Global renewables investments hit a speed bump
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Editor’s Note

The coronavirus pandemic has rocked global commodity markets, disrupting supply chains and slashing demand for many products.

The spread of the virus has also coincided with a breakdown — and hurried patching up — of the OPEC+ alliance. Crude oil, as the linchpin binding many other raw materials markets and economies, has been on a rollercoaster ride. The outlook for demand and prices remains weak compared with recent years, and analysts forecast an oversupply of 20 million b/d and upwards in the coming months.

Coronavirus has exposed existing weak spots in other sectors too, particularly LNG. Consumption has slumped in an already vastly over-supplied market that is reliant on archaic pricing mechanisms, hampering efforts to rebalance supply and demand, as Abache Abreu explains from page 18.

In the global power generation sector, there has been a sharp short-term shock as industrial sites and commercial premises locked down and workers stayed at home. Planned renewable generation capacity may be exposed to new risks as funding dries up, just as zero-carbon technologies were beginning to achieve cost competitiveness without government support. Bruno Brunetti offers a panorama of recent capacity additions across generation types worldwide from page 38, and points out that wind power support schemes in China and the US will still be in place this year, providing an incentive to bring projects online.

By the end of 2019, it seemed the momentum gathered by the Extinction Rebellion movement was unstoppable, with pressure mounting on energy majors and governments to move faster towards decarbonization. Among other things, this yielded a wave of announcements from global oil and gas majors as they set ambitious targets for renewable energy and emissions reductions. Their recent behaviour and possible next steps are explored from page 22.

Meanwhile, a number of US states have been making progress towards ambitious renewables targets. Rocco Canonica and Kassia Micek look at the challenges of integrating a rising share of renewables onto the grid, and what California’s experience managing excess power supply can teach other regions whose energy transition is less advanced (page 8).

This edition of Insight also looks at new frontiers in the energy transition, such as a nascent hydrogen economy, which still needs to surmount issues of cost and scale to really take off and help play a part in decarbonizing the global energy system (page 32). And as electric vehicle adoption grows, Felix Maire and Zane McDonald take the US state of Virginia as a case study to examine how power grids can accommodate new demand patterns (page 50).

Finally, our correspondents in Washington, Moscow and Shanghai write about the latest policy developments – from gas flaring in the Permian basin to Russia’s turbulent relationship with OPEC and China’s quest for domestic gas growth, all from page 58. plattsinight@spglobal.com

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Renewable power generation growth in the US is soaring and is expected to overtake natural gas-fired power generation by 2045, according to the US Energy Information Administration, leading to major concerns about the reliability of these intermittent resources and the significant impacts they will have on US power supply and prices.

The coronavirus pandemic has compounded the problem by slashing power demand, exacerbating oversupply and the challenge to grid operators as they try to balance the system. Operators are increasingly having to manage oversupply, often through generation curtailments, in a trend that will also intensify in the long term as the renewables fleet grows further. They will also have to address the negative impacts that low power prices will have on future generation development.

California has provided a stunning example of these challenges. The state has by far the largest amount of solar power generation among US states, with nearly 13 GW. Renewable output across the California Independent System Operator nearly doubled in the last decade to account for roughly 40% of its total fuel mix in 2019, according to ISO data. This rapid growth has also brought with it adverse impacts, including generation curtailments. More recently, the state’s power system has been grappling with lower demand caused by stay-at-home orders alongside a seasonal rise in renewables output, leading curtailments to surpass 17,000 MWh on April 1.

In Texas, wind power capacity has grown to nearly 24 GW, with huge wind and solar growth expected again.

US renewables: the paradox of plenty

On a rising number of days each year, some areas of the US have more renewable power than they know what to do with. System operators are having to tackle the challenges of unpredictable generation and excess output, write Rocco Canonica and Kassia Micek.
this year. The Electric Reliability Council of Texas has seen the most wind power development in the US, and power prices in the state have weakened, significantly diminishing the incentive for developers to build new power plants to compensate for retirements and load growth. Reserve margins in ERCOT have become increasingly thin, raising concerns about potential future summer reliability.

These examples reveal just some of the challenges ahead for the multiple US states pursuing 80-100% targets on carbon-free power generation over the next few decades.

The intermittency and reliability of renewable generation adds uncertainty around operations requiring additional reserves, as well as uncertainty in resource adequacy, such as demand response, said Morris Greenberg, senior manager of North American resource adequacy, such as demand response, said Morris Greenberg, senior manager of North American power analytics at S&P Global Platts.

### Curtailment basics

There is so much solar power in California today that it can generate more electricity than is needed during the middle of the day. In order to balance supply and demand on the grid, the ISO must automatically reduce the production of energy from renewable resources, or “curtail” generation. In rare instances, when economic bids from generators are insufficient, the ISO also must manually curtail production to maintain the supply and demand balance.

Two types of curtailments have been taking place. Systemwide curtailments occur when generation is curtailed because there is too much supply. Localized curtailments occur when there is congestion on the grid when the amount of power from one point on a transmission line to another point must be controlled.

“It may be that the most effective way to manage this constraint on the transmission line is to manage the supply of renewables on the line,” said Guillermo Bautiste Alderete, Cal-ISO director of market analysis and forecasting, adding that congestion management makes up the vast majority of ISO curtailments.

The ISO publishes a daily report that breaks down the types of curtailments for each hour of the day. The high level of congestion management curtailments can be seen in data for January, when ISO curtailments totaled 138,002 MWh, a jump of nearly 100% month on month and more than the last five Januarys combined. Outages in the southern region caused localized curtailments during the month, Alderete said.

There were 300,323 MWh of curtailed Cal-ISO generation March 1, of which 223,266 MWh or 78% was from congestion management or localized curtailments, according to the daily Cal-ISO Wind and Solar Curtailment report.

To keep things in perspective, renewables curtailments make up about 2-3% of total renewable production, Alderete said. So, while large amounts of generation are being curtailed, it is still a fraction of overall generation.

Nevertheless, this problem is only going to become more challenging in the future as even more solar is added to the grid. There are increasing efforts to pair storage with solar generation to address the problems directly.

The current California ISO interconnection queue includes active requests for 14.5 GW of solar photovoltaic, 10.5 GW of solar PV with storage as a secondary generation source, 14.9 GW of storage with solar PV as a secondary source and 16 GW of storage with no secondary source.

### Spring ramp

Cal-ISO is currently in the middle of a seasonal ramp effect due to lower load, higher wind and solar generation, and increasing hydro generation that typically happens between winter and spring.

“Curtailments are significant at certain times of the year, such as spring,” Greenberg said.

There is increased solar during that time, but also lower loads due to milder weather. That means there is not a large market to absorb the increased renewable generation.

The ISO’s curtailments take place to drop the supply to the level of demand. This automatically happens in the market when there is an oversupply of renewable resources, said Anne Gonzales, Cal-ISO’s senior public information officer.

ISO curtailments reached a record level in May 2019 as the ISO slashed a total of 223,195 MWh of wind and solar generation to balance supply and demand, a more than 17% month-on-month increase, according to ISO data. Curtailments in 2019 more than doubled year on year and have averaged a nearly 97% increase annually over the last five years.

### California SO systemwide total daily curtailments

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When daily curtailments spiked above 17,000 MWh on April 1, SP15 on-peak day-ahead LMP dropped 27% day on day to $12.51/MWh. Likewise, SP15 on-peak real-time prices were slashed in half to $6.02/MWh, according to ISO data.

“High levels of curtailments would be related to low or negative prices so the ability to predict curtailments would help in valuing a market position,” said Greenberg. “Ultimately, periods of oversupply/curtailment (zero or negative prices) will require high prices in other intervals to cover investment costs. These prices/spreads may ultimately cover the cost of maintaining dispatchable capacity, either gas peaking or storage.”

Towards zero-carbon in 2045

In its latest long-term projections, EIA forecasts that electricity generation from renewable sources such as wind and solar will surpass nuclear and coal by 2021 and surpass natural gas in 2045. The share of renewables in the US electricity generation mix is expected to increase from 19% in 2019 to 38% in 2050, according to EIA data.

California has long been a leader in US renewables development. Cal-ISO had a record-breaking year in 2019 for the amounts of solar and wind energy, with a historical peak of 80.3% of renewables serving demand reached May 15. More than 51% came from solar and nearly 19% from wind, according to the ISO. The highest amount of renewables serving peak electricity demand occurred on August 8, 2019 at 14,766 MW, or 41.8%, surpassing an August 6 record of 13,902 MW.

Other renewables records set in 2019 include a new solar generation peak record of 11,473 MW reached July 2, surpassing a June 29 record of 10,739 MW, and a new wind generation peak record of 5,309 MW.
reached May 8, surpassing a June 8 record of 5,193 MW, according to ISO data.

“Things are moving so quickly,” Alderete said about the evolving generation stack and advancements in technology.

There will be increased penetration of clean energy as the state moves toward its goal of 44% renewables by 2024 and 100% carbon-free generation by 2045. Diversity of resource mix both technologically and geographically is key, Alderete said about incentivizing technology.

“California is over-complying with the current [Renewable Portfolio Standard] target and [Portfolio Content Category] 1 allowances are being banked,” Greenberg said, adding that the overcompliance reflects current low development costs due to the availability of investment tax credit for solar and solar/storage projects, lower-than-expected loads and future increases in the RPS target of 60% of retail sales in 2030.

Northeast US

California’s challenges from rapid renewables growth and market penetration are just beginning to be felt in other regions of the US. Curtailments are not yet a significant issue in the Northeast, where renewable resources still account for a small portion of the overall power generation fuel mix. However, the New York Independent System Operator already has observed some onshore wind curtailment at certain times in the northern part of the state and anticipates the phenomenon could increase as New York moves toward a zero-emissions power system by 2040.

“Based on the NYISO’s operating experience, there are already high levels of wind curtailment in northern New York,” the market operator said in its 2019 Power Trends report.

The Climate Leadership and Community Protection Act requires 70% of statewide power sourced from renewable energy resources by 2030, 6 GW of installed solar capacity by 2025 and 9 GW of offshore wind power capacity by 2035.

A renewables-heavy market dominated by resources with zero variable fuel costs will depress and flatten location-based power prices, which places greater importance on ancillary services revenues, according to a presentation by PA Consulting given to the NYISO Market Issues Working Group on behalf of the Long Island Power Authority.

