S&P Global Platts

Insight

April 2019

Global Power Markets Conference™
Where energy connects

Global electricity trends | Maritime risk in the East Med | What's next for US shale oil? | Renewables in Asia-Pacific

Shape shifting

US power markets

Insight

ISSN 2153-1528 (print)
ISSN 2153-1536 (online)

Publisher
Murray Fisher, +1 720 264 6644
murray.fisher@spglobal.com

Editor
Emma Slawinski, +44 207 176 0365
emma.slawinski@spglobal.com

Copy Editors
Alisdair Bowles, James Leech

Production Manager
David Sullivan, +44 (0)20 7176 0268
david.sullivan@spglobal.com

Production Office
Platts Insight Magazine
1800 Larimer, Suite 2000
Denver, CO 80202

Advertising Sales – Americas
Bob Botelho, +1 720 264 6618
robert.botelho@spglobal.com

Advertising Sales – EMEA, Asia-Pacific
Irina Bondareva, +44 207 176 0253
irina.bondareva@spglobal.com

Circulation Manager
Kacey Comstock, +1 720 264 6631
kacey.comstock@spglobal.com

Article Reprints & Permissions
The YGS Group,
+1 717 505 9701, ext 105
plattsreprints@theygsgroup.com
Subscribe free at:
spglobal.com/insight

S&P Global Platts
20 Canada Square, 9th Floor
London, E14 5LH, UK

President
Martin Fraenkel

Global Head of Market Insight
Sarah Cottle

Global Head of Pricing
Dave Ernsberger

Global Head of Analytics
Chris Midgley

S&P Global
Platts

Contributors

Jared Anderson
Senior Writer, Power

Bruno Brunetti
Head of Global Power Planning, Analytics

Rocco Canonica
Director, Power

Katherine Dunn
Associate Editor, Light Ends

Lin Fan
Director, Analytics

Meghan Gordon
Senior Writer, Oil

Morris Greenberg
Senior Manager, Analytics

Siobhan Hall
Senior Editor, Energy News

Paul Hickin
Associate Editorial Director, Oil

Marc Howson
Director, LNG

Sebastian Lewis
Content Director, China

Felix Maire
Senior Analyst, Analytics

Miriam Malek
Senior Editor, Energy News

Jasmin Melvin
Editor, Generating Fuels

Steve Piper
Research Director, S&P Global Market Intelligence

Jeff Ryser
Senior Editor, Generating Fuels

Emma Slawinski
Editor, Insight

Starr Spencer
Senior Editor, Oil

Mark Watson
Senior Editor, Generating Fuels

Kate Winston
Editor, Generating Fuels

Eric Yep
Senior Editor, Energy News

Contents April 2019


44


70

Editor's Note

Emma Slawinski

Editor

As energy sector participants gather in Las Vegas for the S&P Global Platts 34th Annual Global Power Markets Conference, the industry is confronting seismic shifts.

While huge strides continue to be made towards decarbonization, amid mounting public and governmental pressure to keep climate change in check, the overall pie of electricity demand is also growing at speed. Fossil fuel additions will slow, but are starting from such a high base that 20 years from now coal and gas will still make up around half of total output, according to the International Energy Agency.

S&P Global Platts Analytics' research provides a panorama of developments in electricity generation across the continents from page 18, showing that renewable additions to the global fleet slowed in 2018 but still far outpaced those of fossil fuels and nuclear combined.

The Asia-Pacific region is leading the way both in terms of demand growth and the race to install more renewables, as Eric Yep writes from page 70. While China continues to steal headlines, the impact of fast power sector development in countries like India and Thailand should not be overlooked.

In our cover story, Platts' North American power editors report on a conundrum facing the US, that will be familiar to other countries too (page 8). There is a surfeit of natural resources – from abundant shale gas to plentiful sun and wind – but the challenge is now to harness that energy so that it can be delivered precisely where and when needed.

US wind and solar power costs are dropping and allowing the technologies to compete more aggressively with existing coal and gas plant, Steve Piper of S&P Global Market Intelligence writes (page 60). The side effect is a risk of insufficient baseload generation to back up intermittent renewables, but there are hopes that battery storage can at least mitigate this in the short term, and eventually become a more comprehensive solution. Jared Anderson and Felix Maire look at progress made so far, and targets for the future, in US power storage (page 44). In the longer term, they write, electric vehicle adoption will help to drive battery storage costs lower, while the large pool of capacity already queued for connection to the grid is a promising sign.

Although giving special attention to the electricity sector, this edition also ranges across developments in other commodities, including LNG's commoditization (page 35), the next steps in the US shale oil boom (page 50), and the impact on commodities of slowing growth in China (page 78).

Finally, for some thought-provoking commentary on energy transitions, the geopolitics of oil, and diversity in the energy industry, turn to page 38 for our recent Insight Conversation with Carole Nakhle, CEO of independent consultancy Crystol Energy, and founder of Access for Women in Energy.

plattsinsight@spglobal.com

Best of the Rest

Our website **spglobal.com/platts** contains an extensive selection of free news, videos, podcasts and special reports about energy and commodities. Here's our pick of recent highlights

Interview: Arnoud Balhuizen, BHP Billiton

BHP's chief commercial officer, Arnoud Balhuizen, speaks with S&P Global Platts about developments in the iron ore and metallurgical coal markets, the company's business priorities and China's environmental push on raw materials

Special report: Turning tides

A stricter IMO sulfur cap on marine fuels is due to come into force in 2020. S&P Global Platts outlines the regulation's effect on refiners and shipowners, analyzes how markets will adapt and offers a birds-eye view on the environmental impact

Podcast: Battery metals and raw materials

In this podcast, S&P Global Platts metals specialists discuss developments in nickel and cobalt supply – including how the "much forgotten" battery metal nickel has come to the forefront of discussion in recent months

Blog: Chinese LNG goes counter-seasonal

China has played an outsized role in LNG markets in the last two years, but its demand patterns and trading strategies are changing. This article analyses the impact of shifting government policies on imports and seasonal price variation.

Special report: Building bridges

Construction markets have specific challenges and opportunities, but are always exposed to global energy and commodity prices. S&P Global Platts explores some of the factors driving construction and how developments in commodities play a key role in determining whether projects get built, and how much they may cost to develop.

Shape-shifting: US power markets in 2019

Evolving regulation is a top preoccupation for the US power sector this year. At stake are a reliable energy supply and the ability to integrate new, clean sources of energy. By S&P Global Platts Staff

As the US power industry grapples with reliability concerns due to low power prices, rapid renewable power growth and baseload power plant retirements, policymakers are scrambling to offer solutions.

Regulators are also trying to work out how to best incentivize adequate generation capacity additions, and how to ensure compensation of existing power plants and other resources operating in competitive markets.

The current challenges have already led to a variety of complicated market design proposals and other potential fixes created at both the state and federal level.

Among the major federal issues being watched closely this year are efforts by the White House to keep nuclear and coal-fired power plants afloat, although so far the Trump administration's efforts have been frustrated. Among the states, meanwhile, Texas has made market design changes to encourage generation capacity development at a time when reserve margins are extremely low

PJM Interconnection also has the daunting task of installing reforms to maintain a competitive marketplace in the face of state subsidies designed to prevent the retirement of major baseload nuclear facilities because of low energy prices.

In California, the effort to go 100% renewable has led to a number of reliability questions. And these challenges come amid the massive fallout from the bankruptcy of the state's largest utility, PG&E, which is likely to have widespread and longstanding impacts on the power market.

Appealing to the base(load)

The White House's effort to keep struggling coal and nuclear plants solvent is perhaps the highest-profile power industry event in 2019. However, many Washington insiders have grown increasingly skeptical that action at the federal level to keep these baseload coal and nuclear plants online can find a legal foothold.

The federal government-owned utility Tennessee Valley Authority voted February 14 to close two coal generation units despite pressure from President Donald Trump

In a recent development, the board of the federal government-owned utility Tennessee Valley Authority voted February 14 to close two coal generation units despite pressure from President Donald Trump, who tweeted ahead of the vote that the utility "should give serious consideration to all factors before voting to close viable power plants".

TVA responded that while coal was an important part of its generation mix, the Paradise and Bull Run coal plants at issue no longer met its system needs. Retiring the plants is expected to save TVA customers more than $1 billion.

This latest snub to the White House's efforts comes over a year after the Federal Energy Regulatory Commission rejected the administration's original plan to prop up coal and nuclear generators. That involved a notice of proposed rulemaking from the Department of Energy that sought to guarantee full cost recovery and a return on investment for generators that had 90-day, on-site fuel supplies.

"I think it's just going to be very difficult to do anything on the federal level although I think the administration is going to continue to try," Barry Worthington, executive director of the United States Energy Association, said in an interview. Action from states could be more likely, he said.

States such as Illinois, New York and New Jersey have turned to zero emissions credits programs to save their nuclear fleet, and Worthington said coal-producing states may look to craft programs to help coal units.

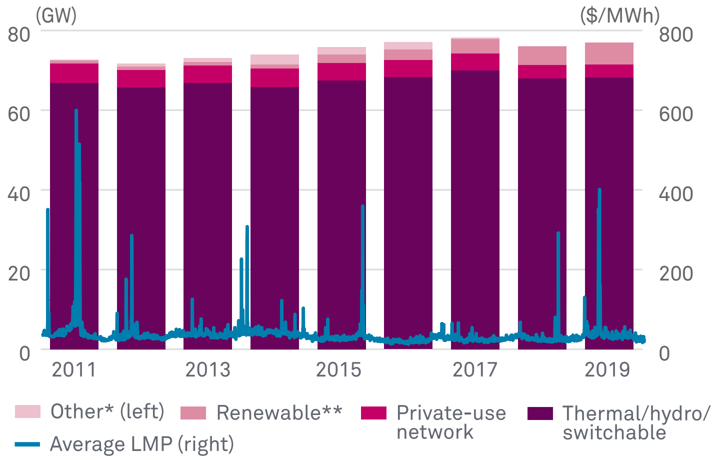
FERC Chairman Neil Chatterjee said on the sidelines of an industry conference that if a threat is identified, his preference would be to resolve it with a market solution. “Whatever action we take on resilience will be based firmly on the record, on evidence, on science without any political influence or favoritism for one fuel source or another. We just want to make sure we do it right.”

ERCOT struggles with tight capacity

Among the state initiatives being watched are the Electric Reliability Council of Texas’ market reform strategies to encourage development and retention of dispatchable generation resources, in light of the low reserve margins the Texas grid is expected to face again this summer.

A number of recent capacity retirements resulting from renewable power generation growth, cheap and abundant natural gas, and low power prices have put the state grid in a precarious supply situation.

ERCOT summer operational capacity



*Includes available mothballed capacity or capacity under reliability-must-run contract
**Wind and solar discounted for relevant intermittent resource capacity factors.
Sources: S&P Global Platts, ERCOT Capacity, Demand and Reserves reports from the preceding December of each year, except for summer 2014, which is based on the CDR issued in February of that year.

Over 5 GW of fossil-fuel generation – including 4.2 GW of coal-fired generation – has been retired in ERCOT since May 2017. This summer the market has a projected 7.4% planning reserve margin, the lowest on record and well below the system's target of 13.75%.

In February, ERCOT issued a market notice stating that it would implement the first change to its Operating Reserve Demand Curve on March 1. ORDCs are used to calculate scarcity prices when supply and demand tighten, providing incentives for new generation development. ORDCs enable wholesale prices to increase automatically as available operating reserves decrease. The actual price adjustment is based on the level of increasing risk that a rotating outage could occur and the potential consumer impacts associated with an outage.

In order for the ORDC change to have the desired generation retention and growth effect, investors and developers must have faith that the resulting higher wholesale prices will be sustained, and such faith may be hard to find during a biennial legislative session in which lawmakers may hear complaints from consumers about surging electricity bills.

ERCOT, market stakeholders and industry observers all seem to disagree about how successful the market reform actions will be – or indeed can be – in encouraging new generation capacity.

“Market reforms are good but probably not enough to yield new dispatchable capacity within 2-3 years,” said Gurcan Gulen, energy economist and principal of G2 Energy Insights.

However, Gulen said that if the reforms enable developers to obtain financing, 2 to 3 GW of gas-fired generation may result.

In contrast, Cyrus Reed, conservation director of the Sierra Club's Lone Star region, said, “We do not think the ORDC adjustment will make a large difference in providing an incentive to more dispatchable generation, though it could provide an incentive for investments in demand response as a reaction to higher prices.”

In Texas, demand response often takes the form of on-site fossil-fueled generation, either with natural gas or by a liquid fuel such as diesel or gasoline. Such relatively high-cost, inefficient resources could be aggregated and dispatched to serve the grid in high-demand situations.

"Alliance" of renewables, oil, gas

In February, the ERCOT Board of Directors learned the Far West weather zone's peak demand has doubled since 2009 – from about 1.8 GW to about 3.7 GW – largely because of Permian Basin oil-and-gas development.

ERCOT projects about 20 significant new wind and solar projects in West Texas by 2033, but Neil McAndrews, an energy market consultant based in Austin, Texas, said the region's natural gas production is a more significant impediment to ERCOT's thermal generation fleet.

"The essential problem faced by all US utilities is that natural gas is priced, in large part, as a by-product," McAndrews said. "The Permian oil field is wasting 55 Bcf per year via flaring, according to industry sources. ... The gas that is flared is considered valueless."

"Look for many more retirements of coal and nuclear units in the US," McAndrews added. "Without addressing the fundamental problem of natural gas oversupply, there is little ERCOT or the PUC of Texas can do."

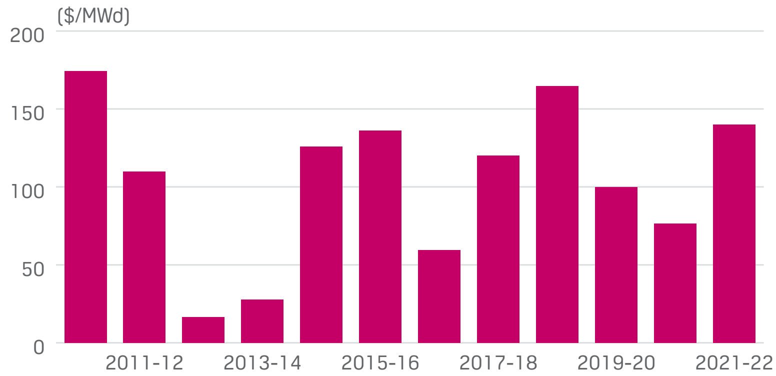
PJM markets in flux

ERCOT has not been alone in attempting to manage challenging capacity trends. PJM Interconnection has been at the forefront of the situation in large part because of low power prices due to cheap natural gas from the Appalachian Basin, as well as several state efforts to subsidize uneconomic baseload facilities in response to those low power prices and the likelihood of plant retirements.

In its 2018 capacity auction, the PJM base residual auction RTO clearing price came in at $140/MW-day for capacity in the 2021-2022 period, an 83% increase from the previous year's clearing price of $76.53/MW-day.

The capacity price increase was attributed to a response to continuing energy prices declines, and thus, net revenue for generators, Stu Bresler, PJM's senior vice president of operations and markets, said when the results were released. Since generators have been receiving less revenue from the energy market, they have looked to earn higher capacity payments and thus bid into the auction at higher prices.

PJM base residual auction resource clearing prices (RTO)



Source: PJM

PJM has been working to adjust some of its energy market pricing rules, adding uncertainty to the pricing dynamics between the energy and capacity markets.

In addition, the Federal Energy Regulatory Commission issued an order in June 2018 that found the PJM Interconnection's existing tariff governing its capacity market is unjust and unreasonable, which set off a major proceeding to adjust the rules. The order said PJM's capacity pricing model had become "untenably threatened by out-of-market payments provided or required by certain states". Illinois, New York, New Jersey and Connecticut have passed laws or issued regulations designed to financially support a number of at-risk nuclear plants, while several other states are considering similar actions.

"The essential problem faced by all US utilities is that natural gas is priced, in large part, as a by-product."

A decision from FERC is expected in the first half of 2019 to keep the capacity auction on schedule for August. The upcoming auction already has been delayed three months due to the complexity of the process.

FERC's order will be one of the most important capacity market developments of 2019.

PJM's energy price formation contains two main elements: fast-start pricing and reserve price reform. Fast-start pricing, which would modify pricing treatment for generation resources that can start up quickly, awaits a FERC response. A contentious filing on reserve reform from PJM at FERC can be expected around mid-March, PJM president and CEO Andy Ott said in a recent interview. Reserve pricing reform is expected to include multiple components affecting several major aspects of the wholesale power market in the region.

Initial S&P Global Platts Analytics modeling of the impact of both fast-start pricing and reserve reform resulted in an overall price increase of $1-2/MWh. Since the analysis was conducted, updates to the proposed ORDC as well as a larger penalty adder could increase this estimate, according to Platts Analytics power market analyst Kieran Kemmerer.

Ott said in the interview that he believes reserve price increases will incentivize new alternative technologies to provide more reserves and "compete away the advantage that generators have had and so the price will drop".

As the rule changes encourage technologies such as storage and demand response, providing additional reserves to the market, the increased supply of reserves could exert downward energy price pressure.

The outcome will provide valuable lessons that could influence future state or federal actions.

ISO New England faces controversy

Stakeholders in ISO New England's capacity market also recently raised concerns that low prices, a renewable exemption and a specific contract with the gas-fired Mystic power plant near Boston in a recent capacity auction, all conspired to damage the viability of generation resources in the region.

ISO-NE's 13th forward capacity auction held in February closed at a preliminary clearing price of $3.80/kW-month, an 18% decline from last year's auction price and the lowest clearing price in six years.

Worries arose that the Mystic power plant's exemption and contract dampened the impact of ISO-NE's rules for competitive auctions with sponsored policy resources. In December 2018, FERC accepted a cost-recovery proposal for Mystic, providing ratepayer support for the plant, which was allowed "price-taker" status in the next three annual capacity market auctions.

The New England Power Generators Association said that with Mystic entered as a price taker, the auction undervalued other fuel-secure resources in the market. "Coupled with the future scale of subsidized new entry, competitively-determined adequate revenues are at grave risk in New England," NEPGA President Dan Dolan said.

New York carbon price

In New York, efforts to price carbon emissions into the wholesale market could lead to price increases. The New York Independent System Operator's five-year power grid plan sets out strategic initiatives to guide its projects and resource allocation that include pricing carbon emissions into the wholesale market, which could increase power prices by about $10-$15/MWh, according to Platts Analytics.

"The carbon prices being discussed for implementation in New York are significantly higher than the current [Regional Greenhouse Gas Initiative] RGGI prices," said Manan Ahuja, senior director of North America power modeling at S&P Global Platts Analytics.

If implemented, the carbon prices could add significantly to the wholesale power prices, increasing location-based marginal prices "by about $10-$15/MWh (in the proposed carbon price vs the RGGI price) based on our recent modeling," Ahuja said.

Such changes would also impact decisions about what type of supply resources get built or retired, he added.

"Analysis conducted by the Brattle Group on the carbon pricing proposal under consideration, found a slight, short-term increase of roughly $1.50 on the average consumer's monthly bill," said Kevin Lanahan, vice president of external affairs at NYISO. "However, the same analysis found that costs drop quickly in the out-years, and produce savings as markets respond," he added.

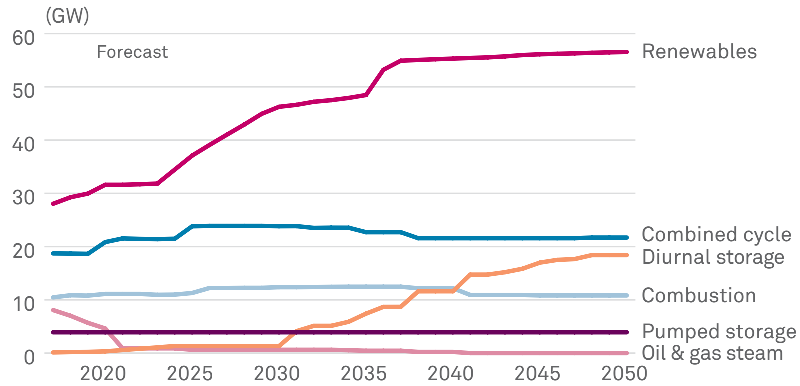
The initiative could go into effect in the second quarter of 2021, NYISO has said.

California worships renewables

Many states have ambitious clean energy goals and vague perceptions of the challenges they carry, but none are as far along or as deep into the difficulties as California. The state is forging ahead toward a goal of 100% clean energy by 2045, but to get there it will need new rules and at least some gas-fired power to ensure resource adequacy.

Meeting the target with only renewables and the current storage technology is likely to be too expensive, stakeholders say.

California net summer generating capacity



Source: Energy Information Administration

The PG&E quagmire

Perhaps the biggest side-issue among 2019 themes in the US power market, is the bankruptcy of PG&E Corp. and its California utility subsidiary Pacific Gas & Electric. In its bankruptcy filing on January 29, PG&E said its utility subsidiary was, as of January 2019, the counterparty as buyer under at least 387 power purchase agreements, which, it said, involve 350 counterparties, for a total of approximately 13,668 MW of contracted capacity.

These PPAs are now a major subject of contention in court proceedings involving a large number of counterparties, stakeholders and FERC. The fate of these power supply agreements, and potentially the ongoing financial viability of some of the counterparties, hangs on the court's decision.

Shortly after PG&E said it would file for Chapter 11, NextEra Energy filed a petition seeking a ruling from FERC that PG&E could not reject its power purchase agreements. On January 25, FERC issued the order that NextEra Energy sought.

On January 29, the day of the Chapter 11 filing, PG&E also filed with the bankruptcy court an adversary case against FERC, asking the court for a declaratory judgement confirming that the bankruptcy court had exclusive jurisdiction over PG&E Corp's rights to reject "certain executory power purchase agreements" and that FERC did not have 'concurrent jurisdiction,' or any jurisdiction, over their PPAs.

In response, FERC has argued that PG&E Corp was going "well beyond seeking to enjoin their regulator" and was "using the Bankruptcy Code as a shield to permit rejection of PG&E's executory contracts and instead demand that the court turn the code into a sword that would slice through the Federal Energy Regulatory Commission's long-standing statutory obligation to regulate wholesale energy contracts".

FERC went on to say in subsequent filings in the case that when a debtor like PG&E Corp entered into PPAs in accordance with FERC regulations, "those PPAs took on the force of federal regulation, with terms and conditions enforceable independent of the parties' private contract rights".

Judge Dennis Montali, who is overseeing both the bankruptcy and the adversary proceeding between PG&E Corp. and FERC, has set an April 10 hearing in his San Francisco courtroom to decide on granting PG&E Corp.'s request for a preliminary injunction that would give the court sole jurisdiction over the PPAs in the bankruptcy case.

Not every megawatt needs to be clean and green under the state law that set the mandate, and there are certain resources needed for reliability that have a carbon footprint, said Karl Meeusen, senior advisor for infrastructure and regulatory policy at California Independent System Operator.

But while some thermal generation is needed in the short term, the possibilities are endless for the resource mix in the future, Meeusen said. And both Cal-ISO and the CPUC are working on rule changes to help transition to a low-carbon grid.

Getting to 100% clean energy with only wind, solar and short-duration storage is cost-prohibitive because it requires a massive overbuild of the renewable and storage portfolio to ensure reliability, according to Arne Olson, senior partner with consultancy Energy and Environmental Economics.

But getting to 80-90% clean energy can be done without sacrificing reliability, Olson said. “Natural gas capacity will continue to be needed indefinitely barring a breakthrough in nuclear, carbon capture and sequestration, or very long-duration storage,” he said.

While solar and storage will play a major role in California, there is also room for other resources, said Morris Greenberg of S&P Global Platts Analytics. Remote wind in Wyoming and New Mexico could be an important source of clean energy as inland coal retirements free up transmission, Morris said. The state can also rely on in-state hydro, some Pacific Northwest hydro, and California utilities’ share of the Palo Verde nuclear plant in Arizona, he explained.

The CPUC could improve the way the resource adequacy program accounts for the value of projects that combine renewables and storage, said Mark Specht, an energy analyst at the Union of Concerned Scientists. These projects create a value that is greater than the sum of their parts, he said.

