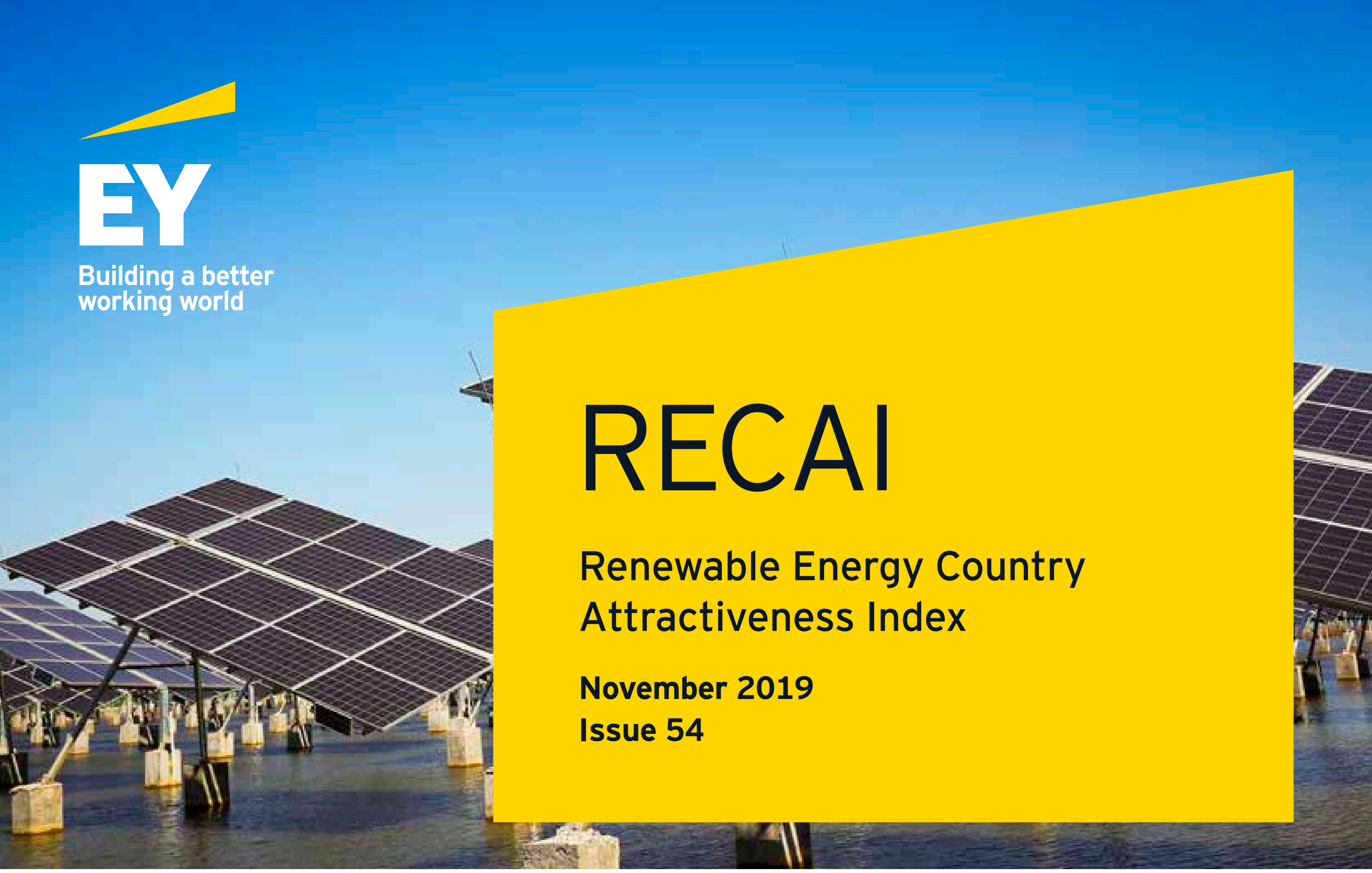

Building a better working world

RECAI

Renewable Energy Country Attractiveness Index

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Matching capital with capacity in the low-carbon transition

Putting a cost on the low-carbon transition is challenging, but it presents huge opportunities. Earlier this year, then-UK Chancellor Philip Hammond estimated the cost to the UK would be £1t (US$1.3t) by 2050 – and was roundly attacked for looking only at the costs and ignoring the benefits.

In the US, on the other hand, Alexandria Ocasio-Cortez, the left-wing Congresswoman promoting a Green New Deal designed to tackle climate change and reduce inequality, has said it will cost at least US$10t. Its critics put the price tag at US$93t.

There are, however, parts of the low-carbon jigsaw that are easier to cost, namely the decarbonization of the world's electricity systems. To meet the Paris Agreement's climate change goals, the International Renewable Energy Agency estimates around US$26t will need to be invested in low-carbon power generation by 2050.

This is a significant sum. Fortunately, the apparently insatiable appetite of large institutional investors for physical assets generating predictable yields suggests that the capital exists. The challenge is matching these massive pools of capital with the developers and utilities building out the clean energy systems we will need to address climate change. EY teams consider how a new twist on the yieldco model could help bring utilities and investors together.

Of course, one person's cost is someone else's revenue. The low-carbon transition presents a gigantic set of opportunities for electric transportation, renewable heating and cooling, a green hydrogen economy and an electric grid fit for distributed, digitized electricity supply and demand. EY teams also examine how the power and utilities sector can begin to grasp the opportunities presented by commitments to move to net-zero, and what obstacles need to be overcome for them to do so.

Dive into the RECAI in more depth and read the featured EY articles via the links below.

Featured articles:

- Index country rankings: China remains top, with the US and India completing the top three and Denmark climbs to number nine, its highest position since January 2005
- How net-zero emissions present the power sector opportunity – considering the opportunities and challenges facing the power and utilities sector from four major parts of the decarbonization jigsaw: electrifying transport; low-carbon heating and cooling; a clean hydrogen economy; and a smart transmission and distribution network
- How companies can fund the next wave of green generation – the decarbonization of utilities' power-generation fleet involves recycling large volumes of capital to invest in renewables projects. But as we explore different approaches, involving new financial structures could prove more efficient
- An in-depth look at the latest renewable energy developments in Germany and India, alongside seven other key country developments