The consultants also pointed out that despite limited nameplate wind power capacity in New York of about 2 GW in 2018, the state is already seeing increasing levels of curtailment. For example, the percentage of energy curtailed in the state – measured as the ratio of curtailed energy to total production – was between 1% and about 3% from December 2018 to December 2019, according to the grid operator’s December Operations Performance Metrics Monthly Report.

ISO New England also appears to be experiencing limited instances of renewable energy curtailment, primarily from onshore wind plants, due to transmission system constraints or economic decision-making on behalf of the plant owners. However, renewable energy curtailment is not mentioned in the market operator’s 2020 Regional Electricity Outlook.

ERCOT

With nearly 24 GW of wind capacity, the Electric Reliability Council of Texas has seen the most wind power development in the US and is beginning to see an increasing push to add solar generation as well, driven by tax credit availability rather than a state renewable portfolio standard, which is surpassed long ago.

As tax credits phase down and transmission congestion drives down prices, generation additions could slow, but wind capacity is currently projected to jump as much as 40% year on year by the end of 2020 to nearly 33,450 MW if all signed Interconnection Agreements are executed, according to ERCOT’s “Capability Changes by Fuel Type Charts” reports for January. Solar capacity could spike as much as 149% year on year by the end of this year as well and then 105% year on year for 2021.

Battery storage additions are also growing, with 262 MW expected to be added in 2020 to bring the total up to 366 MW and to as much as 568 MW in 2021, according to ERCOT data.

However, curtailments are also on the rise. An estimated average of nearly 550 MW of wind generation was curtailed in January due to oversupply, which was a jump of 87% month on month and nearly three times the level a year ago, according to ERCOT data.

While ERCOT is adding renewable generation, it is shedding thermal generation to the point that very tight reserve margins the past few summers, when demand is the strongest due to rising temperatures, have caused concern. This will be the third summer that ERCOT is projecting a reserve margin below its 13.75% target. In addition to less capacity coming onto the grid, ERCOT is one of the few regions where demand continues to grow with rising population, putting more pressure on the system. But low, renewable power prices are not creating the incentive to build new generation.

With the increase in less-expensive renewables sources comes a decrease in power prices. ERCOT West Hub on-peak real-time locational marginal prices have fallen into negative territory in five out of the last seven years as most wind – and more recently solar – is added across the sprawling open fields of west Texas. West Hub real-time prices have already fallen as low as negative 3 cents/MWh so far this year, something that typically happens later in the year. In 2016, West Hub real-time prices fell as low as negative $9.68/MWh in Q4.
US renewables: forecasts and targets

US Renewables: EIA forecasts electric generation from renewables will surpass nuclear and coal by 2021 and surpass natural gas in 2045. Renewables share of the US electricity generation mix is expected to increase from 19% in 2019 to 36% in 2050.

Cal-ISO: California leads the country in renewable generation at an average of about 40%, nearly doubling in the last decade, while renewable curtailments more than doubled year on year for 2019 and reached a record of 223,195 MWh in May 2019.

ERCOT: Wind capacity forecast to jump as much as 40% year on year and solar capacity could climb 149% by the end of 2020. Grid operator forecast 10.6% reserve margin, below the 13.75% target for the third straight summer, as weak power prices from increased renewables diminish incentive to develop new power plants.

NYISO: Observing onshore wind curtailments and expects phenomenon to increase as the state moves zero-emissions power system by 2040. CLCPA requires 70% of statewide power sourced from renewable energy resources by 2030, 6 GW of installed solar capacity by 2026 and 9 GW of offshore wind power capacity by 2035.

Future
Cal-ISO is well aware that the rest of the country, as well as the world, is looking at how they manage a growing renewables fleet for cues on what to do in other regions. Many states study California’s actions as an example of how to manage the increase in renewables onto the grid, which is growing ever more important as states increase their renewable portfolio standards and target dates fast approach.

“We know full well what we’re doing here is an example for the national and internationally,” Cal-ISO CEO Steve Berberich told Platts.

Forecasting is the critical factor to making the transition to more renewable generation work on the electric grid.

“You have to change your entire outlook, even from a planning aspect,” Berberich said about the reliability concerns of renewables and the solar ramping. That includes load and renewables generation output forecasts, as well as distributed generation forecasting; Berberich said, adding that getting the necessary generation flexibility is important to fill in any potential gaps.

Cal-ISO recently completed a study in partnership with Avangrid Renewables, the National Renewable Energy Laboratory and General Electric that showed a commercial wind plant with a smart inverter-based controller can provide regulation up and down, voltage regulation control, active power control and frequency response, all important services to maintain grid services, according to an ISO news release. These are services that are currently being provided by conventional sources, including natural gas plants.

With some relatively simple operational upgrades and market redesigns, virtually all wind plants could provide the ancillary services and be compensated for them, creating new markets for renewable resources separate from energy, according to the news release.

“We don’t have all the answers for getting to 100% carbon-free,” Berberich said, adding that storage will be a critical element, and a variety of storage at that. In addition, having a wide geographic area from which to leverage generation resources will also play a major role in balancing generation.
The spread of coronavirus across the world has generated an unprecedented global health and economic crisis, and presented the LNG and energy industries with a demand shock like no other in history. It has severely disrupted global LNG trade flows and fundamentals, derailed project investment plans amid uncertainty over the length and depth of the crisis, and could impact the role gas and LNG may play in clean energy transitions.

But the chronic epidemic destabilizing LNG markets and causing disruptions across supply chains pre-dates the coronavirus outbreak. This virus has been around for much longer, gaining strength over time, and has become particularly disruptive at times of supply and demand shocks.

Oil indexation, which still dominates Asia’s long-term LNG pricing, has not only hindered the ability of buyers to resell unwanted volumes to other end users with appetite for opportunistic purchases when faced with falling demand, high stocks and limited gas storage. It has also made supply less responsive to demand shocks and falling prices.

Unresponsive supply

Export facilities across Australia, Qatar, Indonesia, Malaysia and Russia, which supply China with long-term oil-indexed LNG contracts, ran at an average utilization rate of more than 90% in the first quarter 2020, according to S&P Global Platts Analytics. This came despite China’s struggle to keep up with deliveries and low demand elsewhere, adding to Asia’s supply glut and pushing spot prices even lower.

In the wider Asia Pacific region, which represents nearly 60% of Asia’s LNG supplies, export facilities ran...
Oil indexation: the virus behind LNG disruptions

at 88% in Q1, a five percentage point increase year on year, despite limited demand growth: import terminal utilization in the region only grew 1 percentage point on year in Q1 2020.

Australian exporters, which account for almost half of China’s total LNG imports, said the virus outbreak has had limited impact on their operations given their low exposure to spot markets. A similar statement was made by Russia’s Novatek, which also supplies China with oil-indexed LNG contracts.

Meanwhile, disruptions in Asian LNG trade flows have been widespread. Lockdowns in China and India resulted in tens of contractual cargoes being delayed, diverted or turned into distressed floating storages awaiting alternative buyers at significant commercial losses.

The meltdown in crude oil prices in March only worsened the situation. As the oil price slump is yet to filter into LNG contracts – generally linked to Brent prices over the three months preceding the delivery month – suppliers of oil-indexed LNG contracts have had another incentive to maintain high operating rates, a trend that is deepening the supply glut.

Oil-indexed LNG exporters such as QatarGas, Brunei LNG, Gorgon, Australia Pacific LNG and North West Shelf have reportedly deferred maintenance schedules to later this year or next, citing financial and manpower considerations, but the incentive to maintain output ahead of a price slump is too great to ignore.

Buying patterns

And while contracted volumes have been left stranded in Asia-Pacific waters, some of the same Chinese and Indian importers impacted by national lockdowns, demand contractions and force majeure declarations have returned to the spot market, where prices are yet to find a floor.

The incentive for buyers to postpone contractual deliveries is as strong as that of sellers to boost prompt supplies.

Lockdowns in China and India resulted in tens of contractual cargoes being delayed, diverted or turned into distressed floating storages awaiting alternative buyers at significant losses

Platts Dated Brent prices averaged $55.44/l in February and $31.82/l in March. Assuming April average prices at $35/l and an oil slope of 13.5%, a buyer would pay $5.50/MMBtu for a May cargo versus $8.37/MMBtu for a March delivery.

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Cross currents: Big oil and the energy transition

By Henry Edwardes-Evans, James Burgess and Emma Slawinski
W ell before the oil price rout caused by the coronavirus pandemic, commentators and shareholders were calling on Big Oil to make step-out energy transition acquisitions.

Now, with economies in lockdown and corporates fighting to survive, the oil sector’s incremental move into new energy looks over-cautious. As the value of their fossil fuel assets tumbles, the coronavirus lays bare these companies’ exposure to a world of massively smaller oil and gas demand, offering a glimpse of the EV revolution to come.

And environmental groups are keeping the pressure on oil companies during the crisis even as they cut capital spending, arguing that once economic activity picks up again, new investment should be channelled into stable renewable energy jobs.

In the last three years, global oil and gas companies have branched out into new sectors, ramping up investments in the power sector, low-carbon technologies and mobility, as they respond to intensifying climate campaigning that has also spurred activism among their traditional investors.

The new strategies on display raise questions about how far – and how fast – the giants of fossil fuel production are willing to go in their pursuit of decarbonization.

The start of 2020 saw France’s Total fly out of the energy transition blocks, winning Europe’s largest EV charge point contract in the Netherlands, partnering Groupe PSA in a pilot EV battery facility and taking a 2 GW Spanish solar position.

Others are adding to incremental gains in renewables. Lightsource BP, which is 43% owned by BP, has just closed financing on a 250 MW Spanish solar portfolio while late last year Shell bought out floating wind pioneer EOLFI.

Now BP’s aspirations, although thin on detail, have upped the ante with new CEO Bernard Looney in February committing the company to net-zero carbon emissions by 2050, implying a fundamental shift over the coming decades to renewables and carbon abatement. Shell followed suit in April, also announcing a target of net-zero emissions by 2050, along with greater cuts to the carbon footprint of its products compared with previous announced goals.

While the coronavirus pandemic presents a grave risk to near-term electricity demand, electricity price and on-time project deployment, the fundamentals remain in place for renewables to dominate energy capital disbursement once the crisis eases.

