



Energy outlook 2021

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Executive summary

The pandemic reduced energy demand in 2020, but the energy markets will bounce back in 2021 as the global economy recovers. Covid-19 has had little impact on the growth prospects for wind and solar, the oil market continues to tighten and LNG is boosting the gas market. On the back of these market trends, European utilities will likely increase investment by +5.5%.

The European wind and solar markets are expected to provide solid growth of 8% and 13% in 2021 in terms of capacity additions, which require €60 billion of investment. On the supply side, wind and solar continue to benefit from policy support for green local power systems. On the demand side, we expect power demand to increase by 3% in 2021, although the extension of lockdown periods and delays to the vaccine rollout could lead to stagnation.

Wind and solar energy are expected to gain cost competitiveness over fossil fuel and nuclear power in 2021. It's getting increasingly cheaper to add new wind and solar capacity compared to new fossil fuel power plants or nuclear power plants. The anticipated 35 GW addition of wind and solar capacity is likely to add to price volatility in European power markets in 2021 as large scale power storage facilities, such as batteries and electrolysis, remain relatively small.

European utilities showed resilience in 2020 on the back of the Covid-19 pandemic, however they were not immune from declines in power and gas consumption and company financials felt the impact. European utilities should be able to return to growth in 2021 and many are maintaining their ambitious capital expenditure plans. Overall, we anticipate a +5.5% increase in investment from utilities. This will lead to additional needs for financing as the sector's cash flow generation in 2021 will not be sufficient to cover the higher level of investment. We expect utilities to be printing €40bn of bonds in 2021 of which €20bn will be green bonds.

Gas markets had a volatile 2020, with prices initially coming under pressure from both the hit to demand and ramping up of LNG capacity. However, a rallying Asian LNG market has dragged the whole natural gas complex higher. We believe that the spread between Asian LNG and European prices will continue to support spot cargoes to flow into Asia rather than Europe.

The tightening in the oil market is expected to continue over 2021, which suggests further upside for oil prices. Bear in mind though, that there is still plenty of uncertainty due to Covid-19, the rollout of vaccines and future supply cuts from OPEC+.

Solid growth for wind and solar

Covid-19 has had little impact on the growth prospects for wind and solar. The European wind and solar markets are expected to provide solid growth of 8% and 13% in 2021 in terms of capacity additions, which will require €60bn of investment

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Power demand: on the rise again

Eurozone power demand took a hit of c.5% in 2020 as a result of the lockdown measures. Heavy power users in manufacturing, transportation (notably railways) and commercial real estate (offices) required less power as a result. Increased power demand from working from home could only partially compensate for these declines.

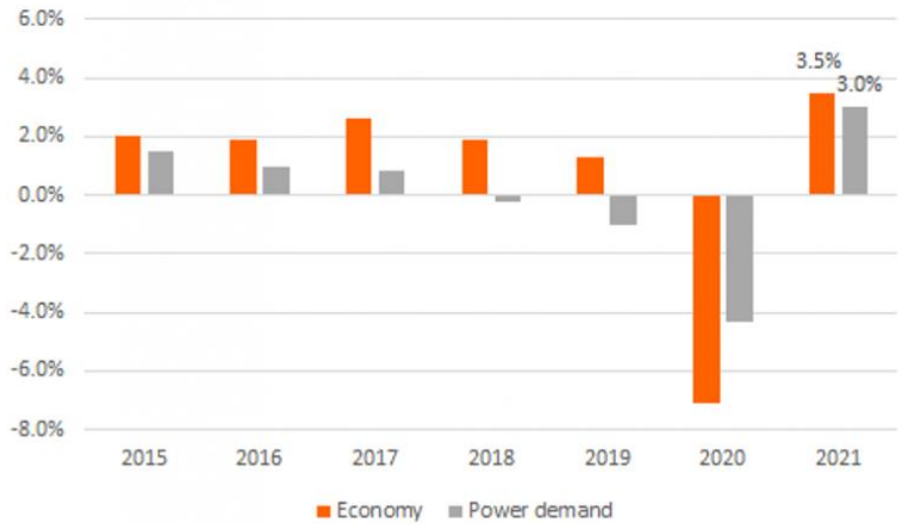
The shape of the economic recovery will determine power demand in 2021. Economic growth depends critically on the evolution of the coronavirus and the vaccine rollout. ING's [base case scenario](#) assumes that lockdowns are alleviated in 1Q21, but social distancing remains the norm for much longer in 2021. We believe a handful of vaccines will be available and rolled out in 1H21. In this scenario the eurozone economy is expected to grow by 3.5% in 2021 and power demand by c.3%, mostly driven by the manufacturing sector. Currently, downward risk is mounting with the emergence of a virus mutation in the UK that is more contagious. If the virus lengthens the current lockdown period, reignites a third lockdown later this year, or if the vaccine rollout takes longer, the eurozone economy could shrink by -0.5% in 2021. In that case, power demand would be flat in 2021. On the upside, rapid testing capability and faster vaccine availability could boost economic growth to 6.1%, resulting in power demand growth of c.4%-5% in 2021.

Power demand increasingly decoupled from economic growth in the years before the outbreak of the Covid-19 pandemic. In 2018-2019, power demand fell while the

eurozone economy grew by 1.3 to 1.9%. Increased energy efficiency and the large share of services in the economy made the economy less power dependent. And [electrification](#) of energy-intensive sectors, such as manufacturing and the built environment, is not expected to lift power demand considerably before 2025. Covid-19 has temporarily put a brake on this decoupling process. Lockdowns, and the resulting recovery phase, are causing power demand and economic growth to move in tandem again.

