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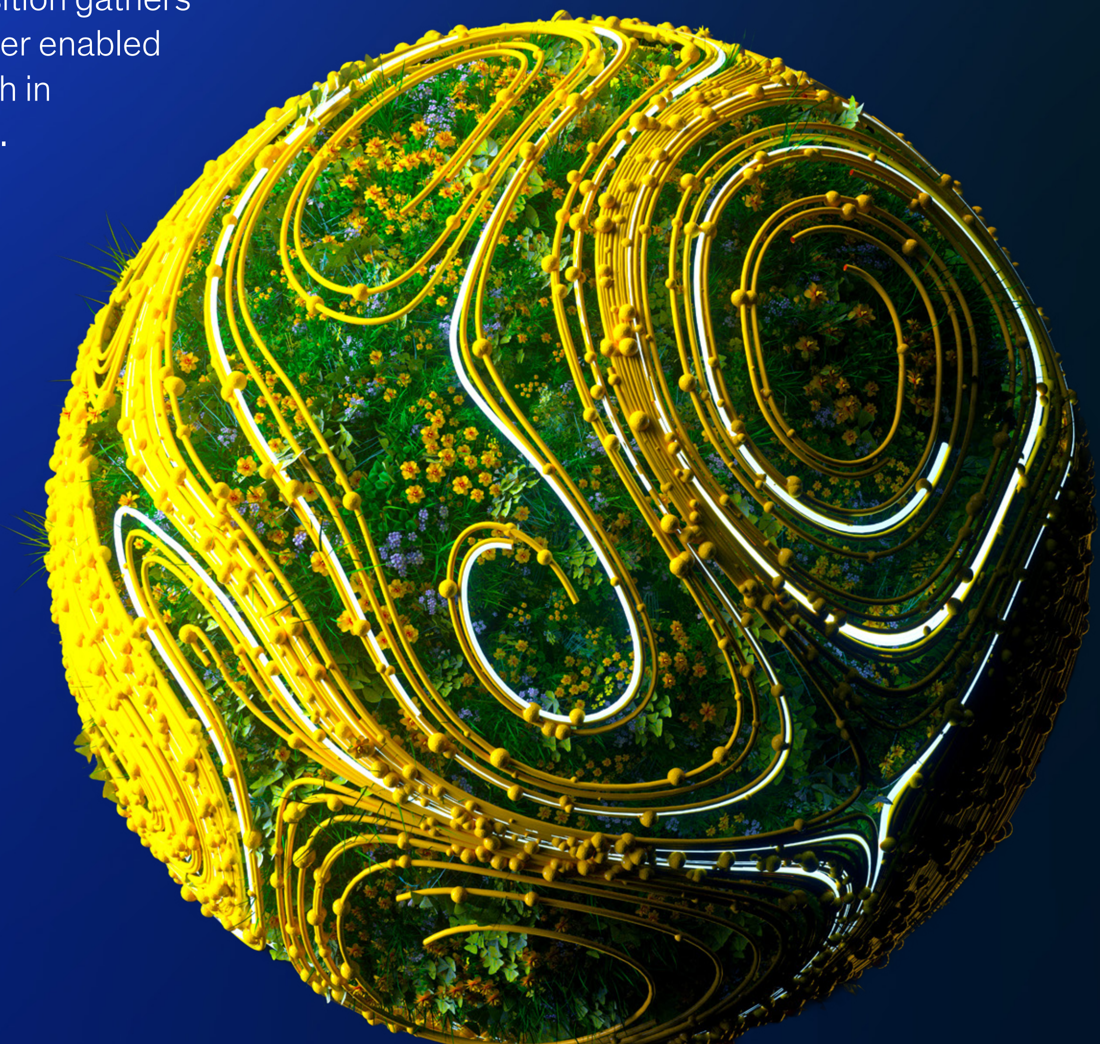
# Accelerating the journey to net zero

As the energy transition gathers pace, it will be further enabled by continued growth in green technologies.



Compendium
December 2023

# Contents

# Introduction

**Many of the articles we published in 2023 show that, although there has been a strong increase in low-carbon technologies such as solar, wind, and electric heat pumps, more-urgent global momentum and collaborationacross the energy value chain is needed.**

As the world strives to limit temperature increases to 1.5°C, in line with the Paris Agreement, investment in a broad and balanced portfolio of low-carbon solutions is one of the most critical levers for accelerating the transition.

According to McKinsey's Global Energy Perspective 2023, total annual investments in the energy sector overall are projected to grow by 2 to 4 percent per annum, roughly in line with global GDP growth, to reach between $2.0 trillion and $3.2 trillion by 2040.[1] Furthermore, decarbonization technologies demonstrate the highest levels of investment growth at 6 to 11 percent per annum, driven predominantly by the strong uptake of electric-vehicle charging infrastructure and carbon capture, utilization, and storage.

This compendium includes a representative selection of articles with findings that help illustrate the evolving net-zero landscape, including the following:

— *The number and scale of capital projects crucial to the energy transition will not suffice.* When the Inflation Reduction Act was signed in 2022, the US federal government released $370 billion in funding to provide tax credits for clean-energy projects. Today, the challenge is securing the right people, resources, and physical space while overcoming supply chain constraints and financing for nonestablished players.

— *More than $5 billion was invested in battery energy storage systems (BESS) in 2022—almost a threefold increase from the previous year.* By 2030, the global BESS market could reach between $120 billion and $150 billion, more than double its size today. Yet the fragmented nature of the market means many providers are wondering where and how to compete.

— *Nuclear power is a proven technology that can be called upon to play a bigger role in decarbonization.* As rapidly as renewables have scaled up in recent years, it's unclear whether wind and solar—along with other emerging solutions, such as carbon capture, long-duration energy storage, and hydrogen—can grow fast enough to meet net-zero targets and projected increasing electricity demand. Recent developments show that nuclear power is emerging as a key component of decarbonization plans.

— *The sustainable-fuel market is still mostly nascent, characterized by complex regulations and interdependencies across sectors.* With such complex market fundamentals, sustainable-fuel traders are seeking to understand which markets will increase in liquidity, which arbitrage plays to explore across products, which storage hubs to invest in, and which offtakes to secure to gain access to supply.

— *Natural gas can play a critical role in decarbonizing the US power supply by providing a backup energy supply for renewables.* In the following decades, a fully "dispatchable" backup energy supply will be required to ensure the reliability of the power grid for multiday swings. However, infrastructure upgrades and new market mechanisms will likely be required to position mainstream gas operators to provide the natural gas that consumers will need.

We hope this compendium offers new insights that can help energy executives remain competitive as the transition continues apace.

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[1] "Global Energy Perspective 2023," McKinsey, October 18, 2023.

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# Energy Transition

# The role of natural gas in the move to cleaner, more reliable power

Natural gas can play a critical role in decarbonizing US power supply by providing a backup energy supply for renewables—but infrastructure investments and market mechanisms will be needed.

*by Jamie Brick, Dumitru Dediu, and Jesse Noffsinger*

**Across the United States**, renewable energy sources are impacting natural gas generation. The growth of renewables in the grid, compounded by the increased electrification of energy demand, will expose the grid to the risks of an intermittent renewables supply to meet growing power demand.

As a result, in the coming decades, a fully "dispatchable" backup energy supply will be required to ensure the reliability of the power grid for multiday swings. In the absence of breakthroughs in long-duration energy storage, natural gas—which can be implemented at scale—could be the cheapest and lowest-carbon candidate for this role.

Demand for gas is expected to be more volatile going forward—lower on average, but potentially much higher on peak-demand days when intermittent renewables are at low generation levels. However, today's gas system was not designed and sized to deliver the high gas volumes that will be needed on these peak-demand days in the future. Infrastructure upgrades and new market mechanisms will likely be required to position mainstream gas operators to provide the natural gas that consumers will need.

## Natural gas' track record in decarbonizing the power sector over the past decade

Since 2005, the United States has reduced its energy-related $CO_2$ emissions by about 18 percent.[1] A switch from coal to natural gas accounts for a significant portion of this reduction. According to the US Energy Information Administration (EIA), the use of natural gas in the electric power sector increased by more than 100 percent between 2005 and 2022, while coal use declined by about 55 percent.[2]

This shift from coal to natural gas for power generation resulted in an estimated reduction of 532 million metric tons in $CO_2$ emissions over the same period.[3] This has been the most significant decarbonization lever, mitigating the equivalent of more than 10 percent of 2021 US greenhouse gas (GHG) emissions. This is more than double the mitigation of approximately 248 million metric tons of $CO_2e$ (carbon dioxide equivalent), which can be attributed to the increase in renewable generation.[4]

Moving forward, the United States has the opportunity to increase the decarbonization impact through natural gas, alongside other power supplies, by continuing coal-to-gas switching, implementing carbon capture and storage (CCS) solutions on existing and future gas-fired power installations, supporting blue hydrogen production, and accelerating the rollout of intermittent renewables beyond the level of 13 percent of power generation in 2021.[5] In addition, natural gas exports from the United States can support energy supply security and decarbonization efforts overseas—for example, in Europe through coal-to-gas switching and enabling the accelerated rollout of renewables and new energies (such as the hydrogen economy).[6]

## The electrification of energy demand and the growth in renewables

A major trend in the energy transition is the electrification of energy demand. The greater the electrification of end-use energy needs, the higher the importance of the energy supply reliability to meet growing power demand.

To illustrate, the electrification of road-based transportation is currently taking place by replacing internal combustion engine (ICE) vehicles with electric vehicles (EVs), the electrification of household heating is occurring through heat-pump adoption, and the electrification of industrial processes is happening through the electrification of low-temperature heat.

[1] *US energy-related carbon dioxide emissions, 2021*, US Energy Information Administration, December 2022.
[2] "Electricity data browser," US Energy Information Administration, June 6, 2023.
[3] "Electric power sector $CO_2$ emissions drop as generation mix shifts from coal to natural gas," Energy Information Administration, June 9, 2021; metric tons: 1 metric ton = 2,205 pounds.
[4] *Global energy review 2021*, US Energy Information Administration, April 2021.
[5] "Electricity data browser table 1.1. Net generation by energy source: Total (all sectors), 2013–March 2023," US Energy Information Administration, 2023.
[6] "How climate action can help deliver EU energy security," McKinsey, August 12, 2022.

To meet US decarbonization goals, this higher electricity demand must be met with a clean power supply. Power supply decarbonization can be achieved with a higher share of renewables in the grid (for example, solar and wind), alongside other low-emitting energy sources—such as nuclear, hydroelectric power, or gas-fired power generation with CCS.

In virtually every decarbonization scenario and each independent system operator (ISO) in the United States, the share of renewable generation is expected to increase and coal generation is expected to decrease. Renewable growth is supported by federal policy and state-level decarbonization goals. At the federal level, the Inflation Reduction Act of 2022 directs roughly $400 billion in federal funding to renewables, also lowering carbon emissions by providing decarbonization incentives for operators throughout the energy value chain.[7] Parallel to this, individual US states have set ambitious targets to achieve substantial decarbonization, with 22 states (representing around 45 percent of the US population) already having deep decarbonization targets of 80 to 100 percent by 2040 or 2050.[8]

There is no doubt that many challenges will need to be resolved to substantially increase renewables supply. For example, regulations around land access will need to be updated—especially around densely populated areas—to provide the land required for renewables. Solar requires roughly 10 to 20 times more land than gas, and onshore wind up to 200 times more, to generate the same amount of electricity.[9]

Overall, significantly larger investments will have to be made in the power grid to support the rollout of renewables. This could amount to an increase in investment of five to ten times historical levels.[10] In addition, supply chain constraints and other factors, like the availability of craft labor, may lead to cost increases and delays in renewables projects.

Depending on the degree to which the renewables industry manages to address these challenges, the share of renewables in power generation may range from very low (15 percent solar and wind by 2040 in the "current trajectory" scenario as laid out in the *Global Energy Perspective 2022*) to very high (70 percent solar and wind by 2040 in the "achieved commitments" scenario) (Exhibit 1).

Across all scenarios, however, gas-fired power generation will play an important role: in a "less-renewables" scenario, gas-fired generation will be needed to meet higher electricity demand as renewables scale up; in a "more-renewables" scenario, gas-fired power generation can provide affordable and dispatchable power supply to balance out the intermittency of renewables.

**Renewable growth is supported by federal policy and state-level decarbonization goals.**

[7] "The Inflation Reduction Act: Here's what's in it," McKinsey, October 24, 2022.
[8] McKinsey analysis based on industry figures.
[9] Hannah Ritchie, "How does the land use of different electricity sources compare?" Our World in Data, June 16, 2022.
[10] *Life cycle assessment of electricity generation options*, United Nations Economic Commission for Europe, 2021.

## Decarbonizing the grid with a large share of renewables comes with reliability challenges

Decarbonizing the US power supply with solar and wind generation entails the challenge of an intermittent supply that cannot reliably match power demand, especially the multiday variability of this demand.[11] The higher share of electrified energy demand implied by decarbonization will make reliability in the grid even more important, as electricity will be needed for residential heating and critical industrial processes.

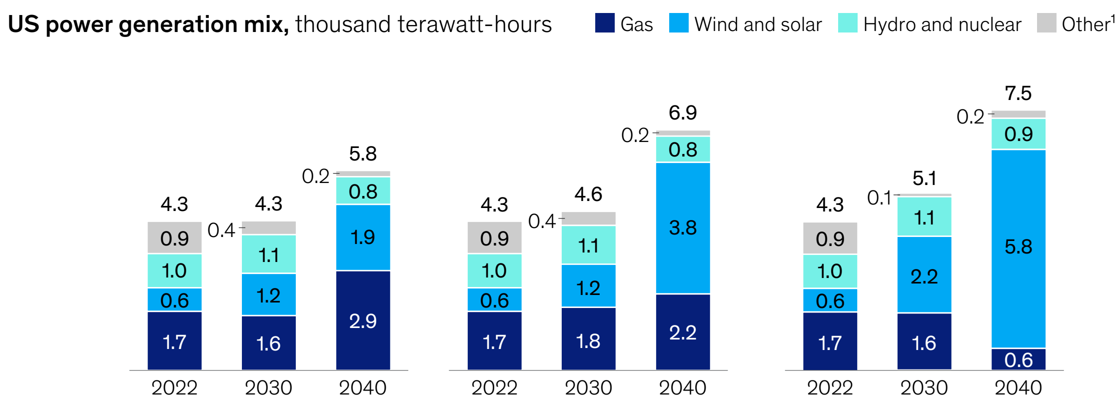
There are several options for securing a reliable and dispatchable power supply in a decarbonized grid to address multiday variability (Exhibit 2). While various long-duration energy storage (LDES) solutions may be economic in some geographies to provide electricity during multiday periods of low renewable generation, natural gas is consistently the most reliable and cost competitive—even after accounting for carbon costs.

Natural gas generation is known as a "dispatchable" energy source, meaning that the facilities for natural gas generation can be switched on or off depending on need—demonstrating its suitability as a security supply for the grid.

Exhibit 1

### The share of renewables in the grid has a direct bearing on US decarbonization goals.

**US power generation mix,** thousand terawatt-hours




| **Scenario** | **Current trajectory (CT)** | **Further acceleration (FA)** | **Achieved commitments (AC)** |
|---|---|---|---|
| **Description** | • Decline in cost of renewables continues and existing enacted targets are met, but no new policies are put into law | • Driven by increased commitments, though financial and technological restraints remain | • Presupposes that most ambitious publicly discussed ambitions are met<br>• In the US, this includes net-zero power by 2035 on a path to a net-zero economy by 2050<br>• Largely ignores supply chain issues and other constraints |

Slower → Faster

**Speed of energy transition**

[1]Includes coal and dispatchable renewables like hydrogen and bioenergy.

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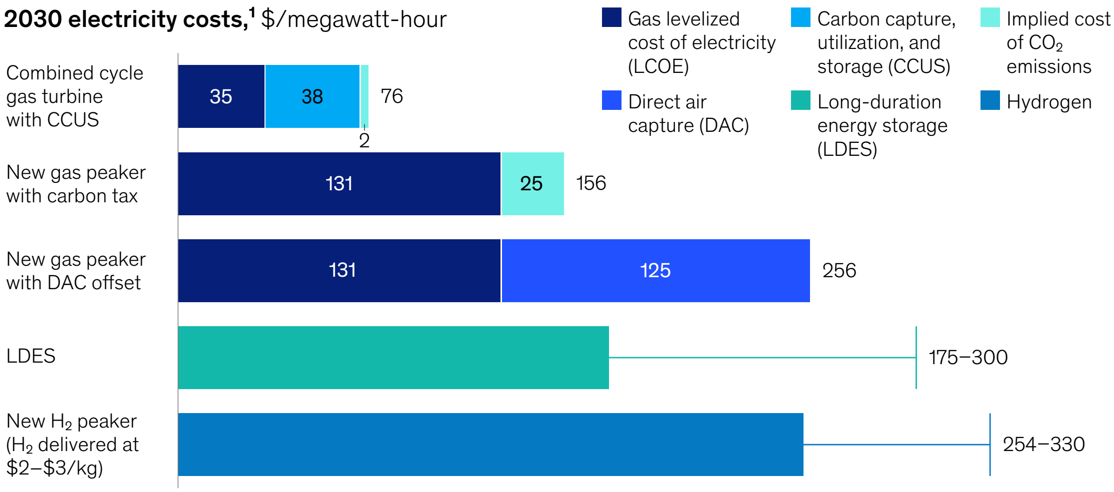
[11] "Toward a more orderly US energy transition: Six key action areas," McKinsey, January 12, 2023.

Exhibit 2

## Gas generation is less expensive than hydrogen turbines or other long-duration energy storage solutions to address multiday power supply variability.

**2030 electricity costs,**[1] $/megawatt-hour




Note: Metric tons: 1 metric ton = 2,205 pounds.

[1]Key assumptions: Gas CCGT w/CCUS—LCOE $35/MWh; CCUS costs of $85/ton; emissions 0.45 $tCO_2e$/MWh; 90% $CO_2$ capture; 85% utilization; new gas peaker—LCOE $131/MWh; gas price $3/mmbtu, utilization 10% pa, emissions 0.5 $tCO_2e$/MWh; social cost of carbon $51/ton, as per current US federal guidance; DAC cost $250/ton; 100% of emissions offset; LDES approximate costs across multiple technologies including: iron air/flow, Li-ion, modular CAES and gravity assuming 24-hour discharge; 90 cycles per year; new $H_2$ peaker, utilization 10% pa; hydrogen costs delivered to peaker.

Source: EIA

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## The natural gas system needs to be built out to deliver on peak-demand days when renewables cannot generate at full capacity

To ensure that dispatchable gas-fired power generation can be used to complement renewables, the supply of natural gas to power plants must be robust enough to meet demand on peak days—occurring when solar and wind generation are low for multiple consecutive days.

In deeper decarbonization scenarios, this will lead to a lower average annual gas demand volume, with higher peak-day gas demand. The need for dispatchable power will likely vary by region—with some regions relying much more on gas-fired power generation than others depending on the availability of attractive renewable generation, such as solar and wind (Exhibit 3) (See sidebar, “The need for natural gas in a transition to renewables: A case study”).

## New market mechanisms and gas infrastructure investments will be needed to bridge the gap

The natural gas infrastructure in North America—pipelines and storage facilities—has grown over decades to transport gas based primarily on long-term, take-or-pay contracts between pipeline operators and customers (typically gas marketers or large buyers, like utilities or industrial companies) that pay a reservation charge (or tariff) for capacity.

In the coming decades, the capacity of the natural gas system will have to be increased to allow it to deliver on peak-demand days when renewables cannot generate at full capacity, even in areas currently not impacted by insufficient pipeline capacity. However, expanding this gas infrastructure capacity and maintaining the existing gas infrastructure will require new investments, though the capacity will be utilized at a much lower

## The need for natural gas in a transition to renewables: A case study

**To meet decarbonization goals,** New York (NY) and New England (NE) ISOs are starting to replace natural gas with renewable generation as a power source. From 2021 to 2040, gas generation is expected to decrease with a CAGR of 6 percent, while renewable generation grows with a 1 percent CAGR. Although gas accounted for over half of NY's and NE's power generation in 2021, by 2040, renewables would contribute the bulk—around 75 percent (exhibit).

Despite this shift from gas to renewables and the ultimate drop in annual gas generation, demand for gas on peak days—when renewables generate below full capacity—could increase, especially in the absence of other dispatchable energy supplies that can be ramped up to meet power demand. In 2021, peak-day gas demand in NE and NY reached up to 6.6 billion cubic feet per day (bcfd) above the average annual gas demand. By 2040, peak-day demand in NE and NY could quadruple the annual demand, with an 11.5 bcfd difference.

Natural gas, therefore, will remain essential to the grid in NY and NE, as in the rest of the country. This poses a challenge for natural gas providers and consumers—how best to organize and regulate access to an emergency supply of natural gas?

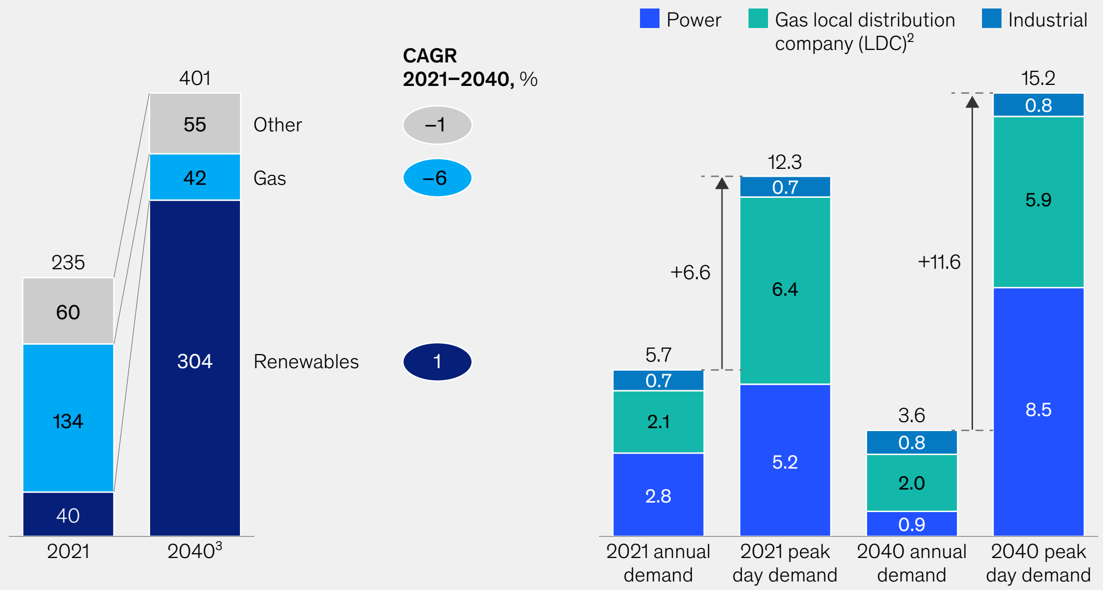
To ensure grid reliability, access to gas will be needed. And this, in turn, will require new infrastructure to be developed (such as pipelines and gas storage). Providing—and paying for— this infrastructure requires a change in how the gas and power market currently operates; new market mechanisms will have to be introduced to allow full access to the natural gas market.

