

Highlighting the scale of the transformation required, and the not necessarily complementary issues that have to be balanced, the World Energy Council’s “energy trilemma index” ranks India a lowly 91st in the world with a B for energy security, but just a C for energy equity (representing accessibility and affordability) and also C for energy sustainability.

Serious business

There is little doubt the government of Prime Minister Narendra Modi, which took office in May 2014 with a strong mandate for reform of the country, is serious about coming to terms with the issues. The urgency of the task to transform India’s energy system derives not only from the fact that India is highly vulnerable to the impacts of climate change and suffers terribly from pollution, but also the need to lift vast swathes of the population out of poverty and attract more foreign investment to drive economic growth.

“Nobody,” India’s minister for power, coal, and renewable energy Piyush Goyal said recently, “is going to come to India with the kind of outages we have.”

Underscoring the pollution aspect, although New Delhi may have recently lost the unwanted crown of most polluted city in the world in the World Health Organization rankings, 10 Indian cities were in the top 20. And the capital may well reclaim that spot soon: in November, the government was forced to declare a pollution emergency in the city, temporarily shutting down construction for five days, halting a power plant for 10 days, and closing the city’s 1,800 schools for three days.

The key aim of India’s NDC, however, is not actually to reduce emissions, which are seen rising rapidly, but to curb emissions intensity by around a third compared with 2005 levels by 2035. The headline target is an increase in renewables capacity from 35 GW as of March 2015 to 175 GW by 2022, including 135 GW of utility-scale renewables.

Of the 175 GW target 100 GW is intended to be solar, including 40 GW of rooftop installations, and momentum in the Indian solar sector has certainly gathered: out of Rupees 304 billion ($4.5 billion) invested in the sector in the last three years, 60% came in 2015, including the addition of 3 GW of new capacity, according to the energy ministry. Obviously this still leaves a long way to go, although in June this year Minister Goyal was exceedingly upbeat, saying: “There was a time when a 5,000 MW solar energy target looked large. Now, a 100,000 MW [100 GW] target looks small.”

A survey of solar power developers conducted earlier this year by analysts Bridge to India was less optimistic, putting the likely figure at 57 GW by 2022. Grid connectivity issues, the lack of feed-in tariffs, and a poor operating environment for business are the key challenges, alongside a lack of policy certainty and poor offtake from the financially stressed state-level utilities. These issues could lead to a slowdown in the solar sector, particularly after 2017, and there have been definite signs this year of that happening with various projects held up or abandoned over distribution companies’ reluctance to sign offtake agreements.

Wind swings back

Following a big push on solar over the last couple of years, the government is now turning back to attempts to stimulate wind power, as well as hydro, Goyal said earlier this year. Wind power accounts for 27 GW of India’s installed capacity, the world’s fourth largest, and the government’s NDC set a target of 60 GW of installed capacity by 2022.

Plans are afoot to raise this target to 100 GW, matching solar gigawatt for gigawatt, after the National Institute of Wind Energy in Chennai last year revised its estimate of wind power potential in the country from just over 102 GW to 302 GW, based on technological improvements that mean it is now possible to install wind mills of up to 100 meters in height, rather than a maximum of 80 meters previously.

It won’t be plain sailing, however. With the 2016/17 state budget reducing the accelerated depreciation tax benefit for wind power projects to a maximum of 40% from 80% previously, the wind sector could also see a major slowdown, observers fear. Around 70% of the installed wind power capacity in the country was built on accelerated depreciation, which allows greater deductions in the earlier years of an asset so as to minimize taxable income.

Although instrumental in encouraging capacity growth the policy has some serious flaws, notably that it rewarded capacity rather than generation, the
green bonds. the issuance of the country’s first
released November, which also noted
acquisitions, “BNEF said in a report
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capacity by 2022. “The sector is
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through greenfield investments or
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released November, which also noted
the issuance of the country’s first
green bonds.

Indelible black spot
Whatever happens coal is certain to
remain an important, probably the
most important, component in India’s
ergy mix for decades. The country has
added about 100 GW of capacity in the
past four years taking its total to
around 300 GW from various sources,
with coal-fired generation accounting
for nearly 60% of that increment. And a
huge number of coal-fired plants are
under construction and in the planning
phase—enough to more than double
India’s current coal-fired power
capacity of 186 GW, according to
the Central Electricity Authority’s
June 2016 report. Some 70 GW of
coal-fired capacity is already in
the construction phase.

Squaring this with controlling air
pollution and GHG emissions is pinned
on retrofitting existing stations with
clean coal technology such as coal
washing, wet scrubbers, or flue gas
desulfurization systems, electrostatic
precipitators, low nitrogen oxide
burners and integrated gasification
combined cycle systems, as well as the buildout of new supercritical and
ultra supercritical coal-fired
plants, which require less fuel and
create less emissions.

There remains however a certain
vagueness to these aspirations. “We are
working with academics and research
labs, to look at better and more efficient
ways of using coal,” Goyal told the
Indian business daily Mint’s Annual
Energy Conclave in October. “In the
future, we will not permit anything less
than supercritical plants so that the
pollution levels are kept at the barest
minimum. I have stopped all repair and
modernization of older plants. I would
hope we can phase out over 25-30 and
35-year-old plants so that more new
and efficient plants come into play,”
he added.

India, whose coal fleet came bottom in
a survey of global fleet efficiency
covering the years 2009–2011 with a
rating of 26%, is also at the forefront of
pioneering advanced ultra supercritical (AUSC) technology for coal-fired power
plants although expectations for
proving the commercial viability of the
technology are sometime around 2020
at the earliest, too far away to start
pinning any hopes on.

Currently only a fraction of India’s
colal-fired fleet is supercritical and
many of the efficiency gains are being
nullified by low utilization, or peak load
factor. Operating at reduced load
reduces thermal efficiency, leading to
higher operating costs and higher
emissions than projected. This is also a
factor limiting any efficiency gains at
older plants.

Low peak load factors can be caused by
inadequate grid connections, poor siting
of a new plant, lack of coal and so on,
but in older units it tends to be due to a
vicious circle of low revenues leading
to lack of maintenance, according to a
November 2015 report by the IEA’s
Clean Coal Center. “Inadequate revenue
and so lack of sufficient funds for
maintenance remains a problem in India
and it will continue to limit advances in
efficiency until it is corrected,” the
report’s author Colin Henderson said.

One interesting new solution got the
go-ahead recently when state-owned
utility NTPC awarded a contract for
Asia’s first integrated solar thermal
power plant at Dadri in Uttar Pradesh. A
concentrated solar (CSP) field will feed
14 GWh/year of solar thermal energy
into the water-steam cycle of a 210 MW
unit at the Dadri coal-fired power
station, heating the feed water to the
steam generator so reducing coal
consumption and thereby emissions.
The technology is fairly fast to
implement—the Dadri project is
expected to take less than a year to
complete—and in future could
incorporate the capability to store
high-temperature energy for solar
power generation during night time.
However, the total market potential for
such projects in India is estimated by
the developers at just 1.7 GW.

The biggest challenge
No matter how much capacity, and of
what flavor, is built, distributing power
remains perhaps the biggest challenge.
Exporters queue up to slake India’s insatiable thirst for oil and gas

Indian oil demand growth is seen as “insatiable,” in the words of the IEA, and is expected to account for nearly half of global oil demand growth through 2040. Given its huge population and its exceptionally low vehicle penetration (149 motor vehicles per 1,000 people, compared to 781 in the US), and its need to import the vast majority of the oil it consumes, it is set to be a key area for demand growth.

Refining capacity, already the world’s fourth biggest and including the world’s largest refining complex at Jamangar, is set to continue expanding, reaching 313.6 million mt/year (6.26 million b/d) by the end of the 2016-17 fiscal year, according to government data. From a net importer at the start of the century, India has become a major exporter of refined products despite having to import nearly 80% of its crude.

The recent deal by Russian oil giant Rosneft to buy Essar’s 405,000 b/d Vadinar refinery underscores its international importance as a key refining center, but was also perhaps a signal that local companies are less optimistic about the sector’s future.

The pronouncement earlier this year by Power Minister Goyal that India intends to switch its entire vehicle fleet to electric by 2030 may have been viewed with skepticism in many quarters, and no firm announcements have been made on how this might be achieved – it is to be funded by fuel savings – but it indicates the direction of travel could be set to change, and soon.

Gas presents an attractive alternative to various coal and oil uses for India – conversely presenting a big opportunity for gas exporters – and persistently low global prices for the hydrocarbon seem to have reignited India’s interest in securing imports, both as LNG and by pipeline from Russia. India and Russia recently agreed to explore building a pipeline, at an estimated cost of up to $25 billion, to connect the Russian gas grid to India through a 4,500-6,000 km pipeline, potentially passing through the Himalayas into northern India – although this not surprisingly poses serious technical challenges.

Alternately, the pipeline could pass through Central Asia, Iran and Pakistan into western India, or through China and Myanmar into northeastern India, bypassing Bangladesh. The cost of transporting gas may be $12/MMBtu, according to EIL. The cost via the long discussed IPI or Peace pipeline from Iran via Pakistan was put at less than $1/MMBtu, while through the Turkmenistan-Afghanistan-Pakistan-India pipeline it was around $2/MMBtu. Neither of these projects has advanced though.

India’s current regasification capacity of 25 million mt/year is currently massively underutilized, with not much more than 50% capacity utilization in the latest year. There are various reasons for this, including lack of pipeline connectivity between terminals and demand centers, as in the case of the Kochi LNG terminal. However, to meet an anticipated surge in future demand, planned LNG infrastructure – including both brownfield and greenfield projects – is expected to exceed 65 million mt/year by 2030.
Of India’s nearly 60 state-run utilities two-thirds reported at the end of fiscal 2013/14 that their average revenue per kWh was below the cost of supply. These losses have starved the utilities of capital for investment in their distribution networks and the collapse of old transmission lines and transformers is not uncommon.

The government in late 2015 put in place a new scheme called Ujwal Discom Assurance Yojana (Uday), which seeks to enable the state power distribution companies to become profitable within two to three years through improvements in operational efficiency, reductions in the cost of power, enforcing financial discipline and tackling all outstanding debt by shifting three-quarters of it over to the respective state governments, which can issue bonds.

According to Bridge to India, the initiative is “bearing surprisingly quick and positive results,” with early indications showing the state power distribution companies have reduced commercial losses and interest costs. However, a fundamental weakness of the Uday scheme remains the lack of penalties for non-compliance once states have joined, leaving the success of the scheme dependent on the political will of state governments.

Meanwhile, a 1,200 kV ultra-high-voltage power transformer – the highest alternating current voltage level in the world – was recently energized at the national test station at Bina, Madhya Pradesh, representing a key step forward in India’s plans to build a 1,200 kV transmission system to supplement the existing 400 kV and 800 kV transmission grid.

A 1,200 kV transmission system will help strengthen the grid, enhance load capacity and minimize losses, which are a big problem in the country.

The path ahead

Where does all this leave India? The situation is developing so rapidly and on so many fronts it can be hard to get a firm handle on the current picture. Not even mentioned so far is a big planned buildup of nuclear, with India signing agreements in November that will give it access to Japanese nuclear expertise. On top of this Russia is building more plants in India and nuclear is envisaged accounting for as much as 25% of the power mix by 2040, although things have been far from plain sailing on this front for India to date for the usual reasons – lack of public acceptance and problems with delivery.

Meanwhile hydro power, already a significant contributor with 42 GW accounting for about 15% of the power mix, is also set for a big push focused on overcoming regulatory impediments and catalyzing finance. The country’s potential for hydro is estimated at 145 GW.

In addition, in April the Central Electricity Authority cut its assessment of the future requirement for generation capacity in 2022 by 20% to 238 GW, down from an estimate of 298 GW made five years previously, despite assuming a high economic growth rate of 8% a year. The reason for the downward revision is the rapidly spreading efficient lighting program and other energy efficiency measures. The replacement of 100 million incandescent bulbs by LED bulbs has already reduced peak load demand by 2.6 GW. This saving is expected to rise by 20 GW by 2019 as the number of LEDs reaches 770 million. A major energy efficiency drive is also being implemented in the agricultural sector, which accounts for over a fifth of annual electricity consumption.

There are genuine reasons to be optimistic, even if forecasts by Bloomberg New Energy Finance estimate that, after adding a projected 470 GW of renewables capacity at a cost of $611 billion over the period to 2040, India’s coal- and gas-fired power generation emissions will still more than triple. That BNEF report was however sent out with a press release headlined “India making strides on clean energy”, and there was a good deal of optimism at the recent COP22 UN climate meeting in Marrakesh in November, highlighting already significant progress and anticipating further acceleration.

“We expected that the emissions from [India’s] coal-fired power would increase but we don’t see that. We instead see that there’s a huge renewable energy installations [push] and this is growing rapidly. This is very positive and was surprising for us,” Professor Niklas Höhne of the New Climate Institute said at one session.

“With those targets [175 GW of clean energy], India is already on target to over-achieve its emissions intensity target. The likely continued expansion of renewable energy after 2022, for which no targets have been set, would result in India also overshooting its 2030 non-fossil capacity target,” he added.

But, as with most things it seems, the shock success of Donald Trump in the US presidential election has heightened
India

India, which has the highest cost of capital in the Asia-Pacific region, had always made its support of the Paris Agreement to a large extent contingent on access to technology and assistance funds pledged by developed countries, and the country’s environment minister Anil Madhav Dave headed to Marrakesh with a strong brief to lock down commitments to the Green Climate Fund. This is seen as critical to ensuring that “climate justice” – a concept strongly put forward by Prime Minister Modi – is ingrained in the new rules.

In the immediate wake of Trump’s triumph, expectations were running high that “all the promises made by the Obama administration on finance and technology to the developing countries will go down the drain,” according to Chandra Bhushan, climate change expert and deputy director general of the Delhi-based think-tank Centre for Science and Environment. If that is the case, the task of transforming India’s energy landscape will be considerably harder – but still not impossible.
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Coping strategies

Big Oil’s struggles to adapt to new market realities look set to intensify

As the oil price slump enters its third year many hope the worst is over for oil and gas producers, with the biggest companies emerging leaner and more focused following a traumatic transition to a world of cheaper crude. But that process of metamorphosis, rather than coming to an end, may have to accelerate as new clouds gather over the industry that potentially pose an existential threat.

Oil prices themselves are seen staying below $70/b for the foreseeable future, capped by ample reserves of easily accessible US shale oil, shaky global demand growth, and falling costs. The “lower-for-longer” mantra for global oil prices has morphed into a “lower forever” outlook, a term first used by Shell in reference to falling operating costs.

In the short term, any recovery will be slow and most producers are clinging to self-help through capital discipline and further efficiency gain to hold cash flows above water and sustain shareholder dividends.

The toll on industry investment levels so far has already raised alarm bells over future growth. Capital spending by the global oil and gas industry has shrunk by more than 40% or $280 billion since 2014 in response to low oil prices and field decline rates have accelerated as a result, according to Bank of America Merrill Lynch.

And as low prices linger, a rising tide of debt is building among the oil majors as they struggle to meet capex and dividend commitments with anemic positive cash flows. Record industry debts are near ceiling level and with gearing rising quickly, shareholder payouts are under threat.

The big-ticket spending cuts have triggered real concerns that the upstream spending collapse will see volumes growth, already close to flatlining at many majors, take a turn for the worse in coming years. New oil discoveries are at a 70-year low with just 2.7 billion barrels of new reserves discovered last year, the smallest volume since 1947, according to Edinburgh-based consultants Wood Mackenzie. Norway’s Rystad Energy has warned of a new shortage of crude “a few years down the road” and French major Total sees a possible 10 million b/d global oil supply deficit by 2020.

Most companies already have limited
growth prospects, and production sharing contracts – where oil prices affect the company’s share of production – act as a further headwind in a rising price environment. Production growth through 2018 will be, in large part, driven by the major capital projects sanctioned pre-2015.

**Downstream, price threats**

In the downstream segment, oil majors’ refining businesses have been struggling with fragile margins for years due to overcapacity and tougher climate regulations, and the pain is set to continue. NGLs (natural gas liquids), biofuels, coal-to-liquids and gas-to-liquids products are feeding an increasingly larger share of the world’s liquids fuels demand. With ever greater volumes of liquids fuel demand produced outside the traditional refining system, refiners will see their market share fall, a factor likely to keep a lid on future margins.

Indeed, the International Energy Agency believes the world’s current installed refining capacity of some 97 million b/d is already sufficient to cover the global demand for refined products well into the future, likely beyond the period of peak oil demand. In the medium term alone, the agency expects the refining industry to add nearly 8 million b/d of new capacity to 2021, taking global excess refining capacity to over 5 million b/d.

