S&P Global Ratings

EMEA Utilities

Europe's energy transition: Still on, despite crosscurrents

January 9, 2024

This report does not constitute a rating action.

What's changed?

Positively, gas is no longer scarce. Nevertheless, because of Europe's low supply buffer, power and gas prices remain elevated and volatile.

The economics of power supply decarbonization have weakened for offshore wind and power grids. This makes the transition less affordable and slower than hoped.

Higher-for-longer interest rates, high inflation on renewables, and grid capital expenditures (capex) test energy transition economics, including for nuclear. Yet most Western European grids benefit from regulatory values indexed to inflation and remuneration to interest rates.

What are the key assumptions for 2024?

Continuing high and volatile gas and power prices benefit power generators. Demand containment efforts may be tested by ongoing affordability measures and slight GDP growth.

Caution on generation and grid investments. With higher capex, we expect prudent financing.

Reduced ratings headroom outside thermal and hydro generators. Balance sheets, while typically solid, are eroded by high and growing capex, interest rates, and dividends.

What are the key risks around the baseline?

Supply chain issues, interest rates, inflation, and regulatory and fiscal setbacks aggravating energy-transition economics. Changes in assumptions or weak contracting could impair the economics of large projects and a utility's business risk or financial risk profile.

Political and regulatory risks. Pressures to accelerate the energy transition and affordability measures could weigh on ratings via higher debt and lower earnings.

Cyber risk, physical sabotage, or weather. These could weigh on issuers with thin liquidity.

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Ratings Trends: EMEA Utilities

Chart 1
Ratings distribution

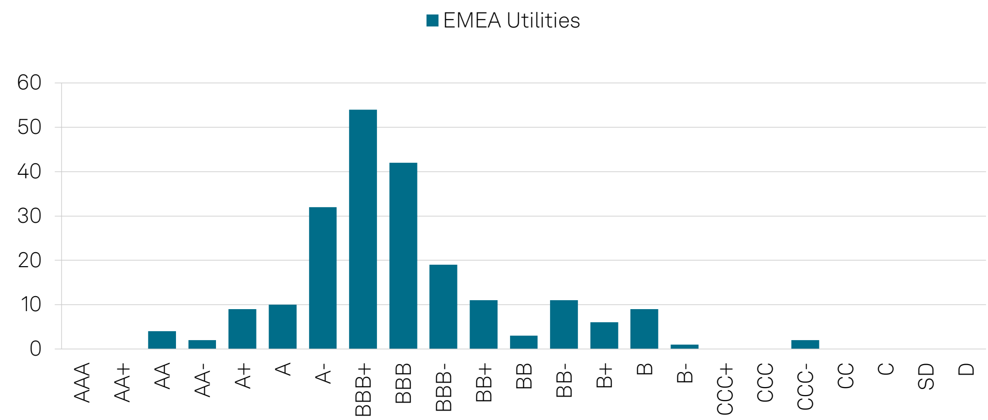


Chart 2
Ratings outlooks

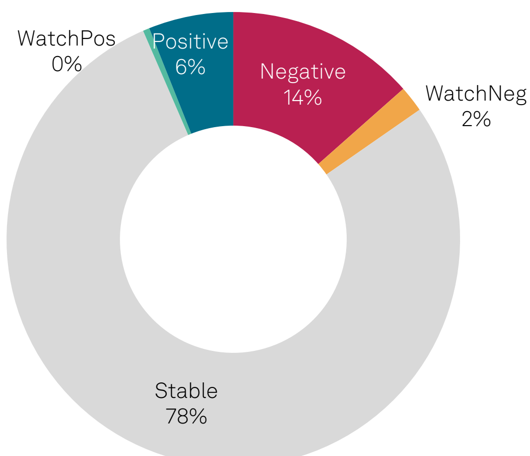
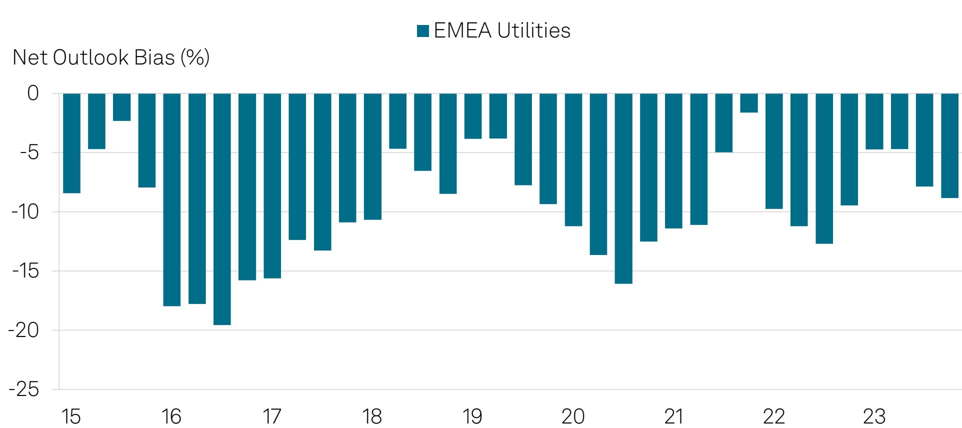


Chart 3
Ratings outlook net bias



Source: S&P Global Ratings. Ratings data measured at quarter-end.

Industry Outlook

Ratings trends and outlook

We maintain a degree of negative bias that primarily reflects:

- Risks and opportunities from gas and power prices, with prices elevated through 2025, even if much less so than in 2022; rising refinancing rates; and continuing issues around supply-chain and sector-specific inflation (well above the consumer price index [CPI]), notably for offshore wind and power networks.
- For networks, notably power, tensions are emerging on financial risk profiles from heavy capex, regulatory reset risks on the weighted-average cost of capital (WACC), and dependence on issuing new equity.
- For U.K. water utilities, sustained political, media, and social scrutiny are prompting a need for greater investment--although the financing mix for 2025 onward, particularly from additional shareholder contributions, remains uncertain. With two-thirds of ratings on negative outlook or a CreditWatch negative placement, the subsector has the most negative bias of EMEA utilities overall.

However, we expect inflation to subside in 2024 and approach 2% in 2025 across most of Western Europe.

