Global Nuclear

Nuclear for a decarbonized future

Nuclear's high load factors and reliability could make achieving net-zero affordable. Nuclear is safer than commonly assumed, and new technology and further research could make it even cleaner, safer and cheaper. This could pave the way for a greater contribution to the global energy transition.

As we transition to net-zero-carbon energy usage, we think a robust discussion on nuclear is timely. All of our upcoming work on this topic can be found in #nuclearfuture on Barclays Live.

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Nuclear is net zero: Nuclear energy – like solar, wind, geothermal and hydroelectric – generates no direct carbon or GHG emissions, and has one of the lowest life-cycle carbon emission rates of all generation technologies, when accounting for indirect emissions associated with the mining of fuel and plant construction. We believe nuclear could form the base load generation necessary to enable the safe, reliable, affordable decarbonized grid ESG investors are pushing for.

Nuclear can be affordable: Nuclear has a reliability factor of 80-90% (with many plants above 90%), compared with wind at 30-40% and solar at 10-25%. Along with its long plant life, nuclear works out comparatively affordable, especially when factoring in storage costs required for renewables. Nuclear's high capital costs could come down if its life were extended or more plants were built, allowing for construction experience to shorten construction time and costs.

Nuclear is becoming safer with new technology: The disasters at Chernobyl and Fukushima caused numerous deaths through sickness and displacement, but both incidents prompted wholesale upgrades to fleets and structural reforms to safety systems. Data from Energy Central show that nuclear has the lowest mortality rate of all types of power generation, in terms of deaths per terawatt-hour. New technology aimed at protecting reactor cores using the laws of physics (as opposed to power) should create even safer solutions.

Nuclear waste is small on a comparative basis: Annual nuclear waste generation is significantly less than the expected volumetric annual waste from retired solar panels, wind turbine blades and lithium ion batteries (including in electric vehicles). Recycling or reprocessing fuel in the case of nuclear could reduce waste by up to 97%, which is more efficient than solar panels, wind turbine blades or lithium ion batteries.

Nuclear power still divides investor opinion: Significant regional differences are evident regarding how nuclear power is viewed from an ESG perspective. The EU has not yet formed its official view, but when this comes it may provide additional clarity on the role of nuclear in the green transition.

Nuclear could contribute more towards net zero

The energy sector will be key to the decarbonization debate as it generates about 35Gt of CO2 emissions annually relating to power, heating and transport. This means that to make net zero carbon a reality by 2050 the world's energy mix will have to transform at its fastest pace in a century. Consequently, there will be a major shift away from fossil fuels to zero carbon emitting generation sources.

The Barclays Energy Research Team examined this transformation in Global Energy: Opportunities in decarbonisation (9 March 2021) (see also the section Insights from our decarbonization report below), in which the team highlighted that one of the most important strategies to reach ambitious decarbonization targets is to shift the global generation mix towards a significantly higher share of generation that does not emit CO2. These sources can include, wind, solar photovoltaic (PV) , hydro and also nuclear.

Working to the scenarios established in the March report, Figure 1 shows the required significant increase in renewables secondary energy even in the most conservative decarbonization scenario. In our Dynamism mix 2050 scenario, which assumes that the IPCC ambition of limiting the global temperature increase to 1.5 degrees above pre-industrial levels is reached, the world would need to increase its secondary renewables energy demand nearly 25-fold. However, this assumes that nuclear (and hydro) secondary energy demand only sees a marginal increase.

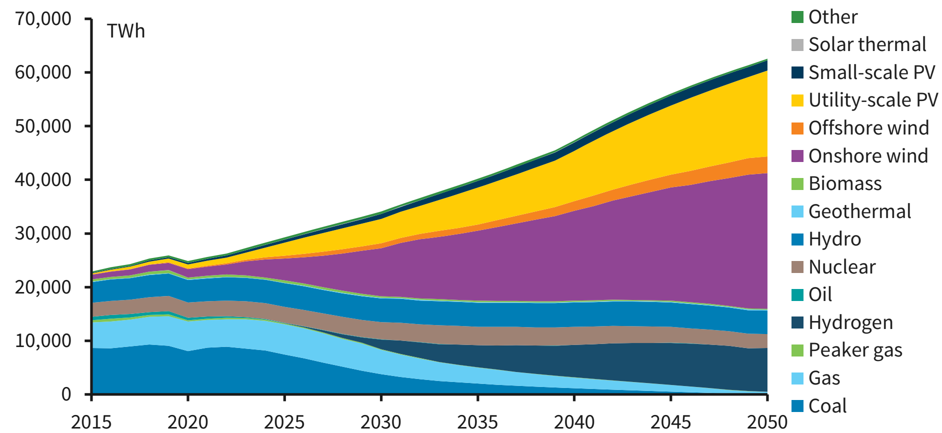
FIGURE 1. Even in more conservative decarbonization scenarios the requirement for renewables generation build is significant

Secondary energy demand (TWh)	Renewables	Nuclear
Energy mix 2019	3015	2657
Dynamism mix 2050	74250	2769
Development mix 2050	52481	2769
Deadlock mix 2050	36297	2769

Source: bp Statistical Review, Total Energy Outlook, IEA, Barclays Research

Our scenarios are matched by the assessments of other important energy market participants. For example, in Figure 2 Bloomberg New Energy Finance (BNEF), projects a similar significant rise in the output from solar and wind generation capacity until 2050, in contrast to the very slim rise for nuclear. This is based on their Net Zero 2050 scenario.

FIGURE 2. Renewable electricity generation output is set to increase significantly to hit net zero 2050 targets



Source: BNEF

We believe that the current view of investors is that almost the entire gap of required carbon free generation output until 2050 will be met by building more renewables capacity. Nuclear energy, even though still a key part of the global generation mix, is not expected to see an increase in installed capacity.This is partially because of a view that while some countries could add net generation capacity to their power markets such as China and the US, others, such as Germany or Spain, want to exit nuclear altogether. We believe that this is an overly simplistic assessment.

Given the scale of the challenge to transform the global generation mix, it is likely that nuclear will have to play a more important role in certain power markets, especially where there is clear and adequate government support. We believe such a potential in increase in nuclear build would be driven by three factors:

1. Higher load factors[1], implying lower capacity build requirement, particularly against renewables.
2. Higher reliability, reducing the need for battery storage.
3. Affordability, particularly so with new technology.

[1] Load factor, also called capacity factor, for a given period, is the ratio of the energy which the power reactor unit has produced over that period divided by the energy it would have produced at its reference power capacity over that period. (From PRIS)

Higher load factors

As illustrated in Figure 3, an important aspect that is sometimes not taken in account is that based on the superior average 90% load factor of nuclear, there is lower implied capacity build requirement than for renewables to close the CO2 free generation gap to reach net zero targets. Assuming an average blended 25% load factor for renewables (solar, onshore and offshore wind) in order to close the CO2 free generation gap you have to build more than 3.5x the amount of renewables than for nuclear. Based on our analysis you would need 9,030 GW of additional nuclear generation capacity by 2050 in our Dynamism scenario if you were to close the CO2 free generation capacity with nuclear alone compared with 32,579 GW if you would do it with renewables alone. Although we do not see it as realistic that you would get a new nuclear build on this scale, the current implied assumption that there will be no net addition of nuclear capacity in the world in the next 30 years is overly simplistic, in our view. This is enforced by the fact that many countries do not have the ability to derive most of their generation output from renewables given population density and availability of sites with superior renewables output yield.

FIGURE 3. **Given nuclear's higher load factors, less generation capacity needs to be built than if fully dependent on renewables to close the carbon free gap**

	CO2 free generation gap (TWh)	Nuclear capacity required addition equivalent (GW)	Renewables capacity required addition equivalent (GW)
Dynamism mix 2050	71,347	9,030	32,579
Development mix 2050	49,578	6,274	22,638
Deadlock mix 2050	33,394	4,226	15,248

Source: bp Statistical Review, Total Energy Outlook, IEA, Barclays Research

Greater reliability

As stated earlier, reliability of nuclear is also an important positive factor that gets overlooked Nuclear is not only CO2 free generation, but also its generation output is not influenced by weather conditions and seasonality. Although it is sensible to assume that over the long term energy storage solutions will become more efficient and cheaper, there will still be a need of a certain level of generation output, where the variability over the year is not significant. This is not the case for renewables, which is why we believe there will be a focus of government to ensure a certain level of nuclear generation that would require new build (current stated strategy of several countries).

Affordability

Lastly, net zero carbon scenarios mostly assume that there will be a certain level of thermal generation output in operation in 2050 that will be using carbon capture storage solutions in order to have zero CO2 emissions. This is in order to have flexibility in the power system to match variable renewable generation output with demand. However, not every country or region has the ability to pursue large scale carbon capture and storage, and public acceptance also an issue sometimes. In addition, when discussing current technology, carbon capture storage solutions are still not economic and need higher government support than other generation types, particularly for renewables and nuclear. Therefore, we think it is reasonable to assume that there should be more nuclear generation capacity by 2050 to reflect a replacement of thermal capacity not only with carbon capture and storage solutions, but also nuclear.

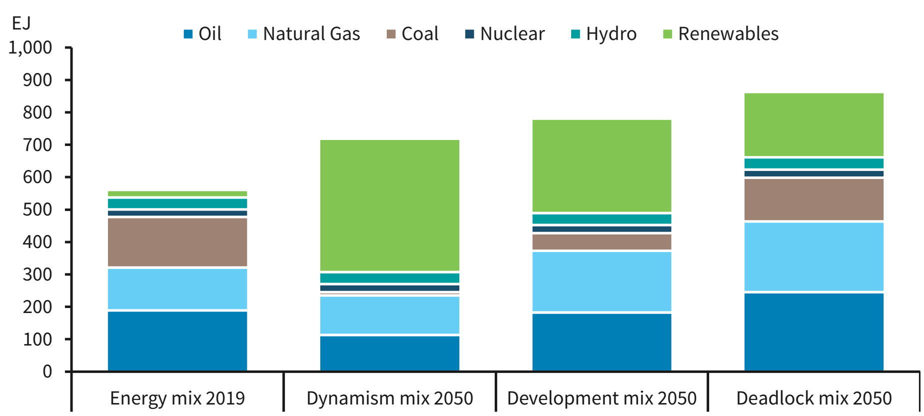
In the section The attributes of nuclear, we also argue that nuclear is safer and cleaner than one would commonly assume. All these factors pushes us to conclude that nuclear needs to play a bigger role in the transition to the a net-zero world by 2050.

Insights from our decarbonization report

In Global Energy: Opportunities in decarbonization (9 March 2021), the Barclays Energy Equity research team has looked at the evolution of energy demand in three potential scenarios. These are the Dynamism, Development and Deadlock scenarios. The Dynamism scenario entails low-carbon energy sources (including nuclear and hydro) accounting for about 70% of the energy mix compared with about 40% in our Deadlock scenario. Fossil fuels continue to make up a meaningful part of the overall energy mix with coal declining by the largest amount and almost disappearing in our Dynamism scenario. With continued usage of fossil fuels there will be a need for carbon-sequestration technologies – either through industrial carbon capture or nature-based solutions. Natural gas should become the most dominant fossil fuel, partially driven by hydrogen deployment, which could reach up to 15% of total energy demand by 2050.