The current optimism over a turnaround in oil prices also means oil prices have few signs of support in coming years. On top of that, uncertainty over the strength of the global economy, stoked by worries of the impact of the UK’s Brexit process, is also weighing on expectation for future crude demand.

**Peak oil demand**

According to a report by the World Energy Council, global oil demand will peak in 2030 and decline thereafter if rapid improvements continue in electric vehicles, renewable energy, and other disruptive technologies.

The IEA is less pessimistic. Its central demand scenario currently sees oil use expanding to 2040. Oil companies themselves are resolute that oil demand will continue to grow in the coming decades, underpinning the rationale for current spending on new upstream projects.

Despite the rapid growth of renewable energy sources, BP predicts that fossil fuels will remain the dominant form of energy to 2035, meeting 60% of the projected increase in demand and accounting for almost 80% of the world’s total energy supplies in 2035. To meet growing energy needs in the years ahead, the world will need to pursue all energy sources to meet future demand, it says.

The industry also remains upbeat that new technology can overcome most hurdles when it comes to climate change, either through economically competitive fuels or carbon capture. “Never bet against the creativity and tenacity... of our industry,” ExxonMobil’s Rex Tillerson said recently. Many would agree. But time may be running out for oil producers to reinvent themselves in the upheaval from the age of fossil fuels to renewable energy.

For its part, Shell largely concurs with warnings over peak oil demand, claiming the threat underpins its own strategic thinking on a focus on gas and new biofuels. In surprisingly candid comments for an oil major made during an earnings call in early November, Shell’s CFO Simon Henry even signaled peak oil demand could come as soon as 2021.
The industry has retreated to short-cycle assets with quick payback times as it focuses on maximizing cash flow.
“We’ve long been of the opinion that [oil] demand will peak before supply and that peak may be somewhere between 5-15 years hence,” Henry said. “It will be driven by efficiency and substitution more than offsetting the new demand for transport.”

Warnings that the writing is on the wall for oil majors’ traditional business models are not new. In April, Paul Stephens, a fellow at the Chatham House think-tank, claimed in a research paper that the oil majors were facing a life-threatening crisis within a decade – hit by low oil prices, ever tougher climate laws and their own ill-designed strategies.

Stephens, for one, believes that oil companies have spent too much time trying to maximize shareholder value by targeting and booking new reserves while outsourcing valuable upstream expertise to service companies.

Chasing new oil and gas reserves has become a costly pursuit. Last year the world’s top six oil majors saw their proved reserves shrink by more than 2.8 billion barrels of oil equivalent as the price slump and growing difficulty in accessing new resources takes a rising toll on sources of future growth. ExxonMobil, Chevron, ConocoPhillips, BP, Shell, and Total all saw their combined proved oil and gas reserves slip to an eight-year low after the biggest year-on-year drop, according to company filings. ExxonMobil, which has made much of its multi-year track record of more than replacing its production with new reserves, was forced to post a 67% reserves replacement ratio (RRR) for 2015 after shedding 510 million boe of proved reserves. It is now considering further reserve downgrades due to low prices.
While much of the current pain on recoverable reserves is the result of their lower value, many industry watchers believe the trend also reflects a deeper underlying problem of reduced access to new, resources-rich exploration plays. Indeed, drilling opportunities for large new oil and gas finds have thinned with the rise of cash-rich national oil companies increasingly able to hire the oil field technology needed to tap their own ample reserves.

Shift to renewables

Perhaps the biggest threats to the oil industry are climate change and technological innovation, key elements of the battle ground over the world’s future energy supply and delivery systems. A record $367 billion was invested in renewable energy globally in 2015, according to Clean Energy Canada, a figure which outpaced fossil fuel investments for the first time.

Big Oil has actually pumped millions of dollars into renewable and cleaner energies including solar, biofuels and wind power, although many projects have not paid off and have been dialed back considerably. But there are signs that oil companies are paying heed to expectations of a faster-than-expected rise in renewable energies.

In May, France’s Total agreed to buy French battery maker Saft Groupe in a $1.1 billion deal, expanding its renewables portfolio, which began in earnest with its 2011 purchase of a majority stake in US solar-panel maker SunPower. Crucially, the Saft deal goes beyond backing an emerging clean energy production technology or fuel as previously favored by oil majors. Total’s move marks the jump to an energy delivery system for the first time, widely seen as recognition of the disruptive potential of electric vehicles on its core business.

Battery costs have been cut by a factor of four since 2008 and are set to fall further as their energy density increases. Indeed, Total said it wants to become a leader in renewables and electricity storage within 20 years by targeting the “entire electricity value chain.”
chain," in addition to its traditional oil and gas business.

In the US, BP is also considering its first significant new investment in renewable energy for five years, as it looks to expand its wind power business by the end of this year.

So why should oil companies invest in green tech at a time when weak oil prices has seen spending on upstream projects collapse? One possible answer is simply the risk of being left behind as capital markets divert investment dollars to back future clean energy winners, according to Fitch. Oil companies foot-dragging in the push to cleaner energy will likely suffer reduced access to equity and debt capital for green projects when they most need it, according to the ratings agency.

“If nothing else, this diversification will help guard against the risk that the markets turn against them," Fitch said in a recent report. "The narrative of oil's decline is well rehearsed – and if it starts to play out there is a risk that capital will act long before any transition occurs.”

Consensus over the scale of the threat from electric vehicles (EVs) on oil companies' future balance sheets is lacking. Bloomberg New Energy Finance (BNEF) believes EVs could represent a quarter of the cars on the road by 2040 when they will displace 13 million b/d, or about 12%, of global oil demand.

Others are more conservative and note that adoption rates are dependent on oil prices. If prices stay around current levels the incentive to switch will be much reduced. The IEA predicts oil demand won't peak in the medium term due to booming EV sales as the driver of future oil demand growth is from trucks and planes, where EV penetration will be much lower than for cars. Even if every second car sold next year were electric, global oil demand would continue grow, the IEA general director Fatih Birol said recently. ExxonMobil sees EVs making up less than 10% of new cars sales in 2040, an estimate which would amount to a paltry 830,000 b/d of displaced oil demand, according to Platts estimates.

Even if forecasters can't agree on the mass adoption of EVs, most accept that the push to renewables could well surprise to the upside. Some European countries may introduce a floor on the price of carbon, accelerating the switch to gas and renewables. Many also predict that low oil and gas prices are also unlikely to significantly dent investment in renewable energy in the long term as the industry continues to be supported by government subsidies.

**The pivot to gas**

Even hopes for the rise of the oil industry's second hydrocarbon fiddle – natural gas – are in doubt. Referred to as playing the role of a “bridge” from fossil fuels to renewables, gas has been touted as set for a golden age, able to provide a lower carbon supply alternative to oil. Led by Shell, oil companies have been shifting their output in favor of natural gas. Total believes that natural gas, a cleaner substitute for coal in power plants, will likely move up from third to second place in the global energy mix by 2035.

But sharply falling costs of wind and solar power mean gas demand for power generation is in terminal decline within a decade after peaking in 2025, according to BNEF. If true, the prediction presents a further big headache for major oil companies, many of which have grown the share of gas in their production mix to close to 50% in recent years. Shell, arguably the industry's prime mover and leading proponent for natural gas, is working hard to create a market for gas-fueled transport and shipping to sustain its gas credentials beyond just a bridge fuel.

In terms of investment returns though, gas may still be a riskier bet than oil, at least in the short term. Huge recent gas finds mean the current oversupply in natural gas won't disappear until after end of the decade, the IEA believes, meaning gas prices will remain under pressure. Until traded LNG volumes pick up, natural gas will also remain regionally priced for the time being, with some contracts continuing to track oil.

Shell's Henry at least remains sanguine that the end of the hydrocarbon age will not pen the final chapter for oil companies and their investors. “We still have a view that there will still be a substantive business for us for many decades for us to come," Henry said. “New forms of energy use for transport such as gas or electricity, or biofuels or hydrogen will form part of the future energy system after the transition and therefore, even if oil demand declines, its replacement will be in products that we are very well placed to supply, one way or the other.”

With the momentum towards a post-fossil fuel world building in the wake of the 2015 Paris Agreement on climate change, many will hope that Shell is not the only oil company keen to avoid ending up on the wrong side of history.
Technology: a seductive answer to industry woes

Innovation is touted as crucial to the upgrading of the industry for a low-oil price future

As low oil prices persist, some see technological innovation as a transformative force that will rescue the oil industry and restore its competitiveness, though others argue its impact is being overstated.

Oil majors such as BP and Shell have recently been boasting of great efficiency improvements in their offshore operations, particularly in the North Sea in the last couple of years, partly because of new technologies and the rise of digitization. A given piece of equipment such as a compressor on the seabed can now have a “digital twin” that helps engineers predict when intervention is really needed, rather than carrying out maintenance to a set schedule, for example.

“Digital is what is going to change the life of the industry,” Michele Stangarone, European president at GE Oil and Gas, which provides round-the-clock monitoring of 750 pieces of oil and gas machinery worldwide from centers in Florence, Houston and Kuala Lumpur, told S&P Global Platts recently. “Today the efficiency, the productivity that we can reach was unimaginable two years, three years ago,” he said.

To the extent that technology is a differentiator, countries that lack access to technological know-how, perhaps due to sanctions in the case of Russia, or wariness on the part of investors in the case of Iran, risk falling behind. However Andrew Gould, former chief executive of service giant Schlumberger, says that Western technological dominance is no longer a given. Unlike in previous cycles the last oil price boom led to more spending on education, research and development in the Middle East, Gould told a recent conference in London.

Ironically, Gould is skeptical of the transformative power of technology. While acknowledging the impact of small technology companies, he noted that decades can elapse between the first use of a technology and its mass adoption – an example being the use of extended reach drilling in locations...
such as Sakhalin, off the coast of Russia, long before it became cheap enough for the US shale industry.

“The industry is capable of creating more and more small startups, which produce innovative ideas, which may or may not succeed,” Gould said. However, “the adoption problem is a problem of proof-of-concept and testing. The more offshore it is, the more difficult that is. It’s extremely complex to ask an oil operator to test a remote technology when he doesn’t have a method to recover from a failure.”

“That has been the general experience of the industry over time and it explains the 10-20 year framework for a major technology to be developed,” Gould said.

Some readily available technology is providing easy wins for the industry, helping it to pare back staffing levels offshore for example. Drones and sensors are increasingly used to monitor difficult-to-access parts of offshore platforms, and are also a feature of remote US shale operations. In terms of digitization, BP plans to connect all its wells to the Internet, providing access to centralized real-time performance data. Over the longer term, developments such as lighter materials, needed for ultra-deepwater development, and even 3D printing, are likely to make a difference.

Subsea specialism

When it comes to more specialist technology, specific to the industry, the North Sea remains a testbed, helped by the sheer number of fields, well-developed infrastructure and nearby centers of expertise. Norway, with its strong state supervision of the industry, has paid particular attention to maximizing oil recovery rates. State-controlled Statoil now aims to recover 74% of the oil from the Gullfaks South field, far above the industry average, and 84% from the Mikkel reservoir of the Asgard field.

Statoil last year embedded 700 kilometers of seismic cables on the seabed above the Snorre and Grane fields to enable what it calls permanent reservoir modeling – the tracking of the movement of oil around a field over time, also known as 4D seismic. The company is one of a number that are working on surfactant and microbe technology to ensure maximum volumes of oil are “washed” from reservoirs, as well as an opposite approach: the use of gel to block flows through high-permeability “thief zones” from which liquids are lost.

In deploying such technology at fields like Grane in the North Sea, Statoil has half an eye on fields further afield. The Norwegian company is also part of a general effort to reduce the cost of offshore installations. In the UK a focus on small oil accumulations has accentuated efforts to design lighter structures that might be moved from field to field for re-use. Such efforts have not all been successful; a “floating buoy” system proposed for development of the 10 million barrel Fyne field off the coast of the UK has come to nothing.

However, off the coast of Norway Statoil has developed subsea installations that remove the need for a structure above the surface, partly with a view to expansion into the Arctic. At the Tyrihans field seawater is injected into the reservoir from pumps on the seabed – the company says it is achieving performance from such subsea systems close to that achieved at conventional platforms. At the Tordis field, water and sand are removed and stored in an underground reservoir without using any surface facilities.

But it remains the case that cost-cutting technology breakthroughs cannot be summoned up overnight in response to low oil prices. And there will always be winners and losers. Innovation has the potential to shake up the supply chain, as seen from GE’s recently announced tie-up with Baker Hughes, following an earlier failed attempt by Halliburton to take over Baker Hughes. GE, a relative outsider, may be leap-frogging some incumbents.

Conversely, for some oil majors new technology provides an opportunity to reduce their reliance on the supply chain, a sector that some view with distrust. “As far as maintenance is concerned, we have moved away from subcontracting everything,” Total’s head of rotating machinery, Bernard Quoix, said at a conference in 2016.

GE’s Stangarone argues that it is not simply a question of new technology fixing the industry, but how that technology is deployed. The focus should be on using technology to remove complexity, rather than adding to it, he says. As demonstrated by some other industries such as car manufacturing, “it is a question of rearranging components and taking things out of the stream and removing inefficiencies,” he said.
Where have all the commercial oil hedgers gone?

When oil price volatility began to rise in 2014, there was an interesting development: producers seemingly started using less futures and options contracts to hedge.
start to see more movement. In Set 2, the standard deviation more than doubled, to $12.31/b, around an average of $49/b. In other words, the average price/b was essentially cut in half, and relative to that lower average, prices bounced around considerably more.

Let’s take a minute to think about the economic incentives of a crude oil or natural gas producer. These producers are naturally “long” crude oil and natural gas given their role in the economy – they retrieve the hydrocarbons from below the surface and bring them to market. They have a vested interest in prices moving higher. Of course, once a well starts producing, and barring some sort of unusual event or engineering hiccup, it will produce 24 hours a day, 7 days a week, 365 days a year – regardless of what spot prices are doing. There are very few events for which an energy producer would deign to shut in a well – perhaps a Gulf Coast producer might do so with a looming hurricane bearing down on the region. As a result, the line of business in which these companies engage is to spend considerable capital on drilling and completing a well, and incur further expenses in production. These companies inherently take on considerable risk, because they are largely price-takers in global markets (more so for crude oil, but increasingly true for natural gas as well, given the advent of LNG). Given this positioning, most independent producers aim to be net short in the futures and options markets – because it hedges their natural long position.

Now let’s dig into the data. We retrieved weekly observations from the US Commodity Futures Trading Commission (CFTC), and focused on the number of short contracts on the NYMEX’s WTI crude oil calendar swap from 2012 through 2016. We started in 2012 in order to give more or less an equal footing to pre-collapse activity as post-collapse activity. It was at the end of September 2014 that Saudi Arabia went public with its decision to pursue a market share strategy by cutting its official selling prices. This was a marked divergence from past practice of focusing on a price protection strategy and, in our view, tacitly recognized the US E&P industry as a budding swing producer.

Between January 2012 and September 2014, using weekly data, commercial hedgers had a short position averaging about 108,000 contracts. In the following two-year period, though, from October 2014 through September 2016, that average dwindled to 70,000 contracts – a drop of 35%. Let’s summarize: the price of WTI crude oil in the spot market, we calculate a correlation between the two time series of 0.85, which is fairly high in our view.

Now let’s consider some possible explanations for the above graph. One possibility is that, even if the number of short contracts fell, the number of long contracts fell even more, so on a net basis, producers were more short than before? Unfortunately, no. In the post-Saudi decision era, the average net short position was about 31,000 contracts. Prior to the Saudi decision? The average net short position was actually slightly higher – about 38,000 contracts. Similarly, commercial short positions used to account for about 63% of the open interest in the WTI Crude Oil Swap market. Post-Saudi decision, however, commercial shorts dropped to just 54% of open interest, on average.

A third possibility is that much of the commercial hedging activity has simply moved off the exchange, in favor of over-the-counter trade, or OTC. The OTC market is not burdened by the requirement of standardized products for trade, and the OTC market has grown in size over the years. Looking over the

COMMERCIAL SHORT WTI SWAPS VS WTI SPOT

Source: COT report, EIA
data from the Bank for International Settlements (BIS), however, we find that the global OTC derivatives market for commodities (which includes any commodity aside from gold and other precious metals) fell sequentially by 19% in the second half of 2014, followed by another 9.5% drop in the first half of 2015, and another 25% sequential drop in the second half of 2015 (latest available). Granted, the overall OTC market in this context is more than just crude oil, but barring specific data on the size of the OTC market for crude oil, it’s difficult to argue that more crude oil hedges simply shifted over to OTC from the exchanges.