Conversely, the CPUC might also need to weigh whether to require longer durations for storage projects to qualify as resource adequacy capacity, Specht said. Current CPUC rules allow four-hour storage to qualify.

In many ways, California will be the power sector’s guinea pig for the relationship between clean energy and reliability. Big questions remain in many ISOs about the appropriate generation fuel mix and capacity levels to meet reliability standards, and the answers may hinge on technological advances in storage. However, one of the biggest challenges is establishing the right market design that leads to appropriate price signals to meet those reliability goals. ■

Reporting by Jared Anderson, Mark Watson, Kate Winston, Rocco Canonica, Jasmin Melvin and Jeff Ryser

Renewables in the driving seat

Renewable energy continues to lead capacity additions amid a slowdown in coal and limited new gas-fired generation. By Bruno Brunetti and Lin Fan

Global investment in renewable power capacity continues to outstrip that in fossil fuels and nuclear, but growth has softened recently as a result of policy U-turns – with solar additions notably impacted.

A major change in the support for renewables was announced in May 2018 in China, creating uncertainty in a country that had been a global leader in terms of solar growth over the past several years. PV tariffs and installation quotas were reduced, while China is looking to introduce tenders for utility-scale plants and market-based allocation for distributed PV. Capacity additions in China during 2018 have totaled only about 44 GW, a decline by 16% on the year.

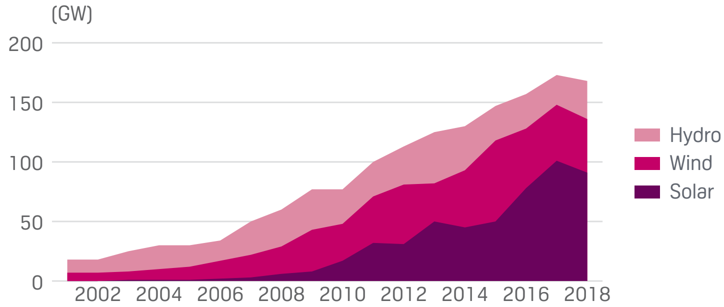
Early in 2019, some encouraging signs for solar developers once again emerged, as the Chinese government removed quotas on projects built without central government support and made efforts to reduce taxes, land costs, administrative burdens for developers and also prioritize grid access to non-subsidized projects. This latest announcement is likely a positive for Chinese solar development. Although declining costs are making solar photovoltaics more appealing, it's still unclear how the new regime will impact the development of unsubsidized projects. That means continued uncertainty around annual PV additions in the near future.

Meanwhile, headwinds have also been emerging in another important market for solar additions, India. While an ambitious solar target of 100 GW by 2022 has been set under the Jawaharlal Nehru National Solar Mission (JNNSM), a government initiative, there are nonetheless uncertainties related to the implementation of a 25% safeguard duty for imported modules, and other taxes have further dampened the enthusiasm around solar.

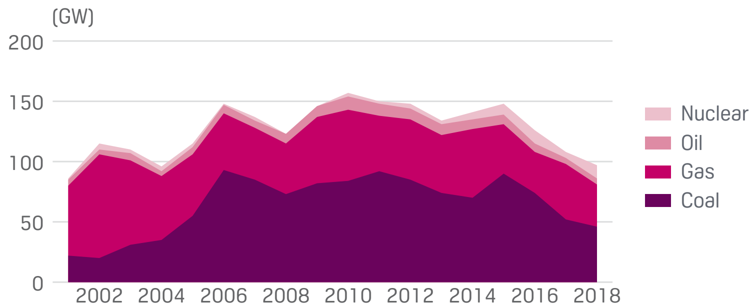
Tariffs on imported PV modules also took effect in early 2018 in the US, adding 30% to the cost of a module in the first year of implementation. The tariffs are set to decline by 5 percentage points each year over the next four years, and so will equal 25% in 2019. Module prices have, however, declined by over 30% over the past year, offering support to growth. The pipeline of utility-scale projects in the US totaled 38 GW as of January 2019, according to the S&P Global Market Intelligence World Electric Power Plants Database. Corporate-backed renewable projects remain a positive driver of installations, along with utilities' procurements under state-level renewables mandates.

Solar tops new capacity additions

Renewables



Fossil fuel and nuclear



*2018 is a preliminary estimate
Source: IRENA, S&P Global Platts Analytics, S&P Global Market Intelligence World Electric Power Plant Database

Interest in offshore wind grows

In the wind sector, capacity additions globally last year are estimated to have totaled around 44 GW, about 3% below 2017. Almost half of this capacity was added in China, with wind additions trending higher, in spite of uncertainty around its renewable supporting mechanism. While feed-in tariffs for onshore wind have been progressively lowered, China also took the decision in 2018 to switch to an auction mechanism, with gradual elimination of government subsidies. China has a strong pipeline of projects that will still be able to benefit from the prior or current support mechanism and will still be largely unaffected by the switch to auctions in the near term.

However, Europe has seen a significant decline in newly added capacity. Among the major markets, Germany installed over 3 GW in 2018, the UK about 2 GW and France around 1.8 GW. But overall, wind additions were well below 2017 and previous year levels, and were mostly in the onshore segment. To put this in perspective, there is rising interest in developing offshore projects, where Europe is already a leader. This is the result of a significant decrease in the overnight costs in recent years, while financial institutions are now comfortable with the technology.

Some 2.7 GW of offshore plants were connected in 2018, with the pipeline of offshore projects much larger, in the order of 27 GW, and Germany and the UK lead the way. The UK will see a third contracts for difference auction in May 2019, with offshore wind projects widely expected to capture most of the available funds. Up to 6 GW of offshore wind capacity may be awarded in this round. Also, a number of offshore projects in Europe are not relying on public support – other than grid connection – which suggests an increasing confidence that wholesale prices will be sufficient to cover installation costs.

Also worthy of note is the widening pipeline of offshore projects in the US East Coast – now totaling over 25 GW. Onshore wind is already the largest non-hydro, renewable source of power in the US, but development of offshore projects is gaining momentum.

The 800 MW Vineyard Wind project, being developed off the coast of Massachusetts, signed a power purchase agreement starting in the early 2020s at $65/MWh, a recent indicator of where US offshore wind costs may be in this early stage. With the supply chain now just being developed, this is already comparatively low, considering that UK projects will be allowed to bid in the upcoming May 2019 CFD auction for up to £56/MWh (equivalent to $73/MWh) with completion set for 2023/24. Beyond the costs, a more critical issue to watch for offshore wind is the timing of development of these projects, especially the permitting phase, which has been particularly lengthy.

Coal projects deferred, canceled

Although China remains the leader in clean energy installations and manufacturing, it may seem ironic that the country is also bringing online a large amount of coal capacity – 38 GW alone in 2018, just a few gigawatts below China's annual PV solar additions.

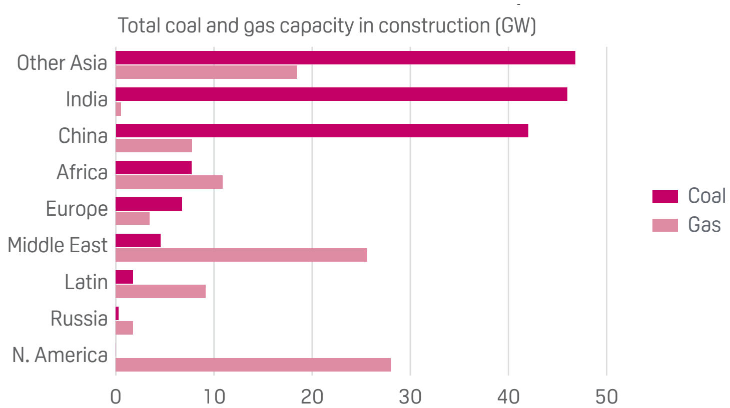
The World Electric Power Plant database indicates that about 45 GW of coal-fired projects are still in an active construction stage, although a growing number of projects face a more uncertain fate. It should be noted that Chinese power demand continues to grow, with a 49 GW increase reported in 2018. Last year's additional renewable capacity (solar, wind and hydro) would meet only a quarter of this demand increase. But the central government is getting more cautious and it recently started restricting the coal-fired capacity to be connected to the grid, in an effort to address growing overcapacities in certain provinces and air-quality concerns in major cities.

Similar trends have also emerged in India. According to the Central Energy Authority, India's net coal capacity has increased to 197.4 GW as of the end of 2018, up by only 4.5 GW on the year, with 6 GW of capacity

commissioned offset by about 1.8 GW of retirements. To put things in context, India had been installing some 20 GW/year of coal in the prior five years. Increasing renewable generation, together with fuel availability problems, have undermined utilization of the existing coal assets – now in the 50-60% range, whereas load factors were at 70-80% earlier this decade. India has 13.8 GW of solar in construction and 22.8 GW is already tendered, with bids in 2018 as low as Rupee 2.4 /kWh (equivalent to about $33.60/MWh), making coal newbuilds a considerably more difficult proposition, especially in a context of elevated imported coal prices.

While Asia continues to bring coal plants online – albeit at a slower rate – gas-fired capacity is increasing mostly in the US and Middle East. In fact, out of the 35 GW of gas generation connected in 2018 across the globe, the US accounted for about half, with another 20% in the Middle East. Cheap gas is clearly a major driving force in these regions. In the case of the US, lower gas prices have had a major impact on the erosion of coal-fired capacity. Over 70 GW of capacity with coal as the primary fuel has been retired over the

Coal generation build outstrips gas, led by Asia



Source: S&P Global Platts Analytics, S&P Global Market Intelligence World Electric Power Plant Database

past seven years. A further 20 GW of retirements have been announced, with much more capacity at risk. As many as 150 GW of coal units have been operating for more than 40 years. In addition, Platts Analytics sees another 16 GW of nuclear capacity at risk of retiring within the next five years, in spite of states in the Northeast implementing policies to aid at-risk nuclear generation.

The appetite to invest in large-scale gas-fired units has been fairly limited in other regions, especially in Europe. Baseload retirements in Europe are not expected to be as large as in the US, at least within the next 10 years. Platts Analytics forecasts that 20 GW of nuclear and 56 GW of coal/lignite will be closing in the upcoming decade in the major European markets. But uncertainties over competing renewables and operating hours are dampening power generators' interest in large-scale CCGT investment, while relatively high imported gas prices have hurt the margins of existing gas units. Even in countries where capacity mechanisms are in place, such as the UK, large-scale gas units were unable to secure long-term contracts, as distributed resources were more competitive. Instead, there have been a lot more small-scale OCGTs, which have low capex and considerably higher operational costs, with their flexibility matching the intermittency of renewables.

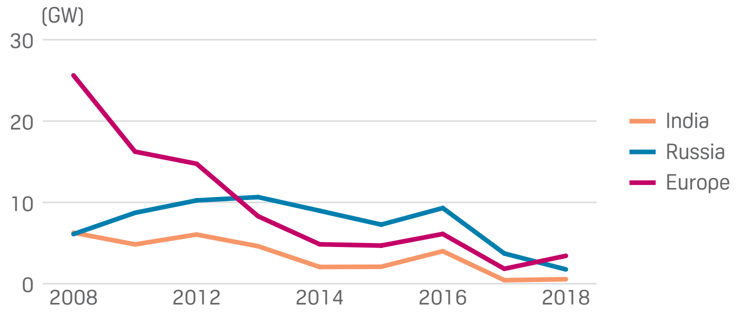
Gas-fired projects in Russia appear so far to be limited, considering that a large portion of the country's operational fleet is more than 40 years old. However, things will likely change as the Russian government recently approved a new capacity mechanism under which long-term contracts will be awarded for the upgrade of some 40 GW of aging thermal units. The first tender will be held in April-May for 11 GW that will have to be available from 2022-24.

Pace of nuclear build lifts

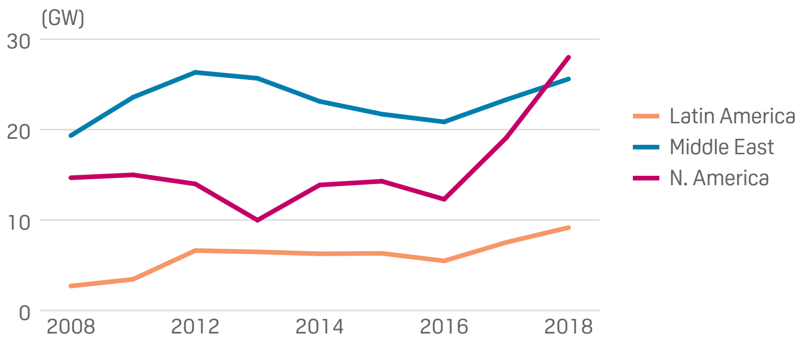
Nuclear remains a more marginal technology, although nine nuclear units were connected to the grid during 2018, representing some 10.4 GW, making 2018 one of the best years for nuclear in terms of capacity growth. Worthy of note is the fact that all of the Western-designed generation III+ reactors under construction in China – the French-designed EPR at Taishan and the AP1000 projects in Sanmen and Haiyang – have been connected to the grid. The pace of nuclear restarts in Japan has also picked up, with four reactors reconnected. However, the pace of global nuclear growth remains largely tied to China too, since the country has the largest capacity under construction globally. At present, there is only about 60 GW of nuclear capacity in construction worldwide.

Gas capacity under construction

Europe, Russia and India see declining gas projects under construction



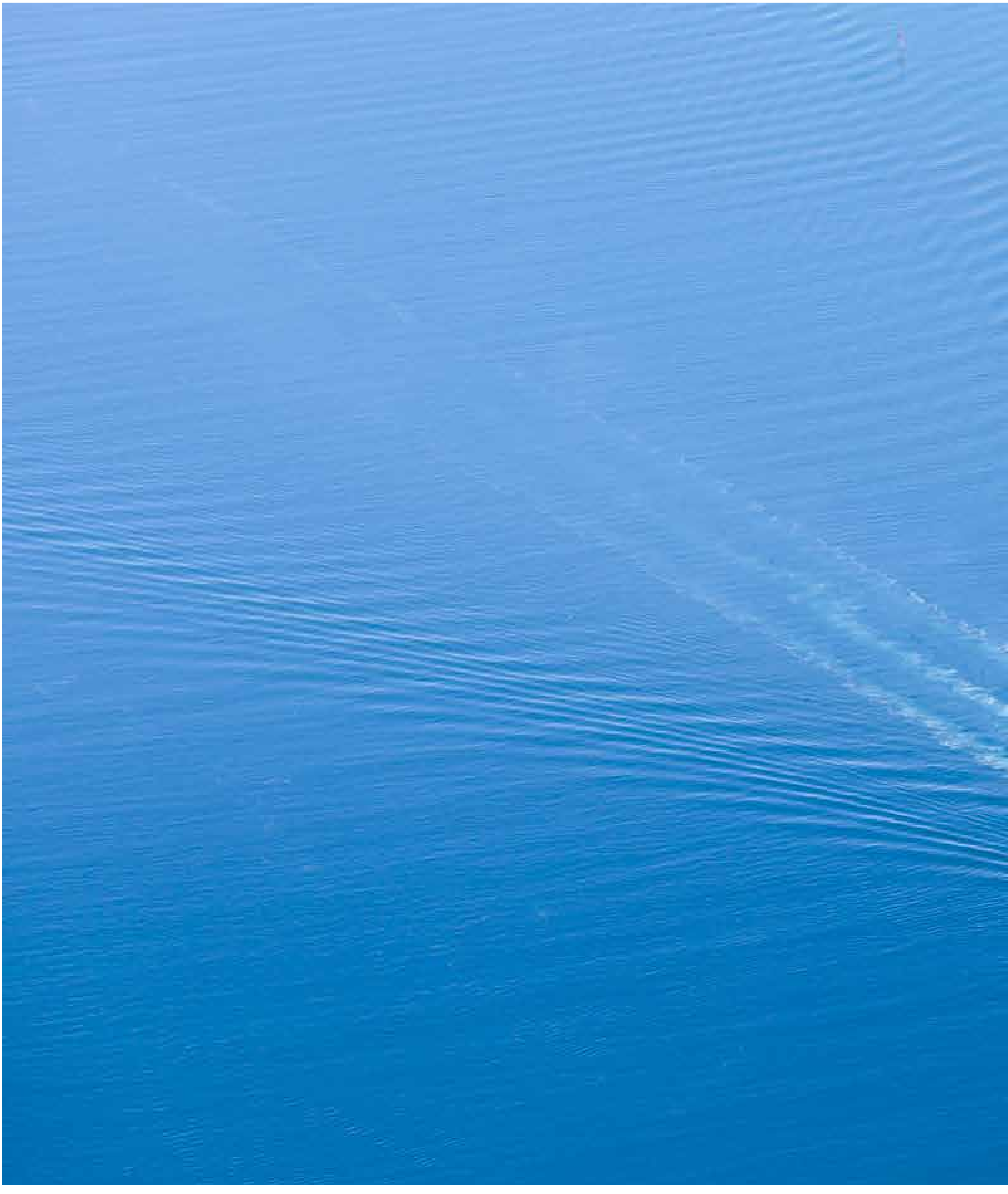
N. America, Middle East and Latin America see increasing gas projects under construction



Source: S&P Global Platts Analytics, S&P Global Market Intelligence World Electric Power Plant Database

Although the relatively limited investments in nuclear energy globally are in part driven by local opposition and national policies, the technology is another victim of the conundrum currently facing the power industry. Platts Analytics' long-term scenarios clearly show that the world will need more generating capacity, yet there is not enough investment in non-emitting (or even low-emitting) technologies.

Current renewables and nuclear yearly additions could at most meet annual global power demand growth, but what about the gap opening up as a result of coal retirements? Even investments in flexibility appear to be lagging behind, with batteries accounting for only up to $1 billion/year, with less than 2 GW of batteries currently added each year. Reform of market design and the introduction of carbon pricing more widely across the globe could address some of these concerns going forward. ■



Signal failure

GPS is a pivotal technology for the shipping industry, but is proving vulnerable to malicious interference and military activity. Katherine Dunn investigates maritime risk in the East Mediterranean

Early one Sunday in March 2018, a ship in Port Said, the northern gateway to Egypt's Suez Canal, suddenly and inexplicably lost all connection to GPS on board.

"All of them affected," the vessel's crew wrote in a report to the US Navigation Centre of Excellence (NAVCEN), after a total of seven receivers lost connection to GPS. "Disturbance still continuous."

The cause of disruption, after an investigation by NAVCEN, was listed as "unknown interference."

In the following days, vessels in and around Port Said and the Suez Canal reported sudden and unexplainable outages in their GPS, some lasting days, and referenced dozens of vessels in the area experiencing the same problem.

The disruptions were concentrated around the canal, but also extended north along a strip of sea, from just east of Cyprus to the Lebanese coast. NATO has also reported disruptions off the south coast of Turkey. While the GPS mostly just disappeared, the reports noted, sometimes it placed the vessels somewhere they were not: in one case, a vessel in Port Said appeared on GPS to be west of Alexandria, more than 150 nautical miles to the west.

US and NATO officials were paying attention, with good reason. The region has seen military tensions escalate in recent years, particularly off the coast of Syria. It is also a vital trade route: in March 2018, 1,450 vessels of all sizes transited the waterway, about a third of which were oil tankers or LNG ships, according to data from the Suez Canal Authority. Those vessels were carrying about 61 million barrels of crude oil alone, or nearly 2 million b/d.

By March 23 last year, just five days after the first report, the US Maritime Authority (MARAD) released an alert warning vessels of possible GPS interference in the East Mediterranean. By the summer, the incidents had drawn an alert from NATO's Allied Maritime Command (MARCOM).

"In recent months, several electronic interferences have been detected, particularly GPS and AIS interference, as well as possible GPS jamming in the East Mediterranean," a July 31 advisory warned.

Altogether, 16 individual reports of GPS interruptions were made between March 18 and November 4, all with the cause listed as unknown.

In a February 2019 newsletter, NATO's Shipping Centre confirmed they are still investigating in the region and encouraged merchant ships to report any incidents. "GPS jamming continues to be present in areas of the Eastern Mediterranean," the centre said.

Cheap tricks

The Global Positioning System, or GPS, underpins most of the world's digital systems for determining location, time, and communication — on everything from your mobile phone, to the world's largest commercial vessels.

"For so many years we were used to using [only] GPS," says Chronis Kapalidis, an expert in maritime security and the East Mediterranean at Chatham House.

It has always been possible to disrupt GPS, but doing so is now easier and cheaper than ever, experts say.

That has meant an explosion of both GPS "jamming" – when GPS is interrupted – and "spoofing" – when a receptor is tricked into believing it is somewhere it is not.

Disruption can come from civilians, who can now buy cheap jammers on the internet. It also comes from states, appearing in geopolitical hot spots alongside a new wave of cyber conflict.

Experts say many large vessels have no back-up to GPS, and crew often lack awareness that it is even vulnerable to disruption. Without back-up, an increasingly digital generation of commercial vessels risks getting caught in the crosshairs.

States or rogue elements?

There is no official explanation for why GPS is being disrupted in the East Mediterranean, but a patchwork of military operations in the region is likely to be a major cause of the interruptions. That itself is a result of rapidly rising tensions north of Egypt and off the coast of Syria.

“The eastern Mediterranean is extremely busy militarily,” MARCOM officials wrote in a report in October. “There are numerous warships operating in the region all with high powered transmitting devices.”

In fact, the East Med disruptions began before March, according to a specialist on the region, citing NATO intelligence.

Reports of disruption were heard in 2017, says Hans Tino Hansen, the CEO of Copenhagen-based maritime risk consulting firm Risk Intelligence, who published a report on GPS disruptions based on anecdotal reports from clients.

Those disruptions are likely a result of both military operations by the Egyptian army, who are fighting militants in the Sinai, and Russian warships off the coast of Syria.

“The GPS spoofing and jamming in [Port] Said and Suez is a byproduct ... from a military operation that has nothing to do with the ships,” says Hansen.

GPS jamming technology is now accessible enough for jamming to be the work of “rogue” individuals, says Todd Humphreys, director of the Radionavigation Laboratory at the University of Texas at Austin.

But experts agree that in the East Med, the location and sheer scale of the interruptions points towards the work of nation states.

As a result, the potential risks of a vessel losing the ability to navigate, or drifting off course without realizing, are countless.

“The political situation in the East Med is so tense, everyone is at each other’s throats,” says Sebastian Bruns, head of the Center for Maritime Strategy and Security at the University of Kiel. “Just imagine if a Turkish freighter ran aground and spilled oil all over the Israeli coast.”

Geopolitical tensions

The Eastern Mediterranean is just one of the latest hot spots in an expanding list of regions that have seen interruptions rise alongside geopolitical tension.

The US-based Resilient Navigation and Timing Foundation reported in 2017 that hundreds of vessels in the Black Sea saw their GPS locations disrupted. Many saw their locations at an inland Russian airport. Anecdotal reports of interruptions in the Black Sea date to at least 2016, multiple experts say.

Recurring, large scale disruptions have been reported off the Korean peninsula, in Lapland in northern Finland, and on the northern Norwegian border with Russia during NATO military drills, which Norway’s Foreign Ministry blamed on Russian forces in a comment to the Associated Press. Russian officials denied involvement.

Last October, one report was logged in the Strait of Hormuz, off Iran, and two more were logged at the Saudi Arabian port of Jeddah, in the Red Sea, prompting another advisory from MARAD.

GPS disturbances are just one element in an expanding list of threats to cyber infrastructure, affecting everything from banks to social media websites and consumer utility grids. Cyber-attacks have already affected the shipping industry. In 2017, Maersk suffered an attack to its central networks that disabled the company for 10 days and cost the company an estimated $250-$300 million.

Meanwhile, GPS interruptions have continued in the East Med. In November, interruptions were reported at the Israeli port of Haifa, and from near the eastern tip of Cyprus.

“We have encountered more severe than normal GPS interference tonight,” read the November 4 report. “Thank goodness for paper charts.”

Costly misadventure, existential risks

The risks from GPS jamming and spoofing are countless – accidents, collisions, confusion, and other costly mistakes – not to mention the risk of straying into contested waters and military conflicts.

Take the Suez Canal. One of the world’s key transit choke points, the canal forms a crucial link from Europe to Asia. In 2017, nearly 780 million barrels of crude passed through the canal, or about 2.13 million b/d, according to the Suez Canal Authority.