Renewable Energy Country Attractiveness Index

recai

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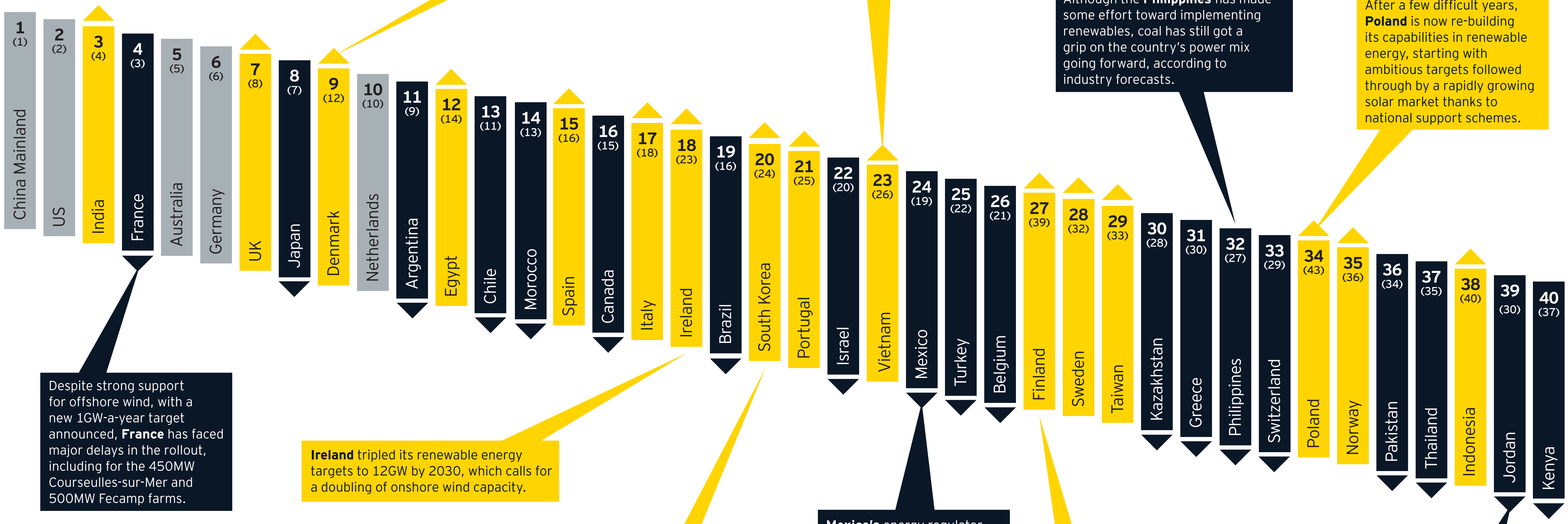
Methodology
The index was recalibrated in October 2019, with all underlying datasets fully refreshed. To see a description of the EY methodology, visit **ey.com/recai.**
A country's chart position in the previous index is shown in brackets.

LEGEND
- Increased attractiveness compared with previous index
- Decreased attractiveness compared with previous index
- No change in attractiveness since previous index



Denmark has improved its renewables market via investing in the latest technologies such as bifacial solar panels, as well as launching more offshore wind tenders.

An increasingly supportive political environment has meant **Vietnam** is making strides in renewables, with support mechanisms and greater access to the market unlocking potential, piquing investor interest.

Although the **Philippines** has made some effort toward implementing renewables, coal has still got a grip on the country's power mix going forward, according to industry forecasts.

After a few difficult years, **Poland** is now re-building its capabilities in renewable energy, starting with ambitious targets followed through by a rapidly growing solar market thanks to national support schemes.

Despite strong support for offshore wind, with a new 1GW-a-year target announced, **France** has faced major delays in the rollout, including for the 450MW Courseulles-sur-Mer and 500MW Fecamp farms.

Ireland tripled its renewable energy targets to 12GW by 2030, which calls for a doubling of onshore wind capacity.

Mexico's energy regulator Garcia Alcocer resigned over Government corruption claims, causing market uncertainty, in addition to a canceled auction.

South Korea is experiencing significant offshore wind activity, particularly with its national utility KEPCO looking into floating offshore wind.

Finland is benefiting from strong headwinds in the renewables sector, with a 10-year PPA signed by a global tech company, from what is due to be one of the largest unsubsidised wind farms in Europe.

Jordan's renewables market has been a shifting landscape, with the Government suspending renewables auctions earlier in the year and a lack of significant activity thereafter.

Net-zero emissions: the power sector opportunity

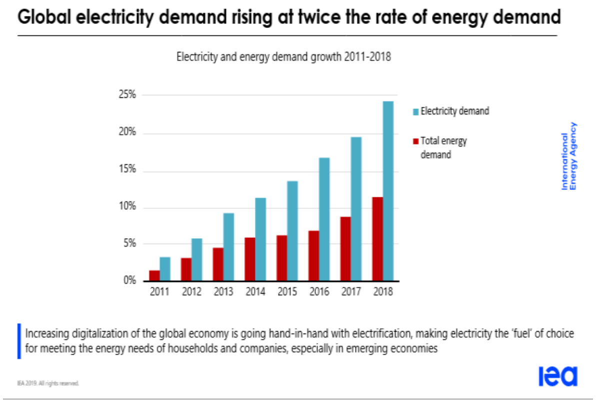
Meeting mid-century climate targets poses enormous challenges that touch on every part of the modern economy. But decarbonisation also offers a transformative opportunity for the power and utilities sector

Climate policy is beginning to catch up with climate science. Last year, the Intergovernmental Panel on Climate Change – set up by governments to help them understand the underlying science explaining climate change – warned that global emissions need to reach net-zero by mid-century if we are to have a reasonable chance of keep warming below the Paris Agreement's goal of 1.5C above pre-industrial levels. Current policies in place around the world would result in around 3.2°C of warming.

Roughly a year later, at the UN Secretary-General's Climate Action Summit in New York in September, Antonio Guterres announced that 77 countries had committed to net-zero carbon emissions by 2050. Some, such as the UK, France, Sweden and Norway, have introduced legislation to that effect. For others, the goal is currently aspirational.

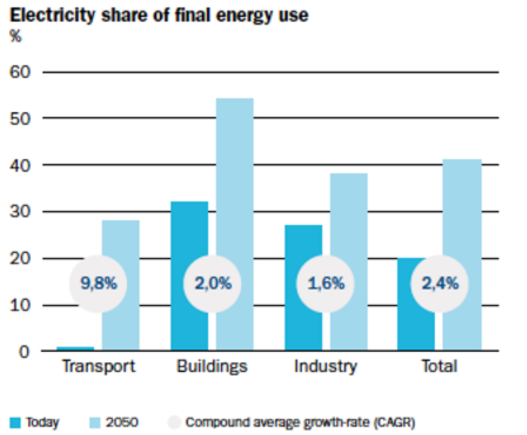
"Setting targets can be unhelpful, if they are insufficiently tangible," says Joseph Dutton, a policy advisor at E3G, a UK-based climate change thinktank, but the "net-zero policy has been helpful to give a point of focus for policymakers and industry, to pose the question of what we need to do, working backwards, in each sector."

Decarbonisation will require profound change in almost every part of the economy – and the power and utilities sector will play a central role in most (if not all) of these efforts. The electrification of the economy will create new demand for power companies – demand that will be increasingly met by zero-carbon renewable sources.



Norwegian power company Statkraft estimates that electricity demand will double by 2050, with its share of final energy use multiplying by 20 times in transport and growing by two-thirds in buildings and by 40% in industry.

According to Eurelectric's Decarbonisation Pathways report, under a scenario whereby the EU achieved 95% emissions reductions by 2050, electricity demand would be more than double – at 6,000TWh/year – 2015 levels.