Although each scenario results in material differences in the energy mix, they all show a large rise in global energy demand by 2050 totalling between 20% and 50%. This is mainly because of growing and more wealthy populations. Renewable energy (wind, solar and biofuels) is the fastest growing part of the energy mix with a projected 8-10% rise per year in the next three decades. This is mainly driven by a significant rise in electrification in countries across the globe. Although in all three scenarios the nuclear share in the energy mix is dwarfed by other types, it shows that nuclear will continue to make up a key part of future primary energy demand. It continues to represent a possible solution toward reaching net zero carbon targets, because contrary to fossil fuel nuclear energy does not emit CO2.

FIGURE 4. Primary energy demand in the three Barclays Energy team scenarios

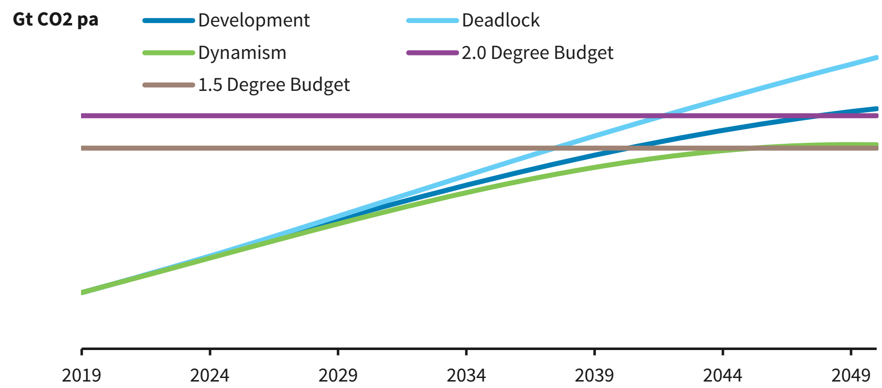


Source: bp Statistical Review, Total Energy Outlook, IEA, Barclays Research

These three scenarios have different implications for carbon budgets with the Dynamism scenario envisaging net-zero emissions by 2050.

This would be in line with the Intergovernmental Panel on Climate Change's (IPCC) ambition of limiting the global temperature increase to 1.5 degrees above pre-industrial levels. The Development scenario is consistent with a carbon budget that limits the global temperature increase to two degrees. In case of the Deadlock scenario a 3.5 degrees' rise is assumed. Figure 6 below shows the implications for carbon emissions.

FIGURE 5. Carbon emissions in our three scenarios



Source: IPCC, IRENA, Barclays Research

Figure 7 shows the main outputs and key metrics relating to the Barclays Energy's team three primary energy demand scenarios. They are based on different assumptions relating to key drivers of demand, ie, GDP per capita growth (split by OECD and non-OECD countries), population growth and energy intensity improvements.

FIGURE 6. Key 3D model outcomes and metrics

	2019	Dynamism	Development	Deadlock
Energy demand, EJ	584	719	780	863
Energy demand, mb/d oe	297	366	397	439
% change		23	34	48
Population, bn	7.7	9.8	9.8	9.8
% change		28	28	28
Primary energy demand growth, % per year	2.1 (2000-2019)	0.7	0.9	1.3
Energy intensity improvement, % per year	1.6 (2000-2019)	2.5	1.8	1.3
Electricity as % of primary energy consumption	c17%	31%	24%	21%
Electricity as % of final energy consumption	c20%	53%	42%	33%
% electricity from wind & solar	8	71	58	40
EV penetration, parc, %	<1%	64	56	24
EV penetration, % sales	3	90	85	40
Sustainable Aviation Fuel, %	0	42	22	3
Hydrogen as % of energy mix	2	13	9	3
Liquids demand, mb/d	101	62	96	125
Oil as % of liquids demand	97	83	91	95
Oil demand	98	51	87	119
Carbon capture and storage, Gt	0	15	13	8

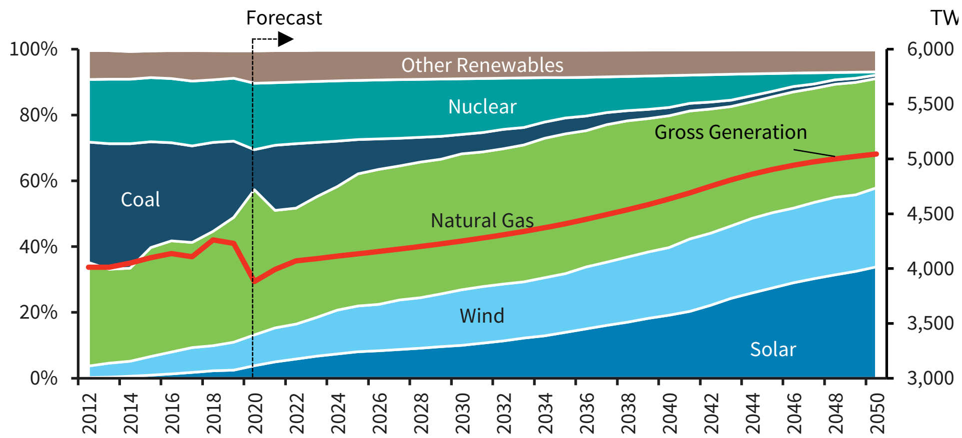
Source: Barclays Research estimates

Energy transition

The energy transition is driving a major shift in the global power system profile

With solar and wind power costs now highly cost competitive, storage costs dropping and a significant focus on decarbonisation, the future of fossil and nuclear generation are in question. In the US, solar and wind have seen their collective market share expand to 13% in 2020 (vs 7% in 2015), while other renewables (hydro, geothermal, biomass) have grown more modestly to 10% (vs 8% in 2015). Bloomberg's 2050 Economic Transition Scenario (ETS), which is its core economics-led scenario, calls for solar to grow its market share nearly 9x to 34% by 2050 and for wind to grow about 2.5x to 24% share, as shown in Figure 7. This figure simply shows the Bloomberg Economic Transition Scenario. If decarbonisation is the primary focus, natural gas will need carbon capture to remain viable. The significant reduction in nuclear generation is based on current nuclear plant operating license expiration and does not represent the next phase of 20-year licence extensions, let alone any new nuclear capacity additions (conventional or small modular reactor).

FIGURE 7. **US electricity generation forecasted mix and generation through 2050 (Bloomberg Economic Transition Scenario)**



Source: BloombergNEF 2020 New Energy Outlook and Barclays Research.

The bridge to decarbonization

Regardless of generation technology, the global generation provided by fossil fuels and even nuclear power can be considered a bridge to the decarbonized generation fleet of the future. The length of the bridge and where the bridge ultimately leads to are questions to explore at a later date. As we examine ways to achieve decarbonisation, we must first discuss the limitations of the existing energy infrastructure, and the difference between on demand, intermittent and storage resources to understand why not all electric capacity is created equally. We see multiple technologies all of which can theoretically achieve the goal, but all of which create their own challenges.

The technologies we explore are carbon capture for natural gas generation, nuclear (conventional and small modular reactors), offshore wind, onshore wind, solar, battery storage and hydrogen. We briefly examine how each technology fits into the decarbonisation framework focusing on reliability and affordability. We do not postulate any new technologies or additional disruptions that could ultimately prove to be part of the transition to decarbonisation.

Limitations of current energy infrastructure

The historical design of the electric transmission and distribution grid was to site large central power plants and build electric transmission to connect these large power plants to cities or load centers. Large central power plants (coal, natural gas, oil, nuclear, and hydro) all required access to railway, waterway and/or gas/oil pipelines in general. Large central plants also provide voltage stability and reactive power to the transmission grid, allowing for the ability to maintain reliability with significant shifts in supply and demand. The increase in renewable generation is notably shifting this model as the geographic requirements both in location and power density of the generation source are quite different from traditional generation. These differences drive a considerable need for a more varied and flexible transmission grid.

Different roles for different types of electric capacity?

Prior to looking at specific generation resources,we note that different types of electric resources fall into one of the following buckets: on demand resources, intermittent resources, or storage resources. A brief definition of each resource is provided below.

- **On-demand resources**: These resources, with some level of scheduling/planning, can provide power as demanded at levels up to their rated capacity. This allows for the greatest flexibility to the grid as power levels can be increased or decreased as needed to keep supply in balance with demand. The ability to supply power is tied to fuel source, generally with multiple weeks if not more of supply fuel either on site or contracted for at any given time.

- **Intermittent resources**: These resources provide power on an intermittent basis, meaning that there may be an expectation of times when the resource is available, but no certainty as to if the fuel source (predominantly wind and sun) will be available. These resources provide very little benefit to the transmission grid as from a voltage or reactive power standpoint To ensure reliable power, on-demand resource or storage assets must be available to fill the gap when intermittent resources are not.

- **Storage resources**: These resources can provide power as needed, subject to the constraints of the given technology, and require power from the grid to create the storage asset. In layman's terms this is converting energy electricity to some form of stored energy to be later converted back to electricity when needed. This creates a few issues for consideration, first is the energy loss that occurs when converting electricity to storage back to electricity. Moreover, whether pumped hydro storage or some form of battery, the electricity, while having the ability to be flexibly dispatched has a set amount of MWhs that can be provided before the capacity needs to be replenished using either intermittent or on-demand resources. Hydrogen is a specialized, more flexible form or storage and will be discussed later in this report.

Carbon capture for natural gas generation

Carbon capture has two main applications. First, as an addition to existing plants to allow continued operation with carbon constraints. Second, as an option for new generation given several technologies exist for new build gas plants with carbon capture. Given that carbon capture is used on fossil generation, this is an on-demand resource; however, it does have some drawbacks as the carbon capture process tends to be power intensive, meaning that the net load for the plant is lower than it would be without carbon capture. Thus, even if carbon capture could be added to all existing gas plants (which is unrealistic) there would continue to be a gap in electric supply given the amount of load needed to operate the carbon capture equipment.

Nuclear generation

Nuclear has three paths to maintaining or increasing generation market share. First, operating plant life extensions to 80 years or more. We expect to see a continue push for longer operating lives for existing plants, the biggest question is whether there will continue to be rolling 20-year extensions or might the extension period shrink to 10-year periods as plant continue to age. Second, nuclear new build similar to current AP1000 projects in the US and China. Third, next generation nuclear new build relying on small modular reactors and/or new plant designs.

Offshore wind

Globally, offshore wind continues to increase market share and many projects are planned and progressing towards permitting and construction in the US. Offshore wind has the benefit of higher and more consistent capacity factors than onshore wind, but also faces higher costs and longer construction periods. Lease availability, transmission connectivity, and maritime concerns are major barriers affecting the offshore industry.