Exhibit

### In New York and New England, average gas demand will decline, and peak-day demand will increase.

**NY and NE annual generation to meet decarbonization targets,** terawatt-hours

**2040 NY, MA, CT, and RI demand,**[1] billion cubic feet per day




Note: Assuming IRA and current state carbon policy.
[1]Excludes Maine, New Hampshire, and Vermont.
[2]Based on modeled gas LDC consumption for 2040 and the average winter peak day demand of ~3× higher.
[3]Assuming a constant demand for industry.
Source: ISO New England; Power forecast data; McKinsey Energy Insights; McKinsey Global Energy Perspectives

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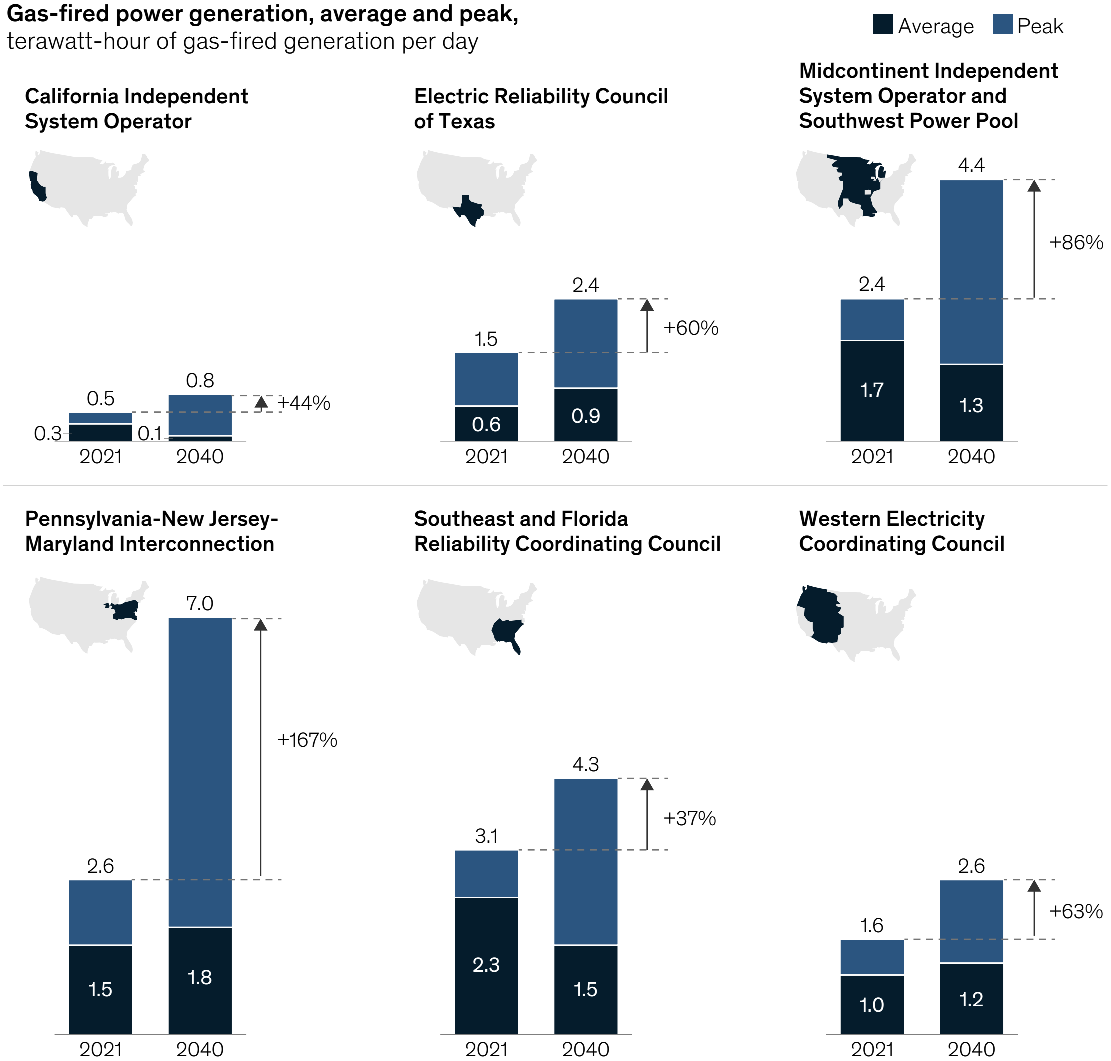
Exhibit 3

## Gas demand for power will decrease on average and increase on peak days.

**Gas-fired power generation, average and peak,**
terawatt-hour of gas-fired generation per day

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rate. The regulatory and market mechanisms that will support such investments are the key unlocks in this regard.

Addressing this challenge requires collaboration across the entire value chain—gas producers, pipeline operators, utilities or power producers (PPs), ISOs or regional transition organizations (RTOs), and policy makers—and a recognition that the solution needs to balance out the three imperatives of decarbonization, affordability, and reliability.

*Pipeline and storage operators:* These operators in particular will be affected by this. Together, lower average gas demand and the costs of increasing gas infrastructure capacity pose a unique challenge for pricing the delivery of midstream gas services to customers.

Current patterns of compensation for gas assets (such as storage facilities and transport pipelines built for predictable demand at moderate volumes) are not designed for this volatile demand. If these patterns persist, end users will likely be forced to pay for year-round access to a gas supply they may only need a few times a year. Additionally, pipeline operators have proposed peaking services to address some of these issues, which require investments (for example, flexible storage assets or new pipeline connections). However, in the current regulatory environment, investment costs often are not allowed to be passed onto customers.

Participants in the natural gas market will need to choose carefully how they approach the conundrum to justify gas infrastructure investments. One option is to continue to offer connection tariffs. The weakness here, however, is that customers will have to pay for infrequently used gas infrastructure capacity. For example, gas infrastructure capacity could be booked on a monthly basis with a fixed reservation charge. Peaking power plants would often not know whether they will dispatched and therefore may find it uneconomic to pay a monthly reservation charge. Another option is to offer customers hourly, pay-as-you-go payment plans, which may require regulatory support and customers' willingness—such as power generation utilities—to pay high hourly rates for short periods during peak gas demand days (Exhibit 4).

Without market mechanisms (and regulatory support) to justify infrastructure investments (for example, secure funding and engineering, procurement, and construction [EPC] contracts), the current challenges of pipeline constraints may become exacerbated with a higher share of intermittent renewables and electrification of energy demand.

*Power-generation utilities:* Gas-fired power generation will be exposed to far greater volatility in seasonal, daily, and intraday load—while the importance of reliability will increase. For example, during the winter storm Elliott in December 2022, plant equipment outages accounted for a large share of power supply shortages, followed by securing gas supply.[12] As outlined in a previous McKinsey article, "The future of natural gas in North America," decarbonization policies will likely drive gas-fired generation to average loads of 10 to 20 percent by 2040. This increase may create a need for capacity markets or other mechanisms to remunerate dispatchable gas-fired (peaker) capacity supporting renewables unless more attractive solutions emerge for dispatchable generation and storage.

*Upstream gas producers:* Over the last decade, upstream gas producers have provided US customers with affordable energy and ensured energy supply security both domestically and overseas through LNG exports. If gas is to remain a core pillar of the power generation system, the importance of the reliability of gas supply will only increase. For example, winter storm Uri that hit in February 2021 (which impacted 30 percent of nationwide production mainly in Texas and the Southwest), and winter storm Elliott that hit in December 2022 (which affected 20 percent of nationwide production mainly in Appalachia), have emphasized the need for investments, solutions, and mechanisms to ensure a reliable gas supply, especially during extreme weather conditions.

*Policy makers and regulators:* The role of policy makers and regulators will be critical in establishing the pace of decarbonization and the appropriate market incentives to shape the role of gas to support renewables penetration—such as the provision of flexible dispatch in power generation to compensate for intermittency in solar and wind power. If the power system relies on gas for flexibility, then capacity markets or other mechanisms will be required to ensure that necessary investments are made in the gas system.

[12] "Winter storm Elliott," PJM Interconnection, December 2022; PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, the District of Columbia, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

Exhibit 4

## New market mechanisms will be needed to allow gas suppliers to meet peak-day demand.

Power market change   Gas market change

Minimal change — **Change to gas and power market** → Substantial change

| | Maintain current G&P contracting structure | Option based pricing | Require firm transportation (FT) for gas generators | Hourly gas prices |
|---|---|---|---|---|
| **Potential option** | • Continue operating gas and power markets under current standard contracting practices | • Variable cost gas supply that changes based on market conditions (for example, pay less during normal conditions but pay a premium during a price fly-up) | • Require generators to have FT to participate in power capacity markets | • Offer gas supply on a dynamic hourly basis |
| **Additional considerations** | • Power generators may be unwilling to pay for year-round gas access when it is required infrequently | • Getting power and gas players to agree to terms when higher prices are permitted may be difficult<br>• More variable revenue (pipeline) and costs (power) | • May increase power costs<br>• Power generators and regulators may be unwilling to pay for year-round gas access when it is required infrequently | • Pipeline revenue becomes highly volatile<br>• Power generators and regulators may be cautious to pay potentially thousands $/mmbtu for a few hours of gas access |

Note: To meet higher peak-day gas demand in a renewable-dominant power grid, additional infrastructure (such as pipelines and underground storage) will be required.

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With the right regulatory and infrastructural changes, natural gas can play a key role in decarbonizing the US power supply in the coming decades, supporting the accelerated rollout of intermittent renewables through affordable and reliable grid balancing. To do this, the gas system must be ready to deliver high volume on peak-demand days when renewables cannot generate at full capacity—this will require the introduction of market mechanisms and infrastructure not in place today.

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# Toward a more orderly energy transition: Six key action areas

The US drive to decarbonize is at an inflection point. Critical actions could accelerate the transition while enhancing energy affordability and supporting inclusive economic growth.

*This article is a collaborative effort by Gracie Brown, Blake Houghton, Jesse Noffsinger, Hamid Samandari, and Humayun Tai, representing views from McKinsey's Global Energy and Materials and Sustainability Practices.*

**A combination** of federal legislation, state targets, corporate commitments, investor pressure, and advances in clean technologies is giving new momentum to public- and private-sector efforts in the United States to moderate the effects of climate change.[1] This forward movement improves the country's chances of significantly reducing its emissions by 2030 and coming closer to meeting its climate commitments.

At the same time, powerful headwinds are present. The war in Ukraine has shattered lives and livelihoods, disrupted energy security and affordability, and deepened geopolitical tensions. It has also exacerbated the supply chain issues and inflationary trends that arose with the pandemic and increased the threat of a global recession. An increase in US natural-gas prices of more than 50 percent in September from a year earlier led to the announcement of delays in the retirement of some coal plants.[2] Supply chain challenges in the United States have also increased the price of renewables, with reduced access to solar panels from Asia raising prices by 30 percent and causing project delays.

Indeed, it seems that over the past three years, the United States, and the world, have been witnessing a confluence and mutual reinforcement of the four main systemic risks facing humanity: global-health, macroeconomic, geopolitical, and environmental risks. Yet that same confluence makes the case for action even stronger as the relationship between the risks becomes clearer.

## Where do we go from here?

The energy transition, as it is often called, includes not only the decarbonization of the electric sector—which accounts for about 25 percent of US greenhouse-gas (GHG) emissions today[3]—but also three additional elements: the development of new

**The requirements of the transition must be carefully balanced with the need to ensure a reliable, resilient, and affordable energy supply all along. The United States does not seem to have found this balance.**

[1] The passage of the Inflation Reduction Act (IRA), and the government's commitments to cut greenhouse-gas (GHG) emissions by 50 to 52 percent by 2030 and to achieve a net-zero grid by 2035, represent the most ambitious climate actions by the federal government to date. For more information, see "Fact sheet: President Biden sets 2030 greenhouse gas pollution reduction target aimed at creating good-paying union jobs and securing U.S. leadership on clean energy technologies," White House, April 22, 2021. (See sidebar "The potential impact of the Inflation Reduction Act.") At the same time, policies put in place by the 25 states that have set economy-wide emissions-reduction targets continue to accelerate decarbonization ("U.S. state greenhouse gas emissions targets," Center for Climate and Energy Solutions, updated August 2022). In addition, more than $30 billion in climate-focused assets are under management in the United States ("Climate funds dig deeper roots," Morningstar, April 13, 2022), while more than 1,500 businesses have committed to setting net-zero targets (Science Based Targets home page, accessed December 18, 2022).
[2] Timothy Gardner, "U.S. coal plants delay closures in hurdle for clean energy transition," Reuters, August 10, 2022.
[3] "Sources of greenhouse gas emissions," US Environmental Protection Agency, August 5, 2022.

## The potential impact of the Inflation Reduction Act

**The Inflation Reduction Act** (IRA) of 2022 will likely have a significant impact on enabling the United States to achieve climate commitments. The law directs an estimated $393 billion in climate spending to six key categories: energy, climate and environmental justice, manufacturing, land and agriculture, transportation, and water. Funding is channeled through tax investment and production credits, federal grants, and loan programs. Many of the tax credits are uncapped, meaning no limit is written into the law that restricts how much they are used. Moreover, the $40 billion in funding for loans covers subsidy costs exceeding $400 million for direct loans or loan guarantees for innovative clean energy, energy infrastructure reinvestment, and upgrading transmission lines, among others. The true magnitude of the public-sector investment could reach $1 trillion if implemented effectively.

The IRA has the potential to support a more orderly energy transition but also could introduce further risks and challenges. Key implications of the legislation for the power sector include the following:

1. accelerating the transition of the US power mix toward renewables
2. expanding the distributed solar market, with different customer segments, such as low-income customers, taking on more prominence
3. unleashing of a new stand-alone storage market for developers and asset owners
4. unprecedented expansion of US cleantech manufacturing and supply chains
5. directing investment to energy-producing regions and communities that may be most affected by industry changes
6. accelerating of electrification and energy-efficiency opportunities, increasing the importance of serving low-income customers
7. jump-starting the hydrogen market, with a relatively higher emphasis on lower-carbon supply
8. creating a $CO_2$ economy driven by expanded credit options
9. kick-starting production of sustainable aviation fuels, including novel power-to-liquids pathways

net-zero energy supplies (for example, scaling up production of low-carbon hydrogen); the electrification of demand, such as transportation and buildings; and the transition of the gas system to being primarily a capacity provider. These will require new policies, markets, business models, and technologies to be rapidly developed and deployed at scale.

At the same time, the requirements of the transition must be carefully balanced with the need to ensure a reliable, resilient, and affordable energy supply. On its current trajectory, the United States does not seem to have found this balance. Resilience investments, where they are being made, appear set to radically increase bills. Where they are not made, customers would face expensive and dangerous outages. The speed of the deployment of renewables remains insufficient. There appears to be little agreement on the extent to which new fossil-fuel investments would be required to ensure resilience, or how to make them as low-carbon as possible and without long-tail stranded assets. Moreover, the transition could exacerbate consumer inflation, which is already historically high. In other words, the energy transition is currently on a disorderly path.

Persisting on this path could mean that achieving the same cumulative net emissions by 2050[4] would

[4] Delay in taking action could require an estimated $5.7 trillion in generation investment alone through 2050, compared with about $4 trillion for a more orderly energy transition—a 42.5 percent increase.

cost at least 40 percent more (Exhibit 1). This would also likely entail much greater environmental damage than a more orderly energy transition, in which emissions reductions in the near term rapidly put the United States on a path closer to a 1.5°C global warming scenario while balancing affordability, reliability, resilience, and security. (See sidebar "Modeled scenarios underlying our analyses.") An even more dramatic scenario, in which no abatement action is taken and US emissions are aligned with a 4.8°C warming pathway, would be drastically more costly.

McKinsey's 2022 report on the transition highlights nine critical requirements to reach net-zero emissions.[5] From these, we have identified six action areas that we believe are critical at this point to enable a more orderly energy transition in the United States. Although the following actions will probably not be sufficient in themselves, we believe they constitute the necessary bedrock for this transformation and take priority at this stage:

1. designing and deploying a capital-efficient and affordable system

2. strengthening supply chains to provide stable access to raw materials, components, and skilled labor

3. securing access to adequate land with high load factors for the deployment of renewables while taking into account the needs of local communities

4. reforming transmission development to include proactive planning, fast-track permitting, and systematic consideration of transmission alternatives

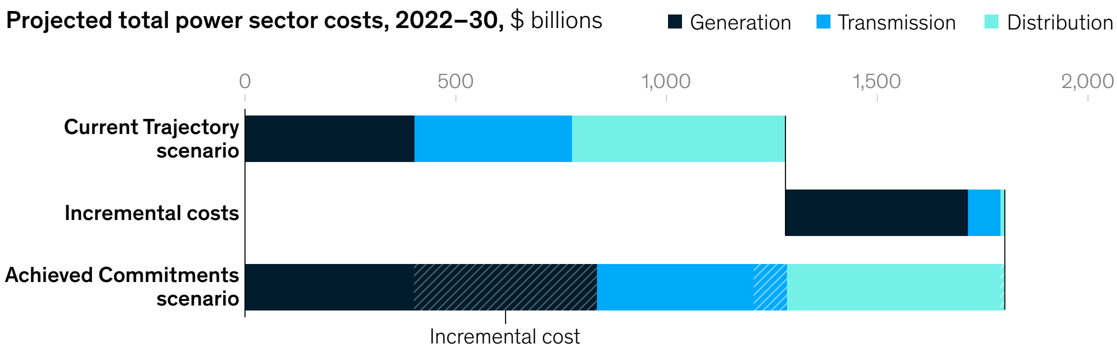
5. creating market mechanisms for expanding firm capacity to ensure reliable and adequate clean energy supply

6. accelerating technological innovation to ensure timely deployment of new clean technologies

Exhibit 1

**Energy transition investments could increase power sector capital by approximately 40 percent through 2030.**

**Projected total power sector costs, 2022–30,** $ billions




Source: McKinsey Energy Insights Global Energy Perspective 2022; McKinsey Power Model; McKinsey Transmission Model

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[5] The nine critical requirements to reach net zero are: *physical building blocks*, encompassing (1) technological innovation, (2) ability to create at-scale supply chains and support infrastructure, and (3) availability of necessary natural resources; *economic and societal adjustments*, comprising (4) effective capital reallocation and financing structures, (5) management of demand shifts and near-term unit cost increases, and (6) compensating mechanisms to address socioeconomic impacts; and *governance, institutions, and commitment*, consisting of (7) governing standards, tracking and market mechanisms, and effective institutions, (8) commitment by, and collaboration among, public-, private-, and social-sector leaders globally; and (9) support from citizens and consumers. See "The net-zero transition: What it would cost, what it could bring," McKinsey Global Institute, January 2022.

## Modeled scenarios underlying our analyses

**For the purpose** of this article, a more orderly transition pathway has been modeled as a scenario in which the United States achieves its stated commitments of a 50 to 52 percent reduction (from 2005 levels) in economy-wide greenhouse-gas (GHG) emissions by 2030 and 100 percent carbon-free electricity by 2035. We call this the "Achieved Commitments" scenario. It is modeled to align with a global pathway that limits warming to about 1.7°C, which can still result in severe climate change impacts. Further action will be required to go beyond commitments and hold warming below 1.5°C.

We contrast the Achieved Commitments scenario with two other scenarios:

1. *The Current Trajectory scenario,* in which the current path of technology cost decline continues, though active policies remain insufficient to close the gap required to meet policy objectives. The Current Trajectory scenario is modeled to align with a global pathway that reaches 2.4°C of global warming.
2. *A Delayed Trajectory scenario,* in which the United States continues on the Current Trajectory until 2030 and then needs to "catch up" to achieve the same cumulative GHG emissions as the Achieved Commitments scenario by 2050. Under the Delayed Trajectory scenario, the United States must both accelerate deployment of clean technologies after 2030 and invest in abatement technologies such as direct air capture to negate earlier emissions.

ACTION AREA 1

## Designing and deploying a capital-efficient and affordable system

Meeting the US government's 2030 emissions-reduction goals would require more than $500 billion in additional generation, transmission, and distribution infrastructure investments compared with the current trajectory of the US power system (Exhibit 2).

That figure does not include so-called stranded investments: assets such as fossil fuel–intensive thermal plants that are retired early or are no longer used to the extent originally planned. However, these net new investments could help avoid the even more costly consequences of delayed action and reduce ongoing fuel costs, resulting in a system that could be less expensive to operate in the long term.

Spending on the energy transition, coupled with the significant grid investment needed for reliability and resilience under any scenario, could increase the cost of the energy system for households and businesses in the coming decades. If these cost increases aren't carefully managed and mitigated to the extent possible, they could hamper economic activity and create customer backlash. This, in turn, would delay needed action and result in a less orderly energy transition. Businesses and policy makers will thus need to target capital expenses to mitigate the affordability challenges that customers will face. (For more detailed context, see sidebar "Investments and affordability.")

### KEY PRIORITIES

To enable a capital-efficient system, business leaders and policy makers need to consider three key priorities now: planning investments for long-term decarbonization, deploying capital more cost-effectively, and empowering and educating customers to manage rising costs.

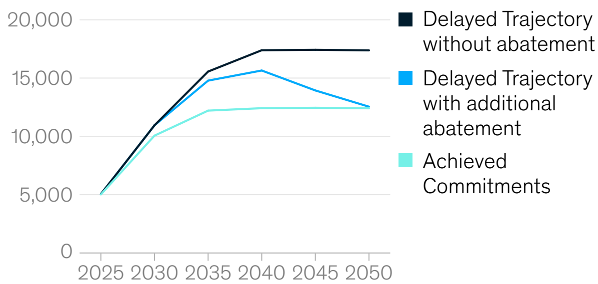
1. *Planning investments for long-term decarbonization.* Energy infrastructure is depreciated over long periods, potentially requiring customers to bear costs over many decades. The assets that go into the ground this year will affect costs and the system composition through the 2040s and '50s. The exact makeup of a decarbonized power system is uncertain, so scenario planning will be helpful in identifying investments that could be valuable under a range of decarbonization scenarios and hence more judicious in the near term.

   By incorporating new asset types, utilities could identify and plan the right portfolio to deliver the energy transition at a lower cost. These include hydrogen-related assets; carbon capture, utilization, and storage assets; nuclear power; electric-vehicle-charging infrastructure; batteries; and long-duration energy storage.

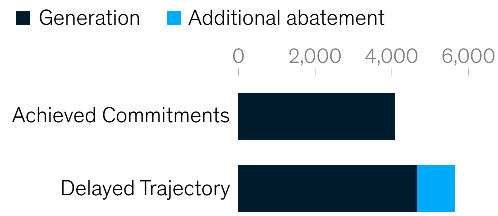
Exhibit 2

## A more orderly transition could save the United States more than $1.5 trillion compared with achieving the same emissions under a less orderly path.

**US cumulative GHG[1] emissions from 2022,** Gt $CO_2e$[2]




**Generation and additional abatement capital investment, 2022–50,** $ billions




[1]Greenhouse-gas.
[2]Metric gigatons of carbon dioxide equivalent.
Source: McKinsey Energy Insights Global Energy Perspective 2022; McKinsey Power Model; McKinsey analysis

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In addition, investments in fossil-fuel assets would best be made based on their anticipated useful life, with a view to ensuring what is needed for a reliable and affordable energy system in the shorter term while aiming to making assets less carbon-intensive, more flexible in their usage, and potentially used for a shorter duration. Asset owners could look for ways to repurpose assets that are no longer used and useful—for example, by using brownfield coal sites for new nuclear assets or upgrading gas pipelines to transport hydrogen. Lean-asset retirement and removal (decommissioning) could improve efficiency of processes and reduce costs.

Investing in the right assets could have massive impact. Under the current trajectory, for example, 110 gigawatts (GW) of existing coal capacity would remain online in 2030. However, the Achieved Commitments scenario, in which the United States meets its emissions-reduction goals, would call for only 60 GW, a 45 percent difference. (In the Achieved Commitments scenario, the United States would achieve its stated commitments of a 50 to 52 percent reduction in economy-wide GHG emissions by 2030 and 100 percent carbon-free electricity by 2035. See sidebar "Modeled scenarios underlying our analyses.") Capital that otherwise would have been spent on maintaining coal assets could be significantly reallocated across other asset types, such as solar and wind.

2. *Deploying capital more cost-effectively.* All companies and utilities along the electric value chain could identify opportunities to reduce costs. The most significant target would likely be capital efficiency, given that investment accounts for 70 percent of overall costs by 2030 under the Achieved Commitments scenario, and there are ways to lower those costs significantly. In our work with renewables developers, we found that they can drive capital productivity through three key levers: design and engineering, contracting and procurement, and project execution. Combined, these could reduce capital expenditure by about 10 to 20 percent. In another example, we found that better planning and project design reduced transmission spending by 13 to 19 percent.

## Investments and affordability

**The economics** of the energy transition is a critical piece of the puzzle: significant investments will be needed in the coming decades, but they must be made with affordability in mind. Fortunately, these capital investments will likely result in an energy system that costs less overall to operate as society transitions away from a fuel-intensive system (such as oil for vehicles and natural gas and coal for power). Nevertheless, making capital as efficient as possible will require action. Additional measures will also likely be required to mitigate costs, particularly for low-income customers who are disproportionately affected by rising energy costs.