We think some negative bias remains elevated, even after noticeably receding for energy companies. Still, over three quarters of utilities are on stable outlook, underpinned by solid fundamentals and, on the power side, medium- to long-term business prospects as Europe accelerates its energy transition. The very volatile power-market environment since fall 2021 has been offset by significant political support and company-specific actions to support credit metrics and liquidity.

Consistent with COP28 commitments to triple global renewable capacity by 2030, Europe's wind and solar capacities remain set to more than double over 2023-2030, despite recent offshore wind setbacks as solar installations progress steadily. We therefore expect the EU to approach, but not reach, its 2030 target of a 42.5% share of renewables (versus 23% in 2023, and 13% in the U.S.) in the primary energy mix, finalized in the Renewables Energy Directive III in October 2023. In December 2023 the European Commission stated that current national energy plans (despite boosting targets) would achieve only about 39%.

While wind additions will likely underperform expectations, solar will exceed them, continuing on from 2023's record addition of 56 gigawatts (GW). For offshore wind to accelerate again, 2024 might prove pivotal if the massive auctions expected this year--50GW according to S&P Global Commodity Insights (SPGCI), more than the entire current 33GW fleet--prove successful. As the buildup accelerates, by 2030 we expect renewables to reach 70% of Europe's power demand (despite demand increasing by one fifth), up from about 46%. This will require power transmission and distribution grid expansion costing €584 billion over 2023-2030, according to the EU's 2020 estimate. Given sector-specific inflation, however, we expect this bill to be nearer €800 billion for Europe. Based on SPGCI’s data, we expect 2022-2030 wind generation investments alone to also approach €800 billion. Overall, including all generation technologies and storage, costs will likely exceed €2 trillion across Europe, about 20x the total annual capex of our top-25 rated European energy utilities (top-25).

Against this background, we anticipate sector capex and debt to rise steadily. For our top-25, we project capex to represent 1.1x-1.2x funds from operations (FFO) compared with just under 0.9x each year in 2017-2019. Leverage in particular could increase for some power grids and U.K. water utilities, which face growing media and political pressure to raise service quality. We will monitor the extent to which higher interest rates are effectively and timely passed onto WACCs, with some European regulators (such as Italy and Belgium) already consistently applying their methodology, resulting in higher remuneration. EBITDA should also rise somewhat, although not as fast in some regions, potentially weakening credit quality.

Europe's high energy prices support earnings for fixed-cost power generators for the next two years to the degree they are exposed to merchant activities or have rolled over hedges at favorable prices. Rating risk can notably come from:

- Poor management that exposes projects to write-downs, power purchase agreement (PPA) renegotiation, and other losses;
- Deteriorating economics for renewable capacity additions; or
- Weather-related renewables generation shortfalls.

For integrated companies, rating downside could come from a worse-than-expected dilution of regulated activities in their overall business mix.

We believe utilities can generally manage such deviations within a notch of our ratings on them, through remedial measures on their balance sheets--asset disposals and hybrid capital (utilities are by far the biggest issuers among European corporates, together with telecom companies)--or equity raises.

Flexibility from asset disposals--whether subsidiaries or stakes in renewable farms--is particularly strong at large integrated companies, while it is limited for gas and power grids.

We monitor hybrid instrument issuers' approaches to refinancing, particularly at high single-digit rates, and whether they opt for calling the instrument at step-up date, as all European rated corporates have done to date except real-estate company Aroundtown. All issuance across EMEA utilities includes step-ups except for EDF's June 2023 $1.5 billion U.S. issue.

Issuing common equity could be a credible avenue for regulated power and water, notably for existing government-related entities (GREs) or entities that could become GREs.

Financial policy and credit rating commitments support many ratings and stable outlooks in the 'BBB' band, which many managements appear to see as a floor, including to preserve continued and competitive access to debt markets. We expect downgrades to be limited to one notch in 2024, similar to 2021-2023, and senior debt to remain clustered in the 'BBB+' and 'BBB' range.

We factor in potential new equity to the extent we believe key shareholders are committing to it. We have observed renewed sovereign government interest in building up their presence in the sector since 2022, for instance with power networks in Germany and the Netherlands or gas assets in the Czech Republic, with the full nationalizations of EDF, Uniper, and SEFE in 2022-2023. Often-increasing budgetary constraints frequently mitigate these perspectives.

Main assumptions about 2024 and beyond

1. Continuing high gas and power prices until 2026 in an evolving market design.

Through next winter, Europe's gas and power markets will remain somewhat tight, resulting in still-elevated and volatile power prices.

2. Heavier investments, notably in power networks and renewables.

Based on recent strategic updates, we see capex for power grids rising by 50%-200% over 2023-2025, mostly to accelerate the energy transition. However, capex is moderating for some companies, notably on renewables.

3. Financial policy remains supportive despite the current uncertainty.

Despite higher capex and energy market worries, the sector generally has solid balance sheets, asset sale flexibility, and access to capital. Therefore, posting metrics within expectations at current rating levels is mostly predicated on financial policy.

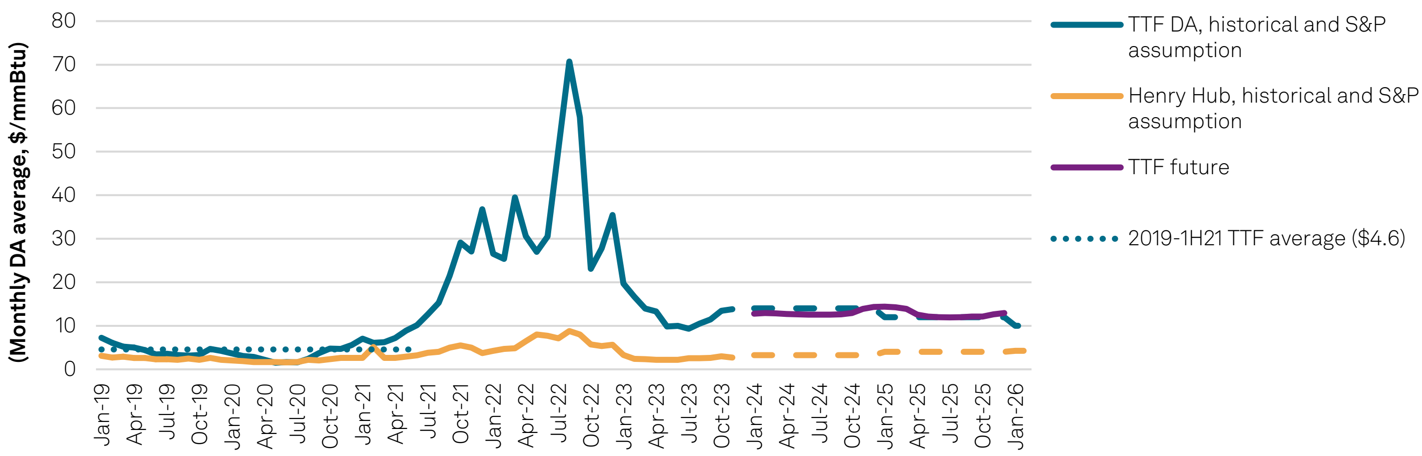
Gas prices to remain high and volatile in 2024-2025 (see chart 4). This is due to Europe's supply-demand tightness following the loss of most Russian volumes, supporting prices that are over twice pre-pandemic levels. As its energy transition goals make long-term contracting less attractive, Europe needs to continue capturing excess spot liquefied natural gas (LNG) volumes at prevailing prices. For most of the decade, according to SPGCI, Europe will need to import at least 160 billion cubic meters (bcm) of LNG annually as both demand and pipe supplies erode.