Economic recovery lifts power demand in 2021

Year on year change in Eurozone economic growth and power demand



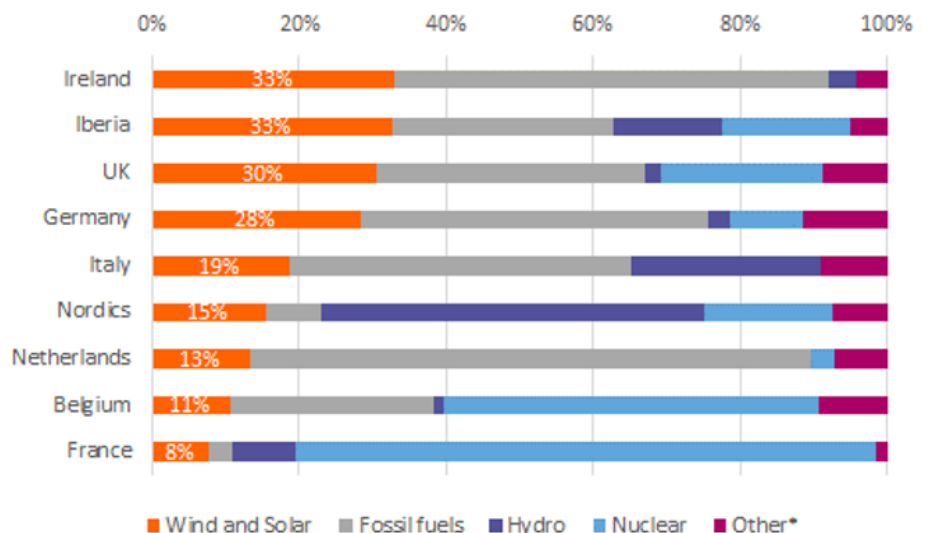
Source: Eurostat, ING Research

Power supply: Ireland, the Iberian region, UK and Germany are most dependent on wind and solar

Over the year, up to a third of power comes from wind and solar in Ireland, Spain and Portugal (the Iberian region), the UK and in Germany. During the year, on a daily or hourly basis, shares can range from almost zero to over 100% depending on local weather conditions and power demand.

Ireland and Iberia region most dependent on wind and solar, France and Benelux least

Expected power mix in 2020 based on power generation

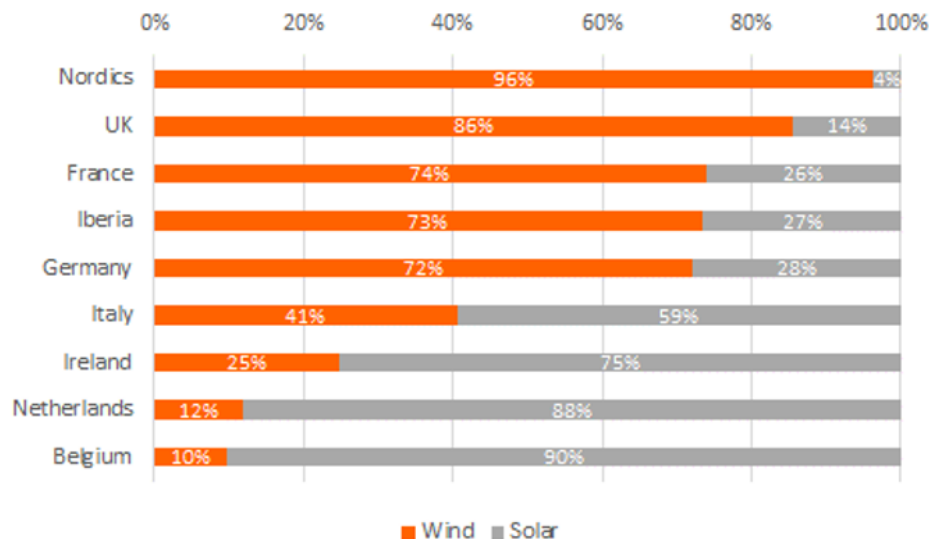


*Mostly biomass and geothermal energy

Source: Eurostat, BNEF, ING Research

Wind is big in the larger Eurozone countries, solar in the Benelux countries and Ireland

Expected division between wind and solar in power generation in 2020



Source: Eurostat, BNEF, ING Research

Countries so far have taken different strategies regarding wind and solar. In the Benelux countries and Ireland, much more power comes from solar panels than from wind turbines. In the Nordics and the UK - and even in sunny countries like France, Spain and Portugal - more power is generated with wind turbines compared to solar panels.

Globally, the wind market is an onshore market, as around 80% of wind power is generated on land, but again this varies from country to country. In Europe, onshore wind power dominates in Germany, France, Italy, Ireland and the Iberian and Nordic regions. In the UK and the Netherlands, wind comes equally from on- and offshore windfarms, whereas in Belgium, almost all the wind power is generated offshore.

€60bn investment in wind and solar anticipated for 2021

The European wind and solar markets are expected to provide solid growth of 8% and 13% in 2021 in terms of capacity additions. In absolute terms, capacity additions are largest in the onshore wind sector (13 GW) and for small scale solar projects (12 GW). In the offshore wind sector c.2GW of capacity will be added in 2021. That is relatively small compared to the other segments, but policymakers in the Nordics, UK, Ireland, Germany and the Netherlands continue to work on special planning for offshore wind farms and grid infrastructure. So more is about to happen in the coming years for offshore wind farms. All in all, we expect to see c.35 GW growth in the combined wind and solar market, which will require €60bn of investment.

Growth in solar outpaces growth in wind

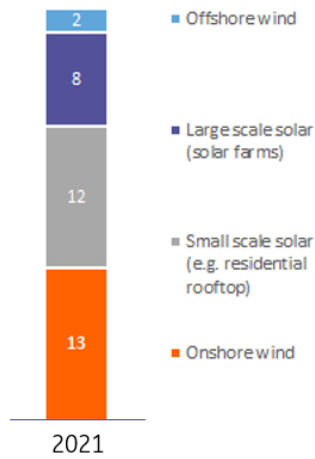
Yearly growth in installed capacity for solar and wind energy in Europe



Source: BNEF, ING Research.

Most capacity is added in onshore wind and small-scale solar projects

Added capacity in Europe in GW



Source: BNEF, ING Research.

Wind and solar get increasingly cheaper

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Wind and solar energy are expected to gain cost competitiveness over fossil fuel and nuclear power in 2021. Increasingly, it is becoming cheaper to add new wind and solar capacity compared to new fossil fuel power plants or nuclear power plants



The anticipated 35 GW addition of wind and solar capacity will likely add to price volatility in European power markets in 2021, as large scale power storage facilities, such as batteries and electrolysis, remain relatively small.