The bottom line in our view is that the commercial short WTI crowd appears to have dwindled. We can think of two possible explanations for this move – one potentially bearish, the other potentially bullish.

The possible bearish view is that the avoidance of commercial short positions is a function of behavioral economics – people tend to avoid making a modest loss a certainty when there is some chance that the loss can be avoided entirely – albeit by taking on more risk that they might incur an even greater loss. If in fact prices are not supportive of profitable production (see how few energy companies are poised to generate profits in 2016), then slashing the number of short WTI contracts is effectively banking on hope – that spot prices rise markedly and come to the rescue.

The alternative, a bullish view, is that while yes, prices have come down, so have costs, such that break-even levels are now at the point that E&Ps are actually making money anyway. In other words, why hedge against a possible recovery in crude oil if you can bide your time for now with modest profits and retain the upside potential? To evaluate that potential, we looked at two factors. First, how have break-even costs in key oil basins fared recently? Second, how have projections of free cash flow fared?

Looking at the first factor, we turn to estimates from Platts Analytics’ Bentek Energy. We looked at so-called “break-even” internal rates of return (IRRs), where a break-even return is defined as one where an E&P can earn a 10% IRR – enough to essentially cover their cost of capital, but little more than that. More specifically, we looked at break-even IRRs in the Eagle Ford Shale, Bakken Shale and DJ Basin, all of which are considered mainly liquids plays (as opposed to gas plays). For each play, we looked at IRRs at two points in time – in October 2014 (just as Saudi Arabia embarked on their market share strategy) and again in October 2016. In
all three cases, break-even IRRs currently stand in the mid-$30/b range, and all are lower today than they were two years ago – anywhere from 5% lower to 8% lower.

Looking at the second factor, we evaluated projected free cash flow for 2015, 2016 and 2017, starting nine months in advance of each of the start of the three respective calendar years, and continuing three months into the new year (where possible). For anticipated 2017 results, of course, we only have data for April 2016 through October 2016.

In our view, the data show some evidence that for both 2015 and 2016, any optimism that our upstream universe would be free cash flow positive, for the median company, was fairly short-lived relative to 2015 and 2016 estimates. For 2017, however, optimism has blossomed and stayed high, with the median estimate at or above 105%.

Based on the results from the Bentek and S&P Global Market Intelligence data, we see some validity to the bull argument as well. Commercial short positions in WTI swaps bottomed in early 2016, more than a year after the down cycle commenced, and never really recovered significantly. By early 2016, market participants are beginning to look ahead to 2017 and budget planning, while not complete by any means, is underway.

It’s also worth noting that even if the summary data suggest less hedging, this is hardly true for all participants. Many independent E&Ps have followed a more conservative strategy and hedged a large chunk of forward production anyway. For example, Oil & Gas 360 (an industry news and information provider) noted recently that both Pioneer Natural Resources as well as Cimarex Energy had hedged more than 80% of 2H 2016 production.

Overall, it remains a trying time for the E&P community. Efforts to break strongly above the $50/b mark continue, with sporadic successes. New glimmers of hope have emerged with OPEC talking as if a new agreement is imminent, but of course the devil is in the details. Longer term, we think the depth of this downcycle will prove to be extremely useful for the E&P community, as difficult as it has been, as it has forced these E&Ps to wring costs out of their system far more than previously done. When the next upcycle does occur, the E&Ps will be in a better cost position and can leverage higher prices more so than in the recent past.
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Nuclear headaches: fear, failures and market forces

Nuclear still has an important role to play, but public opinion and government support remain critical. Botching the next generation of reactor construction could be terminal for the industry.

On September 15, representatives of the nuclear industry meeting in a London hotel for an annual conference were greeted with what seemed like welcome news. The long-delayed project of France’s EDF Energy to build the 3.2 GW Hinkley Point C nuclear plant in southwest England with substantial price guarantees from the UK government was approved by the country’s prime minister the morning the conference was set to begin.

The next day, as many in the industry celebrated the news, the price of uranium — which reflects sentiment towards the global nuclear power industry, the only end-user for the material — fell to its lowest in 11 years. With sky-high inventories and sales of secondary material in the market heaping on the pressure it continued to drop like a stone in the succeeding weeks, losing around a quarter in value to dip below $19/lb; by the end of October the price was at its lowest since September 2004.

After a period of high expectations for growth in nuclear energy use in 2007 sent uranium to more than $140/lb, prices have declined precipitously, especially since the March 2011 nuclear accident at the Fukushima I plant in Japan. That disaster has not only seen the vast majority of Japan’s reactors remain closed since, but also spurred a decision to abandon nuclear energy use in Germany and slowed or sent into reverse nuclear power even in countries with a strong commitment to the energy source.

While safety concerns are at the core of the decline in some countries, it is market forces that are contributing to shrinking nuclear energy use in places like the US, where power markets in about half the country have been
There, low power prices triggered by a sharp decline in natural gas costs have resulted in the closure of three reactors since 2013, with the closures of five more units in the next three years already announced.

To be sure, nuclear energy is poised for growth in some countries, especially as China and India have ambitious plans to expand its use and build dozens of new reactors. However, in developed economies where electricity markets have been liberalized, nuclear energy is finding it difficult to compete against natural gas-fired generation and subsidized wind and solar power. Its place on the grid is being threatened by market prices that do not reflect the reliability and carbon-free nature of the power source, industry proponents say.

The International Atomic Energy Agency said in a September forecast that nuclear energy capacity globally is set to grow by 2030, but could soar to 598 GW if policies to curb climate change are put in place and incentives result in existing reactors operating for longer than currently licensed to run, IAEA said.

There are 68 power reactors under construction, the highest number since the 1970s, pointed out William Magwood, director general of the OECD’s Nuclear Energy Agency, during the World Nuclear Association’s annual meeting in September in London. However, government policies ostensibly designed to reduce carbon emissions are having a deleterious effect on nuclear energy, and in the end could increase emissions instead of reducing them, he said.

Providing above-market financial support for renewable energy has created overcapacity in many electricity markets and the excess and variability of renewable generation benefits natural gas, which is ideally suited for fast startup peaking plants. The growth of natural gas at the expense of baseload nuclear units will increase emissions in some countries, Magwood said.

In the US, where nuclear energy grew the quickest, deregulated power markets are proving the undoing of the technology that promoters once suggested could provide power “too cheap to meter.” Merchant power companies are closing or selling off generating assets in the US. The CEO of Entergy, Leo Denault, told investors in September the company no longer thinks of itself as a merchant power company, selling speculatively in unregulated markets, preferring to stress its regulated businesses.

The US nuclear industry has launched an effort to reduce its operating costs by 30% from 2012 levels by 2020 to below $30/MWh, but officials say that with prices for power some days below $10/MWh, cost-cutting alone will not prevent another 10-15 of the country’s 99 reactors from shutting.

During a meeting to discuss what the US government could do to assist nuclear energy, John Deutch, a professor at the Massachusetts Institute of Technology who is chairman of a board advising the country’s energy secretary, said the US risks losing its influence on nuclear security issues if it fails to restore leadership in the field of nuclear energy. And he assessed that the current design of deregulated power markets was largely to blame. “If you don’t see a change in the market situation, you’re going to see the existing reactors falling like flies,” he said in late September.

Deutch’s committee provided the energy secretary a plan it said could restore the financial health of existing...
reactors and spur new reactor construction, but it is not clear whether there is support for such a program. There are indications policy-makers in the US may offer lifelines to at least some nuclear plants in danger of closing. The prospect of the loss of jobs and the resulting increase in carbon emissions in New York State caused the Public Service Commission there to implement a system of “zero-emissions credits” targeted narrowly to nuclear plants in the less-developed parts of the state.

If the plan remains in place, Entergy said it would sell its FitzPatrick nuclear plant to merchant nuclear operator Exelon instead of shutting it in January. And Exelon executives said recently they were holding out hope that three reactors tagged for closure in Illinois could be spared if the legislature there passes an energy plan providing it similar support before the end of the year.

Those plans are basically “bailouts” for a technology that cannot compete and has become too expensive to support, the heads of Greenpeace USA, the Sierra Club and Friends of the Earth said in a joint statement recently. “With catastrophic climate change staring us in the face, it is clear that continued efforts to save the nuclear industry are nothing less than a financial and technical distraction,” Friends of the Earth climate and energy program director Ben Schreiber said.

Deregulated markets will be able to handle retirement of nuclear units that are not competitive, Peter Bradford, a former commissioner of the US Nuclear Regulatory Commission who is now a critic of the industry, told reporters on a conference call November 3. Markets will handle any reliability issues that come with retiring nuclear units “with the tools they have available now,” he said.

**Reasons to be cheerful**

There are reasons, however, to be bullish about both uranium and nuclear energy, advocates say. The biggest is China, where 24 of the 68 power reactors under construction at the end of 2015 are located. In the 12 months to the end of October, China connected 11 reactors to its grid, accounting for almost all the new grid connections globally during that time period. The country has reactors under construction using homegrown as well as French, US and Russian designs, a veritable Noah’s Ark of nuclear units.

India is also planning a significant expansion of nuclear energy, rising from 5.3 GW to 14.6 GW by 2024 and 63 GW by 2032, according to the World Nuclear Association. Russia’s state nuclear company Rosatom earlier this year broke ground on two more reactors at Kudankulam on the southern tip of India, where the first unit, originally mooted in 1988 was finally officially commissioned – after years of protests and delays, and with serious reservations about safety having been publicly expressed by prominent experts.

Platts data shows that the 1 GW Kudankulam-1, which began commercial operation at the end of 2014, had a capacity factor of only 40% for 2015, being shut for several months amid reports of equipment problems.

Performance improved in 2016, with a capacity factor of 78% through the end of September. Kudankulam-2, also of 1 GW capacity, connected to the grid in July.

Russia, although it has slowed domestic deployment somewhat in the face of lagging electricity demand and a sluggish economy, remains an active vendor of nuclear plants and has offered to build, own and even operate nuclear units for countries without nuclear power – an attractive offer that has been accepted by Turkey among other countries. Russian reactors are also scheduled to be built in Bangladesh, Belarus and Finland.

And South Korea continues to be one of the most consistent builders of nuclear power plants, with 24 reactors operating and four under construction. Four Korean-designed reactors are also under construction in the United Arab Emirates, the start of what South Korean government officials have said may be a competitive export program.

However, Asia’s biggest nuclear power operator, Japan, has been at a virtual standstill since the Fukushima I accident. Of its 43 operable reactors,
only two are generating power, with almost all the rest awaiting reviews to show they meet new safety standards established after the accident.

More recently, a court injunction has kept two units at Kansai Electric Power’s Takahama plant offline despite approval from regulators. “This was rather surprising,” said Yoichi Maeda, executive director of Mitsubishi Power Systems, in an interview October 17. But polling shows around 60% of the Japanese public is opposed to restarting nuclear units, a significant reversal of attitudes since 2011. “It’s a reality we have to accept,” Maeda said.

**Late for an important date**

Meanwhile, new project delays, especially in Europe and the US, continue to do further damage to the nuclear industry’s reputation. The most notable may be the Olkiluoto-3 project in Finland, which is nine years behind schedule and some three times over budget. French nuclear company Areva and Germany engineering giant Siemens, which signed a turnkey contract for a first-of-a-kind new reactor design, have been embroiled in a battle with the project owner, Finnish utility TVO, over the years of delays and cost overruns, although TVO executives have said recently the unit should be operating by 2018.

EDF Energy, the UK subsidiary of the French utility EDF, believes the two EPRs it plans to build at Hinkley Point in the UK will be different. CEO Vincent de Rivaz said in September they will incorporate lessons learned from the construction progress so far in Finland, China and France. “It is a huge challenge, but we are confident,” he said. None of the similar projects in other countries has yet started, however.

Hinkley Point C will comprise two EPRs and is currently expected to cost about GBP18 billion ($21.96 billion), a huge sum that does not even include financing costs which could add an extra 25%. Construction will be funded by a contract for difference which provides a set price for power from the project of GBP92.50/MWh ($112.87/MWh) for 35 years – far above the current cost of power in the UK. EDF will own 66.5% of the project, partnered by China General Nuclear Power Corporation with 33.5%. The latter’s involvement threatened to end the project this year, with the new post-Brexit government of Theresa May apparently having serious concerns about Chinese ownership of such critical national infrastructure. After yet another delay, it was finally given government sanction.

De Rivaz famously said back in 2007 that Britons would be cooking their Christmas turkeys using electricity from Hinkley Point C by 2017.

**UNDER CONSTRUCTION AND PLANNED NUCLEAR POWER PLANTS**

![Map of nuclear power plants](Image)
They will not. It has been troubled every step of the way since it was first proposed in 2006 under Prime Minister Tony Blair – including a European Union investigation into the legality of the guaranteed power price, and notably by the resignation of EDF’s CFO Thomas Piquemal earlier this year in protest at the project’s potential to bankrupt the already debt-laden company.

If it does prove successful, more plants are expected to follow. But, given its history so far – and that of other similar designs – the chances of the project starting up on schedule and on budget are widely viewed with skepticism.

Meanwhile in France itself, which is second only to the US in terms of installed nuclear capacity after heavily backing the technology in the 1970s, a decision on nuclear reactor decommissioning has been effectively put on hold and could be overturned with a change of government next year. A government investment roadmap published in late October stopped short of identifying reactors for closure under legislation passed in 2015 by the Socialist government that commits France to reducing nuclear to 50% of its power mix, from around 75% currently. A strategic review of plants and energy requirements will now be published by EDF next year.

And in various other European countries nuclear power is in serious retreat. Germany is continuing with a plan reintroduced following Fukushima to phase out all its nuclear capacity. The country, which used to be an exporter of nuclear technology, will have no nuclear generation by 2023. German utilities have sought compensation for the phase-out decision but are not contesting it further, and only eight operating reactors remain of a fleet that in 2010 numbered 17 units.

In Switzerland, voters were due to go to the polls in late November to decide whether to effectively phase out nuclear energy by prohibiting nuclear plants from operating beyond 45 years, which would mean all Swiss reactors would shut by 2029.

Critical delivery

There is no doubt that nuclear can, and probably will, have a significant role for decades to come as the low-carbon transition gathers pace. But most of the solutions being offered in the US and Europe to spur new nuclear construction and the continued operation of even existing reactors amounts to “really going back on the liberalization of power markets,” said Steven Kidd, an industry consultant, at the Florida uranium conference in October. It is not clear that this will be a popular way forward, he said.

And costs of nuclear reactors are not dropping, as would be expected of a mature technology, but rising instead, he said. Nuclear energy is in fact now more expensive than onshore wind and solar, said Laszlo Varro, chief economist for the International Energy Agency, during an appearance in Washington October 24. However, renewables provide challenges because of their intermittency, requiring investments in transmission lines that are often difficult to implement, he said during a conference at the Center for Strategic and International Studies.

The solution will likely involve a great deal of government support, as with Hinkley Point C, Varro said. But no amount of subsidies will protect the nuclear industry if it fumbles the next generation of reactor construction. “The industry has to get its act together and deliver projects on budget and on time,” Varro said.

Oliver Adelman contributed to this story
Honored to be a 2016 Global Energy Awards Finalist.

Our $30 million investment to upgrade critical transmission lines in the heart of New Orleans was a success in more ways than one. Not only was the project finished ahead of schedule, it was accomplished without a single injury and with the cooperation and support of our community.

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Global NGL markets, highly fragmented in the recent past, are expected to be tightly linked moving forward, with supply or demand shocks anywhere in the world affecting all pricing hubs.

The ongoing energy renaissance in the United States, driven by new drilling and hydraulic fracturing technologies, has altered global energy flows and affected commodity prices around the world. While crude oil typically dominates the headlines, US exports of natural gas liquids (NGLs) are causing a sea change in European and Asian markets, with massive shifts already evident in global petrochemical industry investment which may be felt for decades to come.

NGLs, generally ethane through pentane, are not easily categorized in a binary oil and gas world. Too volatile to be wholly stored and transported with oil, they cannot be fully blended into the natural gas (methane) stream due to their higher heat content and tendency to condense at common temperatures and pressures. Propane and butane, often blended together as liquefied petroleum gas (LPG), have a mature global market and robust distribution networks in many countries, used primarily for residential heating and cooking, as well as petrochemical feedstocks. Ethane, historically more difficult to transport than LPG, is either used as a petrochemical feedstock in regions with sufficient volume to justify infrastructure buildout, or left in the natural gas stream to be burned.