The main European exchange-traded index, the Title Transfer Facility (TTF), remains in backwardation. Specifically, we assume it will moderate from a high $14 per million British thermal units (mmBtu) in 2024 to $12/mmBtu in 2025 and $10/mmBtu beyond (see "S&P Global Ratings Has Raised Its Henry Hub Natural Gas Price Assumptions For 2024 And 2025," published Nov. 7, 2023). For most of 2023, landed LNG hovered around $10-$15, ending the year at the bottom of this range as U.S. exports' 11 bcm monthly record almost fully covered European demand. In our analyses we therefore reflect:

- Continued demand moderation, at 20%-25% below 2019 levels, and eroding LNG import needs in 2024 continuing on 2023's 1.4% fall, as households and industries barely increase consumption and gas-to-power use reduces sharply, helped by eroding power consumption and recovering hydro and French nuclear generation (up 14% or 40 TW hours [TWh]).
- Underground storage fullness of 86% as of Jan. 1, 2024, 5% stronger than a year before and which we expect will stay comfortably above a healthy 50% by April 1 (see chart 5). Additional storage includes about 3 bcm stored in Western Ukraine and LNG tanks, and a potential release of 5 bcm globally from record-high storage on the waters.
- Prospects for a 75 bcm per year (bcmpa) regasification capacity increase over 2022-2024, focused on Italy and Central and Eastern Europe, the regions on the continent that most need to replace Russian gas. German terminals' spare capacity will remain considerable.
- Confirmed prospects for major global LNG capacity additions (more than 10 bcm, 60 bcm, and 110 bcm over 2024, 2025, and 2026, respectively, focused on North America and Qatar).

Chart 4

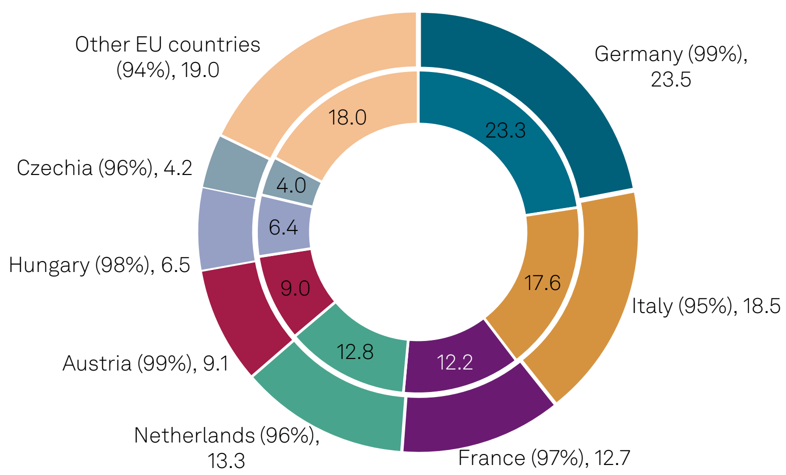
Gas prices will remain multiple of 2019 levels until 2025



Sources: S&P Global Commodity Insights, S&P Global Ratings.

Chart 5

EU countries' current storage (inner ring) versus capacity (outer ring)



Figures in billion bcm as of Dec. 1, 2023; includes countries with 4 bcm+ working storage capacity.
Sources: AGSI GIE and S&P Global Ratings calculations.

The factors weighing on prices are balanced by Asia's demand pickup since the spring (with China increasing its gas use by some 7% this year), continued robust U.S. demand, and, eroding residential and industrial demand within Europe--and above all RepowerEU's accelerating renewables generation ramp-up, the latter adding some 80-100 TWh to power supplies each year (see sidebar).

RepowerEU's renewables acceleration visibly impacts European gas demand from 2024

For 2024 and 2025, we expect additional wind and solar generation to offset grid-connected power demand growth of about 3%. Across Western Europe, the narrowing of the thermal gap (the demand for coal, oil, and gas-fired generation) primarily affects coal and lignite, as the most CO2-emissions-intensive power sources; and 2024 will mark a new milestone on their path to vanishing from the mix by 2030 as the U.K. ends its 142-year coal-fired power generation history (the world's first station was built in London in 1882) and overall nearly 15 GW of thermal capacity closes--some two-thirds in Germany alone. And in 2025, utilities will double down; the Spanish government has announced its coal exit will start in 2025, and Enel has announced the closing of all coal plants outside Sardinia by 2025. Such closures lend near-term support to gas use in its role as a crucially flexible power source.

Yet, given each year's renewable capacity additions, this respite for gas will likely be short-lived. Gas burn will be increasingly confined to times of renewable intermittencies or surges in demand during cold snaps (as early December 2023 multi-year generation records showed) or heat waves. We will monitor how, during the critical years of 2024-2025, gas plant operators in Western Europe can consolidate credit-supportive capacity revenue bases, notably in the U.K. and Spain.