Speaking to investors March 19, Enel CEO Francesco Starace said Europe’s Green New Deal was “an ideal vehicle” for kick-starting economies stalled by the virus. In the meantime the company noted Chinese equipment supply delays of just 40-45 days, pushing deployment of 200 MW back from December 2020 to January 2021. Meanwhile, in a week almost devoid of positive newsflow mid-March, it was Total making headlines with two new energy plays in onshore and floating wind.

**Distinct strategies**

While sentiment among the oil majors is definitely changing, investments remain modest compared to the size of their overall capex. The International Energy Agency says investment to date by oil and gas companies outside their core business areas is less than 1% of total capital spending. “A much more significant change in overall capital allocation would be required to accelerate energy transitions,” it said in January.

“We are likely to see more divergence across companies in their approaches and in the speed of the transition”

**Bassam Fattouh, Oxford Institute for Energy Studies**

In the same month Shell CEO Ben van Beurden said he “regretted” missing out on purchasing Dutch sustainable energy utility Eneco last year, outbid by a consortium of Japan’s Mitsui Corp and Japanese utility Chubu Electric Power Co in a Eur4.1 billion ($4.5 billion) deal.

Van Beurden said that to succeed in the competition the oil major would have “busted” its “new energies” budget, illustrating how competitive the market is for transition plays – and how cautious Big Oil remains when presented with a relatively modest step-out opportunity.

S&P Global Platts’ Power Plays Database, which tracks eight international oil and gas companies’ approaches to the energy transition, reveals several distinct strategies (see infographic, pages 26-27). Broadly speaking, the six Europe-based majors surveyed have launched more enthusiastically into both renewables and the utilities space than the two US-headquartered companies.

Total and BP are clear leaders in terms of installed renewable generation capacity with 3 GW and 2 GW respectively. Repsol, with around 700 MW currently installed, has over 1 GW already in development across wind and solar, and a target of 7.5 GW of “low-carbon” generation capacity by 2025 – this includes existing CCGT and co-generation capacity, but new additions will be renewable, Repsol said.

Norwegian state-owned Equinor wants to have 12-16 GW of renewables installed by 2035, and can lay claim to being a sector leader in floating offshore wind, as well as carbon capture and storage technology.

The US majors ExxonMobil and Chevron have taken an approach that is more closely aligned with their traditional business models, focusing on improved efficiency, increased biofuels production and CCUS (carbon capture, utilization and storage). Venture capital initiatives and R&D investments are also a big theme.

Chevron has a small renewables portfolio of around 65 MW. This is geared towards serving its core oil and gas producing operations rather than constituting a separate business, CEO Mike Wirth said at Chevron’s analyst day in early March.

Chevron has invested $1 billion in CCS projects in Australia and Canada, and in 2018 launched a $100 million Future Energy Fund to invest in “breakthrough technology.” The venture capital fund has targeted EV charging, battery technology and direct CO2 capture from the air.
### Power plays: energy majors’ transition strategies

<table>
<thead>
<tr>
<th>Company</th>
<th>Total</th>
<th>Shell</th>
<th>Equinor</th>
<th>Repsol</th>
<th>BP</th>
<th>Chevron</th>
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<td>3</td>
<td>2</td>
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<td>2</td>
<td>7</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>3</td>
</tr>
<tr>
<td>Large focus on solar, with interests in batteries, wind, retail</td>
<td>Large footprint</td>
<td>Inroads into retail power and sustainable transport</td>
<td>Aims to become global offshore wind major</td>
<td>Betting big on gas as transition fuel</td>
<td>Existing focus on solar, wind and EV charging, ambitious emissions targets from new CEO</td>
<td>Leveraging downstream networks for low-carbon liquid fuels</td>
<td>Focus on CCS and R&amp;D on low-carbon technologies</td>
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<td>65.5</td>
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<tr>
<td>Large biofuels producer, with ambitions in solar and wind</td>
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<td>Moderate footprint</td>
<td>Minimal or no footprint</td>
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<tr>
<td>Betting big on gas as transition fuel</td>
<td>Large footprint</td>
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<tr>
<td>MW total renewable capacity installed*</td>
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*Total renewable capacity includes solar, wind, hydro and geothermal power. Source: S&P Global Platts Power Plays Database

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**BP**

- Ambition ranking: 5
- Power Plays 2020 ranking: 6
- Large footprint

- **BP’s Strategy**
  - Aims to cut net CO2 footprint by 2025, compared to 2016.
  - Reduce methane emissions by 15% by 2025.
  - Aims for near-zero net CO2 emissions by 2050.

**Chevron**

- Ambition ranking: 7
- Power Plays 2020 ranking: 7
- Moderate footprint

- **Chevron’s Strategy**
  - Focus on CCS and R&D on low-carbon technologies.
  - No CO2 reduction or renewables targets.

**Equinor**

- Ambition ranking: 3
- Power Plays 2020 ranking: 6
- Moderate footprint

- **Equinor’s Strategy**
  - Aims to become global offshore wind major.
  - Aims to cut net GHG emission intensity in upstream oil business by 5%-10% and upstream gas by 2%-5% from 2016-2023.
  - Aims to cut net GHG emissions by 90% by 2050.

**ExxonMobil**

- Ambition ranking: 8
- Power Plays 2020 ranking: 8
- Minimal or no footprint

- **ExxonMobil’s Strategy**
  - Focus on CCS and R&D on low-carbon technologies.
  - No CO2 reduction or renewables targets.
  - Reduce corporate-wide methane emissions by 15% by 2020, compared to 2016.

**Eni**

- Ambition ranking: 5
- Power Plays 2020 ranking: 5
- Moderate footprint

- **Eni’s Strategy**
  - Aims to cut net GHG emissions by 2050, including Scope 3.
  - Aims to cut net GHG emissions by 2030.
  - Low carbon electricity generation capacity target of 1.6 GW by 2022 and 5 GW in 2025, with ambition of 10 GW by 2030.

**Power Plays**

- The Power Plays 2020 ranking and the Ambition ranking below are derived from the relative positions of the eight companies surveyed in S&P Global Platts’ Power Plays Database, based on two criteria. The Power Plays ranking reflects the companies’ existing footprints in renewable power generation and related activities including electric transport networks. The ambition ranking is based on targets for the scale and speed of further development of renewable power capacity, and secondly, CO2 emissions targets.

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- Reduce methane emissions by 15% by 2025.
- Aims for near-zero net CO2 emissions by 2050.

**Chevron’s Strategy**

- Focus on CCS and R&D on low-carbon technologies.
- No CO2 reduction or renewables targets.

**Equinor’s Strategy**

- Aims to become global offshore wind major.
- Aims to cut net GHG emission intensity in upstream oil business by 5%-10% and upstream gas by 2%-5% from 2016-2023.
- Aims for 12-15 GW renewables installed by 2025.

**ExxonMobil’s Strategy**

- Focus on CCS and R&D on low-carbon technologies.
- No CO2 reduction or renewables targets.
- Reduce corporate-wide methane emissions by 15% by 2020, compared to 2016.

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**Power Plays**

- The Power Plays 2020 ranking and the Ambition ranking below are derived from the relative positions of the eight companies surveyed in S&P Global Platts’ Power Plays Database, based on two criteria. The Power Plays ranking reflects the companies’ existing footprints in renewable power generation and related activities including electric transport networks. The ambition ranking is based on targets for the scale and speed of further development of renewable power capacity, and secondly, CO2 emissions targets.
ExxonMobil has been spending in excess of $1 billion/year on RD&D, and has tied up several agreements with universities, including in Singapore, the US and India, for research on biofuels and low emissions technology, among other areas.

ExxonMobil is targeting biofuels output of 10,000 b/d by 2025 (US biofuels production in 2019 was 1.09 million b/d, according to the US Energy Information Administration). The company has also invested heavily in CCUS, and says it has a working interest in approximately one fifth of the world’s total carbon capture capacity.

At an investor day in early March, ExxonMobil stressed that its approach to energy transition would build on its existing infrastructure, which can be produced on a smaller land footprint than traditional biofuel crops – and new hydrocarbon-based structural materials to reduce emissions in construction and industry.

“Instead of replacing the world’s existing power generation system, we’re collaborating with others and researching more effective technologies to capture the carbon they emit,” said CEO Darren Woods. “Using existing infrastructure significantly lowers the cost of transition and could accelerate decarbonization in the power generation sector, particularly when you couple that with natural gas.”

In adapting and expanding their business models, international oil companies can follow two approaches to the energy transition that are not necessarily contradictory, according to Bassam Fattouh, director of the Oxford Institute for Energy Studies. “On the one hand, IOCs will continue to focus on traditional activities, increasing the efficiency of their operations and decarbonizing those operations to extend the life of their business and respond to government, societal and financing pressures. On the other hand, they need to develop new business models and de-risk low-carbon technologies extending beyond their core traditional activities,” Fattouh told S&P Global Platts in an interview.

“We are likely to see more divergence across companies in their approaches and in the speed of the transition, with some continuing to focus mainly on their core activities and traditional strengths in oil and gas while others accelerate the shift to low-carbon technologies.”

Beyond the majors, a handful of smaller oil and gas companies have undergone more radical transformations. Denmark’s Orsted – formerly known as Dong – has reshaped itself from a fossil fuel business to a pure-play renewables company in 10 years, reducing its carbon emissions by 86% in the process, while the UK’s Centrica is exiting oil and gas production in favor of an asset-light, retail customer-focused strategy.

Utility revival

Meanwhile, utilities that now consider renewables to be their core business are feeling the benefits after years of value destruction in their conventional assets. Last year the top 10 stocks in the utility sector rose in value by an average 49%, led by those with significant exposure to renewables. These are prime targets for Big Oil.

While the stock sell-off prompted by the coronavirus wiped gains off utility shares, a swift bounce for several in late March meant that, over a year view, these stocks remain on an upward trajectory with regulated businesses serving as something of a safe haven for investors.

And the underlying fact remains that as the share of green electricity in final energy consumption rises, so does the need for oil companies to hedge their E&P exposure, said Societe Generale’s utilities analyst Luede Schumacher. “If you want to hedge upstream, do it by going after these disruptive technologies in renewables and associated infrastructure,” Schumacher said.

The financial markets are increasingly seeking exposure to renewables as the energy transition challenge escalates, so why not oil companies? Eni, Total, Repsol and Shell already have a sizable presence in the downstream retail sector.

“The big stocks in the utilities sector are small fry compared to the oil majors,” Schumacher said.

And while renewables generation assets are currently favored above transmission networks, growth in infrastructure over the next two decades is “expected to be massive,” he said. “We are just at the beginning of the energy transition.”