US production of NGLs from gas plants was steady for over 30 years, averaging 1.7 million b/d from 1973–2008, according to the US Energy Information Administration. With rapid increases in oil and gas drilling, NGL production has more than doubled in just eight years, jumping to 3.5 million b/d in H1 2016. Consequently, while US net imports of NGLs averaged 165,000 b/d from...
NGLs

As total US NGL exports have grown, Europe has been the second largest destination after Asia for American LPG cargoes. From negligible amounts in the last decade, 25,000 b/d of LPG was sent to Europe in 2012, rising to 119,000 b/d in 2016. Along with higher volumes and now readily available supply, increases in terminal infrastructure and shipping (Very Large Gas Carrier) fleet counts have driven the realized (after freight) price spread between Mt. Belvieu and Northwest Europe to near zero. The propane realized price spread has dropped from $380/mt in 2012 to just $20/mt in 2016.

Global NGL markets, highly fragmented in the recent past, are expected to be tightly linked moving forward, with supply or demand shocks anywhere in the world affecting all pricing hubs, similar to crude oil.

Petrochemical demand for NGLs consists almost entirely of feedstock to steam crackers, which produce olefins such as ethylene and propylene, the building blocks for almost all plastics. While naphtha and even crude oil or coal can be used as cracker feedstock (if properly designed), lighter feedstocks are generally more economic due to higher yields and ease of processing. As such, newer ethane crackers in Saudi Arabia and the US are the most competitive, with older naphtha crackers around the world and coal-fed (methanol to olefins) plants in China facing the worst economics.

Europe’s cracker fleet has been weighted heavily toward naphtha, while the North Sea crackers that do take ethane have been at risk from declining local production in recent years. One of the major challenges to large-scale, waterborne ethane exports is ship capacity. Unlike LPG or liquefied natural gas (LNG), ethane has never been shipped overseas in large quantities, and thus a new class of ships needed to be designed and built to serve ethane projects. Ineos, Borealis, and SABIC, along with ship owners Evergas and Navigator Gas, have undertaken significant investments in infrastructure and new shipping technology to import American ethane. The first ethane export cargo left the US 1973–2008, by H1 2016 this had totally reversed, with net exports averaging 1.05 million b/d.

Meanwhile, NGL export terminal capacity has grown from approximately 350,000 b/d ten years ago to 1.4 million b/d by the end of 2016. Platts Analytics expects US NGL production to grow an additional 1 million b/d to 4.5 million b/d by 2021, with demand growth split roughly equally between domestic petrochemical demand and exports.
NGLs

in March 2016, and waterborne ethane exports are expected to slowly ramp up to 235,000 b/d by 2019 as more ethane carriers are commissioned.

While some European petchems are securing ethane supply for decades to come, others have increased the flexibility of their crackers to accept LPG instead of naphtha, without making large feedstock commitments. In addition, more than 9.2 million mt/year of ethylene capacity is expected to come online on the US Gulf Coast over the next four years, with much of the end products export capable. Faced with competing against relatively inexpensive US NGL feedstock, older naphtha crackers in Europe and Asia may increasingly be at risk of economic obsolescence.

As with any rapidly changing market, risks abound. Small changes in the global growth rate of plastics demand could blow out or destroy petrochemical margins in the medium term, regardless of feedstock. Consecutive warm winters would test already high NGL stock levels and further depress prices, while a cold winter on multiple continents could wipe out global stocks in a season, now that markets are better linked. Despite record US NGL production, an over build of demand users, both domestically and abroad, could leave some users wanting if production growth falls short.

The NGLs of today are no longer an afterthought for producers, and are far removed from being the unwanted byproduct of a generation ago. While it may take another decade or more to fully realize the longer term consequences of the American energy renaissance, we can be certain that global NGL markets will never be the same again.

“Global NGL markets, highly fragmented in the recent past, are expected to be tightly linked moving forward, with supply or demand shocks anywhere in the world affecting all pricing hubs.”

2015 CRACKER FEEDSLATE, EUROPE vs US

US LPG EXPORTS BY DESTINATION

Source: US Census Bureau
A Middle Eastern hub rises

Fujairah’s efforts to establish itself as a global energy trading hub to rival Rotterdam and Singapore are bearing fruit

The rapid evolution of the Middle East’s budding energy trading ecosystem is on track to create a new oil products hub alongside behemoths Rotterdam and Singapore within a decade. The UAE’s Port of Fujairah is leading this charge to become a global energy hub, a multifaceted and challenging goal.

Rising throughput and increasingly sophisticated infrastructure at the port – the world’s second-largest bunkering hub behind Singapore – have galvanized local government and energy stakeholders’ desire to build a trading identity. At a fundamental level, oil products storage at the port has increased significantly over the last few years, rising from just above 2 million cubic meters in 2011 to as much as 9 million cu m in 2015, and projected to rise to 14 million cu m in 2018. Similarly, the region has seen a well-documented rise in refining capacity in recent years, with another 1.2 million barrels/day of capacity added in the last few years, and more to come in the years ahead.

That growth in product supply and storage capacity has been a key driver of oil flows in the region. The Middle East now regularly sits at the heart of traders’ analysis of the potential for arbitrage economics between east and west across a range of oil products. Diesel and jet fuel flow out of the region and head to Europe in volume, but are also seen heading south to East Africa. High gasoline demand in the region means that lighter products are pulled into the Gulf and increasingly blended in Fujairah, even as excess naphtha is exported out to the Far East. And residual fuels have long been sent to the port for blending to meet growing bunker demand.

But physical flows of oil alone are not sufficient to create an oil trading hub; a hub needs the “software” of trading as much as the “hardware.” And that is where there have been some important changes in the last several months. The Gulf ecosystem is developing the essential building blocks of a commodity hub: transparent data, regulatory and legal clarity, robust volumes, independent oil benchmarks and a strong talent pool.

As recently as September, the Port of
Fujairah announced that it would begin publishing weekly inventory data for major oil products to provide insight on the market's supply-demand balance. Improved transparency will whet the appetite of traders based in the Gulf, as well as at trading desks in the world's major trading hubs of Houston, Rotterdam and Singapore. Information on market fundamentals is a key requisite for trading commodities, and this step lowers one of the barriers to entry for the Middle East oil market.

It also begins to place Fujairah on a par with Singapore, Europe, Japan and the US in terms of fundamental data. In all those locations, regular data on inventories and product flows provides the market with the major pieces of information that drive price. It gives traders a first indication of how long or short a market is. It also moderates the advantages of incumbents and owners of major infrastructure, who often have access to private inventory information. For Fujairah to become a true trading hub it is important that a variety of market participants feel able to enter the market on a fair footing.

The next step in data for the region would be to see the publication not just of inventory data but also of imports and exports of individual products. Weekly flow data underpins a trader's understanding of the changing nature of an oil hub's place in the broader region. And again it is an area where the largest market participants tend to have a key advantage since they tend to have the clearest picture of flows since they are the ones moving product in the first place.

Beyond fundamental data, transparency is also vital for the prices of commodities. In another development on the "software" side of the Middle East market, S&P Global Platts launched new FOB Fujairah assessments for oil products on October 3. The new assessments reflect loadings from the region's ports – Saudi Arabia's Ras Tanura, Kuwait's Mina Abdulla, Oman's Sohar and Qatar's Ras Laffan, for example – but are normalized to the Port of Fujairah as a basis port. The assessments cover the major fuels flowing through the area: gasoline, jet fuel, diesel and fuel oil.

Historically contracts for those products have tended to price using Platts MOPAG netback values. The netbacks take values in Singapore and subtract freight to arrive at a figure for the Gulf, thereby linking the value of, for example, fuel oil in Fujairah to the closest and most liquid global fuel oil hub. The netbacks have been published for many decades, and provide stable pricing for regional contracts. They were also a necessity borne out of opaque and illiquid regional markets.

But as the markets themselves have become more liquid, the reality of Middle East oil product independence has been shown more clearly. Trading bunker fuel using a $10/mt differential has become increasingly problematic. The new Fujairah assessments offer the increasingly savvy market players in the Middle East an independent alternative to the netback prices, providing the possibility of price exposure that more closely aligns to their physical trading.

Transparent spot pricing provides clear signals to the market and enables informed trading decisions. Without it, choosing where to send cargoes can seem little more than a roll of the dice. Moreover, the publication of spot pricing is an essential prerequisite to hedging tools, providing the basis for settlement of derivatives.

That said, the Middle East has also this year seen growth in the use of derivatives. The Dubai Mercantile Exchange announced in May that it had cleared its first ever fuel oil derivative, 7,000 mt of July 180 CST fuel oil paper. That was followed in August by the Intercontinental Exchange announcing the launch of fuel oil and gasoil futures contracts for the Middle East. Both exchanges are initially listing contracts that settle against Platts MOPAG netback values. Those values are used in a variety of long-term physical contracts across the Indian Ocean and it therefore makes sense that companies are looking to hedge their exposure to them.

But these derivatives do not yet provide real hedging for the local spot market; they only provide cover for the exposure to price bases in contracts, not for the exposure to the ebb and flow of the local markets themselves. For real spot market hedging, derivatives that settle against local spot prices will need to evolve.

Moreover, challenges remain if Fujairah is to reach the status of the major energy trading hubs. An active market will require a clearer and firmer legal structure, to boost participants' confidence. The UAE's legal architecture is just 44 years old and the speed at which greater clarity is provided will directly correlate with the desire of traders, brokers, accountants, bankers and all other relevant professions to embrace what is largely an untested market. For example, will the Port of Fujairah fall under federal law that is spearheaded by Abu Dhabi, or are the country's global energy interests best
served by appointing the port as a legal island, from a trading perspective?

The high cost of soft infrastructure also needs more attention, as escalating telecommunication costs for trading stakeholders in the Gulf threaten to curb momentum, especially for small and medium-sized enterprises. The most efficient connection provided by a leased line between, say, a US city and Dubai incurs crippling costs. An affordable alternative is required in today’s environment where profit margins are under stress.

The pace of Fujairah’s efforts to establish itself as a key global energy trading hub to rival Rotterdam and Singapore is impressive. If it continues to pay attention to the needs of the oil trading community, Fujairah will reap the benefits of its geographical location and grow from strength to strength.
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Be part of Asia's premier gathering for the oil and refining industry
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Kaushik Deb, Senior Economist, BP
Giacomo Rispoli, Executive Vice President Portfolio Management & Supply and Licensing – Refining & Marketing & Chemicals, Eni
Maria Victoria Zingari, Executive Managing Director of Downstream, Repsol

Antony Francis, Assistant Vice President - Refining & Marketing Business, Reliance Industries
Luan Bo, Vice President & General Manager, Shandong Chambridge
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Bridge to a sustainable future

The opportunity for gas to play a key role in Southeast Asia’s energy transition needs to be backed by policy

Less than one year after the historic COP21 Paris Agreement on climate change was negotiated in Paris, the treaty has been ratified. With most of the world’s major carbon emitters and four of the 10 Asean economies, Singapore among them, having already ratified the agreement, it is clear that a commitment has been made to take serious and concerted action on climate change. The big challenge now is how to turn the commitment into concrete actions.

For Southeast Asia, climate change presents more than simply an economic or political challenge. Fundamentally, it will result in more dramatic weather events, leading to floods and storms that are particularly devastating for island nations. This means the region must work to adapt to a changing climate, while at the same time ensuring continued economic growth and providing access to power for those lacking it.

Many countries, such as those in Southeast Asia where electrification is still increasing rapidly, will heavily rely on conventional generation for years to come due to the sheer scale of their demand growth.

But the longer-term future of secure and accessible power generation in the region – and across the world – needs to be low-carbon electricity, including renewables and conventional generation with carbon capture and storage. This transition will be difficult. Despite the declining cost of renewables, a lack of policy support and the difficulty in integrating variable renewables into 20th century electricity grids have contributed to investment in renewables generation in the region falling last year to its lowest level in five years.

Outside of hydropower, support for renewables in Southeast Asia has been strongest in Thailand, driven by long-term targets. Policies in the Philippines and Indonesia have also attracted investment. While a country like Singapore is limited by its geography in the extent it can take advantage of renewables, it is taking steps to bolster research and deployment efforts. Yet despite strong electricity demand,
policies elsewhere in the region have not managed to attract significant new financing.

Gas is widely considered as a good transition fuel as it is relatively clean burning. Also, natural gas power plants can react quickly to demand peaks, and are thus ideally twinned with intermittent renewable options such as wind power. Recently, gas prices have fallen sharply as demand has slowed, while new supply has come to the market. For gas-importing countries, the key challenge is to take advantage of this opportunity.

But is gas as cheap as it seems? The geography of Southeast Asia means that most countries rely on long-distance imports, putting gas at a disadvantage vis-a-vis coal.

This cost advantage has meant that developing Asia saw more than 75 GW of coal come online in 2015, roughly the same amount as all the new renewable generation that came online across the region.

In developing Asia, outside of China, more than 50% of new coal-fired capacity has been subcritical, which means between 33% and 37% of the energy in the coal is converted into electricity. The implications of burning more and more coal in the region will be felt for decades to come. It would not just hamper efforts to reach climate goals, but could also have major implications for air quality.

So gas finds itself squeezed between renewables and coal, potentially slowing the transition to a cleaner energy system. Southeast Asia could unlock significant demand growth for gas through implementing appropriate market regulation. This current period of low gas prices is the perfect time to do so.

Clear, predictable policy can encourage investment in additional infrastructure, including in the Asean Power Grid, while opening the door to affordable, long-term supply contracts. Demand for gas could also benefit from governments enacting stricter environmental policies to curb air pollution.

By contrast, if energy investment decisions are based only on today's market conditions, it could lock in patterns of consumption and fuel use that will have implications long into the future. This period of low gas prices will put pressure on producers – that is unavoidable. But for the region's gas-importing countries, this is an opportunity to realize the policy and the infrastructure necessary to ensure a secure and sustainable energy future.

To strengthen our role in realizing this shared global energy future, one year ago I announced that the International Energy Agency was “opening its doors” to emerging economies, forging stronger ties with those countries that are increasingly critical to energy and the environment.

The response from Asian countries has been remarkable. China, Thailand and Indonesia were the first countries to become association members, signaling enhanced collaboration on energy security, policy analysis, and data and statistics, along with stronger institutional ties. I am hopeful that other countries in the region will follow soon and that we can all work together to ensure the secure and sustainable energy supplies that are needed to foster economic development.
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Bruce Power

Formed in 2001, Bruce Power is an electricity company based in Bruce County, Ontario. We are powered by our people. Our 4,200 employees are the foundation of our accomplishments and are proud of the role they play in safely delivering clean, reliable, low-cost nuclear power to families and businesses across the province. Bruce Power has worked hard to build strong roots in Ontario and is committed to protecting the environment and supporting the communities in which we live.

The company inject billions of dollars into Ontario’s economy annually, while producing safe energy that produces zero carbon emissions.

Bruce Power currently provides over 30 per cent of Ontario’s electricity at 30 per cent below the average residential cost of power. In fact, Bruce Power is the source of about half of Ontario’s nuclear generation and is the lowest cost source of nuclear energy in the province.

Bruce Power has transformed its site by returning four units to service through billions in private investment in our publicly-owned assets. Bruce Power has transformed its workforce through new hiring and training, extending the life of operating units through innovative, planned maintenance programs.

In 2015, Bruce Power secured a long-term agreement with the province of Ontario that will see six-units refurbished over the next two decades, extending the life of our site to 2064.

This $13 billion private investment program will guarantee one in three homes, hospitals, schools and businesses receive carbon-free nuclear electricity for generations.

By building on the experience we have gained over the past 15 years, while continuously innovating in order to become more efficient at these important infrastructure programs, we are in a strong position to fulfill our commitment to Ontario’s Long-Term Energy Plan.

Bruce Power provides approximately one-third of its output (2,400 MW) as flexible generation, allowing the province to balance system needs in a post-coal market on a permanent basis. This is a feature that only the Bruce Power units can provide, and has been used by the IESO frequently since 2009.

In addition to keeping the lights on, Bruce Power positively impacts millions of people through the world’s health care systems.

Bruce Power has a long-term agreement with Nordion, another Canadian-based company, to supply Cobalt-60 that is used to sterilize more than 40 per cent of the world’s single-use medical equipment. In addition to this, in 2016, Bruce Power and Nordion strengthen their partnership and entered into a new agreement to supply medical-grade Cobalt-60 that will benefit cancer patients in Canada and around the world.

Bruce Power is a Canadian-owned partnership among TransCanada Corp., Borealis Infrastructure (a trust established by the Ontario Municipal Employees Retirement System), The Power Workers’ Union and The Society of Energy Professionals. Over 90 per cent of employees also own a part of the company.
Cairn India Limited

Cairn India is one of the largest oil & gas exploration and production companies in India with a portfolio of 8 blocks across India and South Africa. We contribute significantly to India’s quest for energy security. A low cost operator and a pioneer in the innovative application of technologies, Cairn India is also credited with building the world’s longest continuously heated and insulated crude oil pipeline, and executing the world’s largest polymer flood Project. We combine a world-class asset portfolio with proven expertise across exploration, development and production to create significant value for our all stakeholders.