First tipping point: gifts of nature

The price development of wind and solar is marked by three important tipping points (see table). First, wind and solar power have always benefited from close to zero marginal costs. Once the panels and turbines are in place they are the cheapest technology to produce an extra MWh of electricity, as wind and sun are freely available whereas fossil power plants need to pay for gas or coal. In short, existing wind and solar projects outcompete existing coal and gas power plants. Renewables drive out fossil fuel production once they enter the power mix.

Overview of renewable energy price tipping points: competition continues in 2021

Indicative ranking for the cost competitiveness of wind and solar (renewables) versus fossil and nuclear power (non-renewables).

Tipping point	Holds in 2021?
1. Existing renewables versus existing non-renewables	
It is (much) cheaper to produce power with existing wind turbines and solar panels compared to existing coal and gas fired plants	Yes
2. New-build renewables versus new-build non-renewables	
It is cheaper to build new wind and solar plants compared to fossil fuel or nuclear plants:	
a) When investments in grid infrastructure to accommodate renewables are excluded	Yes
b) When investments in grid infrastructure to accommodate renewables are included	Sometimes
c) When the costs for curtailment are included in case of subsidy free solar and wind projects	Sometimes
d) When the costs for energy storage are included: for example wind and solar projects with battery storage	No
3. New-build renewables versus existing non-renewables	
It is cheaper to build new wind and solar plants compared to running existing fossil fuel and nuclear plants*	No

*In economic terms: the Life Cycle cost OF Electricity of solar and wind are lower than the marginal costs for coal and gas fired power plants. A distinction between a) to d) also applies to this third tipping point, but none of them is valid for renewables in 2021 and therefore left out.

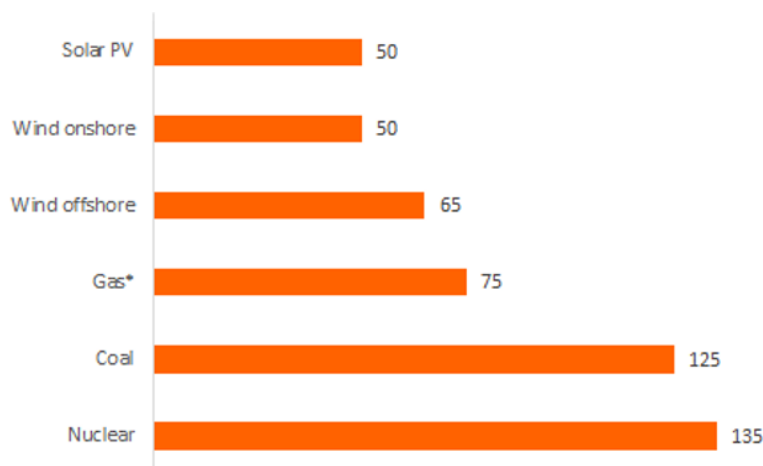
Source: ING Research

Second tipping point: new-build wind and solar cheaper than new-build coal, gas and nuclear plants

For investment decisions, one must also include the initial investment through capital costs and the maintenance costs to keep the technology running. The Life Cycle cost Of Electricity (LCOE) does just that and can be viewed as the total cost to produce a MWh of electricity during the lifespan of the asset. Nowadays, even new-build renewables are, on average, cheaper than new-build fossil fuel or nuclear power plants (see graph). We expect this gap to widen further in 2021. First, solar panels and wind turbines continue to get cheaper and experience favourable tender conditions in the current economic environment. Second, we expect upward pressure on fossil and carbon prices in 2021. Lastly, an estimated 35 GW of solar and wind capacity is expected to enter European power systems, which will lead to lower utilisation rates of fossil fuel power plants.

Wind and solar are cheapest ways of power generation

Average Life Cycle cost OF Electricity (LCOE) for major power technologies in Europe in 2019 in euro/MWh



*Combined Cycle Gas Turbines or CCGT power plants. The LCOE for gas peaker plants is much higher.

Source: IEA World Energy Outlook 2020, ING Research

This tipping point of new-build wind and solar projects being cheaper compared to new-build fossil fuel power plants is likely to get more nuanced in 2021 and the years beyond. It holds in most cases if the cost for investment in the power grid are not taken into account. But power grids are increasingly showing their limitations to accommodate renewables in areas with a high supply of renewables (e.g. large wind and solar farms in rural areas) or strong growth in power demand (e.g. new data centres in urban areas).

Furthermore, this tipping point needs to factor in the production profile of renewables during the day. For example, power generation from solar and wind has a strong peak at noon, especially on sunny days. Production needs to be shut down (curtailed) in case supply exceeds demand or if prices are negative and the plant is penalised for power generation¹. In 2021, new-build renewables could be cheaper compared to new build fossil fuel plants even if a couple of days of curtailment per year are factored in.

Curtailement could be technically avoided by adding storage facilities to solar and wind projects so that electricity can be stored during times that supply exceeds demand or when prices are too low to cover costs. However, new-build wind and solar projects combined with large scale battery storage or hydrogen electrolysis is not yet cost competitive with new-build fossil fuel plants.

Third tipping point: new-build wind and solar cheaper than existing, gas and nuclear plants

Finally, a third and even more disruptive tipping point would emerge if the costs of building new solar and wind projects are lower than running existing coal or gas fired power plants. In that case, it would be economically viable to replace fossil fuel power generation with wind and solar energy. A considerable part of fossil fuel generation is still needed though to act as a back-up facility at times when the sun and wind are not strong enough, especially in the absence of large scale storage facilities. This third tipping point does not hold in 2021 and power market structures are likely to change once markets reach this tipping point in order to guarantee the reliability of power systems at all times.