The profitability gap

Big oil companies reference lower returns as a barrier to investing more heavily in the increasingly competitive world of renewables, according to Mark Lewis, Global Head of Sustainability Research at BNP Paribas Asset Management.

“The biggest block on these companies moving into renewables is the so-called profitability gap,” Lewis said.

The oil majors traditionally expect returns of 15%-20% from upstream investments. “For renewables the return is 5% to 10%, at most 15% with clever financial engineering,” he said. “But you’re not going to get that if you’re looking at 15%-20%.”

The oil sector, however, is “completely missing the point in the assumption that because it made 15%-20% before, it can carry on making 15%-20%. Those returns were only possible because there was no competition,” Lewis said.

Fossil plant comparison

Only now are oil analysts waking up to a comparison with the utility sector, where for a long time executives argued renewable energy projects would end up as stranded assets since subsidies would be withdrawn.

“Now when you compare oil plant with these new renewable technologies, these are stranded assets but you can now see the upside of being stranded assets, impacted by renewables in terms of market share...”

“The oil industry is unused to dealing with this sort of competition, I don’t think they can see how quickly things might change”

Mark Lewis, BNP Paribas Asset Management

April 2020
"Utilities have a different business model and operate in a very regulated environment. It’s not clear what benefits such integration would bring to IOCs and whether shareholders would reward them for such a move," he said.

Whichever path they decide to take, the strategies of this handful of companies could make a big difference given their generous R&D spending and venturing in pioneering technologies.

Even if the oil and gas majors steer clear of traditional utility business models, by helping to link up changing trends in transport, power distribution and low-carbon energy, they may end up wielding an outsized influence in the electricity systems of the future.

**Change is coming**

Big Oil faces an existential challenge in the decades ahead. Will it maintain focus as a sunset industry, cashing out its business model to grateful investors? Or, as is the case today, will it continue to reposition itself incrementally in sustainable fuels, EV infrastructure and sustainable energy markets?

Taking the Orsted "big bang" approach seems a big stretch for these huge companies. In the near term, it seems likely that we will see a more prudent accrual of start-ups. But in the mid-term, it would not be surprising if one of them seeks to differentiate itself from the pack with a step-out acquisition.

There is also the question of the impact the oil majors will have as they look to reshape their businesses, both in terms of the energy sector’s evolution and the global race to curb emissions and slow global warming.

Currently, not only are the low-carbon investments small compared to their overall portfolio, but the eight majors surveyed in Platts’ Power Plays Database are responsible only for a small proportion of global hydrocarbons production. State-owned behemoths such as Saudi Aramco and China’s CNPC are far more insulated from societal and investor calls to decarbonize.

The stance taken by ExxonMobil and Chevron, that divestments from fossil fuel assets simply shift the emissions problem from one company or country to another, reasonably suggests the need to look at the issue globally.

But it may also miss a bigger point: the pressure from governments and investors on producers of hydrocarbons is only going to intensify, and the recent behavior of the high-profile oil majors is simply the most visible symptom. Those oil and gas producers that stay on the sidelines and resist a bigger shift in model may find they have missed the boat later on.

"The oil industry is unused to dealing with this sort of competition, I don’t think they can see how quickly things might change," Lewis said.

Climate is the existential theme everyone has been focusing on, “but what people miss about renewables is the decentralization theme, reducing the barriers to entry,” he said. “The way costs are coming down, it is really only offshore wind that remains as a capital intensive activity for big energy companies.”

In 2006 wind and solar accounted for just 6%-7% of total German power production, but 100% of power demand growth, Lewis noted.

"Once renewables account for 100% of the growth component, that tells you the fossil fuel component has peaked and is going into decline," he said.

The profitability gap notwithstanding, investor pressure is building on the likes of BP, Lewis noted.

"Brokers think one of these companies is going to be make a big step-out transaction in the next two years," he said.

Orsted, as the sector leader in offshore wind, is an obvious target, but the Danish government would likely block any takeover bid. "And Orsted would argue: we don’t need it, we transformed ourselves. Look at the multiples. Orsted is trading over 30 times earnings, I can’t see any oil companies trading at those levels," he said.

**New model**

An alternative view is that the IOCs could have a far more transformative impact on downstream power systems, following a disruptive model rather than behaving like – or simply acquiring – a large utility.

A report co-authored by OIES’ Fattouh last year, The Energy Transition and Oil Companies’ Hard Choices, suggests that IOCs could bypass the traditional utility model as they carve out a niche in the power sector.

Venturing into EV charging, the authors argue, could be “an entry point to decentralized energy systems... part of a strategy to become a virtual power producer (VPP) and to optimize the use of distributed energy resources.”

"IOCs are in good position to leverage their assets to extend to the business of power and EV charging, for instance by developing gas-to-power and developing their renewables business,” Fattouh told Platts.

But he questioned the appeal of a significant move into the traditional utilities space for oil and gas majors.

"Utilities have a different business model and operate in a very regulated environment. It’s not clear what benefits such integration would bring to IOCs and whether shareholders would reward them for such a move,” he said.

Whichever path they decide to take, the strategies of this handful of companies could make a big difference given their generous R&D spending and venturing in pioneering technologies.

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The stance taken by ExxonMobil and Chevron, that divestments from fossil fuel assets simply shift the emissions problem from one company or country to another, reasonably suggests the need to look at the issue globally.

But it may also miss a bigger point: the pressure from governments and investors on producers of hydrocarbons is only going to intensify, and the recent behavior of the high-profile oil majors is simply the most visible symptom. Those oil and gas producers that stay on the sidelines and resist a bigger shift in model may find they have missed the boat later on.
In December 2019, Japan’s Kawasaki Heavy Industries launched the world’s first ocean-going liquefied hydrogen vessel. It is part of an ambitious plan to produce hydrogen in Australia from coal and deliver it to Japan, but also symbolic of the growing interest in hydrogen’s potential to deliver a cleaner energy future.

Hydrogen use is already well-established in industry, such as oil refining and ammonia production, but the Hydrogen Council believes hydrogen can address 18% of global energy demand and abate one fifth of carbon emissions. The ship won’t come cheap. Scaling up the hydrogen economy will take investments of $20 billion-$25 billion each year through 2030, the council says.

Compared with other commodities, there is not much of a market for hydrogen. Trade is localized, and takes place between supplier and end user based on bilateral transactions, with little chance for price discovery.

Currently, roughly 95% of hydrogen is produced on-site. For example, refiners will contract with a hydrogen supplier to build a hydrogen production facility on the refining site, to produce so-called “on-purpose hydrogen.” Hydrogen not produced on-site is transported as a compressed gas, either via dedicated pipeline or truck (typically for the transportation market).

Powerful molecules

Hydrogen is a fuel for the future, but its use is already well established. To harness its potential to decarbonize energy systems and create a real hydrogen economy, large-scale investments are needed, write Jeffrey McDonald and Andrew Moore.

![Powerful molecules](image.jpg)
As the world pursues decarbonization, hydrogen is likely to play an important role, though cost and greener production methods will present challenges.

**Hydrogen production**

Hydrogen does not exist alone in nature. Rather, it combines with other elements to form well-known compounds such as water, natural gas and petroleum. Once separated, hydrogen is a colorless, odorless and highly combustible diatomic gas with the molecular formula H₂.

The overwhelming majority of hydrogen is currently produced from fossil fuels, including natural gas and coal, using a process called steam methane reforming (SMR). A downside to this process is that it emits carbon dioxide as hydrogenics are broken up. The CO₂ emissions could be mitigated with carbon capture and storage (CCS), but that is not standard industry practice at present.

“There is no real market for CCS [produced hydrogen],” one industry source told S&P Global Platts. “What is needed is a clear CO₂ price, or regulation or mandates for lower carbon solutions. We are not there yet.”

Hydrogen produced through SMR without CCS is sometimes referred to as “gray” hydrogen, whereas that produced with CCS is known as “blue” hydrogen. A greener production method can be achieved through both proton exchange membrane (PEM) and alkaline electrolysis, which both use electricity to separate hydrogen from water. There are no carbon dioxide emissions, and when paired with electricity from renewables, these processes help solve two key problems with wind and solar generation: curtailment and energy storage. “Green hydrogen” results when renewables are used to power PEM and alkaline electrolysis.

S&P Global Platts Analytics Scenario Planning Service estimates that a shift to zero-carbon hydrogen in existing applications along with modest penetration in gas pipelines and commercial trucking could reduce global energy-related CO₂ emissions by 4.8%. Transitioning industrial heat and some steel production to zero-carbon hydrogen could increase emissions to 6.8% globally, or nearly 2.3 billion metric tonnes (mt) of CO₂.

To give an idea of the scale of growth that could be achieved under these scenarios, global demand for pure hydrogen could increase from around 76 million mt today to 160-235 million mt.

With this growth expected, Platts in December 2019 launched its first-to-market suite of hydrogen price assessments, which model the cost of production, and added new assessments in 2020. The assessments reflect the value of hydrogen produced at hubs that are significant regions of consumption in the US, Canada, the Netherlands and Japan.

The modelled prices include SMR without CCS, PEM and Alkaline electrolysis in each of the different regions, plus a fourth production pathway – SMR with CCS or blue hydrogen – in the Netherlands.

**Industrial uses**

Current hydrogen use is centered around oil refining and ammonia and methanol production. Refiners use hydrogen to lower the sulfur content of fuel, and this use is expected to increase, according to the International Energy Agency’s 2019 report, “The Future of Hydrogen.”

The International Maritime Organization’s new bunker fuel regulations limiting sulfur content of marine fuels to 0.5%, which started January 1, 2020, are also expected to lead to a “significant increase” in hydrogen use for marine fuel production, the IEA said.

Global ammonia producer Yara has seen a 30% drop in gas consumption and a reported reduction of 10,000 kt/year in carbon emissions since it began

Global annual demand for pure hydrogen could increase from around 76 million mt today to 160-235 million mt.
receiving hydrogen at an ammonia plant in the Netherlands. Yara is also assessing the feasibility of integrating electrolysis-based hydrogen into its Australian operations, according to the IEA.

Steelmakers, who account for 7% of global CO2 emissions, are also considering ways to use more hydrogen to lower carbon emissions, particularly in markets such as Europe where carbon costs continue to rise. One company, SSAB, is converting operations from blast furnace to electric arc furnace fuelled by hydrogen to reduce iron ore. SSAB expects fossil-free steelmaking to be commercially viable by 2035.