Sudhir Mathur, was appointed as the Acting Chief Executive Officer of Cairn India Limited in June 2016, bringing nearly thirty years of senior management experience to the role. Since joining Cairn in 2012 as Chief Financial Officer and Member of the Executive Committee, he has been instrumental in the continuing growth and success of the Group. During his career, spanning a number of sectors, he has had responsibility for Strategy, Restructuring, Supply Chain, Corporate Finance, Treasury, M&A and External Affairs.

Prior to Cairn, Sudhir was the CFO of Aircel Cellular Limited and Business Head of Netco, where he was instrumental in the roll out of their Pan India Operations. He was Chief Commercial Officer of Delhi International Airport Limited where he oversaw the positioning of the airport as an international and domestic passenger and cargo hub, post privatization. Following a number of years with the Management Consultancy division of PriceWaterhouseCoopers India, he also held senior management positions at Idea Cellular and Ballarpur Industries.

Sudhir is a Bachelor of Economics from Shriram College of Commerce, Delhi University and MBA from Cornell University, New York.

Cairn India has set technology benchmarks in Oil & Gas over last 2 decades:

- Executed Mangala EOR: World’s largest polymer flood project (Year 2015-16)
- Executed world’s largest jet-pump operation (Year 2010-16)
- Built the world’s longest continuously heated and insulated pipeline (~670 km) (Year 2007-10)
- One of the largest onshore discovery in India, Mangala Field, Rajasthan: Discovery to production in 5 years (Year 2004-09)
ENGIE Global Markets: Building Energy Value Worldwide

ENGIE Global Markets is the trading arm of ENGIE, a global energy player in natural gas, power and energy services, active in 70 countries throughout the energy value chain. Operating at the heart of our parent company, we have nearly 20 years of experience acquired throughout the process of market liberalization, and combine in-depth industry experience and financial market know-how.

With four trading platforms in Paris, Brussels, Rome and Singapore, we employ 390 people worldwide and are active in 40 countries. We serve all ENGIE business activities and contribute to optimize its physical and financial asset portfolio, among the largest worldwide:

- 1,132 TWh natural gas supply portfolio
- 117.1 GW installed power production capacity
- N° 1 LNG importer in Europe
- N° 1 provider worldwide in energy efficiency services

We leverage ENGIE’s presence on all continents to increase our global reach and client base, and we contribute to create competitive environments in emerging markets, including Asia-Pacific where our established presence places us at the forefront of ongoing market liberalization.

Our offer covers the entire energy mix (natural gas, power, oil and derivatives, bulk commodities and environmental products) and includes market access, asset optimization, and risk management services. We also contribute to developing cutting-edge solutions to manage renewable intermittency and strongly support the development of energy efficiency services, in line with ENGIE’s goal of becoming the world leader in energy transition.

We customize our solutions to meet the fast-changing needs of a highly diversified counterpart base from up to downstream - producers, refiners, shippers, trading counterparts, financial institutions and industrials.

Our Investment Service Provider status entails compliance with the highest standards in risk control, client protection and business practices. Group affiliates and third parties alike thus benefit from the best of both worlds in our utility and banking expertise.

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Essar Oil Limited

Essar Oil Limited is a fully integrated oil and gas company of international scale with strong presence across the hydrocarbon value chain from exploration and production to refining and oil retail.

Essar Oil owns and operates the 20 MMTPA, or 405,000 barrels per day, refinery at Vadinar in Gujarat state. It is India's second-largest single site refinery with complexity of 11.8, ranking amongst the highest globally. The refinery is capable of processing some of the toughest crudes and simultaneously produce high quality Euro IV and V grade products.

Soon after the petroleum sector was partially deregulated in 2002, Essar Oil was the first private sector company in India to launch a retail outlet. In 2005-06, trial production at the refinery commenced and the year 2008 saw the launch of commercial operations with 10.5 MMTPA capacity. By 2012 the production had been scaled almost double to 20 MMTPA, a milestone achievement.

The prestigious Vadinar refinery is an asset of national pride and is a testimony of Essar’s philosophy, vision and committed efforts. Essar has the unique ability to build world-class businesses and create enterprise value of high order that benefit all stakeholders. Essar believes in incubating, nurturing and scaling up business in which it operates. Today, Essar Oil stands tall with its state-of-the-art integrated refinery that produces over 9% of India’s refining output.

The Vadinar refinery was the first in India to use coal based power plant to meet its power and steam requirements. The complex benefits from an integrated infrastructure developed around the site including a power plant, port, pipelines and tankages and despatch facilities through land, rail and sea.

Essar Oil has demonstrated its business excellence by becoming India’s largest private-sector retail fuel network with more than 2,700 retail operational outlets.

This was developed in two years after the government almost fully de-regulated the petroleum sector in October 2014. With another 2,800 outlets in various stages of commissioning, Essar Oil is the fastest growing private sector company in India.

In October, the promoters of Essar Oil signed a definitive agreement to sell a total of 98% of the company to PJSC Rosneft Oil Company (49%) and a consortium of Trafigura and United Capital Partners (49%).

Essar Group has a high impact portfolio of conventional and unconventional assets in proven plays. With an acreage of 13,000 sq kms spread across India, Vietnam, Nigeria, Madagascar, the portfolio, on an aggregate basis, is assessed to hold reserves and resources of around 1.7 billion barrels of oil equivalent.

A landmark feat was achieved in July 2016 when CBM production from Essar’s Raniganj (East) block crossed production of 1 million metric standard cubic meters per day, the first by any company in India. Essar is focused on growing its E&P portfolio of unconventional and conventional assets with significant resource potential in India and overseas. Essar enjoys a leadership position of CBM production in India.

### Statistics

- India's second-largest single site refinery
- Processed over 100 types of crude, 11.8 complexity among world's highest
- India's largest private sector retail fuel network, fastest growing
- Over 2,700 retail outlets across 28 States, Union Territories
- Largest CBM gas producer in India
HPCL - Mittal Energy Limited

HPCL-Mittal Energy Ltd (HMEL) a Joint venture company between Hindustan Petroleum Corporation Limited and Mittal Energy Investments Pte Ltd, Singapore, represents an exciting fusion of the best of public sector pedigree and global private sector entrepreneurship.

HMEL has spanned its operations in Crude Oil Refining and Exploration of crude oil. It owns and operates a Single Point Mooring, a Crude Oil storage terminal and a Crude Oil transportation pipeline (1,017 km) for providing storage & logistical solution to its refining business through its wholly owned subsidiary, HPCL-Mittal Pipelines Limited. It owns and operates the Guru Gobind Singh Refinery of 9MMTPA capacity and 165MW captive power plant in Bathinda, Punjab and has participating interest in an oil and gas block situated in Rajasthan.

As an environmentally sensitive and safety conscious organization, energized by a mission to drive excellence across the Health, Safety & Environment platform, HMEL has launched many initiatives like Green coverage, Solid waste management, Secured Landfill etc. to create a greener business eco-system, driving greater business efficiencies and empowering the future generations. HMEL has received the prestigious “Sword of Honour” for Excellence in Health and Safety Management systems by the British Safety Council in Oct ‘16.

Mr. Prabh Das has been the CEO of the Company since formation of the Joint Venture in 2007-08. He has been on the forefront in the dual role of building the organization from ground zero as well as simultaneous safe construction and commissioning of the Greenfield GGSR Refinery project within record time, cost and quality. He then led the smooth transition from the Construction phase to a fully Operative Refinery that constantly benchmarks itself with the best in the Industry.

Mr. Das, a leader who believes in challenging conventional wisdom and spotting opportunities quickly has already initiated an upgradation of the refining capacity at Bathinda from the present 9 to 11.3MMTPA and further augmenting production capacity of Polypropylene, a high value-added product thereby creating new capacities to deliver higher production excellence.

He has identified capabilities needed, gaps thereof to build competencies to provide the next S-Curve emphasizing overall growth, performance excellence and stakeholder empowerment.

HMEL's outstanding performance during FY 2015 with an encouraging gross refining margin is a testimony of his distinctive leadership to drive excellence and scaling new milestones of success in the Company's growth story.

Mr. Das is a visionary in the Industry owing to his rich and diverse experience in various facets of the Oil Industry like Oil Diplomacy & Administration, Project Management & Financing, Refinery Operations, Marketing and Corporate Governance. He was conferred with “Outstanding Achievement Oil & Gas (Refining) Leadership & Excellence Award” at the Oil & Gas World Expo, 2014.

His recognition extends beyond awards owing to his significant contributions to the industry, notable being implementation of the Auto Fuel Policy & Strategic Storages, during his earlier stint as Joint Secretary Refineries-Division in the Ministry of Petroleum and Natural Gas, Govt. of India (2003 to 2008).

<table>
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<tr>
<th>Statistics</th>
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<tbody>
<tr>
<td>Safety TRIR in the First Quartile of US Refineries Benchmark. Recipient of “Sword of Honour” by British Safety Council</td>
</tr>
<tr>
<td>First Indian Refinery to have a 4th Stage Separator in the FCC unit to ensure better compliance to Environmental norms</td>
</tr>
<tr>
<td>First Indian Refinery to build a Secured Landfill to handle solid hazardous waste</td>
</tr>
<tr>
<td>First Indian Refinery to build a Vapour Recovery System to recover fuel vapours emanating during Product loading at Gantries</td>
</tr>
<tr>
<td>Customer Base: 4,260 within 4 Years of operation</td>
</tr>
<tr>
<td>Employees: 1,223 Nos</td>
</tr>
</tbody>
</table>

Customers Base: 4,260 within 4 Years of operation

Employees: 1,223 Nos
Jamaica Public Service Company (JPS) is an integrated electric utility, and the sole distributor of electricity in Jamaica. Approximately two-thirds of Jamaica's electricity is generated by JPS, with the balance generated by Independent Power Producers (IPPs) and sold to JPS for distribution to customers.

In 2001, JPS was privatized by the Government of Jamaica, which has maintained just under 20% share ownership in the company. The majority shares are jointly owned by Japan-based Marubeni Corporation, and Korea East West Power (EWP).

JPS recently embarked on a journey to change the local and regional energy landscape by inviting its stakeholders to “Re-imagine Energy... Together.” The company’s vision is to lead an Energy Revolution, unleashing Jamaica's growth and prosperity. This vision is fully aligned to Jamaica's national goals of energy security, sustainability, and affordability.

JPS’ strategy for modernising the local energy sector has four main pillars: Fuel Diversity; Smart Grid; Unique Customer Solutions; and Economic Development & Nation Building.

Modernizing Jamaica's Energy Sector

For many years, JPS and the Government of Jamaica have articulated a vision for greater fuel diversity. In 2016, the country took a huge step towards achieving this vision, as JPS partnered with US-based New Fortress Energy to bring natural gas to Jamaica. JPS will be utilising LNG at its recently converted 120-megawatt Bogue Power Station, and at the 190-megawatt power station to be built starting in 2017. The goal is to position Jamaica to become the energy hub of the Caribbean region.

The introduction of natural gas will also allow for more seamless integration of renewables, an area that is seeing rapid expansion in Jamaica. In 2016 alone, the country added 80 megawatts of wind and solar power to the grid, bringing total renewables to approximately 160 megawatts, of an average load of 565 megawatts.

The introduction of smart grid technology is central to JPS’ strategy. In 2016, JPS added significant automation to its power grid, expanded the reach of smart meters, introduced its smart house pilot, and started a smart streetlight program. The company is now preparing to unveil the first smart city in the Caribbean.

JPS aims to provide an energy solution for every Jamaican. Recognising that customers have very different needs, JPS offers a range of solutions, to include: prepaid meters, mobile money, mobile applications, energy management tools, and energy saving devices at its retail stores.

JPS considers itself a key partner in national development. As part of its support for nation building, the company has implemented a Community Renewal program in vulnerable communities. JPS also plays a leading role in energy education and energy efficiency through energy audits, Energy Clubs in schools, a Power Smart reality TV show, and the use of music and dance to educate on the impacts of energy waste.

The company recently introduced its Clean & Green initiative, which promotes care of the environment, as part of efforts to support the Government’s aim of making Jamaica the place to live, work, raise families and do business.

Statistics

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<th>602,000</th>
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<tbody>
<tr>
<td>Customers served</td>
<td></td>
</tr>
<tr>
<td>Jamaica's total installed capacity</td>
<td>902 MW</td>
</tr>
<tr>
<td>Average daily demand</td>
<td>565 MW</td>
</tr>
<tr>
<td>Energy delivery</td>
<td>14,000 km Transmission &amp; Distribution network</td>
</tr>
<tr>
<td>Owned &amp; operated by JPS</td>
<td>4 power stations, 9 hydro plants, 1 wind farm</td>
</tr>
</tbody>
</table>
ONGC

Oil and Natural Gas Corporation Limited (ONGC) came into existence in 1955 which was later converted into a Commission and christened as 'The Oil & Natural Gas Commission' on 14th August 1956. In 1994, ONGC Commission was converted into a Corporation and in was conferred with Maharatna status in 2010.

ONGC is engaged in the exploration, development and production of crude oil and natural gas. The Company's segments include Exploration & Production (E&P), and Refining. The Company's geographical segments include operations in two categories: In India, which includes Onshore and Offshore, and Outside India. The Company’s business spread include various areas, such as oil field services, transportation of the oil and natural gas, and production of value-added products, such as Liquefied Petroleum Gas (LPG), Naphtha, Refining, Petrochemicals, Power, unconventional and alternate sources of energy. The Company's subsidiaries include ONGC Videsh Limited (ONGC Videsh), Mangalore Refinery and Petrochemicals Limited (MRPL) and ONGC Mangalore Petrochemicals Limited. The Company's oil and gas reserves are located internationally at Russia, Colombia, Vietnam, Brazil and Venezuela.

ONGC produced almost 1,700 million metric tonnes of oil equivalent energy during last 60 years. Oil and gas production from ONGC Group, including PSC-JV and from overseas assets has been 57.38 MMTOE during FY 2015-16. As on 01.04.2016, ONGC has established 8506.73 MMtoe In-Place Volumes of Hydrocarbons of which 2969.11 MMtoe are Ultimate Reserves.

The Govt. of India promoted ONGC with an equity of Rs. 342.85 Crore contributed over 22 years during 1959 to 1981, has so far realized (till 30th sept, 2016), an amount of Rs. 27,885 Crore through disinvestment of 31.07% equity in ONGC. The Company has paid dividend of Rs. 101,528 crore to shareholders and has also contributed Rs. 453,152 crore to the Government exchequer by way of taxes, duties and levies. ONGC also contributed Rs. 310,116 crore towards under-recoveries of Oil Marketing Companies till FY’16.

ONGC conducts its business as a responsible corporate and believes in holistically addressing all issues related to People, Planet and Profit for a sustainable business and better future for all living beings and is committed to achieve inclusive growth of the marginalized and deprived sections of the society through its CSR initiatives to be implemented within the geographical boundaries of India, with preference to its Operational Areas, by supplementing government’s effort and / or by making independent efforts.

Some Innovative Corporate Governance initiatives taken are (i) a unique system for resolution of disputes between the Company and the Contractors/ Vendors, (ii) the Company has positioned an Integrity Pact (in association with Transparency International) which is signed with bidders to enable them to raise any issues with regard to tenders floated by the Company. ONGC was the first Indian company to sign the Integrity Pact. People of high repute and integrity are appointed as Independent External Monitors to oversee implementation of the Integrity Pact. (iii) SAP for online payments for total elimination of cash and cheque transactions and thus bringing total transparency (iv) HR initiatives for online settlement of all dues of employee.
Reliance Industries Limited (RIL), founded by Dhirubhai H. Ambani four decades ago, is India's largest private sector company. RIL's activities span hydrocarbon exploration and production, petroleum refining and marketing, petrochemicals, retail and telecommunications.

A significant global player in the integrated energy value chain, RIL recorded a consolidated turnover of INR 296,091 crore ($44.7 billion), a cash profit of INR 40,737 crore ($6.1 billion) and net profit of INR 27,630 crore ($4.2 billion) in FY 2015-16.

In 2004, RIL became the first private sector company from India to make it to the Fortune Global 500 list of 'World's Largest Corporations'. It currently ranks 215th in terms of revenues, and 126th in terms of profits. In FT Global 500 list (2015), the company ranks 238th, and in FT Emerging 500 it ranks 31st. RIL ranks 121st on the Forbes Global 2000 list (2016), continuing to be the top-ranked Indian company.