Source: Statkraft

Indeed, the power sector has played the leading role in the first phase of the low-carbon transition, with most the emissions reductions achieved to date delivered by utilities switching from coal- to gas-fired generation, and by massive investment in renewable energy capacity.

But this process has only just begun. Deployment of key technologies, such as distributed energy resources, electric vehicles, demand response and energy storage systems, will only accelerate. Below, we consider the opportunities – and challenges – facing the power and utilities sector from four major parts of the decarbonisation jigsaw: electrifying transport; low-carbon heating and cooling; a clean hydrogen economy; and a smart transmission and distribution network.

Electrifying transportation

The transport sector is responsible for 27% of emissions in the EU, and 29% in the US. While the uptake of electric vehicles is accelerating, the vehicle fleet will need to become entirely decarbonised to meet net-zero commitments.

The opportunity

EY commissioned a study of 29 EV value pools to identify the eight most attractive opportunities for utilities. It found that the most important is electricity retail – the sale of electricity for EV charging, including electricity retail to commercial charging spaces, battery swapping stations and residential charge points.

The electrification of transport represents an enormous new source of power demand. According to International Energy Agency (IEA) data, electricity demand to serve EVs globally is projected to reach almost 640 terawatt-hours (TWh) in 2030 in its central New Policies Scenario, and 1,110 TWh in its more aggressive EV30@30 Scenario, which assumes 30% market share for EVs by 2030. The latter is more than three times total UK power consumption in 2018.

The second biggest value pool is public charging stations – turnkey solutions for installation of public EV charging stations, including site evaluation and selection of chargers as well as the operation and maintenance of charging station networks.

Electric vehicles – more specifically the batteries within them – also offer a partial solution to the problems caused by the supply of power from intermittent renewables. Smart grid infrastructure and dynamic time-of-use charging could help soak up surplus supply from renewables, and shave demand from peaks in consumption. In the future, as vehicle-to-grid (V2G) capability comes on line, millions of stationary EVs could be linked together to form a giant virtual power plant to meet peaks in demand, such as on a windless winter evening.

Developing EV infrastructure also provides direct opportunities for utilities. For example, SSE Enterprise, an arm of UK utility SSE, provides a range of solutions to support the electrification of vehicle fleets across the private and public sectors. "We construct, own, operate, maintain and optimise localised energy infrastructure" to support EVs, says Kevin Welstead, Sector Director Electric Vehicles, SSE Enterprise.

The challenge

The biggest challenge is ensuring that infrastructure is able to meet power anticipated power demand, which is likely to be concentrated at parts of the day, such as during existing evening peaks, when commuters arrive home. "It's an open question – will demand from the transport sector exacerbate current demand peaks?" asks Maria Bengtsson, a Director at EY in London. "We can't possibly afford to build out capacity to meet maximum possible demand."

There has also been limited progress in deploying the V2G technology that will allow grid operators to use electric vehicle batteries as a giant distributed source of power supply.

Paying for EV infrastructure also creates equity challenges, particularly during the early phase of the EV uptake. Should the investments needed by utilities and grid operators be shared among all electricity users – as they typically are now – or should those who benefit, the affluent early adopters, shoulder most of the costs?

What needs to happen

Electric cars are expected to become cheaper than their combustion engine equivalents by 2022, according to Bloomberg New Energy Finance. However, government incentives to reduce their costs can speed penetration: in Norway, which offers attractive tax breaks and road-toll discounts, nearly half of new cars sold in the country in the first six months of 2019 were electric.

Meanwhile, governments need to act to coordinate the roll-out of EV charging infrastructure, says SSE's Welstead, who notes that the involvement of different layers of government can complicate planning and regulatory approvals.

As electric vehicle penetration increases, there will need to be an education process to change behaviours and mindsets, says Bengtsson, to make car owners comfortable with a third-party drawing power from their battery. "It's putting control into someone else's hands – there needs to be a clear commercial case," she says.

More immediately, she adds that there is an urgent need to develop the technological tools, regulatory frameworks and business models to enable V2G power supply. She notes that many chargers currently being installed do not enable the two-way flow of power.

Heating and cooling

Buildings currently account for around 30% of global final energy consumption, according to the IEA, with more than half of that supplied by natural gas, coal or biomass. Electricity supplies about a quarter of the energy used in residential buildings. Current patterns of heating demand, in particular, are characterised by highly distributed sources of emissions – namely small-scale gas boilers – and, in colder countries, by high peak demand.

The opportunity

As with transportation, there is considerable potential to electrify heating. Ground or air-source heat pumps – which are three to four times more efficient than other types of space heating – could replace conventional heating.

As with electric vehicles, domestic heating systems offer enormous potential to act as a huge distributed energy storage system. Smart electric water heaters could be set to heat up during periods of high levels of renewable power generation, and to turn off at times of peak demand.

There is considerable potential for utilities to develop or expand products and services around energy management – home automation, smart tariffs, facility management and ancillary services, energy efficiency solutions, asset maintenance and building energy management systems.

District heating systems – using waste industrial heat, large-scale heat pumps, or sustainable biomass – also offer considerable potential to reduce emissions. For example, in Amsterdam, Swedish energy company Vattenfall is co-investing with the municipal government in Europe's largest heat network, adding 5,000 new connections each year.

Incumbents favour alternatives: substituting natural gas with carbon-neutral biogas or even with green hydrogen, but there, serious questions exist over the likely available supply of those alternatives, as well as the cost of the latter.

The challenge

Strong policy action is needed by government to mandate low-carbon heating and cooling in new-build properties, says Dutton at E3G. He notes that in the Netherlands, for example, since July 2018 new buildings are not allowed to be connected to the gas grid (unless an exception is sought), to promote lower-carbon alternatives.

For existing housing stock, particularly for older properties, aggressive action is needed on insulation, given that heat pumps work best in well-insulated homes. "There's no point trying to decarbonise heating without such action," says Richard Lowes, a research fellow and member of the Energy Policy Group at Exeter University, in the UK. He says that such

initiatives would need to be state-led and ensure that the skills existed to ensure that energy efficiency retrofitting is done properly.

More broadly, Lowes argues that decarbonising heating requires decisive policy interventions, including devolving responsibility to local authorities (alongside adequate financing), attractive incentives for building owners to replace gas boilers and, potentially, imposing a carbon tax on gas used for heating.

But there could be a private sector-driven offering that combines time-of-use electricity tariffs and upfront, third-party financing to allow homeowners to buy heat pumps. "It's possible to provide low-carbon heating at no additional cost to the consumer … there's a holy grail the private sector could get to," says Lowes.

District heating systems, meanwhile, need to be designed with flexibility in mind, says Stuart Allison, head of solutions at Vattenfall. "The engineering decisions being taken and the contracts that are being put in place today need to have the capacity built in to move to zero-carbon," he says. While the engineering solutions exist to build zero-carbon district heating systems, cost considerations mean that they may well initially operate on a low-carbon basis instead.