“A spoofing or jamming attack in a congested shipping lane in poor weather could cause a collision between large ships similar to the collision between the USS Fitzgerald and the ACX Crystal,” says Humphreys. That incident, between a US naval ship and a Philippine container ship off the coast of Japan in June 2017, caused seven deaths.

But the largest risk would not be in a canal – where other visual cues exist – but at open sea, where spoofing might not be immediately detected, and other forms of navigation are more difficult.

The larger risk, however, goes beyond a one-off disaster. As conflict increasingly takes the form of “hybrid warfare” involving cyber attack, the digitized commercial trade faces huge risks.

Outside of navies, few vessels have full back-up systems to GPS, or robust crew training in purely analogue navigation methods that haven’t been widely used in decades.

“Virtually all large non-military seagoing vessels... have only standard single-frequency GPS receivers onboard, with no special protection against jamming and spoofing,” says Humphreys.

Analogue methods and extensive back-up systems have been maintained by navies, and the risk of GPS disruption is widely known in military circles. This is not the case in commercial shipping.

No ship owners contacted for this article said they were aware of involuntary disruptions of GPS in the East Mediterranean.

Taking attention away from just operating a large vessel, even when everything is going smoothly, also presents a challenge to improving the industry’s resilience to potential GPS disturbance.

“Unless a big accident [occurs] that can be traced to GPS spoofing, the attention of [the crew] will be elsewhere,” says Sebastian Bruns, head of the Center for Maritime Strategy and Security at the University of Kiel.

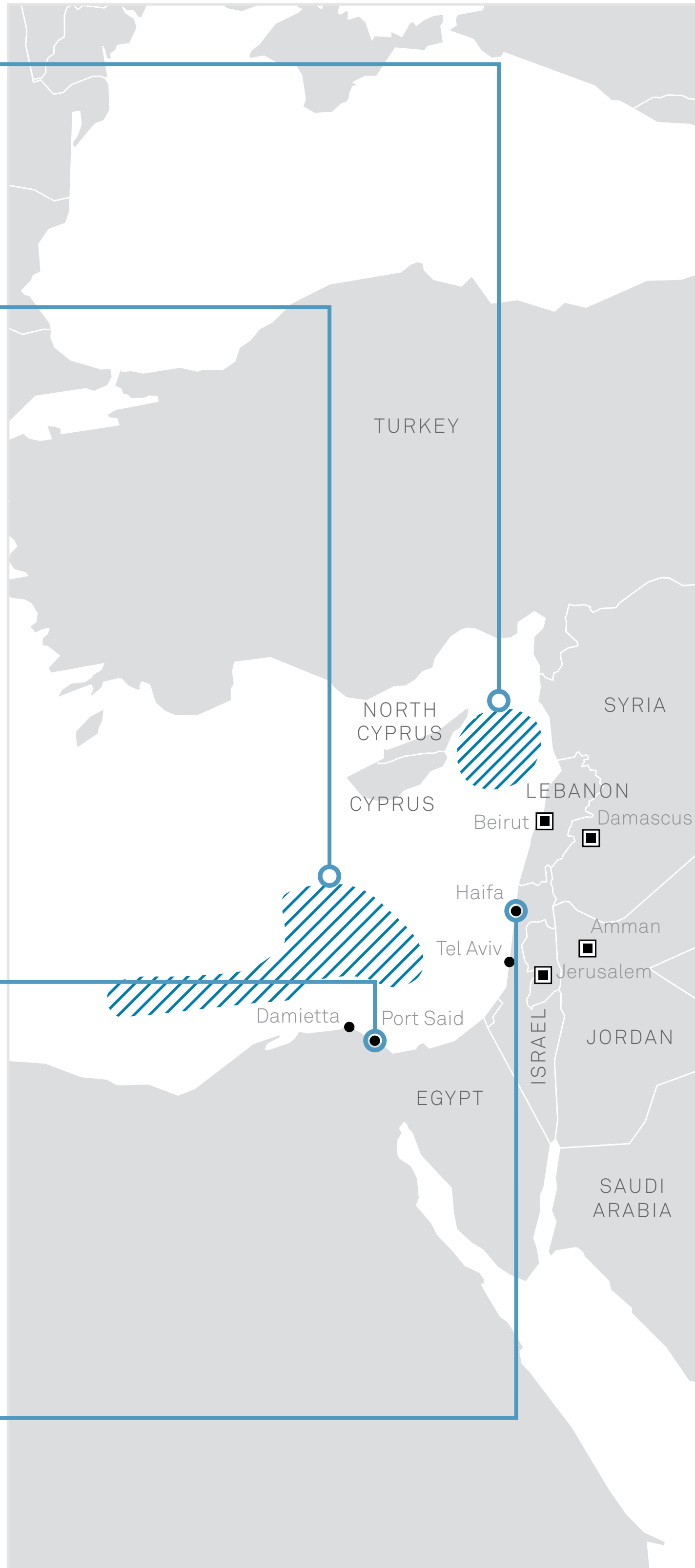
Tech and training needed

There are practical ways to limit the risk of jamming or spoofing. But to really safeguard the satellite systems on which we have come to rely, governments will have to provide back-up.

The first step needs to be an awareness among crews that GPS can be purposely disrupted, and why. Planning for an outage requires preparing crew to navigate using alternate, often traditional methods, particularly at open sea, where there are no obvious visual cues to help with navigation.

Hardware can also help, from GPS receptors that only point to the sky – making it more difficult for them to receive interrupting signals by land – to counter-jamming technology, largely used by navies.

GPS interruptions reported in the East Med in 2018



Cyprus

19-Mar	1100	Multiple sources indicating GPS accuracy issues
4-Nov	1800	Nighttime GPS interference more severe than previous encounters. "Thank goodness for paper charts"

Eastern Mediterranean

21-Mar	0400	No GPS signal sailing west of Port Said en route to Gibraltar, other ships experiencing GPS issues.
21-Mar	2000	No GPS signal after departing the Suez Canal, Port Said side. Four other ships also had the same problem with varying frequencies
22-Mar	0200	GPS loss of signal
16-Apr	1700	Very frequent loss of signal, ships in vicinity reporting same problem
18-Apr	1300	GPS disruption every few minutes - no location for three hours
18-May	1430	GPS signal lost on three occasions
18-May	1730	GPS signal lost or incorrect, other ships reporting the same issue

Port Said, Egypt

18-Mar	0600	GPS lost, continuous disturbance with non-stable position
18-May	0954	GPS location changing when vessel is stationary
4-Jul	1500	GPS lost at anchor in port, interference continued during the day
4-Jul	1500	GPS lost at anchor in port awaiting Suez Canal transit
1-Oct	0030	Lost GPS fix on approach to Port Said

Haifa, Israel

1-Nov	1600	Erratic signal

Source: US Department of Homeland Security

“These civilian ships, they have no defense for these kinds of attacks, or these kinds of effects. So they are much, much more vulnerable than a naval ship would be,” says Hans Tino Hansen, the CEO of Risk Intelligence.

Those efforts all present their own challenges in an industry with paper-thin margins, where shipowners are already struggling to adapt to the costs associated with the 2020 IMO regulations on the shift to cleaner bunker fuels.

Governments have the ability to provide a further safety net, by creating land-based navigation networks, known as eLoran systems, which have stronger signals and as such are more difficult to disrupt. Whether they will step up is another question.

Both China and Russia still maintain such regional systems, and the US government has repeatedly pledged to create a reinforced transmission system, too. One is now expected to arrive: in December, a law was signed to establish a back-up system to GPS, under the National Timing Resilience and Security Act of 2018. That system is due for completion by December 2020.

But even if it passes, progress could be slow – the system will not get funding until the 2020 budget, at the earliest.

“The technology is solved. The policy is solved. It’s just a matter of nations implementing the policies and the technology,” says Goward. “It is really just a willingness and a leadership problem.” ■

GPS - three steps to chaos?

Interrupting GPS – even the GPS of a large vessel – requires just three simple steps.

“Disrupting GPS signals into these vessels is as easy as buying a GPS jammer off the Internet, hooking this to an amplifier and an antenna, and pointing the antenna at the intended target vessel,” says Todd Humphreys, who directs the Radionavigation Laboratory at the University of Texas at Austin.

The system behind GPS is straightforward. There are at least 24 active GPS satellites circling the earth, many equipped with atomic clocks. At any point, a receiver should be within sight of four of them. A receptor then determines from those signals where it is located, and at what time.

The system is still maintained by the US Air Force. While regional alternatives exist, including both Chinese and Russian systems, GPS has come to be used globally by every conceivable industry for nearly every conceivable purpose.

The problem is that those signals are surprisingly weak: anything from averse “space weather” to a conflicting signal can disrupt them. As a result, GPS jamming is a simple point and shoot operation.

GPS spoofing is more difficult to achieve, and still largely the domain of nation-states. It is also more dangerous, producing conflicting locations that, if subtle, can insistently lead a vessel off course without detection.

The largest risk, however, is the sheer scale of the disruptions to a system that is often taken for granted.

Between January 2016 and December 2017, more than 250,000 incidences of disruption, whether accidental or intentional, were detected by Strike3, an EU-funded project for tracking disruptions to GPS and other satellite-based systems.

Outside of military circles, experts say, there is little awareness that a GPS signal can be lost or misdirected.

“What we have generally seen [is] that disruption is getting more frequent, and the disruption devices are getting more sophisticated,” says Dana Goward, President of the Resilient Navigation and Timing Foundation, and a former civil servant in the US Maritime Authority. “Every time we think there’s a safeguard, or an obstacle to folks messing with it… they overcome it.”

Winds of change

Countries in the Middle East are taking small but important steps to clean up their power generation mix. Saudi Arabia is at the forefront of the trend, but needs to convert challenging goals into more development on the ground, writes Miriam Malek

Saudi Arabia, the world's largest oil exporter, has ambitious plans to tap into the potential of renewables to fill a shortfall in regional power demand. But opinions are divided on how realistic the Kingdom's strategy is, given its track record of delayed projects and a shortage of domestic policies to help support investment.

The drive to increase renewables generation in the region is not limited to Saudi Arabia. With economies in the Middle East region set to grow in the coming years, power demand is projected to surge in tandem. Despite an abundance of natural resources, electricity supply is a major issue for Gulf countries and oil-fired generation is still the dominant source.

The case for renewables

Saudi Arabia's economy is set to grow 2.7% over the next year, according to ratings agency Moody's, and S&P Global Platts Analytics expects Saudi Arabian power demand to continue to grow at a rate of 3.3% through to 2030. The looming threat of a power crisis has helped speedball the idea that including more renewables in the region's energy mix could be the solution.

"Populations in the region are growing much faster than other areas of the world and are set to maintain a rapid pace of growth to the middle of the next decade," Edward Bell, commodity analyst at Emirates NBD told Platts. "The power infrastructure that's in place will need to be expanded or enhanced to meet that growth so a push into renewables makes obvious sense as part of that dynamic."

The push towards renewables has been led by Saudi Arabia, which earlier this year announced intentions to develop and install 60 GW of clean power sources over the next decade, including 40GW of solar power, and plans to eventually generate 200 GW from renewables. Around 30% of the power mix is to be supplied by renewables by 2030, with the remainder to be sourced from gas and some nuclear. This compares with a target of 15% of the power mix for Kuwait to be supplied by renewables by 2030, and a target of

10% for Oman by 2035, according to the latest GCC report from the International Renewables Energy Agency (IRENA).

Saudi Arabia's energy ministry has also set an interim target of developing 27.3 GW of clean power by 2024, of which 20 GW will be from solar.

"The region can't afford not to be too ambitious in trying to get more and more of its power mix provided by renewable sources given the power demand pressures and what will likely be increasing international pressure to clean up the energy mix in the region," Bell said. "So the 'over ambitious' nature of the targets may be more an issue of capacity to tender, construct and deliver projects rather than a lack of 'resources,' either in the form of capital or solar irradiation."

This year, the ministry released expressions of interest for the seven solar PV projects that will be tendered in the first half 2019, with a combined capacity of 1.51 GW which the ministry expects to attract $1.51 billion of investment this year. Saudi Arabia's energy minister, Khalid al-Falih said in January that around 12 renewables projects would be tabled for investment this year, including four solar PV parks and 300 MW solar power stations in Rabigh and Jeddah.

"By using our two awarded projects [Sakaka 300 MW Solar PV and Dumat Al Jandal 400 MW onshore wind] as benchmarks, we can estimate that required capex per 100 MW of Solar PV is $100 million and $125 million per 100 MW of onshore wind," Turki M Shehri, head of renewable energy projects at the ministry of energy, industry and mineral resources told Platts. "These two projects involved a capital investment of $800 million in 2018."

This can be compared with an investment of $765 million to develop Abu Dhabi's 100 MW Shams 1 project, the first concentrated solar power project in the Gulf region.

Aside from solar, Middle East countries are also increasingly looking to wind as an option for development. Oman, which already boasts the first onshore wind farm in the Gulf region (50MW), has been mulling the possibility of developing offshore wind farms.

Subsidies persist

One of the biggest obstacles facing Middle Eastern governments in their drive to push renewables is the sizable subsidies that they offer to their citizens. In 2018, the cost of electricity consumption for Saudi residents ranged from Riyal 0.18 – 0.30/kWh (Eur0.042–0.071/kWh). This eats into the profit margin for renewables developers, making it essentially economically unviable to develop alternative energy sources for consumer use.

At the moment, generation costs are higher than consumer electricity tariffs. Saudi Arabia is making attempts to raise tariffs and fuel prices, which could eventually bring consumer tariffs in line with or lower than the cost of renewables, plus the infrastructure needed to use them.

“Efficient price signals in both the electricity and fuel markets can certainly play a role in attracting more renewable investment,” King Abdullah Petroleum Studies and Research Centre, also known as KAPSARC, told Platts. “The speed of the development is subject to additional factors such as the regulatory framework and the financing mechanism available to support these projects.”

Some countries, including Bahrain, are in the midst of developing incentive policies that would effectively make it cheaper for industrial customers to use photovoltaic solar power rather than gas. This is a first step, but the gap between current consumer prices and those required to breakeven or profit on renewable-generated power is much greater than it is at the industrial level.

“The [Bahraini] government is working on [policies] to try and incentivize,” Shaikh Mohammed bin Khalifa Al Khalifa, Bahrain’s minister for oil, told Platts in an interview. “Today you can buy and install photovoltaic that will generate you power cheaper than you can buy on the grid, for commercial customers.”

In Saudi Arabia, industry tariffs were not raised at all in 2018, which means that for solar to be cost-competitive in this sector, deeper reforms are needed than those that have begun implementation in the consumer, agricultural and commercial sectors.

Luring investment

Despite question marks over how robust investor appetite would be following the killing of Saudi critic and journalist Jamal Khashoggi, one banking analyst who wished to remain anonymous told Platts that investor sentiment into Saudi Arabia remains strong and that a view towards commerce is prevailing over conscientious concerns.

“Given that auctions have already been awarded for both wind and solar, and sites have been carefully selected and are clearly assigned, we expect that the projects will be realized,” David Linden, director at Wood Mackenzie told Platts. “Previous plans were not organized in the same way as the most recent ones, which may have contributed to earlier problems with execution.”

More than 16 bidders took part in the latest Saudi auction from outside Saudi Arabia which vindicates this view, but investors have been concerned over the implementation of local content strategies, both for materials and for staff, and how this affects businesses operating in the Kingdom. Projects need to use at least 30% of local content, which limits the amount of imported material which can be used in development.

There are several reasons why Saudi Arabia's renewables plans could prove important for advancing its economy. The local content requirement will serve to create jobs and reduce the country's unemployment rate. And rising renewable generation will eat into the share of petroleum-product fired plants in the energy mix, freeing up crude that can be exported at international prices, hopefully fetching prices that will be worth making the switch.

To really entice consumers, it is critical that the Kingdom can offer supporting infrastructure and pricing structures which will enhance development. The Kingdom would do well to ensure cheap panels and turbines are available through ultra-large scale PV manufacturing, Linden told Platts. A $2 billion deal with China's Longi and South Korea's OCI could also give the Kingdom competitive panel pricing that will further the case for developing the technology. The deal will bring fully integrated solar manufacturing to Saudi Arabia. Feasibility studies for the deal are scheduled for completion in the first half of this year.

Saudi Arabia's past experience with renewables projects rings a cautionary note. A giant 200GW deal the Kingdom signed in March last year with Japan's Softbank Group Corp, would be the world's biggest solar project and nearly triple Saudi Arabia's power generation capacity but there has been little sign of progress on the venture.

"Negotiations and [requests for proposals] with potential partners are ongoing and are being led by the Public Investment Fund (PIF) and the Saudi Arabia General Investment Authority (SAGIA) – these partners include, but are not exclusive to, Softbank Energy," Shehri told Platts. "Most recently the PIF and SAGIA have issued an RFP inviting qualified companies to propose plans to build 1-to-2 GW per year of solar PV components manufacturing based within the Kingdom."

Nonetheless, the drive at least appears to be there, and despite a tumultuous 2018, investors do not seem to be shying away from the Kingdom. In the past, several government agencies were all pursuing renewables. Since 2017, they are all run and overseen within the ministry of energy, industry and mineral resources. "This unification of governance means that the Kingdom has been able to deploy two projects totalling 700 MW within one year – a process that would usually take closer to five years," Shehri told Platts.

The rate of development will rest on how quickly Saudi Arabia can implement deals and pass supporting legislation. The scale of the projects and timeframe for their development is not impossible, but without action on the Kingdom's side and changes aimed at supporting foreign investors, like clarity on local content requirements and available solar manufacturing in country, Saudi Arabia's grand plans may yield much more modest results. ■

Liquid market: LNG comes of age

As new LNG projects come on stream, the market is undergoing a sea-change. Spot prices are increasingly defined by LNG-specific fundamentals, and buyers are adjusting their expectations accordingly. By Marc Howson

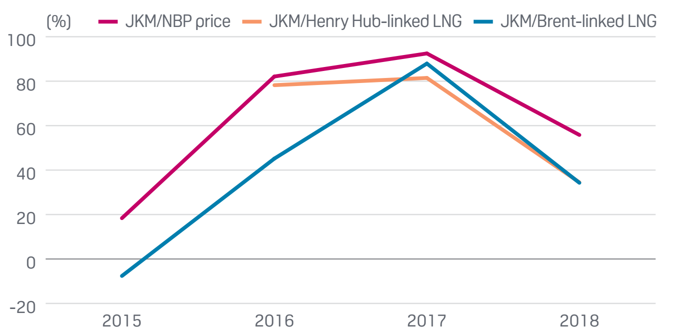
The LNG market continues to confound expectations. The past year saw three big surprises: strengthening of S&P Global Platts' JKM despite new supply, as well as de-correlation from other commodities, and flattening seasonality.

Meanwhile, in 2017/2018, large volumes of more flexible, market-priced LNG supplies reached final investment decision and were agreed for delivery. These will start to flow into the market in 2023/2024, providing an additional medium-term catalyst for the ongoing commoditization of LNG.

JKM decouples from other LNG pricing indexations

In 2017 there was a relatively high correlation of global LNG and gas prices as increased supply of destination-flexible US LNG helped reduce the spread between JKM and NBP prices. JKM is the benchmark LNG spot price, reflecting LNG deliveries into northeast Asia, and JKM derivatives are cash-settled against JKM.

Average JKM correlation to other LNG price indexations



Note: Brent-linked LNG price is 13.5% of Brent + $0.50/MMBtu constant. HH-linked LNG price is (Henry Hub*1.15)+$3.00/MMBtu + freight. HH-linked LNG price data only starts from 15 June 2016. Graph shows yearly average of daily correlation.

Source: S&P Global Platts

But expectations of continued strong price coupling, as US LNG ramped up further, proved misguided in 2018. JKM's correlation to typical Brent- and Henry Hub-linked LNG contracts, as well as to the NBP, fell sharply. Drivers included new US and Australian liquefaction trains suppressing JKM in the first

quarter, while Brent stabilized with OPEC production discipline. Subsequently, during summer 2018, JKM rose far quicker than Brent due to proactive Chinese and South Korean pre-winter LNG buying.

JKM's correlation with Henry Hub-linked LNG contracts was especially hampered by Henry Hub's unexpected price surge in the last quarter of 2018, underpinned by a particularly cold winter. In addition, soaring Atlantic and Pacific LNG charter rates after the summer further eroded the relative competitiveness of US LNG, as shipping journeys lengthened with US LNG deliveries into Asia, while JKM declined.

Legacy LNG contracts linked to either oil or Henry Hub prices face very different price drivers to LNG. This provides an incentive for counterparties to re-negotiate contracts based on non-LNG market pricing, to better reflect LNG market fundamentals.

JKM strengthens despite supply growth

JKM reduced its discount to the typical Brent-linked LNG contract price by almost 50%, in absolute terms, year-on-year. By contrast, the absolute premium of JKM over NBP prices grew by nearly 50% year-on-year. Whereas JKM was assessed at a discount to typical Henry Hub-linked LNG contract pricing in 2016 and 2017, this reversed last year, as JKM averaged over US$1/MMbtu above Henry Hub-linked LNG contract pricing.

JKM seasonality flattens

Strong growth in the seasonal Chinese gas market underpinned JKM's particularly high 2016 and 2017 seasonality, peaking in the northern hemisphere winter.

However, in 2018 sharply declining global LNG supply in the second quarter, combined with proactive north Asian buying ahead of winter facilitated by growing Chinese LNG/gas storage capacity, reduced JKM's seasonality. LNG production then ramped up aggressively during the November and December higher demand months, contributing to an uncharacteristic JKM decline in late 2018.

LNG marketing strategies evolve

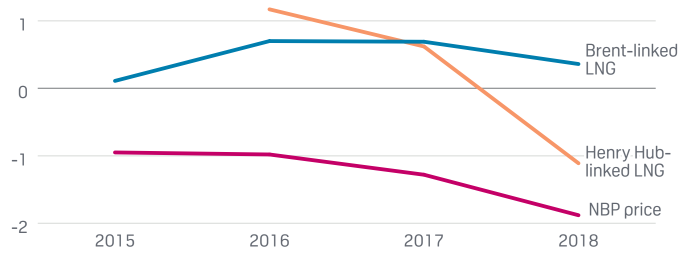
While the LNG market in 2018 proved unpredictable, it was primarily driven by LNG-specific influences leading to JKM's decoupling from other commodity prices. It is therefore unsurprising that LNG players are increasingly adopting physical, and derivative, pricing based on LNG benchmark to minimize cross-commodity pricing risks and undertake like-for-like hedging.

This was publicly illustrated by Tellurian's 15-year agreement with Vitol, announced in December, for the supply of 1.5 mt/year of JKM-priced LNG. In addition, three of the four liquefaction projects, taking FID in 2017/2018, accounting for over 80% of the volumes, were underpinned by portfolio supplies, as the chart above shows.

These supplies, from Canadian and African projects, are usually marketed by a portfolio offtaker who is free to sell the volumes at LNG market prices, with

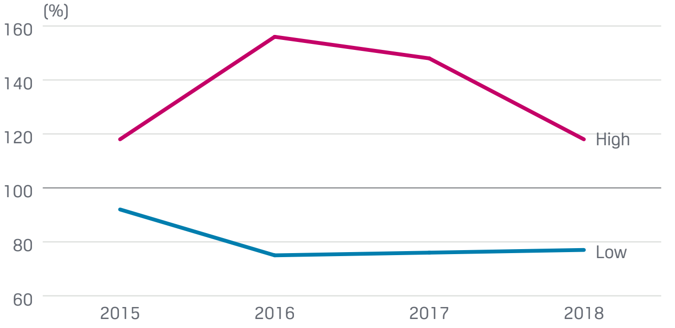
JKM vs other LNG indexations

$/MMBtu



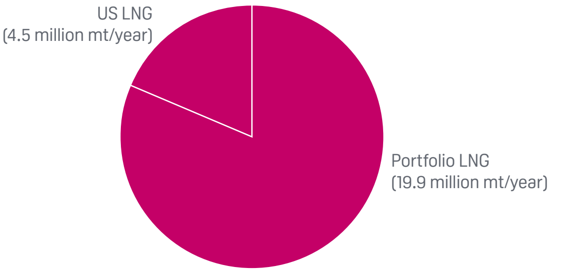
Note: Brent-linked LNG price is 13.5% of Brent + $0.50/MMBtu constant. HH-linked LNG price is (Henry Hub*1.15)+$3.00/MMBtu + freight. HH-linked LNG price data only starts from 15 June 2016. Graph shows yearly average of daily correlation.