Renewables and power prices: a comparison between Germany and the Netherlands

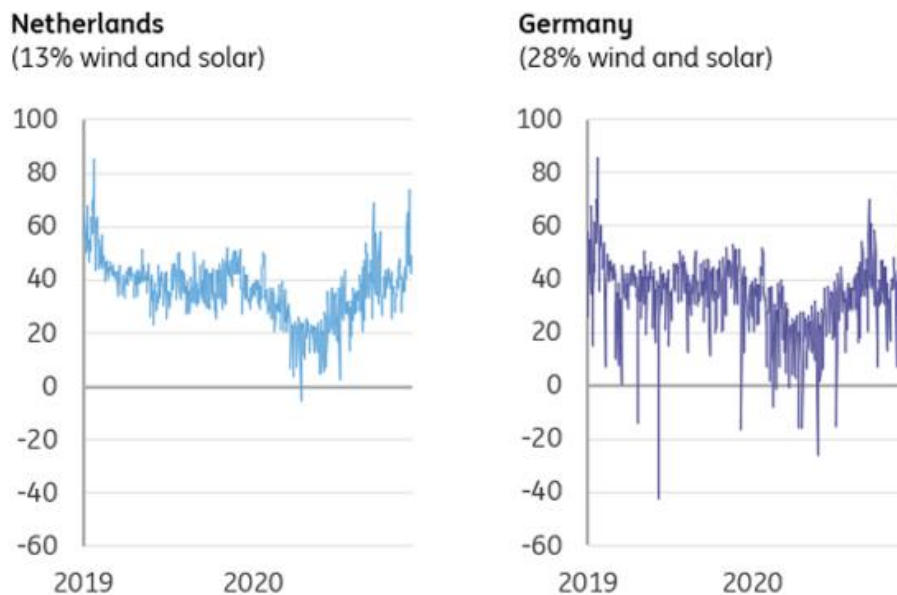
The impact of renewables on European power prices is likely to increase. Research shows that power prices get more volatile as wind and solar leave their mark on the power mix². In that respect it is interesting to compare the German and Dutch power markets. These markets are quite similar but differ in the degree of wind and solar power generation. First, the similarities. In both countries the majority of power is little market risk and produce as much power as possible, irrespective of the power price. In Germany, however, the share of wind and solar in the power mix is twice the share of wind and solar in the Dutch power mix (28% vs 13%). That is a major difference that sets these markets apart.

¹ This is the case for subsidy free wind and solar projects where the owners run merchant risk.

² See for example the energy outlooks by Aurora Energy Research, DNV-GL and Bloomberg New Energy Finance.

More wind and solar add to volatility in power prices

Daily spot prices of baseload power in euro/MWh



Higher daily power generation from wind and solar in Germany caused power prices to be more volatile, with more days of negative prices.

Source: IEA World Energy Outlook 2020, ING Research

Higher shares of renewables make German power markets more volatile

The higher share of renewables in Germany has two major implications for power prices (see graph). First, German power prices are more volatile as wind and solar push down the power price on sunny and windy days much further than in the Netherlands³. Second, with the lack of large storage facilities for surplus power, and with most wind and solar assets producing as much power as possible (subsidy-based renewables), the higher share of wind and solar in Germany results in more days with near zero or even negative power prices. We expect this situation to continue in 2021 for two reasons. First, more renewables will enter European power markets in 2021. Second, the vast majority of power generation from renewables will be subsidy-based in 2021 despite the early trend of subsidy-free tender bids for renewables. Therefore, owners of wind farms and solar panels have little incentive to cut back on production when prices are low or negative.

In Germany, the average power price in the 2019-2020 period is €2 lower compared to the Netherlands (34 vs 36 euro/MWh). Volatility is €4 higher (standard deviation 15 vs 11 euro/MWh).

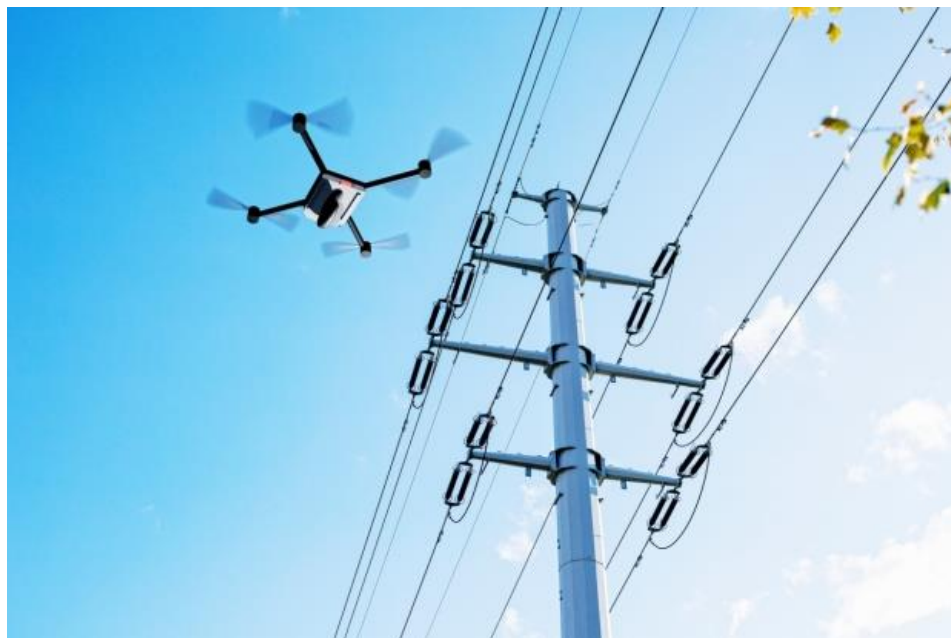
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Rise in investments increases capital needs for utilities

A recovery in power demand of 3% on average for the European Union, coupled with a recovery in power prices, should bring European utilities back to growth in 2021



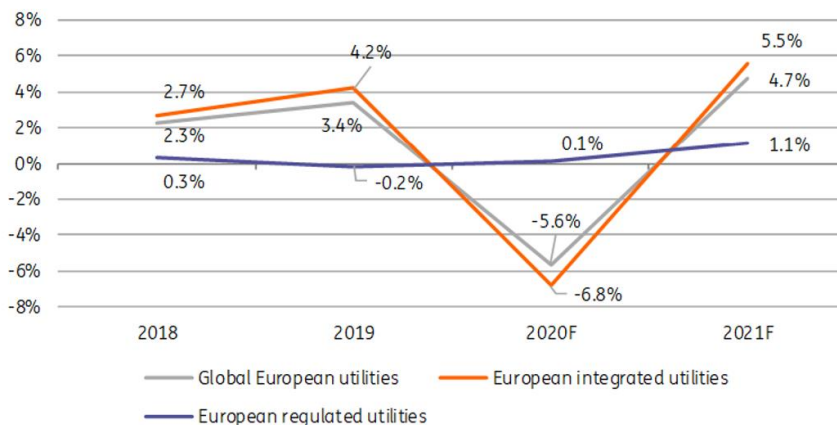
Across Europe, power demand fell 4.3% in 2020, according to ENTSO-E's statistics. Depending on the severity of the Covid-19 pandemic and lockdown measures implemented by governments, some countries were more severely impacted than others. The consumption of natural gas also drastically slumped and its price on the markets reached all-time lows. A recovery in power demand of 3% on average for the European Union (according to Eurostat's expectations) coupled with a recovery in power prices should bring European utilities back to growth.