The hydrogen economy

As a (potentially low-carbon) fuel, hydrogen has a number of advantages. Like liquid fossil fuels, it has a high energy density, making it suitable to power vehicles, heat buildings and even fuel industrial processes such as steel production. It is non-toxic, abundant and, if produced using electrolysis powered with renewable electricity, or from natural gas using carbon capture and storage, emissions-free in production and use. On the other hand, it is highly flammable and needs to be stored and transported under pressure, adding to its costs.

The opportunity

Hydrogen offers the prospect of both helping to decarbonise the transport, heat and industrial sectors while also providing a use for surplus renewable power. The International Renewable Energy Association (IRENA) estimates that it could supply 6% of final energy consumption by 2050, while industry body the Hydrogen Council estimates this figure could be as high as 18%.

A number of pilot schemes to replace fossil fuel with hydrogen are underway:

- Swedish utility Vattenfall is working with Preem, a Swedish fuel refiner and supplier, on a pilot 20 MW hydrogen production plant, using water electrolysis using renewable power.

- Steel maker ArcelorMittal is working on a €65m demonstration project in Hamburg to replace coking coal with hydrogen produced using power from offshore wind farms.

- In the UK, Danish clean energy firm Ørsted is working with fuel cell company ITM Power and renewables development firm Element Power on a UK government-funded project to investigate the large-scale delivery of green hydrogen.

- In South Australia, the government has unveiled a Hydrogen Action Plan which sets out how the state could become a major producer and exporter of green hydrogen, based on a major expansion of its renewable energy capacity.

For utilities, hydrogen production could play a particularly important role in the seasonal storage of renewable electricity, IRENA argues, in scenarios with high renewables penetration (and, therefore, periodically large volumes of surplus capacity).

The challenge

The main challenge is the cost of green hydrogen, and the vast investments in infrastructure that will be required for its roll-out. Currently, green hydrogen is too expensive to economically produce for any but a handful of niche, high-value applications – although its costs are falling.

However, cost comparisons are only useful up to a point, says Tim Calver, an Associate Partner at EY. "The true value of hydrogen is as an energy vector to get green energy to end-consumers. It can have additional value in terms of enabling storage of intermittent power, and in providing a combustible gas rather than electrons."

What needs to happen

Critical to developing a hydrogen economy is reaching scale quickly, says Calver. "Governments need to support large-scale trials – that's the only way to tackle a number of challenges at once." Equally, attention should be focused on developing large-scale sources of demand first, such as industrial applications, rather than the use of hydrogen in heating.

Secondly, policymakers and regulators need to take a systems-wide approach. "This is about the convergence of power and gas as a means of driving deep decarbonisation," says Calver. "Ensuring joined up regulation between power and gas markets will be critical."

Grid infrastructure

A zero-carbon electricity system will need a substantially different grid: one that has shifted from large, centralised sources of generation to a distributed model, with hundreds of thousands of small-scale or micro renewables systems, and which has the flexibility to much more dynamically match supply and demand. Including by tapping large-scale storage capacity. Substantial investments at both the transmission or distribution levels will be required, not only in the physical wires but also in the IT needed to balance an increasingly complex and intermittent generation system.

The opportunity

For grid operators that are able to recover their costs, plus a margin, from regulators, this presents an opportunity for significant investment. For institutional investors, grid modernisation presents an opportunity to earn reliable, regulated returns.

"There's a massive amount of investment needed," says Calver at EY. "At the moment, we are seeing regulators drive a very hard bargain in terms of rates of return, which is obviously important from the point of view of the consumer. But you don't want to discourage grid operators from deploying capital."

"We're going to see the biggest changes at the edge of the grid, on the distribution side, to support high penetration of variable resources," says Juan Torres, Associate Laboratory Director, Energy Systems Integration at the National Renewable Energy Laboratory (NREL) in Golden, Colorado. "We have to install much smarter devices to manage grid variability."

"We do have an opportunity in the rapid advancement in terms of the technology available to manage the grid … moving into the age of artificial intelligence and Big Data, the owners of the grid are looking at how they can use those to make the grid more reliable," he adds.

The challenge

One particular challenge, says Kevin Schneider, Chief Engineer at the Pacific Northwest National Laboratory (PNNL), will be a how to compensate those utilities that operate distribution networks as behind-the-meter renewables generation undermines their revenues. "They will have to look for non-megawatt sources of revenue," he says, such as consulting services.

Schneider also notes that the communications capacity of a modernised grid will have to be an order of magnitude greater than what is currently required and will require grid operators to have considerably more control over third-party assets, such as batteries, and smart heating and cooling systems.

Schneider also adds that another often overlooked aspect is the workforce that will be required to operate an increasingly sophisticated electricity system. "It's going to be a really big cost. Look at a crew in a bucket-truck – 20 years ago, it was very blue collar. Today, it's a far more technically demanding job, requiring much more training."

What needs to happen

Calver at EY argues that the type of mechanisms that exist to manage supply and demand at the transmission level will need to be developed at the distribution level, enabling small-scale sources of generation and load to trade locally. "Using new, automated technology systems, commercial mechanisms and price signals need to be put in place to enable supply and demand to be balanced at the local level – that would help reduce the need to invest in transmission capacity."

Distributed system operators (DSOs) – responsible for connecting new capacity to the grid and improving system resilience through appropriate reinforcement – will be essential in enabling the energy transition and guaranteeing network stability. They must be enabled, through forward-looking regulation, smart technology, and greater interaction with customers, to tap flexibility mechanisms such as demand response and storage capacity. EY has worked with Eurelectric to provide guidance for DSOs, regulators and policy makers to inform the next generation of DSOs.

There are also less tangible changes needed, says Schneider at PNNL. For example, regulators and utilities and grid operators need to work closely together to forge a way forward, while regulatory bodies themselves need to improve their levels of technical understanding of the issues at play. "Regulators are not typically power system engineers: but they need to be able to find sources of trusted knowledge to ensure that what they propose is grounded."

Funding the next wave of green generation

The decarbonisation of utilities' power-generation fleet involves them recycling large volumes of capital to invest in renewables projects. But different approaches, involving new financial structures, could prove more efficient

The low-carbon transition is an enormously capital-intensive undertaking, particularly in the power-generation sector. Here, massive investment in wind and solar capacity is under way and, in contrast to gas or coal plants – which are cheaper to build but have relatively high operational costs – almost all the expenditure is upfront.

The sums involved are vast. To meet the International Energy Agency's Sustainable Development Scenario, investment in renewable power would have to double from the US$300bn committed in 2018 to an annual average of US$600bn, totalling around US$18.6tn by 2050. According to the International Renewable Energy Agency, the cost is even greater: US$26.4tn will need to be invested in renewable energy between 2016 and 2050 if we are to meet the goals of the Paris Agreement on climate change.

Traditionally, utilities raise equity or debt capital at the corporate level, which they then invest in capital projects and use for other corporate functions, such as sales and marketing, trading, and so on. To raise the large volumes of capital needed to invest in renewables projects, they have adopted the practice of recycling capital: developing and derisking renewable energy projects before bringing in long-term, low-cost capital from institutional investors – such as insurance companies or pension funds – as minority partners.