RIL has always been committed to the Common Man. Surging forward through backward vertical integration and raising money from the masses, it went on to become India's largest company. In 1977, Reliance Textile Industries' IPO created history by introducing the equity cult in India.

RIL took its policy of backward vertical integration to an altogether different plane when it diversified from textile and petrochemicals into petroleum refining, and forayed into oil & gas exploration and production. In 1999, it set up the world's largest grassroots refinery at Jamnagar, Gujarat. A second refinery followed in 2009. Currently, the combined Jamnagar refining hub processes 1.40 million barrels of crude a day – the maximum at any single location globally.

RIL commenced production in its KG-D6 block in Bay of Bengal in September 2008. It took just two years to start extracting oil following its discovery, making it the world’s fastest green-field deep water oil development project. In April 2009, it also commenced gas production from India's first deep-water production facility. RIL's success boosted key sectors like fertiliser and power, and saved the nation $35 bn in foreign exchange and reduced the domestic subsidy burden.

RIL is the second largest polyester yarn and fibre producer in the world and among the top-10 petrochemical producers.

In 2006, Reliance joined the retail revolution through Reliance Retail. Reliance Retail has built the widest geographical footprint with physical stores now covering nearly 3500 stores in 679 cities spread over 13 million square feet and many more through its ecommerce reach, catering to over 3.5 million customers every week.

The world's largest start up - Reliance Jio Infocomm Limited (“Jio”), a subsidiary of RIL, has built a world-class all-IP data strong future proof network with the latest 4G LTE technology. It is the only network conceived and born as a Mobile Video Network from the ground up and supporting Voice over LTE technology. It is future ready and can be easily upgraded to support even more data, as technologies advance on to 5G, 6G and beyond.

Keeping with its commitment to sustainability and growth, RIL through its CSR arm - Reliance Foundation, is working wonders in areas of rural transformation, education and healthcare.

The company complies with international benchmarks and voluntary guidelines. In keeping with the benchmarks the company sets for itself, RIL has been publishing Annual Sustainability Reports since FY 2004-05 as per the Global Reporting Initiative (GRI) guidelines. The reports were externally assured with an A+ rating indicating highest level of comprehensive disclosures. RIL is also a member of World Business Council of Sustainable Development (WBCSD) and Global Reporting Initiatives (GRI). WBCSD's ‘Reporting matters’ has recognized RIL's sustainability report as leading example on aspect of reliability.
Sentient Energy Inc.

Sentient Energy develops, manufactures and sells power-grid analytics systems for leading electric utilities. We make electric power delivery safe, reliable and solar ready. Our systems consist of intelligent line sensors, distributed software apps, and our Ample® Analytics Suite. Sentient Energy offers the Utility Industry's only Grid Analytics System that covers the entire distribution network with intelligent sensors that are quick and easy to deploy, as well as analytics that detect and analyze potential faults and other grid events that can disrupt electric service or present potential hazards. We lead the market with the largest mesh network line sensor deployments in North America, and partnerships with leading utility network providers, including Silver Spring Networks, Landis + Gyr, Cisco, and AT&T.

Sentient Energy's flagship sensor product, the Sentient MM3™, is an intelligent oscilloscope with high-performance sensors featuring substation-class measurement, computing and processing capabilities. These sensors have been described as the “wearables” of the Utility Industry with the capability to monitor all vital signs on the distribution grid, much the same way an Apple® watch or a fitbit® monitors the vital signs of a human. These advanced sensors are capable of capturing thousands of different waveform signatures, that once catalogued, can identify anomalies on the power line, predict failures before they occur, and dramatically increase the efficiency of both preventative and remedial maintenance. Major utilities such as Pacific Gas & Electric (PG&E), Florida Power & Light (FPL) and Southern California Edison (SCE) are already realizing significant improvements in the speed of service restorations as well the identification and remediation of system operation issues and equipment failures. FPL is currently completing the deployment of approximately 24,000 Sentient sensors that will cover the Utility's entire 42,000-mile overhead service territory.

Sentient Energy is led by James A. (Jim) Keener, Chief Executive Officer. Mr. Keener has served as an electric utility officer for almost two decades in both power generation and power delivery. He is a recognized leader in electric utility new technology evaluation, introduction, and large scale operation. Since his appointment in 2014, the company has achieved significant growth in both personnel and revenue, and has been recognized with a number of industry accolades, including “Smart Grid Pioneer,” “Smart Grid Company to Watch.” Red Herring 100 North America,” and finalist in the “Platts Global Energy Awards - Rising Star Company” category.

Since its inception in 2009. Sentient Energy has been laser focused on developing technology to improve the reliability and resilience of the electric distribution grid. One hundred percent of our R&D budget has been devoted to advancing the technology of our distribution grid analytics platform that includes our Sentient MM3™ intelligent sensors, our Waveform™ high resolution oscillography technology, and our Ample™ analytics software. Our sales and marketing efforts have been devoted to deployments of our technology at electric utilities, developing partnerships with industry data network providers, and educating the industry on the benefits of intelligent sensors and analytics to meet the challenges of providing, safe reliable electric service in a changing grid model that incorporates the rapid growth of distributed renewable resources.

Statistics

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<table>
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<tbody>
<tr>
<td>Employees</td>
<td>83</td>
</tr>
<tr>
<td>Intelligent sensors shipped</td>
<td>30,000</td>
</tr>
<tr>
<td>Grid miles monitored</td>
<td>50,000</td>
</tr>
<tr>
<td>Faults detected</td>
<td>&gt; 100,000</td>
</tr>
<tr>
<td>Grid disturbances analyzed</td>
<td>1 M</td>
</tr>
<tr>
<td>2014-2016 CAGR</td>
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</table>
TRADEX: a companion for individuals, a partner to industry

TRADEX distributes a wide selection of petroleum products in Cameroon and Central Africa Area. The company has become a Leader in the Downstream sector in this part of Africa and is actively consolidating its regional development and diversification.

Founded in 1999, TRADEX pursues its corporate development with a view to becoming a Major Player in key segments of Africa’s oil industry.

Initially, the company focused on trading before starting to diversify and branch out into supply and bunkering operations in 2002. TRADEX entered the distribution sector in 2006. The company has since expanded beyond Cameroon’s borders, becoming a key player in the trading of petroleum products in the Central Africa Area.

TRADEX has 58 service-stations in Cameroon, up from 32 in December 2011. 04 new ones were built in 2015, allowing the company to boost its market share to 22% compared to 14% three years earlier. TRADEX has the highest retail efficiency ratio of the Cameroonian network of service-stations, compare to the one of its competitors, including the multinational oil companies.

In 2014, TRADEX launched its distribution network in Chad, where it has been active through a local subsidiary since 2004. Since 2006, the company has also added some twenty service-stations in the Central African Republic. Always on the lookout for new opportunities, TRADEX is open to any investment in Africa.

In April 2012, TRADEX became the fuel supplier for Camair-Co, Cameroon’s national airline company, joining the small circle of companies approved for the supply of Aviation Jet fuel.

TRADEX was awarded the contract for the supply of fuels and lubricants to CWE – a Chinese company building the Lom-Pangar hydroelectric dam, one of the biggest in Central Africa Area. Since then, TRADEX has continued to increase its partnership with construction companies and on strategic building sites.

TRADEX is also the reliable partner of most of the largest companies operating in Cameroon in strategic areas such as power generation, hydrocarbons exploration and production, merchant marine, construction, public works, mining and the agro-industry.

TRADEX maintains a number of initiatives to contribute to Cameroon’s societal development and growth. Corporate Social Responsibility sits at the centre of the company’s operations and indeed, forms part of its mission. TRADEX is widely recognized for responding quickly and positively to social needs and aspirations. The company focuses its CSR efforts on promoting road traffic safety, education, public health, sports, culture, the environment and the ongoing fight against poverty.

Statistics

<table>
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<tr>
<th>Statistics</th>
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<tbody>
<tr>
<td>Number of service-stations</td>
<td>80</td>
</tr>
<tr>
<td>Countries of presence</td>
<td>Cameroon, Chad, Central African Republic, Equatorial-Guinea</td>
</tr>
<tr>
<td>Direct employees</td>
<td>155</td>
</tr>
<tr>
<td>Indirect employees (service-stations staff)</td>
<td>1800</td>
</tr>
<tr>
<td>Rank in Cameroon Economy by turnover</td>
<td>7th</td>
</tr>
<tr>
<td>Rank in Central Africa Area Economy by turnover</td>
<td>11th</td>
</tr>
</tbody>
</table>
Blue Pillar

Blue Pillar’s Aurora® Energy Network of Things™ platform automates the ability to connect anything that generates, stores, measures, switches, or consumes energy through a template-driven process where security is built-in from sensor to cloud. With this connectivity, energy providers and C&I facilities have unprecedented insight into their energy needs to become more efficient, sustainable and protect the grid from outages. Take control of your energy future by visiting www.bluepillar.com to learn more.
Continental Resources

Growing up in rural Oklahoma, Harold Hamm was the last of 13 children born to sharecroppers. He went to work in the oil fields as a teenager and established Continental Resources in 1967. He built Continental into an NYSE-traded, Top 10 oil producer in the U.S. Lower 48.

In addition to his role as Founder, Chairman and Chief Executive Officer of Continental Resources, Mr. Hamm co-founded and serves as Chairman of the Domestic Energy Producers Alliance. Through DEPA, Mr. Hamm is widely recognized as the man who worked tirelessly to help lift America’s 40-year-old ban on U.S. crude oil exports.

In 2016, Mr. Hamm was inducted into the Horatio Alger Association and has received awards and recognition for his lifetime of contributions, including, Oil and Gas Investor magazine’s “Executive of the Year,” Western Energy Alliance’s “Wildcatter of the Year,” Platts Global Energy Awards “CEO of the Year” (while Continental Resources was also named “Energy Company of the Year.”) In 2012, he was named one of TIME Magazine’s “100 Most Influential People in the World.” He was inducted into the Oklahoma Hall of Fame in 2011.

Itron

Philip Mezey is the president and chief executive officer of Itron, a world-leading technology and services company dedicated to the resourceful use of energy and water. Mezey has served the company in several capacities, most recently as chief operating officer for Itron’s global energy segment, prior to his role as CEO.

Mezey is an industry visionary working to drive digital transformation in the utility space. Mezey’s vision for the Active Grid—an ecosystem that brings the power of the Internet to devices, sensors, applications and more across a single network—will create a new frontier for resource management, resulting in enhanced public safety, reduced waste, greater efficiency and faster adoption of more sustainable technologies.

During his tenure at Itron, the company has grown from a metering technology provider to a leader in the Internet of Things, connecting smart devices to better manage resources. Itron, under Mezey’s leadership, will continue to shape the industry while creating more resourceful cities and utilities.

Prior to Itron, Mezey worked at Silicon Energy as vice president, Software Development, and was a founding member of Indus, a provider of integrated asset and customer management software.

Mezey earned his BA in history from the University of California, Berkeley.
NRG is the leading integrated competitive power company in the U.S., built on the strength of the nation’s largest and most diverse competitive electric generation portfolio of nearly 140 generating facilities and the largest competitive retail electricity platform that serves nearly 3 million customers in 10 states and the District of Columbia. NRG’s retail business is focused on powering, protecting and simplifying life for customers across the country.

As President of NRG Retail and Reliant, Elizabeth Killinger is responsible for all aspects of NRG’s $5 billion leading multi-brand competitive retail business that provides consumer power products like electricity, natural gas, rooftop solar and back-up generation, as well as services like home security and protection products. In addition, the retail business includes Goal Zero, the leading portable solar and battery power business in the U.S. In more than 15 years with NRG, Killinger’s proven success with delivering consistent financial results, customer growth, operations excellence and employee development ultimately led to her promotion to Executive Vice President and the consolidation of all of NRG’s retail businesses, which garners more than $5 billion in revenue, under her leadership.

Prior to joining NRG, Killinger spent a decade in management, strategy and systems consulting with a global services firm.

Recurrent Energy, a wholly owned subsidiary of Canadian Solar, is redefining what it means to be a mainstream clean energy company with utility-scale solar plants that provide competitive electricity to large energy buyers. Recurrent Energy holds one of North America’s largest solar development portfolios, with a pipeline across the United States exceeding 4GWp. To date, Recurrent Energy has secured $8B in capital, contracted more than 2.1GWp of utility-scale solar projects, and developed and sold 1.9GWp of assets.

Founded in 2001 in Canada, Canadian Solar (NASDAQ: CSIQ) is one of the world’s largest and foremost solar power companies. As a leading manufacturer of solar photovoltaic modules and provider of solar energy solutions, Canadian Solar also has a geographically diversified pipeline of utility-scale power projects in various stages of development. In the past 14 years, Canadian Solar has successfully delivered over 16GW of premium quality modules to over 90 countries around the world. Together with Recurrent Energy, Canadian Solar is ushering the way into a new era of clean, competitive, mainstream power.
San Diego Gas & Electric

San Diego Gas & Electric (SDG&E) is an innovative San Diego-based energy company that provides clean, safe, reliable, energy to better the lives of the people it serves in San Diego and southern Orange counties. More than 4,300 employees work to provide the most reliable and clean energy in the West. The company has been recognized by the U.S. Environmental Protection Agency for leadership in addressing climate change, was the first to meet California’s renewable portfolio standard goal of 33 percent of energy from renewable sources, has fueled the adoption of electric vehicles and energy efficiency through unique customer programs, and supports more than 600 non-profit partners. SDG&E is a subsidiary of Sempra Energy (NYSE: SRE), a Fortune 500 energy services holding company based in San Diego. For more information visit sdge.com or connect with SDG&E on Twitter (@SDGE), Instagram (@SDGE) and Facebook.

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S&P Global Platts – Insights That Drive Opportunities

www.platts.com/products/biofuelscan
Despite today’s low-price energy environment and difficult economic conditions, there are a select few who have what it takes to prevail, through their innate ability to seal deals and innovate rather than simply tread water. Now in its 18th year, the Platts Global Energy Awards program honors these top performers – businesses and individuals who have demonstrated innovation, leadership and superior performance.

Nominees came from across the entire energy complex and around the globe, with more than 170 nominees representing 30 countries. While the US made the strongest showing for any individual country in this year’s Platts Global Energy Awards, some 50 percent of the 2016 finalists hail from outside the US, with notable showings from India and the UK. The mix of competitors reflects a wide but changing geographic footprint, and categories including Deal of the Year, Rising Star Company and CEO of the Year continue to elicit tight competition.

Winners were chosen after rigorous review by an independent panel of judges; neither Platts nor its sponsors vote in selecting the winners. The panel is comprised of former national regulators, legislators, heads of major energy companies and leading analysts. S&P Global Platts commends the recipients of the 2016 Platts Global Energy Awards for their extraordinary commitment to the industry's advancement.
Energy Company of the Year
Southern Company
United States

Energy Company of the Year, the program's highest honor, is selected by the independent judging panel from all Platts Global Energy Awards finalists. The award recognizes all-around distinction in executing a total energy strategy. With consistently compelling performance exhibited as a finalist in the categories for CEO of the Year, Industry Leadership for Power and Strategic Deal of the Year, Southern Company was described by judges as “strategic,” “diverse” and “dynamic”.

The panel chose to bestow on it the top award, marked by unparalleled corporate vision and courage.

One of the largest US energy providers, Southern Company has operated for more than a century. The company now owns electric utilities in four states, natural gas distribution utilities in seven states, a generation company serving wholesale customers and a provider of customized energy solutions, fiber optics and wireless communications. It is continually top-ranked in Fortune Magazine’s annual listing for World’s Most Admired Electric and Gas Utility.

Judges commended Tom Fanning, Southern Company’s CEO, for his in-depth knowledge of the company, which stems from 35 years at the firm, encompassing 15 different positions in eight different business units. He maintains what judges call a “high profile throughout the industry... he is recognized as a leader and a spokesperson.” Fanning holds positions including chairman of the Federal Reserve Bank of Atlanta and the Edison Electric Institute as well as co-chair of the Electricity Subsector Coordinating Council, the principal liaison between the US government and the electric power sector to protect the electric grid from national security threats.

Fanning has maintained the company’s strong financial reputation – remarkably, every quarter since 1948, the company has consistently paid a dividend to its shareholders equal to or greater than the previous quarter – while taking decisive actions to move the company forward. He has said, “In the electric utility industry, the vision and courage to be steadfast in support of energy innovation are absolutely essential.” His vision includes spearheading our Strategic Deal of the Year, Southern Company’s $12 billion merger with AGL Resources, as well as broadening Southern Company’s portfolio to include new approaches to power generation. The corporation has committed $20 billion to developing low- and zero-carbon emission generating resources, incorporating investments in natural gas, solar, wind and integrated gasification combined cycle technology.