**1. The energy transition will require increased capital investment**

The energy transition will require energy companies to effectively manage significant infrastructure investment. McKinsey analysis found that the US power sector may need more than $500 billion in additional capital investment between 2020 and 2030 to build and upgrade generation, transmission, and distribution in line with the Achieved Commitments scenario. That represents a 40 percent increase compared with the Current Trajectory.[1]

The incremental investment needed will vary by state. For example, in the case of distribution grid infrastructure, states with quicker adoption of electric vehicles (EVs) will need more distribution spend than those with slower adoption. Also, while significant distribution spend is required in the Current Trajectory, much of that investment becomes even more critical for the energy transition. For example, many customers may not want to buy an EV if they think the grid is too unreliable for them to charge it when they need to.

*In the long term, delay and inaction will ultimately require far more investment than the Achieved Commitments scenario.* While meeting the US government's commitments would be costly, inaction could cost significantly more, both in economic terms and in the effects of climate change on livelihoods.[2]

In addition, waiting to act until 2030, and then seeking to achieve the same cumulative net emissions by 2050, will likely be significantly more expensive than acting today. For example, investment for generation alone could increase by almost 40 percent by 2050 if the United States continued on its current trajectory and then attempted to make up ground starting in 2030. Much of the additional cost would come from technologies to remove carbon from the air to achieve the same cumulative emissions as the Achieved Commitments scenario. These "negative emission" technologies are still precommercial, making them a high-risk option.

While some advocate for waiting for technology costs to come down before scaling investment, solar and onshore wind can already be deployed cost-effectively today; they make up approximately 75 percent of new generation capacity forecast in the Achieved Commitments scenario. Despite near-term supply chain challenges that bottleneck deployment today, not deploying renewables in the coming years would lead to a dramatically more expensive pathway in the future, as shown by the Delayed Trajectory scenario.

Of course, parallel progress of continued innovation and deployment will likely also be needed to enable a more orderly and less onerous energy transition as costs come down (see "Action area 6: Accelerate technological innovation to ensure timely deployment of new clean technologies"). Technologies in earlier stages than solar and onshore wind, including hydrogen and offshore wind, are forecast to begin ramping up in this decade. Acting early to plan, pilot, and demonstrate these and other technologies could inflect the cost curves for their larger-scale deployment in the 2030s and beyond.

**2. Beyond 2050, a more orderly energy transition could lower overall energy system costs**

Historically, ongoing fuel costs have made up the bulk of the spend in the energy sector. By contrast, through 2030, almost 75 percent of energy-sector transition spending will go toward capital investments under the Achieved Commitments scenario, such as to deploy more renewable-energy facilities and boost electric-grid capacity. By 2050, the power system enabled by those investments would require only half as much expenditure on primary fuels as today's fossil fuel–based system would under the Achieved Commitments scenario.

Customer-side transitions show similar results. For example, the Department of Energy's Office of Science estimates that a battery electric vehicle reaches

[1] This analysis does not incorporate impacts of the Inflation Reduction Act (IRA) of 2022. Under the IRA, the federal government supports these investments with tax credits, grants, and other policy instruments that might be funded through the bill instead of being recovered directly by energy users.
[2] *Climate risk and response: Physical hazards and socioeconomic impacts*, McKinsey, January 2020.

parity with an internal combustion engine vehicle after five years of operation.[3] And in many climates, air source heat pumps could cost up to 40 percent less over their lifetime than gas furnaces.

**3. Reliability and resilience could drive significantly more spending in the near term**

As seen in Exhibit 1, the power sector could require significant investment even on the current trajectory. One example: about 75 to 90 percent of expenditures through 2030 In the distribution system—the fastest-growing area of spending in the electric value chain—would be focused on reliability and resilience. Only 10 to 25 percent would be spent directly on the energy transition.

The principal cost drivers in this area have been traditional reliability investments, particularly to replace assets that are significantly older than their planned or useful lives. More than 70 percent of transmission lines and transformers are more than 25 years old, "creating vulnerability," according to the Department of Energy (DOE).[4] One utility estimated that to maintain the current age of the grid and avoid further deterioration, it would need to increase spending to 52 percent above current forecasts through 2030.[5]

Reliability investments are likely to be accompanied by a rapidly increasing category of resilience investments as customers become increasingly concerned about the performance of the grid during disaster events and in storms.[6] Climate change is exacerbating the problem as extreme weather events become more frequent and intense.[7] Furthermore, if the electric grid increasingly powers vehicles and heating, customers would be ever more reliant upon a resilient system.

These projected reliability and resilience investments would increase customer bills regardless of additional energy transition investments. However, to enable a more orderly energy transition, those investments could also be accounted for and managed cost-effectively, or customers could push back as they face increasing energy bills. Such public discontent would pose a challenge to the energy transition because those reliability and resilience investments are effectively being made to avert future crises through actions such as undergrounding of distribution lines to mitigate wildfire risk and hardening electric poles so that fewer come down during intensifying windstorms. These efforts at crisis avoidance might not be understood by customers who otherwise won't experience much difference in service. There is a risk, therefore, that customers could attribute rising energy costs to more-visible solar farms and windmills rather than to reliability and resilience measures that are less visible and feature less often in public discourse.

**4. Management of costs is critical for customers and utilities to support the energy transition**

Because investments in grid reliability and resilience would grow significantly even under the Current Trajectory scenario, with additional energy transition investments under the Achieved Commitments scenario, customer costs are likely to rise in the coming years. The Pacific region experienced significant rate increases of about 5 percent a year from 2018 to 2021.[8] McKinsey modeling found that if energy providers and policy makers don't act to optimize affordability, bills could increase by as much as 30 to 40 percent in real terms by 2050 for a fully electrified single-family home in the Northeast. Such increases would likely be hardest on low-income households, whose energy bills account for a disproportionate share of income.

Costs that aren't managed appropriately could cause setbacks to the energy transition from customers, regulators, or both. Customer backlash against rising bills has driven notable challenges to the energy transition in Germany and the United Kingdom. In these cases, when energy expenditure rose to 5 percent of household income, prices were capped for customers and green-electricity surcharges were reduced. Similarly, utility regulators have often cited affordability when denying funding requests. In recent years, US utilities have been asking regulators for more increases—from 12 requests in 2000 to 90 in 2018—yet gaining approval for much lower amounts. In 2000, utilities received a total of $1.2 billion less than they requested; in 2018, this shortfall more than tripled to $4 billion.[9]

[3] Zhe Liu et al., "Comparing total cost of ownership of battery electric vehicles and internal combustion engine vehicles," *Energy Policy*, November 2021, Volume 158.
[4] "DOE launches new initiative from President Biden's Bipartisan Infrastructure Law to modernize national grid," US Department of Energy, Office of Electricity, January 12, 2022.
[5] Utility executive testimony, FERC.
[6] Pacific Gas & Electric has announced $15 billion to $30 billion of spending on undergrounding through 2030.
[7] Sarah Brody, Matt Rogers, and Giulia Siccardo, "Why, and how, utilities should start to manage climate-change risk," McKinsey, April 24, 2019.
[8] US Energy Information Administration (EIA) data for average electricity prices across all sectors from 2018 to 2022.
[9] Dan Lowrey, "Inflation rearing its head in electric, gas general rate cases nationwide," S&P Global Market Intelligence, October 4, 2022.

Utilities can also conduct cross-sector planning through the central assessment and prioritization of grid changes. For example, electric and gas companies could work with regulators and communities to identify areas where full electrification and gas-pipeline decommissioning could be feasible, reducing the need for future gas-system investment or ongoing maintenance spending. And a study on the British transmission grid found that consumers could save up to 18 percent of their transmission costs if offshore wind developers used an integrated approach to transmission development rather than creating their own lines, a process known as the generator lead line approach.[6]

Government and regulators could push utilities toward improved capital efficiency by revising incentives. Under current regulations, utilities are encouraged to deploy as much capital as possible, even when operations and management solutions might be more effective. As a result, utility expenditures are not always allocated to maximize efficiency or innovation. New capital projects often take priority over operations and management solutions including energy-efficiency initiatives, opportunities to repair instead of replace, and the use of technologies that optimize current infrastructure such as advanced analytics. Grid-enhancing technologies (GETs), for example, are almost twice as cost-effective as traditional transmission upgrades for equivalent levels of avoided renewable-energy curtailment.[7] But there is no incentive to use GETs, because they minimize capital growth. This factor is often cited as the key limitation to their widespread adoption.

Regulators could evolve this system by putting in place performance-based rules involving multiyear rate plans, revenue decoupling, and earning-sharing mechanisms designed to determine profit caps based on true performance rather than on total capital spending. So far, 20 states and the District of Columbia and Puerto Rico have made regulatory changes related to performance.

Another option is evaluating utilities on their total expenditure—assessing both capital and operations outlays rather than just capital. This method, which is used globally, could help promote operations and management solutions that are deprioritized in the legacy US utility regulatory environment.

3. *Empowering and educating customers.* Customers need to be empowered both to take control of their energy bills where possible and to understand their energy expenditure.

   Utilities can use rate design that empowers customers to both lower their bills and provide value to the grid in the form of flexibility, possibly reducing the need for capital build-out. Customers could be offered rates with charges proportionate to their demand during “flex” periods, time spans with the largest spread between demand and renewable production. This would motivate customers to use less electricity and lower their bills when the system is most constrained. To ensure an optimal experience, this would have to be simple for residential customers to implement, either through automated devices (such as smart thermostats that allow users to define their preferences) or by providing information about usage periods, such as typical days throughout the year when the most flexibility is needed.

   Residential customers may not have time to monitor the “flex” market regularly, but additional incentives could be offered to commercial and industrial customers to better match their needs to the system. And there is evidence that customers have the ability to

[6] Justin Horwath and Yannic Rack, “US offshore wind boom entangled in transmission debate,” S&P Global Market Intelligence, July 6, 2021.
[7] Grid-enhancing technologies can be used in transmission to help expand line capacity at lower costs than building or upgrading lines. Examples include dynamic line rating, or the use of sensors that provide real-time line-capacity information by reporting varying environmental conditions such as ambient temperature, solar radiation, and wind; devices that can change the flow of power through the grid and provide real-time control over how renewable energy is routed; and topology optimization—software and hardware that can provide grid system reconfiguration to reliably route power around congested lines.

respond when necessary. During the summer of 2022, for example, the Electric Reliability Council of Texas (ERCOT) drew critically close to its constraints as renewable supply sagged, thermal plants tripped, and a heat wave caused a surge in consumer demand. When ERCOT simply asked customers to decrease their usage, usage rapidly fell by as much as 500 megawatts.[8] Providing incentives to customers could yield even more significant benefits.

Some utilities offer discounted rates to mitigate costs for lower-income customers, who suffer disproportionately from rising energy bills. Options such as on-bill financing, in which utilities incur the up-front costs and are repaid over time via the customer's bill, could also be provided to assist with the electrification of households and vehicles, particularly for lower-income households that might not be able to afford the up-front cost even if they would save money over the lifetime of the investment.

Innovative products and services can provide options to help mitigate bill challenges. Utilities could provide digital tools to customers, allowing them to assess how different capital investments (such as the purchase of an electric vehicle) would affect their energy bills. Consumers could then manage usage or identify the rate design option that would minimize their bill. Utilities could also offer discounts to customers deploying distributed energy resources (DERs) such as local storage in instances when the DER's function drives down utility costs.

Similarly, governments and utilities could significantly ramp up their efforts to explain what it would take to transition the energy system and maintain it against rising climate challenges. Utilities could communicate the benefits of necessary reliability and resilience investments, which otherwise could go unnoticed by the customer. At the same time, they could effectively communicate about the drivers of cost increases to help customers understand, prepare for, and adapt to changes. This is not a common muscle for utilities, which for decades have mostly connected with customers when asking them to pay a bill. Marketing and communications will be critical to future success.

## ACTION AREA 2

## Strengthening supply chains to provide stable access to raw materials, components, and skilled labor

A more orderly transition faces five potential sources of disruption: volume shortages; price volatility; political, social, or regulatory uncertainty; long lead times; and unreliable quality. Each reflects essential priorities that energy-sector executives would need to evaluate and master on the road to decarbonization. Business leaders and policy makers could mitigate some of the impact of these disruptions by securing the availability of raw materials, scaling up resilient manufacturing of key technologies, and developing and acquiring talent in a tight labor market. (For more detailed context, see sidebar "Strengthening supply chains.")

### KEY PRIORITIES

**Secure availability of raw materials**

1. *Increase supply sources.* Suppliers and miners of raw materials are already busy identifying sources for many of the components that will clearly be in demand. But they also will need to dramatically increase supply in several areas, including lithium for lithium-ion batteries. Lithium demand is expected to grow by at least 25 percent a year,[9] and new technologies such as direct lithium extraction offer enormous potential to help provide new sources of supply.

2. *Use advanced analytics.* Suppliers are also applying advanced analytics. One start-up company is using this method to identify entirely new deposits of critical metals in Greenland

[8] Mitchell Ferman, "Texans asked to conserve energy to protect the power grid for the second time in a week," *Texas Tribune*, July 13, 2022.
[9] Marcelo Azevedo, Magdalena Baczyńska, Ken Hoffman, and Aleksandra Krauze, "Lithium mining: How new production technologies could fuel the global EV revolution," McKinsey, April 12, 2022.

and other locations.[10] There might be much to learn from oil and gas exploration companies that—despite several warnings of "peak oil"—found innovative solutions to ensure more supply. When applying advanced analytics to enable increased extraction, it will be critical for suppliers to respect local laws, environments, and communities.

[10] Willem Marx, "Forget gas prices. The billionaire club's run on cobalt says everything about our battery-powered future," *Vanity Fair*, April 2022.

## Strengthening supply chains

**As the power sector** begins a dramatic transformation toward electrification and clean energy, critical supply chain challenges could pose a challenge to the ability of the United States to execute a more orderly energy transition. The new technologies required for this transformation rely heavily on the steady supply of resources that, in many cases, are vulnerable to disruptions. We estimate, for example, that by 2030, the global energy transition would demand a nearly ninefold increase from 2020 levels in lithium supplies, more than eight times the volume of nickel, twice the amount of copper, and three times the level of rare earth minerals. The United States could seek stable access to supply even as many other countries pursue the same base materials, exacerbating the challenges.

In addition, the construction of new capacity for clean power generation and storage in the United States could require surging the production of generation equipment, including solar panels (more than triple 2020 levels), wind turbines (more than four times higher), and lithium-ion batteries (more than 20 times higher). Insufficient or unsecured manufacturing capacity for key components could slow the pace of deployment of these assets. For example, when the United States began investigating tariff challenges on key solar supplies at the beginning of 2022, project delays increased, and solar developers raced to identify alternative pathways to access supply. Significant portions of the solar manufacturing supply chain remain concentrated in China: 95 percent of solar ingot manufacturing supply is concentrated in China or Taiwan.

Development of renewables, meanwhile, could require significant scaling of the labor market. In the Achieved Commitments scenario, more than 550,000 direct and indirect job opportunities could be created in 2030 to support deployment of needed generation resources, including solar, wind, and natural gas.[1] Those jobs would be in addition to those needed to develop other technologies, perform grid build-out and management, and deploy electrified equipment and vehicles. And the number of jobs required to support the transition could continue to increase beyond 2030 as the United States seeks to achieve longer-term commitments.

**Potential sources of disruption and delay**

Five factors could contribute to delays in deployment of the technologies needed for a more orderly energy transition:

1. *Volume shortages.* Suppliers could be unable to deliver sufficient quantities of materials or components because of long lead times required to scale up or fundamental limits. For example, constraints on mining capacity for lithium while demand for lithium-ion batteries increases could result in a supply–demand gap.
2. *Price volatility.* Market forces could create price volatility for many materials and components.
3. *Geographical sourcing dependency.* Political, social, regulatory, and other uncertainties could roil trade flows in some regions, disrupting materials or component suppliers.
4. *Long lead times.* Material or components could take even longer to procure as manufacturers grapple with capacity and logistical constraints.
5. *Unreliable quality.* Demand increases could affect quality as suppliers (and their vendors) loosen quality controls to accelerate production.

[1] Employment and job opportunities are not equal to full-time-equivalent (FTE) roles but rather an industry-specific mix of full-time, part-time, and seasonal employment roles typically referred to as job years. This metric accounts for seasonality and follows definitions used by the US Bureau of Labor Statistics and Bureau of Economic Analysis.

3. *Reduce demand for raw materials.* Manufacturers could continue to innovate products and technologies that use fewer of the materials facing supply constraints. In the case of lithium-ion batteries for electric vehicles (EVs), for example, General Motors has announced a battery system design that reduces cobalt use by 70 percent, and Tesla has said it is developing a cobalt-free battery.[11] Introducing more-efficient products also diminishes the need for materials. Solar panels have become 50 percent more efficient in recent years,[12] driving a proportional reduction in the materials needed. While there is potential to improve existing technologies, some newer materials that could provide a step change in performance are not commercially proven. Perovskites are a potentially promising material for solar energy that could dramatically increase cell efficiency, using materials that are relatively inexpensive to produce, widely available, and 20 percent more efficient than typical cells today.[13] There are also significant opportunities to further reuse existing materials.[14] For example, second-life EV batteries could potentially cover all demand for utility-scale lithium ion–battery storage from the power sector.

4. *Plan for and manage constraints.* Players would need to recognize the potential for continued supply constraints and the likely volatility of commodity markets while supply chains continue to reorganize and experience geopolitical shocks. As these actors evaluate their upstream supply chain, they could potentially look to lock in suppliers that have stable supply access in areas with stronger institutions. They could also structure contracts that recognize this supply chain dynamic by demanding provisions such as shared-risk agreements for commodity price fluctuations as well as political and technological risks. These agreements could factor in materials to build facilities and secure access to supplies to run them and obtain critical replacement parts in the future.

5. *Develop domestic supply and trade agreements.* Governments can develop resilience plans for access to rare earth metals and other raw materials in the United States and the countries with which it has fair-trade agreements. (The US Inflation Reduction Act of 2022 [IRA] provides for additional rebates for EVs made with critical minerals such as lithium sourced from fair-trade countries such as Chile.) The United States could also look at supporting development of local supply where possible. For example, there are lithium opportunities in the United States that are potentially more expensive today but could ultimately increase domestic capacity.

**Scale up resilient manufacturing**

1. *Develop local capacity.* Onshoring key areas of solar manufacturing such as larger and n-type silicon wafers used in solar panels is estimated to increase the cost of solar modules by about 20 percent, which would raise the levelized cost of solar by only 5 percent. By contrast, delays in accessing solar panels from Asia earlier this year raised prices by roughly 30 percent. Companies could create a cost-effective and more secure pathway forward by building local manufacturing capacity. While such a move would increase prices, companies would be able to pass those costs on to counterparties who value long-term certainty of supply and guarantees that they would be less subject to supply chain delays. To be effective, however, this solution would need to be implemented now, because building a manufacturing plant takes approximately one to three years.[15]

2. *Diversify suppliers and countries of origin.* US players up and down the electric value chain could also provide incentives to manufacturers to diversify suppliers and source countries.

[11] Jo Olson, “What’s up with the cobalt used in EV batteries?,” Fresh Energy, April 22, 2021.
[12] Barbara Zito, “The most efficient types of solar panels 2022,” *Forbes*, July 25, 2022.
[13] Iain Wilson, “Solar’s hot new thing nears production: Q&A,” BloombergNEF, June 11, 2019.
[14] Hauke Engel, Patrick Hertzke, and Giulia Siccardo, “Second-life EV batteries: The newest value pool in energy storage,” McKinsey, April 30, 2019.
[15] The time it takes to construct a solar manufacturing plant varies based on the part of the value chain.

While many countries and the United States face similar challenges with developing domestic capacity, American businesses could look into monitoring developments in manufacturing and continue to build more resilient supply chains through diversification.

3. *Reduce demand and employ alternative technologies.* Additional cutting of end demand for manufactured materials could further reduce the need for manufacturing capacity. Alternative technologies up and down the value chain could be explored as potential substitutes when supply chains become truly constrained. (See "Action area 6: Accelerating technological innovation to ensure timely deployment of new clean technologies.")

4. *Plan for and manage constraints.* Private-sector players could leverage AI to increase the resilience of the supply chain by incorporating uncertainty into realistic simulations to evaluate scenarios, identify risks, and develop optimal plans for different time horizons.[16] They could also use AI to evaluate contracting mechanisms and the benefits of built-in supply chain flexibility.[17]

5. *Provide incentives for domestic manufacturing.* Government could consider tax and financial incentives to develop and support domestic manufacturing. These enticements include the Advanced Manufacturing Production Credits for clean technologies contained in the IRA. For example, solar panels can receive more than 18 cents per watt of tax credits for domestic manufacturing of polysilicon, wafers, cells, modules, and polymeric backsheet. Solar trackers, solar inverters, wind components, and batteries are also eligible for manufacturing production tax credits. And some rebates, such as those for electric vehicles, are contingent on domestic assembly or component manufacturing.

**Develop and acquire talent**

1. *Hire workers from retiring assets.* People working in retiring assets such as coal have many transferable skills that would be needed in rapidly growing areas of the energy transition. McKinsey analysis estimates that nearly 10 percent of total energy transition labor needs in 2030 under the Achieved Commitments scenario could be met with the workforce currently employed at assets that are likely to retire.

2. *Develop deeper labor pools.* There will be significant need to develop new labor to achieve the energy transition. For example, only 3 percent of the electricians needed for the Achieved Commitments scenario could be hired from assets that are likely retiring without training or reskilling. To develop new talent, hiring practices might have to be adapted, such as by shifting to skills-based rather than credential-based hiring. On-the-job training and collaboration with vocational schools, universities, and nongovernmental organizations (NGOs) would be critical to create training programs. This training and development not only is needed for the energy transition but also would facilitate the creation of good jobs.

3. *Increase efficiency.* Players could ensure efficiency at all levels of their organization by adopting lean practices and digital and automation tools that can reduce overall labor demand. For example, in our experience, contractor productivity can be improved by approximately 40 percent on average through lean practices.

4. *Create incentives and pathways to good jobs.* Government could consider opportunities to support the creation of good, viable positions through incentives for jobs above a wage threshold. For example, the IRA provides credits for "businesses that pay prevailing wages and hire registered apprentices, ensuring local wages are not undercut by low-road contractors."[18] Additionally, governments could develop partnerships with community colleges, vocational schools, and companies

[16] "Building value-chain resilience with AI," McKinsey, November 26, 2021.
[17] "Supply chains: To build resilience, manage proactively," McKinsey, May 23, 2022.
[18] "Fact sheet: The Inflation Reduction Act supports workers and families," White House, 2022.

to create programs that drive labor supply growth, particularly for trade jobs such as local electricians that lack sufficient scale in the industry today.

ACTION AREA 3

## Securing access to adequate land with high load factors for the deployment of renewables

If the 2030 goals set by the US government are to be met, about 75 percent of all land with strong renewable-energy potential (95th percentile of capacity factor) and proximity to transmission lines would need to be developed for generation of either solar or onshore-wind power.

Access to this land could be impeded by siting and permitting challenges, including community pushback. Competition with other uses, such as farming and grazing, could also present obstacles. In addition, high costs and elongated project timelines associated with transmission interconnection could affect project viability. (For more detailed context, see sidebar "The challenge of finding high-quality land.")

## The challenge of finding high-quality land

**The Achieved Commitments** scenario would require building 600 gigawatts (GW) of solar generation and 300 GW of onshore wind. The infrastructure needed for this deployment would take up about 56,000 square kilometers, an area roughly equal to the size of West Virginia, representing approximately 75 percent of all US land with strong renewable-energy potential and proximity to transmission lines.[1] At the state level, the challenge is even greater: only five states have enough high-quality land for the solar deployment they would need for the energy transition. Only seven states have enough high-quality land for the wind infrastructure.[2]

Notably, this assessment does not account for two key challenges facing renewables developers: siting and the cost and timeline associated with connecting to the transmission grid (known as interconnection). Both could further limit the high-quality land available for cost-effective, rapid wind and solar development.

1. *Siting* is fraught with uncertainty because of the potential for competing land uses and the different stakeholders that could be involved (such as government versus private landowners). The type of resource being deployed will also determine siting challenges. Wind turbines, for example, tend to raise more concerns with local communities. Therefore, turbines must be physically spaced out, resulting in the need for more land per capacity deployed than solar power. At the same time, the physical area disrupted for land uses such as grazing and farming is smaller per energy generated compared with solar power.