The growing volume of renewable energy projects on utility balance sheets, however, risks putting pressure on their credit ratings, while selling minority stakes on a project-by-project basis can be inefficient and costly for utilities and investors.

"Renewables projects, particularly offshore wind farms, are becoming truly industrial in scale, creating an increasing urgency to find new sources and structures for raising capital efficiently and effectively," says Ben Warren, a partner at EY in London.

"Utilities have traditionally approached this on a very transactional, project-by-project or portfolio-by-portfolio basis. There are more strategic and sustainable ways of doing this."

The current model – and its challenges

Spanish utility and developer Iberdrola illustrates the scale of the challenge. It plans to invest €13bn (US$2.1bn) in renewable energy by 2022, and its £1.63bn (US$14.6bn) sale of 40% of its 714MW East Anglia offshore project to Macquarie's Green Investment Group is just the latest example of how it is bringing in long-term investment to enable it to recycle its own capital.

There are disadvantages to this approach, however. Each of these transactions results in millions of euros being spent on costs – for the utility and the investors they bring into each deal. They place a burden on utilities in terms of managing multiple shareholder relationships and, because the assets very often remain on their balance sheets, there is an increasing strain on credit ratings and demand for capital elsewhere in the group.

The process is inefficient for institutional investors, too. Some big pension funds are developing the capacity in-house to make and manage infrastructure investments, including in renewable energy. For most, exposure to this asset class is obtained through third-party infrastructure funds, introducing a layer of cost.

Alternatively, they can invest directly in the equity or debt of the utility itself, but that brings with it other risks – namely, an exposure to other elements of the utility business model, such as retail marketing operations, legacy fossil-fuel assets, or efforts to diversify into new markets, such as energy services or electric vehicles.

Brendon Moran, Senior Banker for Energy & Utilities at French bank Société Générale (Socgen), notes that the utilities sector is at a crossroads with respect to the energy transition and needs to adapt its approach.

"Incumbent utilities are faced with an urgent need to be as agile as possible. The energy transition is demanding they compete across a much wider range of often contending pressures – a changing energy mix towards renewables, the rapid change in mobility and the rise of electric vehicles, and the need for innovation in energy efficiency. Focusing on their strengths and partnering with others in new ways will demand a break from the past approach of doing it all."

Moran adds: "Some utilities are now recognising that it may not make sense to pursue the old models of vertical integration but, instead, to segment their business and focus on what they do best."

Rethinking the yieldco

An alternative approach to raising the finance that utilities will need to build out their renewables portfolio could be found in the yieldco model. First developed in the UK, it involves creating a publicly listed entity, run by a fund manager, that would invest in a number of typically small-scale renewable energy projects, which – at the time – enjoyed guaranteed revenues through feed-in tariffs or similar subsidies.

"It's a relatively simple model … and a very efficient one," says James Armstrong, Managing Partner at Bluefield Partners, which listed one of the first yieldcos, the Bluefield Solar Income Fund, which had a net asset value of £436mn (US$561.7mn) as of June 2019. Yieldcos such as Bluefield pay dividends to investors, promising stable, long-term returns.

A more aggressive version of the model was adopted in the US, however, with less positive results. Developers such as SunEdison used yieldcos to raise large volumes of debt and fund aggressive expansion strategies. Their returns were based on aggressive capital growth as well as the yields generated by projects, and initially performed strongly.

According to data from Bloomberg, around $8bn was channelled into yieldcos in 2015, at the height of their popularity. Rising share prices – providing capital growth in addition to dividend yields – fuelled investor enthusiasm for the structure.

This flood of capital depressed investor expectations of future growth, however, while their returns proved to be more correlated with oil prices than expected. Inflows became outflows, leading to some high-profile failures – of pioneer SunEdison and Spanish construction firm Abengoa's US arm – both brought down in 2015 by aggressive debt-fuelled growth enabled by yieldcos.

Why private yieldcos would work

While these losses dented investor demand for yieldcos, the structure is coming back into favour. In September 2019, Goldman Sachs announced that it has raised US$1.9bn into Goldman Sachs Renewable Power LLC, a private yieldco, while, in January 2019, Investec became a cornerstone investor in an Africa-focus yieldco, Revego Africa Energy, alongside the UK government-funded UK Climate Investments, managed by Macquarie's Green Investment Group.

Warren, at EY, suggests that a reinvention of the yieldco could offer a more efficient means for utilities to hive off and fund renewable energy assets. "An evolution of the yieldco structure could provide a route to long-dated capital that is cost-effective and enables them to grow their asset base uninhibited by their balance sheets," he says.

The way the model works, basically, is that the utility would develop renewables projects and, once they are derisked sufficiently, sell them to an arms-length private yieldco, probably majority owned by a third-party investor or investors. The utility would maintain an ownership stake in the yieldco and provide asset management and operational services to the vehicle, creating an alignment of interest between the investors and the utility as the promoter. The projects themselves may well enter into PPAs with the utility promoter.

Moran, at Socgen, notes that such an approach is essentially mirroring what already happens in oil and gas. There, the large incumbents, such as the oil majors, partner with more agile, upstream exploration and production companies, engineering firms, and other parties such as governments. The oil majors bring balance-sheet strength and, most importantly, offtake demand for the oil produced.

"It plays to the strengths of utilities to be asset operators, offtakers and traders, but not necessarily asset owners," says Warren. These vehicles effectively provide a "shadow balance sheet" to which utilities could transfer assets and protect their credit ratings, while offering efficient, sustainable and replicable investment platforms.

For institutional investors, such vehicles give them exposure directly to the infrastructure that utility companies own, rather than also investing in corporate equity or debt and taking other business risks.

By giving investors the opportunity to isolate one part of the existing utility business model, such yieldcos could help incumbents and their investors navigate the low-carbon transition. "There is a debate going on among the big utilities as to whether they want to be generators or operators, and how to best use their capital in what is a very fast-moving transition," notes Armstrong, at Bluefield. "Every single participant is re-evaluating how they engage with the market, and all financing options need to be on the table."

Pros and cons

The proposal, however, is not without its drawbacks, believes Marc Groves-Raines, Head of Renewable Energy for Allianz Capital Partners, one of Allianz Group's asset managers for alternative equity investments, which owns €4.3bn (US$4.78bn) of renewable energy equity assets. "I can see the theory, but there may be issues in applying it in practice," he says.

One such issue would be questions over transfer pricing, the value ascribed to a renewable energy asset when it is sold by the utility to the yieldco. "Utilities will want to sell their assets at market value, which is why they are running the strategy they are doing now – that is, targeted competitive processes," says Groves-Raines. "They want to maximise the value they can squeeze out of the projects, to recycle capital while retaining operational control."

"Investors would want reasonable scrutiny of how their money is invested and, if you're simply putting it into a yieldco, that could dilute that scrutiny," he adds.