Onshore wind

Onshore wind continues to increase market share and many older projects are “repowering” to make use of newer technology. However, as optimal wind sites are a limited commodity, the acceleration of capacity has slowed. Onshore wind is an intermittent resource.

Solar

Solar costs continue to decrease and based on the coincident nature of solar generation to peak load in many areas has led to a solar generation growing faster than other generation types in recent years with an expectation for this trend to continue. Utility scale solar tends to have the best economics, but distributed solar (rooftop) provides a path for non-traditional energy participants to make energy decisions and impact generation mix.

Battery storage

Battery storage continues to see improved economics, but does not generate energy, rather it provides the ability to shift generation by a matter of hours or days as needed. This makes storage critical for system balancing and reliability, but must be paired with physical generation in order to fill generation gaps.

Hydrogen

Hydrogen is not an energy source in itself, but a secondary energy carrier. It also occurs naturally in a bonded form, rather than as a stand-alone form. As such, it has to be released, or ‘produced’ from its compounds by using energy.

In terms of sources, industry convention has emerged that colours are typically used as shorthand to refer to the sources of energy that fuel production. These are widely known as:

- **Green hydrogen**: Hydrogen generated from renewable sources, mainly through electrolysis.
- **Brown hydrogen**: Used generically to refer to conventional production using fossil fuels by steam methane reforming, without reduced emissions via the use of carbon capture utilisation and storage (CCUS).
- **Blue hydrogen**: Steam methane reforming with CO_2 emissions reduced by CCUS.

In terms of the current split of hydrogen production, only 4% is generated through electrolysis, with natural gas and steam methane reforming the main forms of production. About 96% of hydrogen is currently produced from fossil fuels (48% from natural gas, 30% from oil and 18% from coal), leaving around 3-4% of hydrogen produced using renewables.

The attributes of nuclear

How nuclear power fits into a decarbonized future is less clear than for other generation types. The crux of global debate on nuclear power is finding a balance between largely divided advantages and disadvantages.

In contrast to other conventional fuels, nuclear emits zero direct emissions and, over the lifetime of a plant, will typically be 10 times and 20 times cleaner then equivalent gas and coal plants respectively. While this is similar to renewables, the real ‘nucleus’ of nuclear power in the transition to net zero emission lies in its powerful reliability, with healthy plants exhibiting capacity factors in excess of 90% and able to generate power for up to 80 years. This compares favourably across both the conventional and renewable fuel spectrums (Figure 8 and Figure 9).

From this perspective, nuclear power is an optimal ‘plug-in’ base-load power to complement developing storage facilities as intermittent renewables energy increasingly penetrate the grid in the coming decades. However, in reality, this optically simple solution is complicated by interrelated issues of capital intensity and operational safety as well as environmental issues elsewhere in the value chain (mining and waste).

Comparative economics: expensive, yet affordable

There is no question that capital costs are higher for nuclear than for most other sources of generation. However, given nuclear plants’ long lives, on-demand generation and high capacity factors, they fare much better on the levelized cost of energy (LCOE). Renewables such as onshore wind and solar PV still tend to screen as the least costly option for new generation. **While accurate today, as renewable generation increases on the grid, at some point incremental generation will need to be on-demand or come from bundled technologies that provide an on-demand resource**.

A good way to think about bundled technologies is some combination of wind, solar and batteries that can provide 1 MW of capacity on demand throughout a given day. In a simplified example, you would need 4-6 MWs (based on average capacity factors) of resources to replicate 1 MW of nuclear capacity, without even considering the attributes that nuclear provides to the transmission grid. Figure 8 shows capital costs and levelized costs of energy by generation type, assuming only energy needs not an on-demand resource (or capacity) needs, and based on estimated long run costs. Hence, to properly compare nuclear with an on-demand mix of 4-6 MWs of wind, solar and battery storage one would need to know all the associated costs. Figure 9 shows experienced levelized costs of energy: which is much higher for nuclear given cost and schedule overruns of recent projects. However, as with other technologies, we would expect the nuclear LCOE to reduce as the industry gains more experience.

In Figure 8, we also show the EIA’s calculated levelized avoided cost of energy (LACE) and the value-cost ratio (ie, the ratio of LACE to LCOE). LACE accounts for differences in the grid services that each technology provides, recognizing that intermittent resources have different duty cycles to baseload resources (eg, nuclear). When LACE exceeds LCOE for a technology, that technology should be economically attractive to build, and offer a point of comparison for first-order economic competitiveness. Geographic differences and policy preferences (for example, carbon emissions and maintaining or enhancing strategic technological applications) are incremental considerations. In terms of value-cost ratio, while nuclear is low (0.56) versus combined cycle, geothermal and solar, it is higher than off-shore wind. There is c.30GW of US offshore wind pipeline across different regulatory constructs, largely on the East Coast, highlighting the importance of policy preferences in generation technology construction. We reiterate that these estimates are relevant for the generation mix today, and would change as more intermittent generation is added.

FIGURE 8. Comparative generation technology costs

Plant Type	Capacity Factor (%)	Levelized Capital Cost	Levelized Fixed O&M	Levelized Variable Cost	Levelized Transmission Cost	Total System LCOE or LCOS	Levelized tax credit	Total LCOE or LCOS including tax credit	LACE	Value-cost Ratio
Dispatchable Technologies										
Combined Cycle	87%	$7.78	$1.61	$26.68	$1.04	$37.11		$37.11	$36.35	0.98
Advanaced nuclear	90%	$50.51	$15.51	$2.38	$0.99	$69.39	-6.29	$63.10	$35.41	0.56
Geothermal	90%	$19.03	$14.92	$1.17	$1.28	$36.40	-1.9	$34.50	$40.89	1.19
Biomass	83%	$34.96	$17.38	$35.78	$1.09	$89.21		$89.21	$36.60	0.41
Battery Storage	10%	$57.98	$28.48	$23.85	$9.53	$119.84		$119.84	$90.95	0.76
Non-Dispatchable Technologies										
Wind, onshore	41%	$27.01	$7.47	$0.00	$2.44	$36.92		$36.92	$31.87	0.86
Wind, offshore	44%	$89.20	$28.96	$0.00	$2.35	$120.51		$120.51	$33.19	0.28
Solar, standalone	29%	$23.52	$6.07	$0.00	$3.19	$32.78	-2.35	$30.43	$31.66	1.04
Solar, hybrid	28%	$31.13	$13.25	$0.00	$3.29	$47.67	-3.11	$44.56	$42.74	0.96
Hydro	55%	$38.62	$11.23	$3.58	$1.84	$55.27		$55.27	$34.74	0.63

EIA estimated unweighted levelized cost of energy(LCOE) or levelized cost of storage (LCOS) for new resources entering service in 2026 (2020 dollars per MWh). Solar hybrid = single-axis PV system coupled with a four-hour battery storage system. EIA assumes that hybrid solar and hydro have storage so they can dispatched by day/season respectively, but overall operation limited by resource availability by site.
Source: EIA

FIGURE 9. Snapshot: Nuclear vs other fuels

	Offshore wind	Onshore wind	Solar PV	Nuclear	Gas	Coal
Global LCOE avg ($/MWh)	c.80	c.40	c.50	c.225	c.80	c.100
Construction time (years)	5-10	4-6	4-6	>10	5-8	5-8
Plant useful life (years)	25-30	25-30	25-30	40-60	25-30	40-60
Reliability (capacity factor)	40-50%	30-40%	10-25%	80-90%	50-70%	50-70%
Emissions (gCO2/kWh)	<20	<20	<50	<50	400-500	900-1000

Source: BNEF, IPCC, World Nuclear Organisation, Barclays Research

Safety: reassuring statistics

The largest pushback on nuclear tends to relate to the significant potential impacts of a nuclear accident. There have been several high profile nuclear accidents , all of which were at earlier generation nuclear plants. No nuclear accidents for commercial power plants[2] have caused more than four deaths, of which only one was directly caused by radiation.

While the long-term impact from radioactive release from Fukishima will not be known for years, and even with the spectre of significant event risk from accidents, nuclear remains the safest generation technology based on deaths/year/Twh (Figure 11). Furthermore, advanced nuclear reactors and proposed small modular reactors do not rely on power to drive safety systems. Instead, they depend on the laws of physics (gravity, convection, heat transfer) to protect the core in the event of an accident. These designs should provide even better safety statistics than the historical comparables.

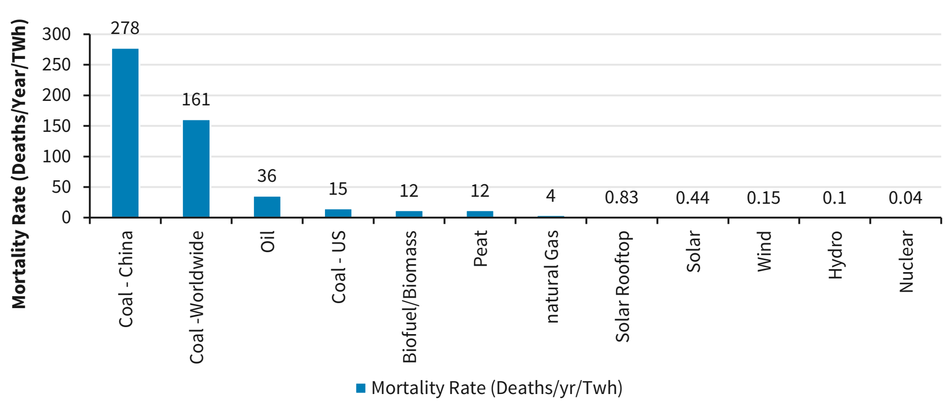
[2] Outside of Chernobyl, which was caused by flawed design and test which overrode all safety systems.