Monthly JKM variation from annual average



Source: S&P Global Platts

Liquefaction capacity FIDS in 2017-18, by type



Source: S&P Global Platts

no fixed destination, when volumes ramp up. This type of flexible marketing strategy provides a further medium-term catalyst for LNG's commoditization, increasingly ensuring LNG is priced against its own fundamentals. ■

Insight Conversation: Carole Nakhle

Carole Nakhle, CEO of independent consultancy Crystol Energy and founder of Access for Women in Energy, speaks to Paul Hickin about energy transitions and shifting oil and gas politics

How do you see the energy mix changing in the next decade?

The global energy mix is unlikely to look much different from today. The lion's share will continue to be provided by fossil fuels – that is coal, oil and natural gas, accounting for more than 85%. The rest will come from energy that does not emit CO2, with an increasing contribution from modern renewable energy – solar and wind.

Often, we hear about the impressive double-digit growth rates of renewable energy, suggesting – wrongly, in my view – that the world's energy mix will change drastically in the next few years. This is surely a noble aspiration, but a degree of realism will have to prevail once the numbers are put into perspective. Renewable energy is starting from a very low base. The current share stands at just under 12%, according to the IEA. However, in this account the majority comes from the oldest forms of renewable energy, such as biomass and hydropower. Biomass is usually poor people burning wood or dung. It is neither new nor green nor healthy. And hydropower's contribution alone is more than 7%, but its growth is constrained by nature, meaning the availability of rivers, and many doubt the wisdom of expanding it further, given the often detrimental impact on the ecosystem.

History and experience show how transitioning from the dominance of one fuel to another is a complicated and lengthy process. Coal, for instance, replaced traditional biofuels, fueled the Industrial Revolution and dominated the world energy mix for decades. It took oil more than half a century to crowd out coal. Next, gas came into the picture along with other energy sources. However, despite coal's bad reputation – it is the largest emitter of CO2 from of all the fossil fuels – today it still contributes nearly 28% of the world energy mix. In the developing world, where the use of widely available and cheap coal is considered essential to support economic growth and lift billions of people out of poverty, its share is even higher, at 36%. Clearly, economic priorities continue to take precedence over environmental concerns.

So, if we are to see notable changes in our energy mix, we need to look beyond the next couple of decades.

Where do you stand on the question of peak oil and electric vehicles, and the longevity of fossil fuels?

Within a decade we have moved from discussing peak oil supply to talking about peak oil demand. The former was proven wrong, the latter is yet to happen. Eventually, it will happen, but the big question is when – this is anyone's guess. Just look at the divergence in forecasts between various agencies. Even if and when peak oil demand finally happens, it doesn't mean a sudden collapse in the demand for oil. The example of coal is a good illustration – the share of coal in the global energy mix peaked around the early decades of last century, yet coal remains ingrained in modern economies.

Of course, the deployment of electric vehicles will dent demand for oil. After all, oil's dominance in the transport sector remains unchallenged. Despite suffering a long-term decline in total energy market share since its peak in 1973, oil has expanded its share in the transport market. How significant that dent will be, however, remains doubtful. Although sales of EVs have boomed in the last few years, they remain very small compared to the conventional car fleet: we are literally comparing a few millions with billions. Also, the transport sector is not just cars; it also covers air, water and other means of land transport. Improvements in the efficiency of the conventional internal combustion engine are likely to cause a bigger dent in oil demand than EVs.

And, of course, there is an additional dimension that is not that often discussed: government finances. One of the attractions of the petrol-based internal combustion engine is the fuel tax, a long-established tradition, especially in the developed world. In the UK, fuel duties alone represent about 4% of total government tax receipts. Also think of the revenues generated for host governments from oil and gas companies operating in their countries. Annual taxes collected in some countries run into multiple billions of US dollars. Almost no other commodity, industrial or service sector component can offer sustained tax revenues on this scale. Ending the oil and gas age will leave a sizable hole in many governments' budgets, in consumer and producer countries. Greener alternatives are unlikely to fill the gap.

What does the US' dominant role in oil and gas mean for oil and gas markets?

The US has long been a major oil and gas producer. This is where, more than a century ago, business started for some of the oil and gas companies which are still the largest today. However, from the mid 1970s up until the end of the last decade, oil production seemed to be in relentless decline. With the US being the largest oil consumer in the world, this translated into an increasing dependence on imports, often from countries perceived to be hostile to the US. That created a feeling of vulnerability, and achieving self-sufficiency became a top priority for every American president for decades.

The shale revolution made that aspiration a reality. Not only did it reverse the declining trend of oil and gas production – but the trend reversed for production to reach record levels. More importantly, the US has gradually moved from an importer to an oil and gas exporter. Today, the US is challenging major producers, the likes of Saudi Arabia and Russia, for global market share. It has created strong competition in key large and growing markets like Asia, once considered a "safe haven" for the traditional exporters.

Then there is the impact on prices, be this in natural gas markets, mainly for LNG, with clear repercussions for the bargaining power of producers and consumers, or be it in oil markets. As an example for the impact on natural gas markets, think of the relationship between Russia and Europe. It is true that Russian gas imports to Europe increased last year but this came at the expense of discounted prices that Russian companies offered to European customers. In the global oil market, the price collapse in the summer of 2014 is a major manifestation – US tight oil production has successfully placed a lid on the global price of oil, despite the relentless efforts of the biggest producer

alliance in the history of the oil industry, the so-called OPEC+, to counter the effect and to put upward pressure on prices.

And of course, there are wider repercussions on the geopolitical front, with the US clearly feeling more empowered now than as an energy importer.

> “US tight oil production has successfully placed a lid on the global price of oil, despite the relentless efforts of the biggest producer alliance in the history of the oil industry, the so-called OPEC+.”

How do you see the OPEC-Russia pact evolving longer term? Will OPEC stay relevant?

The OPEC+ alliance, formed in 2016 and led by Saudi Arabia and Russia, came to existence out of common interest: the challenge that US tight oil imposed was so big that OPEC on its own could not achieve much. For many traditional OPEC members, their dependence on oil revenues was such that they could not sustain the lower oil prices resulting from the new market conditions, for any prolonged period. For many non-OPEC producers, in particular for Russia, the benefit from an alliance with OPEC became clear in 2014, when Russia was hit by a double whammy – first, sanctions imposed by Western governments in retaliation for Russia’s annexation of Crimea; second, the oil price collapse. Russia’s economy is more diversified than that of Saudi Arabia, but it still relies on oil revenues.

The stated aim of OPEC+ is to “rebalance” the market in a way that benefits its countries. In other words, the alliance wanted to achieve a market balance at a higher oil price than what the system would have generated by itself, if left to market forces and prices. In this respect, they have successfully managed to put a floor on the oil price.

However, US tight oil is a difficult adversary. Whenever, in the recent past, prices went above a certain threshold, more production came out of the US, putting downward pressure on prices. Unlike conventional oil, tight oil responds fast to changes in prices, thereby limiting the influence of traditional powers like OPEC over the market. A conventional oil project might take seven to 10 years to convert investment into production. For tight oil projects, the time frame has now shrunk to months, making it more sensitive to price changes.

As a result, despite daily volatility, oil prices currently tend to remain in a well-defined corridor, averaging between $60-80 per barrel – whereby the upper limit is set by tight oil and the lower by OPEC+.

The challenge of plentiful and flexible oil supplies has been so large that OPEC+ has held together for longer than many expected. In the immediate future, it is unlikely that the alliance will dissolve, especially as long as it makes sense for its main architects – Saudi Arabia and Russia – despite growing frustration among the smaller OPEC producers with respect to those two big players’ dominance of the alliance’s strategy.

How do you see the dynamic between the big three in oil markets – Saudi Arabia, Russia and the US –playing out in the next couple of years? Could this come at a cost to OPEC itself?

We are talking here about the three biggest producers, two of them in an alliance of convenience. Competition between the three producers for global oil market share will intensify. The US, for instance, though not the lowest cost producer, has been expanding its global market share while that of Saudi Arabia has not changed much since 2014, given production constraints imposed by OPEC+.

On a more regional level, competition is mostly visible in Asia, which is expected to be the world's main growth center for oil demand, at least in the coming two decades, given its population and economic growth. That said, oil is a fungible commodity traded in a global market, therefore looking at regional market shares may not be good enough. For instance, US refineries have a historical legacy – they are configured to take relatively heavy crude from the Middle East while lighter tight oil is often sent to refineries outside the US.

In Russia, many oil and gas companies have been rather frustrated by the OPEC+ alliance, as it has restricted them from freely expanding their potential. Russia's tax code benefits volume over price increase for exported crude oil, and consequently Russian oil exporting companies tend to favor high volumes to speed up payback for investments carried out in the past. So far, their discontent has not resulted in a significant impact, but this may well change.

With respect to OPEC's longevity, two things are worth mentioning. In the short term, in addition to various market risks and economic challenges, OPEC is facing the risk of the No Oil Producing and Exporting Cartels, or NOPEC, bill which is being pushed by US Senator Chuck Grassley. If passed, the legislation would allow the US attorney general to sue OPEC for price manipulation under the Sherman Antitrust Act. Note that this is not the first time that such a bill has been introduced in the US Congress but it never passed – both Presidents George W. Bush and Barack Obama threatened to veto it. This time, however, OPEC seems to be more concerned, especially given President Donald Trump's hostile tweets toward the organization, which he has called a monopoly. Whether he will endorse the NOPEC bill remains to be seen.

In the longer term, however, OPEC's influence may well increase just when loses its appeal. After all, in such a scenario, the oil price is likely to be low, and the low-cost producers will be the last to leave the market. As a low cost producer, it is easier to defend the oil price from going from, say, $30 to $5 per barrel, than from $100 to $50, especially if competition in the higher price range is substantial, because of shale oil. But this is subject to them maintaining their commitment to the longevity of the organization and their ability to diversify their economies.

> "Over the last 10 years, there has been an increasing trend towards women's empowerment and promoting their participation in the labor force and across various sectors of the economy."

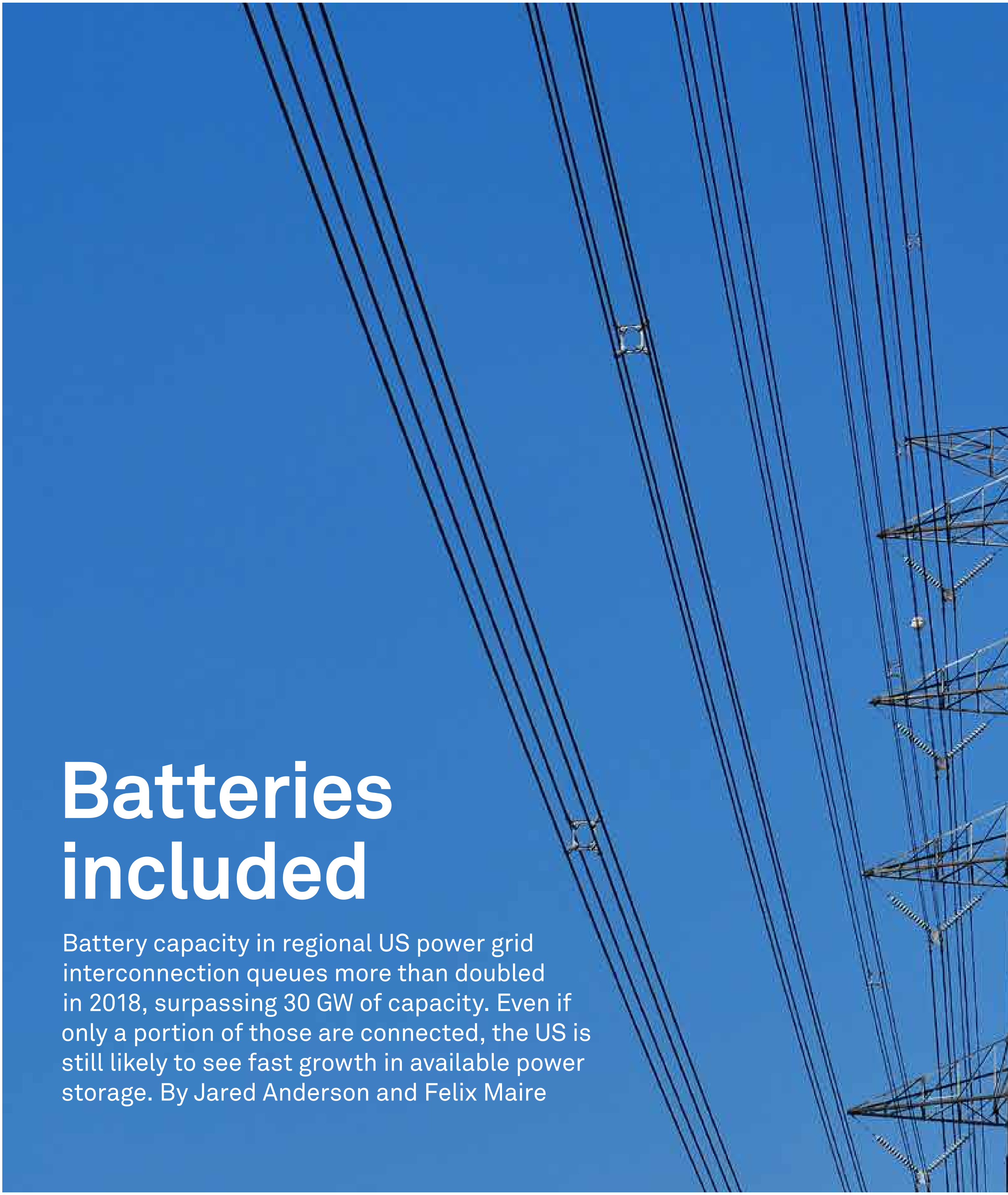
Since you set up Access for Women in Energy in 2007, how has the energy industry changed for female participation? What needs to change and is it happening?

At AccessWIE, we offer an equal platform for female and male energy experts and we focus on showcasing women's expertise in timely energy matters.

Over the last 10 years, there has been an increasing trend towards women's empowerment and promoting their participation in the labor force and across various sectors of the economy. Initiatives are mushrooming around the world, within the private and public sector alike, supported by dedicated international organizations and governments passing legislation to support women's participation and achieve a healthy and balanced society. The list of benefits from such an essential aim is non-exhaustive. But a lot remains to be done in this area given that we are starting from a very low base, particularly in the energy sector where women's participation is meagre, especially at the senior level.

The oil and gas industry remains a big boys' club. Just think of OPEC and its male-dominated gatherings! Among the oil majors, probably no more than two companies have had a female CEO, although some of these companies are more than 100 years old. The presence of females on these companies' boards is equally scanty. The oil field service providers and national oil companies are not any different. Very few oil and gas producing countries have ever had a female energy or oil minister, or a female head of the national oil company. When questioned, several reasons are given but none of them are convincing.

Practices among companies and governments are gradually changing but at a varying speed. International oil companies and national oil companies have started programs to support the development of women in their organizations. This is a move in the right direction. However, no matter how noble women's empowerment initiatives are, it is important to promote systems that are based on merit and not on gender alone. ■



Batteries included

Battery capacity in regional US power grid interconnection queues more than doubled in 2018, surpassing 30 GW of capacity. Even if only a portion of those are connected, the US is still likely to see fast growth in available power storage. By Jared Anderson and Felix Maire

Battery energy storage deployment in the US has rapidly increased in recent years and appears set for further growth, assuming costs continue decreasing and pending market rule changes that increase opportunities for storage resources to participate in wholesale power markets. But importantly, the economics, policy drivers and use cases differ widely among regions.

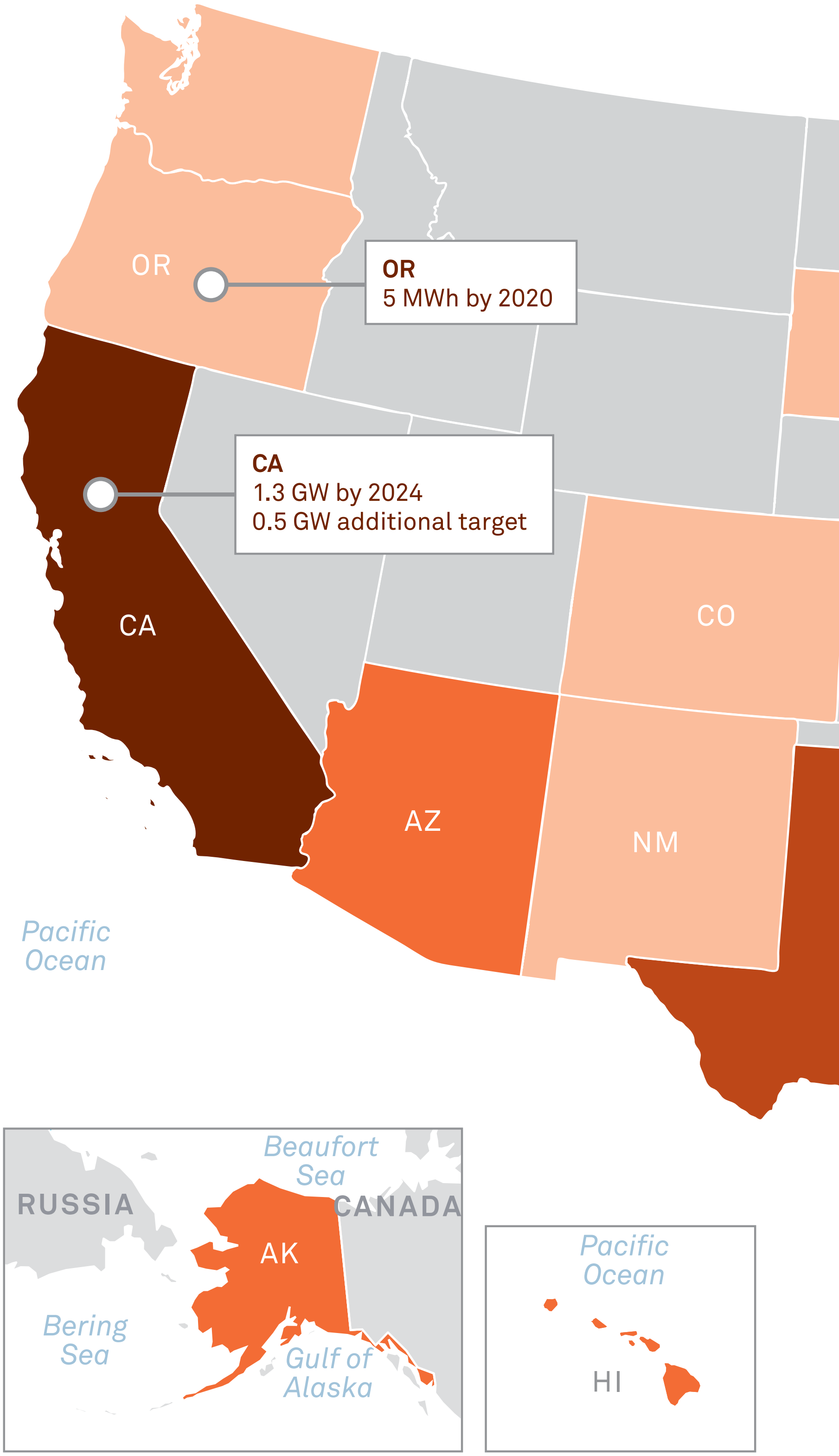
The US currently has a little over 1 GW of installed battery storage capacity and could have more than 7 GW of utility-scale and grid-connected battery storage operating by 2022, according to S&P Global Platts Analytics' most recent *US Power Storage Outlook*.

Lithium-ion battery prices have sharply declined in recent years driven by steadily expanding manufacturing capacity, which has led to economies of scale and improved learning. That learning curve is expected to continue as battery companies are planning a six-fold manufacturing capacity increase by 2023.

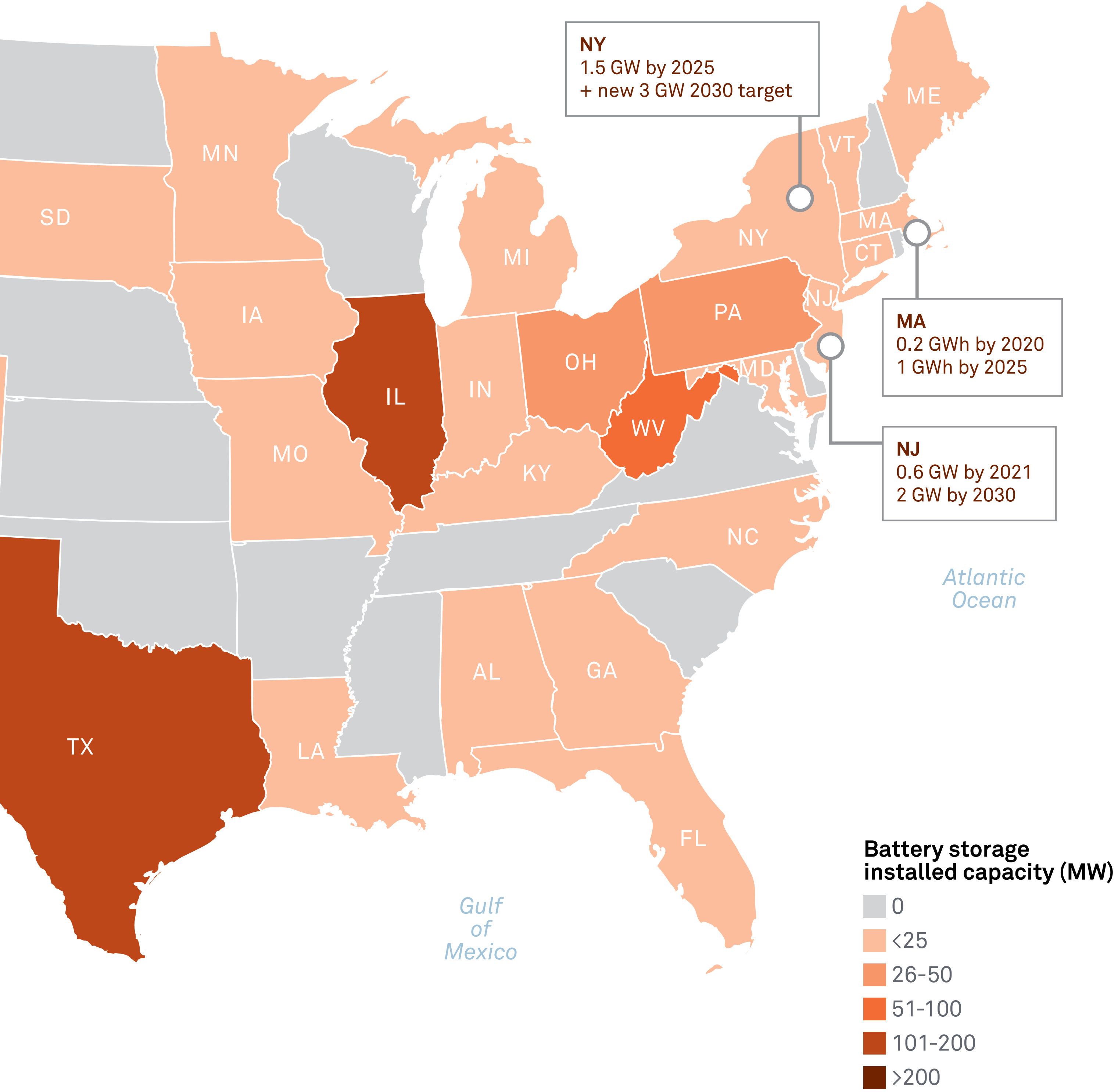
Over the medium to longer term, Platts Analytics anticipates that mass-market electric vehicle adoption will continue to drive battery costs down despite concerns around raw material prices. Lithium-ion battery prices are expected to decline 40% by 2025, making it difficult for other technologies such as flow-batteries to compete, particularly for shorter durations.