"As an investor, you're one step further removed from the project. You're purely reliant on the dividends coming through, and you have very little broader control or security – it's more akin to a pure, subordinated hold-co financing," says Stephen Jennings, Head of Energy and Natural Resources for EMEA at Japanese financial services group Mitsubishi UFJ Financial Group (MUFG). "It might suit some investors, but not others. Some institutional investors might struggle with their internal ratings models on that basis, whereas they might find it easier lending directly to a sponsor, albeit as very much a minority interest."

Ultimately, it's likely that a thousand flowers will bloom when it comes to financing models. "Given the size and scale of investment, many different forms of financing are going to be required, particularly as we move to an environment where there's less subsidy support," says Jennings. "The credit profile of transactions will change [and] investment-grade ratings are going to be less achievable. The market will have to be more innovative to react to the volumes we're likely to see coming through and find new ways of churning capital to allow investors and banks to reinvest in new projects."

"With such an enormous need for capital for renewables projects, numerous investment models will emerge and evolve over time," says Warren, at EY. "Of course, the question of what structures to employ and where to source the capital will always be pertinent, and these are not without complexity." For example, the risk inherent in a particular structure, the depth of liquidity for a certain pool of capital, and the pricing of that capital will have a huge impact on the value of an asset.

"In addition, factors such as commercial, legal and tax structuring, accounting treatment, and the impact of credit ratings and currencies, to name a few, all have a critical part to play," he adds. "There is plenty for utilities and investors to consider, not least in an unsubsidised future, where calculating the very value of a kilowatt hour is becoming increasingly complex."

As wind dips in Germany, solar shines

Germany's federal climate and renewable energy policy is meeting headwinds from local resistance to onshore wind and new transmission infrastructure – but solar power, the emerging hydrogen economy and e-mobility offer bright spots.

In November, Germany's Bundestag – its lower house of parliament – passed the Government's long-awaited Climate Protection Package 2030. The legislation is intended to kick-start stalled progress towards Germany's goal of reducing emissions to 55% of 1990 levels by 2030; the Government has admitted it will only reduce emissions by 32% by 2020, not 40% as targeted.

Among other things, the suite of planned policies – expected to pass the upper house later this year – will: raise the country's 2030 renewable electricity target to 65% of power supplied, up from around 47% at present; scrap a planned 52GW cap on solar subsidies; and introduce a carbon price for the heating and transport sector.

However, disappointing on- and offshore wind rollout, and a 'distance rule' restricting onshore wind farms, have depressed a renewables sector that has been struggling with poor auction results and a lack of long-distance transmission capacity.

In onshore wind, the switch from a highly successful feed-in tariff system to auctions has stalled the sector. By July 2019, almost 29,250 onshore turbines, with a total capacity of more than 53GW, were in operation across the country – with 5.3GW installed in 2017 alone. Expansion slowed to 2.4GW in 2018, however, and 2019 has seen the lowest level of capacity additions in 20 years.

Under new rules, just 2.8GW per year were tendered for onshore wind from 2017 to 2019, rising to 2.9GW from 2020. However, the six latest auctions were undersubscribed, with just 204MW of successful bids for 675MW of capacity – bid at the ceiling price of €62/MWh – at the last auction in October.

This low utilisation of the bid capacity was a function of currently low yields on invested capital and delayed permitting processes, affecting around 11GW of capacity as of mid-2019 – partly because of increasing objections from wind opponents, with even repowering projects struggling to win permits. An additional factor is Germany restricting development in regions where there are grid bottlenecks – notably the north of the country – to 58% of the average of the past three years.

This follows a drop in installed capacity in 2019, caused by a change in policy to favour community projects, many of which have struggled to move into development. That preference for community projects was reversed by the Government in an amendment to the country's renewable energy law at the start of 2019.

The benefits of this reform, however, are likely to be offset by the proposed distance rule, which requires a minimum of 1km between new wind farms and settlements. This could reduce the land area available for onshore wind by between 20% and 50%, according to Umweltbundesamt (UBA), Germany's environment agency.

Offshore, the climate package would increase the 2030 wind target to 20GW, from 15GW, compared with 6.7GW at present. However, this target is dependent on agreement with transmission system operators, who have been struggling to overcome local opposition to new high-voltage lines to carry power from the North Sea to demand centres in southern Germany.

One possible medium-term solution to the transmission problem could be the use of surplus power for producing hydrogen or methane in plants close to the offshore wind farms, effectively 'storing' excess generation. Among other initiatives, the HYPOS Consortium is undertaking a two-year R&D project to explore the technical feasibility of storing hydrogen in underground caverns, a large number of which The picture for solar is considerably sunnier. In the auction in October, 648MW of bids were tendered for 150MW of capacity, with contracts awarded at an average price of €45.90/MWh, compared with €54.70/MWh at the last auction.

In addition, subsidy-free projects are coming forward, such as EnBW's 180MW array in Brandenburg, which will be Germany's largest solar farm. On the demand side, large industrials are increasingly entering into corporate power purchase agreements (PPAs). Mercedes-Benz has signed Germany's first such PPA as part of its plans to supply all of its plants in the country with carbon-neutral energy by 2022. The carmaker will buy wind power, from 46MW of wind-power capacity, from six wind farms in Lower Saxony and Bremen.

Improvements in solar technology also promise to boost installation. As systems become lighter, retailers are showing greater interest in installing rooftop systems. They are also eyeing the installation of electric vehicle charging stations, in a bid to encourage shoppers to stay longer and spend more.

Germany's climate strategy is aiming for 7-10 million electric vehicles by the end of 2030. This is to be delivered through an exemption from car tax until 2030 and an additional €6,000 bonus for each new electric vehicle bought. Company electric cars will also be subject to lower rates of tax. In addition, the Government is to address the current lack of charging stations, with plans for one million to be installed by 2030.

More generally, the combination of distributed solar and electric vehicles could support higher renewable penetration in Germany by bringing supply and demand closer together without triggering local opposition to wind farms or transmission lines. Reform to grid charging could also help in this regard, if some of the costs of transmitting electricity were passed on to generators, thereby incentivising local storage. are located in northern Germany.

India: developers face challenges as a giant awakes

India's Prime Minister, Narendra Modi, claimed one of the most high-profile announcements at the UN Climate Action Summit in September, with a commitment to increase his country's renewable energy capacity to 450GW – a significant increase on the existing 2022 target of 175GW of new renewables.

However, for all the positive momentum created by the new goal – for which the Government has yet to specify a timeframe – the focus for the renewables sector is on the existing 2022 target. There continue to be challenges in getting capacity installed, which the Government is trying to help overcome.

As of the end of last year, India had installed 128GW of renewables, of which onshore wind made up 37GW, solar 31GW and hydropower 50GW. Biomass and waste-to-energy made up the remaining 10GW.

Its 2022 target – which comprises a goal of 100GW of solar, 60GW of wind, 10GW of biomass and 5GW of small-scale hydro – makes India one of the most compelling renewables markets globally in terms of size. Even before Modi's announcement in New York, the Indian Government estimated the sector's investment needs to be around US$30bn/year over the next five years.