On aggregate, based on a panel of 38 utilities⁴, we estimate that European utilities' EBITDA will be 5.6% lower in 2020 vs. 2019. While regulated utilities' EBITDA should come in flat (+0.1% in 2020 vs. 2019), integrated utilities bear most of the impact from the Covid-19 pandemic with an aggregate EBITDA down 6.8%, according to our estimates.

4.7% European utility sector's EBITDA to grow by this amount on average in 2021 vs. 2020

⁴ 38 utilities: A2A, Acea, Alliander, Centrica, CEZ, EDF, EDP, Elia Belgium, Enagas, EnBW, Enel, Enexis, Engie, E.ON/Innogy, Eurogrid, Fluvius, Fortum, Hera, Iberdrola, Italgas, National Grid, Naturgy, Nederlandse Gasunie, Orsted, Red Electrica, REN, RTE, RWWE, Snam, SSE, Stedin, Suez, TenneT, Terna, Vattenfall, Veolia, Viegas.

European integrated and regulated utilities – sector EBITDA 2018-2021F



Source: Company data, ING

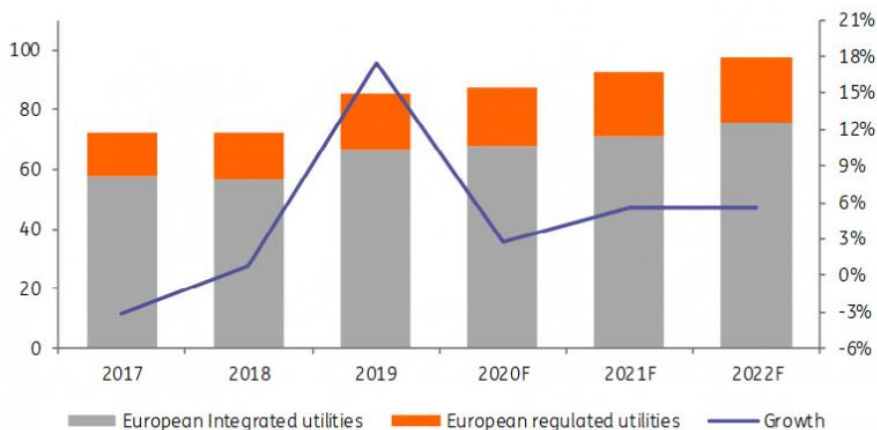
Earnings growth in 2021

While a number of grid utilities will see their remuneration reduced by (new) regulatory packages, their strong capital expenditure plans will preserve cash flow generation growth thanks to inflated regulated assets bases. In 2021, we expect European regulated utilities' EBITDA to grow 1.1% vs. 2020. With power and gas prices as well as consumption up in 2021, integrated utilities should be able to catch-up with a sector EBITDA growth estimated at 5.5%, based on updated strategic plans and our assumptions. All in all, we estimate that the overall sector (integrated utilities and regulated) will grow earnings before interest, depreciation and amortisation by 4.7%. Although it will not erase completely the 5.6% reduction in 2020, we consider this number to be very supportive for the sector.

Contrary to oil & gas majors, European utilities are maintaining their ambitious capital expenditure plans. A number of utilities have even posted new strategic plans including bigger investments in 2021 and beyond, in comparison with their initial intentions last year and two years ago. Total investment in 2021 is expected to surpass 2020 by 5.5% with a strong focus once again on renewable capacity development and upgrade, as well as the expansion of power networks. We expect a similar expansion of investment in 2022, with growth of 5.6%, according to companies' information and our estimates.

5.5% Increase in investments in 2021

Total investment (€bn) and growth for the European sector (selection of 38 utilities)

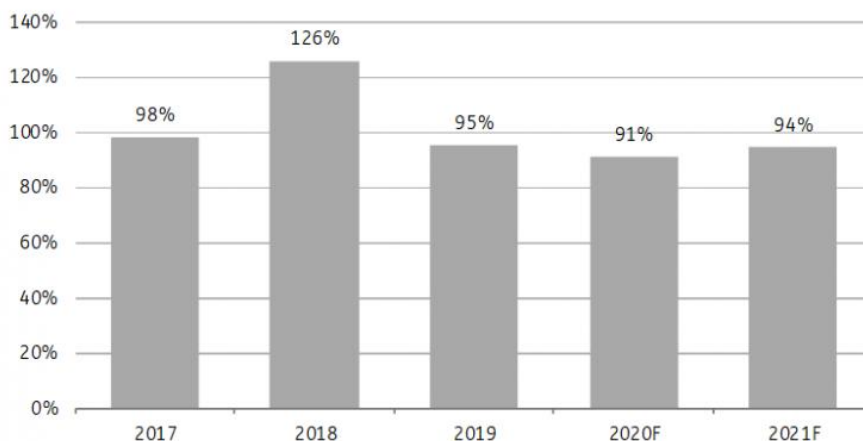


Source: Company data, ING

Financing capex plans

The expansion of capital expenditure, which started in 2019 and will go on in 2021 and beyond, suggests that cash flow generation (represented by cash flow from operations) will not be enough to fully finance investments. This is particularly true for regulated utilities, whose capital expenditure is expanding even more strongly than for integrated utilities. Taking our panel of 38 utilities altogether, we expect cash flow from operations to cover 94% of investment expenditures in 2021. Taking expected dividend payments into consideration, this ratio falls to 80%, according to our estimates.