One potential battery storage deployment growth metric lies in the interconnection queues maintained by each wholesale power market operator, known as independent system operators or regional transmission organizations. Any resource that wants to connect to a regional power grid must progress through a formal interconnection process. Not every resource will ultimately connect to the grid, but the queues provide a view of the level of market participants' interest in storage.

US battery storage trends: grid connection queues and state targets



Source: S&P Global Platts Analytics


NY
1.5 GW by 2025
+ new 3 GW 2030 target
MA
0.2 GWh by 2020
1 GWh by 2025
NJ
0.6 GW by 2021
2 GW by 2030
ME
VT
NH
MA
CT
NY
NJ
PA
MD
WV
OH
MI
IN
IL
KY
MN
SD
IA
MO
NC
AL
GA
LA
TX
FL
Atlantic Ocean
Gulf of Mexico
Battery storage installed capacity (MW)
0
<25
26-50
51-100
101-200
>200

Battery capacity in RTO/ISO interconnection queues more than doubled in 2018, surpassing 30 GW of capacity. The largest queued capacities are in the California ISO (CAISO), supported by storage mandates, and in the Southwest Power Pool (SPP), where several large solar-PV-with-battery projects entered the queue in 2018.

The Federal Energy Regulatory Commission's energy storage order 841 will impact the volume of wholesale power market energy storage participation over the longer term, but the impact is expected to vary by region.

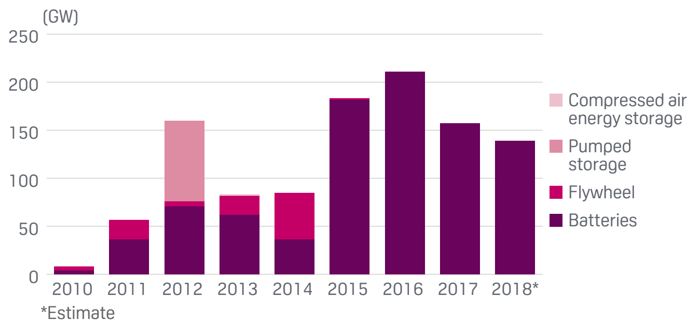
The ISOs filed plans with FERC detailing market rule changes that would allow energy storage resources to participate in regional power markets on a level playing field with other resources. FERC is reviewing the proposals that were filed in December.

Market observers were initially concerned that a 10-hour participation requirement for storage in PJM Interconnection's proposal would limit the ability of battery storage to engage. PJM Interconnection is an RTO whose territory spans a number of states in the eastern US. However, president and CEO Andy Ott explained in a recent interview that changes to its energy and reserves markets are expected, to allow storage resources to earn the bulk of their revenue from those market segments. The 10 hour requirement only applies to the capacity market, which is not ideal for storage resource participation, according to Ott.

Outside those regions covered by RTOs/ISOs, several utilities have announced plans to procure battery storage as part of their Integrated Resource Plan processes. Portland General Electric recently announced a first-of-a-kind combined facility with 300 MW of wind, 50 MW of solar PV and 30 MW of batteries. And Arizona Public Service Company in February said it plans to add 850 MW of battery storage and at least 100 MW of new solar generation by 2025.

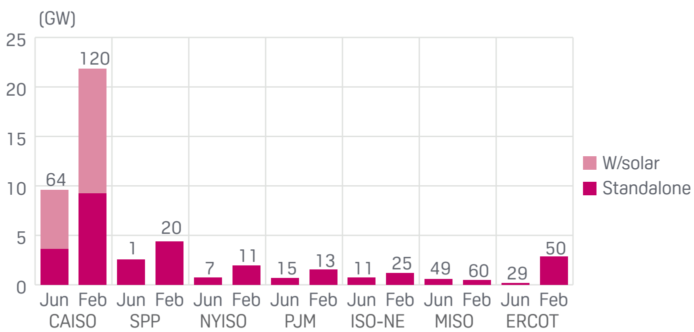
Platts Analytics estimates that solar PV with storage will become increasingly competitive with natural gas peaking plants in regions with high solar resources. ■

US power storage capacity additions



Source: S&P Global Platts Analytics

Battery storage in RTO/ISO connection queues, June 2018 vs. February 2019



Note: # equals number of projects
Source: S&P Global Platts Analytics

Battery capacity in RTO/ISO interconnection queues more than doubled in 2018, surpassing

30 GW

of capacity

After the revolution

Breakneck expansion in shale production has propelled US oil towards new records, but a change of pace is now on the cards. By Starr Spencer

Upstream oil and gas producers are trapped in a dilemma they might have previously thought would be desirable: abundant production at low cost.

For decades, higher production from oil companies was what the market wanted and rewarded. If producers had to borrow and overspend to do it, the attitude was “c'est la vie”. But in the last couple of years, it has become clear that what is desired, often voiced and certainly rewarded, is slower production growth and reined-in spending.

Capital discipline has been the watchword among upstream producers and Wall Street alike for at least 18 months. That could help brake production growth this year, along with small decreases in well productivity and efforts to return more capital to shareholders.

Increases in US unconventional production from shale, particularly shale oil, are the product of years of innovation. In particular, during the industry downturn between 2015-2017, E&P companies hacked away at their costs and forced down their breakeven prices. The industry has more than doubled production since 2011, and the fastest growth has been in the last couple of years.

According to the latest US Energy Information Administration figures for November, domestic oil production is closing in on 12 million b/d, of which nearly 2 million b/d was added last year alone. S&P Global Platts Analytics, which puts current production at 11.83 million b/d, forecasts year-end production at 12.78 million b/d and end-2020 production at 13.48 million b/d.

Long-time energy economist Phil Verleger, in a report in January cited EIA projections of 800,000 b/d additional production from December 2018 to December 2019, adding that the International Energy Agency figures on 780,000 b/d of added production in the same time span and OPEC, 1.7 million b/d.

“The level of activity last year will be difficult to maintain without oversupplying the market,” Credit Suisse analyst Jim Wicklund observed in a recent investor note.

But operators can't help it: the efficiencies achieved in recent years have made it easier to produce more oil from every well. They're not going away anytime soon, so something else will have to slow down their progress.

When crude prices dropped from over $100/b in mid-2014 to about half that level at the end of the year, operators learned the meaning of efficiency the hard way. Suddenly each barrel they produced was bringing in 50% of the money it had done just months earlier, so they had to make each drilling and production dollar they spent work harder.

From necessity to invention

Through diligent operational streamlining, they squeezed every last drop of value out of each stage of the E&P chain. They eventually brought their breakeven price – the cost of producing a barrel of oil to get a 10% return – down to levels that would have seemed miraculously low a few years before. These days, oil breakevens for the best operators in the most prolific plays are not too much more than the cost of an extra-large pizza with the works, plus a magnum of Coca-Cola and tip for delivery.

The continuous technological wizardry of well drilling and completion improvements allowed the industry to produce far more oil and gas in far less time at ever-lower costs – and at extremely economic return rates which often yielded 100% or more. But it also brought the supply genie ahead of the demand curve faster than expected.

Producers exploiting US plays from Texas to North Dakota, from Pennsylvania to Wyoming, have pulled gargantuan volumes of shale oil and gas out of the earth in the last 15 years. Gas was the initial commodity to be produced unconventionally – meaning horizontally – starting in the early 2000s. So successful were producers at coaxing large gas volumes out of shale wells that eventually the domestic market was facing a glut that pushed gas prices to low levels within a few years. Prices have continued to stagnate.

Pre-shale, a decent initial flow rate for a conventional gas well was about 1,000 Mcf/d. Now many shale wells yield initial rates of 20,000 Mcf/d and double that rate is not unheard of. Those numbers have kept gas storage bins full and gas exports to markets around the world humming.

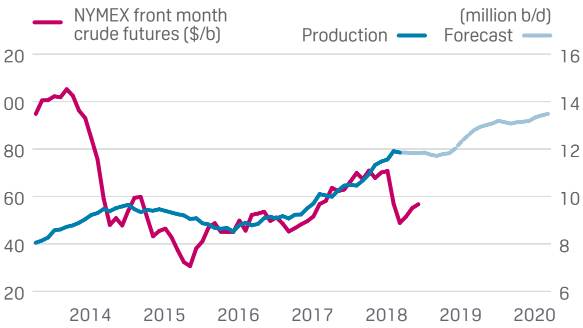
Increases in crude well outputs are also robust even if not as dramatic. Conventional oil wells of the past might have yielded 500 b/d, while early shale oil wells saw typical initial outputs of 1,000 b/d. That has frequently doubled and sometimes tripled, while in rare cases 5,000 b/d or 6,000 b/d have been eked out of wells. Even so, total oil production growth over the last eight years as the shale oil revolution blossomed has been phenomenal. In January 2011, US oil production was just below 5.5 million b/d. By January 2015, just as the recent industry downturn had begun, domestic oil production stood at 9.3 million b/d. That increase was largely achieved at prices of $90/b-$100/b.

Production peaked in April of that year at 9.6 million b/d, but fell back because operators cut back activity and capex during the downturn. The 50 largest E&P companies slashed their 2015 capital budgets collectively more than 40% year on year, and another 25% or so for 2016, according to research from EY (formerly Ernst & Young). By that time, oil prices had fallen to levels around $30/b just as operators were releasing their annual budgets at the start of that year.

But then, oil prices stabilized around $50/b for several months, and heading into 2017, E&P operators were more sanguine. The constancy of prices lent confidence to the sector and the operational improvements forced by low crude prices had put them in good stead to produce oil for less than before. Capital budgets rose that year about 32% to a total $114.5 billion – still far below the $198 billion spent in 2014. But spending didn't need to return to former levels, as E&P operators found they could still grow production at $50/b.

Even at capex levels 65% to 70% lower, during the downturn, US production from January 2015 to January 2017 dropped only about 6%, to 8.8 million b/d. And given the efficiency improvements achieved during that time, it didn't take long for US production to climb back up.

US crude oil production continues to rise



Source: S&P Global Platts Analytics, EIA, CME-NYMEX

From November 2016 to November 2017, at an average price of $50/b, US oil production grew by 1.2 million to 10 million b/d. And from November 2017 to November 2018, at an average price of $64.83/b, production grew just under 1.8 million b/d, hitting 11.9 million b/d.

In the low oil-price environment of 2015-17, operators drastically reduced the number of days needed to drill wells. They became more precise in placing drill bits within an oil formation to land in a reservoir's sweetest spot. And they continually streamlined and perfected their recipes for completing wells at increasingly lower costs.

Continually evolving well completion designs have allowed operators to bring down the cost of a well by about a third or more. At the start of 2014, the Permian Midland –the eastern and part of that giant West Texas basin– had an average oil breakeven cost of about $44/b; currently it is $30-ish/b, according to S&P Global Platts Analytics data.

Prices point to slowing growth

What to do about the US supply glut, then? It is likely that a combination of technical production limits, investor demands and the simple factor of oil price will start to redress the imbalance this year. Lower crude prices should put a brake on production growth this year by some order of magnitude. E&P company capital budgets for 2019 are coming in flat or lower on average, and some operators that late last year guided this year’s spending at higher levels, have revised them down.

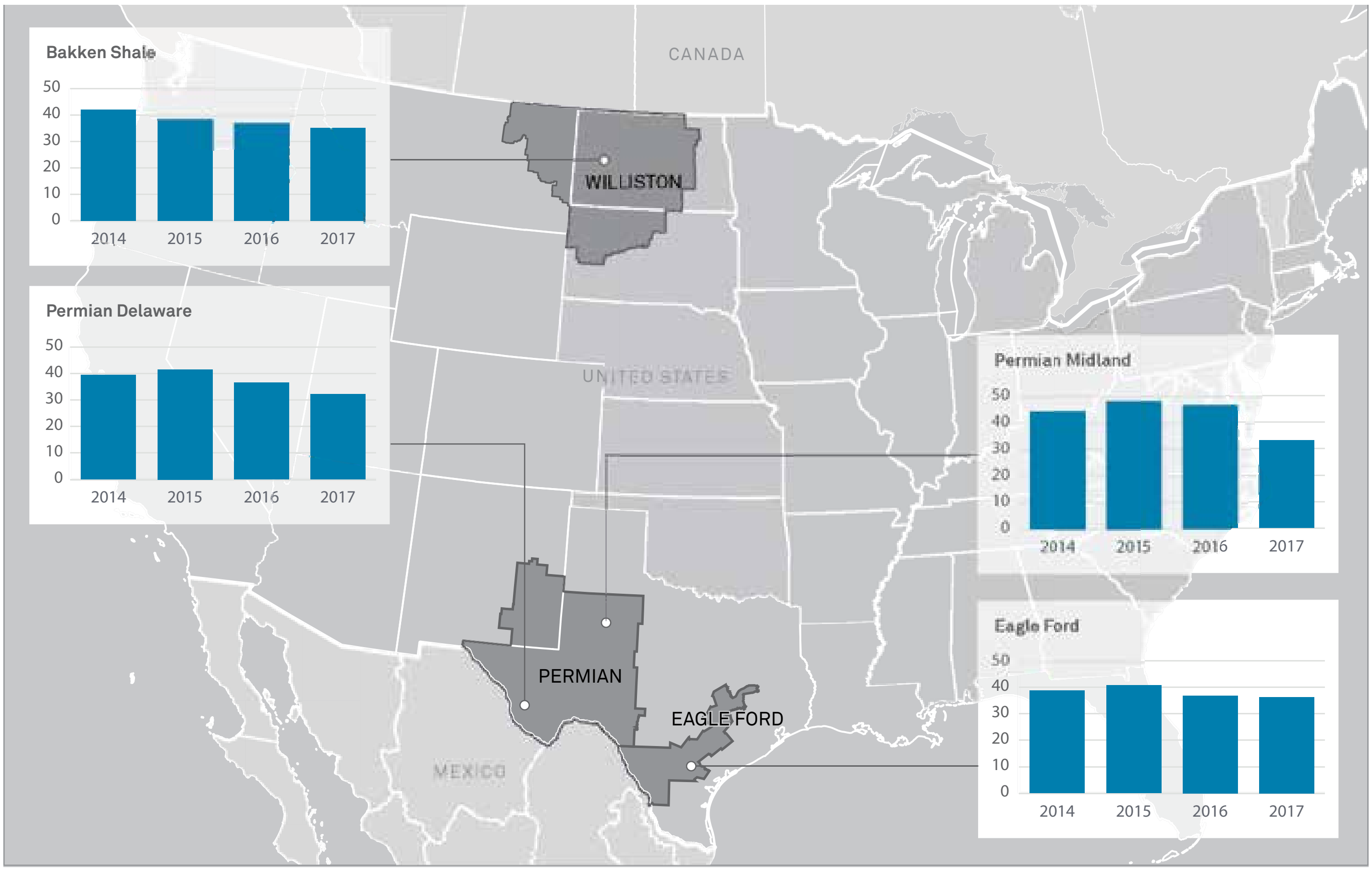
Also, operators are being encouraged by market forces to spend money in other ways than growing production. E&P companies that return more cash to shareholders are being rewarded, since in some cases dividends were reduced or eliminated during the downturn. Companies that are more disciplined and keep spending at the level of cash flows – which was uncommon in years past when operators typically outspent their income – have also been rewarded with higher share price. Access to credit is also a likely consideration in times of volatile oil prices, as a more restrained approach to spending may help when companies are looking to the capital markets for funding.

In any case, premium acreage – the so-called "Tier 1" areas – is starting to decline for many companies, although some claim that continued efficiencies and cost control can turn many drilling locales to premium status that were not originally deemed that way.

Well productivity also appears to be reaching a plateau, many operators say. In a recent report on basin trends in Q4, Evercore ISI analyst Stephen Richardson said that more corporate level efficiencies are expected in 2019, although finding the optimum spacing between wells remains an ongoing challenge.

Richardson's examination "reveals the pace of incremental [well] performance gains have tapered across basins," he said, adding: "The market needs producers to exhibit restraint in 2019 plans." ■

Costs drop in major US oil basins ($/b)



Source: S&P Global Platts Analytics

Coal: out in the cold

The aging US coal fleet is being squeezed from all sides, with policy, cheap domestic gas supply and developments in clean energy all contributing to fast-paced closures. By Morris Greenberg

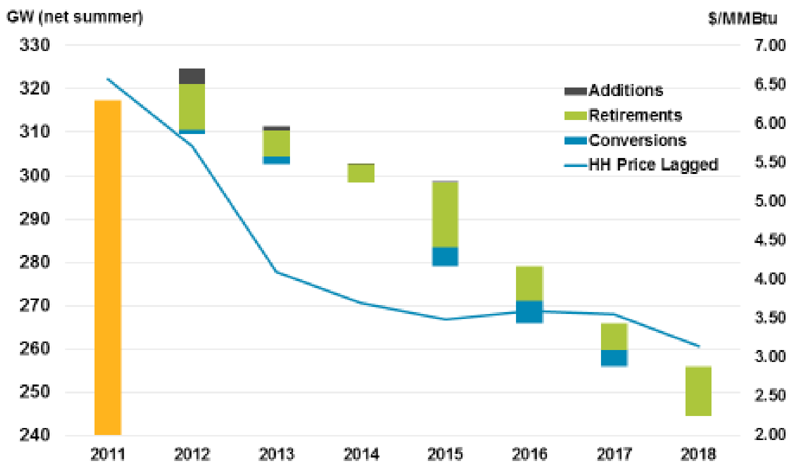
Since peaking at 317 GW at the end of 2011, US generating capacity with coal as the primary fuel fell by 73 GW, or 23%, due to the retirement of 61 GW and primary fuel conversion – mainly to natural gas – of 16 GW. This was offset by additions of 4 GW.

Most of the additions were made early on in this eight-year period. Coal-fired generation has fallen even more steeply than capacity, with a decline of 33.5% between calendar years 2011 and 2018. The drop reflects a reduction in average capacity factor (utilization rate) from 62% to 52%.

While capacity factors have stabilized during the past three years, announced plans for the retirement of around 20 GW and the conversion of around 5 GW indicate that, without some form of policy support, capacity declines will continue.

Indeed, the announcements may only reflect the tip of an iceberg that includes many more GW of capacity at risk. To get a better handle on that number, it is useful to review first the economics of retirement and then factors that have driven the restructuring observed to date. These factors are: an aging coal fleet; stagnating demand; low natural gas prices; environmental regulation; and finally, cost declines and policy support for clean energy.

US coal capacity vs. Henry Hub natural gas prices (three-year average, two-year time lag)



S&P Global Platts Analytics

Retirement economics

The decision to permanently retire a merchant coal unit, or really any merchant unit, is made by comparing the present value of future revenues from sale of energy, capacity and ancillary services to the present value of costs including fuel, non-fuel variable operating and maintenance expense, fixed operating and maintenance expense, and required capital spending. For regulated units, the relevant measure is the present value of revenue requirements. The calculations are similar if replacement energy and capacity is acquired from the market. There are several factors that play into this calculation and have driven the restructuring seen in the US market in recent years.

Aging fleet

Of the 317 GW of operable capacity in 2011, 125 GW exceeded 40 years of age and 50 GW exceeded 50 years. Older units are less efficient, require higher spending per unit of capacity to maintain availability, and tend to face higher capital requirements for environmental retrofits, leaving them more vulnerable to changes in market conditions.

Stagnating power demand

A combination of improving energy efficiency among consumers combined with rising behind-the-meter generation has led to stagnating demand, leaving US retail electricity sales virtually unchanged from 2011 to 2017. Weak demand depresses energy and capacity prices for all generation, but coal units were exposed due to the factors that follow.

Lower natural gas prices

Low natural gas prices have had a major impact on the erosion of US coal-fired capacity. The direct impact is the conversion of existing capacity from coal to gas. But there is also an indirect impact, as lower electric energy and capacity prices reduce the value of coal capacity and may boost operating costs due to operational changes. Since 2011, rising gas supply associated with shale gas development has allowed US consumption of gas for power generation to increase by 38%, from 21 Bcf/d to 29 Bcf/d and accommodated higher net exports with no upward pressure on prices.

Accounting for permitting, financing and engineering, the development cycle for gas capacity ranges from about two years for fuel conversions, to five years for greenfield development. As a result, while gas prices have an immediate impact on energy prices, the impact on capacity prices and decisions to build or retire plants occurs with a lag of that duration. A three-year moving average of Gulf Coast gas prices lagged by two years peaked in late 2010 near $8/MMBtu, fell to the $3.50 range in 2015-17, and to the low $3 range in 2018. It will fall below $3/MMBtu this spring and will likely remain there for several years. That means gas markets will remain a drag on coal unit economics for years to come.

Environmental regulation

Coal units must comply with air, water and solid waste emissions standards. Air emissions include sulfur dioxide, nitrogen oxide, particulates, mercury and other air toxics, and carbon dioxide. Water standards cover plant effluents as well as cooling water intake structures and temperature impacts. Coal combustion residuals are also regulated.

The Environmental Protection Agency's Mercury and Air Toxics Standards, which took effect in April 2015, was the most important regulation to impact coal capacity during the 2011-18 period, driving units facing high compliance costs to retire. In some cases, units that remained in service faced increased costs associated with operating emissions controls or purchasing coal additives to improve mercury capture.

While the Obama administration's Clean Power Plan proposed in 2014 was never implemented, the potential for future carbon regulations must be considered in a decision to retire or maintain coal capacity, particularly if capital infusions are required. In addition, while the federal regulatory role is currently limited, carbon emissions caps are in effect in California and the Northeast, through the Regional Greenhouse Gas Initiative, and several other states have emission reduction targets.

Cost declines and policy support for clean energy

A combination of falling costs and state, as well as federal, policy has led to rapid growth in US wind and solar generation. Solar PV costs have declined from about $4,000/kW-AC in 2011 to about $1,200/kW-AC at present. During the same period, onshore wind costs fell from over $2,000/kW to about $1,500/kW. In addition, the cost of battery storage that can help integrate intermittent renewables, particularly solar, has fallen dramatically.

States have played a role in renewables growth primarily through renewable portfolio standards, which mandate a certain proportion of renewables in the energy mix. Twenty-nine states and the District of Columbia currently have mandatory RPSs. Qualifying technologies vary from state to state – though solar and wind qualify everywhere – and percentage requirements vary over a wide range. Based on current law, renewable generation to meet RPS requirements of load serving entities – that is, companies that provide power on a retail basis, mainly utilities but also unregulated marketers – will more than double between 2018 and 2030. Corporations in pursuit of sustainability goals have also stepped up their purchases of renewable energy, signing deals for over 6 GW of capacity in 2018 alone.

State support for merchant nuclear units challenged by weak margins may come at the expense of coal capacity. Unlike intermittent renewables, nuclear units provide significant capacity value – meaning they can provide energy whenever needed. New York and Illinois are already providing support, with New Jersey and Connecticut also moving down this path. Pennsylvania, home to 10 GW of nuclear capacity, may follow.

The federal role in promoting renewables has mainly been through tax credits, including production tax credits (PTC) for onshore wind and investment tax credits (ITC) for solar. Under legislation enacted in late 2015, wind projects starting construction in 2016 are eligible for a PTC of $23/MWh for 10 years; the value of the credit steps down for projects started in subsequent years and is phased out for projects begun after 2019. The ITC is 30% for projects started by the end of 2019 and then steps down over the following two years, with the residential credit expiring for projects begun after 2021, and the ITC for non-residential systems falling to 10%.

The cost of wind generation (including ROI) from projects qualifying for the full PTC in areas with high average wind speeds is in the $15-20/MWh range, competitive with the variable cost of coal and gas generation. The cost of solar PV qualifying for the full ITC in areas with high insolation is in the $25/MWh range. Variable production costs are lower, and producers are often willing to sell at negative prices to capture tax credits (in the case of wind) and renewable energy credits (used for RPS compliance). Due to lower variable production costs, rising renewables generation will displace both coal and gas generation and result in lower energy prices. In addition, more extensive cycling of dispatchable generation to balance supply and demand will result in higher operating costs.

Despite its impacts on energy prices and operating costs, growth in renewables output by itself has not been a major driver of coal retirements because the resources do not provide much capacity value, and lost energy revenues can be partially recouped in capacity markets. That may change, however, with additional investment and the ability of battery storage to add capacity value. There is 35 GW of wind capacity in advanced development, according to the American Wind Energy Association. The Solar Energy Industry Association reports 27 GW of solar projects with signed power purchase agreements, and another 37 GW announced.