FIGURE 10. **History of nuclear accidents**

Date	Location of accident	Description of accident or incident	Deaths
5-Oct-66	Frenchtown Charter Township, Michigan, USA	Partial meltdown of Fermi 1 fuel elements	0
21-Jan-69	Lucens reactor, Vaud, Switzerland	Loss of coolant accident, meltdown of one fuel element, radioacitve contamination of the cavern	0
5-Jan-76	Jaslovské Bohunice, Czechoslovakia	Fuel rod ejected from reactor into reactor coolant hall during refueling	2
28-Mar-79	Three Mile Island, Pennsylvania, USA	Loss of coolant accident, partial core meltdown and small release of radioactive gases	0
26-Apr-86	Chernobyl, Chernobyl Raion (Now Ivankiv Raion), Kiev Oblast, Ukraininan SSR, Soviet Union	A flawed reactor design and test led to an explosion and meltdown necessitating the evacuation of 300,000 people and dispersing radioactive material across Europe Around 5% (5200 PBq) of the core was released into the atmosphere and downwind	28 direct, 19 not entirely related and 15 children due to thyroid cancer, as of 2008. Estimates are for up to 4,000 deaths
9-Dec-86	Surry, Virginia, United States	Feedwater pipe break at Surry Nuclear Power Plant kills 4 workers	4
30-Sep-99	Ibaraki Prefecture, Japan	Tokaimura nuclear accident killed two workers, and exposed one more to radiation levels above permissible limits	2
10-Apr-03	Paks, Hungary	Collapse of fuel rods at Paks Nuclear Power Plant led to leakage of radioactive gases	0
9-Aug-04	Fukui Prefecture, Japan	Steam explosion at Mihama Nuclear Power Plant killed 4 workers and injured 7 more	4
11-Mar-11	Fukushima, Japan	A tsunami flooded and damaged the plant's 3 active reactors, drowning two workers. Loss of backup electrical power led to overheating a core meltdown and evacuations. One man died suddenly while carrying equipment during the clean-up	1 and 3+ labour accidents; plus a broader number of primarily ill or elderly people from evacuation stress
12-Sep-11	Marcoule, France	One person was killed and four injured, one seriously, in a blast at the Marcoule Nuclear Site. The explosion took place in a furnace used to melt metallic waste	1

Source: Barclays Research, NRC, AEC

FIGURE 11. **Mortality rate by generation type (deaths/year/TWh)**



Source: Barclays Research, Energy Central

Waste and disposal: putting things in context

Nuclear is often perceived as inferior to pure renewables due to the need for uranium mining and waste disposal. However, the rare earth metals required for wind turbines and solar panels also require mining and, while the waste is not radioactive, the disposal requirements for these materials and for lithium ion batteries create a larger volume of waste than for nuclear fuel. Figure 12 shows the annual volume of waste associated with the operating nuclear fleet as compared to the expected retirement of solar panels, wind turbine blades and lithium ion batteries commissioned in 2020. Nuclear waste is also much more dense than other waste – all the nuclear waste generated from commercial nuclear power plants since 1950 would fit on a football field stacked 30 feet tall. Moreover, if recycling/reprocessing is considered, up to 97% of nuclear waste could be reused, compared with up to 96% for lithium ion batteries, c.80% for solar panels, and c.85% for wind turbine blades.

FIGURE 12. **Annual volume of waste by technology**

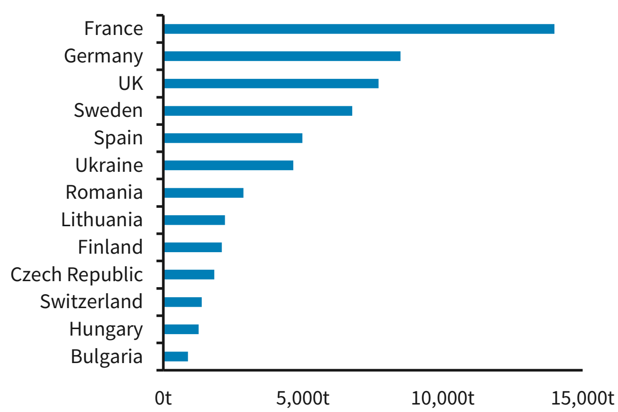
Technology	Annual Volume of Waste (Metric Tonnes)
Nuclear	6,360
Wind	150,000
Battery Storage	2,000,000
Solar	6,000,000

Nuclear is for the existing fleet, all other generation types are based on expected retirement of 2020 installations
Source: EIA, DOE, NEI

Additionally, we argue the sustainability benefits are still much stronger in comparison to other on-demand generation fuels. More specifically, global uranium production in 2019 of the 54k metric tonnes was dwarfed by the likes of thermal coal (6.8bn metric tonnes), oil (4.6bn) and natural gas (4.0bn), according to figures from the International Energy Agency. This reflects the exponentially higher power yield of uranium relative to coal and natural gas.

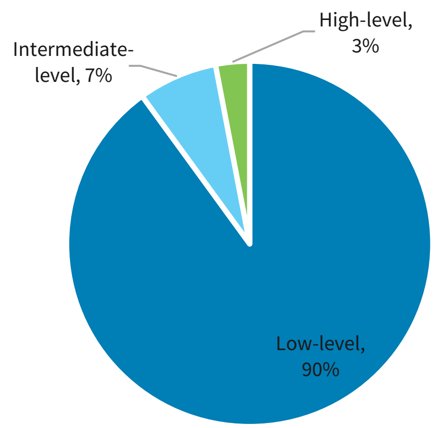
Importantly, this also results in relatively small and dense waste, of which just 3% of total volume is typically classified as "high level" (mainly spent fuel, which accounts for 95% of the radioactivity). While this appears manageable, the only country to have found a permanent solution for nuclear waste is Finland, which is currently constructing a permanent deep geological repository. To this effect, The World Nuclear Waste Report estimated there was 60.5k tonnes of spent nuclear fuel in interim storage across Europe in 2016. That said, this should be considered in the context of more than 3bn metric tonnes of carbon dioxide emitted across the continent each year.

FIGURE 13. **High-level waste (spent nuclear fuel) in interim storage by European country (2016)**



Source: The World Nuclear Waste Report, Focus Europe (2019)

FIGURE 14. **Nuclear waste typical split: High-level >95% of radioactivity**



Source: World Nuclear Association

Construction lead times: a longer wait

System planning is a critical process in ensuring adequate capacity and reliability. Prior to the power grid hitting renewable saturation (ie, when any incremental capacity needs to be on-demand capacity), new capacity will favour solar PV, onshore wind and battery energy storage because of their relatively short construction/lead times. The longer lead times for nuclear, carbon capture and offshore wind require a longer-term focus and commitment. The issue is that with rapidly changing technology and the potential adoption of hydrogen for longer-term storage and on-demand resources, it is not always clear which technology is best. The history of after-the-fact second-guessing and regulatory disallowances have further favoured technologies that can add capacity to the grid in the shortest time. Figure 15 shows lead times by generation technology, with that for small modular reactor including the expected time needed to complete research, development and licensing.

FIGURE 15. Construction lead time by generation technology

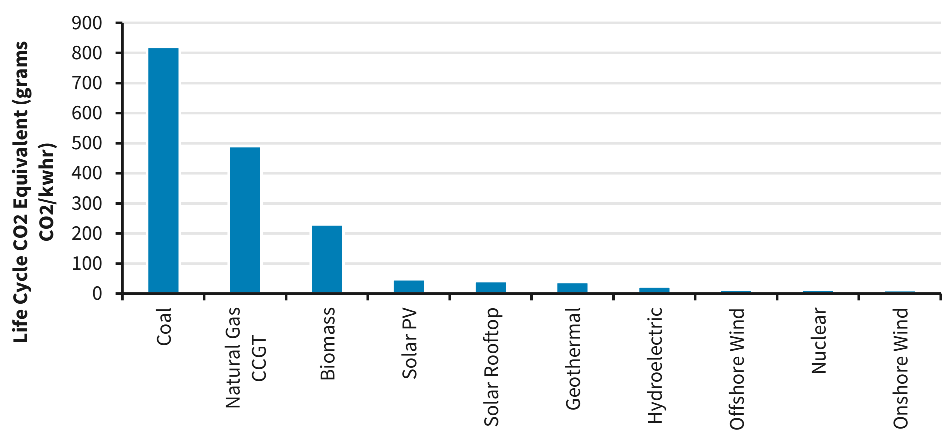
Technology	Construction Lead Time
Conventional/Advanced Nuclear	6-10 years
Small Modular Reactor	10-15 years
CCGT w/90% carbon capture	3-5 years
Battery Energy Storage	<1 year
Onshore Wind	1-2 years
Offshore Wind	3-10 years
Solar PV	<1 year

Source: EIA, S&P Global, Barclays Research

Evolving technology: the uncertainty of change

Technology is often considered a double-edged sword, because while solving one issue, it can often create others. This is prevalent in the world of decarbonisation: taking the time to examine the carbon footprint of a supply chain and either constructing a new technology or waiting for developmental technologies, runs the risk of delaying decarbonisation or mischaracterising societal benefits. As Figure 16 shows, the perception that nuclear contributes more to CO2 emissions than renewables based on uranium mining or construction, tends to ignores the rare earth material mining required for solar or wind.

FIGURE 16. Lifecycle CO2 emission intensity by generation technology



Source: Barclays Research, EIA

Reliability: nuclear can support the transmission grid

A key concern over ever-increasing renewable and intermittent capacity additions to the system is over electric grid reliability. While technology continues to evolve, allowing battery storage to provide voltage and reactive power support to the electric grid, these costs are not often considered when deciding on generation capacity additions. Also, wind and in some cases solar installations tend to relatively far from load centres, requiring more transmission system upgrades as well as contributing to higher line losses (electricity generated but lost during transportation). Large central stations (nuclear plants, coal plants, and natural gas CCGTs and CTs) provide voltage support and reactive power to the grid, ultimately aiding in reliability of the electric system. While some system operators pay generators for these attributes, their value is largely unappreciated until reliability suffers. The electric grid of the future is likely to be significantly more robust and resilient, supporting high levels of renewable penetration, but the time and cost it will take to transition to such a grid means that large central stations need to be expanded in the meantime.

Overall, nuclear power is far from perfect but we believe it offers the best solution to network reliability from what is scalable at present and workable within the net zero by 2050 deadline. Questions clearly remain over the long-term solution to waste but this could be a reflection of the indecision and/or misalignment across countries on nuclear policies. With the long lead times in building new or extending current capacity, we argue these decisions will come to the fore in the coming decade, and in the mean time, we expect a divergent stance to remain worldwide. The case studies at the end of this report identify the real world issues facing the nuclear industry today.

Time is of the essence

Nuclear power, given the significant regulatory, safety and compliance requirements, has a meaningfully longer planning, siting and construction timeline than most if not all other types of generation. This makes decisions to extend the life of existing plants and to build new plants critical today given the expected generation capacity needs through 2050. We address the planning and timing considerations of current nuclear plant licence extensions, conventional nuclear plant construction and new technology (small modular reactors and advanced technology) research and development.

Nuclear generation

Nuclear has three paths to maintaining or increasing generation market share:

1. Operating plant life extensions to 80 years or more.
2. Continuation of new nuclear reactor construction for conventional and advanced nuclear plant design.
3. Focusing on research and development to allow small modular reactors and other proposed designs to advance to commercial viability.

Given the long lead times for construction of current designs, and the even longer lead times to design, test and license new designs and concepts, any delays in committing to nuclear is effectively a decision to exclude nuclear from the generation fleet of the future.

Licence extensions for operating nuclear plants

Some currently operating plant licenses were extended from 40 to 60 years, with some older plants now looking to request extensions to 80 years. We expect a continued push for longer operating lives for existing plants, and the biggest question here is whether we will see rolling 20-year extensions. We expect to see some such extensions but that, at some point, the capital cost of ensuring safe reliable operation will make extensions unrealistic.