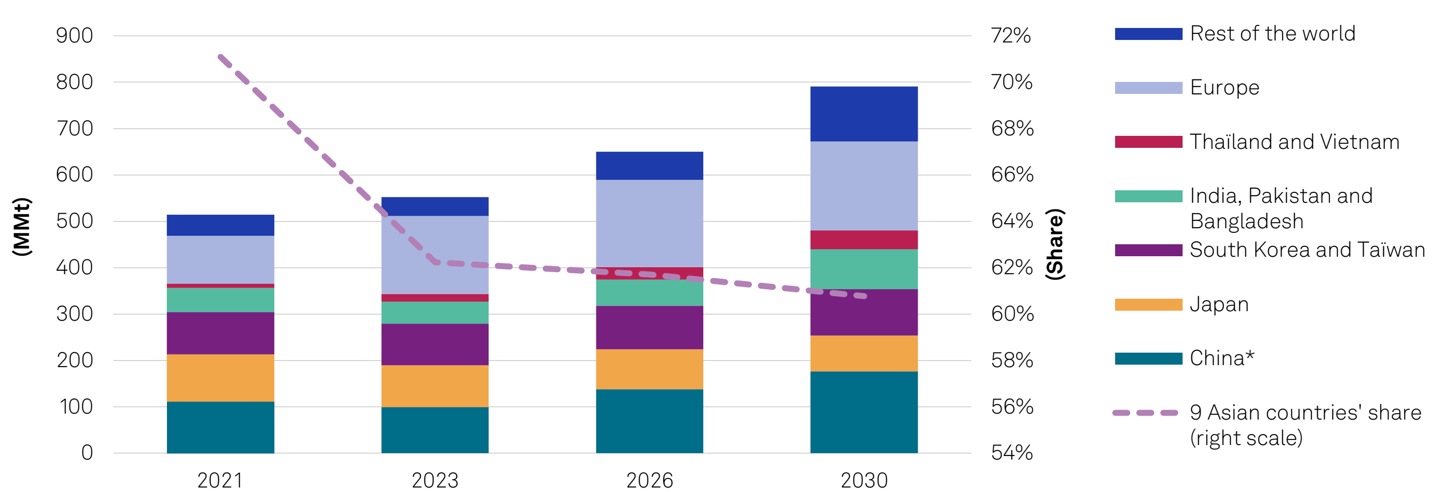
Europe is progressing with its wind and solar ambitions, with generation up almost one-tenth year-on-year in 2023 (+23% for laggard France alone). In Europe's biggest market, Germany, while total primary energy use reduced by 8% (28% below the 1990 level), renewables increased their contribution to the mix by a notable 230 basis points (to 19.4%) according to AG Energiebilanzen. This was driven by wind and solar, while coal and lignite fell by the same amount, to 40.7% of the mix. For the first time, similar to Spain, over half of Germany's power was from renewables. Europe's power mix is greener than that of the U.S., where gas retains a 42% share and coal continued to exceed wind and solar combined in 2023 (perhaps not for much longer).

We see physical curtailment risk as low because, well ahead of its 2027 target, Europe has replaced about 120 bcm of piped gas imports from Russia and does not significantly depend on the remaining 45 bcmpa piped and LNG imported from the country (see chart 6). Piped imports could suffer from 2025 as Gazprom's long-term shipping contract through Ukraine lapses in December 2024.

Chart 6

As APAC continues to dominate LNG imports, Europe's share will erode back to one-quarter

2021-2030 LNG import by country/region



MMt—Million tons. *includes Hong Kong. Source: S&P Global Commodity Insights.

Power prices will remain high and volatile until 2026. We expect €80-€100/MWh outside Scandinavia and Spain. Over 2024 and 2025, European gas prices will continue to drive (and therefore support) power prices, as should EU carbon allowance prices--the other key factor. According to SPGCI, the latter should remain broadly within the €70-€100 per ton range, even after the EU raised the 2005-2030 cut in the emissions cap to 62% from 43% in 2023, effectively doubling its speed (the linear reduction factor) for 2024-2030. Dependency on U.S. LNG imports should support a $9 per thousand cubic feet (mcf) floor for the cost of landing a cargo in Europe, very roughly structured as the Henry Hub price plus over $5/mcf including liquefaction tolling and shipping. Combining these two factors suggests a short-term marginal cost for a combined-cycle gas turbine (CCGT) with 60% efficiency in the €70-€80/MWh range, which appears to be a sustainable equilibrium in terms of affordability for most power users and incentive to build more renewables. It is also the range the French government is targeting from January 2026 for its nuclear fleet, according to its November 2023 market consultation. Across Europe, SPGCI expects wind 10-year PPA pay-as-produced prices (for 2025 starts) to be €70-€90/MWh.

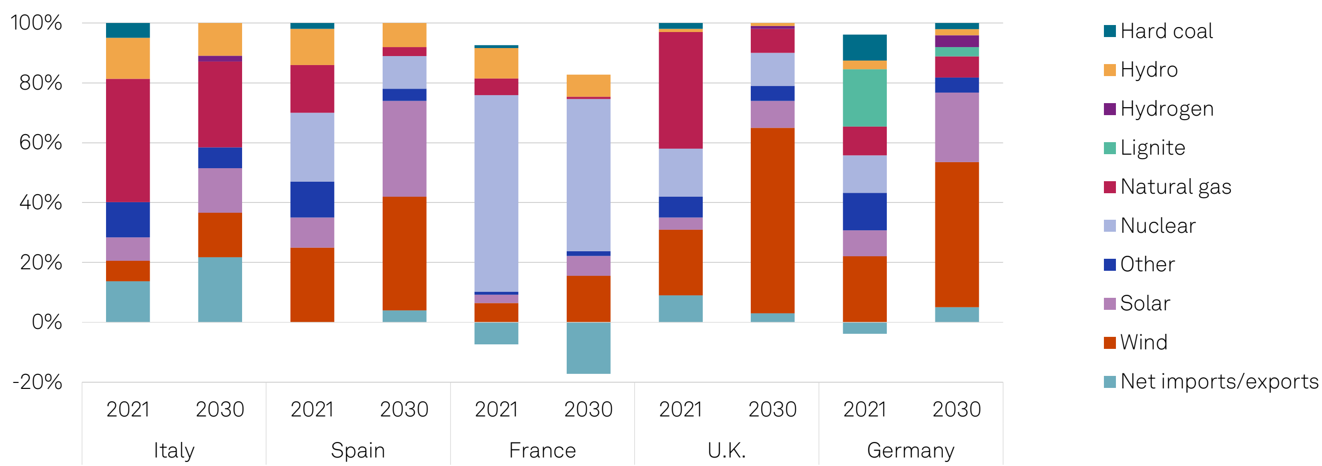
Demand, after weighing on prices by declining in 2022 and 2023 (to below-pandemic levels), should offer some price support given gradual electrification as electric vehicles (2% of current demand) and heat pumps are deployed. We see power demand growing some 3% in both 2024 and 2025, and 30% cumulatively by 2030, more slowly in already-more-electrified France and faster in Scandinavia driven by electro-intensive industries.