Power generators, the transportation sector and manufacturers of building materials, such as cement, also have an eye on hydrogen.

**Transport and power**

Due to its relatively simple chemical structure, hydrogen can power vehicles equipped with fuel cell technology, emitting only water. Transportation as a sector is the second-largest producer of CO2 emissions, after electricity and heat generation, but among the hardest to decarbonize because of its distributed nature.

Toyota and Hyundai are among the early adopters of this technology, both having introduced commercial fuel-cell passenger vehicles in California. The state aims to have 1,000 hydrogen fueling stations by 2030. In Europe, the Hydrogen Mobility Initiative is also underway, to build out hydrogen refueling infrastructure.

Hydrogen production is expected to grow as the gas evolves from an “on-purpose” industrial product into a commodity, addressing hydrogen, will likely mean more time is needed to adopt emissions markets that will spur investment in CCS and other technologies.

Customers also have a role to play. Are they willing to absorb higher costs from new CCS projects, or to help pay for emerging electrolyzer technologies to decarbonize energy use? Ultimately, creating a global market for hydrogen will need to cross national and regional boundaries, as we look toward a decarbonized future.

As industry looks to a decarbonized future, gas plant operators would need to include hydrogen as part of their proposals to receive investment from banks increasingly focused on environmental concerns. Some governments, including Japan, are taking the lead, by introducing hydrogen strategies for both blue and green hydrogen pathways. Germany’s plan to introduce its National Hydrogen Strategy will go a long way toward establishing its credentials in the new economy.

Obstacles remain, however, including COP25’s failure to agree on new emissions markets under the 2015 Paris Agreement. The failed negotiations, while not directly

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<th>Co2 abatement</th>
<th>Industrial applications</th>
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</table>

Source: S&P Global Platts Analytics

Additional analysis by Zane McDonald, S&P Global Platts Analytics

A glimpse into hydrogen’s future

Japan’s initiative to ship hydrogen over substantial distance offers a taste of how the market could potentially evolve, and could stimulate efforts by global oil and gas companies to open their seaborne trade routes to hydrogen.

The same is true for future gas plant investment. As industry looks to a decarbonized future, gas plant operators would need to include hydrogen as part of their proposals to receive investment from banks increasingly focused on environmental concerns.

Some governments, including Japan, are taking the lead, by introducing hydrogen strategies for both blue and green hydrogen pathways. Germany’s plan to introduce its National Hydrogen Strategy will go a long way toward establishing its credentials in the new economy.

Obstacles remain, however, including COP25’s failure to agree on new emissions markets under the 2015 Paris Agreement. The failed negotiations, while not directly

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S&P Global Platts Analytics Scenario Planning Service combines global, comprehensive, cross-commodity modeling with deep dives into transformative technologies and policies – with hydrogen a key area of focus. Detailed research includes analysis of hydrogen production and transport pathways, cost trajectories and uptake in key sectors. Learn more: www.spglobal.com/scenario

With the goal of bringing price transparency to hydrogen markets, S&P Global Platts offers a world-first, comprehensive suite of hydrogen price assessments covering North America, Europe and Asia. Learn more about the assessments and methodology here: www.spglobal.com/hydrogen

Powerful molecules

Powerful molecules

Additional analysis by Zane McDonald, S&P Global Platts Analytics

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Global renewables investments hit a speed bump

After strong growth, renewables face diverse challenges in China and Europe, while new coal build in Asia continues to show resilience. Bruno Brunetti presents S&P Global Platts Analytics' latest findings on the evolution of the global power mix.
Global renewables investments hit a speed bump

As the extent of the impact of the coronavirus outbreak on economic activity and power demand emerges, newbuild activity in global power faces old and new sets of challenges.

The short-term focus has been shifting due to coronavirus-related disruptions of manufacturing activity and logistics, but delays will most likely be short-lived.

The global power capacity mix has already been shifting toward renewables. S&P Global Platts Analytics estimates that solar photovoltaic, wind and hydro made up almost 67% of total power capacity additions over the past year. The question is whether renewables investments will accelerate, but so far we do not see major signs that this could happen soon.

Solar PV now accounts for about a third of the total incremental power capacity additions annually, as presented in our latest Global Solar PV Outlook, 2019 marked an inflection point for the technology.

Solar additions were 4% lower year on year in 2019 and near-term challenges emerged for solar PV development, as policy support is being withdrawn across key markets and it is unclear at this time if stimulus packages that are being proposed across the globe could boost solar.

China’s PV capacity growth declined by over a third, with lingering concerns around delays of subsidy payments for plants already commissioned in prior years, which are straining developers’ finances. Platts Analytics expects a stabilization in the Chinese market in the second half of the year, under the assumption that the coronavirus is successfully contained.

Europe’s wind capacity growth has been above expectations in 2019, with almost 15 GW installed, of which over 3.6 GW offshore plants. A lack of suitable space and growing local opposition have now become a major bottleneck to new onshore projects, especially in Germany.

Growth for onshore wind has been driven by Spain and Nordic markets, representing over 20% of the total, with Sweden in particular among the largest (+1.6 GW). But Europe’s wind development is now shifting offshore, with 80 GW of offshore capacity targeted by 2030, which compares to 22 GW currently installed.

The pipeline of offshore projects has also become large in the US. In spite of a levelized cost of electricity (LCOE) for US offshore wind projects estimated to be in the mid $80s/MWh (moving down to the mid $60s/ MWh assuming Investment Tax Credit), offshore wind is being developed to meet state-driven mandates, with some 27 GW of combined offshore capacity targeted by 2030 across the Northeast. Energy mix diversification and emissions reductions are the main drivers of these procurements, while proximity to load centers is an additional attraction.

Coal fleet continues to grow

As investments in renewables dominate, it’s remarkable that the coal fleet continues to expand globally. About 48 GW of coal capacity was commissioned in 2019, similar to the level seen in the prior year. China accounts for over 60% of these additions, followed by India with about 7.8 GW of coal newbuild (about 16% of the total).

The amount of coal capacity commissioned remains well above the approximately 20 GW of capacity retired across Europe and US. Retirements are set to increase across these major markets, as loads contract and gas prices move lower, while Germany and a number...
of countries in Europe are moving ahead with plans to exit from coal.

However, it’s worth noting that Chinese authorities are looking at building more coal capacity as a way to stimulate the economy, in the aftermath of the coronavirus outbreak.

China’s National Energy Administration has been guiding the construction and commissioning of coal-fired units across the country, based on an assessment of overcapacity, fuel availability, environmental and other resource constraints for each province. The latest guidance – issued this February – allows more provinces to bring coal units online by 2023 versus the policy issued a year ago.

As China’s coal capacity grows, its role in the mix is changing, as coal is increasingly complementing intermittent renewables and higher air-conditioning usage during the summer peak.

Stronger power demand growth is the driver of the large number of coal projects in Southeast Asia. Vietnam stands out for its pipeline of projects outside of China and India. Almost 1.4 GW was commissioned during 2019, while over 40 GW of capacity is at different stages of development. Availability of capital from financing institutions, notably from China, has also been a driving force behind these projects.

Indonesia has about 14 GW of coal in construction and over 2D GW in the planning stage, although the country’s power development plans have often seen delays. Indonesia’s government announced it will replace old thermal with renewables, for a total of 13.4 GW of capacity. With all this capacity up for retirement, new thermal capacity will have to be built to meet rapid growth in electricity demand.

Gas-fired capacity added to the grid across the globe slowed in 2019, in spite of falling gas prices. Fewer units came online in the US (11 GW), or about a third of the global gas capacity coming online in 2019. However, the US maintains a very large pipeline of gas-fired projects, as do gas-rich countries in Middle East and North Africa.

The recent oil price crash could have an impact on the further development of gas projects in these gas-rich areas, but new opportunities for gas may now emerge in importing countries, given the low current price environment.

A number of LNG-to-power projects are underway in Asia, with 9 GW in construction and about 52 GW in planning, on top of the 127 GW of LNG-fired power capacity currently operational in the region. We see a shift away from the three traditional large LNG importers – Japan, South Korea and Taiwan – as newer LNG importing countries, including Bangladesh, China, and other South East Asian countries are building LNG to power capacities.

The appetite to invest in large-scale, gas-fired units has been fairly limited in other regions, especially in Europe, but with the emergence of about 5.7 GW of gas projects in Italy, which have secured payments in the recently-introduced capacity market.

**Nuclear additions slow**

Nuclear remains a more marginal technology, with plant commissioning slowing in 2019. China continues to lead in nuclear newbuild, but only about 4 GW entered commercial operations during 2019, which is considerably below the almost 9 GW of capacity...
commissioned during 2018. In addition to China, South Korea, Russia, and India all have significant construction activity.

The combination of sustained lower natural gas prices, renewables penetration, and weak electricity demand, has been challenging nuclear generation in more mature wholesale power markets, especially in the US. Retirements equivalent to 1.5 GW of capacity took place in 2019 – the 0.7 GW Pilgrim 1 and the 0.8 GW Three Mile Island #1. Approximately 1.7 GW of capacity is slated to retire during 2020 – the closure of the Duane Arnold #1 (Iowa) and 1.1 GW Indian Point #2 (New York) plants will bring nuclear output down by an average 2.2 GW year on year. Support mechanisms for other struggling nuclear units in the US remain possible after the legality of recent legislative policy measures in Illinois, Connecticut, New York State, and Ohio was upheld by courts. A more substantial amount of nuclear retirements loom down the road both in the US and Europe, while we estimate that at least 70 GW of operational coal units are ripe for retirement.

The unprecedented hit to the economy from the coronavirus pandemic is leading to significant demand destruction – with our estimates for power demand growth downgraded by about 2.5% so far this year. While uncertainties remain around the pace of the demand recovery, the world will still need to replace large amounts of ageing thermal capacity in the future.

As China is likely to continue to build more coal as a way to stimulate the economy, gas newbuild in the power sector has become more uncertain in the current market environment. Lower oil and gas prices are making gas or LNG projects in a number of importing countries a more interesting proposition, but the future of a number of gas projects is less clear in regions with associated gas production fields.

The outlook is also uncertain for renewables, especially solar, as it is still too early to say whether stimulus packages that are being proposed across the globe will include clean energy, and could eventually give new impetus to green investments.