   Many US renewables and transmission development projects have been delayed, paused, or even canceled because of these challenges.[3] A 2021 study in the United Kingdom found that local opposition could increase the cost of deploying wind power by 10 to 29 percent.[4]

2. *Challenges associated with transmission interconnection* can dramatically affect project viability, increasing total project costs by 3 to 33 percent.[5] Interconnection costs and timelines are often opaque to developers when they assess a potential site's economic viability, adding to the risk and expense associated with renewable-energy development.

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[1] For the purpose of this analysis, high-quality land is defined as land with a capacity factor in the 95th percentile and above, and within 1.5 miles of an existing transmission line. Note that capacity of transmission lines also plays a role, though this modeling does not incorporate it. Existing transmission lines could already be congested based on existing demand.
[2] The five states with sufficient solar are Arizona, California, Colorado, Nevada, and New Mexico. The seven states with sufficient wind are Kansas, Mississippi, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas.
[3] Lawrence Susskind et al., "Sources of opposition to renewable energy projects in the United States," *Energy Policy*, June 2022, Volume 165.
[4] Stephen Jarvis, *The economic costs of NIMBYism: Evidence from renewable energy projects*, Energy Institute at Haas working paper number 311, January 2021.
[5] "New national lab study quantifies the cost of transmission for renewable energy," Berkeley Lab, October 24, 2019.

KEY PRIORITIES

To accelerate cost-effective renewables deployment, developers and policy makers could consider eight actions to increase the high-quality land available for development, more efficiently use existing land, and build community support to mitigate siting challenges.

**Increase high-quality land available for renewables development**

1. *Increase transmission access.* Many of the highest-quality renewable land areas are far from demand centers. For example, only approximately 25 percent of land with high-capacity factors is in the US coastal states, where approximately 60 percent of Americans live. Expanding transmission to connect high-quality land to population centers could increase the potential land available for cost-effective renewables development. (The challenges of transmission build-out are discussed in "Action area 4: Reforming transmission development to include proactive planning, fast-track permitting, and systematic consideration of transmission alternatives.")

2. *Go offshore for wind power.* Offshore wind tends to be located close to population centers and could prove a valuable alternative if onshore transmission struggles to develop. The National Renewable Energy Laboratory estimates that the United States has the technical potential to produce 4,200 GW of energy from offshore wind. Our modeling of the Achieved Commitments scenario forecasts 30 GW in 2030 and 140 GW in 2050—well below the potential 4,200 GW. However, there are still significant barriers to offshore wind development, particularly in the near term, including the limited availability of ships compliant with the Jones Act,[19] construction obstacles, and permitting constraints.

3. *Offer incentives and increase land access.* Policy makers could provide incentives for high-quality land for renewables development, including by providing property tax credits for sites, streamlining permitting processes, and leasing public land. Roughly 30 percent of all land is publicly owned and not protected specifically as a national or state park, so leasing public areas could be a significant opportunity to expand land for renewables. The US government has a long history of leasing public lands to further economic objectives. It continues to do so today with land leased for energy production—including oil and gas as well as renewables.

**Use available land more efficiently**

4. *Improve sites with technological innovation.* Solar and wind generation facilities could be upgraded as renewables technology becomes more efficient. Leveraging existing developed sites to install later-generation—and typically higher-efficiency—solar and wind can increase renewable power output without increasing the amount of developed land. For example, about 33 percent of all wind capacity was built more than ten years ago.[20] Turbine efficiency has improved by 10 percent in that time, which suggests a potential increase of at least 3 percent in total capacity.[21]

5. *Improve efficiency of solar and wind.* Making solar and wind more efficient could reduce renewables' overall land needs per unit of output. Over the past ten years, the amount of land per gigawatt-hour (GWh) of solar has been cut in half as solar arrays that track the sun have become the dominant technology.[22] More improvements could dramatically open more land usage.

**Build community support to mitigate siting challenges**

6. *Develop brownfield sites in ways that support the local community.* In a study of utility-scale renewable-energy projects, the most often-

[19] Among other provisions, the Jones Act requires that ships servicing offshore wind in the United States be built, owned, and operated by US citizens or permanent residents. As a result of the Jones Act, total costs of offshore wind projects can increase by about 40 to 55 percent, and implementation can take up to 50 percent longer.
[20] "Most U.S. wind capacity built since 2011 is located in the center of the country," US Energy Information Administration, June 23, 2021.
[21] "Wind turbines: The bigger, the better," US Department of Energy, August 16, 2022.
[22] Cheryl Katz, "More energy on less land: The drive to shrink solar's footprint," *Yale Environment 360*, July 28, 2022.

cited reasons for opposition were the potential consequences for land value and environmental impacts. In some cases, these concerns could be lessened if developers identify sites in communities that have recently experienced economic disruption and that might benefit from a new source of jobs and development.[23] As an example, Savion Energy is building a solar project on a reclaimed coal mine.[24] Several other companies are also repurposing land belonging to closing fossil-fuel plants that has ready access to transmission—for instance, Vistra Energy's Moss Landing storage facility in California.

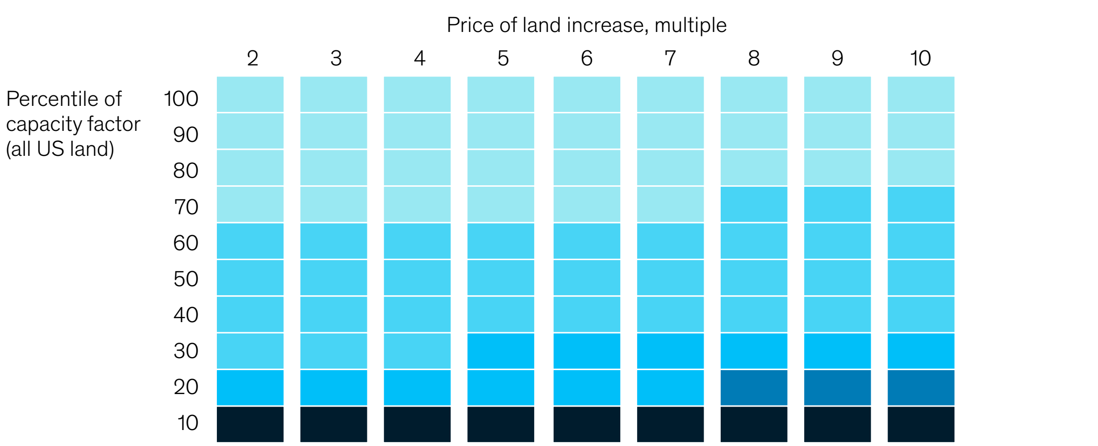
7. *Share the economic value of high-quality land with owners and local communities.* High-quality land is limited, which means it is very valuable. Land in the top 100th percentile of capacity factor for solar could be priced more than ten times higher than land in the 70th to 80th percentiles and still result in a lower levelized cost of electricity (approximately $14 per megawatt-hour compared with $16 per megawatt-hour) (Exhibit 3).[25]

If a developer is willing to pay a premium for land with a high capacity factor, that value could be shared among developers, landowners, and nearby communities. Developers often acquire large land portfolios to mitigate the risk of uncertainties such as interconnection cost and timeline. They could mitigate community

Exhibit 3

## Levelized cost of electricity for solar and wind development is driven by capacity factor and cost of land.

**Levelized cost of energy (LCOE) produced by effect of capacity factor and land price for wind energy,[1]** $/MWh




[1]Assumptions: LCOE = (capital expenditures + fixed operations and maintenance [FOM] costs) / (8760 x capacity factor [CF]). Lifetime: solar, 25 years; wind, 30 years. CF for wind is for the Vestas V112 3 MW turbine at a 120-meter hub height.
Source: McKinsey analysis using the proprietary REMAP tool; McKinsey Global Energy Perspective Achieved Commitments Scenario

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[23] Lawrence Susskind et al., "Sources of opposition to renewable energy projects in the United States," *Energy Policy*, June 2022, Volume 165.
[24] "Martin County Solar Project to locate on former eastern Kentucky coal mine," *Lane Report*, December 9, 2021.
[25] This analysis assumes a lifetime of 25 years for solar and 30 years for wind. Capacity factor assumes solar is for fixed-tilt panels with CSi technology and wind is for Vestas V112 3MW turbine at a 120-meter hub height. This analysis assumes constant renewables capital expenditure costs. Over time, land costs are likely to increase, while other factors driving renewables capital expenditures are likely to decrease (for example, the cost of panels after current supply chain challenges are mitigated). As these cost dynamics shift, the high value of optimal land will decline.

concerns by securing land leasing rights at a base rate and providing financial compensation to landowners and communities for the sites that are ultimately developed. While there is a long history of economic benefit for Midwestern farmers and ranchers who allow wind farms on their property, so-called good neighbor payments could help spread the benefit across communities.

8. *Develop multiuse siting.* Encouraging the siting of wind turbines on farmland and innovative agriculture practices alongside solar farms or creating public-use lands along transmission corridors could in some cases reduce the exclusionary impacts of energy-transition projects. This kind of mixed use is largely impossible with existing thermal-generating assets such as gas, coal, and nuclear power plants.

## ACTION AREA 4

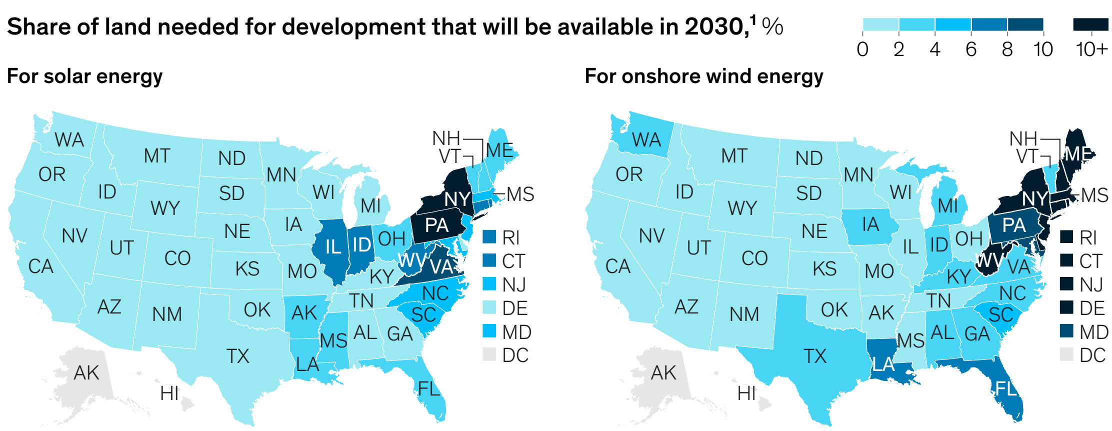
### Reforming transmission development to include proactive planning, fast-track permitting, and systematic consideration of transmission alternatives

Transmission is critical to achieving a more orderly energy transition, given its role in connecting renewable power with the grid. We estimate that if transmission interconnection is not accelerated, there could be a supply gap of 175 gigawatts of renewables, which is equal to nearly 500,000 gigawatt-hours of zero-carbon electricity each year. Without transmission build-out, this 500 GWh shortfall and the additional renewables that are forecast to be needed could remain untapped. In addition, regions with poor renewables could face challenges in reaching the decarbonization goal. This situation is particularly acute in the Northeast (Exhibit 4).

Transmission investment faces three primary complex barriers today: undervaluing necessary spending due to reactive planning processes and

Exhibit 4

**Regional variation in the availability of land for solar and wind suggests that transmission could be needed for a more orderly energy transition.**




[1]Data for Alaska, Hawaii, and Washington, DC, are not included. Available land is defined as suitable for development across several metrics: land cover class, protected land, distance to airports, and land slope. For solar, this excludes all protected land, land within 0.02 miles of airports, and land with a slope greater than 2 degrees; it includes the following land cover classes: bare or sparse vegetation, shrubland, herbaceous vegetation, and open forest. For wind, this excludes all protected land, land within 8 miles of airports, and land with a slope greater than 11 degrees; it includes the following land cover classes: bare or sparse vegetation, shrubland, herbaceous vegetation, cropland, or open forest. These metrics consider changes in land available from 2022 to 2030. Capacity factor for solar is for fixed panels and crystalline-silicon (cSi) technology. Capacity factor for wind is for the Vestas V112 3 MW turbine at a 120-meter hub height.
Source: McKinsey analysis using the proprietary REMAP tool; McKinsey Global Energy Perspective Achieved Commitments Scenario

McKinsey & Company

misaligned cost and benefit allocation; elongated project timelines due to complicated siting and permitting; and lengthy interconnection wait times due to high demand, low bandwidth to process applications, lack of standardization, coordination issues among stakeholders, and lack of innovation in considering solutions such as bundling projects.[26] (For more detailed context, see sidebar "Transmission.")

### KEY PRIORITIES

Government would need to consider three core issues to expand transmission: planning, cost allocation across jurisdictions, and permitting and siting challenges.

1. *Plan transmission to account for the comprehensive range of benefits it can enable*. Deficiencies in this area are well documented. For example, transmission is often planned "one line at a time," as opposed to a more diverse portfolio approach that considers the wide range of regional needs that transmission could address. Furthermore, business cases supporting the build-out of transmission lines typically value only the reliability benefit of the line or the benefit of enabling lower-cost fuels. They often don't consider easing access to cleaner energy sources, reducing operating and planning reserves, enabling electrification, or ensuring resource adequacy—that is, sufficient power supply to meet demand. In addition, planning doesn't consider the possibility of melding transmission with other technologies such as storage, which can often significantly reduce costs. One example of successful transmission planning and cost allocation was the decision by the Midcontinent Independent System Operator (MISO) to authorize $10.3 billion in transmission spending through 2030, a notable sum given that the total US annual capital investment today is less than $30 billion.[27] In making the business case, MISO invoked the benefits of reliability, access to lower-cost energy, resource adequacy, and decarbonization. MISO also studied a portfolio of projects including complementing transmission with storage. (See sidebar "FERC's Advance Notice of Proposed Rulemaking and ISO Evolutions.")

2. *Align costs and benefits of transmission projects.* Some transmission benefits can be difficult to directly allocate to a state. In part, this is because states place different values on transmission, particularly in cases where they have differing decarbonization objectives. And transmission that crosses an entire state could, in some instances, provide larger benefits to the ultimate end state than to the states it crosses through. Some cost-allocation pathways have worked, however. MISO, for example, devised an approach in which benefits greatly exceeded costs for each zone, reducing barriers to transmission build-out.

3. *Manage permitting and siting challenges.* Large-scale transmission lines can take more than a decade to permit, site, and plan.[28] Important national conversations to devise solutions are under way, and some regional efforts have demonstrated progress. Consider the New Mexico Renewable Energy Transmission Authority (RETA), created to ease the development of electric transmission and storage projects by providing input on project impacts and ensuring that landowners are treated fairly and equitably. RETA was critical in the passage of the recent SunZia transmission project, which provides direct access to renewable resources to up to 2.5 million customers in Arizona and will eventually serve California.[29] One report identified at least 22 other shovel-ready projects that could potentially benefit from similar efforts and enable a 50 percent increase in wind and solar generation from current levels.[30]

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[26] *Transmission planning for the 21st century: Proven practices that increase value and reduce costs*, Brattle Group and Grid Strategies, October 2021.
[27] *Reliability imperative: Long range transmission planning*, MISO Board of Directors, July 25, 2022.
[28] *Informing the Transition Discussion*, ScottMadden, January 2020.
[29] David M. Brown, "$8B SunZia transmission, wind project work to start in 2023," *ENR Southwest*, July 27, 2022.
[30] Michael Goggin, Rob Gramlich, and Michael Skelly, *Transmission projects ready to go: Plugging into America's untapped renewable resources*, Americans for a Clean Energy Grid, April 2021.

## Transmission

**As the backbone** of the energy system, transmission is vital to a more orderly transition. But widespread deployment of renewables and maintaining a reliable and resilient transmission system would require significant investment. Under the Achieved Commitments scenario, the transmission grid would need $450 billion in capital investment between 2022 and 2030.

Expanded transmission infrastructure is required to connect areas with high renewable-energy resources to population centers. The United States has sufficient wind and solar power to meet national needs, but at the regional level, deployment sometimes faces constraints caused by limited land availability. These obstacles are particularly acute in the Northeast (for example, Connecticut does not have sufficient onshore land available to develop adequate renewable capacity for its own demand).

A recent study by the New York Independent System Operator (NYISO) found that the pace of transmission development must increase to keep up with renewables development and meet state policy targets. The operator projects that transmission limitations could curtail at least five terawatt-hours (TWh) of renewable energy by 2030 and at least ten TWh by 2035.[1] NYISO calculates that this would result in 5 percent less renewable energy to count toward New York's Climate Leadership Community Protection Act target of 100 percent zero-emission electricity by 2040.[2] And regardless of the pace and scale of renewables deployment, the transmission system would need considerable investment to upgrade aging infrastructure and improve resilience in the face of the increased frequency and severity of extreme weather events resulting from climate change.

However, transmission projects in the United States have been very challenging to execute, which could constrain renewables deployment. Furthermore, transmission is critical to ensure that more rural locations with strong renewable resources benefit from the job growth that will accompany the energy transition. Without the expansion of transmission, alternative options to meet demand would likely be built closer to the end-demand sources.

Transmission investment faces three complex barriers:

1. *Undervaluing benefits due to reactive planning.* Transmission planning shortfalls are partially driven by planning processes that are siloed and reactive, and do not consider longer time horizons (including the changing energy mix, physical hazards, and cost-effective technology). In addition, the current cost allocation and benefit quantification are a disincentive to transmission build-out because funds are allocated to transmission projects that improve reliability at the regional level. This narrow view disregards larger-scale interregional projects that could provide benefits such as improved reliability, operational flexibility, and lower dispatch costs.

2. *Longer project timelines.* Siting and permitting can delay projects by ten years or more. The multiple levels of approval needed at the local and federal levels, along with the lack of consistent application processes and frequent public pushback, often lead to greater project costs and a higher chance of failure.

3. *Lengthy interconnection wait times.* Slow interconnection processes contribute to high rates of projects being withdrawn as well as hefty backlogs of projects, low completion rates, and cost overruns. In 2020, the average wait time for interconnection was roughly four years. That is expected to double by 2030,[3] though the wait time may differ by region.

Potential fixes for these barriers to transmission are being piloted or deployed.[4] Most, however, remain far from realization, despite a number of attempts at transmission reform over past decades.

[1] *2021-2040 system & resource outlook*, New York Independent System Operator, September 2022.
[2] Ibid.
[3] "Generation, storage, and hybrid capacity in interconnection queues," Berkeley Lab, accessed December 12, 2022.
[4] For more information about best practices for regional transmission organization and independent system operator planning, see *Transmission planning for the 21st century: Proven practices that increase value and reduce costs*, Brattle Group and Grid Strategies, October 2021. The Princeton Net Zero America Project highlights potential transmission solutions in its reports, including streamlined processes and planning of interconnection, and improving efficiency in permitting processes; see *Net-Zero America: Potential pathways, infrastructure, and impacts*, Princeton University, October 2021.

## FERC's Advance Notice of Proposed Rulemaking and ISO evolutions

**The Federal Energy Regulatory Commission's** Advance Notice of Proposed Rulemaking puts forward a new cost-allocation model for new transmission commensurate with broad estimated benefits, including increased renewables integration and environmental benefits. This new method could expand the pool of transmission projects considered—and approved—for development. Similarly, the recent grid planning process by the Midcontinent Independent System Operator (MISO) quantified potential reliability and economic benefits (such as congestion and fuel savings, and avoidance of additional transmission investment). The independent system operator's analysis showed that reusing existing rights-of-way for long-range transmission plan (LRTP) projects could offset the costs of age and condition replacement for existing facilities, and that transmission costs from a resource build-out are two times more efficient than a regional transmission build-out.[1] In 2022, MISO secured approval for $10.3 billion of LRTP projects to support reliability, which accelerated the construction of transmission lines.

[1] *Reliability imperative: Long range transmission planning*, MISO Board of Directors, July 25, 2022.

### KEY PRIORITIES

While scaled build-out of transmission would lead to the most orderly transition, businesses and governments would be prudent to plan for alternatives if transmission gridlock isn't resolved. There are three ways to diversify transmission: deploying distributed energy resources; co-optimizing electric transmission and gas; and transitioning to dispatchable zero-carbon resources.

1. *Deploying DERs.* A potential alternative to transmission build-out is local sources of zero-carbon electrons and reliability such as rooftop solar, behind-the-meter storage, and demand-side management. These solutions at least partially circumvent the need for further transmission build-out, which is particularly critical in congested areas. For example, a model by the National Renewable Energy Laboratory shows that meeting Los Angeles's target of 100 percent renewable energy by 2035 would require three to four gigawatts of energy from rooftop solar by 2045, with development on up to a third of existing homes to bring energy supply closer to demand.[31] In addition, energy efficiency and demand response are low-cost levers to reduce transmission needs. A McKinsey analysis found that distributed-resource aggregation could unlock nearly 100 GW of new potential flexible capacity by 2030.[32]

2. *Optimize electric transmission with the existing gas network.* Even though fossil fuel–based natural-gas consumption in buildings is expected to decline in the Achieved Commitments scenario, the gas system would likely still be needed to support a more orderly energy transition by alleviating some of the most significant demands for electric build-out. For example, while building electrification is likely to be a cost-effective decarbonization lever in many regions, it could drive extremely high electric-system needs in winter in colder climates.[33] By contrast, a system that uses electric heat in the shoulder seasons (spring and fall) and gas heat in winter was estimated to be half the cost in one colder-climate state, according to McKinsey analysis.[34]

3. *Transition to dispatchable zero-carbon resources.* In its most recent *System & resource*

[31] *LA100: The Los Angeles 100% renewable energy study*, Los Angeles Department of Water & Power and National Renewable Energy Laboratory, March 2021.
[32] Evan Polymeneas, Humayun Tai, and Amy Wagner, "Less carbon means more flexibility: Recognizing the rise of new resources in the electricity mix," McKinsey, October 1, 2018.
[33] Including capital, fuel, and operation and maintenance costs and savings.
[34] To hit decarbonization targets, the carbon emissions associated with this heating system will need to be netted out. Local distribution companies are exploring zero-carbon fuels such as renewable natural gas and zero-carbon hydrogen. Or the emissions could be netted out from negative emissions in other parts of the economy—for example, via distributed air capture or bioenergy with carbon capture and storage. See "Decarbonizing US gas utilities: The potential role of a clean-fuels system in the energy transition," McKinsey, March 2, 2022.

# While scaled build-out of transmission would lead to the most orderly transition, businesses and governments would be prudent to plan for alternatives if transmission gridlock isn't resolved.

*outlook* report,[35] the New York Independent System Operator estimates that about 12 to 25 percent of 2040 system capacity will be met by dispatchable emissions-free resources, zero-carbon power generators that can ramp up quickly to meet grid reliability needs. This need is similarly reflected in McKinsey analysis on deep-decarbonization scenarios across several US regions. That research shows that in scenarios with less transmission build-out, systems rely more heavily on dispatchable technologies (natural gas with carbon capture and sequestration) or combustion of clean fuels (renewable natural gas, synthetic natural gas, or zero-carbon hydrogen). These systems could also use technologies such as nuclear and long-duration energy storage to meet grid needs with zero-carbon power.

If transmission bottlenecks are not resolved, these alternative dispatchable technologies, now in varying stages of development, would have to go to market and scale at significantly faster speeds than currently planned. (For further detail, see "Action area 6: Accelerating technological innovation to ensure timely deployment of new clean technologies.")

### ACTION AREA 5

## Creating market mechanisms for expanding firm capacity to ensure reliable and adequate clean energy supply

More than 80 percent of today's power system is made up of flexible sources such as natural gas plants that can ramp up and down quickly to meet sudden shifts in supply or demand. As more renewables come online, the power system would benefit from more flexible power sources to mitigate the intermittency of renewables—for example, to provide power when the sun goes down.

Renewables coupled with shorter-duration storage, such as four-hour batteries, are able to satisfy most load demands through intraday balancing. However, the power system will likely also require longer-duration capacity to support longer periods when demand is high and renewable generation is low. That could include dispatchable resources such as natural gas with carbon capture and sequestration, combustion of low-carbon fuels, nuclear, or long-duration energy storage. While capacity from these types of resources is critically needed, their utilization is likely to be low (Exhibit 5).