For all its potential, however, policy challenges are deterring investment and imperilling the Government's goals. CRISIL, an India-based credit-rating agency owned by S&P Global, has forecast that the sector will install just 58% of the 175GW target, which does not include hydro, by 2022.

It cites policy changes, overly aggressive lowering of the tariff caps set in renewable energy auctions and foot-dragging by state power distribution companies (discoms) once developers have successfully bid into auctions.

For example, the shift in the wind sector from fixed feed-in tariffs to competitive auctions means that few bids are being received from developers. Equipment manufacturers have made representations to the Government, but it is unlikely to change its decision to move to competitive bidding.

In Andhra Pradesh, one of the leading states for renewables development, the state is attempting to renegotiate power purchase agreements (PPAs), resulting in disputes with developers and leading discoms to delay payments to operating projects. The Ministry of New and Renewable Energy is strongly opposed to any changes in signed PPAs, however, so it remains to be seen if such a step will be taken.

In solar, ground-mounted systems are expected to provide 60GW of the 100GW target. Here, developers are under pressure from squeezed margins from reverse auctions, tariffs on imported systems, and rising financing costs. As of the end of September, about 29GW of ground-mounted solar had been installed. Similarly, roof-top solar uptake has a long way to go; by the same date, only 2.2GW was operational.

However, the Government – which hit back at the CRISIL report, claiming it doesn't take into account projects under development or in the bidding process – is acting to relieve some of these pressures. For example, land acquisition has been a challenge for developers, but the Government has stepped in to provide sites in recent tenders. It is also working to provide transmission capacity for sites that are distant to demand centres, which should ease pressure on potential bidders. In addition, it has encouraged discoms to begin giving letters of credit to power generato

On roof-top solar, the Government is responding by incentivising distribution companies, offering them subsidies for speeding up connections, while the Kerala State Electricity Board – the local discom – has launched a programme to install 500MW of rooftop solar. In addition, the World Bank and the Asian Development Bank are offering discounted lending to installers of rooftop solar, to help reduce financing barriers.

While the onshore wind sector is stalled – and likely to remain so until cost reductions allow bids to meet the expectations of central and local governments in India – the country is pressing ahead with offshore plans. A 1GW tender is due to be launched before the end of this year, as part of the country's goal of installing 5GW by 2022 and 30GW by 2030. The Government is reportedly planning to offer around US$900m of funding to bridge the gap between prevailing domestic power prices and the likely cost of offshore wind, but it is an open question as to how much offshore wind capacity will be possible in the near term in such a cost-sensitive market as India.

Large-scale hydro, however, presents opportunities. Earlier this year, the Government ruled that hydro plants greater than 25MW would qualify as green, allowing them to access cheaper finance and opening the door to a hydro obligation on utilities, which would require them to obtain a proportion of their supply from hydroelectric sources. The country has significant untapped hydro potential in the Himalayas, which the Government's growing willingness to provide transmission capacity promises to unlock.

Unquestionably, the Indian renewable energy market faces some challenges, many of which lie within the power of central and local governments to address. Nonetheless, the size of the market, and the Government's clear ambition to place renewables at the heart of its energy policy over the coming decades, make it impossible to ignore for renewable energy investors and developers alike.

Putting a cost on the low-carbon transition is enormously challenging, and open to enormous dispute. Earlier this year, then-UK Chancellor Philip Hammond estimated the cost to the UK would be £1t (US$1.3t) by 2050 – and was roundly attacked for looking only at the costs and ignoring the benefits.

In the US, on the other hand, Alexandria Ocasio-Cortez, the left-wing Congresswoman promoting a Green New Deal designed to tackle climate change and reduce inequality, has said it will cost at least US$10t. Its critics put the price tag at US$93t.

There are, however, parts of the low-carbon jigsaw that are easier to cost, namely the decarbonisation of the world's electricity systems. To meet the goals of the Paris Agreement on climate change, the International Renewable Energy Agency estimates around US$26t will need to be invested in low-carbon power generation by 2050.

This is a significant sum. Fortunately, the apparently insatiable appetite of large institutional investors for physical assets generating predictable yields suggests that the capital exists. The challenge is matching these massive pools of capital with the developers and utilities building out the clean energy systems we will need to address climate change. In our latest edition, we consider how a new twist on the yieldco model could help bring utilities and investors together.

Of course, one person's cost is someone else's revenue. The low-carbon transition presents a gigantic set of opportunities for electric transportation, renewable heating and cooling, a green hydrogen economy and an electric grid fit for distributed, digitalised electricity supply and demand. We also examine how the power and utilities sector can begin to grasp the opportunities presented by commitments to move to net-zero, and what obstacles need to be overcome for them to do so.

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Key country developments

Australian renewables advance, despite federal indifference

The Australian renewable energy sector has shrugged off the re-election in May of a climate-sceptic and coal-friendly federal government, with renewable energy growing three times faster, on a per capita basis, than the next fastest country, according to analysis by the Australian National University (ANU).

The country is set to install 16GW of wind and solar over 2018-20, at a rate that is 10 times the global average, driven by the low power prices renewables can deliver compared with wholesale rates – less than A$27/MWh (US$31/MWh), compared with average long-term prices of A$58/MWh, ANU says – and state government programmes to support renewables

For example, the state government of South Australia has said it has 10GW of large-scale wind and solar projects in the pipeline, which means the state is set to be 100% powered by renewable energy by 2030

A number of large-scale projects are underway elsewhere, with the Western Australia solar and wind complex targeting 15GW of capacity, to supply the Pilbara region and Singapore through an undersea cable.

Australia's first offshore wind farm, the 2.2GW Star of the South project, is also advancing, with the launch of a study to assess whether the Australian power market has the capacity and expertise to deliver the project. The project, backed by Copenhagen Infrastructure Partners and to be built off Victoria, would be the southern hemisphere's first offshore wind farm.

French renewables advance onshore and off

France is to open 2GW of solar tenders and has confirmed plans to increase its annual target to 1GW for offshore wind.

The solar tenders will be split into three independent rounds, one for rooftop and two for ground-mounted installations. The first ground-mounted tender, expected to be for 845MW of capacity, will be opened in January, followed by a 1GW round in July 2020. A 300MW rooftop auction is to be held in February 2021.

This follows the award of 858MW to 107 planned projects in France's latest solar auction, in March. The average tariff paid was €67.5/MWh (US$75.3/MWh) for projects between 500kW and 5MW, although larger projects will be paid a slightly lower tariff, of €59.5/MWh. The average price, of €64MW, was around 2% higher than the previous round.

Looking to the offshore market, the French government has confirmed plans to increase the country's offshore target to 1GW a year, up from around 750MW. According to estimates from the WindEurope trade association, that would likely translate into 6.5GW of offshore wind power being installed by 2028, equivalent to around 6% of French electricity consumption.

Meanwhile, prices also rose slightly in the country's latest onshore wind energy tender, the results of which were announced in October. Bidders will be paid an average of €66.50/MWh (US$74.2/MWh) for 567MW of onshore wind capacity, across 20 projects. This compares with €63/MWh bid for 516MW of capacity in June, in the third tender.