LNG to power projects (GW)

<table>
<thead>
<tr>
<th>Country</th>
<th>Under construction</th>
<th>In planning stage</th>
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</thead>
<tbody>
<tr>
<td>Japan</td>
<td>2</td>
<td>6</td>
</tr>
<tr>
<td>Indonesia</td>
<td>2</td>
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<tr>
<td>South Korea</td>
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</tr>
<tr>
<td>China</td>
<td>2</td>
<td>6</td>
</tr>
<tr>
<td>Others</td>
<td>2</td>
<td>6</td>
</tr>
</tbody>
</table>

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

“We let us operate your plant efficiently and reliably.”

We bring an ownership perspective when it comes to operating and maintaining power plants. It’s one driven by knowledge and fueled by over 30 years of experience in operating our own various asset types.

We’re a problem solving organization with focus on operational excellence. Complemented by our commitment to safety and best-in-class technical expertise - that’s how we help our clients generate value and keep their units operating efficiently and reliably.

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INSIGHT
Cockett Marine Oil, owned by Swiss trader Vitol and South African holding company Grindrod, resold an estimated 5.5 million tons of marine fuel in 2019, versus 6.5 million tons in 2018. Saral was named Cockett CEO in September 2016, after working for Vitol and Chemoil. Cockett handles roughly 18,000 deliveries to customers annually in every single line of shipping. The company has about 185 employees, with about 60 of them in Dubai, the operating headquarters.

Very low sulfur fuel oil (VLSFO), with no more than 0.5% sulfur, became the go-to fuel for shipowners at the start of this year, after the International Maritime Organization (IMO) required ships to stop using high sulfur fuel oil (HSFO) with 3.5% sulfur. Marine gas oil (MGO) also became an option as IMO-compliant fuel, especially when the spread between MGO and VLSFO narrows. All MGO is either max 0.5% or max 0.1% sulfur, and is more expensive because it’s a better quality product.

How has the IMO 2020 transition been for the industry and Cockett Marine Oil?

For the industry, I think we are a good representation of the transition as a global reseller. I think what we were expecting was probably more of a worst case scenario than what was actually realized. There was a lot of scaremongering to do with availability, product quality, enforcement, etc.

We’ve had quality issues, although they were far more minor than what we expected. We had a number of near sulfur limits, some minor flash-point related issues and some sediment related stuff. By no means should we minimize concerns about VLSFO (very low sulfur fuel oil) quality issues, nor do I see that they are as elevated as they were perceived to be a couple months ago.

What has become the chief marine fuel after IMO 2020?

Our assessment shows that global marine fuel demand was near 300 million tons/year before the IMO 2020 transition, with nearly 20% of this gasoil for consumption in auxiliary engines, generators for larger ships and for main propulsion needs for a large number of smaller sized vessels.

Considering LNG, emission control areas-compliant fuel consumption, vessels fitted with scrubbers and other considerations including average vessel speeds and the shape of global trade activity, we estimate that around 185 to 210 million tons/year of HSFO (high sulfur fuel oil) marine fuel demand would need to switch to new compliant fuel, VLSFO with a max 0.5% sulfur content.

During early months of the transition, we estimate a run rate of about 70-75% or 140 to 160 million tons/year equivalent of this demand would be met with VLSFO while the rest of marine fuel demand would be met with marine gasoil. While we see VLSFO becoming a chief fuel of choice after January 2020 for the main engine propulsion for medium and large size fleets, going forward we also see a significant increase in marine gasoil’s share in the marine fuel demand.

Looking at recent developments surrounding COVID-19, and the drastic drop in oil and product prices that points to strong headwinds to refinery run rates as well as demand, we also anticipate increased interest in marine gasoil and compliant products with a large portion of distillates such as vacuum gasoil in their blends.

Do you use Fujairah port for supplies?

Fujairah is probably one of our top 5 or 6 ports.

Has Fujairah had any issues related to IMO 2020 that are different to other ports?

Not really. The market was really concerned last summer about availability of VLSFO. Now with the two existing facilities there, through Uniper and VTTI, I don’t think the market has suffered from a lack of availability. In the early days of the transition, December and January, the difficulties we faced were mostly logistics rather than availability. Most of the concerns or difficulties we had were not to do with availability but...
with logistic constraints of waterborne assets, which is, for now, by and large all settled in. The world has moved into a VLSFO reality today.

People were not demanding the new fuel early on because the difference in fuel costs (between HSF0 and VLSFO) is so high – you wouldn’t be looking to pay for something that is 30% to 40% more expensive a day sooner than you had to. The economics dictated that the transition had to be abrupt. And that brought about some logistical constraints, mainly on barge availability. But that’s becoming a thing of the past.

Has liquidity been a challenge in IMO 2020?

I think liquidity has always been an issue. What we’re seeing, and it’s not exclusive to marine fuel, we’ve seen international banks, especially the European banks, strategically shying away from the shipping business over the last couple of years. And we also have seen a number of incidents that have put a lot of constraints on the marine insurance business.

Has Cockett had to change the way it does business because of IMO 2020?

Yes and no. Basically we do not exist in the physical supply chain. We sit on top of the value chain. We have a huge number of global vendors that provide us the fuel and we have a global set of customers who need the fuel. So from our perspective, what we needed to do is understand the landscape, to understand the new demand profile, and understand the capacity of our vendors to adapt to IMO 2020.

We had to educate and train our staff, we have implemented a lot of technical engagements with our customers to educate them on quality issues. I would say we were as ready as we could be with regard to our understanding of the landscape. We didn’t need to transform how we do business from what we were doing a year ago.

Obviously it brought some different aspects to it. It takes a bit longer to conclude a trade today because the information needed to transact a VLSFO trade is far more detailed than previously with HSF0. People want to know more about the exact quality, the compatibility. So for the transaction, from origination to conclusion of a trade, we see a bit more communication or interaction with the end user and the vendor taking place. But other than that, nothing monumental I would say.

What is the outlook for the bunker industry?

The concern now is what is the marine fuel business going to do to adapt to a decarbonized world.

So IMO 2020 isn’t the end of the shipping sector effort to reduce emissions?

Absolutely not. It’s just the beginning of the new challenges. I think decarbonization is a challenge that will require a far bigger collaboration, a far longer and far more dynamic engagement that needs to be implemented globally. This is already happening today on shipping and ship liners and that will unquestionably impact the marine fuel pool, because the pressure to decarbonize is far more intense, the challenges we need to adapt to, the goals, are far higher than the mountain we climbed for VLSFO.

Do you expect mergers in the marine fuels industry?

Yes, absolutely. The industry is fragmented and the industry needs consolidation. This isn’t new, it’s been there for a long time. The underlying headwinds that are coming [from the move] to decarbonize [the shipping sector] will define those consolidation efforts rather than VLSFO. We will see more players entering the market, providing different types of fuels that are not in the playground of the existing fuel provided, such as ammonia, hydrogen, methanol, biodiesel and biofuel electricity. These are not in the main, but I think the next three years will be a wake-up call for many.

It’s impossible to meet decarbonization challenges by staying with the existing marine fuel products we have. You can’t simply decarbonize the world by selling VLSFO. You would need to be looking into different mixes of products and services entering the supply pool.

Will Cockett be a buyer or seller?

We will always be facilitators. I think our strength will come as we understand the changing demand profile, it will be much easier for a company like us to go and get the provider of the changing demand, the new product, and translate it into something our customers would need. So facilitation will become far more important if you are looking into a fragmented pool of maybe a dozen different options that end users have to choose from. Clearly, going forward, the marine fuel pool will be much larger with regard to the product count than it is today.

Do you have any plans to apply for bunker licenses in Singapore or Fujairah?

No. We are a reseller and we will remain a reseller. The essence of how a reseller model works is significantly different to how a physical supply chain participant’s dynamics work. We don’t try to mix the two. We believe it’s a dangerous mix. Our primary concern is understanding the cash we put at risk and understanding and comparing the risk-adjusted return of the cash. If you run a physical business, your metrics change drastically. And combining the two is not an ideal mix.

Does Cockett plan to go into other markets than reselling bunker fuel?

Yes we do, we already are. We deal with a number of petroleum products. We have a small aviation business and we have a global marine lubricants business. We provide services to more than 120 airports. That started two and a half years ago, and it is growing. But I think at this point in time, the period from 2016 to 2019, the main concern was IMO, so we put most of our efforts into the transition of IMO. Once we are past that, I think we can look at more strategically our diversified businesses.

The marine lubricants business has been consistently growing simply because an engine needs fuel and an engine needs lubricants. And the VLSFO changes also transformed the marine lubricants business and the demand profile changed drastically. So we created a partnership model where we are providing technical advisory to our customers, not only about getting the right fuel, but getting the right lubricant so their engines run properly.

Is that business growing faster than bunkers?

Our marine fuel business is not growing volumetrically. If you look at the major resellers, their tonnages have not been growing for the past two or three years. We are trying to be more efficient and we try to be more profitable by trading more efficiently rather than let’s say prioritizing having a larger market share. We never had that intention and we will never have that intention. We have no desire to look into having a higher market share as a primary goal. What we would like to do is how efficient and how proactive we can be in the use of our cash and resources to be able to deliver a reasonable return to our shareholders and a good service to our clients.

“We will see more players entering the market, providing different types of fuels that are not in the playground of the existing fuel provided, such as ammonia, hydrogen, methanol, biodiesel and biofuel electricity”

Cem Saral, Cockett Marine Oil
EVs on the grid

As EV adoption grows, new challenges and opportunities are emerging for power grids. Felix Maire and Zane McDonald explore scenarios for the integration of EVs into US power systems, highlighting the role of charging behavior.
The large size of the US auto market and high GDP per capita, as well as easy access to financing options, make it a leading candidate for electric vehicle uptake. However, the lack of a strong regulatory foundation represents a substantial barrier, as does the relatively low cost of gasoline and diesel.

Depending on the region, S&P Global Platts Analytics forecasts plug-in electric vehicles to reach total cost of ownership parity with internal combustion engine vehicles over the next 10 years. Market fundamentals will begin to drive PEV sales to a greater degree as consumers become aware of the savings associated with reduced operational costs.

As PEV adoption moves away from early adopters, the development of a robust and ubiquitous charging infrastructure will become even more important than it is now.

PEVs will raise power demand, but the effect on the grid will depend on the speed, time and location of the charging. In this article, we will take a look at the impact on the grid of rapid PEV adoption, focusing on passenger vehicles and taking the US state of Virginia as a case study. The electrification of commercial and other heavy duty vehicles would pose different challenges to the grid due to different utilization patterns and charging requirements.