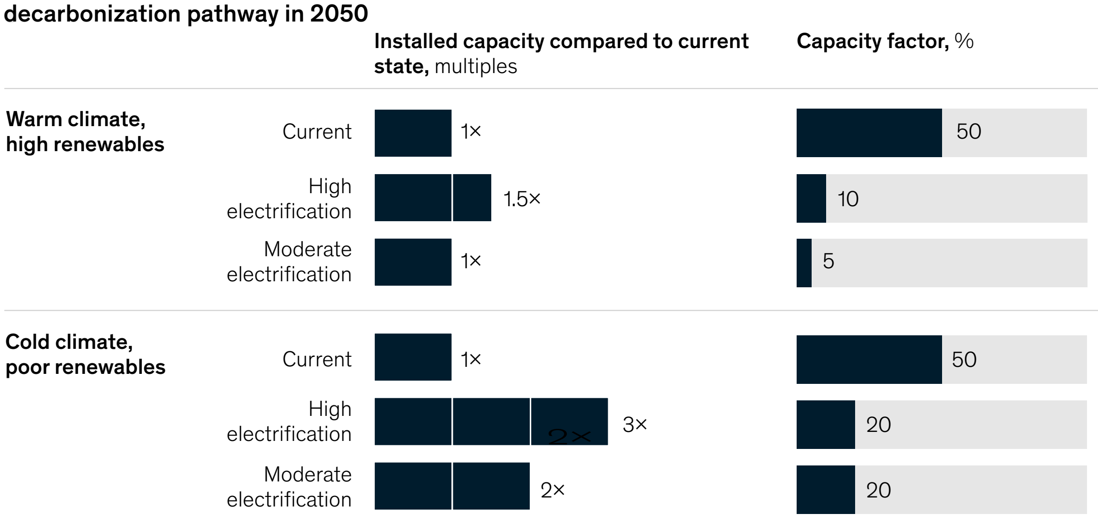
Although those resources are forecast to be in operation relatively infrequently compared with today's natural-gas plants, the dispatchable capacity, or on-demand generation, they provide to the system could be critical for reliability. Many investors are hesitant to finance these resources,

[35] *2021-2040 system & resource outlook*, New York Independent System Operator, September 2022.

Exhibit 5

## On a deep decarbonization pathway, the required capacity of flexible resources such as gas plants is likely to stay constant or grow.

**Generation capacity metrics of natural gas and natural gas with carbon capture on a deep decarbonization pathway in 2050**




Source: McKinsey analysis

McKinsey & Company

concerned that forecast low utilization would make them unprofitable. This creates the danger that these flexible resources may not be sufficiently built, which could become a risk to system reliability.

### KEY PRIORITIES

To improve the business case for dispatchable resources, system planners, utilities, generators, and policy makers could jointly establish and implement market mechanisms that would explicitly value resource flexibility. Stakeholders would need to consider three key priorities to develop market mechanisms and enhance flexibility.

1. *Revise methodology for resource planning to avoid overstating firm capacity.* As renewables become a larger share of generation, resource planning could be adapted to reflect the intermittency of these energy sources. Today, resource planners such as independent system operators (ISOs) assign capacity credit to renewables. Overstating the capacity potential of a renewable resource could have severe implications. For example, the resource adequacy report released by MISO forecast that, based on existing and planned resources, it could fall short of capacity by 2027. However, if MISO's renewables do not generate when expected—that is, if a zero percent capacity credit is applied to renewables—the operator could fall short of capacity as early as 2024, highlighting the need for additional flexibility in the very near term. Several ISOs, including MISO and PJM, are revising their methodologies to lower the credit assigned to renewables.

This issue is not limited to renewables; system planners could also carefully assess other resources to reduce the risk that firm capacity is overstated. For example, gas plants that are not fully weatherized might not be able to dispatch at full capacity during extreme weather events. Similarly, hydropower and pumped hydro storage might not be able to operate at full capacity during drought years.

System operators could revise capacity credits for intermittent renewables and other resources by using a more conservative calculation that bases projections on future forecasts of resource availability. They could also take a stricter view of what constitutes reliable output based on historical performance, as described below.

2. *Evolve resource planning to address changing supply and demand.* At the moment, many system operators' plans rely on historical data to forecast peak demand (for example, driven by extreme weather events). But as weather increasingly deviates from historical patterns, these data become no longer reliable for either supply or demand. ERCOT used the most recent 15 years of weather figures for its load forecasting model,[36] and the California ISO uses the most recent 20 years of data.[37] Recent events such as winter storm Uri in 2021 and the 2020 and 2022 heat waves in California demonstrated how resource planning failures due to extreme weather events can result in grid outages.

Such weather events, which are likely to dramatically increase load and decrease supply, are becoming more frequent as a result of climate change. For example, under a 2.0°C warming scenario, the number of heat waves[38] in Texas and California would increase by about 20 and 30 percent a year, respectively.[39] During these events, the impact on power generation systems is projected to lead to lowered supply. For example, wind farms may not be able to produce electricity at typical levels when demand is at its peak because the large high-pressure systems that most often cause heat waves can bring lulls in high-velocity winds. This occurred during the early July 2022 heat wave in Texas, when wind power was at 8 percent of potential output.[40] In addition, solar production is lower when ambient temperatures are higher,[41] and thermal plants operate at lower efficiencies with higher intake air temperatures. Drought-related shortages of water carry a risk of shutdown because water is needed to cool these facilities. Low-water conditions can also result in hydropower shutoffs, further exacerbating energy supply problems.

Moreover, many system operators rely on imported power as a source of firm supply, and this added power may become urgently necessary during extreme weather events. However, neighboring regions might be facing the same weather events, limiting their availability to provide necessary imports, as was the case in California in August 2020 when rolling blackouts occurred.[42]

In response to these challenges, system operators could evolve market scenarios to capture more of the nuances of intermittent supply, including a broader range of acute and chronic physical climate risks and the resulting changes in generation. They could also reform capacity markets to focus on net load, capturing the variation across both demand and intermittent supply hourly.

[36] *2022 ERCOT system planning: Long-term hourly peak demand and energy forecast*, Electric Reliability Council of Texas, January 18, 2022.
[37] *2022 summer loads and resources assessment*, California ISO (CAISO), May 2022.
[38] Heat waves are defined as a minimum of three consecutive days when temperatures maintain a high of 35°C or above.
[39] McKinsey Climate Analytics analysis.
[40] Sneha Dey and Mitchell Ferman, "Texas grid operator urges electricity conservation as heat waves drive up demand," *Texas Tribune*, July 2022.
[41] Amelia Razak et al., "Investigation of the effect temperature on photovoltaic (PV) panel output performance," *International Journal on Advanced Science, Engineering and Information Technology*, October 2016, Volume 6, Number 5.
[42] "Preliminary root cause analysis: Mid-August 2020 heat storm," CAISO, January 2021.

Furthermore, scenario planning could address the increasing intensity and frequency of extreme weather events. This would mean looking beyond historical data when revising forecasting to account for factors including increased load driven by electrification and impacts from behind-the-meter resources.

Finally, operators could expand the geographical focus of their planning beyond the jurisdiction of the managed area, more conservatively anticipate what could happen in adjacent areas that could affect imports, or both.

3. *Provide adequate incentives to ensure that the grid is resilient to longer-duration events.* In a deep-decarbonization scenario, there would be multiday stretches when net load remained positive given high demand and low supply. A classic challenge for system planners would be a week of low wind in February in a northern region. Perhaps in those circumstances, demand for electrified heating would coincide with minimal solar output, coupled with an occasionally expected "drought" of wind power that puts the system in a bind. During these periods, the grid would require resources that have a higher energy and duration output threshold than today's markets encourage through incentives.

However, most market signals do not provide incentives for flexible capacity resources that can generate power for long periods (more than 12 hours). Utilities could share data with regulators and system operators to show load projections for deep-decarbonization scenarios and demonstrate the need for duration.

Regulators and system operators, meanwhile, could consider policies that avoid providing incentives for a single time threshold and instead reward longer-duration resources. For example, they could create mechanisms that auction capacity in tranches of duration that go beyond managing four-hour peaks. A report this year by the Pacific Northwest National Lab points to specific examples of policies like these being put in place. These include the California Public Utilities Commission mandate for procurement of long-duration energy storage, and PJM's notice in its 2021 Federal Energy Regulatory Commission (FERC) compliance filing that energy storage assets need a minimum of ten hours of duration to receive full capacity credit.[43]

Collaboration among stakeholders will be critical to develop market mechanisms to support an evolving grid. In particular, system operators, regulators such as FERC, utilities, and energy providers could work together to accurately reflect capacity needs and send the necessary signals to investors and energy companies to encourage development of flexible resources.

### ACTION AREA 6

## Accelerating technological innovation to ensure timely deployment of new clean technologies

Historically, clean technologies have come onto the grid over several decades, from initial small-scale deployment to broad commercial deployment. For example, offshore wind took 25 years to progress from the first commercial demonstration in Europe to starting to scale in the United States.

[43] D. Bhatnagar et al., *Compensation mechanisms for long-duration energy storage*, Pacific Northwest National Laboratory, August 2022.

Similar timelines would be too long for developing and deploying a range of newer technologies—such as natural gas with carbon capture, advanced nuclear, hydrogen, and biomass—that could help derisk the energy transition by rapidly scaling up if an alternate technological pathway proved unfeasible. For example, if the timeline for connecting renewable-energy facilities to the transmission grid is not accelerated, alternate technologies would need to generate nearly 500,000 GWh of zero-carbon energy for the United States to be on track for a more orderly transition[44] (see “Action area 4: Reforming transmission development to include proactive planning, fast-track permitting, and systematic consideration of transmission alternatives”). These alternate technologies may need to scale much more rapidly than currently envisioned to produce that output, as shown in Exhibit 6. (For more detailed context, see sidebar “Technological innovation.”)

[44] In models of decarbonization across several regions, scenarios with lower electric transmission and distribution investment require additional build-out of alternative technologies, including carbon capture, nuclear, hydrogen, and biomass.

## Technological innovation

**The first offshore wind farm** in the world was built in Denmark in 1991. The first US installation began operations 25 years later in Rhode Island, generating 30 megawatts (MW). Today, only 42 MW of offshore wind capacity is commercially operational in the United States, with less than one gigawatt (GW) in construction and 18 GW of projects in permitting.[1] Our modeling projects that 30 GW would need to be deployed by 2030 in the Achieved Commitments scenario. To achieve that level, all of these projects—and more—would need to come online in the next eight years. Such a timetable is too slow to develop and deploy the newer technologies that would be needed to affordably meet 2030 decarbonization goals.

Grid operators express concern over the pace and scale of the technology development and deployment needed to meet policy requirements while maintaining system reliability. In a September 2022 report, the New York Independent System Operator (NYISO) warned, “The sheer scale of resources needed to satisfy system reliability and policy requirements within the next 20 years is unprecedented. … DEFRs[2] that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. While essential to the grid of the future, such DEFR technologies are not commercially viable today.”[3]

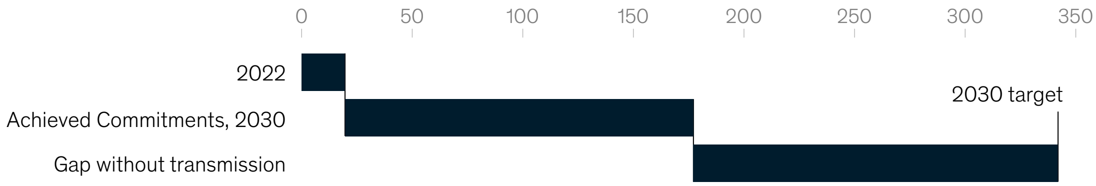
Many of the technologies that could be required to meet the US government’s 2030 goals are either already beginning to be piloted (as in the case of long-duration energy storage and direct air capture) or in the early stages of scaling—such as with polymer electrolyte membrane (PEM) electrolysis and membrane-based carbon capture. Some are already widely deployed, but with technical innovation they could realize significant improvement in cost or performance (for example, perovskite solar cells with potential to improve solar module efficiency). While these technologies may not be a significant part of the country’s energy system by 2030, their accelerated scaling over the course of this decade could enable significant scale-up in the 2040s and beyond, when their role in the energy transition could be even more critical.

[1] *Offshore wind market report: 2022 edition*, US Department of Energy, August 16, 2022.
[2] Dispatchable emissions-free resources.
[3] *2021-2040 system & resource outlook*, New York Independent System Operator, September 2022.

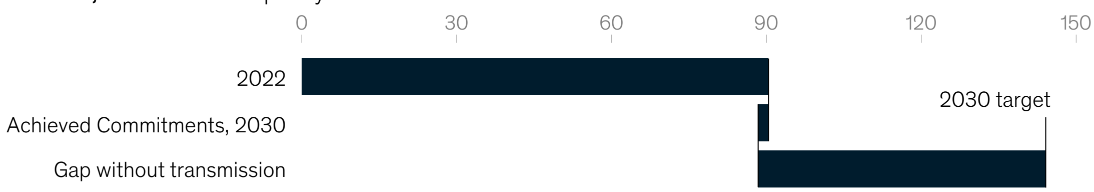
Exhibit 6

## If transmission is not accelerated, alternate technologies would need to be scaled at an accelerated pace.

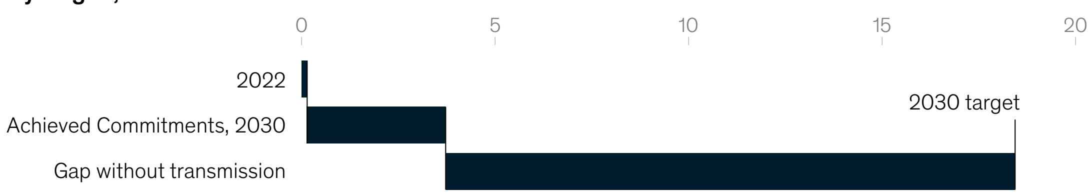
**Natural gas with carbon capture and storage (CCS),**[1] millions of $tCO_2e$[2] to be captured



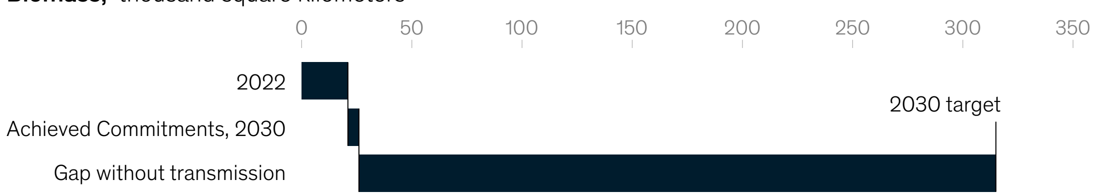

**Nuclear,** GW installed capacity




**Hydrogen,** billion tons




**Biomass,**[3] thousand square kilometers




[1]CCS value is the total capacity of 12 operational CCS projects in the US.
[2]Metric tons of carbon dioxide equivalent.
[3]Theoretical future land use to grow switchgrass for bioelectricity. Does not account for biofuels crops.
Source: Global CCS Institute; US Department of Agriculture Economic Research Service; McKinsey Global Energy Perspective Achieved Commitments scenario

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## KEY PRIORITIES

Businesses and policy makers could focus on four key priorities to accelerate technological innovation from first demonstration to at-scale deployment by more than 50 percent, which could help make the energy transition more orderly. Lessons about accelerating technological innovation and rapid deployment can be learned from projects in other industries, such as pharmaceutical companies' development of a COVID-19 vaccine,[45] and suggest that innovation could be unlocked even faster.

1. *Collaborate across the value chain.* Many of the new technologies needed for the energy transition would benefit from an "ecosystem," meaning that upstream production, delivery infrastructure, and downstream consumers can all contribute to increasing the likelihood of successful deployment and spreading risk. While this would create uncertainty for any single player operating in only one part of an innovative technology's value chain, the risk would be mitigated through collaboration among stakeholders to jointly develop a full value chain. This kind of collaboration is key to the formation of hydrogen hubs like HyBuild Los Angeles and the Houston Hydrogen Hub, where alliances of private companies, industry coalitions, governments, and community groups are building out hydrogen production and transportation infrastructure to specific end users. Similar hubs are being explored to scale the development of carbon capture, utilization, and sequestration.

2. *Lower the cost of capital for new technologies.* Financial institutions and government entities could develop new measures such as public grants and low-cost loans to provide insurance for technical performance risks for early-stage technologies. These solutions could be designed to lower the cost of capital and stimulate more investment to accelerate "proof of failure" and commercialization. For

**If carefully planned and executed—with attention to socioeconomic impacts and affordability concerns; supply chain, transmission and land constraints; technological innovation; and enabling market mechanisms—the United States can make marked progress toward a more orderly energy transition.**

[45] "Fast-forward: Will the speed of COVID-19 vaccine development reset industry norms?," McKinsey, May 13, 2021.

example, the US Department of Energy's Loan Programs Office provides loans and loan guarantees to decarbonization technologies that are technologically mature but have not achieved full market acceptance.

3. *Provide long-term market and regulatory clarity.* While technological promise can motivate small-scale initial investments, investors often seek long-term clarity before making the large-scale investments needed to move from pilot program to full commercial deployment. Corporate players could help signal market direction by announcing commitments to transition to new technologies, even when those technologies are still in early stages. Amazon, for example, has committed to making 50 percent of its shipments zero carbon by 2030 and to becoming fully zero carbon by 2040. To reach those goals, the company has placed orders for 100,000 electric delivery trucks from Rivian.[46] Large commitments like these could help support early-stage technology companies in acquiring the financing to scale.

   Policy makers, for their part, could seek to provide clear regulatory guidance to the industry. Uncertain regulation can delay industry investments. Policy makers could aim to follow a principle of understanding the industry's questions and uncertainties so they can provide clear guidance and rapid communication to accelerate needed investments.

4. *Plan and invest in the shared infrastructure needed to scale.* Many new technologies must overcome a "tragedy of the commons," when shared ancillary infrastructure—such as pipelines to transport hydrogen or carbon dioxide—is not planned in advance and is underinvested. For example, while EV deployment is accelerating, more than 40 percent of customers report that their vehicle's driving range is the top buying factor they consider. In some states, including California and New York, regulators have authorized electric utilities to build charging infrastructure in public locations, in part to mitigate these concerns. At the same time, private players such as Ford and GM are investing in shared charging infrastructure that can be used by many EV models.[47]

   Measures identified in earlier action areas could also support acceleration of technological innovation. For example, business leaders could develop supply chains and start to build talent pipelines for new skill sets to prepare for technologies that are precommercial today but could be rapidly scaled in the energy transition (see "Action area 2: Strengthening supply chains to provide stable access to raw materials, components, and skilled labor"). Similarly, the capital excellence solutions identified in "Action area 1: Designing and deploying a capital-efficient and affordable system" could be leveraged to lower costs, even in early-stage deployments of new technologies.

## The time to act

Recent policy measures along with rapidly accelerating corporate commitments and private-sector investments put the United States at long last on a path to decarbonization. This is a new era for the energy sector: industry stakeholders no longer debate which targets to set but instead are turning their attention to the actions needed to execute the energy transition.

[46] *Delivering progress every day: Amazon's 2021 sustainability report*, Amazon, accessed October 11, 2022.
[47] "Ford introduces North America's largest electric vehicle charging network, helping customers confidently switch to an all-electric lifestyle," Ford, October 17, 2019.

Achieving that goal will not be easy, but now more than ever is the time to carefully plan for our energy future and resolve the constraints preventing it from being realized.

If carefully planned and executed—with attention to socioeconomic impacts and affordability concerns; supply chain, transmission, and land constraints; technological innovation; and enabling market mechanisms—the United States can make marked progress toward a more orderly energy transition. Equally important, it would do so by following a path that creates new economic opportunities for individuals, communities, and companies, and sets the tone on a global scale.

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# Four themes shaping the future of the stormy European power market

Demand for electricity in Europe is surging at a time when supplies are disrupted. To adapt to the market's uncertainty and rising prices, players will have to be clear-eyed about what's ahead.

*by Markus Schülde, Xavier Veillard, and Alexander Weiss*

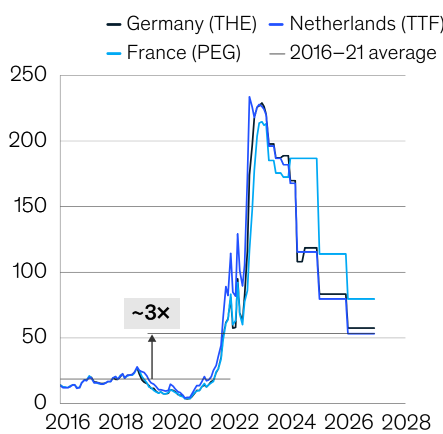
**The past year** has been a tumultuous one for European energy markets. After experiencing extreme volatility and all-time highs little more than a year ago,[1] power prices across the continent rose to a nearly unfathomable level last fall. Wholesale prices of both electricity and natural gas nearly quadrupled from previous records in the third quarter of 2022 compared with 2021, creating concerns for skyrocketing energy costs for consumers and businesses (Exhibit 1). Prices have since fallen unexpectedly, thanks in part to warm winter weather.

Such volatility highlights the structural challenges Europe faces as it seeks to transition its energy system away from carbon-emitting fossil fuels. At a time when these decarbonization efforts are boosting electricity demand across Europe, the market is reeling from unprecedented supply constraints. The war in Ukraine, disruptions to nuclear facilities in France, and low output from hydroelectric plants have combined to significantly reduce the continent's dispatchable power—electricity that can be easily switched on and off. Primarily driven by drought, hydro output was down by 19 percent between January and September 2022 across Europe, compared with the same period in 2021.[2] In France, where 32 of the country's 56 reactors were down for maintenance in September, nuclear energy output has declined by 14 percent over the same period (Exhibit 2).[3] Even more destabilizing is the dwindling supply of Russian gas. Prior to the invasion of Ukraine, Russia supplied 30 percent of Europe's natural gas, a resource that exerts a large influence on electricity prices and is a mainstay of the continent's power

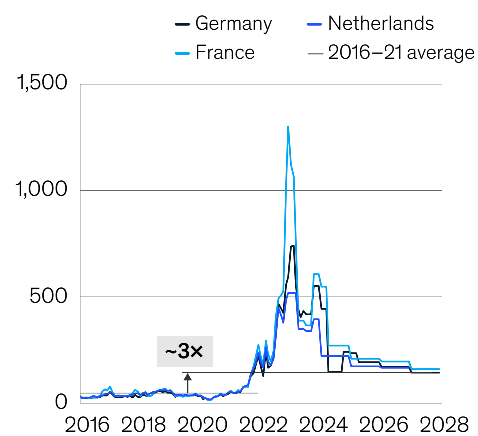
Exhibit 1

## Wholesale power prices in the European Union have surged.

**European gas (TTF, THE, PEG),**[1] € per MWh




**European power (EPEX FR, GR, NL),**[2] € per MWh




Note: Historical data: daily wholesale average prices computed into a monthly basis. Forecast data as of September 16, 2022. Monthly data until June 2023, quarterly data until Q1 2024, and yearly data until 2027–28.
[1]Title Transfer Facility, Trading Hub Europe, and PEG (monthly price produced by EEX).
[2]European Power Exchange: France, Germany, and the Netherlands.
Source: Bloomberg; European Energy Exchange (EEX); Nasdaq; PEGAS; McKinsey analysis

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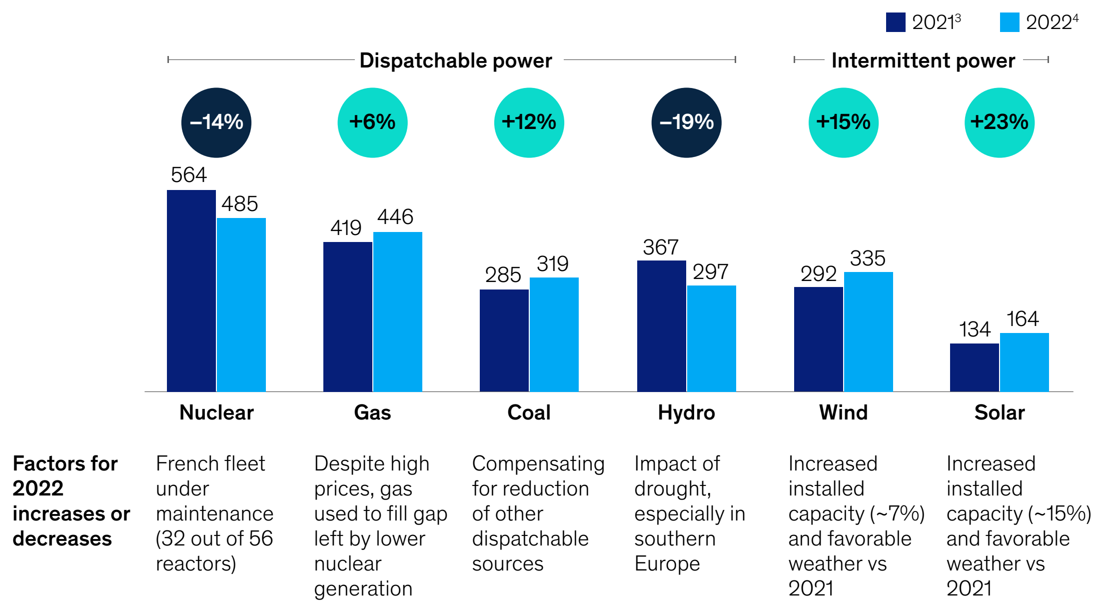
[1] Eivind Samseth, Fabian Stockhausen, Xavier Veillard, and Alexander Weiss, "Five trends reshaping European power markets," McKinsey, October 19, 2021.
[2] McKinsey analysis based on data from Ember, ENTSO-E, Fraunhofer, the International Renewable Energy Agency (IRENA), and National Grid.
[3] McKinsey analysis based on data from ENTSO-E, Fraunhofer, and National Grid; "France to restart all nuclear reactors by winter amid energy crunch," France 24, September 2, 2022.