Global perspective

While this discussion has been focused on US developments, the same factors apply elsewhere in the world as well, though their relative importance may vary. Europe, for example, is expected to see a significant reduction in coal-fired generating capacity during the next two decades. Slow demand growth, policy support for renewables, and explicit coal shutdown plans play a role. As a gas importer, gas prices tend to be higher in Europe, but the impact is offset by carbon allowance prices that boost the effective cost of burning coal relative to gas.

In Asia, the picture for coal is a little brighter thanks to high gas prices, faster load growth and looser environmental regulations. However, renewables are making inroads, particularly in China, causing growth in coal to slow. ■

Morris Greenberg is Senior Manager of North American Power Analytics at S&P Global Platts

Insight from Brussels

Siobhan Hall

Renewables are the big winners in the European Union's new power market rules, which are designed to help the grid cope with ever-increasing shares of variable sources such as wind and solar.

This is part of the EU's long-term push to cut its greenhouse gas emissions and reduce fossil fuel imports.

At the end of 2018 it adopted a binding target to source at least 32% of its final energy demand, including heating and transport, from renewables by 2030.

That translates into sourcing more than half its electricity from renewables by 2030, up from around 30% today, and that upwards trajectory will only continue as the EU seeks to decarbonize its economy by 2050.

The EU's new power market design regulation, which is expected to become binding in 2019, aims to create a flexible, responsive and integrated grid, able to cope with renewable inputs that vary hugely from day to day and from country to country.

Denmark, for example, has for years invested heavily in wind. The share of renewables in its power output varied from zero to 100% within 2017, according to formal EU power grid operators' body Entso-e.

That worked out as around 70% on average for the year for Denmark, compared with well under 50% for most of the rest of the EU.

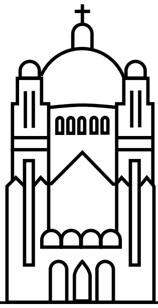
Overall, the EU still sources 70% of its power from non-renewable sources, and this 70:30 ratio has "remained broadly consistent" over the last three years, Entso-e said in early 2019.

The new power market rules are intended to help renewable power grow, and support the flexibility options needed to cope with more variable output. For example, the rules retain priority dispatch for existing renewable power plants, but allow transmission system operators to curtail output from new renewable power plants.

TSOs will also have to report on all redispatch actions – interventions in the expected priority order of different generation assets to balance the grid. They will have to follow recommendations from regulators on how to be more efficient in their redispatch, and avoid curtailing renewables.

"This will help give transparency on any 'must-run obligation' agreements with conventional power plants that are crowding out renewables from the grid," trade body WindEurope said.

The solar sector is also delighted with the new rules, in particular for securing "the uptake of small scale and locally owned solar installations" in the EU, its trade body SolarPower Europe said. This "will pave the way for a new solar boom in Europe."



CO2 limits for power plants

One of the most controversial parts of the new rules centered on emission limits for power plants taking part in national capacity remuneration mechanisms. Such mechanisms, which pay power plant operators to keep capacity available, are becoming popular with many EU governments worried about long-term electricity supply security in markets dominated by variable renewables.

The final deal – like all EU energy policy – is a compromise between what the European Commission, the executive arm of the EU, wants, and what national governments are willing to accept.

The EC was keen to ensure that governments did not use such mechanisms to support power plants with high carbon emissions, such as coal and lignite, and in this it partly succeeded.

Plants starting up after the power market design regulation enters into force – likely to be around mid- to late-2019 – with emissions higher than 550 g CO2/kWh will not be allowed to take part in capacity mechanisms or receive capacity payments.

Existing power plants emitting both more than 550 g CO2/kWh and more than 350 kg CO2 on average per year per installed kW will only be able to receive capacity payments until July 1, 2025.

These criteria impact all unabated coal and lignite power plants, which have emissions well above 550g CO2/kWh. They mean that existing unabated coal and lignite plants will only be eligible to receive capacity payments beyond July 2025 if they run for very limited hours to stay under the yearly average emissions limit. And new unabated coal and lignite plant coming online after 2019 will not be eligible for any capacity payments.

But there is an important exception. National governments will not have to apply the new emission limits to commitments or capacity contracts concluded before December 31, 2019.

This means Poland, which relies heavily on coal-fired power, was able to grant a 15-year capacity contract to the planned 1 GW coal-fired Ostroleka C power plant in December. Ostroleka is expected online in 2023, which means it will be allowed to receive capacity payments until 2038.

Polish energy officials have said this will be Poland's last large coal plant, and that renewables will be the new focus. Poland aims to source 27% of its electricity and 21% of total final energy demand from renewables by 2030, according to its first draft integrated national energy and climate plan.

All EU governments have had to prepare such draft plans showing how they intend to help the EU meet its 2030 targets. The EC is to review them to ensure they collectively meet the 32% EU target, as well as the 32.5% energy efficiency improvement target.

That means 2019 will see a long negotiation between the EC and national governments over who should do what on renewables. But the trajectory remains clear – more renewables, less fossil fuels. ■

Closing the gap

Falling technology costs, greater efficiency and supportive policies are making renewable generation increasingly competitive. Steve Piper of S&P Global Market Intelligence takes a deep dive into returns forecasts for wind and solar

Wind and solar photovoltaic (PV) electric facilities only account for an estimated 11% of US generation, but they are fast closing on a tipping point where they may outperform conventional generation as an asset class.

Several factors have come together to drive this result, starting with a rapid decline in costs for new renewable facilities, both wind and solar, that has offset the advantage to natural gas generation brought about by abundant and economical supply.

Improved efficiency of renewables also means every facility can generate more power, delivering greater value and revenue to the off-takers. Declining cost and increased output drives a cycle of improving competitiveness and returns when compared to conventional generation.

Supportive economic policies such as Investment Tax Credits (ITC) and tradeable Renewable Energy Certificates (RECs) also provide a source of financial support to green energy, although both are expected to be reduced in the future.

Finally, the progressive restructuring of wholesale electricity markets, while traditionally viewed as providing principal support to conventional merchant generation, has also facilitated the spread of green energy. It has enabled multiple points of interconnection, and broad integration of both the green electricity markets and the markets for their environmental attributes. The ability to plug into the grid and realize a backstop price and secure marker for value, at a time when per-MWh costs of production are falling, has further allowed renewable projects to proliferate.

S&P Global Market Intelligence has examined the revenue generation attributes of wind, solar, and natural gas generation across three major US investment markets to illustrate the respective drivers of value as well as the enormous potential for green energy to disrupt generating fleets well into the future.

The chart overleaf presents forecast 10-year merchant development returns to natural gas, wind, and solar PV in three key US markets: the Electric Reliability Council of Texas (ERCOT); the PJM Interconnection (PJM), and

Federal subsidy phase-out

Federal subsidies for renewable energy have fluctuated in recent years, with current law phasing subsidies out over the next two years. The current landscape for federal renewable incentives is as follows:

– Solar – The Investment Tax Credit (ITC) equal to 30% of the installed cost of qualified solar panels or grid-scale solar projects that start construction before 2021, and then falling to zero by 2024;

– Wind – The Production Tax Credit (PTC) for wind resources was extended to include resources that commence construction by January 1, 2020, falling to zero after that time.

The lapse of federal subsidies will drive up the effective cost of wind and solar facilities beginning in 2021-2022, although some of this increased cost will be offset by falling costs on installation and technology improvements that boost output.

Unlike in Western Europe, only about 25% of US electric load in California and the Northeast is subject to taxes on CO2 emissions, and the Northeast program is directed solely to electric sector emissions. Instead, states increasingly focus on mandates to expand zero carbon generation. In 2018 California followed Hawaii's lead to mandate 60% of electricity come from renewables by 2030, with a 2045 goal of 100% carbon emissions-free generation.

Many Western US states are introducing similar targets, with Arizona and Nevada pushing a 50% target by 2030. In the East, New York recently issued an executive order bumping its 2030 target from 50% to 70%. The emphasis on mandates over prior tools such as Renewable Energy Certificates (RECs) and tradeable carbon emission credits reflects a growing consensus on commitment to the infrastructure aspects of the US generating fleet transition, much of which is expressed in early congressional proposals for the “Green New Deal”.

the California Independent System Operator (CAISO). As a whole, low load growth and generation oversupply ensures that none of these asset classes is forecast to achieve a full return (estimated at 9.7%). What is noteworthy, however, is the relative consistency of returns to all classes and the narrowing of spreads between renewable asset classes and new natural gas plants.

Average annual returns by class, 2019-2028

	Asset class		
Region	CCGT	Solar PV	Wind
ERCOT	4.97%	5.46%	**6.29%**
PJM	**6.41%**	5.43%	6.05%
CAISO	**5.78%**	4.67%	4.09%

Source: S&P Global Market Intelligence, information as of 12/31/2018

Electric Reliability Council of Texas: King of the hill in energy

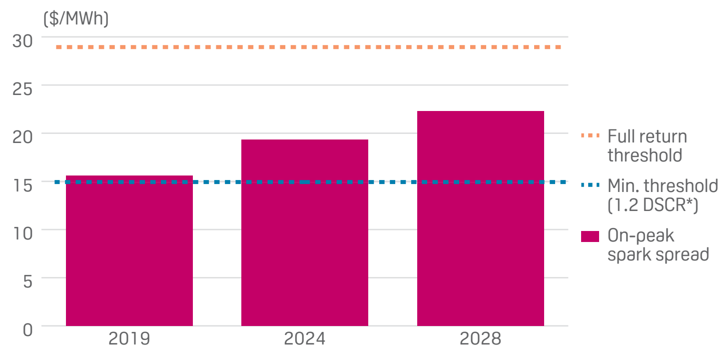
If you were going to choose a market with the best odds of success for a natural gas power plant, you could hardly do better than Texas, where industrial-zoned land is cheap, electricity demand is growing, older coal plants have retired, and natural gas produced here may just be the lowest-cost on the planet. Thanks to burgeoning unconventional oil production especially that coming out of West Texas, the supply of natural gas that comes along for the ride has expanded faster than generators (or anyone else) can use it.

But Texas is also blessed with high levels of wind, be it from the wide flat plains of the West or from the steady coastal breezes. Texas is also at a favorable latitude for solar resource. Furthermore, the Electric Reliability Council of Texas (ERCOT) market only pays for peak generating capacity on an hour-to-hour basis, a situation independent merchant power developers have long decried. With last year's improvement in prices, Market Intelligence estimates spark spreads sufficient to deliver returns to generation equity owners this summer, with growth into the future as the market stays tight on generation.

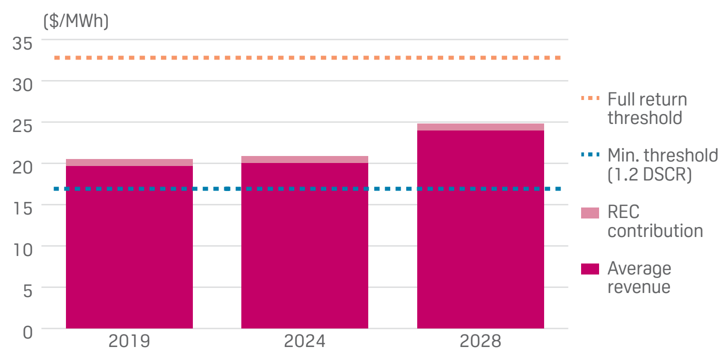
Compare the struggle for returns of a gas-fired combined-cycle (CCGT) plant in ERCOT to a new solar facility. Although solar facilities can't avail themselves of hour-to-hour capacity payments, solar PV drives value during the peak times of the day, receiving arbitrage between the fluctuating price of coal and natural gas and their own marginal cost of zero. Solar PV plants also receive at least a nominal contribution from ERCOT's REC market. While low power prices in ERCOT mean solar PV owners must accept less than a full 9-10% return on capital, Market Intelligence estimates superior returns to solar than those for natural gas.

Wind clean spreads look better still. With modern wind turbines operating close to 45% of the year, the long-cited deficiency in summer peak contribution becomes less relevant. Wind captures more value in winter months than solar PV does, driving a higher overall estimated return.

ERCOT north zone forecast spark spreads



ERCOT north zone forecast wind spreads



*Debt service coverage ratio. Lenders typically apply a 20% contingency to the required debt payments in their pro-forma financial analysis prior to lending, to improve the odds their debt will not be impaired.
Data as of Dec. 31, 2018.
Source: S&P Global Market Intelligence

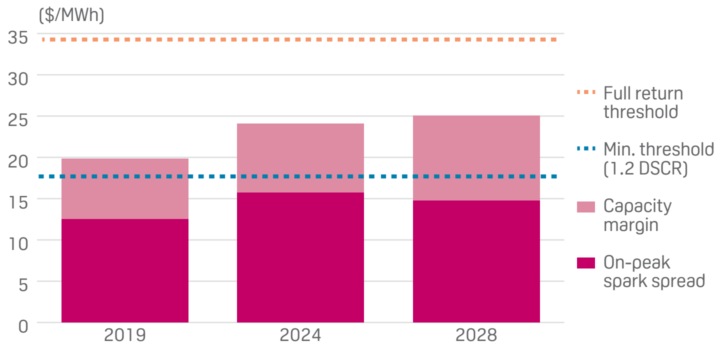
Pennsylvania: Renewables close in on gas

If the Permian Basin of West Texas produces the cheapest natural gas on the planet, the Marcellus Shale centered in western Pennsylvania, eastern Ohio, and West Virginia may come in a close second. Combined with a more stable revenue stream for generating capacity via the PJM Interconnection's capacity auctions, this region has been targeted for merchant CCGT investment. Market Intelligence estimates 16.7 GW of new CCGT capacity will come on-line 2018-2020, offsetting the impact of recently retired coal and nuclear capacity.

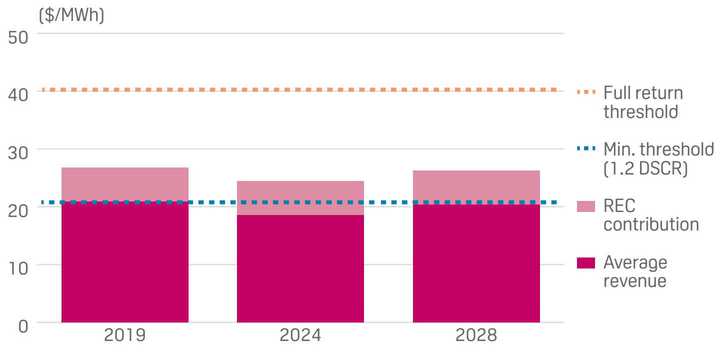
Together with a robust capacity payment, Market Intelligence estimates that a new CCGT will generate a solid return, exceeding that of ERCOT gas plants, over the next 10 years.

But states in the PJM region also support renewable facilities, using Renewable Portfolio Standards (RPS) backed by tradeable RECs. Utilities in Pennsylvania, Maryland, and New Jersey in particular can contract with green facilities or purchase RECs created by a facility potentially anywhere within PJM's 14-state footprint. As in ERCOT, typical wind plants in PJM generate substantial value for their owners, with REC contributions driving comparable returns for wind compared to those estimated for a natural gas plant.

PJM west forecast spark spreads



PJM west forecast wind spreads



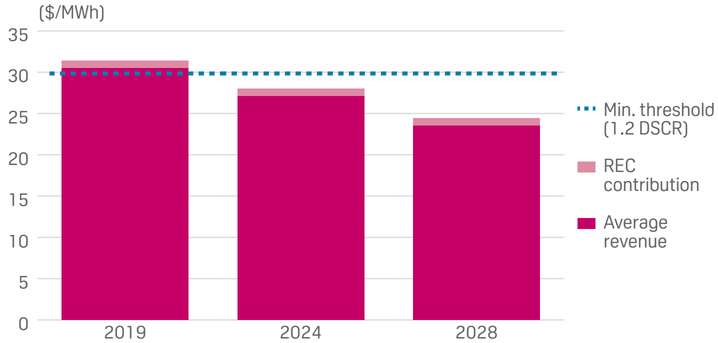
Data as of Dec. 31, 2018.
Source: S&P Global Market Intelligence

California: Gas out of favour amid low power prices

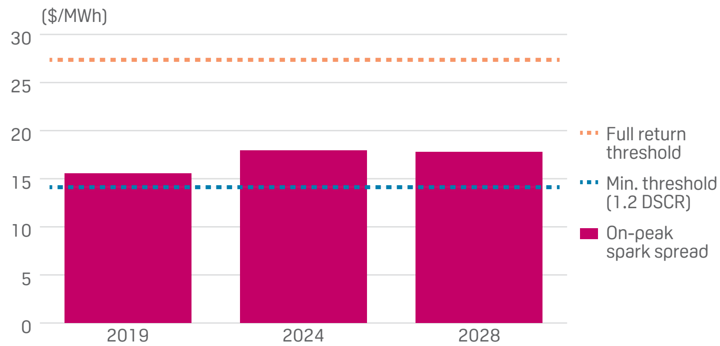
In efforts to modernize its natural gas generation fleet, California has mandated replacement of once-through cooling systems with zero-discharge water towers. Many plants are instead opting to decommission. At the same time, the aggressive build out, especially of solar PV, both distributed and wholesale, has depressed power prices substantially and will continue to do so. This is essentially the wholesale price version of the infamous 'duck curve' for hourly load, resulting in very low prices when solar PV generation is highest. As a result, a new CCGT stands out as a higher-performing asset in our forecast than wind or solar, as the state's enthusiasm for these resources saturates the market.

Importantly, however, the hourly wholesale electricity market supported by CAISO has expanded to cover multiple states of the Western US, allowing developers to site plants in areas less picked-over and still serve California's RPS standard. While total returns in California appear low, stronger returns are achievable elsewhere in the Western US

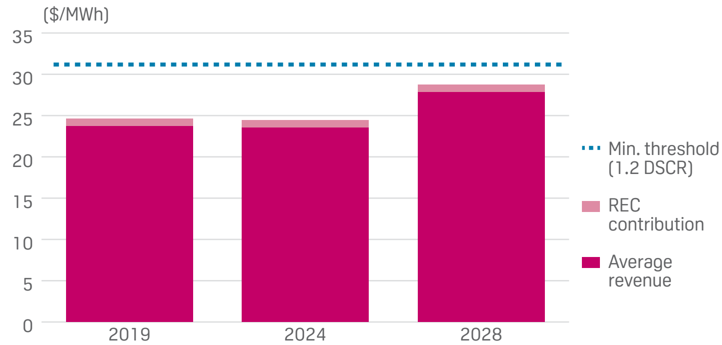
CAISO (SP15) forecast solar spreads



CAISO (SP15) forecast spark spreads



CAISO (SP15) forecast wind spreads



Data as of Dec. 31, 2018.
Source: S&P Global Market Intelligence

Bottom line: renewables pose strong competition to gas

The revolution in US shale gas seemed destined to drive most future generation investment toward natural gas power plants. And indeed it did – for a few years. As costs have fallen for wind and solar PV facilities, Market Intelligence forecasts indicate returns are converging with new natural gas, even in markets where natural gas competes best. This begs an important question: how competitive is green electricity today in parts of the world where fossil supplies are lagging? With just modest additional improvements in technology, we could see capital begin to tilt even further towards renewable energy, and further away from conventional generation. ■

Insight from Washington

Meghan Gordon

A strict sulfur limit for marine fuels starting in 2020 and its potential to boost US gasoline and diesel prices may have caught the White House off guard last year, but it's not taking anyone in the refining or shipping industries by surprise.

US refiners say they have been preparing for the International Maritime Organization's 0.5% sulfur cap for a dozen years by making billions of dollars of investments to their plants. They also think US oil producers are well positioned to meet new global demand for lower-sulfur fuels.

Despite the industry's confidence, Gulf Coast refiners are nevertheless skittish about one major wild card.

The January 1, 2020 implementation date comes right in the middle of President Donald Trump's re-election campaign, and this White House has shown a particular sensitivity to pump prices and their impact on voters.

Trump has proved through his Twitter feed that he personally keeps a close eye on oil prices, even if he sometimes confuses ICE Brent and NYMEX WTI. Additionally, his administration weighs policy options with an understanding of how they might move gasoline and crude oil prices.

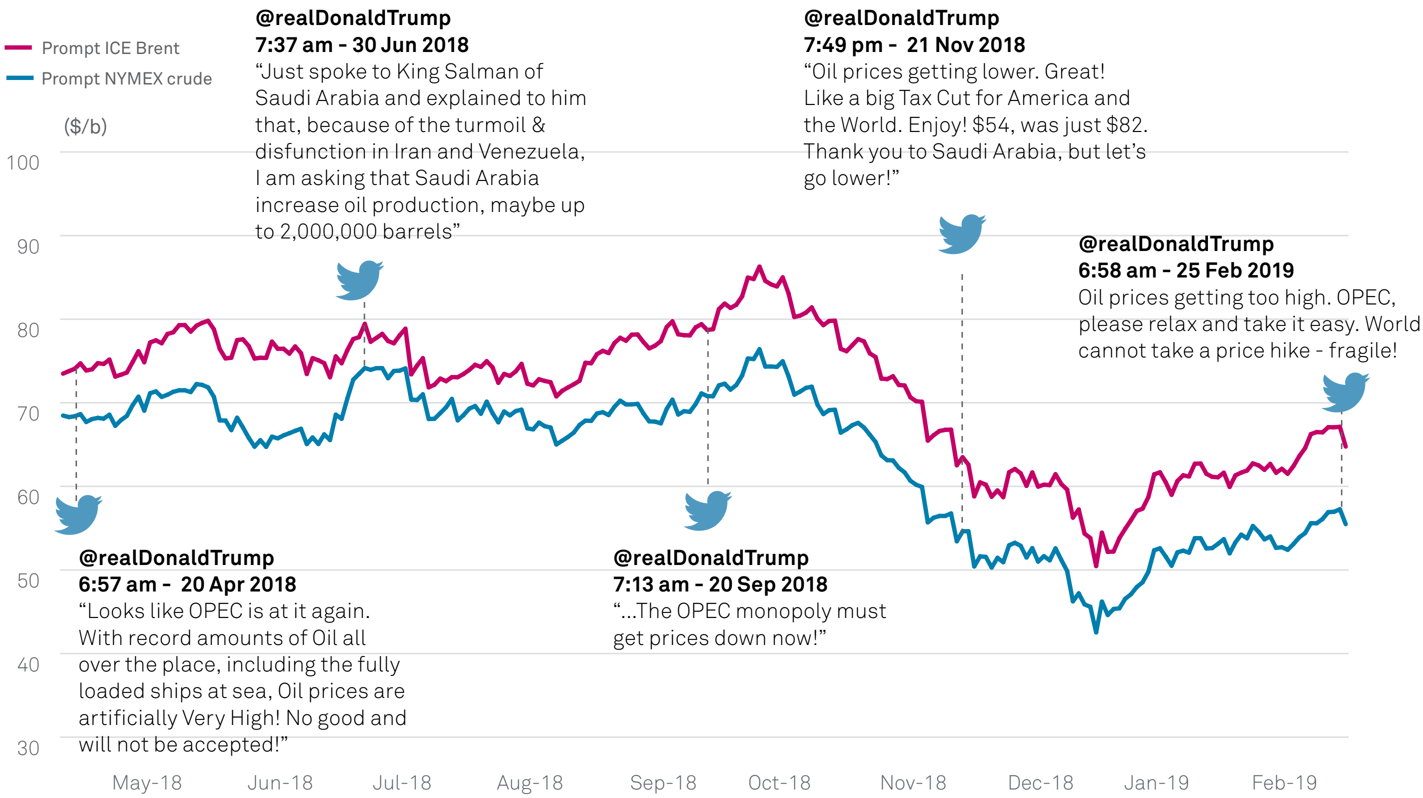
Trump administration sources told *The Wall Street Journal* in October that the White House was considering ways to delay the IMO's 0.5% sulfur cap beyond the long-scheduled January 1, 2020, implementation date. The story alone sent the stock market value of five US refining companies down by a combined $11 billion – hence their skittishness.

Within weeks of the story, trade groups for refiners, oil and gas producers, LNG exporters and steelworkers created the Coalition for American Energy Security to educate White House officials and members of Congress about IMO 2020 and what US industries were already doing to prepare.