State regulations a key driver

The operational costs of PEVs are considerably lower than those of ICEs. Despite this, the high purchase premium of a PEV compared with an ICE, driven primarily by battery costs, now makes PEV ownership less economically attractive for many consumers. Furthermore, low PEV ownership also presents challenges to the grid due to different utilization patterns and charging requirements.

Forecast vehicle sales in Virginia, US

Vehicle sales by type

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<th>ICE</th>
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% of total vehicle stock

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<tbody>
<tr>
<td>2020</td>
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</tr>
<tr>
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</tr>
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<td>2030</td>
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</tr>
<tr>
<td>2035</td>
<td>50%</td>
</tr>
</tbody>
</table>

In 2019, the US had around 85,000 charging points

In 2019, the US had around 85,000 charging points according to the latest data from Platts Analytics EV Essentials. China and the EU-28 region have more charging points with 379,000 and 193,000 installed, respectively.

More charging options needed

The availability of various options and ubiquitous charging infrastructure is seen by many as a prerequisite to the rapid adoption of PEVs. Charging technologies have evolved in the last decade as more PEV models entered the market. PEV charging network operators have both increased the number and the speed/rating of DC fast chargers, as vehicles have become capable of sustaining a higher speed of charging.

In 2019, the US had around 85,000 charging points according to the latest data from Platts Analytics EV Essentials. China and the EU-28 region have more charging points with 379,000 and 193,000 installed, respectively.

PEV owners charge either at home or public infrastructure, which could include public curbside charging, workplace charging, or PEV operator-owned networks. These options differ in terms of availability, convenience (speed, proximity to home or work) and cost.

On average, US commuters drive 40 miles a day to go to work according to the National Household Travel Survey. Home night charging with a level 1 (standard) outlet or level 2 outlet would generally sufficiently recharge a vehicle for the next day. Home charging is more likely in areas with single-family homes.
charging cost and consumer behavior, and will evolve as EVs penetrate more markets and household income levels.

Level 3 DC fast chargers are available in different ratings or speed of charging. In the US, the Electrify America network ranges from 50 kW to 350 kW, and the EVgo network mostly has 50 kW chargers. The higher the power rating, the higher the charging speed, though the speed is also affected by the vehicle’s maximum ability. At 150 kW, a vehicle would add 45 miles of range in five minutes, or 270 miles in half an hour.

While fast charging has the potential to facilitate PEV adoption, it could also have a major impact on the grid both in terms of local grid reinforcement costs and the need for peaking power. Distributed generation could help limit the impact of charging on the local grid. However, one vehicle charging at 50 kW would add an incremental demand equivalent to more than eight individual residential solar PV installations, as the US average size is 6 kW. Standalone batteries, as discussed in previous European Power Storage Outlook reports, will increasingly be used in charging stations to limit the impact on the grid.

**An asset to the grid, or a burden?**

A growing share of passenger vehicles moving toward electricty would be an upside for power demand after years of declining growth in many regions. Platts Analytics forecasts light-duty PEVs alone to add over 40 TWh of load to the US demand by 2030, which could represent either a burden for grids to mitigate, or a resource for the integration of renewable power.

The scale of the impact on the grid will depend mostly on the time and speed of charging, which in turn are affected by the charging infrastructure, the retail tariff structure, and consumer preferences. Impacts will vary at the system and regional/local levels.

We will outline four PEV charging scenarios with incremental level of sophistication to frame the impact of PEV charging on the power system. The state of Virginia is used as a case study, as it features average EV adoption.

**1. Non-managed home charging**

All passenger PEVs would charge at home, starting at the evening peak demand time. Virginia in this scenario could add an extra 2 GW to peaking power needs by 2030. At a high level of PEV adoption, non-managed charging could add a significant amount of load to peak demand. This would affect the grid infrastructure and power capacity investment needs, and the incremental PEV load would likely be served by highly emitting sources, such as natural gas peakers or dual-fuel peakers.

This scenario is unlikely in places with high PEV adoption due to a combination of regulatory and technological factors. The pressure on retail rates from additional grid investment would likely lead utility regulators to implement tariff changes that would incentivize different charging behavior. This may include time-of-use tariffs, with higher rates at peak time and/or the addition of demand charges to residential retail rates similar to what Commercial and Industrial (C&I) customers are paying.
Ultimately, regulators have to balance the scale and distribution across households of the incremental infrastructure cost with the need to support broader PEV adoption.

2. Smart charging

Most of the charging would still be done at home, but with a charging profile minimizing the impact on the grid. As most personal vehicles remain parked at night for eight to 10 hours, charging could be spread through the night and still provide a sufficient range for the next day’s commute.

The likelihood of this scenario will depend on regulatory and technological developments as customers would need to be incentivized to change their behavior. Sufficiently differentiated time-of-use rates, and/or demand response opportunity (e.g. with managed charging or V2G, through a third-party provider) could provide the economic signals to charge at night. Technology could facilitate this change, for instance with the option to let the vehicle charge intelligently without the need of human interactions (e.g. “set and forget”). In California, eMotorsWerk – acquired by EnelX – provided the California Independent System Operator with 30 MW of demand response from the aggregation of 6,000 individual charging points. The company pays the customer for the ability to modify their EV charging profile to reduce load at the time of peak demand without having a major impact on the PEV owner. Many regions are looking into these types of solutions, for instance in the US with Xcel Energy and in Europe with Jetixi or in Asia.

3. Workplace charging

Adding workplace charging to the previous scenario would enable greater integration of renewable generation, particularly in regions with high solar PV resources. In a scenario with very high solar PV generation, a large PEV fleet would limit the need to curtail solar PV generation, overbuild storage capacity or additional technologies.

In the example of Virginia depicted to the right, our model optimized the PEV charging profile to benefit from low marginal cost renewable generation during the day, while ensuring that vehicles have a sufficient range for daily commuting. This charging behavior decreases the system cost and transportation emissions by increasing the share of renewable used for PEV charging.

The number of workplace chargers will reflect employer choices and regulatory requirements. Workplace chargers may include a mix of level 2 and level 3 DC fast chargers.

4. Fully optimized

In this scenario, PEV could provide additional services to the grid (vehicle-to-grid or V2G). In essence, a PEV can be seen as a large movable battery system. Taking again the example of Virginia, the equivalent battery size of the entire BEV fleet may already reach 11 GWh by 2030, a level of storage capacity much higher than our 2030 forecast for standalone storage in that state.

Assuming these vehicles charge during the day and are connected to the grid during the peak time, they may provide peaking capacity. They could also help to balance the grid with the increasing renewable generation. Many regions are conducting V2G pilots, for instance for the provision of ancillary services, such as frequency regulation or spinning reserve, with vehicles.

Ultimately, the extent to which vehicles will be able to support the grid and broader renewable generation will depend on regulatory and technological developments because the benefits will have to balance the potential costs. Greater grid integration of EVs may either infringe on some customer convenience or increase the EV operating cost, both of which could work to slow EV uptake.

Go deeper

S&P Global Platts Analytics forecasts country-level outlooks of passenger and commercial EV adoption and energy impacts, for the US broken down to the state, ISO and PADD level. Explore coverage of alternative transport and electric vehicles, part of Platts Analytics Scenario Planning Service: spglobal.com/scenario

Platts Analytics forecasts light-duty PEVs alone to add over 40 TWh of load to US demand by 2030
Insight from Washington

By Brian Scheid

In February, after months of criticism, Texas Railroad Commissioner Ryan Sitton tried to take the state’s flaring issue head on.

"We want to reduce flaring," Sitton told reporters at the time. Sitton released a report on the path forward on flaring, or burning off associated natural gas during oil production, which has roughly tripled in two years in the Permian.

Sitton’s report, however, offered few solutions and conceded he was unsure about how the commission, which regulates the state’s oil and gas industry, may enforce the laws that are already on the books.

"The state regulator needs to step up and enforce the laws that are already on the books," Castaneda, a Dallas oil and gas attorney, said in an interview. "The state regulator needs to step up and enforce the laws that are already on the books."

Instead of recommending changes to the commission’s seemingly lax enforcement of the practice, the report pointed to the relatively high intensity of flaring in other countries, notably Iraq, and argued that Texas should not be judged in a vacuum.

"When you have the railroad commissioner... issuing that report, pointing the finger at Iraq, that’s not the best standard," Deborah Byers, the head of Ernst & Young’s Americas oil and gas practice, told S&P Global Platts. "You want to benchmark against best in class."

About two weeks after Sitton released his flaring report, he lost his re-election campaign in the Texas Republican primary to Jim Wright, a newcomer to Texas state politics and the owner of an oilfield waste services company located outside Corpus Christi.

While few, if any, would argue that Sitton’s loss can be tied to flaring, the issue could be a defining one in the race to win his seat on the three-member commission in November’s general election.

"There’s a lot of value in this gas long term... the question is how do we do it," Wright said in an interview.

"There’s no sense in putting gas out into the atmosphere, we need to get better about bringing it to market," Wright said. "We’ve got to figure out how to make it feasible and maybe less restrictive on pipeline regulation to get it to a major transmission line."

Like many in the industry, Wright said he was concerned that punitive limits on flaring could upend the state’s oil industry. "You can’t produce oil unless you have gas come with it," Wright said. "There’s a balance there that we have to practice in order to keep our economy strong."

Castaneda, however, said the idea of balance is false premise. "I just don’t buy it," she said. "I see a sea change, even in the industry."

In his questionnaire, Alonzo was also unconcerned about any impact on production, claiming that the oil market was "glutted" due to overproduction in Texas.

By state law, Texas operators are prohibited from flaring after a well has been online for 10 days, but operators continue to flare legally through commission-granted exception permits. A 2018 study by The Texas Tribune and the Center for Public Integrity found that the commission issued more than 6,300 Permian flaring opinions from 2016 through May 2018. The commission issued only 571 flaring permits in all of Texas from 2008 to 2010, according to the study.

Gas flaring at the wellhead in the Permian climbed to 2.48 million b/d in 2017, according to the US Energy Information Administration. Permian flaring opinions from 2016 through May 2018.

Castaneda and Alonzo have focused their campaigns on curbing flaring in the Permian and the Texas commission’s seemingly lax enforcement of the practice has received widespread criticism.