Exhibit 2

## Low availability from nuclear and hydro sources led to increased coal output in 2022.

**Power generation in Europe,[1] 2021–22,** TWh[2]




[1]Austria, Belgium, Bulgaria, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Italy, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, and United Kingdom.
[2]Terawatt-hours.
[3]January to September 2021.
[4]January to September 2022.
Source: Ember; European Network of Transmission System Operators for Electricity (ENTSO-E); Fraunhofer; International Renewable Energy Agency (IRENA); National Grid; McKinsey analysis

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mix. That proportion dropped to 15 to 20 percent in 2022 and is likely to decline further this year.[4]

At the same time, demand for electricity continues to increase because of decarbonization and electrification throughout various sectors. These structural trends mean that Europeans are using more electricity than ever. Sales of electric vehicles (EVs) and electric heat pumps for buildings and homes, for instance, are both up by more than 30 percent, while demand for electricity in iron and steel manufacturing is up 17 percent.[5]

As a result, Europe faces the real possibility of shortages in dispatchable power—sources that are critical for balancing loads across the power system and ensuring there is enough electricity available at times of peak demand. To avoid this

[4] McKinsey Energy Insights' EU PipeFlow and LNGFlow; Cedigaz.
[5] EV sales are from the first half of 2021 compared with the first half of 2022 and include sales from the European Free Trade Association, the European Union, and the United Kingdom. Heat pump sales include 21 European markets; sales are 2020 compared with 2021. Iron and steel demand includes Austria, Belgium, Bulgaria, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Italy, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, and the United Kingdom. Industry demand considers 2020 compared with 2021. European Heat Pump Association; EV-Volumes; IHS Markit (light vehicle sales forecast July 2022).

# European policy makers and regulators are actively discussing solutions to ease the economic impact of high energy prices.

scenario and replace the dispatchable generation lost from natural gas, nuclear, and hydro, many European utilities have increased coal production, which had been scheduled to drop drastically. A range of stakeholders are also investing in alternative, low-carbon dispatchable-energy sources, such as hydrogen, batteries, demand-side response, and biomass.

Acutely aware of the implications of higher bills for energy consumers, European policy makers and regulators are actively discussing solutions to ease the economic impact of high energy prices and continue to bring down costs for businesses and consumers. Nearly all EU governments are pursuing either direct payments to households or temporary reductions in bills via lower taxes and other levies.[6] Additionally, the European Union recently adopted a temporary windfall tax on the surplus profits of fossil-fuel companies and on excess revenues made from surging electricity costs.[7] In December, EU energy ministers also agreed to a price cap on natural gas that is triggered when European front-month gas contracts surpass 180 euros per megawatt-hour for three days.[8]

Although all of these efforts will undoubtedly have positive impacts, the challenges are not likely to end anytime soon. With the frequency of high-intensity heat waves expected to increase, additional outages of nuclear facilities planned in 2023, and further expected reductions in Russian gas imports, we expect that wholesale power prices may not reduce substantially (defined as returning to three times higher than precrisis levels) until at least 2027.[9]

## The future of Europe's power market: Four key themes

We expect four themes to shape the market's evolution over the next five years.

**1. More and more power**

Despite the recent boost in coal generation and new natural gas infrastructure,[10] Europe remains committed to its climate-based decarbonization goals. These efforts will stimulate electricity demand in Europe until at least 2030. Between 2021 and 2030, demand will rise by nearly 3 percent annually, up from the annual 2 percent demand increase from 2018 to 2021. Initially, much of this increase in demand will come from the electrification of transport, where demand will rise by a staggering 13 percent annually. After 2030, the use of green or potentially red hydrogen (hydrogen created with nuclear energy) for manufacturing will ramp up substantially. Demand from the manufacturing sector, which requires electricity for electrolysis, will amount to 200 terawatt-hours (TWh) by 2030. In total, absolute electricity use across Europe is expected to increase from 2,900 TWh in 2021 to 3,700 TWh in 2030.[11]

[6] Susanna Twidale, "Factbox: Europe's efforts to shield households from soaring energy costs," Reuters, October 11, 2022.
[7] Beth Timmins, "EU agrees windfall tax on energy firms," BBC News, September 30, 2022.
[8] Jenni Reid, "The EU agreed to limit gas prices, but some analysts are skeptical," CNBC, December 20, 2022.
[9] Projections based on futures from Bloomberg, European Energy Exchange (EEX), Nasdaq, and PEGAS.
[10] Baird Langenbrunner and Robert Rozansky, "Gas bubble 2022: U.S. edition," Global Energy Monitor, October 2022.
[11] Further Acceleration scenario from *Global Energy Perspective 2022*, McKinsey, April 2022.

## 2. The rise of intermittency

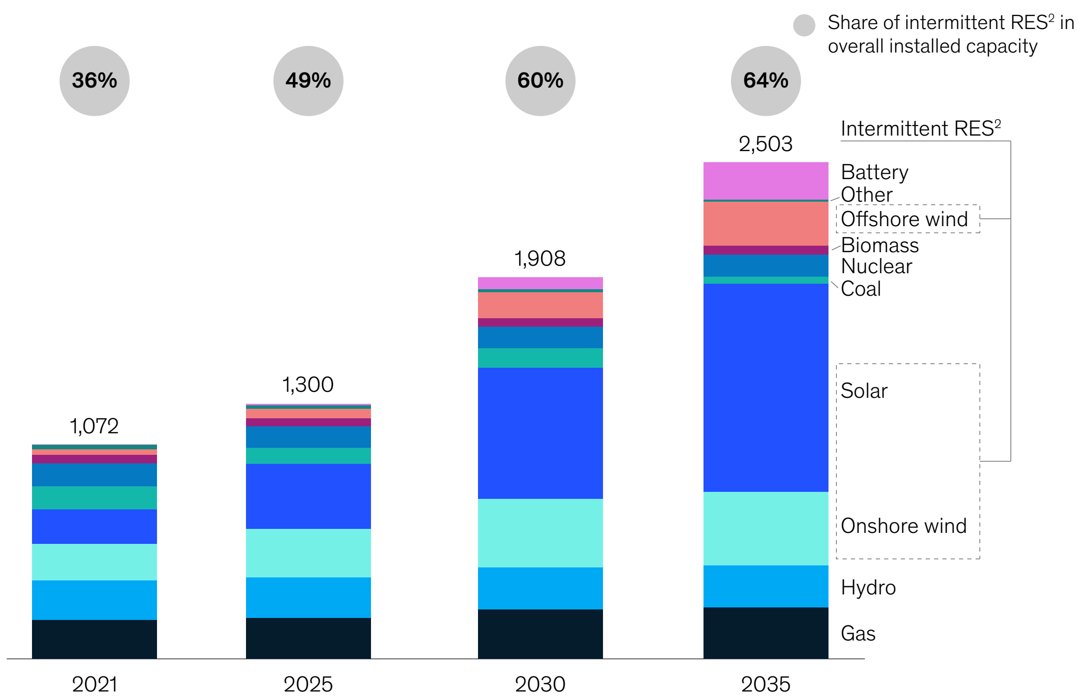
The penetration of wind and solar in Europe's power mix will grow dramatically. By 2030, these renewable sources, which are critical components of Europe's decarbonization efforts, are expected to provide 60 percent of the continent's energy capacity. This represents almost double the share in 2021, or an additional 760 gigawatts (GW) between 2021 and 2030 (Exhibit 3). Yet meeting this challenge will require a massive build-out of new facilities. For example, in Germany, annual new-construction rates will have to triple compared with the 2018–21 period.[12] But this won't be easy—policy makers, regulators, and renewables developers will have to navigate scarcities in supply of both suitable land and talent with needed skills, as well as enduring supply chain issues and shortages of raw materials.[13]

In addition, because wind and solar generation is subject to natural variations and thus provides intermittent sources of green power, balancing resources (such as hydrogen, batteries, demand-side response, and biomass) will also be required.

Exhibit 3

**Renewables will reach 60 percent of capacity in Europe by 2030.**

**Installed capacity in main European markets[1] under accelerated energy transition,** gigawatts




[1]Austria, Belgium, Bulgaria, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Italy, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, and United Kingdom. Includes hydrogen demand.
[2]Renewable energy sources.
Source: McKinsey Power Solutions EU Power Model, November 2022

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[12] Market Master Data Register; German Renewable Energy Sources Act (2023); Fraunhofer ISE (2021, 2022).
[13] "Renewable-energy development in a net-zero world," McKinsey, October 28, 2022.

### 3. Not enough dispatchable power

Over the next several years, a gap will develop between peak electricity loads and the dispatchable power capacity that can be switched on to meet it. This shortage is expected to worsen as natural gas, nuclear, and hydro production continue to decline while peak loads increase. By 2035, Europe's gap will be equivalent to 19 percent of dispatchable capacity, or 116 GW (Exhibit 4). This, however, is a worst-case scenario and assumes no new capacity is built.

Efforts are under way to close this gap with clean sources of dispatchable capacity. Over the past decade, considerable investments have been made in utility-scale battery systems, biomass, and hydrogen. Our model suggests that by 2035, more than 100 GW of battery capacity, five to ten GW of biomass, and 20 to 30 gigawatts of hydrogen electrolyzer capacity will be needed to meet peak loads. Yet these technologies have to be further scaled, with build-outs remaining highly uncertain due to a reliance on supportive regulations, the availability of government incentives, and the need for raw materials that are in short supply, such as lithium ion.[14]

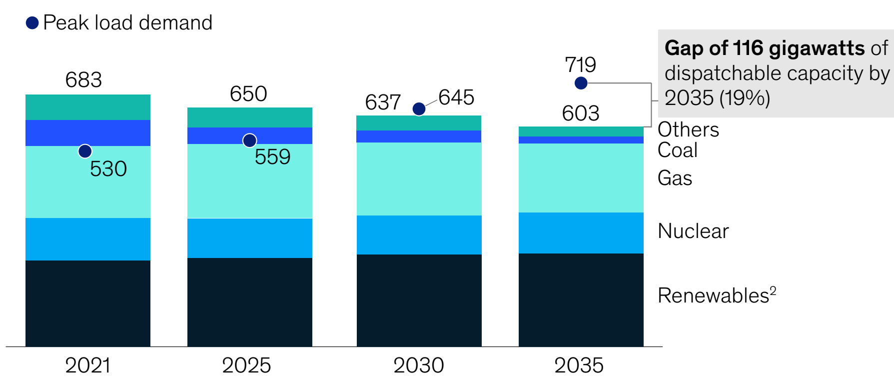
### 4. New and evolving rules

Long-term redesigns of Europe's power market are considered critical to avoiding future price volatility, balancing the needs of consumers and producers, and bolstering investment in new generation capacity. In addition to immediate and temporary measures aimed at lowering prices for energy consumers, European policy makers and regulators are considering several longer-term options to fundamentally reform how the EU energy market operates. Each of these will need to balance the three dimensions of security, affordability, and sustainability:

Exhibit 4

**Assuming no new capacity is built, Europe could face a gap in dispatchable power by 2035.**

**Dispatchable installed capacity in Europe[1] without new build,** gigawatts




[1]Austria, Belgium, Bulgaria, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Italy, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, and United Kingdom.
[2]Comprises hydro and biomass.
Source: McKinsey Power Solutions EU Power Model, November 2022; Platts PowerVision; McKinsey analysis

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[14] McKinsey Power Solutions EU Power Model, November 2022.

# Long-term redesigns of Europe's power market are considered critical to avoiding future price volatility and bolstering investment in new generation capacity.

— *Central buyer model.* Instead of buyers competing in an open and fluctuating market, a single EU or national regulatory agency would purchase electricity from dispatchable sources at fixed prices under long-term contracts. The agency would then sell this energy to the market at prices that represent an average cost. This model can reduce the effects of price spikes and ensure a direct and consistent supply of power to energy retailers and large customers.

— *Decoupled day-ahead markets.* Because Europe's electricity prices are closely tied to the cost of natural gas, energy consumers are unable to reap the economic benefits of low-cost renewables. By separating energy resources with zero marginal costs (such as wind and solar) into one market and marginal cost resources (such as coal) into another, grid operators can prioritize the dispatching of renewables, leaving fossil fuel generation to meet residual demand.

— *Capacity remuneration mechanism.* To ensure a steady supply of dispatchable electricity when customers most need it, a grid operator provides subsidies to producers based on the forecast cost of keeping power capacity in the market. This ensures a secure power supply and protects consumers from paying for more capacity than necessary.

Although the European power market is experiencing one of its most challenging periods, close collaboration among stakeholders (such as utilities, suppliers, and policy makers) can enable Europe's green-energy transition to continue while ensuring a stable supply of power. With market uncertainty high, players will need to pay close attention to how they navigate the economics of their investments in wind, solar, and other new generation assets. McKinsey's work with leading players highlights the importance of building a series of strategic scenarios to model how generation and retail portfolios will evolve under different scenarios. Building optionality in portfolios will be a critical component of thriving in such an unsettled environment.

**Markus Schülde** is a consultant in McKinsey's Munich office, **Xavier Veillard** is a partner in the Paris office, and **Alexander Weiss** is a senior partner in the Berlin office.

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# Five key action areas to put Europe’s energy transition on a more orderly path

To fulfill its ambitious net-zero agenda, the European Union would need to significantly increase the speed and scale of the transition while ensuring affordability, security, and growth.

*This article is a collaborative effort by Tommaso Cavina, Lorenzo Moavero Milanesi, Hamid Samandari, Humayun Tai, and Raffael Winter, representing views from McKinsey’s Electric Power and Natural Gas Practice and Sustainability Practice.*

**The 27-member European Union** has long been a leader in the global energy transition, thanks to strong support for clean technologies and an ambitious decarbonization agenda. That agenda includes policy initiatives, such as the European Green Deal (in 2020) and the Fit for 55 plan (in 2021), which aim for a 55 percent cut in $CO_2$ emissions by 2030 (from 1990 levels) and for net-zero emissions by 2050. Since 2021, however, those goals have encountered headwinds. The Russian invasion of Ukraine, the lingering effects of the pandemic, supply chain disruptions, inflationary pressures, and turmoil in the global economy have threatened energy security and affordability in EU countries. Many of them are net importers of oil and gas and thus particularly exposed to energy reliability and market volatility risks.

Although Russia's natural-gas exports declined after the sanctions against it, the European Union has avoided mandated gas curtailments. One reason was the diversification of gas supply—in particular, liquefied-natural-gas (LNG) imports, which increased by more than 60 percent in 2022 from the previous year.[1] In addition, the European Union reduced gas consumption in industry and buildings by about 15 to 20 percent in 2022 (compared with 2021), thanks to a relatively mild winter and the adoption of behavioral and energy efficiency measures.

Several European nations sought to maintain a steady energy supply by taking steps such as delaying the decommissioning of coal-fired power plants and increasing their utilization, which helped to partially offset reduced generation from nuclear and hydro plants. But by highlighting the European Union's exposure to Russian energy, the crisis gave a fresh impetus to the push for a more orderly energy transition that combines rapid decarbonization with energy security and economic growth (see sidebar "What is a more orderly transition?"). In early 2022, the European Commission announced the REPowerEU plan,[2] which introduced measures "to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition." This sent a signal that the European Union aims to come out of the current crisis with a renewed commitment to climate action (see sidebar "Five interlocking proposals").

## What is a more orderly transition?

**The debate on net zero** often seems to oppose an "orderly" transition to a "disorderly" one in a binary fashion. But orderliness is a relative notion. At one end of the spectrum, instantaneous and abrupt action could jolt economies and societies, impair growth, and lead to public resentment and political backlash. At the other end, delayed or limited action could lead to runaway climate change, threaten the lives and livelihoods of billions of people, bring about massive population displacements, exacerbate political strife and contention, and result in a severe contraction of the world economy. Between these two undesirable extremes lies a range of measured and decisive actions that would enable a rapid ramp-down of high-carbon economic activities in tandem with a corresponding ramp-up of low-carbon ones.[1] For the purpose of this article, a more orderly transition pathway is a scenario in which the European Union achieves its stated commitments of a 55 percent cut in $CO_2$ emissions by 2030 and net-zero emissions by 2050 while balancing affordability, reliability, resilience, and security.

[1] Mekala Krishnan, Tomas Nauclér, Daniel Pacthod, Dickon Pinner, Hamid Samandari, Sven Smit, and Humayun Tai, "Solving the net-zero equation: Nine requirements for a more orderly transition," McKinsey, October 27, 2021.

[1] *Baseline European Union gas demand and supply in 2023*, International Energy Agency, accessed July 10, 2023.
[2] *REPowerEU: A plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition*, European Commission, May 18, 2022.

The European Union accounts for about 8 percent of global energy-related emissions.[3] While it obviously cannot solve the global climate-change problem on its own, it could position itself as a global leader and serve as an example for other countries and regions if it can come close to achieving its commitments.

Still, fulfilling those commitments would require an unprecedented effort, and the current

[3] *BP energy outlook: 2022 edition*, BP, 2022.

## Five interlocking proposals

**The European Union** has introduced five interlocking sets of proposals intended to help meet its net-zero commitments:

1. The European Green Deal, approved in 2020, sets a binding target to reach climate neutrality by 2050. The interim target is to reduce emissions by 55 percent from 1990 levels by 2030.

2. The Fit for 55 package, approved in 2021, includes proposals aimed at revising and updating legislation to put it in line with the intermediary target of reducing emissions by at least 55 percent by 2030.

3. In 2022, the European Commission adopted the REPowerEU plan, which is intended to bolster energy security and further accelerate the transition. The plan sets out measures that aim to reduce the European Union's dependence on Russian fossil fuels. In addition to the replacement of coal, oil, and natural gas, the commission estimates that energy savings, efficiency, substitution, electrification, and the uptake of green hydrogen, biogas, and biomethane by industry can save 35 billion cubic meters of natural gas, beyond the reductions already foreseen in the Fit for 55 proposals. REPowerEU raised Europe's target for the share of renewables in the energy mix to 45 percent by 2030. To reach that target, the plan aims for installed solar-photovoltaic capacity of more than 320 GW by 2025—double today's level—and almost 600 GW by 2030.

4. In 2023, the European Commission presented the EU Green Deal Industrial Plan, which is distinct from the European Green Deal described above. It aims to help the European Union's net-zero industry become more competitive and to "provide a more supportive environment for the scaling up of the EU's manufacturing capacity for the technologies and products required to meet the EU's ambitious climate targets."[1] Furthermore, the Critical Raw Materials Act, which is part of the plan, proposes targets for the amount of 16 strategic raw materials to be extracted, processed, and recycled within the European Union. It also proposes limiting the single-country dependency for imports of each of these strategic raw materials.

   The Green Deal Industrial Plan supplements the European Green Deal and REPowerEU by improving access to funding, making permitting easier, enhancing skills, ensuring a simpler and more predictable regulatory process, and opening trade for resilient supply chains.

5. In March 2023, the European Commission proposed a set of reforms for the design of the power market. The plan introduces interventions and policies aimed at protecting customers from volatility, making the cost of energy more stable and predictable, and boosting renewable-energy investments. The measures include programs for clean-energy solutions, such as demand response and storage, and the strengthening of power-purchase-agreement markets. In addition, the plan calls for the adoption of two-way contracts for difference (CfDs) as the only revenue model applicable to all public support for new RES developments and for the introduction of a wider choice of retail contracts for final users (including the option to lock in stable long-term prices). The proposal will have to be discussed and adopted in the European Parliament and the European Council before taking effect.

[1] "The Green Deal Industrial Plan: putting Europe net-zero industry in the lead," European Commission, February 1, 2023.

speed and scale of the transition would need to increase significantly (see sidebar "Europe's starting point"). From 2019 to 2021,[4] EU power sector emissions decreased at less than half the rate necessary to stay on track for a 1.5°C pathway. The European Union would now need to triple its current pace of renewable-energy-source (RES) deployment to avoid a less orderly transition, which would be far more costly and damaging to the economy and the environment than one that balances affordability, reliability, resilience, and security.

## Benefits and costs

The energy transition could offer broad economic benefits for the European Union—such as increased energy reliability, economic growth, and job creation—for example, by developing supply chains for renewables such as solar-photovoltaic (PV) manufacturing. McKinsey's net-zero report shows that Europe's cumulative incremental investments toward net zero could reach around €1.7 trillion by 2030, equivalent, in real terms, to 11 times the spending of the post–World War II Marshall Plan. Although the transition could eliminate six million

[4] *European Electricity Review 2022*, Ember, February 1, 2022.