“As we draw closer to implementation of IMO 2020, it's essential that the president and his administration are fully aware of the job impacts and energy security benefits of implementing the standards on time,” said Ken Spain, spokesman for the Coalition for American Energy Security. “The American energy industry is ready to dominate the global market for these new fuels, and timely implementation is critical to achieving that objective.”

US oil diplomacy by tweet

US President Donald Trump's latest tweet aimed at OPEC came as ICE Brent crude futures were inching closer to $70/b amid output cuts by Saudi Arabia and other producers, while US sanctions restricted oil flows from Iran and Venezuela.

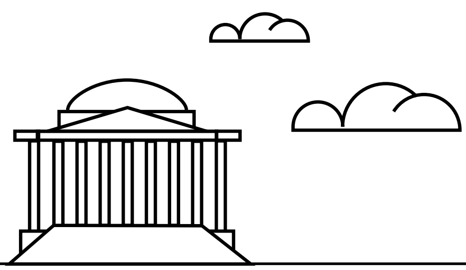


Source: S&P Global Platts

The International Energy Agency and US Energy Information Administration project modest price increases for diesel and jet fuel as a result of the tighter marine sulfur standards, but other analysts see more dramatic impacts coming at the end of the year.

Either way, the impending sulfur cap will bring big changes for the shipping, aviation, refining, oil production and power generation sectors.

IEA Executive Director Fatih Birol testified to Congress in February that there was a "bit of panic" in the oil industry about the impending regulations, but refiners are adjusting.



"There may be some temporary price spikes for diesel and jet fuel prices, but we think the market will adjust, and we don't expect those price spikes will be long-lasting and big," he said. "There will be some adjustment period. But the refineries are now today being configured according to the IMO rules, and the US is one of the leaders."

So if US pump prices or oil benchmarks spike ahead of implementation day, what can the White House do to delay IMO 2020? Not much at all – short of building a majority coalition supporting delay ahead of the IMO's Marine Environment Protection Committee meeting in May. That looks very unlikely, though, after the panel in October already rejected a proposal for a soft rollout of the standards.

Trump does hold a few tools that he could use for domestic messaging purposes if prices spike: releasing fuel from the 1 million barrel Northeast Home Heating Oil Reserve or ordering an emergency crude oil drawdown from the Strategic Petroleum Reserve.

Citigroup commodities strategist Eric Lee said that the White House wanting to lower fuel prices ahead of the November 2020 elections is the most notable policy risk surrounding implementation of the sulfur specs.

"The headline risk alone could drive a selloff in diesel cracks and thus jet cracks, though we see a low probability of IMO 2020 actually being stymied or pushed back, and thus would expect such market reactions to reverse," Lee wrote in a note to clients.

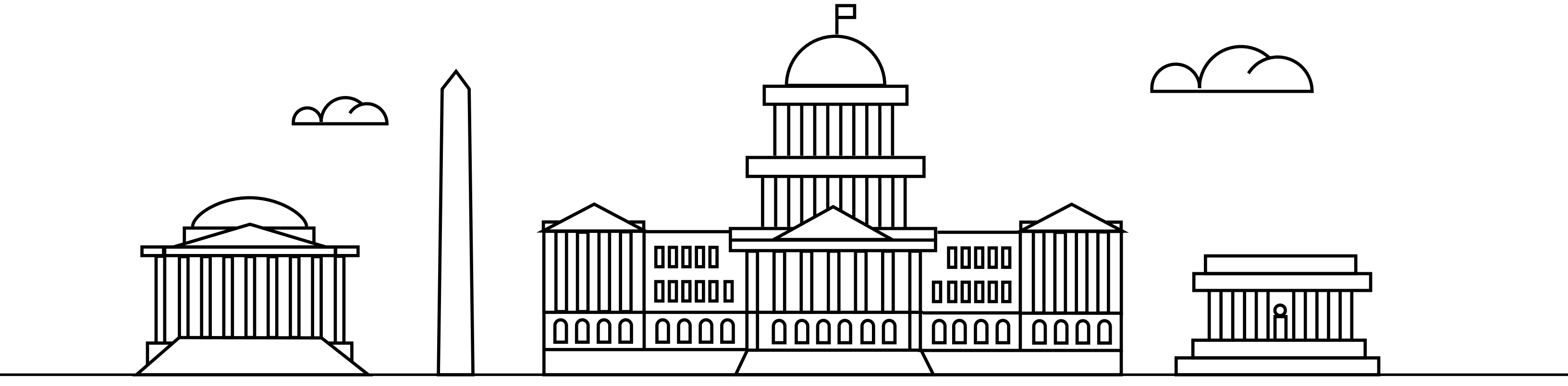
In the year since Trump first used Twitter to complain about high oil prices, his oil-related tweets continue to move intraday prices in a big way. Lee's analysis found an average 1.5% movement immediately after a tweet, with Trump's February 25 tweet driving a 3-4% selloff within five hours.

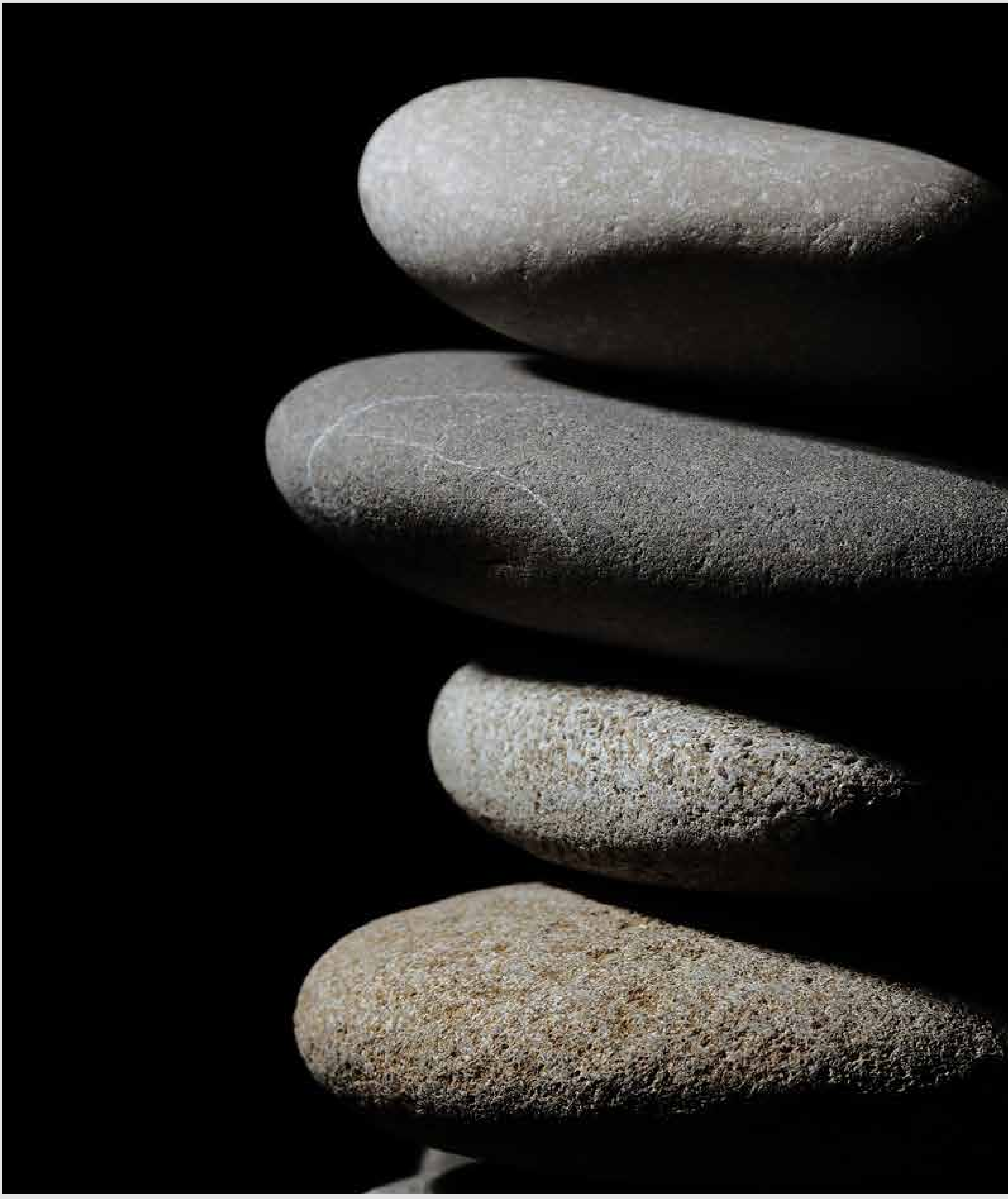
While Trump's oil tweets may move the market for a day or two, however, Lee said the tweets have ultimately had little long-term effect in changing the course of oil prices.

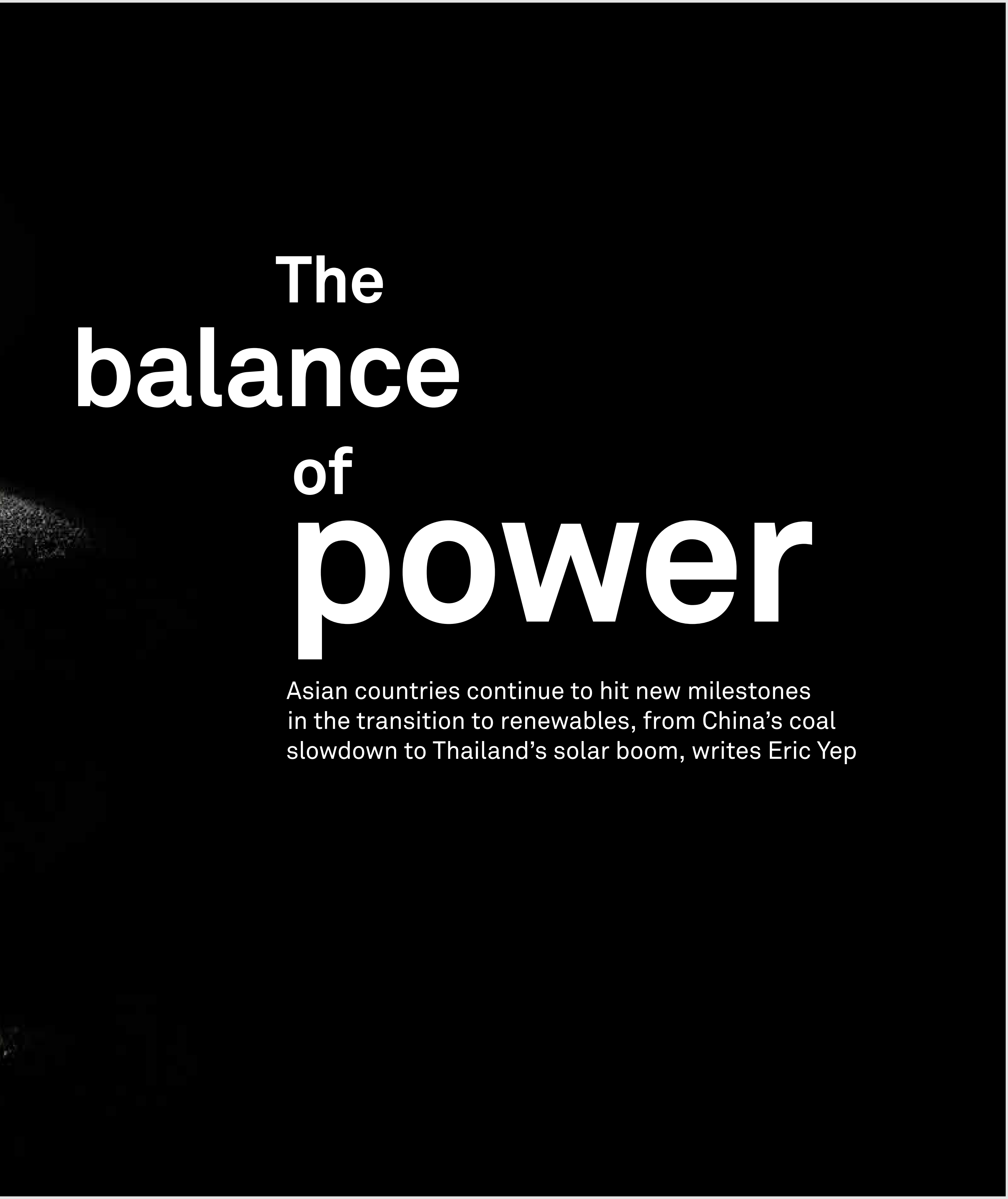
"It is not the first time a US president has tried to influence OPEC policy, but the speed of the new information hitting the market, the specific tone of Trump's tweets, and the automation of trading orders, is driving more short-term and sharp reactions to such messaging for oil markets," Citigroup's Lee said.

Goldman Sachs sees a "non-trivial probability" that the 2020 presidential election will have an influence on IMO implementation.

"There is a risk on the horizon, but it is not our base case," Jeff Currie, the bank's global head of commodities research, told S&P Global Platts. "We wouldn't discount any involvement if prices were to rise significantly." ■







The balance of power

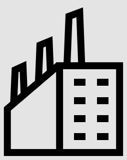
Asian countries continue to hit new milestones in the transition to renewables, from China’s coal slowdown to Thailand’s solar boom, writes Eric Yep

Renewable energy sources are now a commercially profitable business in many parts of Asia Pacific without government largesse and subsidy support. But the renewables story has just started.

Primary energy demand in the region is expected to grow by over 40% to 2040, based on the International Energy Agency's central scenario, accounting for two thirds of global growth.

Renewables will play a major role in meeting the new demand, their expansion supported by rapidly falling costs of key technologies, the drive to reduce air pollution, particularly in China, and the rising popularity of electric vehicles that is pushing forward battery technology.

A tipping point now looks close on multiple fronts. Here are six trends that will have a decisive impact on the renewables landscape in the Asia-Pacific region.



China's last new coal plant in sight

There's a joke that the Chinese government's facial recognition technology is so advanced because it has to operate in hostile conditions like the thick smog that regularly envelops Beijing city.

Chinese cities have been some of the most polluted in the world on the back of rapid industrialization and coal consumption. The government tried to remedy this with its "war against pollution" that initially covered 28 major cities including Beijing and Tianjin.

In July 2018, it expanded the initiative to other pollution hotspots like the provinces of Shanxi, Shaanxi and Henan and the industrial hubs of the Yangtze River Delta.

China's blue sky policy, the enforcement of coal-to-gas switching, and the structural shift in China's economy to a consumer base from an industrial base, will ensure its last coal-fired plant is built sometime in the next decade.

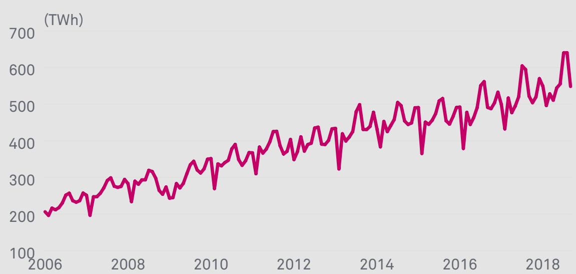
While China's overall energy demand will continue to rise, an increasing proportion of the growth will come from natural gas, renewables and nuclear, especially as coal demand growth plateaus.

Several indicators show China's coal demand growth hitting a wall.

China's coal demand grew by 8.9% per year on average over 2000-13 and contributed more than three-quarters of total energy demand growth over that period. By 2017 it constituted around two thirds of China's energy demand, according to the IEA.

In its 2018 report, the IEA said investment in new Chinese coal-fired power plants in 2017 fell to its lowest level in a decade, and while capacity additions were still larger than retirements, they had slowed dramatically.

China thermal electricity generation*



*Comprises mostly coal, oil and gas
Source: National Bureau of Statistics

"The boom years for coal-fired power investment, driven by an extraordinary expansion of capacity in China in the 2000s, are over," the IEA said.

It said that once plants currently under construction enter into service, the rate of capacity additions will slow sharply along with a marked shift in the technologies being deployed in favour of more efficiency and lower emissions.

"China had been adding about 47 GW of coal [plants] per year over the past decade, but the pace of the coal additions has been steadily declining from a high of 51 GW in 2015 to only about 40 GW in 2017," according to S&P Global Platts Analytics' December report.

Beijing has restricted many provinces from adding new thermal capacity to the grid, but the provinces have been finding loopholes to proceed with the projects. Regardless of a further crackdown by the government, overcapacity will force the pace of new coal plant construction in China, the world's largest coal user and producer, to decelerate further.

"Our view is that coal-fired generation will peak in the 2020s, although that peak could come earlier if renewables growth continues to surprise and the nuclear newbuild continues to be successful," Platts Analytics said.

Indian solar becomes cheaper than coal

India has become one of the largest solar markets in the world.

This is primarily due to one important milestone – it is now cheaper to build 1 MW of a renewable energy project than an equivalent amount of coal-fired power, without subsidy support. The next key marker will be when the cost of renewable energy becomes cheaper than operating an existing coal plant.

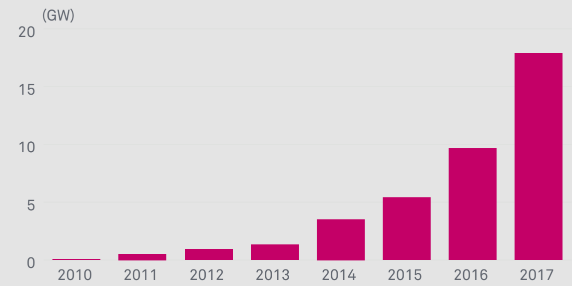
India has the cheapest new wind and solar anywhere in the world, according to Bloomberg New Energy Finance, which says that while coal-fired electricity will continue to grow in the short to medium term, by 2050 wind and solar will dominate, supported by batteries and gas for flexibility.

New Delhi has laid out a renewables target of 175 GW by 2022, of which 100 GW will be solar and 60 GW wind energy; and a 2027 target of 275 GW renewables of which 150 GW will be solar and 100 GW wind.

It proposes to generate 46.5% of its electricity demand from non-fossil fuels by March 2022, including nuclear, hydro and other renewable sources, and increase this to 56.5% by March 2027. Currently, these sources account for 36.16% of electricity demand.

It is now cheaper to build 1MW of new renewable capacity than the equivalent of coal

India solar generation capacity



Source: IRENA

"The 2022 wind target is fairly realistic, with its 2027 target potentially harder to achieve absent additional policy measures to compensate for lower resource potential," Platts Analytics said, adding that Indian solar installations will continue to grow through 2040, driven in part by ongoing competitive state auctions, although the magnitude of its targets as well as fiscal constraints will be challenging.

In October 2018, India announced that it had the fifth-highest solar installed capacity in the world of 24.33 GW, and the fourth-highest wind installed capacity in the world of 34.98 GW.

EVs will redefine mass power storage

Both in Asia and elsewhere, the biggest challenge in the growth of renewables is intermittency. 1 MW of solar or wind does not have the same round-the-clock stability as 1 MW of coal.

One way of filling the gap is battery storage, which is expensive and not commercially feasible for more than one or two hours today. The next renewable energy growth cycle is contingent on the development of low-cost battery technologies.

However, battery demand in the power sector is dwarfed by the automobile sector. And the economies of scale for EV battery production are much greater than in the utilities sector.

"Battery cost reductions are driven by increases in manufacturing scales driven by electric vehicle (EVs) growth expectations and improvements in chemistries that increase the energy density and reduce material needs," according to Platts Analytics.

When EV production scales up it will drive down battery costs and increase the penetration of renewables in the energy mix, similar to how mass commercialization of lithium-ion batteries in electronics like smartphones made it possible for carmakers to produce the first wave of EVs.

Projections of demand for core battery metals give an idea of the scale of battery demand from EVs versus power grids. Glencore estimates nickel demand from non-petroleum vehicles at nearly sevenfold of grid storage by 2030 and cobalt demand will be nearly five times more.

Battery technologies are far from being fully standardized and are still evolving. Platts Analytics expects lithium batteries to remain the primary technology in the near to medium term, although the degree of convergence between EV and power markets will depend on supply and demand dynamics.

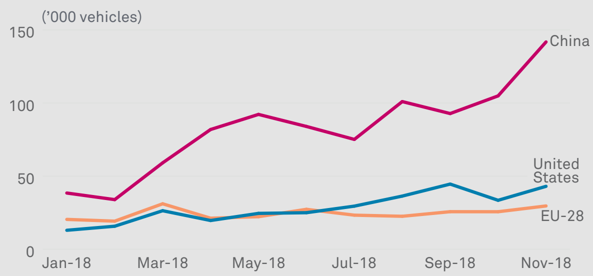
Battery manufacturing capacity was below 50 GWh per year in 2016, but annual capacity could reach more than 300 GWh within the next five years, with two-thirds of new capacity coming from plants in China, Platts Analytics said.

Solar power thrives in Thailand

Thailand is unique among developing Asian countries for consciously minimizing coal use in its power generation mix, due to a history of environmental and human casualties at mines and coal-fired power projects.

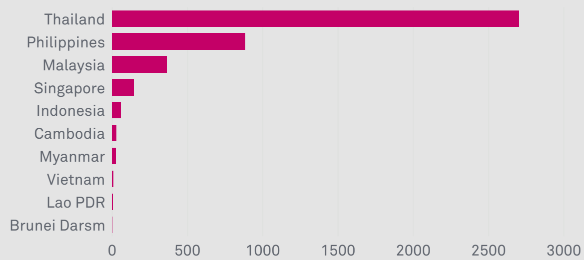
It generates nearly 67% of its power supply from natural gas, 22% from coal and lignite, and the remaining 11% from renewables like solar, hydro and biomass, according to official data.

China leads in passenger EV sales



Data refers to plug-in passenger light duty electric vehicles
Source: S&P Global Platts Analytics

Thailand leads SE Asia solar capacity in 2017



Source: IRENA

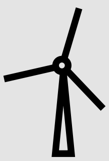
In terms of absolute capacity, Thailand not only has the most solar power generation capacity in Southeast Asia, it has added more solar capacity in the last five years than the rest of Southeast Asia combined.

In 2017, Thailand had 2,702 MW of solar generation, up from 49 MW in 2010, and compared with 1,515 MW in the rest of Southeast Asia combined. The Philippines came in at second place with 885 MW of solar, according to the International Renewable Energy Agency.

"Other regions can quickly catch up. We expect the solar capacity in Thailand to increase over threefold in the next 10 years and escalate further once the storage technology

becomes commercial," said Dr Bikal Pokharel, research director at Wood Mackenzie.

"We expect the share of gas in the mix to stay close to 50% by 2036," he said, adding that dependence on LNG imports will increase as domestic and piped gas imports decline, and LNG will form more than 50% of the gas demand by 2036.



Australia's turbulent transition to renewables

Australia is the world's largest coal exporter and coal ranks as the second-largest export commodity for Australia in terms of revenue, according to the US Energy Information Administration.

Yet the country is unlikely to build another coal-fired power plant, despite 63% of its power supply coming from the fossil fuel. Australia is a case study on how to, and sometimes how not to, make the transition from fossil fuels to renewables, as it struggles with the planned phase-out of old coal plants and the associated risks to energy security.

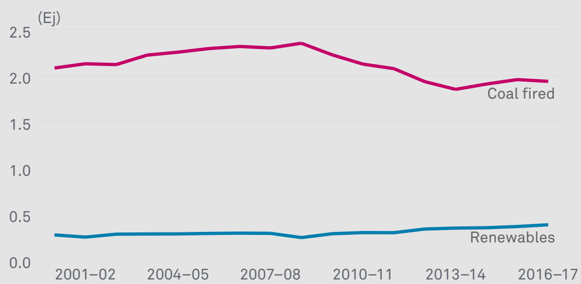
A massive power outage in South Australia in 2016 exposed the dangers of phasing out coal without contingency plans, to the extent that Tesla founder, Elon Musk, took up the challenge of building one of the world's largest batteries in the state in record time.

The lack of a comprehensive national-level energy policy has not helped matters.

"The uncertain landscape continues to undermine investor confidence to plan and undertake investment in new generation capacity to meet variable market conditions," according to a report by S&P Global Platts Ratings published in September.