Castaneda wants to require operators to consider alternatives to flaring, which has skyrocketed amid record-setting Permian oil output due largely to a lack of gas takeaway capacity. Those alternatives include using associated gas for power generation at individual well sites, she told Platts.

Alonzo did not respond to an interview request. But in response to a questionnaire from the Fort Worth Star-Telegram, published in February, Alonzo said the commission must “take more aggressive efforts to reduce flaring and improve air quality by reviewing the permit process and reducing the number of permits being issued.”

Wright, who received nearly 1.02 million votes in the Republican primary to beat incumbent Sitton’s fewer than 798,200 votes, also said curbing flaring is a priority.

"There’s a balance there that we have to practice in order to keep our economy strong."
As China’s energy imports rise, so energy security climbs up the political agenda.

In 2014 Xi Jinping, General Secretary of the Communist Party of China, outlined a long-term energy strategy that included strengthening the domestic and overseas supply of oil and gas. More recently, external pressures, notably a more bellicose United States, China’s key strategic competitor, have only heightened China’s vulnerability as energy imports continue to climb.

It is against this backdrop that in July 2018, Xi Jinping called on China’s major oil and gas companies to take measures to boost domestic output and improve national energy security. They duly complied.

Sinopac’s E&P spend increased 46% in 2019 over the previous year. The major’s efforts had little impact on production at China’s aging oil fields, which are structurally in decline. But natural gas production grew by a record 16 Bcm, reaching 176 Bcm last year. Shale and tight gas accounted for just over 30% of the total.

Shale gas revolutionized US natural gas production. With China having even larger shale gas resources than the US according to some estimates, the question is whether shale gas holds the key to securing China’s energy security.

China is no stranger to tight gas, which it has been producing since the 1990s. Like shale gas, tight gas uses horizontal drilling and fracking to release gas from reservoirs inaccessible using conventional techniques. Most is found in the Ordos Basin, in north central China, which accounts for over 80% of China’s proven tight gas resources according to a paper published by researchers at the PetroChina Research Institute of Petroleum Exploration & Development.

Tight gas from Ordos began to seriously start flowing in the mid-2000s with the development of CNPC’s Sulige field, now the largest gas field in China. But large-scale development faces challenges. Production from individual wells is low, which means drilling thousands of wells, and heavy investment in surface gathering pipelines and infrastructure.

By 2018 CNPC had drilled 10,000 wells at Sulige. Further drilling in 2019 raised Sulige output to an all-time high of 25.45 Bcm. But despite the increase in wells, improvements in horizontal drilling and other technologies to improve well flow rates, production at Sulige in 2019 was still only up 4 Bcm on 2014.

Policy revamp boosts shale

Shale gas output, on the other hand, grew by 14.3 bcm over the same period, with output reaching 15.5 bcm in 2019. Virtually all of this came from the Sichuan basin in Southwest China, which holds around 80% of China’s technically recoverable shale gas resources. Output has been rising as Sinopac and CNPC’s own oilfield service companies gain more experience drilling and extracting gas from the complex geology of the mountainous Sichuan Basin.

Recent growth in output has been supported by a number of policy changes. In 2018 the government cut the resource tax for shale gas by 30%. In June last year the government also changed the subsidy regime for unconventional gas from one where producers received a fixed subsidy per cubic meter of shale and coal bed methane gas produced, to one where funding is dependent on the amount a producer can grow unconventional output over the previous year. The policy, which runs from 2019-2023, also rewards producers who increase production over the winter, when gas demand rises. And it includes tight gas, which was excluded from the previous regime. PetroChina’s tight gas output rose 15% in the first half of 2019, with shale gas production nearly doubling last year to just over 8 bcm, up from 4.26 bcm in 2018. This was helped by the policy tweak, which PetroChina said would deliver an expected Yuan 4 billion (US$580 million) in subsidies in 2019, up from Yuan 1.5 billion in 2018.

International oil companies have been involved in tight gas projects for over a decade, with both Shell and Total successfully partnering with CNPC through production sharing contracts in the Ordos basin. But they have had less success with shale. Despite companies including ExxonMobil, Shell, and BP evaluating and drilling for shale gas none of their efforts led to viable commercial production.

In an effort to encourage investment into exploration and production, starting this year foreign and private companies have been allowed to explore and develop oil and gas resources without having to partner with one of the national oil companies. But until there is greater sharing of geological data, more transparency...
around the competitive bidding and transfer of exploration rights, and laws to ensure equal treatment of private and foreign companies, there’s likely to be very little real competition for the state owned oil majors in the upstream sector.

Shale economics are improving. In 2015 Sinopec said that the cost per well at its Fuling field had fallen from Yuan 100 million to Yuan 80 million ($13 million). Three years later CNPC claimed that the costs per well at their blocks in Sichuan were as low as Yuan 50 million. Despite this, costs are still high compared to the US. In 2016 researchers at the PetroChina Research Institute of Exploration and Development said that like-for-like exploration and development costs of shale gas in China were two to three times those in the US.

Much of China’s shale reserves and resources are locked away more than 3500 m underground, deep in the Sichuan basin. The potential to significantly expand Chinese shale output depends on being able to economically extract gas from this deep shale.

The success last year of Sinopec in achieving high flow rates from an exploration well over 4200 m deep in the Sichuan basin is encouraging, but drilling deeper means more time and cost. Breakthroughs to reduce well development costs and boost production from fracked wells will be required for this gas to be commercially viable.

Despite the recent collapse in oil and gas prices, both CNPC and Sinopec have stated they intend to grow natural gas production in 2020. Between them they are targeting shale gas output of 22 bcm in 2020. This may well be achievable, but it will still be well below the target of 30 bcm for this year in the government’s Shale Gas Development Plan (2016-2020).

Further out, questions remain around whether the economics are favorable enough to sustain large-scale development of unconventional resources. The Shale Gas Development Plan is targeting 80-100 bcm by 2030. Few think China can achieve this, but it might come close. Last year the CNPC Research Institute published its Energy Outlook, forecasting Chinese gas output to grow to around 28 bcm by 2030.

But without a change in the structure and trajectory of China’s energy consumption, gas demand is likely to rise faster than production. The S&P Global Platts Analytics World Energy Demand Model base case is that Chinese gas demand will rise to 555 bcm by 2030. This would see China’s import dependency – net imports as a percentage of consumption – rising from 43% in 2018 to 50% by 2030.

Even if (and it’s a big if) shale gas production can reach 100 bcm by 2030, unless China can find alternative fuels to natural gas, shale production looks unlikely to halt the trend of ever rising imports.

Source: News reports, CNPC, S&P Global Platts Analytics

**China natural gas supply**

| Source: News reports, CNPC, S&P Global Platts Analytics |

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Russia agreed to take unprecedented volumes of crude off the market under a new OPEC+ agreement in April, in response to dire crude demand forecasts and storage concerns.

Russia has signed up to cut 2.5 million b/d in May and June, 2 million b/d from July to December, and 1.5 million b/d from the start of 2021 to the end of April 2022. Its baseline for these cuts is 11 million b/d.

These volumes are significantly greater than Russia’s commitments under previous OPEC+ agreements, and pose a major challenge for Russian oil companies. Due to Russia’s difficult climate conditions, and the advanced age of many fields, producers have long claimed that altering output volumes at their projects is technically complex and requires some time.

There are fears that wells that are shut in now may never produce again.

Russian energy officials and producers have said they are willing and able to meet these targets, however. Russian analysts said they likely don’t have much choice, with prices low and demand forecasts so negative that producers would have had to make significant cuts, with or without the deal.

Russian crude output will be topped up by condensate, which is exempt from the agreement. Analysts expect condensate to push Russian output over 9 million b/d in the first two months of the new deal. Russia does not provide separate figures for crude and condensate production. In March combined output was 47.78 million mt, or around 11.294 million b/d.

Even so, producers may need to make cuts at almost all projects in Russia to meet the new targets.

Oil producers may need to make cuts at almost all projects in Russia to meet the new targets.

Supply impact

In terms of the supply impact, analysts expect deliveries to Europe to be most affected by the new agreement. Shipments to Asia via the East Siberia Pacific Ocean pipeline have been trading at a premium, and are supplied under long-term contracts. There are also signs of a demand recovery in China, whereas much of Europe remains under lockdown. In March Russian exports totaled around 4.99 million b/d.

Deliveries to Russian refineries are also likely to be affected, but much depends on the severity and duration of the lockdown in Russia, which at this point is hard to predict. Russia supplied around 5.98 million b/d to the domestic market in March. The maintenance season, which is due to continue into June, will also impact demand.

Policy change

The April agreement marked a sharp change in Russia’s approach from early March, when OPEC+ talks collapsed without an agreement. Russia had refused to commit to anything beyond an extension of the existing deal for another quarter. Producers were then free to pump at will from April.

Part of the reason for Russia’s reluctance to agree in March was that it has amassed healthy international reserves and boosted its sovereign wealth fund since the OPEC+ deal came into force and it introduced a fiscal rule in 2017. This resulted in a state budget and oil production economics that were considerably more resilient at the start of this year than in 2016.

Immediately following those talks Russian officials said they were happy with oil prices at $25/b and were prepared to maintain their market share. Over the course of the next month a lot changed, however, as much of Europe went into lockdown to minimize the spread of the coronavirus, and Russia itself began to take measures to combat the pandemic.

Analysts pointed to the unpredictability of demand until the end of the year, as well as concerns over storage, as bringing Russia around to a much bigger cut than was proposed at the previous meeting. In early April, forecasts indicated that storage would reach capacity within months. Russia itself has limited crude storage capacity, significantly less than the US and Saudi Arabia, with some analysts estimating that it may be as low as a few hundred thousand barrels.

Domestic storage options include some capacity at production projects, refineries and tankage owned by pipeline operator Transneft. Transneft does not provide figures for its storage capacity, and says that its network is not designed for storing crude, with tankage storage used just to ensure that the network runs smoothly.

Furthermore, a major contamination of crude in the Druzhba pipeline last summer has resulted in oil that contains excess chlorides taking up space in some of Transneft’s storage network.

Finally OPEC+ managed to get some encouraging signs that producers outside OPEC+ will also cut production in the near future. Russian energy minister Alexander Novak said he expects producers outside the group to cut a further 5 million b/d, on top of the OPEC+ cut of 9.7 million b/d.

But this could still prove insufficient to stabilize the market, with analysts predicting oversupply of 20-25 million b/d over the next few months.
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