Conventional/advanced nuclear plant construction

Recent history in China and the United States shows that construction of a AP1000 pressurized water reactor takes at least nine years. Even if this lead time can be cut meaningfully as experience grows (say to five to seven years), once you include a year for planning and licensing you still have a six to eight year schedule from planning to commercial operation. This means that any capacity not already on the drawing board will not be available until at least 2027, but more realistically not until 2030 or later. Moreover, given the highly regulated nature of nuclear power, national policy must be supportive of nuclear and show a long-term commitment to incentivize private investment.

New nuclear plant research and development

Unlike advancements in wind, solar or battery storage, nuclear plant design changes occur slowly and require significant research, development and testing. There is currently research and development exploring small modular reactors based on passive safety systems. Additionally, various nuclear fuels other than uranium and plutonium are being examined to lessen the burden on potential proliferation of uranium and plutonium. Without significant focus and commitment, it is unlikely these plants will be ready for commercial construction over the next 10-15 years. This results in a scenario where commercial operation of a small modular reactor would not occur until 2035 or beyond, under best case scenarios.

Is nuclear ESG friendly?

Investors certainly do not agree on whether nuclear power is ESG friendly, with regional differences evident. The EU has failed so far to reach its own opinion but once it does this may provide additional clarity on the role of nuclear in the green transition. In our view, governance, particularly around how companies manage waste and safety risks, is the key ESG factor in this sector.

Little consensus amongst investors

Unlike activities and sectors such as tobacco, weapons and thermal coal, nuclear power is considerably less clear-cut in terms of how it is viewed by investors from an ESG perspective. As discussed in the prior sections of this report, nuclear reactors can generate electricity with no direct carbon emissions and are more reliable than renewable sources. However, there are numerous other ESG concerns including safety, waste disposal, and emissions created by mining and refining uranium ore, a key input of the energy generation process. There is significant disagreement as to whether the benefit of low carbon emissions outweighs the ESG risks.

Consensus is typically formed on this kind of issue at the regional level. However, in Europe, EU member states often have very different views, evident in the discussions around whether nuclear power deserves a place in the EU taxonomy. There is also a lot of disagreement among the views of asset managers and owners, with no clear consensus on whether nuclear energy belongs in their ESG portfolios. Of the largest five asset managers in France (which relies heavily on nuclear), just one mentions nuclear power companies in their ESG exclusion policy, and even they can still invest as long as the company operates in a country with a strong legal framework and the company itself has appropriate technologies and adequate policies around health and safety and accident prevention. In contrast, of the largest five asset managers in Germany (which has decided to phase out nuclear), four explicitly mention nuclear power in their ESG exclusion lists.

Amongst investors globally, nuclear power is not a common exclusion under firmwide negative screening, as is the case for tobacco, weapons and thermal coal, and seems instead to be end-investor driven. In our latest ESG investor survey, carried out last summer, no respondent noted that nuclear power companies were on their exclusion lists (The rise of ESG: 2020 investor survey results, 9 September 2020). Also, Norges Bank, which is often viewed as a standard setter on negative screening, does not include nuclear power as a criteria for product-based exclusions.

Still, there is certainly some evidence that these companies are less well held in ESG funds compared to non-ESG funds. We recently reviewed the holdings of €-IG credit funds with an ESG label versus those without an ESG label (ESG In Credit: Follow The Money, 16 April 2021). We found that ESG funds hold on average 0.52% of their AUM in EDF, the utility with the most nuclear exposure in Europe, versus 0.74% for non-ESG funds. Of the 27 funds analysed, 15 had no exposure to EDF at all.

The lack of consensus can also be observed in the formation of benchmark ESG indices. Typically, indices attempt to take a conservative approach to ESG benchmark construction to provide a solution suited to as many investors as possible. This means that ESG indices constructed with exclusions in place typically exclude a wide range of sectors, some less controversial than others. Nuclear power companies are excluded from the Bloomberg Barclays MSCI SRI family of fixed income indices as well as the MSCI SRI and DAX ESG indices on the equity side. The FTSE4Good index family includes nuclear power companies, but only if they meet a specific higher requirement around health and safety indicators.

EU decisions will be important

Nuclear power has proven a controversial topic in the development of the EU Taxonomy (for further details on the taxonomy see: EU Taxonomy and SFDR pressures, 5 November 2020), a classification tool to identify green activities. It was excluded from the first draft of the taxonomy, which prompted resistance from France and the Czech Republic (natural gas was also excluded prompting a number of countries in southern and eastern Europe to threaten to veto the regulation).

After significant debate, the European Commission chose to publish the first section of the taxonomy on 21 April without making a formal decision on either energy source and excluding both nuclear and natural gas as for now, stating that they would make a more informed decision on nuclear after further analysis from expert groups.

When this decision is made, the market may feel there is more clarity on the role of nuclear in the green transition, which may help build a stronger consensus amongst investors still unsure about the nuclear power sector from an ESG perspective.

Notable for this decision on nuclear, a report was leaked to the media at the end of March, conducted by the Joint Research Centre, which supports EU policies with independent evidence, analysing whether the power source falls foul of the EU's Do No Significant Harm criteria. The report stated that the "analyses did not reveal any science-based evidence that nuclear energy does more harm to human health or to the environment than other electricity production technologies already included in the Taxonomy as activities supporting climate change mitigation".

However, even if nuclear power is deemed to be "green" and doing no significant harm from the EU's perspective, concerns around the potential for incidents and how to dispose of nuclear waste will remain, in our view. Most of the debate at the EU is over nuclear waste and how to dispose of it, and finding a solution will be a key step for nuclear to become more widely accepted by ESG advocates.

ESG score providers are neutral on the issue

Sustainalytics and VE, whose data are used in the construction of Barclays ESG indicators, do not take a view on nuclear power generation itself in the construction of their ESG scores. Instead, they deem utilities with nuclear operations to have a different level of exposure to various ESG risks than those without.

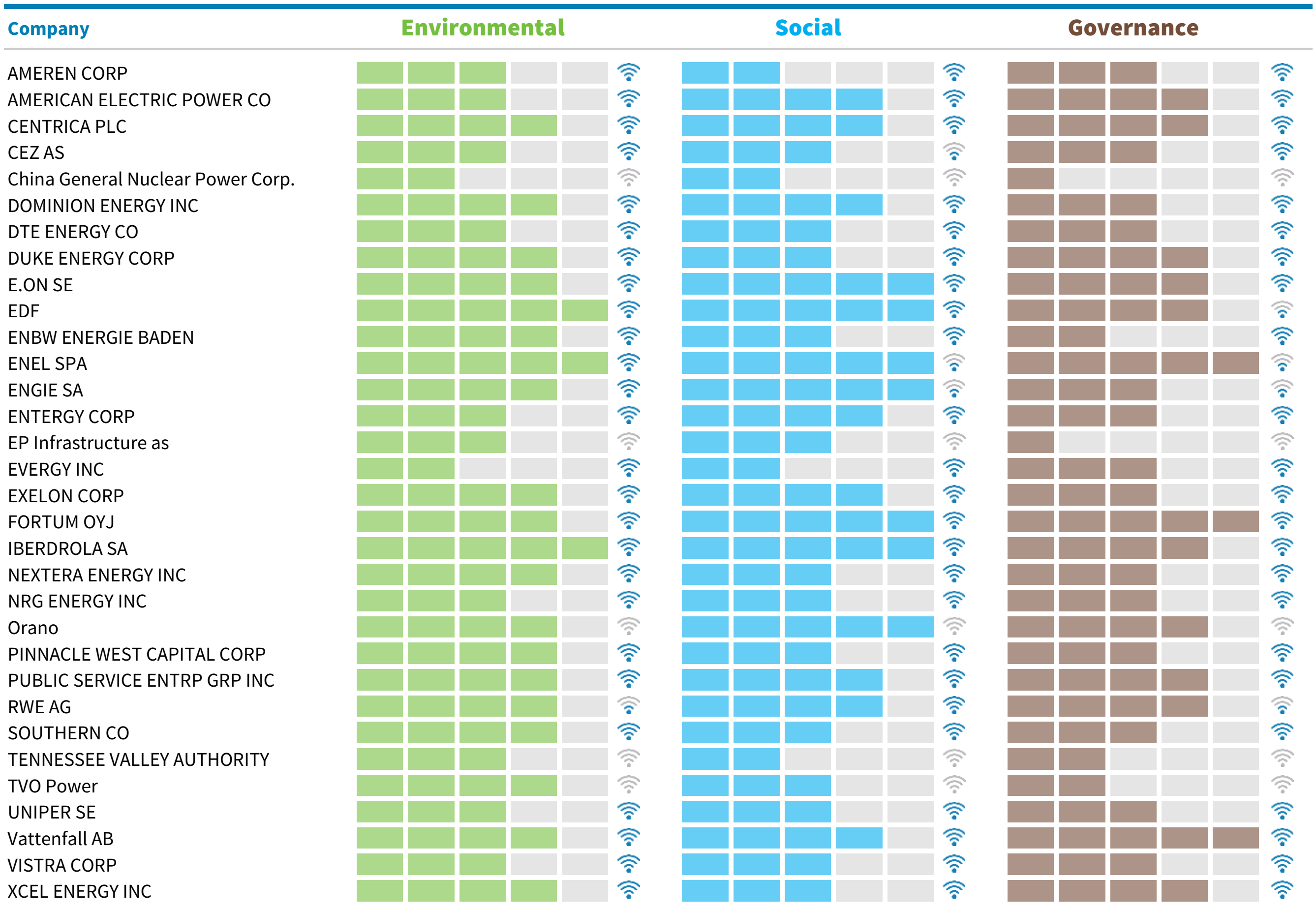
- On the positive side, nuclear power companies have a much lower exposure to risks related to the carbon emissions of their operations.

- On the negative side, they have a higher exposure to risks related to product safety and around effluents and waste (Sustainalytics have a dedicated indicator for nuclear waste management).

However, as with all sectors, final ESG scores are driven by how well a company is managing these risks. If a company has comprehensive commitments and policies around issues such as health and safety, waste management and pollution, as well as KPIs that suggest that these policies are having an impact on the business, then it can still score very well. We find that companies with nuclear exposure have a wide range of scores, as can be seen from Barclays ESG indicators (Figure 17). Interestingly, on average, utilities with nuclear exposure tend to have slightly worse ESG scores than utilities without nuclear exposure, but they are also slightly less likely to be in the tail of the worst-in-class (Figure 18 and Figure 19).

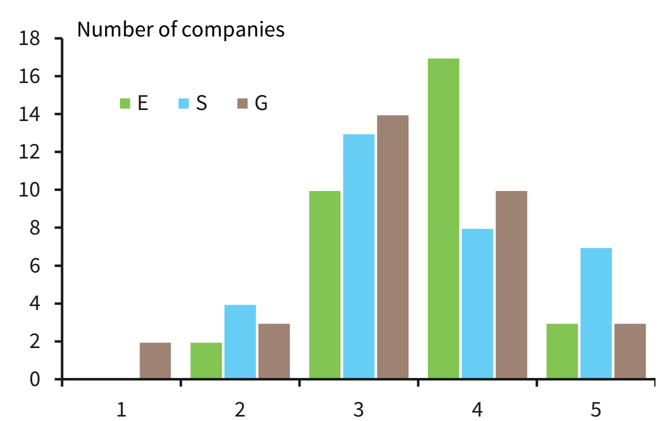
These scores are important for investors who do not screen out the nuclear power sector entirely as the inclusion of companies in portfolios will more likely be driven by an assessment of their ESG credentials, including whether they face any severe ESG-related controversies. The results would suggest that an investor who has no negative view on nuclear power itself is no more likely to exclude nuclear companies from their portfolios than other utilities based on their ESG scores.