On the supply side, according to SPGCI's December 2023 long-term analysis, additional wind and solar capacity will increase their combined contribution to Western Europe’s power mix to 55% in 2030 (67%-71% in each of the pioneering large markets of Germany, the U.K., and Spain, see chart 7) and 66% by 2035 from 33% in 2023. Wind and solar generation growth, by absorbing all of the meagre demand growth (hydro, nuclear, and fossil-fuel generation being about flat), weighs on average annual baseload power prices. We expect these prices to decrease from 2026, reaching €40-€60/MWh by 2030 in real 2022 terms in most markets, with Spain and Scandinavia particularly low and Italy remaining at a premium. At that point, continued gas-to-power demand erosion loosens power price drivers in favor of renewables, which weighs on power prices, and--together with reduced industrial and residential demand--on gas prices.

Chart 7

Evolution of the power generation mix in Europe's five largest energy markets

2021 versus 2030 forecast



Source: S&P Global Commodity Insights.

Beyond average baseload prices, we expect an increasing bifurcation in prices actually captured by the various technologies. The most flexible ones--in particular reservoir-based hydro and CCGTs--should be able to capture peak prices (even economics increasingly relies on remuneration via capacity markets for CCGT plants running for ever-fewer hours, as has occurred in Spain and the U.K. for a number of years). By contrast, captured prices for intermittent renewables should decrease even more than baseload prices, because storage and interconnections (see "Europe's Power Push: Can Project Finance Help Fund Interconnections?," published Nov. 16, 2023) grow too slowly to smoothen the absorption of wind and solar generation and lack the flexibility that would support renewable revenue. This steeply increases the number of hours with low-single-digit or negative prices, to which wind and solar are particularly exposed, notably in the U.K., Spain, and Germany. Material quantities of hydrogen for electrolysis or seasonal storage are not for this decade.

The EU's October 2023 market redesign is evolutionary rather than revolutionary, and we find it to be moderately credit-supportive overall. On the positive side, it reduces market design uncertainties, preserves market signaling and overall market functioning, promotes two-way contracts for differences and PPAs (by fostering a broader and more liquid PPA market, more accessible to weaker counterparties) as well as capacity markets (an increasingly relevant contributor to physical power market stability, if at a record €7.4 billion cost in 2023) and aims to further unify Europe's fragmented energy markets.

On the less supportive side, the redesign could crystallize the EU market's complexity and fragmentation as each country counters high prices through its own type of state intervention (typically targeted at protecting affordability for households and electro-intensive industries). In November, the French government unveiled its intention to apply over 2026-2040 a scheme that captures a significant portion of the benefits from prices above €78-€110/MWh on domestic nuclear generation revenue, without providing a corresponding floor (somewhat like the U.K.'s electricity generation levy running to March 2028).

Still, overall, as generators retain a portion of the upside from strong prices in 2024-2025, we see these schemes as providing a reasonable balance between governments' needs to finance affordability and preserving sufficient profits to power generators. Regulations that merely remove excess cash flow do not overly weigh on credit quality.

U.K. water companies and Northern Europe power grids will increase capex. Across the U.K., Germany, and Benelux, we see water utilities and power transmission system operators (TSOs) increasing capex fast, both to strengthen existing networks and expand them to connect new renewable capacities. Some power grids could more than triple their annual investments by 2025-2026 compared with 2022-2023.

While we see the related regulatory frameworks as strong, we monitor how regulators respond to capex stress on these sectors; tensions that might appear as end users realize the full extent of the increase in their energy bills (including the distribution costs, which could be about double the TSO costs); and the degree and duration of credit metrics being potentially below our guidance for current ratings. Financial policies then become paramount, and the ability and willingness to timely raise sufficient new equity might be an important credit support.

In all cases, we expect funding and liquidity management to bridge discretionary cash flow (DCF) gaps. Given likely rigid capex requirements for urgently needed energy-transition projects, we assess the degree of reliance on new equity issuance in the context of the specific ownership structure and shareholder commitments, full ownership by a single highly rated and committed sovereign being particularly supportive.

Gas grids remain exposed to long-term stranded-asset risk. In 2023, we reflected this by revising to strong from excellent the business risk profiles and correspondingly tighter minimum credit metric expectations on gas grids in the Iberian peninsula. Like in Latvia, we now differentiate Iberian gas networks' long-term prospects from those of power grids. We monitor regulatory developments in other countries too, with Germany for example having enacted a credit-supportive full depreciation by 2045. More generally, we expect gas grid operators that do not invest significantly to repurpose their business away from fossil fuels to accumulate balancesheet headroom as free cash flow remains steady. In that light, financial policies and shareholder support are paramount in our prospective credit analysis.

By contrast, Gasunie, in the Netherlands and Northern Germany, is already preparing its transition to hydrogen. Across gas grids, we monitor closely how regulators prepare the ground, notably through sufficient remuneration of new assets and accelerated depreciation of legacy fossil-fuel assets, unless new hydrogen assets are directly subsidized by the government, as in the Netherlands.

Finally, we observe contrasting capex trends among integrated companies. Positively, most appear to cautiously approach further investments into wind and solar, and particularly offshore wind, given deteriorating economics. Solar unit capex (per GW of capacity installed) has tended to recede after a spike earlier this decade, while wind unit capex appears set to remain high for a while, but solar faces heavier long-term revenue risks. Supply-chain issues remain acute, particularly as Europe's three major wind original equipment manufacturers (OEM) continue to post weak or negative operating margins, just as competition from China-based OEMs emerges.