## Europe's starting point

**The European Union depends** on many energy sources beyond fossil fuels, including nuclear, solar, and wind, though the mix varies from country to country. For example, the share of fossil fuels in Sweden (28 percent) and France (50 percent), which use more nuclear and hydropower, is lower than it is in Poland (92 percent).[1]

About 37 percent of EU electricity generation comes from fossil fuels—largely coal, which generates up to 15 percent of the region's total electricity.[2] Natural gas accounts for roughly 20 percent, and more than 80 percent of the supply is imported from outside the European Union.[3] Historically, Russia has been the largest supplier of gas, accounting for more than 40 percent of the European Union's imports in 2020.[4] Those imports were 54 percent lower in the first half of 2022. Nuclear power accounts for approximately 25 percent of EU electricity production; more than half of the total is produced in France.[5] Still, overall nuclear power production has fallen by 4 percent since 2019.[6]

The European Union produced 37 percent of its power from renewable sources in 2021. By contrast, China produced 15 percent and the United States 12 percent.[7] Wind and hydropower represented more than two-thirds of the European Union's total renewable-energy generation, solar 14 percent, and solid biofuels 8 percent.[8]

Still, the potential for renewables varies from country to country. Northern European ones, such as Denmark,[9] have a lower potential for solar PV than do countries in the south, such as Spain[10] and Italy.[11] Countries near the North Sea are well situated to capitalize on offshore wind potential: more than half of the 300 GW of offshore wind that the European Union aims to deploy by 2050 would be located there.[12]

[1] "Share of primary energy from fossil fuels," Our World in Data, accessed July 11, 2023.
[2] *European Electricity Review 2022*, Ember, February 1, 2022.
[3] "Europe relies primarily on imports to meet its natural gas needs," US Energy Information Administration, February 11, 2022.
[4] Gabriel Di Bella, Mark J Flanagan, Karim Foda, et al., *Natural Gas in Europe: The Potential Impact of Disruptions to Supply*, International Monetary Fund, July 19, 2022.
[5] *European Electricity Review 2022*, Ember, February 1, 2022.
[6] Ibid.
[7] "How much of U.S. energy consumption and electricity generation comes from renewable energy sources?" EIA, accessed July 11, 2023.
[8] *Renewable energy statistics*, Eurostat Statistics Explained, January 2023.
[9] Denmark: specific PV power output of 2.67–3.1 kWh/kWp.
[10] Spain: 3.08–4.9 kWh/kWp.
[11] Italy: 2.67–4.54 kWh/kWp.
[12] Magnus Højberg Mernild, "Harnessing the North Sea's green energy potential," State of Green, May 17, 2022.

jobs through 2050, it could also create 11 million, for a net gain of five million.[5] As job losses and gains will occur disruptively across the labor spectrum, training and transition support will be required.[6]

In addition to reducing $CO_2$ emissions, a successful transition would strengthen the region's energy security by reducing dependence on fossil fuels and energy imports. The goal would be to raise the proportion of renewable energy in the final energy mix to 45 percent by 2030, compared with 22 percent today. By 2030, these changes could reduce the European Union's total energy bill by 10 percent.[7]

On the other hand, a less orderly transition—resulting, among other factors, from a lack of coordinated interventions among EU member states—could ultimately raise the cost of energy for households and businesses in coming decades. We estimate, for instance, that producing green hydrogen in Germany would cost 20 percent[8] more than importing it from Spain. A failure to act would have severe negative environmental and economic costs across sectors, infrastructure, human health, and disaster management. These would far exceed the costs of action and adaptation.[9]

EU member states would need to take transformative collective action to meet their goals. Implementing the transition would mean profound change: substantial shifts in both energy supplies and large-scale electrification—two endeavors of tremendous magnitude. On the supply side, for example, our research shows that the rate of installation of renewable-energy sources (RES), such as wind and solar, would have to increase three to five times from the 2018–20 average. On the demand side, substantial and cross-sector electrification would be required to reduce direct demand for fossil fuels. According to McKinsey's 2022 *Global Energy Perspective*, the number of battery electric vehicles (BEVs) on EU roads, for example, would need to increase from 1 percent of the total today to about 20 percent in 2030.

Stakeholders could then begin the lengthy process of scaling up infrastructure, supply chains, and the availability of talent. The public sector could be called upon to play a significant role—for example, by considering institutional reforms if needed. Private-sector efforts could prove equally important. Individual operators could catalyze a more orderly energy transition by focusing on cross-value-chain and cross-industry partnerships to improve the resilience of supply chains. The private sector could also take a leading role investing in automation, innovation, and new capabilities; attracting and reskilling the workforce; and launching initiatives to increase the social acceptance of the measures needed to achieve net zero. Without these—and other—key enablers, Europe will not be able to deploy energy transition technologies at the necessary speed and scale.

## Accelerating a more orderly energy transition

In 2021, the EU market was the third-largest source of greenhouse-gas emissions, behind only China and the United States. Within the European Union, emissions were highest in Germany, with 23 percent of the total, followed by Italy and Poland, with 11 percent each. The majority of these emissions come from five sectors: transportation (about 28 percent), heavy industry (about 25 percent), power (about 22 percent), buildings (about 13 percent), and agriculture (about 12 percent). Fossil fuel combustion accounts for 80 percent of EU emissions.[10]

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5 Paolo d'Aprile, Hauke Engel, Godart van Gendt, Stefan Helmcke, Solveigh Hieronimus, Tomas Nauclér, Dickon Pinner, Daan Walter, and Maaike Witteveen, *How the European Union could achieve net-zero emissions at net-zero cost*, McKinsey, December 3, 2020.
6 Ibid.
7 We calculated the energy bill and compared the projected 2030 level with the level in pre-COVID-19 and prewar times, in 2019.
8 This includes the cost of transmission.
9 *Climate Change 2022: Impacts, Adaptation and Vulnerability*, the sixth assessment report of the Intergovernmental Panel on Climate Change (IPCC), February 2022.
10 *How the European Union could achieve net-zero emissions at net-zero cost.*

The challenges of reducing them vary from country to country. The Benelux nations, for example, rely on heavy industry and serve as a hub for air freight and shipping—relatively difficult sectors to decarbonize. Other countries, such as Poland, rely on coal-based power generation. Despite these differences, EU member states could act in similar ways to overcome the challenges and help realize the region's climate goals. McKinsey's 2022 report on the transition[11] highlighted nine requirements for reaching net zero. Our research has identified five action areas that EU nations could consider to accelerate the energy transition in an orderly manner:

1. creating resilient, at-scale supply chains for key decarbonization technologies

2. building out the energy grid infrastructure to support resilience and reduce barriers to in-region renewables

3. reexamining land use, societal, and regulatory constraints to accelerate the development of renewables

4. redesigning power markets in line with decarbonization and affordability objectives

5. ensuring the affordability of clean technologies to foster their adoption and accelerate the energy transition

## Action area 1: Creating resilient, at-scale supply chains for key decarbonization technologies

The European Union currently imports many of the critical inputs that clean technologies need, including solar panels, wind turbines, and batteries. Supply chains for some of these key technologies are already stretched, and geopolitical tensions have exacerbated the existing problems. Supply chain blockages risk delaying or increasing the cost of the energy transition. A shortage of labor presents a further obstacle.

**Potential challenges**

The region faces potential challenges for critical decarbonization technologies in three areas of the supply chain:

1. *Raw materials.* Essential materials for decarbonization technologies originate in just a few countries. That makes supply chains vulnerable to geopolitical risks, political instability, and disruptions in trade relationships. This dependency therefore leaves the European Union at risk for supply shortages, long lead times, and unreliable availability, which could cause sharp price increases and delays for clean technologies. For example, the supply of the rare-earth metals neodymium and praseodymium, used in wind turbines and electric vehicles (EVs), depends considerably on China's refining capacity (Exhibit 1). In some scenarios, there could be shortages of 50 to 60 percent in 2030, and the European Union might not be able to scale up local refining capacity in time to fill these gaps.[12] Other key materials, such as nickel and cobalt, are expected to be in short supply by 2025.

2. *Components.* The European Union faces supply resilience challenges for some components of key decarbonization technologies. China, for example, supplies around 70 percent of solar modules and around 60 percent of lithium battery components.[13] To be competitive in these products, the European

[11] The nine critical requirements to reach net zero are as follows: physical building blocks, encompassing (1) technological innovation, (2) the ability to create at-scale supply chains and support infrastructure, and (3) the availability of necessary natural resources; economic and societal adjustments, including (4) effective capital reallocation and financing structures, (5) the management of demand shifts and near-term unit cost increases, and (6) compensating mechanisms to address socioeconomic impacts; and governance, institutions, and commitment, namely (7) governing standards, tracking and market mechanisms, and effective institutions, (8) commitment by (and collaboration among) public-, private-, and social-sector leaders globally; and (9) support from citizens and consumers. See *The net-zero transition: What it would cost, what it could bring*, McKinsey Global Institute, January 2022.
[12] *The role of critical minerals in clean energy transitions*, International Energy Agency, May 2021.
[13] "Geopolitics on the rise in solar PV manufacturing," *S&P Global*, February 8, 2022; Al Root, "China is winning the lithium wars. What it means for Tesla and other EV stocks," *Barron's*, May 18, 2022.

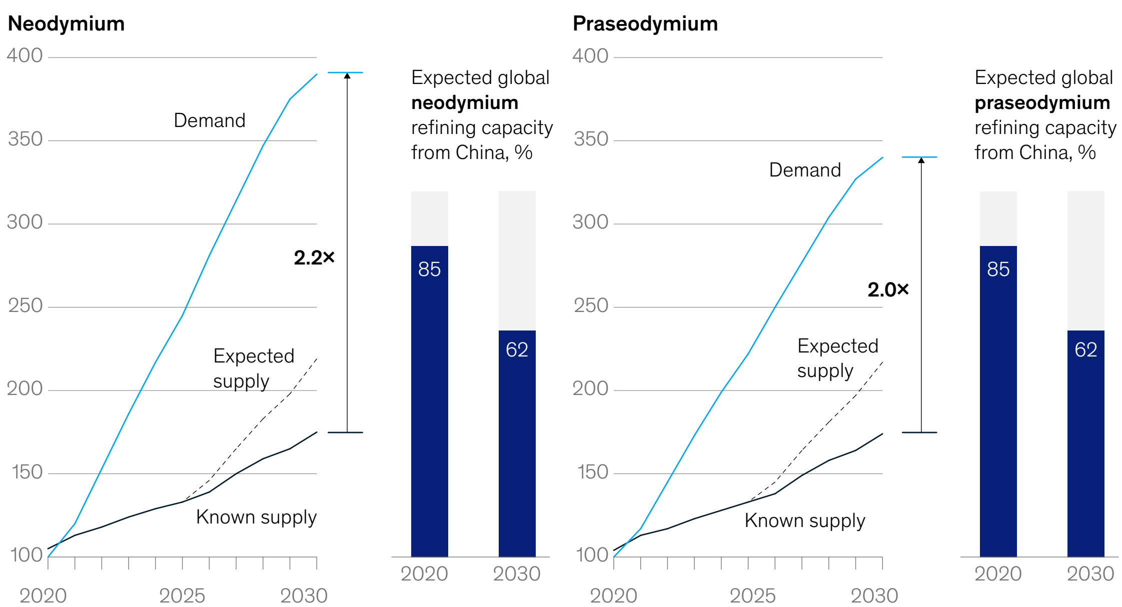
Union would need to bridge the current large cost gap: solar modules made in the region are currently 25 to 30 percent more expensive than those made in China.[14]

3. *Labor.* A shortage of labor could also hamper a more orderly energy transition in Europe. The expected surge in wind and solar installations, for example, could make them difficult to staff with qualified development and construction employees, as well as operations and maintenance workers. Reaching the Fit for 55 target of a 45 percent share of renewables in the energy mix would require a massive redeployment of labor. Almost one million full-time skilled workers would be needed in 2030 just to develop and construct centralized renewable-energy assets. That is more than triple the number needed today. In addition, though new nuclear plants could be commercially viable for decarbonization in the medium to long term, the technical skills and capabilities needed to develop them are very scarce.

Exhibit 1

## Rare earth metals needed for wind turbines and electric vehicles are highly dependent on China’s refining capacity.

**Global expected demand and refined supply development, by rare element,**[1] indexed to 2020 demand




[1]Based on expected growth of existing capacity and known new projects. Capacity of known new projects based on estimated probability of these projects being active, eg, if a project is still in the exploration phase, the probability of it coming live is lower than if it is in a detailed feasibility study phase. Based on base supply and unknown late-maturity projects or projects not yet developed but that are expected to happen toward 2035.
Source: Company websites for new projects related to supply; Grand View Research; Research and Markets; McKinsey Electric Vehicle Perspective; McKinsey Wind Turbine Perspective; McKinsey Global Energy Perspective, 2022

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[14] *Global Energy Perspective 2022*, McKinsey, April 26, 2022.

**Key priorities**

To mitigate the effects of supply chain disruptions and bottlenecks, business leaders and policy makers could consider three key priorities:

1. *Building partnerships with raw-material suppliers from a diversified set of exporting countries.* The European Union could create a more resilient supply chain by identifying scarce materials and technologies produced in geographically concentrated areas and then developing partnerships with suppliers elsewhere. For example, the European Commission, in partnership with the World Resources Forum Association, proposed an EU–Africa collaboration for a sustainable raw-material supply chain. Similar programs may allow countries across Europe to find more resilient and diversified sources of supply.

   The European Union could also consider introducing agreements (such as the European Raw Materials Alliance) among its member states to make the sourcing of strategic raw materials more diversified and secure. Meanwhile, the region could consider scaling up both recycling and R&D for raw-material substitution—for example, switching from lithium iron phosphate (LFP) batteries to nickel-manganese-cobalt (NMC) technology.

2. *Scaling up European manufacture of critical technologies.* The European Union could offer incentives to scale up Europe's manufacturing supply chain by introducing local-content requirements, subsidies, better capital access, and European sustainable labels. It could reduce its dependence on interregional relationships, for instance, by encouraging the manufacture of solar modules, batteries, and subcomponents (such as semiconductor products). EU member states would have a natural role in assessing and prioritizing support measures, including grants or subsidies, to increase onshore manufacturing capacity. Initiatives such as the European Solar Photovoltaic Industry Alliance and the EU Innovation Fund, which support large-scale renewables production in the European Union, are first steps in this direction.

**The European Union could consider introducing agreements among its member states to make the sourcing of strategic raw materials more diversified and secure.**

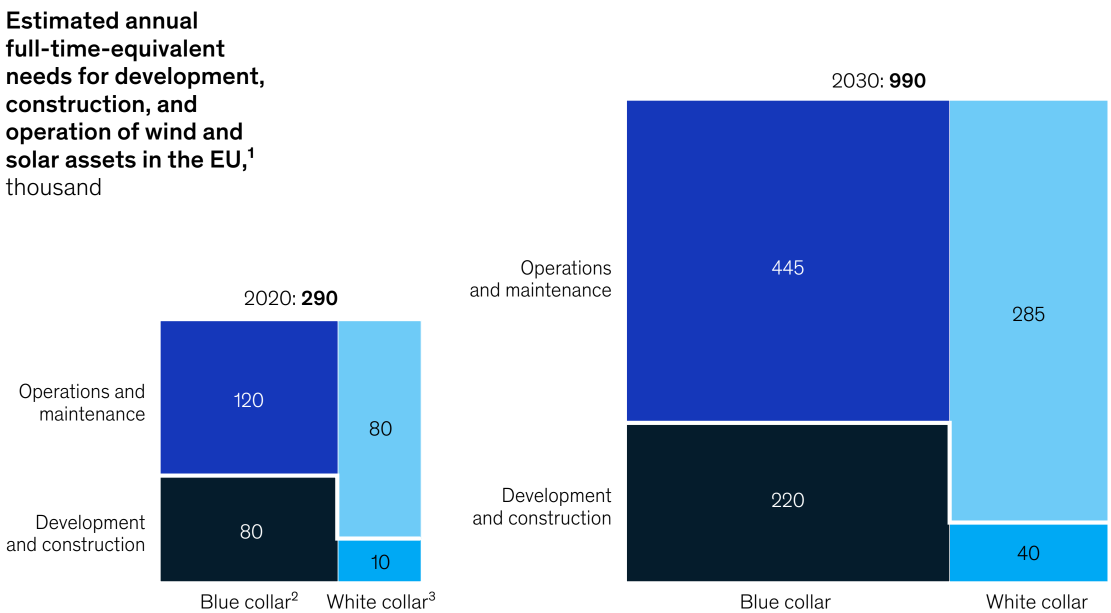
3. *Attracting and training the workforce to ensure adequate labor to scale up clean technologies.* Companies could develop their talent reserves by highlighting the green impact of jobs and by offering clear professional-development pathways for blue-collar workers. This goal could be achieved through investments in company-, country-, or EU-wide labor programs, such as skilling, reskilling, and enabling international and cross-sector utilization (for example, in the telecommunications, rail, and energy sectors). Furthermore, policy makers could provide incentives to help companies attract talent. Easing certification requirements could permit a faster ramping-up of the needed workforce (Exhibit 2).

## Action area 2: Building out the energy grid infrastructure to support resilience and reduce barriers to in-region renewables

Boosting the share of renewables in the energy mix to 45 percent by 2030 could require a substantial expansion and enhancement of the grid infrastructure to support the integration of new green technologies, such as utility-scale and distributed RES, EVs, and heat pumps. A more

Exhibit 2

**Demand for workers to develop and construct wind and solar assets in the European Union is set to increase by a factor of three to four by 2030.**




[1]Estimate based on current and expected build-out and full-time-equivalent workers per gigawatt estimates, based on different publications from International Renewable Energy Agency (IRENA); learning rates have not been applied.
[2]Practical workers (eg, construction workers, technicians, ship crew, and operators).
[3]Remaining workers (eg, electrical, industrial, mechanical, and telecommunication engineers; and safety and regulation experts, financial analysts, and lawyers).
Source: *Renewable energy benefits: Measuring the economics*, IRENA, Jan 2016; McKinsey Global Energy Perspective, 2022, accelerated transition scenario

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up-to-date system could also ensure the security of the gas supply.

**Potential challenges**

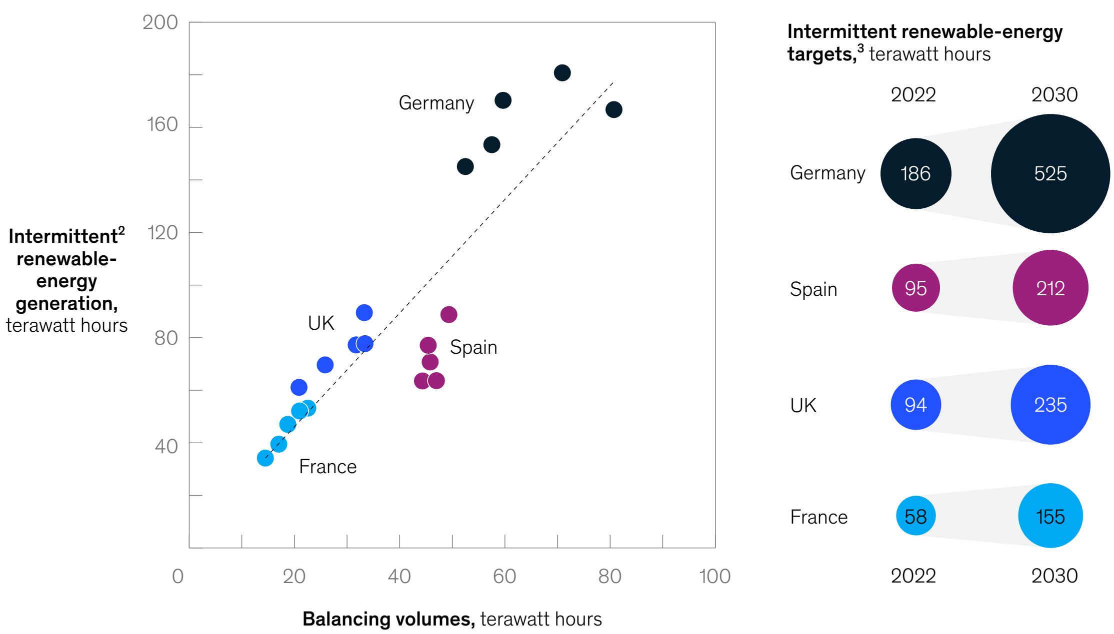
Three areas could prove particularly challenging:

1. *Power.* Annual grid investments of 40 to 70 percent more than the average over the past five years would be needed to support electrification, the integration of renewables and distributed resources, and the digitization of infrastructure. Furthermore, the need for flexibility[15] could triple by 2030 as a result of higher generation by renewables. That could require the development of new flexible capacity, such as energy storage and demand response (Exhibit 3).[16] Connections between wind power generation in northern Germany and the industrial clusters in the south of the country, for instance, remain limited, restricting the

Exhibit 3

## Energy flexibility volumes are likely to increase due to higher renewables generation in European countries.

**EU renewables and balancing volumes[1] 2017–21, by country and year,** terawatt hours




[1]Balancing refers to intraday market volumes and activated control reserve (secondary and tertiary).
[2]Intermittent is defined as wind and solar.
[3]Germany figures are based on Easter legislation package, July 2022; Spain figures are based on the National Integrated Energy and Climate Plan, 2020; UK calculations based on British energy security strategy, April 2022; France figures are based on multinational energy planning targets, 2020 (targets are for 2028, not for 2030).
Source: *Renewable energy benefits: Measuring the economics*, IRENA, Jan 2016; McKinsey Global Energy Perspective, 2022, accelerated transition scenario

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[15] Intraday market and activated secondary and tertiary reserve.
[16] *Global Energy Perspective 2022*, McKinsey.

ability to balance the grid through interregional connections between generation sites and demand centers.

2. *Gas.* The European Union is responding to the energy market disruption that followed the cuts in Russian exports by seeking to increase its liquefied-natural-gas regasification capacity. Russian pipeline gas imports, which accounted for 36 percent of total EU gas consumption in 2021, were down by more than half in 2022.[17] In addition, the limited capacity of gas transport through pipes within Europe hinders the European Union's ability to fully exploit the existing LNG infrastructure. Spain and Portugal, for example, have one-third of the European Union's capacity to process LNG but lack substantial interconnections with the rest of Europe. Furthermore, an estimated 70 percent of the existing EU gas network must be updated to support hydrogen blending.

3. *Integrated planning.* National and cross-national coordination mechanisms could be strengthened to foster integrated planning across value chains, technologies, and countries. A lack of coordination might negatively affect supply resilience and could raise costs.[18]

**Key priorities**

To enhance the gas infrastructure and improve transmission planning, business leaders and policy makers could consider four key priorities:

1. *Promoting integrated transmission planning and reviewing permitting and siting to accelerate build-out.* Large-scale interconnection projects face long development times. Given the complex issues of siting new large-scale energy transmission projects, stakeholders could identify the most critical projects of integrated plans and review permitting and siting support through regional collaboration and cooperation among EU countries.

   National and cross-national coordination mechanisms would foster integrated planning across value chains and technologies—for instance, power, hydrogen, and gas. In the fourth quarter of 2021, the European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Network of Transmission System Operators for Gas (ENTSO-G) took an initial step to implement integrated planning by publishing, for the first time, joint scenarios for the 2022 Ten-Year Network Development Plan. These scenarios capture the interactions between gas and electricity systems to assess the infrastructure of an integrated energy system and optimize overall system efficiencies and flexible use.

2. *Implementing demand-side measures to reduce peak energy loads and defer grid investments.* Grid infrastructure costs are largely fixed, and the deployment of new transmission capacity is slow and costly. Any resource that could improve throughput for these assets at a lower cost and shorten their time to market could increase their overall societal value. The use of demand-side resources has been discussed at length in some markets—for example, the United States—as a way to augment grid capacity.

   Resources may include heating, ventilation, and air-conditioning (HVAC) systems using thermal storage to preheat buildings; the optimized charging of battery electric vehicles; the time (and location) shifting of data center computing loads to areas where the grid is less stressed; traditional industrial load curtailment; and

[17] Gillian Boccara, Diego Hernandez Diaz, Berend Heringa, Ole Rolser, Namit Sharma, Thomas Vahlenkamp, and Cindy Xue, *A balancing act: Securing European gas and power markets*, McKinsey, April 25, 2023.
[18] *Policy toolbox for low carbon and renewable hydrogen—Enabling low carbon and renewable hydrogen globally*, Hydrogen Council, November 2021.

the control of large-scale electricity demand (for instance, to increase green-hydrogen production). The overall loading of the grid infrastructure could be reduced by incentives for flexible demand-side resources to shift loads when grids are most strained to periods of less strain. Flexible demand could help the European Union reduce the need for fossil-based energy generation to ensure energy reliability.

3. *Enabling the development of flexible cross-national gas networks that can carry lower-emission fuels.* Integrating natural gas and hydrogen into European gas networks can help accelerate decarbonization. The enhancement of interregional gas networks could increase energy reliability and enable a more orderly energy transition. Europe could both retrofit its gas infrastructure and build out new capacity to support green hydrogen. As the gas network transitions toward cleaner fuels, policy makers and investors could consider actions that balance reliability and emissions in making investment decisions. For example, could regulatory cost standards for the blended-hydrogen and natural-gas infrastructure be created? Policy makers could also revise the regulations dictating the types of fuels that transmission system operations and distribution network operations may carry.

4. *Raising LNG regasification capacity to support midterm energy security and help alleviate the current energy crisis.* To bolster and diversify domestic natural-gas supply, EU nations could consider coordinated actions, including further work to develop new LNG regasification capacity. Temporary floating storage and regasification units (FSRUs) are already being deployed to increase the European Union's LNG import capacity. Other steps could include building new terminals in Wilhelmshaven, Germany; expanding cross-EU networks, such as the MidCat interconnection between Spain and France, to exploit available capacity; and exploring opportunities to safely exploit indigenous production in areas such as the north Adriatic, the Sicily Channel, and the North Sea. Here too, policy makers and investors could balance cost, reliability, and emissions in making investment decisions, as well as addressing local concerns.

## Action area 3: Reexamining land use, societal, permitting, and regulatory constraints

To reach its 2030 climate targets, the European Union would need to shift rapidly to renewable energy. Our research indicates that from 2022 to 2030, the annual number of solar and wind installations would need to increase by two to five times their 2020–22 levels to meet the region's goals.