Judges saluted Southern Company as Energy Company of the Year for its ability to be “consistently competitive in all nominated categories.” Through establishing itself as an industry innovator and taking proactive moves to diversify its generation fleet in a challenging market, Southern Company truly serves as a paragon of industry leadership and strategic deal making.

CEO of the Year
Kelly Tomblin
Jamaica Public Service Company
Jamaica

CEO of the Year Kelly Tomblin, a West Virginia coal miner’s daughter who was the first in her family to attend college, thrives amidst challenge. With 20 years of experience in the energy industry, in both deregulated and vertically integrated markets in the US, the UK and Latin America, she has developed a reputation for organizational transformation. “I’m usually called when there’s a growth problem,” she has said.

When Tomblin was recruited from GDF Suez in 2012 for the CEO position at Jamaica’s sole distributor of electricity, Jamaica Public Service Company (JPS), a number of significant issues had caused the company’s growth to
stagnate. Its customer satisfaction rating hovered near 20 percent due to high electricity prices, poor customer service, and an aggressive disconnection policy. JPS’s largest business customers were also dissatisfied, waging a public campaign against the company as they contemplated leaving the JPS grid.

Tomblin “turned the company around very quickly in a difficult environment,” said judges. She first united the company around a new vision statement: “We are the people leading the energy revolution, unleashing Jamaica’s growth and prosperity.” She then set out to win back customer satisfaction through programs including introduction of prepaid service, amnesty for outstanding debtors, and introduction of a rewards program for customers who pay on time.

Tomblin also undertook larger initiatives that improved the company’s operational efficiency. In 2016, she achieved the longtime goal of bringing fuel diversity to the country, with the introduction of LNG at its Bogue power station, grid-scale solar, and the addition of significant wind capacity to the grid, all part of the company’s efforts to reduce reliance on oil from 95 percent to 50 percent by 2019. In the past year, Tomblin also led the charge to improve the regulatory environment governing the local energy sector and JPS’ operations, positioning it for the improved growth and profitability that is her hallmark.

JPS is thriving under Tomblin’s watch, reporting a 15 percent increase in profits since 2014, while customer satisfaction has risen to near 70 percent. In this very competitive category, the judges were persuaded by Tomblin’s problem-solving acumen as well as her forward-thinking mindset. Against the backdrop of a difficult year, “she has proven herself by using her skills to transform a challenging country in very creative ways,” said one.

Lifetime Achievement Award

Members of this year’s judging panel felt strongly that two nominees surpassed the criteria for the Lifetime Achievement Award based on their body of work. Though this year’s two winners took very different paths to the top of the oil business, both began in small towns and grew into industry titans, not only within their home countries, but also globally. Like all Lifetime Achievement Award winners before them, their creativity and insight has led to widespread recognition and respect.

Harold Hamm
Continental Resources
United States

Continental Resources Founder, Chairman and CEO Harold Hamm is not one to rest on his laurels. A double Platts Global Energy Awards winner in 2013 for Energy Company of the Year and CEO of the Year, Hamm was awarded for his legacy of leadership and innovation within Continental, as well as his commitment to bring America to energy independence within the next decade. As his company approaches its 50th year of operations in 2017, Hamm has made good on this promise by leading the charge to lift America’s 40-year-old ban on US crude oil exports.

Hamm was born in Enid, Oklahoma to sharecropper parents, as the youngest of 13 children. He began his career pumping gas and fixing flats at a local service station before heading to work in the region’s oil fields as a teenager. In 1967, at the age of 21, he established his own company and set off in search of America’s big oil fields. His Continental Resources claims to be a top 10 independent oil producer in the US lower 48, the largest leaseholder and one of the largest producers in the Bakken oil fields of North Dakota and Montana, with additional significant positions in Oklahoma.

Hamm’s impact on E&P reaches far beyond his Oklahoma roots. Hamm co-founded and serves as Chairman of the Domestic Energy Producers Alliance (DEPA), which aims to preserve jobs, economic activity and tax revenues generated by onshore production activity within the US. Through his work with DEPA, Hamm is widely recognized for his efforts behind Congress’ December 2015 vote to lift the 40-year-old ban on crude oil exports, which he believes will lower US
gasoline prices, create jobs, boost GDP and ensure energy independence for America and its allies.

“No question, he is a lifetime achiever,” admired one judge, echoing the panel’s unanimous approval of Hamm’s decision to utilize his high profile within the energy industry to bolster America’s energy independence and leadership in the new world oil market.

His Excellency Abdalla Salem El-Badri
OPEC
Austria

With nine years as head of the Organization of the Petroleum Exporting Countries (OPEC), holding the position in 1994 and then 2007–2016, His Excellency Abdalla Salem El-Badri is the longest-serving Secretary General in the history of the group. His tenure at this global organization of major oil-exporting nations is but one stop on his more than 50-year industry career, which includes leadership roles both in his home country of Libya and internationally. Judges applaud El-Badri as the epitome of a Lifetime Achievement Award winner: a “great diplomat” who “opened doors in a difficult region” and, in his more than 50-year career, “has had a major impact on the oil industry.”

Born in the small town of Ghemines, El-Badri’s oil industry career began at Esso Standard in 1965. He has served as Chairman of the Libyan National Oil Company, where in 1986, he led complex and delicate negotiations on the country’s behalf for a three-year standstill agreement which froze assets for US oil companies until they were able to return to Libya. He has also served as Libya’s Minister of Petroleum, its Minister of Energy, Oil and Electricity and its Deputy Prime Minister.

During El-Badri’s time at OPEC, he deftly steered the organization through the 2008 financial crisis and its aftermath, playing a critical role in maintaining stability between demands from OPEC members and needs of energy consumer economies. He also opened new lines of communication with countries including China, India and Russia as well as organizations such as the European Union, the International Energy Agency and the International Energy Forum; and enhanced the organization’s global reputation for transparency and credibility.

El-Badri is renowned for his leadership and diplomacy skills, often serving as a broker who ironed out differences between OPEC’s internal rivals. Current OPEC head Mohammad Sanusi Barkindo praises him as a man of “charisma and charm” and “an icon of the global oil industry, and at the same time a humble man of great integrity that is respected around the world.”

Rising Star Award – Company
Aquion Energy
United States

This year saw many qualified innovators vying for Rising Star Company honors, but winner Aquion Energy drew judges’ praise through “helping to drive solar to the forefront by enabling alternative energy.” In what one judge called an “interesting twist,” the company makes non-toxic saltwater batteries that are clean, safe and sustainable – so clean, in fact, that Dr. Jay Whitacre, the company’s founder and chief scientist, has eaten a piece of the battery’s electrode as a joke. While the batteries themselves are impressive, Aquion’s targeted products achieve Rising Star status through their broad range of applications - they are currently in use on every continent in the world by users including homeowners, businesses and utilities.

Aquion’s Aqueous Hybrid Ion (AHI) batteries offer an economical solution to storing large amounts of energy over thousands of battery cycles. The batteries are optimized for stationary energy storage applications, including small, medium and large-scale applications in markets such as microgrids, commercial and industrial, telecom, green architecture, lighting and utilities. These self-balancing batteries, which require no equalizing charge, are the first
and only battery in the world to achieve Cradle-to-Cradle Certification, an independent assessment of material health, material reutilization, renewable energy and carbon management, water stewardship and social fairness.

Typical of a Rising Star, Aquion has exhibited tremendous recent growth. In 2016, the company completed a solar-plus-storage project in Puerto Rico, where its batteries are used to power a 16 MW solar farm, a project that CEO Scott Pearson calls “a great example of large-scale base-load solar shifting using energy storage.” The company introduced a 24-volt version of its battery, designed for use in more energy-intensive applications such as solar panels. It also announced the closing of $33 million from its investors, bringing its total venture funding to over $190 million since its founding in 2009.

Impressed with Aquion’s balancing mechanism and intrigued by the potential of its products, judges feel Aquion has “a head start” on the competition, and they look forward to watching the business develop at this “small company with impressive technology.”

Rising Star Award – Individual

Elizabeth Killinger
NRG
United States

The Rising Star Award recognizes a leader who personifies innovation, creates opportunities and ultimately delivers. With a total of 25 years rising through the industry, Elizabeth Killinger, along with the high-growth businesses she has managed, has charted an impressive trajectory. Now an NRG Executive Vice President and President of NRG Retail and Reliant Energy, Killinger is responsible for directing all aspects of NRG Retail, which is the top multi-brand retail electricity business in Texas, the Northeast’s third-largest residential retailer, and the leading portable solar, power and battery business in the US.

When Killinger lost her own electricity during 2008’s Hurricane Ike, which ironically forced the power company executive to run her own laptop and cell phone from her car battery, she developed her own vision of energy’s future. In the “Era of Personal Power,” Killinger believes consumers should be entitled to make and manage power based on their own unique needs. This thinking exemplifies the thoughtful customer focus she is known for; “she is great at extending the relationship between the power company and the customer,” admired one judge.

Killinger’s customer-focused thinking has helped her bring “a creative portfolio of value-added products and services to market,” as one judge noted. In 2014, Reliant was the first competitive retail electricity provider to offer consumers a plan that included a Nest Learning Thermostat, enabling customers to easily control the temperature in their home. Aware that homebuyers often consider a home security system at the same time they sign up for electricity service, she also launched Security by Reliant as an addition to its smart home portfolio.

Judges appreciated Killinger’s high profile, not only at NRG and within the energy industry, but also within her community; she is a board member for many nonprofit organizations, “an excellent sign of leadership.” They predict Killinger’s star will further ascend as she and NRG continue to reshape the company/customer dynamic.

Financial Deal of the Year

I Squared Capital
United States

I Squared Capital (ISQ), the winner in this year’s tight and contentious race among investment and capital groups in the energy markets, took Financial Deal of the Year honors for a reported €1 billion agreement to acquire Viridian Group Holdings Limited from Arcapita. Judges hailed the deal as “ambitious,” “bold” and “gutsy” due to its complexity, short time frame and significant potential upside.
As an independent global infrastructure investment firm focused on energy, utilities and transport in North America, Europe and select high growth economies, ISQ took a keen interest in Viridian as a potential point of entry to UK markets. Viridian is the leading Irish independent integrated utility operating in both the Republic of Ireland and Northern Ireland in the All-Island Electricity Market, with a 20 percent and 27 percent share of domestic and business electricity sales volumes respectively.

Among Viridian's many promising assets, ISQ took particular note of the company's 793 megawatts of operating wind-farms under long-term contracts, a number expected to increase as other wind-farms become operational. This wind power is critical in Ireland, which has an aggressive goal to generate 40 percent of its electricity from renewable sources by 2020.

Time was of the essence with this deal due to stiff competition among prospective buyers. However, Viridian is a highly complex business, comprised of five distinct segments – conventional generation, owned renewables, regulated and unregulated supply and power purchase agreements – operating in two currencies, and under regulation in two countries. Given the complex capital structure in place, ISQ arranged the deal as an all-cash transaction, paying down £145 million of existing junior debt with new equity at closing. The deal placed Viridian in a markedly stronger financial position, consistent with ISQ's stated strategy to grow the company to its full potential, with the existing management team in place.

Judges rewarded the team at ISQ for their exemplary strategic thinking, backed by the ability to quickly identify the prospect, perform complicated due diligence and flawlessly execute the Financial Deal of the Year.

Strategic Deal of the Year
Southern Company
United States

During the past year, utilities increasingly turned to mergers in pursuit of growth during difficult market conditions. One originator of this trend, Energy Company of the Year Southern Company, demonstrated its dealmaking proficiency in its $12 billion merger with AGL Resources, now Southern Company Gas. The agreement created the second-largest utility company in the US, with nearly nine million utility customers in nine states. Southern Company stood out to judges in a crowded category by taking adept measures to further diversify and strengthen an already powerful company. “They're playing offense,” praised one judge.

This landmark deal represents a continuation of Southern Company's strategy to become more than an electric power provider. With the merger, the company combines electricity, gas distribution, gas transportation, gas marketing and energy asset optimization under one umbrella. Initiated in 2015 and completed in just under one year, the deal gives Southern Company a total of eleven regulated electric and natural gas distribution companies with a projected regulated rate base of nearly $50 billion; operations of approximately 200,000 miles of electric transmission and distribution lines and more than 80,000 miles of gas pipelines; and generating capacity of approximately 44,000 megawatts. The deal earned regulatory approval in six states in just ten months, as well as clearance by the Federal Trade Commission and AGL Resources shareholders.

Judges took particular notice of the fact that the merger essentially doubled the size of Southern Company's customer base from 4.5 million to 9 million, and expanded its geographic footprint to include overall operations in 18 states. These “two good companies,” as one judge praised them, are also essentially compatible, with excellent reputations for customer service, high reliability and affordable prices.

Judges lauded this strategic play that united complimentary companies – a natural gas business and a diversified electric utility. Through this Strategic Deal of the Year, Southern Company
Company’s focus has become more diversified, and judges feel it will continue to exhibit its trademark strong performance.

Industry Leadership Award
Biofuels
Neste Corporation
Finland

Finland’s state-controlled Neste Corporation is pulling ahead of its peers in the competitive race to reduce greenhouse gas emissions. The company has mounted a fierce challenge to both its biofuels competitors and the oil refining industry, as the company officially dropped “oil” from its name in 2015 and its renewable transportation fuels took on the world stage.

Neste is a refining and marketing company specializing in premium-quality, lower-emission traffic fuels based on renewable raw materials. The company is the world’s leading producer of renewable diesel made from renewable raw materials. The company credits its leadership in renewable diesel to its NEXBTL technology, which enables production of top-quality renewable diesel and other renewable products from nearly any waste fat or vegetable oil through a hydrogen-based treatment.

In contrast to conventional biodiesel, the quality of Neste’s product remains consistent even when the raw materials change. Neste’s renewable fuels, with a chemical consistency similar to fossil diesel, have been employed as a blending component for aviation fuel, in turbines, generators, ships, yachts and in construction equipment.

Neste is targeting growth outside conventional oil refining operations, exploring applications for its products in the chemical industry as raw material for renewable plastics or as renewable solvents. Judges were particularly inspired by the company’s planned move into renewable propane by the end of 2016, for use as an industrial gas as well as for cooking and heating.

Neste is committed to sustainability, and “they’re not fighting the ‘food vs. fuel’ battle,” admired one judge. With current volatility in the oil, renewable fuel and renewable feedstock markets expected to continue, Neste has plans to increase the raw material pool; the company has already succeeded in expanding the feedstock selection available for renewable diesel beyond 10 raw materials. With plans to boost its biodiesel production capacity capacity beyond current annual production volume of more than 2 million tons, Neste’s pioneering efforts are recognized by judges for their current and potential influence on global energy markets.

Industry Leadership Award
Exploration & Production
Antero Resources
United States

Amidst a challenging upstream climate, judges deemed Antero Resources the category’s clear winner from the start. The company, which has been the Platts Top 250 fastest-growing energy company worldwide for the last two years, has successfully reduced drilling costs and increased recovery while demonstrating strong community leadership – “a well-balanced strategy” that sets them apart in a down market, according to one judge.

Antero is one of the largest natural gas producers in the nation as well as in the Appalachian Basin, where it operates in two of the premier North American shale plays: the Marcellus and the Utica. Despite the ongoing challenges of the commodity price environment, the company has maintained its operational momentum through the downturn and kept its workforce largely intact – preserving its ability to react quickly when commodity prices recover.
A ready workforce also assisted Antero in reducing drilling and completion costs while increasing recovery. In its second quarter 2016 financial results, the company reported that over the prior 18 months, it reduced well costs by over 30 percent and increased overall recoveries by over 20 percent. Antero expects to generate over 15 percent production growth in 2016 and aims to exceed 20 percent in 2017, while reducing the 2016 budget by 23 percent. The company credits its success through the downturn to its large, low cost, repeatable drilling inventory coupled with management’s forward-thinking focus, which is evident in its liquidity and strong financial profile.

As befits an Industry Leader, Antero has consistently been what it calls “a good corporate neighbor.” In 2015, the company contributed over $600,000 to charitable and civic organizations, upgraded 166 miles of road and announced the construction of a $300 million wastewater treatment facility in West Virginia.

Looking ahead, Antero plans to continue to consolidate the basin and grow its inventory of drilling locations in order to provide sustainable production growth. It will also develop its transportation portfolio, ensuring its products can be sold to favorable end markets. Judges applauded Antero for being “successful by cutting costs, but while also being productive and continuing their growth” in a soft price environment.