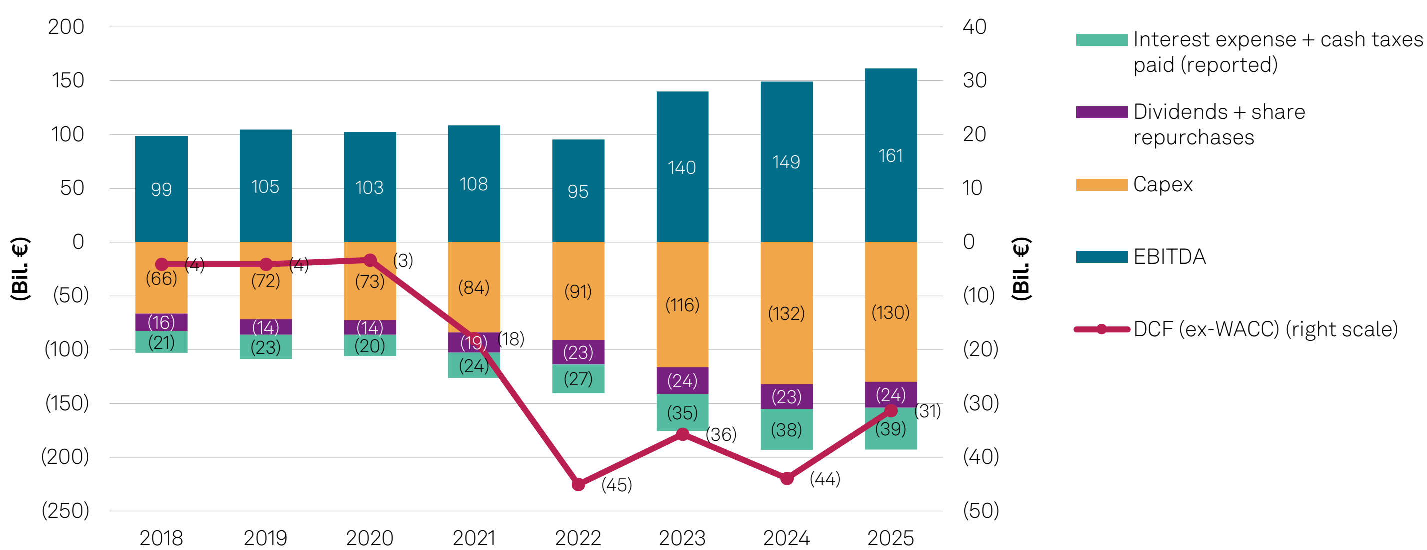
Credit metrics and financial policy

The sector has fairly solid balance sheets, asset sale flexibility, and access to capital, despite higher capex and energy market uncertainties. Overall, we expect the sector to keep posting credit metrics within expectations at current ratings. We anticipate absolute debt to continue rising for the sector, including by some €40 billion annually for our top 25 utilities; this is based on high and increasing capex and continuingly negative DCF (see chart 8). However, EBITDA growth allows leverage to remain near 4.0x, much in line with 2019-2021 levels (see chart 9). We estimate an annual increase in the sector's adjusted debt of 7%-9% over the next three years, with a significant dispersion between those increasing debt 10%-200% (notably networks) and those we expect to stabilize metrics. At the same time, a mild economic recovery from 2024, sustained gas and power prices, and new renewables and nuclear capacity commissioning will support earnings growth.

Chart 8

Top 25 European utilities | 2021-2025: capex and dividends drag DCF

Aggregate numbers mask broader spectrum of capex and shareholder distributions

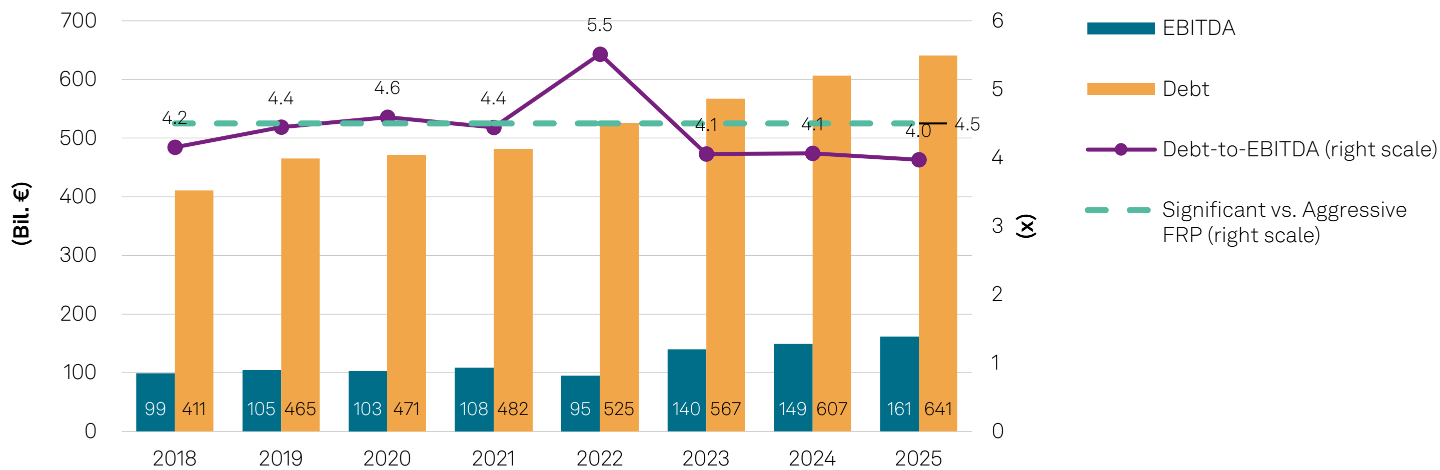


Source: S&P Global Ratings.

Chart 9

Top 25 European utilities | mounting debt keeps leverage around 4x from 2023

Over 2023-2025 utilities in aggregate have a slight buffer to "aggressive" levels



Source: S&P Global Ratings.

Overall, growth should enable utilities to pilot credit metrics within bands consistent with current ratings, to the extent their financial policies are supportive. Beyond earnings, utilities can do this through asset disposals, hybrid capital, or--particularly in the case of government-related power networks--issuance of common equity. The latter will need to be tested given currently high yields, which are reducing valuations for many “clean energy” companies especially, but not only, when they face operating or financial setbacks. While growth ambitions are significant as Europe accelerates its energy transition, some issuers enjoy capex flexibility to adapt to changing energy market conditions, inflation, interest rate fluctuations, and constraints on investments, supply chains, and permitting.