Cash flow from operations/investment ratio



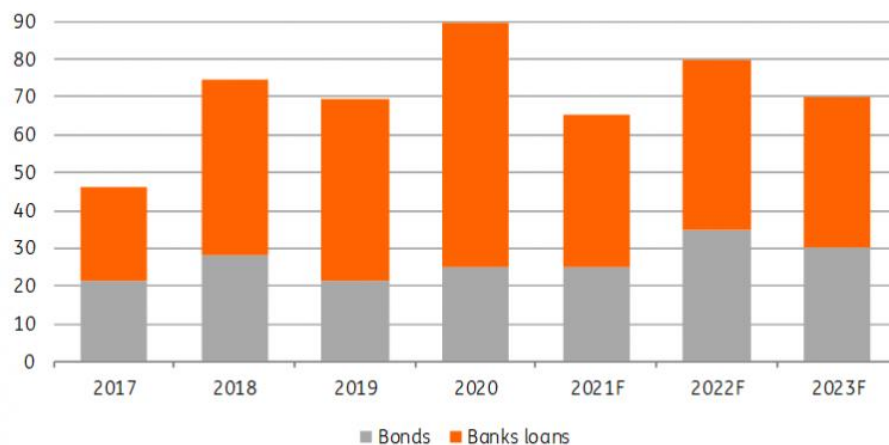
Source: Company data, ING estimates

Bond issuance

With cash flow generation too short to cover the capital expenditure in full, additional debt via bond or bank loan issuance, will translate into higher debt and pressure on credit ratios.

As far as the current debt burden is concerned, the utility sector has a relatively low bond and bank loan redemption schedule in 2021. While bond and bank loan redemptions reached almost €90bn in 2020, this number falls to €65bn in 2021. Total redemptions will step up again in 2022, reaching €80bn.

€ bonds and bank loans redemption schedule 2017-2023 (in €bn)



Source: Dealogic, ING

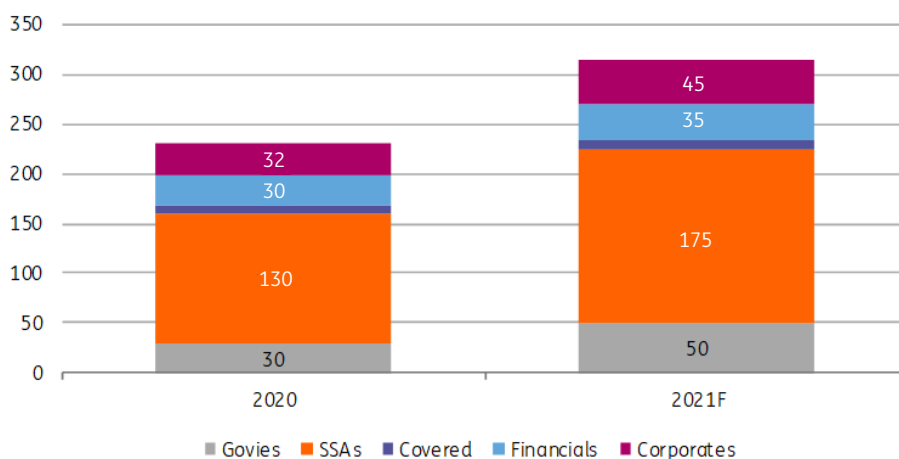
With ambitious capital expenditure plans and dividends payouts not fully covered by cash flow generation, we expect utilities to be printing c.€40bn of bonds this year. The Utility sector will continue to support global green bond issuance. Among all the

corporate sectors (excluding Financials), utilities have been the most active in green bonds in the last few years due to the sector’s major role in energy transition plans.

In 2020, the markets, all currencies included, issued an equivalent of c.€380bn of sustainable bonds including green, social, sustainability and SDG-linked bonds. As far as euro-denominated bonds are concerned, some €230bn of bonds equal to or above €250m were printed in 2020. We forecast total euro-denominated sustainability bonds to reach €315bn in 2021.

20bn € denominated green bonds in 2021 for the utility sector

2020 and 2021F € denominated bond sustainable issuance (in €bn)



Source: Eikon, Informa, Company info, ING estimates

While we believe sovereigns and agencies will continue to dominate green, social and sustainable bond issuance in 2021, we expect the corporate sectors (excluding financials) to issue €45bn, with utilities accounting for €20bn of green bonds. Among the €45bn, we also expect more SDG-linked bonds (€12bn in 2021 against €3.1bn in 2020) as the format becomes more popular. A number of European oil & gas majors and utilities announced they were contemplating the issuance of SDG-linked (Sustainable Development Goals) bonds in 2021 that would allow the companies to target specific sustainability goals.

Asian LNG drags the gas complex higher

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Gas markets had a volatile 2020, with prices initially coming under pressure with not only a demand hit, but a ramping up in LNG capacity. However, a rallying Asian LNG market more recently has dragged the whole natural gas complex higher. In fact, LNG turned out to be the best performing commodity in 2020, and has made record highs at the start of 2021



Soggy demand and growing capacity

As seen with most markets in 2020, LNG was unable to escape the Covid-19 related demand hit, with industrial gas demand weighed down by lockdowns. This saw LNG prices in Asia trading to record lows, which also weighed on regional gas hub pricing around the globe, and in particular Europe. This only added to what was already set to be a bearish year for LNG markets, following a mild winter, along with the fact that around 24mtpa of LNG export capacity was scheduled to start up over the course of 2020, with the bulk of this capacity coming online in the US.