FIGURE 17. Barclays ESG Indicators for utilities with nuclear exposure



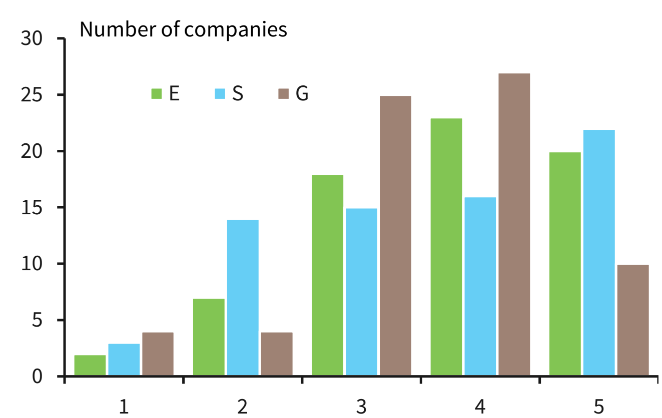
Blocks represent an aggregated view of, E, S, and G factor scores, respectively, across third-party score providers (one block indicates a very low average score, five a very high average score). Icons show the dispersion of those scores (no bars indicates only one source provider, two bars indicate dispersion between providers, full bars indicate aligned scores). For more details on Barclays ESG Indicators, click here. Data as of 31 March 2021. ESG Indicators are published in the first half of each month and reflect the data as of the end of the previous month. Clients can access the latest ESG Indicators on Barclays Live.
Source: Barclays Research, Sustainalytics, Vigeo Eiris (VE, an affiliate of Moody's)

FIGURE 18. Distribution of indicators: utilities with nuclear operations



Source: Barclays Research, Sustainalytics, Vigeo Eiris

FIGURE 19. Distribution of indicators: utilities with no nuclear operations



Source: Barclays Research, Sustainalytics, Vigeo Eiris

Bringing it back to governance

Of course, one specific challenge around nuclear power is the very long life cycle of both the assets and, importantly, the radioactive waste. This sits in conjunction with the low probability but extremely high magnitude of impact from incidents.

Perhaps the ultimate question over nuclear governance is whether a health and safety score taken at this moment in time is a sufficiently robust assessment of future sound governance of the assets and waste to make commitments on behalf of generations to come.

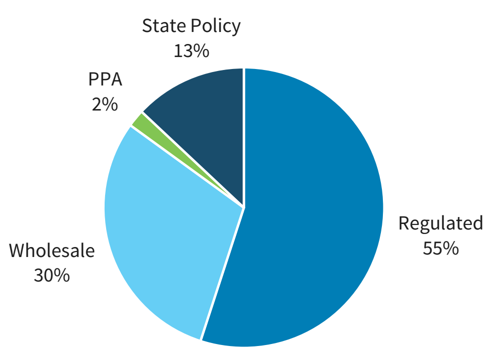
Case studies

In the following sections, we present key information on the major nuclear markets of the US, Europe and China.

US: at a crossroads

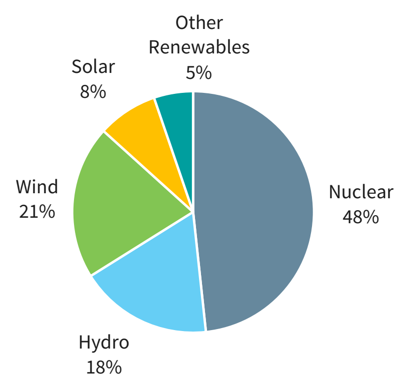
The US is the largest owner of nuclear capacity in the world (96GW) with c.790TWh in 2020, or about 20% of the country's generation mix (France a higher proportion of nuclear in its generation mix at c.71%). Nuclear contributes around 48% of zero-emissions generation in the US (in addition to wind, solar, hydro, geothermal and biomass). The generation mix is split between regulated and competitive markets. Nuclear generators in competitive markets have faced economic pressure over the last decade due to the impact of declining natural gas prices/power prices. Accordingly, there are no new competitive-market nuclear construction projects. Because nuclear also provides a sizable portion of zero-carbon generation, a number of states with competitive generation markets have provided zero-emissions credits to prevent nuclear plant closures. These have not been without controversy. In the regulated market, nuclear new builds have faced significant challenges given delays and cost overruns with AP1000 reactors. In turn, these have challenged regulatory support and credit quality.

FIGURE 20. US nuclear capacity by market type



Source: EIA

FIGURE 21. US 'zero-carbon' generation mix – 2020



Nuclear, hydro and renewable energy together made up c.40% of the US generation mix in 2020.
Source: EIA

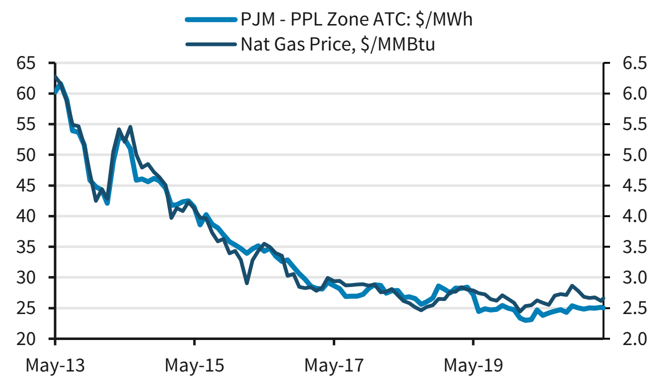
Talen Energy: reducing cost at Susquehanna

Susquehanna is the second largest dual unit Boiling Water Reactor (BWR) in the US with a combined capacity of 2.6GW. The facility was commissioned in 1981 (Unit 1) and 1983 (Unit 2), and is licensed to operate through 2042 (Unit 1) and to 2044 (Unit 3), with the option to extend the licence to 2062/64. **Susquehanna (c.20.5TWh a year) alone generates nearly three times the clean energy generation of Pennsylvania (c.6.7TWh)**. Nuclear overall contributes c.3% of the state's electricity generation, and c.90% of its zero-carbon generation.

Talen Energy reduced Susquehanna's cost profile (including O&M cost, capex and nuclear fuel) to c.$21/MWh by 2019 from $32/MWh in 2016, responding to a severe deterioration of PJM power prices since 2013 (from c.$50-60/MWh to c.25/MWh). PJM power prices have responded to both mild weather and a fall in local natural gas prices; along with elevated reserve margins (c.40%) as more natural gas plants were built to respond to the low natural gas prices. Susquehanna is will within the first quartile of US plants in terms of cost profile. A number of plants have higher cost profiles, but many operate in regulated market structures.

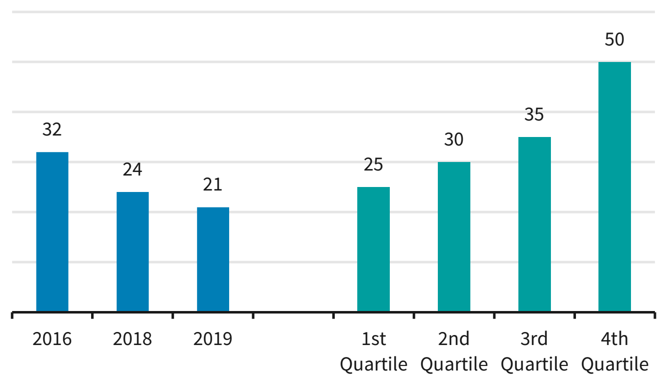
Talen was able to cut cost at Susquehanna through a number of methods: 1) reduction in nuclear fuel costs through improved end-of-cycle fuel optimization and nuclear fuel enrichment contract improvements, 2) reduced forced outages as well as refueling and inspection outages (thereby increasing capacity factor), and 3) labour and capital efficiency programme (staffing level was reduced from 1,244 to 925).

FIGURE 22. **PJM-PPL zone vs natural gas costs**



Source: Bloomberg

FIGURE 23. **Susquehanna versus cuclear cost profile**



Source: Company Reports

Georgia Power: Vogtle Units 3 & 4

Vogtle Units 3 and 4 (c.1.1GW each) will be the first nuclear plants to enter service (expected in late 2021/22) since Watts Bar Unit 2 in 2016 (which itself was the first reactor to come online since Watts Bar Unit 1 in 1996). The plants will be the first in the US to use the Westinghouse AP1000 advanced pressurized water reactor technology. The AP1000 nuclear plants are operational in China, with all four units in the country having completed their first refueling outages, with improving results.

Extended timeline and cost pressures

Since the project was first announced, with an intended completion date for Unit 3 in 2Q 16, the overall construction costs have almost doubled vs the original estimate, while the start date for 2021 was pushed back to 4Q 21. COVID-19 presented a further headwind to completion, with Georgia Power noting in March that meeting the November 2021 in-service date for Unit 3 is 'challenged'. Each additional month delay would add $25mn per month in cost.

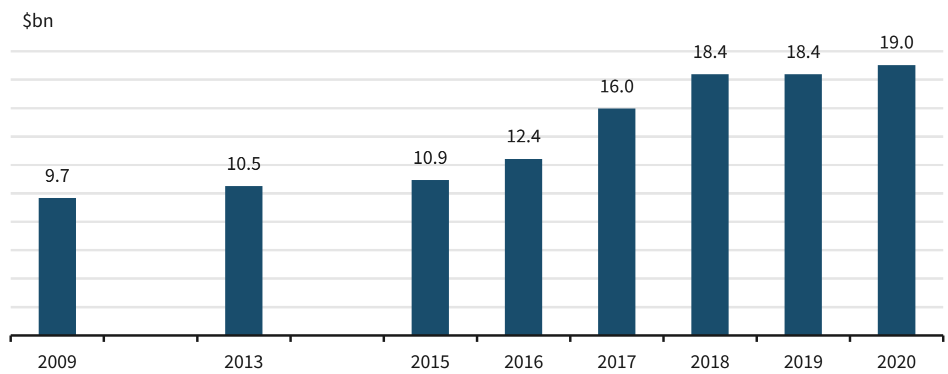
The Georgia Public Service Commission (GPSC) has approved a total construction and capital cost of $7.3bn (for Georgia Power's share) including $3.5bn deemed "prudent" and $2.18bn "presumed" to be prudent but with the burden of proof on any challenging party), and with costs above that $5.68bn to be reviewed for prudence after Vogtle Unit 4 fuel loading, with rates in service one month afterwards. Georgia Power's 45.7% ownership of Vogtle Units 3 and 4 means its share of capital costs are around $8.7bn.