We do not foresee much improvement in credit metrics for the sector in the next few years--aside from some fixed-cost power generators--nor much deterioration apart from select power grids and water companies. Earnings upside would likely finance additional organic or external growth. Our base-case scenario for the sector incorporates no major shift in shareholder stance like debt-financed M&A, or higher shareholder distributions. Already, sustained shareholder distributions are weakening deleveraging dynamics: We expect distributions to absorb slightly over a fifth of FFO for our top 25 companies (over 30% for grids, significantly up from 2019's 18%). Another possible risk relates to increased shareholder activism, which could disrupt strategic plans and swing financial equilibria in a more shareholder-friendly way.

Key risks or opportunities around the baseline

1. Oversized price volatility or event risks disrupt operations or liquidity.

Particularly for companies where increasing capex is depressing DCF, event risks such as cyber or physical sabotage could aggravate liquidity tightness. Companies active on energy exchanges might still face liquidity squeezes.

2. Political and regulatory risks and opportunities cloud the overall investment picture.

Measures to accelerate the energy transition run against affordability constraints and limited budgetary firepower in a context of increasing concerns about security of supply.

3. Deteriorating economics complicate low-carbon power capacity deployment.

Continuing supply-chain constraints, together with persistently high interest rates and slow inflation reduction, complicate the economics of the low-carbon capacity buildup.

Event risks can selectively disrupt operations, liquidity, and credit quality. As for many other corporate sectors, rating risk often relates to liquidity. Some companies' liquidity buffers are thin relative to our minimal expectation at the adequate assessment, a tightness we reflect both in our liquidity and our management and governance analysis. We will continue to monitor liquidity as market behavior is hard to predict, especially as power mixes and market designs evolve.

For 2024, we see event risks affecting liquidity as potentially related to:

- Wholesale price volatility, as happened in 2022;
- Extreme weather;
- Geopolitical events, including wars and sanctions, which could foster volatility and even affect physical supply; and
- Cyberattacks.

We have already seen weather issues elsewhere. In 2023, devastating fires hit the U.S. state of Hawaii hard, leading to tragic loss of lives and a two-category downgrade of the local power utility. However, despite Europe's increasing exposure to extreme weather events--most recently severe storms in early November--the impact on utilities' credit quality has been muted. We expect this to continue and governments to typically play a more supportive role than in the U.S., whether for existing GREs or companies that could become such. Still, weather conditions are expected to continue deteriorating given continued global warming, also affecting LNG traffic through the Panama Canal.

Geopolitical events that might affect EMEA utilities--mostly energy--include wars (the interruption since early December of the Red Sea to LNG traffic implies a two-week detour via the Cape of Good Hope for about a tenth of global traffic, or about 40 bcmpa, as long as the much more critical Strait of Ormuz is open; Israel's 10 bcmpa Tamar gas field was closed for a month, just as Egyptian domestic production fell by 10%, limiting potential LNG supply to Europe; and sanctions to the extent they foster price volatility and affect physical supply. While we do not expect Europe to have to adjust to a supply game-changer like the stoppage of Nordstream I in third-quarter 2022--which we consider permanent--extensive damage and a prolonged outage affected Nordstream II in 2022 and the 2.6-bcmpa Finland-Estonia Baltic connector on Oct. 8, 2023. Since November, U.S. sanctions have halted the commissioning of Russia's Arctic LNG 2 project, now under force majeure since late December.

Generally, physical sabotage cannot be excluded, particularly for offshore assets like the highly developed gas pipes and power lines in the North Sea and the Baltics and gas pipelines to Italy, which are difficult to continuously monitor. Of particular relevance are Norway's gas export pipes and Scandinavia's power interconnectors with their continental clients in Germany and the Baltics.

Finally, cyber risk might materialize, particularly for power grids, especially distribution; for these, digitalization is essential to optimizing the use of existing assets in the face of growing and ever more distributed supply and demand. In turn, it may expose them to even more risk of disruption of operations than for other utilities.

Political and regulatory risks and opportunities abound. Measures to protect end-user affordability could erode related utilities' credit quality, notably via price caps, windfall taxes, and slowness to recognize higher interest rates and inflation in regulated revenues. These measures can prompt higher debt or lower earnings on existing assets; regulatory risk reemerged recently in Finland (see "Finnish Networks' Rating Headroom Could Shrink On 2024-2031 Regulatory Update," published Dec. 8, 2023).

By contrast, political support could move notably in the following directions:

- Governments' willingness to let some taxes lapse (like the emergency windfall taxes instituted in fourth-quarter 2022, most of which lapsed in June 2023).
- Restraint in terms of not overly leaning on regulators to preserve affordability by compressing grid returns on capital.
- Participating at central or local government levels in new equity injections.

In particular, we see a steady trend for regulators to grant stronger remuneration on new projects, as decided in 2023 in Germany and Belgium for 2024-2028, or bring in overall more incentivizing regulation (see "WACC Increase Will Benefit Italian Regulated Electricity And Gas Networks," published Dec. 1, 2023). Besides accelerating the energy transition, affordability is a cornerstone of Europe's REPowerEU strategy and Fair Transition Plan: protecting citizens' purchasing power will remain high on political agendas, just as renewables and grid capex must accelerate. This is against the background of increasing pressure on budgetary energy spending. Illustrating this vividly was Germany's Constitutional Court's ruling in November 2023 that cut by €60 billion the use of COVID-19-related funds for energy sector support purposes, which will need to be scrapped or financed from other sources, reducing GDP growth and energy demand; the government has already announced ending its annual €5.5 billion subsidy to power TSO tariffs in January, weighing further on power demand pressures and adding to other power tariff increase (in aggregate of about €150 annually for a typical household) beyond those needed to remunerate stepped-up capex and (as the BNetz A proposed in Jan. 2024) for gas grid accelerated depreciation.