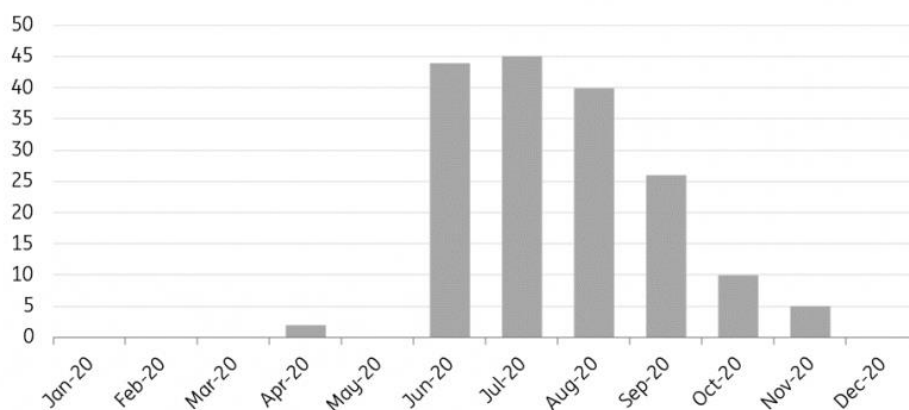
Therefore the market witnessed a large number of US LNG cargo cancellations over the summer, with the price collapse in Asia and Europe making it uneconomical for buyers in the region to take delivery of cargoes. Nearly 175 LNG cargoes were cancelled between March and October of 2020, with the majority of these cancellations taking place in June-August 2020, a seasonally softer period for gas demand.

If we look at export data from the US, volumes collapsed over the summer months as a result of these cancellations. Volumes hit a low of below 1.9mt in August, which is the lowest monthly number seen since 2018, and well below the roughly 5.5mt exported in February. However since then, and with cancellations easing, we have started to see volumes pick up once again. Due to the recovery we are seeing, along with strong export volumes at the start of 2020, total exports from the US over the first 11 months of 2020 are still up around 32% year-on-year, according to IHS Markit, and full year exports will still see very impressive growth.

In Asia, while LNG imports over April and May fell YoY as a result of lockdowns across the region, we have seen quite the recovery in demand since then. Data from IHS Markit shows that LNG imports into Asia over the first 11 months of 2020 totalled a little over 233mt, which is still up almost 7% YoY.

As for Europe, the region continued to see strong growth in LNG imports through until the end of May. Since then though, volumes have come under pressure as a result of cancellations, while more recently given the premium that the Asian market is trading at to Europe, any spot cargoes will likely make their way to Asia rather than Europe. However, over the first 11 months of 2020, imports total a little over 82mt, up 2% YoY, according to IHS Markit data.

US LNG cargo cancellations in 2020



Source: Various media reports

The market roars back

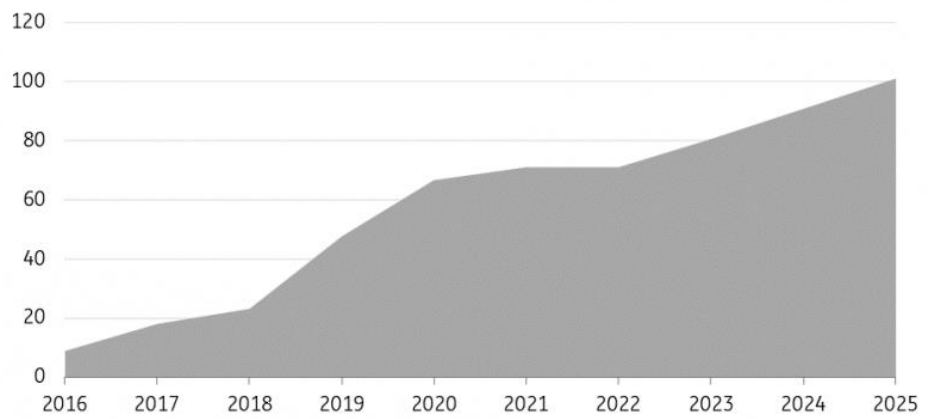
LNG cargo cancellations certainly helped in rebalancing regional markets, which has been more supportive for prices in recent months. A number of unplanned outages in the US as a result of hurricane activity, along with extended maintenance at some LNG plants in Australia, has only provided further support. In addition, colder than usual weather in North Asia has been a bullish driver, while a delay in shipments through the Panama canal, along with rallying freight rates has only helped to push the market even higher. Spot Asian LNG prices have reached record levels in early January, with JKM trading above US\$20/MMBtu. While these very high prices may see some buyers taking a step back, with cold weather expected to continue, prices are likely to remain well supported in the near term.

The spread between Asian LNG prices and Henry Hub in the US is wider than US\$17/MMBtu, suggesting very little chance of seeing further cancellations anytime soon, in fact a spread of that level should see LNG plants in the US maximising throughput. Meanwhile, the spread between Asian LNG and European prices (TTF) is almost US\$13/MMBtu, and so there is a clear incentive for spot cargoes to flow into Asia rather than Europe.

Looking further ahead, and in terms of liquefaction capacity, we do appear to be behind the bulk of capacity additions, at least for the next several years. In 2021, only about 8mtpa of capacity is expected to come online, which should be much more manageable for the market to absorb, particularly with demand expected to grow at a healthy pace.

This all suggests that regional gas markets will be better supported over 2021, and it looks increasingly unlikely that we will see a repeat of cargo cancellations this year. Clearly, Covid-19 remains a risk if we were to see further waves over the course of the year.

Limited US LNG export capacity set to come online over the next two years (mtpa)



Source: EIA, ING Research

ING natural gas forecasts

	1Q21	2Q21	3Q21	4Q21	FY21
ICE NBP (GBP/therm)	45	32	34	40	36
TTF (EUR/Mwh)	16	12	13	15	14
Henry Hub (US\$/MMBtu)	2.8	2.6	2.7	3.1	2.8

Source: ING estimates

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Oil market set to continue tightening over 2021

While there is still plenty of uncertainty over 2021 due to Covid-19, the roll out of vaccines and continued supply cuts from OPEC+ mean that the market should continue to tighten over the course of the year, which suggests further upside for oil prices