VC Summer abandonment

In South Carolina, Scana and Santee Cooper were working on the construction of VC Summer (also utilizing AP1000 technology). The state had passed the Base Load Review Act (BLRA), which supported the new build, which provided for nuclear construction work in progress (CWIP) to earn a return on capital, and the provision to recover construction costs, and a return on capital, even in the event of abandoning the project. With Scana and Santee Cooper deciding to abandon the project due to an escalation in costs, the need arose to recover c.$2.2bn in abandoned project costs (net of tax deductions from write off). However, the issue of recovering costs for an abandoned project became politically charged with South Carolina repealing the

BLRA and the establishment of temporary rates that eliminated the rate increases Scana benefited from as it was constructing the project.

FIGURE 24. Vogtle Units 3 & 4 construction cost estimates



Source: Company Reports

PG&E: Diablo Canyon retirement

In Jan 2018, the CPUC (California Public Utilities Commission) approved the retirement of Diablo Canyon (owned by PG&E) with operations due to cease in 2025. Diablo Canyon (in-service in 1985) provides c.16.2TWh or c.7.5% of California's total electricity generation. Given sizable renewable resources including solar, nuclear makes up c.17% of the state's zero emission generation (c.45% of net generation).

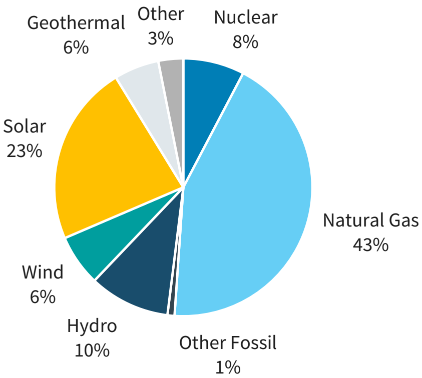
Reliability concerns

CAISO (California Independent System Operator) indicated in a 2020 filing that its modelling indicated that the shutdown of Diablo Canyon would be an inflection point for system reliability, with a 3.5GW resource deficiency. Third parties have noted concerns that natural gas plants would fill the supply gap resulting in higher carbon emissions in the state, with calls for the CPUC to order the procurement of sufficient wind, solar and energy storage to bridge the gap. One study suggested that with no action, Diablo Canyon's retirement would lead to 15.5MMT of additional carbon emissions by 2030 ('Countdown to Shutdown', Union of Concerned Scientists, 23 Feb 2021). The CPUC has suggested it needs 7.4GW of effective capacity additions by 2026, including 1GWof new geothermal, 1GW of long-duration storage (8-hr), and 5.5Gw of 'any type' of resource.

Nuclear decommissioning

In 2018, the decommissioning cost estimate was $4.8bn for Diablo Canyon. Nuclear decommissioning requires the safe removal of nuclear facilities from service, and the reduction of residual radioactivity to a level that then permits termination of the NRC licence and release of the property for unrestricted use. Nuclear decommissioning costs are collected in advance through rates and held in nuclear decommissioning trust to be used for the eventual decommissioning of the nuclear units. PCG files an application with the CPUC every three years requesting approval of updated decommissioning costs and any rate changes necessary to fully fund the nuclear decommissioning trust.

FIGURE 25. Nuclear in California's FY20 generation mix



Source: EIA

Nuclear subsidies: political and governance risk

Over 2017-2019, an increasing number of states were implementing programmes to support nuclear power facing challenged economics in competitive markets. Some states were more targeted in their approach (eg, Illinois provided economic support to only those plants facing economic pressure, while New Jersey provided support to all 3.5GW of capacity in the state).

The support programmes, mostly involving Zero-Emissions Credits (ZECs) vary over $10-17/MWh, and are intended to reflect the environmental cost of carbon emissions. The timing of the programmes also varies, with New Jersey requiring re-application after three years. Programmes in New York and Illinois have been extended to the late 2020s.

Reversal of support in Ohio

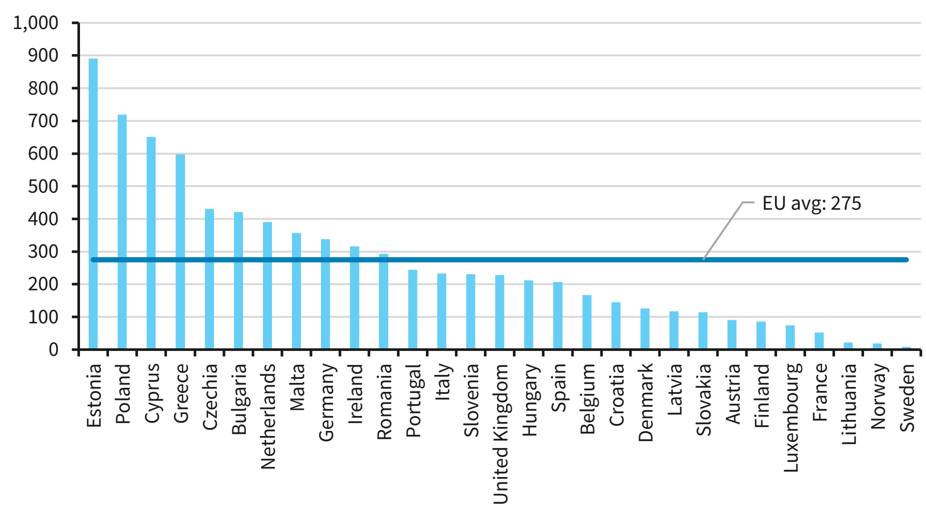
The reversal of support for out-of-market payments to nuclear plants in Ohio is notable in highlighting political and regulatory risk for both nuclear plants, as well as related utilities. Ohio House Bill 6 (included $150mn a year for two nuclear plants through to 2027) was enacted in July 2019; in July 2020 a complaint and supporting affidavit containing federal criminal allegations were unsealed against the now former Ohio House speaker Larry Householder and other individuals. FirstEnergy, which was the prior parent company of the Generation company that owned the nuclear plants also received subpoenas for records. The investigation remains ongoing. As part of the investigation, FirstEnergy has announced significant changes in its approach to political and legislative engagement and advocacy, including stopping all contributions to 501c4s. HB128 was signed in 2021 to repeal the nuclear support portion of HB6 in July 2019, reversing course on the nuclear support programme in the state.

Europe: The great divide

At 26% of total electricity production in Europe, nuclear power is a core component of the continent's fuel mix but there is a sharp divide in its use between countries. For example, France derives around 70% of its electricity needs from nuclear (the highest share of any country worldwide) which contrasts to Italy which closed all its plants in 1990 and Germany which is aiming to phase out nuclear power by 2022. However, while all three nations have similar renewables penetration (just under 20% of energy consumption), the carbon intensity of electricity in 2019 (measured by gCO2/kWh) is much lower in France (at 52) than Germany (338), Italy (233) and Europe on average (275). This reflects much lower level of fossil fuels in the generation mix for France (at 8% in 2019) versus Germany (over 40%, or which +20% is from coal) and Italy (around 55% mostly comprising gas). To this effect, France is aiming to phase out all coal fired plants by 2022 while Germany is aiming to achieve the same goal almost two decades later, by 2038. In this context, adding nuclear to the energy mix can significantly accelerate emission reductions, and we highlight Sweden as a leading example: it has the lowest carbon intensity of all European nations (8 gCO2/kW) through a power mix of predominantly nuclear (40%) and renewables/biofuels (58%). This has allowed Sweden to target net zero emissions by 2045 at the latest (versus 2050 for Europe).

Nuclear has also driven strong improvements in historically carbon-heavy eastern European nations. This includes Slovakia (54% share of nuclear in the fuel mix), Hungary (49%), Bulgaria (37%), Slovenia (37%), Czech Republic (35%) and Romania (19%). For example, as nuclear capacity came online in Slovakia in the 1990s (rising from 45% to closer to 55% in 2005), carbon intensity dropped rapidly from 491 in 1990 to 180 in 2005. This compares to the fall from 523 to 395 for Europe over the same period. Since then, Slovakia has made further headway in emissions with carbon intensity falling to 132 in 2019 supported by an 8% increase in renewables (to around 23%) in the power mix and we expect the construction of two new plans (Mochovce 3 & 4, expected completion in 2021 and 2023 respectively) to mark the next stage of the transition.

FIGURE 26. **European carbon intensity (gCO2/kWh) by country**



Source: European Environment Agency

Building new European capacity has not been smooth

While the benefits to national net zero emission strategies is clear, a persistent drawback for nuclear power in Europe has been construction risk which has arguably added to the reluctance of many countries to engage in new nuclear projects. This has been particularly evident for new builds in developed European nations with issues in building the French European Pressurised

Reactor (EPR) design resulting in severe delays and cost overruns for three major projects over the past decade:

- **Olkiluoto 3 (OL-3), Finland:** With construction commencing in 2005 and first forecast to be completed by 2009, OL-3 is now projected to be connected to the grid later this year and begin providing commercial electricity in 2022. As a result, the plant is now 13 years behind schedule and this has come with substantial costs with the initial budget of €3.2bn comparing to total construction costs in excess of €8.5bn. While the project was signed as a turnkey contract under the initial budget, the operator's (Teollisuuden Voima Oyj) investment has almost reached €6bn.

- **Flamanville 3 (FLA-3), France:** The construction of the Flamanville 3 EPR began 2007 for commercial use initially scheduled for 2012 at an estimated cost of €3.3bn. However, the project is ongoing with the latest delay announced in June 2019 following the discovery of quality issues by the French Nuclear Safety Authority (ASN by the French abbreviation). The fuel loading of the reactor is now postponed until 2022 at the earliest with EDF estimating overall total construction costs of €12.4bn.

- **Hinkley Point C (HPC), UK:** Two new EPRs at Hinkley Point began construction in early 2017 and were scheduled for completion by the end of 2025. Reflecting more expensive earthworks and design costs, in September 2019 the total construction budget was revised upwards to £21.5-22.5bn, from the previous estimate of £19.6bn in July 2017 and initial estimate of £16bn. Due to delays caused by the COVID-19 crisis, the estimate was raised by a further £500mn to £22-23bn in January 2021. EDF has also flagged the risk of another potential delay (up to 15 months), potentially adding an estimated £700mn to the cost.

With the completion of OL-3 leading to low-carbon nuclear power covering 40% of Finland's electricity consumption (versus 28% previously) and with the UK government providing Hinkley Point C with a CfD strike price of £92.50/MWh (in 2012 prices) linked to inflation (versus long-term average baseload power prices closer to £50/MWh), these new nuclear builds are clearly important for respective net-zero emission strategies. However, the construction risk reflects both the complex and niche nature of nuclear technology, and EDF is expected to reveal a new improved EPR model by mid-2021 in an effort to drive down construction costs. While China and Russia are also advancing nuclear technologies with relatively greater success (with China exhibiting a much lower LCOE, according to BNEF, at $60/MWh and Russia's Rosatom experiencing fewer construction delays for new builds in Turkey and Belarus), there are political/security concerns involved in utilising resources from these countries. Overall, this suggests there is no simple solution without more investment and resources, although these are currently being diverted to the development of renewable technologies.