It said Australia's energy policy uncertainty is delaying vital investments in system reliability amid a number of large-scale coal plant retirements in the coming decades.

Australian coal fired power in decline



Source: Department of the Environment and Energy

However, its investments in renewables are still being driven by lower technology costs of wind turbines and solar panels compared with conventional coal or gas-fired generation. Individual state-based targets and renewable schemes, and international investors attracted to the Australian market are also factors supporting renewables growth.

China's curbs on solar have global impact

China accounts for more than half of global solar demand and manufacturing.

But in May 2018, the Chinese government drastically reduced state support for the solar sector, as subsidies had resulted in a growing deficit of several billion dollars at its Renewable Energy Development Fund.

The National Energy Administration also wanted to cool down the sector, as rapid growth has led to overcapacity concerns, and focus on improving the connectivity of solar plants to the power grid rather than adding more unused capacity.

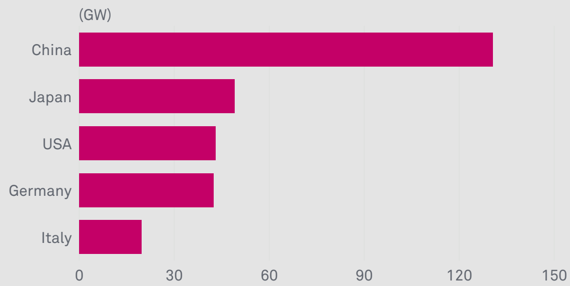
The new policy went further to state that no construction quota would be allocated for utility-scale plants, and a quota for distributed generation was set at 10 GW, among other curbs.

This has massive implications for solar markets globally.

"The first impact of the policy is that we lowered our China PV demand forecast for 2018-20," said Yvonne Yujing Liu, solar power analyst at BNEF, adding that it also resulted in a more significant equipment price drop that depressed global prices.

BNEF estimated that the utility-scale PV market in China contracted by more than a third in 2018 because of policy revisions. Liu said solar equipment manufacturers were under great price pressure,

Top 5 countries for solar capacity in 2017



Source: International Renewable Energy Agency

and developers and investors had been forced to cancel and postpone entire project pipelines.

"On the other hand, overseas PV developers can now enjoy cheaper equipment from China," she added.

Researchers at Wood Mackenzie said China's curbs created a global wave of cheap equipment that reduced the benchmark global PV cost to $60/MWh in the second half of 2018, a 13% drop from the first half of 2018.

With costs for solar equipment plunging globally, there is now a big incentive to build more solar projects outside China. ■

Subscribe to S&P Global Platts Analytics and access a myriad of customer-only benefits

Access to analysts

Our customers get access to our deep and talented team of analysts. They are there to help with your most important issues, providing essential insights at the critical moments, enabling you to act with confidence.

Customer only newsletter

Access the latest cross-commodity analytical content from our global team of analysts, published monthly in our Platts Analytics Customer Newsletter.

Customer only events

Don't miss out on our exclusive customer event series which takes place in London, Houston and Singapore.

Dedicated market analysis

We share free insights every day, but only our customers can access our comprehensive, thought-provoking special reports.

Integrated analysis

We ensure our analysis is integrated across commodities to give our customers the most connected commodity views using the most comprehensive data sets available.

Valuable product portals

Our customers benefit from intuitive [online] product portals, where they can quickly access exclusive services and free trial offers.

Learn more about S&P Global Platts Analytics products and services
http://plts.co/MOSp30o7Vpm

Insight from Shanghai

Sebastian Lewis

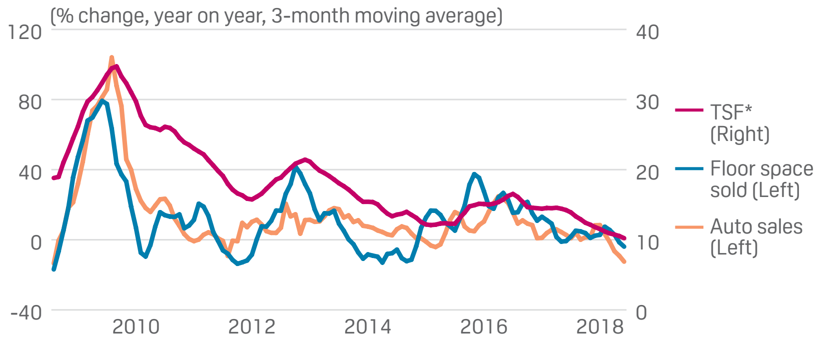
As 2019 rolled in, so did the data painting a downbeat picture of China's economic landscape. The December Caixin Manufacturing PMI, a survey of Chinese manufacturing activity, contracted for the first time in 17 months. Soon after, reports began to emerge that China's growth target would be lower than that set for 2018.

Apple, once the world's most valuable company, sent shock waves across financial markets. It revised down its earnings for the end of 2018 citing an economic slowdown in China that was significantly greater than they had anticipated due to weak demand and the impact of trade tensions with the US.

While the dispute with the US undoubtedly affected sentiment, with the latest data for January showing exports to the US falling for a second consecutive month, over the whole of 2018 Chinese exports to the US were actually very strong, growing at 11% in dollar terms. Rather, it was government efforts to rein in the growth of credit that had a greater direct impact on the economy. As liquidity tightened in 2018, sales of real estate and automobiles turned negative as companies and individuals found it harder to borrow money.

The chart below shows that as credit – represented by Total Social Financing – tightened last year, sales of real estate and automobiles turned negative as companies and individuals found it harder to borrow money.

Credit drives Chinese auto, housing sales



*Total Social Financing
Source: CEIC, S&P Global Platts

Out of the shadows

Since the financial crisis China has been increasingly reliant on debt to maintain economic growth. At the start of 2009 Chinese credit to the non-financial sector – debt owed by the government, households and companies - was slightly more than one and a half times the size of the economy. By the end of 2018 this had grown by 65% to more than two and a half times GDP. This is much faster than any other major economy. Even Japan, the world's most leveraged major economy, only saw debt as a percentage of GDP grow by 14% over the same period.

It's little wonder that the authorities were concerned. Such was the vulnerability of the economy to this rapid accumulation of debt, that starting mid-2016 the government has been engaging in a process of deleveraging the industrial sector and tightening credit across the economy.

Last year saw a particular focus on curtailing lending by China's shadow banks, financial companies outside the conventional banking sector that engage in bank-like lending activity. Not all shadow bank activity is, well, shadowy. But there is little transparency around their activity or the potential risks that they might pose the financial system, and some shadow banking activity has been significantly curtailed by the most recent credit tightening cycle.

This has had little effect on the large state-owned enterprises that dominate the energy and commodity sectors. Their links to the state-owned banks mean they have little problem obtaining finance. The impact has been greater at smaller, private, companies down the value chain like metals fabricators, traders, and even independent refiners, which are unable to easily obtain credit from the state owned banks. Already contending with tighter environmental inspections and a clampdown on tax evasion, as well as slowing demand, the private sector has seen a wave of bankruptcies due to the tighter credit conditions.

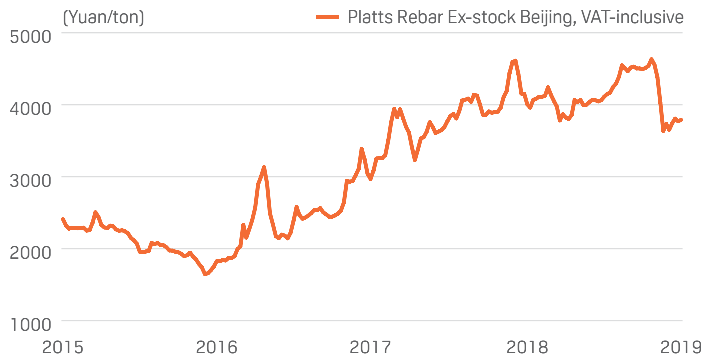
Real estate to the rescue

A move to shut down online peer-to-peer lending platforms, a small but fast-growing part of the shadow credit sector, has also constrained consumer access to finance. With analysts estimating that peer-to-peer lenders financed as much as 15% of new vehicle sales in 2017, the contraction in the sector was a major contributor to the sharp fall in sales in the second half of last year.

Indeed, 2018 was the first year in decades that new car sales were down on the previous year, impacting demand for flat steel and gasoline. With the government announcing that it will not provide relief to the auto sector by cutting purchase tax for passenger vehicles as it did in 2015, gasoline demand is expected to continue to be weak. S&P Global Platts Analytics expects Chinese gasoline demand to grow at under 3% in 2019, down from 6% in 2017.

Given this backdrop, it was somewhat surprising that the property market, that bellwether of the economy, was so resilient last year. It underpinned steel demand, which grew at a robust 8% over the previous year in the first eleven months of 2018. With the clampdown on P2P lending platforms and a 30% fall in the Shanghai Composite index, money flowed into investment property last year, especially in smaller cities where there are fewer restrictions on purchasing investment properties. But with prices softening and home sales falling the outlook is less optimistic for 2019. This has already been priced into the steel market. Although prices rose slightly in the first quarter of 2019, the price of construction rebar is still down 15% since its peak at the end of October last year.

Chinese steel prices weakened in late 2018



Source: S&P Global Platts

Did someone say stimulus?

As we move further into 2019 the signs are that the government will continue down this ascetic path. Yes, it has approved $125 billion of new rail projects and has freed up an estimated $117 billion for new lending by cutting the amount of cash banks are required to hold on reserve. And yes, it has introduced incentives to encourage purchases of automobiles and electrical goods to support consumption as well as announcing a range of tax cuts to support businesses. Some tinkering around the edges to support the property sector, like the lifting of some of the restrictions on secondary property purchases in larger cities, also seems likely. But the effect of this on the economy and commodity demand may well be more muted than the headlines might suggest.

Credit growth was unexpectedly strong in January, leading some analysts to speculate that China was resorting to its bad old ways of pumping out credit to support growth. But Premier Li Keqiang poured cold water on such talk at a meeting of the State Council on February 20 reaffirming that China would maintain a prudent monetary policy and not resort to flooding the economy with credit.

The question is whether the government can stay the course on its debt reduction goals. If the US and China manage to conclude a trade agreement it would certainly provide some relief to export oriented sectors. Premier Li Keqiang has been very explicit that the government will not resort to using a “deluge of stimulus polices” to support growth and that lending will be to support businesses and the real economy, not fuel a speculative bubble.

China has only just finished cleaning up the mess left over from the last decade of credit excess, which left it with industrial overcapacity and a glut of unwanted property. Another credit splurge would see debt compared to the size of the economy rise beyond even that of the Eurozone. Only Japan’s economy would be more leveraged, and China certainly doesn’t want to go down that path. Japan’s economy has gone virtually nowhere since the 1990s. ■

EVs: A "slow-motion" revolution

The S&P Global Platts Researcher Award recognizes the innovative spirit of emerging researchers in commodity markets. We present this year's winning submission, written by graduate student Collin Smith

Launched in November last year, the inaugural S&P Global Platts Researcher Award offered a $5,000 scholarship, as well as airfare and accommodation for the S&P Global Platts London Oil & Energy Forum. Collin Smith, a graduate student at the John Hopkins School of Advanced International Studies in Washington, picked up this year's prize from S&P Global Platts president Martin Fraenkel at the LOEF in London on February 25.

Below is an edited version of Smith's winning submission, written in response to the question, "What is the single most significant factor that will impact the commodities market over the next 10 years?"

The most significant factor affecting commodity markets over the next 10 years will be the electrification of transportation, a slow-motion revolution that will leave few parts of the economy untouched. Although electric vehicles are still a small percentage of total vehicle sales, economic and regulatory factors are combining to accelerate their uptake.

A recent forecast by Morgan Stanley estimated that in 2050, 90% of new vehicle sales will be EVs. This represents a wholesale shift in the fuel input for one of the most important sectors of our economy – an occurrence on par with Winston Churchill's decision to switch the British Royal Navy from coal to oil in the early 1900s, which marked the advent of oil as the transport fuel of choice. It's likely that the coming electrification of transport will also have a significant impact on global consumption of "black gold."

However, EVs' effect on oil consumption is still relatively far off. In the coming decade, the most significant impact of EVs will be a new race to secure the raw materials that go into the production of these technologies, particularly lithium-ion batteries. Increasing demand for EVs is expanding the market for critical components like nickel, cobalt, and lithium to proportions never before experienced. This has created price spikes in markets for these metals, given greater geopolitical significance to countries that produce them, led major mining companies to adjust their expansion strategies, and created new concerns over the ability of existing supplies to keep pace with rising demand.

The road ahead

UBS recently put together a forecast of the impact that 100% EV penetration would have on demand for different commodities, based on the make-up of metals in a standard Chevrolet Bolt. The results indicated a striking jump in demand for several metals that currently trade at relatively low volumes. Demand for lithium and cobalt topped the list, increasing by almost 3,000% and 2,000% respectively. Demand for several other commodities – notably graphite, nickel, and rare earth metals – also saw triple-digit growth.

Although not all EVs have the same proportion of component parts as the Bolt, this analysis allows one to extrapolate general trends – namely, that transport electrification will require substantial new investments in supplies of these commodities. By some estimates, keeping pace with this demand will require between $350 billion and $750 billion of investment by the mining industry in new sources of supply.

Although a 100% EV world is still some ways off, the scale of these increases has meant commodity markets have already been affected, even by today's relatively small EV penetration levels. Demand for lithium is expected to grow by 42% between 2017 and 2020, while demand for cobalt – which shot up by 49% in 2017 – will continue to grow by 61% in 2022. Global supply chains are adjusting to these spikes in demand, but differences in where and how the two metals are produced means the impact their growing demand has on commodity markets will be dramatically different.

Although demand for lithium is expected to increase substantially, the chance of long-term supply bottlenecks developing for this metal seems slim. The world has an ample supply of lithium, 85% of which is mined in Chile, Argentina, and China. Although lithium prices have increased recently as a result of increased EV demand, it's expected that prices will begin to fall again after 2019 as new sources of supply come online. Importantly, much of this new supply can be developed by expanding pre-existing projects. For example, the world's largest lithium miner, Talison, is currently operating at only 60% of its nameplate capacity.

The effects of increased cobalt demand will be much more significant. Growth in cobalt demand – over 50% of which is coming from the battery industry – has already caused the price of the metal to shoot up by 180% over the past three years. Although expansion of additional supplies may be enough to prevent price spikes in the near term, the long-term supply of this commodity is a subject of mounting concern. In July 2018, the science journal *Nature* published an article predicting that, given current estimates of EV growth, demand for cobalt would outstrip the planet's reserves by 2030, just as the global EV industry is scaling up. Growing demand for

The most significant factor affecting commodity markets over the next 10 years will be the electrification of transportation, a slow-motion revolution that will leave few parts of the economy untouched.

an increasingly scarce resource will inevitably lead to further price hikes in the next decade.

In addition to these longer term supply concerns, the availability of cobalt resources is further complicated by the geographic concentration of sources. Roughly two-thirds of cobalt currently comes from the Democratic Republic of Congo, and this share is expected to increase to 75% in the future. Shifting regulations within this country, as well as the ever-present risk of supply disruptions from political conflict, have the potential to dramatically impact the global market for cobalt. In 2018, in response to growing demand, the DRC designated cobalt a “strategic mineral” and increased royalties on the metal by five times. The country recognizes that supply of cobalt is limited and has announced its aim to maximize the country’s revenue from its production, indicating that it may raise royalties again in the future.

Reducing dependence

This supply risk has created a powerful incentive for the EV industry to reduce its dependence on cobalt, and many companies have responded by developing new battery chemistries that use less of the mineral. One alternative is nickel-cobalt-aluminum lithium-ion batteries, which have a significantly lower nickel-to-cobalt ratio than the industry standard nickel-manganese-cobalt chemistry. The main proponent of NCA chemistries at the moment is Tesla, which used them in its Model S EV and will continue to do so in its mass-produced Model 3 cars.

The other popular industry choice is a version of the NMC battery that reduces the proportion of cobalt in the battery’s cathode. This version is commonly called NMC 811 as it has a nickel-manganese-cobalt ratio of 8:1:1, as opposed to the 6:2:2 ratio found in most EVs today. Major battery manufacturers like LG Chem and Samsung SDI have already released roadmaps to transition their technology to NMC 811 in the future.

However, these alternatives also tend to contain a higher proportion of nickel, another metal that will be affected by transport electrification. According to UBS, a 100% EV world would double the $20 billion global market for nickel, an estimate based on current technologies used in the Chevrolet Bolt its analysts examined. As future battery chemistries use higher proportions of nickel, it will accelerate growth in demand for this commodity. Already, growth in EVs has pushed nickel prices up by around 50% since 2015. Tightening supplies may drive further price increases and even supply shortages in the future.

This is exacerbated by the fact that only about half of current nickel supplies – those produced from sulfide and limonite deposits – are suitable for use in EVs. As EV demand grows, it's possible that nickel from these sources will start trading at a premium on international markets. In addition, new discoveries of nickel sources are rare, prompting concerns that EVs will ultimately stretch our planet's nickel supplies to the point of breaking. The aforementioned *Nature* article concluded that, at current projections for EV penetration, nickel shortages would occur by the mid-2030s.

Creating an opportunity

The rise in demand for the commodities discussed above creates an opportunity for mining companies that place their bets on the right resources. Cobalt is one obvious candidate, capitalizing on rising demand that will push up prices for this commodity as supplies tighten. Nickel mines will also be strong investments, as will mines that produce copper, another major component of EVs. As it happens, these three metals contain a certain amount of geological synergy; cobalt is typically produced as a by-product of either nickel or copper mining.

Companies with control over these mines are almost certain to expand their positions in these resources in the near future, and those that don't yet have a stake will be working hard to acquire one. This trend is already apparent in the mining industry today. Currently, the company best positioned to take advantage of the transport sector's shift to electrification is Glencore, which in 2017 produced 22% of the world's cobalt. The company announced its strongest earnings on record that year, and highlighted demand for EVs as a major factor driving demand for cobalt and other metals it produces. Glencore expects its production of cobalt to increase 133% over the next three years, and its production of nickel and copper to increase by 30% and 25%, respectively.

Other companies are moving to capture parts of this expanding market too. In 2017, China Molybdenum, the third-largest producer of cobalt, acquired a majority stake in the Tenke Fungurume copper/cobalt mine in the DRC. International mining giant Vale recently took advantage of expected cobalt shortages to finance an expansion of its Voisey's Bay nickel/cobalt mine in Canada, selling rights to the mine's future cobalt production to Wheaton Precious Metals and Cobalt 27 in exchange for an upfront payment. Glencore is not sitting still either: the company recently announced the expansion of its majority-owned Kamato Copper Company, which is expected to bring 30,000 mt of additional cobalt supply online by the end of 2019.

The other mineral inputs for EV batteries are also driving shifts in the geographic distribution of mining projects worldwide. As EV manufacturers move towards low-cobalt NMC 811 chemistries, this increases demand for lithium produced from hard rock structures (as opposed to that produced from lithium brine bodies, the other primary source of lithium). These lithium deposits are more numerous in China and Australia than in Chile and Argentina, indicating that as low-cobalt chemistries become the industry standard, lithium mining

will move out of Latin America and towards the Asia-Pacific region. Recent announcements by Talison that it would expand lithium mines in Western Australia support this trend.

As mining companies move to control the sources of these materials, companies further down the value chain are taking steps to lock in supply for their products. Volkswagen, which last year approved a €34 billion spending plan to expand EV production through 2022, recently tried to secure a long-term supply of cobalt to feed its production lines. The effort failed – an outcome attributable to a clash between Volkswagen's desire to lock in a lower price and most suppliers' extremely bullish forecasts for cobalt. Meanwhile, Apple made headlines in early 2018 by entering into talks to buy cobalt directly from miners. The company is one of the largest users of cobalt due to its substantial sales of consumer electronics, the majority of which also use lithium-ion batteries.

The race to acquire the building blocks of the future transportation sector is already taking on a geopolitical edge. China has invested heavily in electrified transportation, seeing it as an opportunity to expand high-value industries and reduce its dependence on foreign oil supplies. The country is understandably keen to avoid replacing one material dependency with another, so it has been working to shield itself against future supply bottlenecks for scarce metals like cobalt. Over the last few years, the country has moved to control a large proportion of global cobalt supplies through a combination of supply agreements and the acquisition of mining rights by Chinese firms, as well as 50–60% of global cobalt refining capacity. It has also built up a substantial domestic reserve of the metal, stockpiling up to 400,000 metric tonnes of cobalt to guard against future supply shortages.

The shakiness of future cobalt supplies also creates a powerful incentive – and in the future, an imperative – to find alternative battery chemistries that don't use cobalt at all. Potential alternatives include graphene-based batteries, solid-state batteries, and "conversion cathode" batteries that replace cobalt with more common metals like iron or copper. However, most analysts believe these alternatives are too underdeveloped to be successfully commercialized in the next decade. Therefore, over the next 10 years, the impact of demand for cobalt, nickel, lithium, and other mineral components of lithium-ion batteries on the global commodities market is unlikely to disappear.

Paradigm shift

The electrification of transport is recognized as all but inevitable. Many of the world's major car markets, from California to China to the UK, have developed plans to phase out traditional cars in favor of electrified models that produce no greenhouse gas emissions or urban pollution. The world's largest car manufacturers have increased their investment in new models of EVs, recognizing this is an area where they can't afford to lag behind. And the prices of EVs continue to fall, with some analysts predicting they could reach cost-party with conventional vehicles by the middle of the next decade.

As the EV revolution picks up speed, savvy watchers of commodity markets have recognized that even in the short term, the impact of this transition will be significant. Increased demand for component metals like lithium, cobalt, and nickel are pushing prices for many of these commodities to new highs, radically increasing the value of mines that produce them. Although these price increases are unlikely to derail a global transition in the transport sector, it will affect the investment decisions of many players in the commodity space. Mining companies will work to control or expand stakes in mines that feed the supply chains for EVs, while the companies producing those EVs will struggle to ensure a steady supply at stable prices.

With concerns over possible supply shortages in key inputs like cobalt and nickel becoming more pronounced, countries that attach strategic importance to these technologies, such as China, are taking steps to guarantee the supply of these raw materials will not be affected. Meanwhile, companies will be racing to reduce – or even replace – the amount of these metals they use in their products.

The resulting market will be complex, influenced by an interconnected web of economics, geopolitics, and technological development. However, those that are able to navigate it successfully will emerge as the primary beneficiaries of the upcoming paradigm shift in human transportation. ■

S&P Global
Platts

Register by April 12, 2019 and
Save $300

14th Annual

Northeast Power and Gas Markets Conference

Pre-Conference Workshop—May 29, 2019 | Main Conference—May 30-31, 2019
New York Marriott Downtown | New York, New York

Attend **S&P Global Platts 14th Annual Northeast Power and Gas Markets Conference** to explore which key trends are driving changes in the power sector. Network with a diverse group of professionals from power generation, regulation, renewable, gas pipeline, and electric transmission backgrounds, while gaining valuable insight into where the Northeast energy markets are headed.

Featured Topics Include:

- The Green New Deal—What are the specifics and how can it impact the Northeast?
- Investing in power—What is the current market reaction to PPAs and distributed generation?
- LNG's role in the region—Will potential regulation changes spur new infrastructure?
- Capacity markets—Addressing fuel security challenges and the increasing entry of renewables to the grid
- State-Sponsored RFPs—Lessons learned
- RGGI—Implications of NJ and VA joining the mix

This Years' Can't-Miss Case Study

Off-Shore Wind Farm Projects Shaping the Northeast

Clint Plummer,
Head of Market Strategies and New Projects,
Ørsted

Pre-Conference Workshop:

As Northeast/New England Generation Transitions Towards Gas, Can the Case Be Made Now For a New Pipeline into New England?

- The evolving generation stack—Coal dwindling, gas rising
- Is coal-to-gas switching dead in the Northeast?
- Northeast and New England natural gas demand outlook
- The New England pipeline debate—How the economics of a new pipeline compare to fuel oil and LNG

Sponsored by:

nodal | PIERCE ATWOOD LLP | ENGIE | NG ADVANTAGE A Clean Energy Company

Register Now
www.spglobal.com/northeast
registration@platts.com
800-752-8878 (toll free)
+1 212-904-3070 (outside USA & Canada)

Electric Power **Natural Gas**