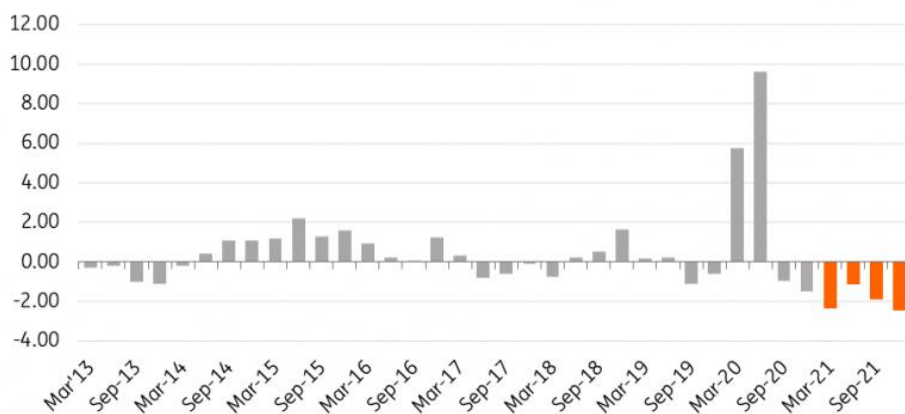
OPEC+ to continue with cuts

2020 was a year which saw OPEC+ having to take extraordinary action in order to try stabilising the oil market. The unprecedented fall in oil demand last year, and in particular over 2Q20, left the market drowning in supply. Covid-19 meant that OPEC+ members had to put aside their differences in April, and agree on historic record production cuts. The group agreed to cut by 9.7MMbbls/d over May and June, and this was eased as we moved through the year. Under the original deal the group was set to ease further starting in January 2021, reducing the level of cuts to 5.8MMbbls/d, which would then be in place until April 2022. However, with the demand recovery this year taking longer than initially expected, coupled with a surge in Libyan supply, the group has been forced to revisit this plan, given the risk that easing too much at the beginning of 2021 could push the market back into surplus.

Instead, OPEC+ will ease output less than originally planned. For January 2021, the group eased cuts by 500Mbbbls/d, leaving the level of cuts at 7.2MMbbls/d. From there, OPEC+ will assess the market on a monthly basis and decide whether to ease further. Under the revised deal, the group will ease by a maximum of 500Mbbbls/d per month.

This approach does create more uncertainty around what OPEC+ may decide every month, and so the potential for increased volatility in the first few months of 2021. We have already witnessed this during the first week, with Saudi Arabia announcing that it would make additional voluntary cuts of 1MMbbls/d over February and March, following the last OPEC+ meeting.

We believe that the changes the group made to the deal will be enough to ensure that the market does not return to surplus in 1Q21 while for the remainder of the year, we would expect the market to continue drawing down stocks. Clearly, much will depend on how Covid-19 develops over the course of this year.

Quarterly oil balance (MMbbls/d)

Source: IEA, EIA, Rystad Energy, ING Research

Limited non-OPEC supply growth

OPEC+ was not the only one to respond to the weaker price environment that we saw in 2020. Non-OPEC+ producers were also quick to shut in production in 1H20 due to the build up in stock, and the weak price environment. At its peak over May, we saw somewhere in the region of 2.7MMbbls/d of non-OPEC+ production shut, with the US standing out, having shut in a little over 1MMbbls/d of production in May.

However, what has been even more surprising is that with the fairly quick recovery in oil prices from the April lows, producers have been quick to bring back this shut-in production. The US has basically brought back all shut-in production, while Norway seems to be the only meaningful producer to have still shut-in production, although that is due to mandated production cuts put in place earlier in 2020.

We saw a large decline in non-OPEC supply over 2020 and this year growth is expected to be limited, with less than a 500Mbbbls/d increase year-on-year, which still leaves non-OPEC supply in 2021 well below 2019 levels.

In the US, while we have seen a pick-up in rig activity in recent months, it is still well below pre-Covid-19 levels, with the number of active rigs in the US standing at 267, down around 61% since mid-March. Therefore, it is difficult to see the US returning to growth anytime soon. We would need to see a further pick up in prices before producers are willing to increase spending, and as a result, a significant pick up in drilling activity. Producers will likely rely on drilled but uncompleted wells (DUCs) in order to try to sustain production levels, although these DUCs have only been declining at a fairly modest pace in recent months. For 2021, US production is expected to fall by a further 300Mbbbls/d YoY to leave output averaging 11.1MMbbls/d. This compares to an estimated 850Mbbbls/d YoY decline in 2020.

Demand uncertainty

The biggest uncertainty and risk for the market remains the demand outlook. While recent vaccine developments are positive for the demand outlook in the medium term, there are still plenty of uncertainties over demand in the short term, with it likely to take some time before a vaccine becomes widely available, allowing us to all return to a more normal life. Before that comes, there are risks of further Covid-19 waves and lockdowns, and international air travel is likely to remain very limited until governments feel comfortable easing border restrictions and quarantine requirements. Assuming that we see an effective vaccine becoming widely available from spring into summer, we believe that we will see a robust demand recovery over the second part of 2021.

However, we are still unlikely to return to pre-Covid-19 levels in 2021. We are currently assuming that demand will grow by around 6.7MMbbls/d this year, after having fallen by

around 10MMbbls/d in 2020. It appears we will have to wait until at least 2022 to reach pre-Covid-19 demand levels once again.

Iranian supply risk

While demand is a big uncertainty for the market, another key downside risk for the market is Iran. Following the outcome of the US election, it is looking more likely that the US will return to the Iranian nuclear deal, and with that the potential for the removal of sanctions. Such action could bring anywhere between 1.5-2MMbbls/d of supply back onto the market. However, the big unknown is around timing, as it's not clear how high Iran is on Biden's priority list. If we were to see a fairly quick return of Iranian supply over 1H21, this could put some pressure on the market, with the market likely finding it difficult to absorb additional barrels. However, if we only see Iranian supply starting to come back in the latter part of next year, the market should be able to digest this oil more easily, given expectations of demand continuing to recover as we move through the year.

Stronger prices through the year

We expect that the oil market will draw down inventories throughout 2021, as demand continues to make a recovery. The key risk was around 1Q21, but OPEC+ have addressed this with its recently revised deal. We forecast that ICE Brent will average US\$55/bbl over 2021 and likely end 2021 in the region of US\$60/bbl. This view is dependent on a vaccine allowing demand to continue to recover, along with the OPEC+ deal holding through the whole of 2021.

ING oil forecasts

	1Q21	2Q21	3Q21	4Q21	FY21
ICE Brent (US\$/bbl)	48	55	58	60	55
NYMEX WTI (US\$/bbl)	46	53	56	58	53

Source: ING estimates

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