US offshore market takes to the seas

Federal regulators have granted the first permits for a US offshore wind farm, with the approval of a pilot project off Virginia under development by Dominion Energy and Ørsted. The move comes as a flurry of tender announcements and project procurements heralds an acceleration of offshore activity in the US.

The 12MW pilot, consisting of two turbines, is the first to receive approval from the Bureau of Ocean Energy Management to operate in federal waters. It is the first stage of a planned 2.6GW project, which Dominion hopes to build in 2024-26. The 30MW Block Island wind farm has been operating off Rhode Island since 2016, but it is not under federal jurisdiction.

The news follows Connecticut's first tender for offshore wind, for up to 2GW of capacity. Bids were due to be submitted by the end of September 2019. The state's Department of Energy & Environment said it expects to select a preferred bidder in November.

In July, New York State Governor Andrew Cuomo's signed the Climate Leadership and Community Protection Act, which sets an offshore wind target of 9GW capacity by 2035. In the same month, New York announced the winners of its first offshore tender: Ørsted and Eversource successfully bid their 880MW Sunrise Wind project, and Equinor its 816MW Empire Wind complex.

In June, Ørsted was successful in New Jersey's first offshore wind tender, with its 1.1GW Ocean Wind project, which is set to be the largest in the country when it is commissioned in 2024. New Jersey has a target of 3GW of offshore wind by 2030.

There are now 15 active commercial leases for offshore wind in the US, totalling 25GW of capacity, according the American Wind Energy Association.

UK offshore wind auction promises subsidy-free power

Winning bidders in the UK's latest auction of renewable energy Contracts for Difference (CfD) have bid to supply power from wind farms for less than the forecast wholesale power price, promising to deliver offshore wind without subsidy.

The government is to enter into 15-year CfDs with 12 projects, totalling 5.8GW of new capacity, of which six are offshore, four are remote-island onshore wind projects, and two advanced conversion technology projects (using biomass gasification or pyrolysis technology). The offshore wind projects made up 5.47GW of the capacity involved.

The auction cleared at a strike price of £39.65/MWh (US$51.13/MWh) for projects that will come on line in 2023/24, and £41.61/MWh (US$53.66/MWh) for those becoming operational the following year. These prices – which are in 2011-12 money, as per the auction terms – are around 30% below the last comparable auction, in 2017.

The government will pay the projects the difference between the CfD strike price and the wholesale market price, if the latter dips below the strike price. The government has forecast market prices of between £48.13/MWh and £51.23/MWh over that period, meaning that it doesn't anticipate paying the projects – and that the auction cleared without the government committing any of the £65m worth of subsidy available in this CfD round.

However, that round is subject to an ongoing legal challenge, by onshore wind developer Banks Group, which argues that the auction rules discriminate against onshore wind projects.

Meanwhile, the UK was subject to a major black-out on 9 August, when more than 1 million customers lost power following two almost simultaneous power plant outages: at the Little Barford gas-fired power plant, followed minutes later by the Hornsea offshore wind farm.

While some commentators initially pointed the finger at the growth of renewable energy in making the grid less stable, National Grid's initial report blamed a lightning strike, and its CEO John Pettigrew has specifically discounted growing volumes of renewables on the system as a cause of the blackout.

Vietnam sees solar rush as FiT expires

More than 5GW of solar power plants are expected to be connected to the Vietnamese power grid this year, as developers rushed to secure an attractive feed-in tariff (FiT) rate before its expiry on 30 June. A new, 20% lower FiT rate for ground-mounted and floating solar has been submitted by the country's Ministry of Industry and Trade, which is expected to run to the end of 2021.

As of April this year, Vietnam boasted just 150MW of solar; however, a FiT rate of US$93.5/MWh triggered a rush of investment, leading to 4.46GW being connected to the grid by the end of June. Another 13 solar plants, with a combined capacity of 630MW, are scheduled to be connected.

Under the latest proposals, the FiT for rooftop solar would be maintained at the current level, but ground-mounted and floating solar would be cut to US$70.9/MWh and US$76.9/MWh, respectively.

The government had proposed a new regime that would divide the country into four regions, with differential FiTs depending on the levels of solar irradiation. However, the latest draft applies the same tariff to the entire country.

Electricity demand is rising fast in Vietnam; it needs to add 3.5-4GW of new capacity each year to meet annual demand growth of around 10%.

China renewables investment tanks

Clean energy investment in China slumped 39% in the first half of this year compared with the same period in 2018, according to figures from Bloomberg New Energy Finance (BNEF).

In the first six months of 2019, US$28.8bn was invested in renewables in China, the lowest six-monthly figure since 2013. However, Bloomberg's analysts said the full-year decline is not likely to be so steep, with some recovery expected in the second half.

Investment in Europe and the US also fell, by 4% to US$22.2bn and 6% to US$23.6bn respectively. Globally, US$117.6bn was committed to new renewables capacity, down 14% year-on-year.

The fall-off in investment in China was triggered by the shift from feed-in tariffs to auctions for new wind and solar capacity. However, a nationwide solar auction in the second half of 2019 is expected to lead to a rush of new financings, BNEF said, noting that several large offshore wind deals are also expected.

Elsewhere, the Japanese and Indian markets were both up, by 3% to US$8.7bn and 10% to US$5.9bn, respectively. Investment in renewables in Spain, meanwhile, jumped 235% to US$3.7bn

Portugal snags rock-bottom solar prices

Developers in Portugal have bid record low prices for new solar capacity, with contracts awarded at an average of €14.80/MWh (US$16.51/MWh) for 1.4GW of projects.

The tender involved 862MW of capacity awarded via 15-year power purchase agreements (PPAs) signed with the government, and 288MW which qualified under a variable tariff scheme that enables merchant projects. An additional 250MW was unawarded.

Big winners were French renewables developer Akuo Energy, winning 370MW of capacity, and Spanish utility Iberdrola, which successfully bid four projects totalling around 150MW.

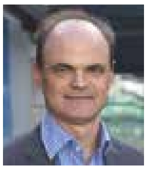
Portuguese developers Prodigy Orbit won 50MW of capacity over four projects, Days of Luck bid in a 110MW plant, and Prosolia Portugal was awarded a contract for a 29MW project. Among other winners, Everstream Energy Management Capital successfully bid a 50MW project, German developer Enerparc bid a 18MW solar park, and Spain-based solar developer Enerland was awarded 15MW.

The price achieved broke the €17.50/MWh record set in Brazil's A-4 renewables auction in June 2018.

However, there are some serious questions as to whether the Portuguese projects will be deliverable. Tender documents initially indicated that the prices paid through the PPAs would be indexed to inflation; however, that reference was removed, and not all developers may have noticed the change, according to observers.

Winning projects have three years to become operational.

Contact the RECAI team



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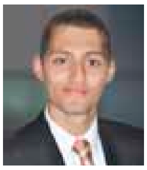

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