FIGURE 27. **New nuclear build summary in Europe and neighbouring countries**

Site name	Country	Operator	Capacity (MW)	Construction start	Est. grid connection	Est. total cost (€bn)	Initial grid connection	Initial budget (€bn)
Olkiluoto 3	Finland	Teollisuuden Voima OYJ	1,600	2005	2021	>8.5	2009	3.2
Ostrovets 2	Belarus	Republican Unitary Enterprise	1,200	2014	2022	4.6*	2018	4.6*
Mochovce 3 & 4	Slovakia	Slovenske Elektrarne, As.	880	2008	2021-23	6.2	2012-13	2.8
Flamanville 3	France	EDF SA	1,650	2007	2023	12.4	2012	3.3
Akkuyu 1-4	Turkey	Rosatom	4,800	2017	2023-26	16.6	2023-25	16.6
Hinkley Point C1-2	UK	EDF SA	3,200	2018	2026-27	26.1	2025-16	18.6

*Reflects 50% of the $11bn total cost for Ostrovets 1 and 2
Source: World Nuclear Association, Company reports, press releases, Barclays Research

China: full steam ahead

In the past six months, the Chinese government has set bigger targets for cuts in carbon intensity[3] and reducing reliance on fossil fuel energy. By 2030, China aims to have achieved peak carbon emissions, and to have lowered carbon emissions relative to economic activity by more than 65%, from 2005 levels (-48.1% in 2019, versus 2005 levels). By 2025 and 2030, China targets for its non-fossil fuel share of primary energy consumption to rise to 20% and 25% respectively (15.8% in 2020). Also, President Xi committed to achieving carbon neutrality by 2060 at the 2020 UN Climate Summit. These lofty targets can only be achieved with a comprehensive plan, which would require a diversification of energy sources to include a majority of non-fossil fuel options, and less energy-intensive and pollutive industries.

FIGURE 28. **China - summary of emissions and green energy targets**

	2020	2021	2025	2030	2060
Carbon emissions				Peak carbon emissions	Carbon neutrality
Carbon intensity targets versus 2005	-45%			-65%	
Forestry area additions versus 2005				6bn sqm	
Non-fossil fuel as proportion of primary energy consumption	15.80%		20%	25%	
Wind, solar installed capacity (GW)	533			1,200	

Source: Reuters, Chinese government work report

Coal accounted for 57% of primary energy consumption in China in 2020, but needs to be limited to 25-30% of total energy and about 20% of electricity generation by 2050, according to BCG. This would require massive growth in renewable energy sources. China is already targeting a significant investment in this area – President Xi said China will boost wind and solar power combined installed capacity to more than 1,200GW by 2030, more than twice the size in 2020. On the other hand, China's ability to further grow hydropower generation capacity is more limited, as total hydropower potential is estimated by the International Hydropower Association to be 600GW, compared to 356GW in 2020.

Nuclear power thus figures as an important part of China's plan to meet long-term energy needs and cut carbon emissions. Nuclear power as an energy source has room to grow in China, given the still-low proportion of the total energy mix it accounts for currently. Based on the existing primary energy consumption mix of countries/regions such as the US, South Korea, and Europe (see Figure 30), we think China's nuclear energy contribution could eventually peak at around 8-10% of primary energy consumption.

Against this backdrop, China has been one of the few countries where nuclear power installed capacity has grown in the past decade. While approvals for new reactors were on pause over 2016-18, they have resumed, and there is widespread expectation that China could approve six to eight new reactors per year during the 14th Five Year Plan (2021-2025)[4]. Plans to release a slew of regulations that serve as guidelines for a myriad of issues including safety, radioactive waste treatment, could also pave the way for faster growth of the sector[5].

China's efforts to cultivate a stronger and self-sustained nuclear power value chain are also factors that could drive faster expansion – 90% of the equipment used in the recently live third-

3 "China's Xi targets steeper cut in carbon intensity by 2030", Reuters, 14 December 2020

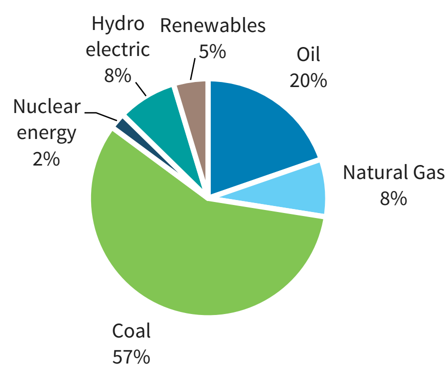
4 "China nuclear power sector ushers in growth era, market could potentially reach trillion yuan size" (我国核电迎发展机遇期 市场空间有望达万亿级), Xinhua, 19 April 2021

5 "China nuclear power sector ushers in growth era, market could potentially reach trillion yuan size" (我国核电迎发展机遇期 市场空间有望达万亿级), Xinhua, 19 April 2021

generation Hualong One reactor constructed by China National Nuclear Corp, the first of its kind to have been put into operation, was made in China.

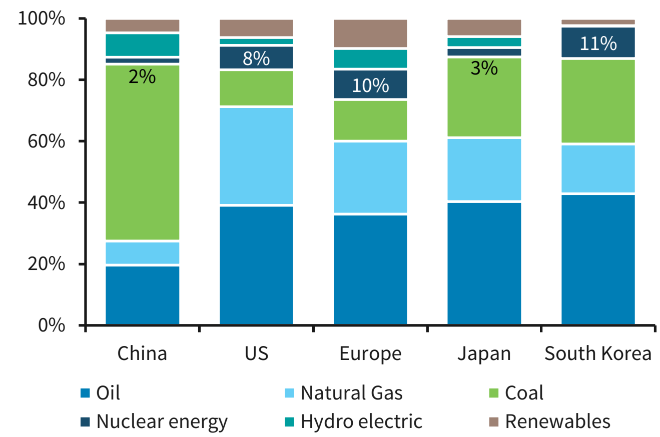
Last but not least, China's nuclear power plants have, on average, a shorter remaining operating life than those in other countries, since China commissioned its first nuclear power plant in 1991, and more than half its existing installed capacity was put into operation on or after 2015. Based on an estimated useful life of 40 years, the majority of existing nuclear plants in China does not need to be replaced before 2050.

FIGURE 29. **China's energy mix still highly reliant on fossil fuels**



Note: 2019 breakdown of primary energy consumption by fuel
Source: BP Statistical Review

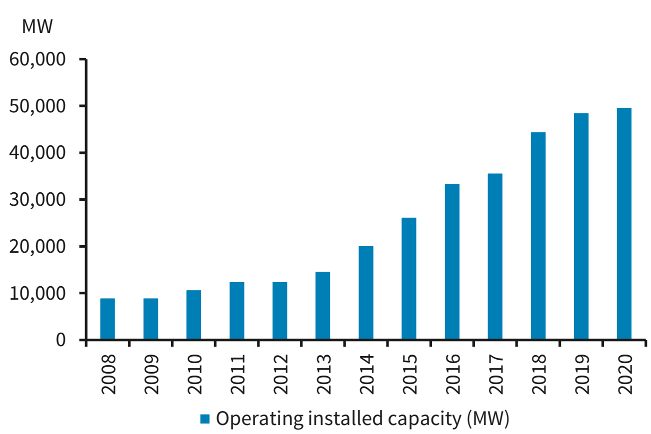
FIGURE 30. **Nuclear remains a small part of China's energy mix, suggesting room to grow**



Note: 2019 breakdown of primary energy consumption by fuel
Source: BP Statistical Review

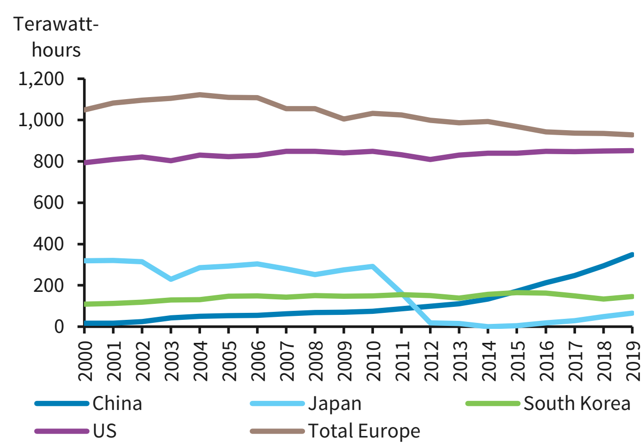
What does this mean for nuclear power growth in China? Conservatively assuming that over the next 30 years China sees a 3% GDP CAGR, a 20% improvement in energy efficiency, and no replacement needs for existing power sources, we estimate it will still need twice the installed capacity as it does now. In order for nuclear power generation capacity to reach 10% of the total power generation installed capacity then, it would require a more than eight-fold increase of the current nuclear power installed capacity, to 438GW. That would also require much faster nuclear growth rates than what is expected between 2020 and 2030, when nuclear power capacity is targeted to rise to 70GW in 2025, and could potentially reach 100-120GW in 2030 (based on 6-10 units approved per year in 2020-25).

FIGURE 31. **China's nuclear power installed capacity has grown exponentially in the past decade**



Source: China General Nuclear Power company reports

FIGURE 32. **China nuclear power generation growth has outstripped that of other countries**



Source: BP Statistical Review

The challenge is made more difficult not simply by the significant upfront costs (USD2.5-3.0mn per MW, accounting for 60% of LCOE) and lead times to complete nuclear plants (potentially three to four years for site selection, demonstration and planning, and another five to six years for construction), but also because regulators and industry players would have to formulate a plan to substantially increase nuclear waste disposal and management capacities and capabilities.

Safety remains an overriding policy consideration, given potential social implications

A generally more prudent approach undertaken by the Chinese government to approving new nuclear plants and reviewing new technologies is positive, given the significant operational hazards and potential impact on residential populations nearby. This is evident from the lack of new reactor approvals in 2016-18, and, more recently, a delay in consideration of inland nuclear reactors (based on progress in this area not being mentioned in the government's 14th Five Year Plan.

Chinese government regulations in this sector, which are expected to be released, could provide further oversight and maintain vigilance on safety, treatment, compensation for displacement of residential populations, and plant management.

The Chinese government and industry players are pursuing new nuclear technologies which could help improve efficacy, yield, and safety, but many remain in pilot stages. Some of the key technologies China is seeking progress on in 2020-25 include modular reactors (SMRs), high temperature gas-cooled reactors (HTRs) and successful commercial mass production of Hualong One reactors.

In the new Hualong One reactor, which was put into operation earlier in 2021, China National Nuclear Corp uses a double-layer safety shell design, which helps prevent the release of radioactive materials into the environment in the event of a serious accident.

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