On the other hand, even under the caps and windfall taxes instituted in fourth-quarter 2022, fixed-cost merchant power generation has proved very profitable in 2022-2023 and this likely will continue in 2024-2025. The additional earnings could support positive rating actions to the extent earnings finance the sustainable reduction of debt, or judicious and business- or credit-metric-enhancing acquisitions. In both cases, we would review the utility's financial policy to assess the sustainability of the credit improvement. Our review would also look at less typical aspects like any geographic rebalancing away from riskier markets (notably Latin America) into more credit-supportive and transition-intended Europe and North America markets; the approach to offshore wind investments; and greater group complexity from increasing minority interests at under-leveraged, fully consolidated subsidiaries or projects.

Low-carbon project economics are thornier. Supply chains, permitting, grid access, and public policies influence project pace, costs, and risks. This is especially the case for offshore wind, nuclear, and hydrogen. While long-term wind and solar continue to indicate stronger economics than carbon-price burdened fossil fuel generation, short-term prospects are more mixed, especially for wind. Both wind and solar revenue are bound to increasingly suffer because of the expected price cannibalization trend, especially Spanish solar and U.K. offshore wind. In second- and third-quarter 2023, the number of hours with negative prices beat previous records (excluding the pandemic-driven second-quarter 2020 record). Inflation and interest rates weigh on operating expenditure and capex, and therefore on free cash flow. Stock prices have reacted accordingly, with operational setbacks severely sanctioned.

Onshore wind capacity growth suffers from permitting and grid access issues. In contrast, distributed solar can expand more easily without grid access. Only recently have European countries started to strongly promote a “shared offshore grid” that would reduce capex, operating expenditure, and curtailment risks for offshore wind. Other less obvious risks include uncapped negative bidding (see "Germany's Green Energy Ambitions Spark A Transformative Decade For Utilities," published Sept. 14, 2023) and load-weakening wake effects.

We expect 2030 offshore wind targets to be difficult. According to SPGCI, Europe’s installed capacity may reach 35 GW by year-end 2023 compared to the Green Deal’s 60 GW objective and the 120 GW target set in 2023 by North Sea countries just for that region. Similarly, the U.K.’s 50 GW target means adding many projects immediately, given the 23 GW operating or under construction.

Positively, authorities in two key renewables jurisdictions indicated further price support for 2024 capacity additions. In November, the U.K. government raised by 66% the level for the allocation round (AR) 6 2024 to £73/MWh in 2012 terms (equivalent to about €100/MWh) and set aside a separate funding pot for offshore wind, the budget for which should be known in March. Likewise, in December, German regulator BNetzA confirmed high levels for capping 20-year support mechanisms, at €74/MWh for wind and ground-mounted solar and €105/MWh for rooftop solar.

We see positive momentum for prolonging existing or developing new nuclear capacities in a number of European countries, subject to appropriate funding, despite higher interest rates for capex set to exceed €10 million per MW. This could partly mitigate closures of existing capacity, particularly in the U.K. (all but one reactor) by 2028 and Spain from 2027 (half of the existing 7.4 GW capacity by 2030). In particular, France, Bulgaria, and the Czech Republic have advanced plans for commissioning new reactors from the mid-2030s (including 10-23 GW in France alone); this has also been the case in Poland, Sweden, and the Netherlands, albeit less so and against the background of fluid dynamics in coalition or minority governments.

Given its innovative proposed regulated asset-based financing, we will continue monitoring progress toward a final investment decision in first-half 2024 on the U.K. Sizewell C project, with 3.3 GW (Europe's largest). Impacts on nuclear-involved utilities’ credit quality from these massive, single-asset and risky developments depend considerably on the degree to which construction and asset-retirement risks are shared with governments; taken on by current and future power consumers; or retained by the builder or utility owning the plant, a pathway that looks increasingly challenging.

European utilities face stiff exogenous challenges. Across Europe, ambitious and proximate targets add to pressure on supply chains, permitting, and grid access. Yet, typically, wind onshore and offshore projects still now take as long as eight and 11 years, respectively, up to commissioning (and nuclear EPRs even longer). Execution risks will remain high just as equipment supply chains need to cater for global expansion, notably in China and the U.S. For now, Europe’s electrification will keep it dependent on China for a large portion of its raw materials and equipment needs, even beyond solar panels--a situation we do not think will change significantly over the next couple of years. European supply chains need to scale up in cadence with growth in investment and demand, which takes time and heavy investments. The wind chain, where Europe's market share is among the highest, remains insufficiently profitable.

We understand that, while permitting has become somewhat faster, overall project length remains too high for both onshore and offshore projects. Grid access is a particularly sore point in many cases, and while power network operators have hiked capex greatly in certain regions like Germany and Benelux, the effects will take time to clear the current project log.

As we expected, the utilities' race for renewables faces stiff competition from cash-rich and strong-DCF oil and gas companies, notably Europe-based integrated oil companies (IOCs). Compared to 2022's sustained M&A activity from various IOCs across wind, solar, biogas, and hydrogen in European utilities' core European and U.S. markets, in 2023 IOCs stepped in more directly: for example, TotalEnergies and bp accepted heavily negative bids on new German offshore wind leases. Another example is offshore bidding in Norway and Portugal, where a number of IOCs (present in Norway as members of three of the seven applying consortia, a fourth one being a single China-based company) apply to unlock these "new offshore basins" along with utilities. Overall, the risk persists that competition from the IOCs tends to deteriorate project economics in an already-fragile and capital-intensive sector.

New technologies struggle even more. Higher power prices and interest rates for longer affect floating offshore wind and green hydrogen economics even more. The former, being even more capital-intensive and technologically less mature than fixed-bottom (with only 0.2 GW installed globally to date), will heavily fail expectations set for 2030 across countries, including the U.K.'s 5 GW 2030 target (AR5 had no candidates). Globally, SPGCI recently halved expectations (to 6 GW globally), as did the Global Wind Energy Council in November.

In November, the Global Hydrogen Council and McKinsey raised their estimates of global levelized cost of hydrogen by 30%-65% above their October 2022 estimate; in the same month, German TSOs submitted a €19.8 billion mega-plan for building the core hydrogen network (of which 40% are new lines) that would find few sufficient early customers absent a government backstop to an amortization account. In 2024, construction should continue on Germany's first repurposing-to-hydrogen project and on the 1,200-kilometer (15% new) Dutch network following the start of work in fourth-quarter 2023, the most concrete step taken to date in Europe. Indeed, among big future users, Central and Western Europe remains one of the costliest places globally. The revision reflects notably higher electrolyzer capex and renewable costs.

Related Research

Sectorwide research:

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