**Industry Leadership Award**

**Midstream**

**ENGIE Global Markets**

France

This year’s Midstream Industry Leader links producer to marketer to consumer, and does so both physically and financially. ENGIE Global Markets, the innovative energy trading platform for power and gas operator ENGIE, grabbed judges’ attention by taking its “excellent reputation for managing logistics” and “providing fresh air to a tough region.”

Formerly GDF SUEZ Trading, ENGIE Global Markets services all ENGIE business activities, in addition to working with third parties to offer energy market solutions. The company operates in 40 countries, providing the midstream and trading markets with services including hedging of indexed gas contracts, futures, swing profile deliveries, storages and transportation agreements.

This past year marked the company’s aggressive push into new territories, where it enabled the interconnection of markets despite the problematic energy context in Europe. ENGIE Global Markets credits its continued expansion to its ability to create value along the entire gas chain. Its strong risk management framework enables the company to safely increase its risk and perform in difficult markets. In Eastern Europe, it became the largest private Western gas importer to Ukraine’s state-owned Naftogaz. One judge commented that the company’s “knowledge of the region is impressive; it’s a difficult landscape to operate in, but they have shown success.”

ENGIE Global Markets is preparing to expand its Singapore platform, which trades a broad array of financial products – a strategic move as energy markets in Japan, China and India become liberalized. The company also announced an agreement with Hague and London Oil (HALO) to co-operate on the acquisition by HALO of natural gas production and reserves within Europe. The company is also planning expansion to the US through origination and trading activities in power and gas.

This “very significant midstream company” is “driving to be more service-oriented,” observed judges, who also appreciated the company’s internal and external commitments to promote diversity and gender equality in a male-dominated industry. As ENGIE Global Markets continues to deploy its strengths to attract new investors into its regions of operation, judges believe it is well-suited to lead the energy industry during transition, and achieve its goal of helping the energy community to prepare markets for the future.
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Industry Leadership Award
Downstream

ESSAR OIL LTD
India

The Industry Leadership Award in the ever-changing downstream market rewards those who maintain focus and growth during volatile times. Essar Oil is this year's winner, applauded by judges for its entrepreneurial spirit, impressive scale and creativity.

Essar is a fully-integrated global oil and gas company operating across the hydrocarbon value chain, with activities ranging from exploration & production to refining. The company maintains a portfolio of onshore and offshore oil and gas blocks with approximately 1.7 billion barrels of oil equivalent in reserves and resources. It owns Vadinar Refinery, India's second largest single site refinery, with a capacity of 405,000 barrels per day and a complexity of 11.8, which is amongst the highest globally. The refinery has the ability to produce high-grade products from some of the toughest crudes.

Beyond the success of its refining assets, judges were most impressed with Essar's bold move to “jump into the retail business,” as one judge observed. Essar is among the first private companies in India to enter the refined products marketing sector, pioneering the franchisee-owned, franchisee-operated model of supplying high-quality petrol and high-speed diesel as well as non-fuel retail. The company is now India's largest private sector oil retail network, operating more than 2,500 branded oil retail outlets throughout India, with another 2,600 in development. Combined with its foray into retail and direct sales in Kenya and South Asian countries, judges felt that the company's retail business has “impressive potential” and a “strong growth outlook.”

Essar's marketing prowess has helped the company report excellent financial performance despite falling oil prices. Retail sales accounted for 16 percent of the company's third quarter fiscal year 2016 revenues compared to 6 percent in the corresponding quarter in 2015; the company's CFO states that retail “will be the key driver to foster the overall growth and profitability of the company.”

As the downstream market continues to develop and Essar's business becomes increasingly global, judges feel that Essar is well-positioned for continued success. “They're nimble – adapting to the environment, and doing so quickly,” remarked one judge.

Industry Leadership Award
Power

Enel
Italy

Founded in 1962, multinational power provider Enel made history as the first Italian electricity operator and the second listed utility in Europe. Today, with a presence in 30 countries across four continents, the company continues to connect people and businesses to electricity, gas and related services in new ways. Enel calls its approach “Open Power,” and it impressed judges with its pioneering spirit, ambitious goals and commitment to sustainability.

Integrated electricity and gas operator Enel has more than 61 million end users around the world, giving it the largest customer base among its European competitors. The company's diversified portfolio runs on renewable sources of power including hydroelectric, wind, geothermal, solar, thermoelectric and nuclear. Nearly half of the energy Enel generates is produced with zero carbon dioxide emissions, enthusing the independent panel as one of the leading producers of clean energy.

Enel was the world’s first company to replace traditional electromechanical meters with “smart” electronic meters – a critical component for the development of intelligent grids, smart cities and electric transport. Judges were impressed by Enel's ability to digitize the grid, which enables accurate pricing, reliable supply and detailed data collection. The company now manages the most digitized grids in the world, and is leading the digital movement in emerging markets.

Enel also exhibited its leadership and innovation through its
collaboration with Nissan on vehicle-to-grid technology, through which electric car batteries are aggregated to act as one giant battery connected to the grid. Enabled by the two-way Enel charger, electric vehicles become a source of grid balance, earning revenue for vehicle owners. With Enel and Nissan’s first fully commercial vehicle-to-grid hub now operating in Denmark, judges applauded Enel for being “farther along than others” with this groundbreaking battery aggregate technology.

“I like what they’ve done so far with sustainable development projects,” remarked one judge, but the company has bigger dreams. Already a champion of innovation, the company aims to be completely carbon-neutral by 2050 – a goal judges feel is within reach for this year’s Industry Leader in Power.

Grid Edge Award
Energy Management
Blue Pillar
United States

The Grid Edge Award for Energy Management reflects the blurring lines between energy providers and consumers, as players on both sides of the meter seek new ways to solve the problem of intermittency. While many of the category’s nominees aim to “manage and orchestrate” power, winner Blue Pillar takes top honors for its ability to “balance thousands of loads of generation sources, and store resources around the grid,” observed one judge.

Blue Pillar, a ten-year-old energy management company, offers universal connectivity and control through its revolutionary Internet of Things (IoT) platform. The company enables its customers to automatically connect and control all “Energy Things” – anything that generates, switches, measures, or consumes – via a single template-based platform. Its customers can then manage everything from heat and power systems and solar arrays to diesel generators, meters and HVAC equipment. Importantly, the platform enables connectivity for all equipment regardless of manufacturer, eliminating the need to “rip and replace” legacy infrastructure. The company, which connects an average of 76 units per site, estimates that its customers can save over 100 man-hours and 15-20 percent on energy costs annually.

Blue Pillar provides real-time status views for all the equipment it connects, sharing the data centrally and enabling energy providers to plug-and-play their own applications such as grid balancing, load shedding, voltage optimization or demand-side management. This gives its customers unprecedented insight into and control over their energy needs, improving reliability, resiliency, efficiency and cost reduction.

Judges remarked on Blue Pillar’s impressive customer list, which is populated by big-scale organizations that require robust security measures and can’t accept risk within their operations. The company began by serving hospitals with emergency power supply systems, and has recently expanded into utility grid operators and energy service providers – “the first company that has attacked the intermittency problem from the generation side,” marveled one judge.

As Blue Pillar’s novel solution can now serve not only utilities’ customers but also the utilities themselves, judges expect continued innovative thinking and strong performance from this Industry Leader.

Corporate Social Responsibility Award
Hindustan Petroleum Corporation Limited
India

Judges appreciate the rich competition in the CSR category, evidence that today’s energy players take seriously the responsibility of being good corporate citizens. Our winner Hindustan Petroleum Corporation Limited (HPCL) is a familiar name at the Global Energy Awards, as now-retired CEO Nishi Vasudeva received last year’s CEO honors. Under new head Mukesh Kumar Surana, HPCL takes this year’s top CSR prize for its “robust portfolio” of “deep, long lasting and comprehensive” programs.
HPCL refines crude oil and markets petroleum products through its E&P and downstream operations. The company has more than 11,000 employees at its various refining and marketing locations across India. As a state-owned entity, HPCL is mandated to pursue certain CSR goals in line with national efforts to improve health, develop a skilled workforce and pursue sustainability. However, judges appreciated that HPCL went above and beyond the national requirements with its meaningful, broad-scope programs.

HPCL’s programs target social and economic development in areas including Childcare, Education, Healthcare, Skill Development, Environment & Community Development and Sports. The company focuses on identifying gaps in the existing system and filling them, creating long-term, sustainable impact rather than create parallel systems. Among its many impressive programs are an initiative to educate 11,000 girls in tribal areas; another focused on feeding 12,000 students in government schools; and one providing free heart surgeries to 800 patients from poor socioeconomic backgrounds.

This broad array of CSR programs is subject to regular evaluation and monitoring during implementation, both by employees who lead the projects and field officers who work in communities near HPCL’s business locations, as well as by third-party auditors. “They’re very well-organized – it’s an impressive independent setup,” approved one judge.

Judges commend HPCL’s employees for carrying out an impactful, wide-ranging program that shows the company is clearly in sync with both its country and its community. The company is clearly achieving its CSR goal: to “Create Shared Values” towards a sustainable future.

Construction Project of the Year

Bechtel
United States

Energy companies often perform difficult work in demanding conditions, but the complexity of Bechtel’s Curtis Island LNG projects earned judges’ unanimous respect. Bechtel’s winning entry detailed the creation of three LNG facilities for Queensland Curtis LNG, Australia Pacific LNG and Santos GLNG. These three simultaneous projects for three separate customers took place in one shared location: Curtis Island, off the shore of Queensland, Australia. This island location, reachable only by water and located near the Great Barrier Reef, introduced further environmental, logistical and labor challenges.

Undaunted, engineering and construction giant Bechtel set out to execute across functions and geographies. It deftly managed the project through a collaborative approach incorporating its three customers, global supply chain participants, regulators and the local community. The project employed 30,000 people across seven countries on four continents at its peak, with 14,500 of them on Curtis Island alone. Bechtel engineers worked on a 24-hour cycle, with employees in Houston, New Delhi and Shanghai gearing their designs to modular construction in order to achieve quality, speed and cost control goals.

A key element of the LNG plants’ construction process was the construction and delivery of modules to the work sites. Working at the company’s yards in the Philippines, Indonesia and Thailand, Bechtel fabricated 260 modules, the largest of which weighed 3,500 metric tons. Bechtel delivered them to Curtis Island in 83 shipments and installed them safely and on time. Together, the projects required enough concrete to construct seven Empire State Buildings; structural steel to build 13 Eiffel Towers; and electrical cable to run the length of the Grand Canyon 11 times.

Now in production, Curtis Island represents part of the largest concentration of private-capital investment in Australia’s history. The projects are expected to produce approximately 25 million metric tons of LNG annually, or approximately 8 percent of global LNG production. With annual global demand for LNG on the rise, judges feel that Bechtel’s impressive execution and ability to “solve issues on an island” is well-deserving of Construction Project of the Year honors.
Engineering Project of the Year
Royal Dutch Shell
The Netherlands

Lauded by previous judges as “the best technical oil company in the world,” global oil giant Royal Dutch Shell returns as winner of Engineering Project of the Year with Stones, the world’s deepest offshore oil and gas project. With its remarkable scale and inherent engineering challenges, Stones impressed the judges as another of the company’s “consistently diverse” projects.

Stones is situated in approximately 2,900 meters (9,500 feet) of water in an ultra-deep area of the Gulf of Mexico. It employs the first floating production, storage and offloading (FPSO) vessel that Shell has put into the Gulf of Mexico, which connects to subsea infrastructure to produce oil and gas from reservoirs 30,000 feet below sea level. Stones offers novel solutions to many of the problems inherent in ultra-deepwater operations. To manage the Gulf’s often-severe weather, the Stones team pioneered the combination of lazy wave risers with a disconnectable buoy, enabling the FPSO to sail away during storms. Shell engineers created prototype of the buoy using 3D printing to ensure efficiency and limit potential safety risks. To maximize production at the project’s record depths, Shell plans to introduce a super-efficient sea-floor pumping technology, employing an artificial lift system expected to be the deepest and highest pressure utilized in the industry. This string of innovations required more than 22 million man-hours for completion and boasts an outstanding safety record.

Shell gains great knowledge by operating in Stones’ record depths, and it has been generous in sharing that knowledge with local scientists. Through partnerships with universities and research institutions, the company is making space on the project’s 3-kilometer mooring line for scientific instruments that collect marine data. Given the ability to track data over the life of the project, this arrangement could shed light on climate conditions in the deep oceans and potentially spur a scientific breakthrough.

“There are a lot of ‘firsts’ here,” approved one judge; the panel concurred by awarding Stones their top scores for taking on new challenges in deep water with innovative concepts.

Commercial Application of the Year
SolarReserve
United States

The independent judging panel saw SolarReserve coming. This year, the company adds to its well-deserved collection of previous Platts Global Energy Awards, including 2012 Rising Star Award – Individual and 2015 Rising Star Award – Company, by definitively commercializing its answer to the intermittency problems plaguing renewable energy sources.

Through the development of its flagship project, the $1 billion Crescent Dunes Solar Energy Facility, SolarReserve has brought to life its proprietary advanced solar thermal technology with integrated energy storage –
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and commercialized it, “something other companies have been grappling with for years” from both technological and financial standpoints, marveled one judge.

Commencing commercial operation in late 2015, Nevada’s Crescent Dunes features SolarReserve’s Concentrating Solar Power (CSP) technology, which employs mirrors to focus sunlight to heat molten salt and then store it so electricity can be delivered around the clock. It is the world’s first utility-scale facility to feature these game-changing molten salt power tower energy storage capabilities, with storage capacity nearly equal to the combined power of all the world’s installed utility scale batteries.

Using its revolutionary CSP, Crescent Dunes delivers firm, reliable electricity from solar energy with the ability to power 75,000 homes during periods of peak demand. The project delivers 110 megawatts of electricity as well as 1,100 megawatt-hours of energy storage to Nevada, under a 25-year power purchase agreement with NV Energy.

While Crescent Dunes itself is an impressive accomplishment, judges appreciated that “customers are lining up” for SolarReserve’s projects. Development activities are underway in a dozen US states and more than 30 countries, including a second plant comparable to Crescent Dunes in South Africa. The judges’ unanimous choice for Commercial Application of the Year, SolarReserve surpasses all category criteria with its emissions reduction, practicality, reliability and overall commercial success. Judges concur that the company has lived up to its Rising Star promise, as SolarReserve’s operations epitomize US-developed technology and set new standards for the future of global clean power generation.

Breakthrough Solution of the Year

DuPont Industrial Biosciences/Archer Daniels Midland Company United States

DuPont and ADM report that nearly one-tenth of the world’s oil is used to produce everyday products such as shopping bags, soft drink bottles and frozen food containers. The partners’ groundbreaking product is a biomaterial that can replace some of the oil in consumer plastics, with improved performance. The companies combined their expertise in agriculture and food science to develop a new process for turning fructose into biomaterial: the molecule furan dicarboxylic methyl ester (FDME).

FDME enables production of a number of high-value, bio-based chemicals and materials with applications in everything from clothing to auto parts. This new FDME technology is a simpler, more efficient process than traditional conversion methods, resulting in higher yields and lower operating costs; better product performance; and smarter renewable materials that are more consumer-friendly. Notably, one material in development using FDME is a novel polyester that improves the gas-barrier properties in product packaging, which improves shelf life and reduces weight. Judges appreciated the implications of this development for global transportation of medicines, making it “safer and more cost-effective.”

ADM and DuPont are now in the process of bringing FDME to market. They plan to build an integrated 60 ton-per-year demonstration plant in Illinois, which will enable potential customers to generate enough product quantities for testing and research.

In developing FDME, DuPont and ADM have set a new standard for both innovation and sustainability by creating a product with greater efficiency, higher productivity, better quality and lower environmental impact. Judges were captivated by FDME’s “enormous scale” and potential, observing that the ability to produce a “stronger product with less waste” has massive implications for packaging, textiles, engineering plastics and countless other industries.

The Breakthrough Solution of the Year award recognizes technology that shows game-changing potential but is not yet in commercial operation. This year’s winner, based on a collaboration between DuPont Industrial Biosciences and Archer Daniels Midland (ADM), was selected for its “huge global potential” to “feed a massive market” as a replacement for glass and plastic.
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Energy and form are a major inspiration for my work

Yousef Ahmad - Artist

Energy powers our world, it enriches our lives.
Qatari artist Yousef Ahmed uses energy as an inspiration for his art.
It fuels his imagination.
RasGas’ liquefied natural gas has a transformative and sustainable effect on Qatar’s future.
Clean, reliable energy for Qatar and the world.
Energy for Life.

RasGas

ENERGY
for life

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“Energy and form are a major inspiration for my work”
Yousef Ahmad - Artist