Indeed, REPowerEU targets include a total solar capacity of 600 GW by 2030, up from 209 GW in 2022.[19] Annual additions of PV technology would need to more than double, from 30 GW a year (2020 to 2022) to around 70 GW a year (2022 to 2030). Annual additional onshore wind generation would need to almost quadruple, to 40 GW, from 11 GW, over the same period. Additional offshore wind generation would need to quintuple. What's more, 60 percent of the region's coal capacity might need to be retired.

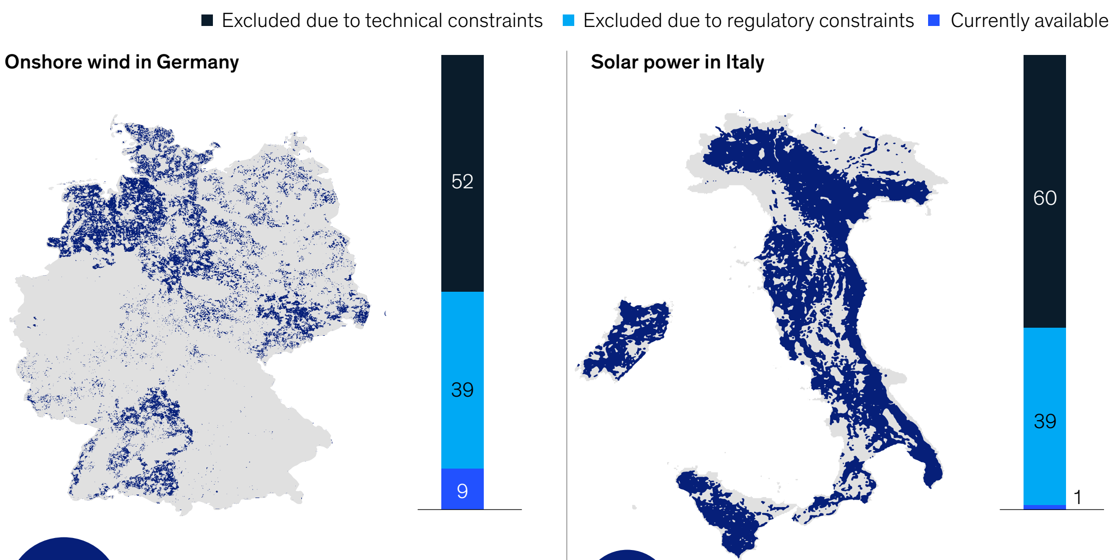
One critical condition of accelerating the use of renewables is the availability of land. Europe's population density and growing concerns about land use have made it more challenging to find adequate areas for onshore wind and solar power. The land requirements for deploying the target capacity of renewables are significant. The 2040 RES targets in France, Germany, and Italy, for example, would require an additional land area of 23,000 to 35,000 km$^2$—equivalent to the size of Belgium (Exhibit 4).[20]

[19] *REPowerEU: A plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition*.
[20] Stathia Bampinioti, Nadia Christakou, Bastian Paulitz, Lukas Pöhler, Antoine Stevens, Raffael Winter, and Ekaterina Zatsepina, *Land: A crucial resource for the energy transition*, McKinsey, May 16, 2023.

Exhibit 4

## Available land for renewables development is limited in several countries.

**Technically available[1] land for onshore wind in Germany and solar power in Italy,** %




**104** gigawatts of additional wind power capacity required by 2040

**50–80%** of available land needed near substations to achieve 2040 additions

**63** gigawatts of additional solar power capacity required by 2040

**60–85%** of available land needed near substations to achieve 2040 additions

Note: For separation of land area, the technical constraints and unsuitable land cover are: Existing wind and solar photovoltaic (PV), urban areas, forests, water, airports, low-wind-potential zones (for wind only), slope, and military zones. Regulatory constraints are distance regulations for onshore wind from settlements, protected land, and, in the case of Italy, regulatory constraints to develop utility-scale solar PV on cropland. General assumption for onshore wind is a density of 5–8 $MW/km^2$, not considering additional capacity need if repowering is not possible in former areas, radars, military flight zones, and further country-specific detailed regulation. General assumption for solar PV is a density of 43–60 $MW/km^2$; excluding overlapping wind areas and roof-top solar PV (for Germany: 1:1 split between ground-mounted and roof-top solar PV; and for Italy, 3:1). Germany has official RES targets; Italy only has official 2030 RES targets and France only has official 2050 RES targets that were linearly extrapolated to 2040 for this analysis.
[1]Sites are restricted to a distance of <5 km to substations.

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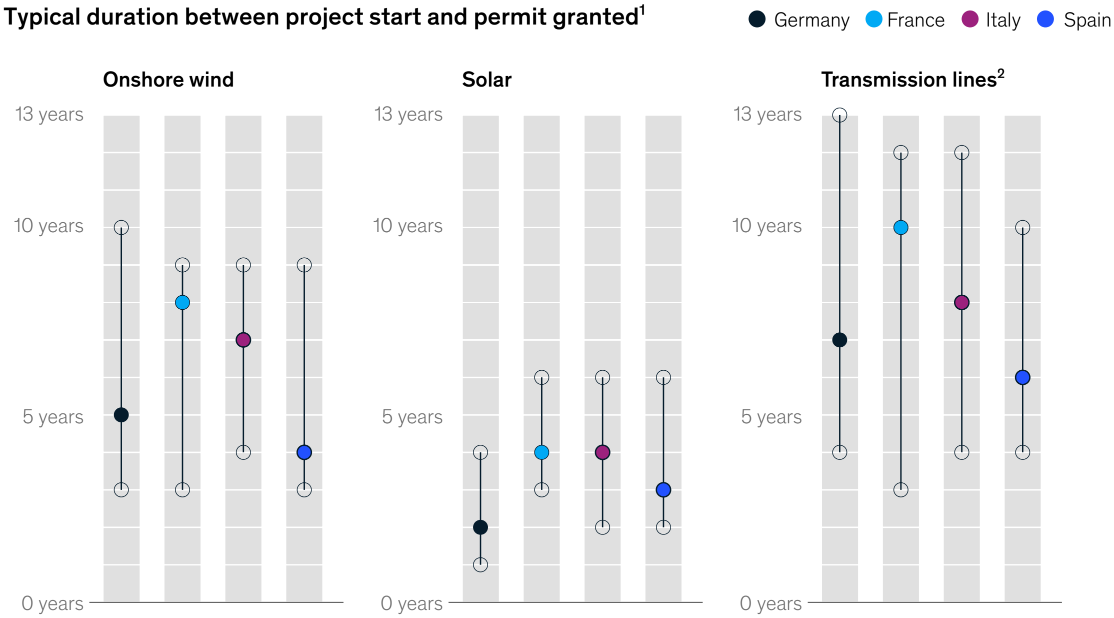
To achieve the necessary deployment of renewables, policy makers could consider accelerating permitting procedures—the part of the RES and transmission-line-development process that typically takes the longest amount of time. In major EU countries, permitting times range from three to ten years for onshore wind installations and from two to six years for solar (Exhibit 5).[21] As a result, recent tenders across the European Union have been largely undersubscribed. Around 80 GW of capacity—some 30 percent of the additions required to achieve the 2030 EU target for onshore wind—is still going through the permitting process.

[21] "Guidance to Member States on good practices to speed up permit-granting procedures for renewable energy projects and on facilitating Power Purchase Agreements," European Commission, Commission Staff Working Document, May 5, 2022.

Exhibit 5

## Long permitting lead times delay the build-out of renewable and transmission projects in Europe.

**Typical duration between project start and permit granted**[1]




[1]Considers only large new-built transmission line projects.
[2]Environmental-impact assessment.
Source: European Wind Energy Association; Fachagentur Windenergie an Land; press searches

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### Potential challenges

The expansion of renewables such as wind and solar power could face challenges in six areas:

1. *Timely allocation.* Meeting the European Union's RES build-out targets could require a reconsideration of spatial-planning processes to ensure the timely availability of sufficient land to develop renewables. In Germany, for example, the amount of available land in areas currently designated for onshore renewables would allow the development of only about an additional 5 to 8 GW of onshore wind.

2. *Distance regulation and other constraints.* Today, a significant share of the land that could be used for RES deployment is either not suitable technically or subject to regulatory restrictions.[22] Rules setting a minimum distance to infrastructure such as settlements, airports, water, and railways, for example, exclude 52 percent of the available land in Germany. Although around 9 percent of the country's land is available for onshore wind build-outs, 50 to 80 percent of these areas near substations would be needed to generate 104 GW of onshore wind additions by 2040.

[22] Suitable land excludes urban areas, forests, bodies of water, airports, very low-capacity zones, high-slope areas, military zones, and protected land (such as biodiversity areas). There are also regulatory constraints on distance to settlement for onshore wind, and Italy bans solar PV on cropland.

3. *Competing land uses.* Furthermore, RES often must compete for available land with alternative uses, such as agriculture and biomass. In Italy, for example, up to 85 percent of available land would be needed to install the 63 GW of solar PV[23] necessary to meet the 2040 additions.[24] Yet a deployment of RES on that huge scale is unlikely, particularly since Italy limits the use of cropland for RES.

4. *Complex and nonuniform regulations.* Across the European Union, permitting is a complex process that involves multiple authorities. In Italy, for example, more than 30 bodies could be involved.[25] Only a few countries or areas have designated renewable-energy land eligible for fast-track permitting or adopted a fast-track permitting process for repowering projects. As a result, more than 70 GW of onshore wind that reaches its end of life before 2030 must go through the full complex permitting process.

5. *Varying permitting capabilities among authorities, developers, and transmission system operators.* Furthermore, permitting authorities frequently lack the resources, such as digital tools, to track permitting status. Among both developers and transmission system operators, the failure to adopt best practices, such as stakeholder engagement and project planning, slows down the process. Upgrading to best-in-class tools and processes could reduce permitting times by 20 to 30 percent.

6. *Societal considerations.* Opposition to renewables projects may lead to lawsuits, which can increase permitting time significantly—for example, by around 40 percent in Germany. Some evidence suggests that concerns about renewables projects can be influenced once they become operational. In Germany, for instance, a recent survey showed that more than 70 percent of the people in communities without existing onshore wind have concerns over permitting but that 78 percent of those with wind plants in their communities do not have a problem with this technology.

**Key priorities**

To help ensure that permitting delays and limited land availability do not become constraints on the energy transition, business leaders and policy makers could weigh six key priorities:

1. *Considering targets for renewables at the national and regional levels to help with land allocation.* Policy makers could address the lack of available land by considering rules, such as those in Germany, that require each state to designate sufficient land for onshore wind to match minimum state-specific targets. If the targets are not met, German law makes it possible to fill the gap by preventing the authorities from denying permits for onshore wind in areas that do not comply with local distance regulations.

2. *Reviewing regulations to safeguard and increase access to land.* Reconsideration of the regulations governing the allowable distance between settlements and onshore wind installations could help increase the area suitable for wind power generation. Relaxing the distance-to-settlement rules in Bavaria, for example, to match those of Lower Saxony could increase the amount of land suitable for developing renewables 80-fold and permit the generation of 100 GW of additional capacity. Public bodies could attract investment by identifying areas suitable and available for developing renewables and prioritizing these to accelerate permitting and interconnections.

3. *Maximizing the repowering of existing installations to improve land productivity.*

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[23] Assuming that 75 percent of solar PV will be ground mounted.
[24] German RES targets were communicated as part of the German Easter legislative package (May 2022); Italian RES targets are aligned with the Next Generation EU (NGEU) program emission reduction target (about 55 percent of greenhouse-gas emissions by 2030 compared with 1990). The official targets of national integrated energy and climate plans have not been updated since 2019.
[25] Ministero Dell'Ambiente e della Sicurezza Energetica, Elettricità futura, Gestore Servizi Energetici.

The energy production of clean technologies has significantly improved in recent decades. Innovations include tracking and bifacial solar panels, larger wind turbine generators built on taller towers, and blades with the aerodynamic ability to better capture energy at differing windspeeds.

Existing wind and solar farms are often located on sites with the highest renewables potential—for example, those with high irradiation or wind speeds and with close interconnections. Since these projects often deploy older technologies, they may be producing less than their full renewables potential. As projects age, owners and grid planners could consider seeking out sites that can produce incrementally more energy with the same footprint and repowering where the improved output outweighs the cost of scrapping a generation source. In Germany, for example, repowering could increase capacity by 45 GW by 2030, lowering the overall need for land.

4. *Considering the introduction of a fast-tracking process for certain projects that support transition goals.* Stakeholders could help ensure the timely expansion of infrastructure by reviewing the criteria for fast-tracking large projects critical for the European Union's energy security and decarbonization efforts. As of November 2022, for example, the European Union allows member states to apply for the fast-tracking of projects focusing on the offshore electricity grid and renewable, low-carbon gas corridors, such as those for hydrogen. These projects, which are designed to help achieve the European Union's overall energy and climate policy objectives, are subject to simplified administrative and judicial procedures. Stakeholders also could consider support for build permitting and siting through regional collaboration and cooperation among EU countries.

5. *Weighing the potential benefits of one-stop shopping and simplifying processes.* To harmonize regulations and establish a central infrastructure authority to oversee permitting timelines, the United Kingdom has undertaken efforts through the Government Major Projects Portfolio (GMPP) from the Infrastructure and Projects Authority (IPA). The new system makes processes more flexible to accommodate changes in technology. Changing a turbine for a more advanced model, for example, would not trigger a restart of the permitting procedure if the change does not increase permitting-relevant risks.

   What's more, permitting organizations, developers, and transmission system operators could improve their ability to manage complex projects. Digital tools, for example, could track the status of permits and potentially create a new action-oriented culture of interaction between developers and permitting organizations.

6. *Launching social-awareness campaigns and implementing incentives to improve public acceptance of solar and wind projects.* Public-opinion concerns about renewables are often best addressed with local solutions that involve the public—not just landowners—in the planning process. Making local communities more aware of the benefits of projects and increasing the transparency of procedures could also ease local concerns.

   Projects that aim to foster public acceptance have encouraged local ownership of renewable-energy sources by citizens and businesses. To achieve the target of 6 GW of onshore wind power by 2020, the Netherlands, for example, initiated a goal of 50 percent local ownership of facilities for the production of onshore renewables by 2023. The country gave residents and businesses the opportunity to participate in the decision-making process, from siting to sharing in the revenues. Ultimately, fostering public participation and shared ownership in the development of renewables created widespread acceptance of wind parks across the Dutch provinces.

## Action area 4: Redesigning power markets in line with decarbonization and affordability objectives

Power and commodity markets have been designed around energy systems with variable expenditures, so these markets fluctuate according to the cost of commodities. The natural gas burned by a combined-cycle gas plant built in the mid-2000s might have been expected to account for 60 to 70 percent of its lifetime cost. But variable expenses over the life of a solar or wind farm are very low: operations and maintenance costs are just 10 to 20 percent of lifetime costs, according to our analysis.

**Potential challenge**

Today's market designs factor in operating costs, as prices are based on marginal production costs for power generation units. This system has created an incentive for technological developments such as more efficient combustion turbines. But in the future, more primary energy supply will come from variable intermittent renewable resources with close to zero marginal costs. Current markets do not provide an equivalent operational mechanism to support the transition. Indeed, the current market structure pays for neither the energy produced nor for the changes that would be necessary to create a reliable and resilient system.

**Key priorities**

To redesign power markets to meet decarbonization and affordability objectives, business leaders and policy makers could consider four key priorities:

1. *Reviewing power markets to strengthen the system in the long term and attract investment.* Wholesale power markets are based mainly on energy markets, reflecting the cost of the power generation technology that produces the incremental (marginal) unit of energy at any given time. Although this system ensures the effective dispatching of resources, it does not provide adequate long-term price signals to support investment decisions in new infrastructure, such as renewables or flexible capacity (for example, battery storage).

   Power markets could be revised to bolster long-term resilience and attract investment while stabilizing the cost of supply for end users. Options for redesigned power markets could include not only centralized competitive auctions (such as contract-for-differences for renewables and long-term auctions for energy storage) but also power purchase agreements (PPAs). Centralized market platforms or green-sourcing obligations for large customers and retailers might also be possible.

   One potential design outcome could be balancing longer-term price signals for reliability, resilience, and decarbonization with incentives for short-term resource efficiency, scarcity, and system balancing. In any case, market participants, planners, and policy makers would probably need to go on paying close attention to managing the price and supply volatility that consumers face. Recent energy volatility has caused significant public distress and could diminish confidence in the possibility of a relatively orderly transition. However, volatility may also create a price signal for investments in the system's flexibility and balancing.

2. *Creating more transparency in energy pricing, with more granular bidding zones.* Many national markets have a single clearing price for electricity and little to no accounting for transmission grid constraints. However, these constraints often cause discrepancies between the demand for and supply of power within clearing regions. Complex mechanisms have been introduced to ensure grid balancing but often do not provide clear pricing signals, particularly for demand-side resources.

   Introducing more granular bidding zones—as many markets, including New York, Norway, Sweden, and Texas have done—could create more transparent pricing signals across the energy system. More localized bidding zones enable price clearing to occur at or near the point of generation. The resulting local price reflects transmission constraints. If the basis risk in the market were included, the signals for where to build additional supply or localize demand could enhance efficiency.

3. *Developing financial incentives to minimize energy shortages.* Long-duration gas storage enables seasonal balancing across the EU energy system. To secure an adequate supply of energy—especially during the winter months, when demand peaks—mechanisms and policies could be developed to minimize shortages. One possibility would be to offer market participants a financial incentive to fill storage. Given more easily contracted offtake, these requirements could support long-term arrangements for additional sources of gas.

4. *Creating compensation mechanisms to reconfigure (rather than strand) assets.* Fossil fuel–fired power plants do not always recover their costs, since their operational expenses are higher than those of renewables. Under the current market design, the early retirement of these assets is sometimes more economically viable than continuing to operate them.

   To ensure that energy supply resilience options exist, capacity markets could be implemented to compensate assets that can reduce volatility of supply by making systems more stable. The gas plants in the European Union could, for example, be gradually transitioned to low-utilization assets that provide power during multiday periods of low renewables production. Instead of classifying such low-utilization assets as stranded, decision makers could designate those with good operational records as sources of surplus capacity, helping to mitigate the system's volatility and provide reliable supply.

## Action area 5: Ensuring the affordability of clean technologies to foster their adoption and accelerate the energy transition

If the energy transition is carried out in a more orderly manner—that is, if renewables account for 45 percent of EU supply by 2030 and the electrification of energy demand meets 2030 targets—it could reduce average EU energy costs by about 10 percent (compared with 2019) by 2030. This reduction could be achieved through a combination of lower energy consumption and the substitution of lower-cost clean energy for carbon-intensive energy (Exhibit 6).

This cost decrease could have two main drivers. First, final energy consumption could fall by 10 to 15 percent through the electrification of final consumption and through energy efficiency (including energy management, HVAC improvements, insulation, and smart lighting, among other things). A fully electric household,[26] for example, consumes around one-third as much energy as an average one. Second, the unit cost of supplying power can be reduced as renewable-energy support programs expire and the levelized cost of electricity (LCOE) of newly installed renewable energy lowers the average cost of generation. These decreases will probably more than offset the increasing costs of flexibility and of transmission and distribution.

**Potential challenge**

However, the current energy crisis in Europe presents it with the acute and immediate problem of affordability. This challenge is a major concern to households and businesses across the European Union, prompting government action in many countries. More may be needed in the future.

**Key priorities**

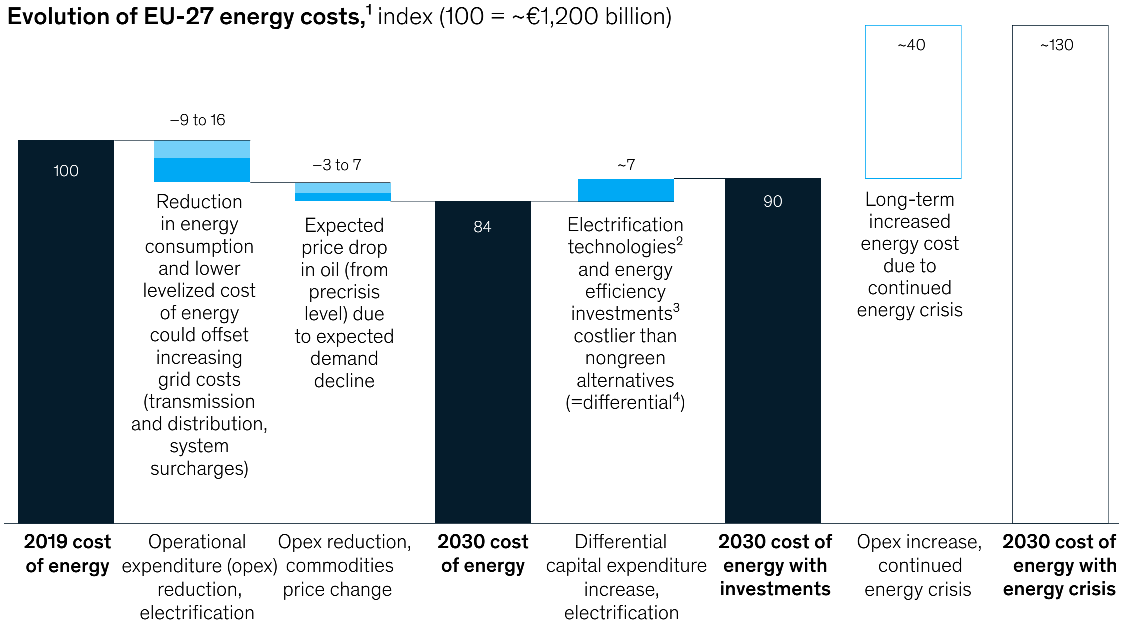
To achieve the necessary reductions, the barriers to the widespread adoption of downstream technologies and energy efficiency measures will have to be overcome. Two of the most challenging obstacles could be high up-front investment costs and the need for subsidies to make technologies such as EVs and heat pumps cost competitive. On average, sustainable cars and heating systems are 7 percent more expensive than conventional ones.

[26] That is, a family with electric space and water heating (heat pumps), cooking (induction/electric ovens), and transport (electric vehicles).

Exhibit 6

## Energy consumption and lower levelized cost of energy in Europe could offset increasing grid costs including distribution and system surcharges.

**Evolution of EU-27 energy costs,**[1] index (100 = ~€1,200 billion)




Note: Total EU-27 energy cost based on detailed analysis on the energy cost of key countries (Germany, France, Italy, and Spain = ~55% of EU-27's energy consumption in 2019). EU-27 cost was estimated proportionally assuming similar average cost of energy in the rest of EU-27. Fuels considered: electricity, hydrogen, natural gas, biogases, motor gasoline, biogasoline, synthetic gasoline, gas/diesel oil, biodiesel, and synthetic diesel.
[1]According to TTF Brent futures (for 2024) as of Sept 2022, assuming gas price of €110/MWh compared with €17/MWh (preinvasion of Ukraine) for 2030.
[2]Eg, electric vehicles, heat pumps.
[3]Eg, building retrofits.
[4]=differential means consideration of delta cost of electrification tech vs nongreen alternative.

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To accelerate the energy transition without adversely affecting affordability, business leaders and policy makers could consider two key priorities:

1. *Lowering financial barriers, such as high up-front investments, by providing incentives and subsidies for the adoption of clean technologies.* The shift to more sustainable energy can require households to pay large sums for clean technologies. The longer-term savings to consumers on items such as air source heat pumps, upgraded building insulation, or electric vehicles may be important. The total cost of ownership of an EV, for example, is in many cases less than that of a vehicle powered by an internal-combustion engine. However, the up-front capital outlay could be a barrier to adoption. To make green technologies cost competitive in the short term, the European Union could consider offering subsidies, tax credits, and additional support while investing to scale up these technologies so they become less expensive.

2. *Enabling active demand participation by removing regulatory and technical constraints for end users and promoting stabilization to mitigate volatility.* Customers could use their own renewable distributed sources to participate in the provision of green energy and flexibility services. In this way, those customers could profit from stable, inexpensive distributed

generation and help integrate renewables into the system. Long-term contract options for customers could increase the appeal of active market participation and provide a shelter from volatile commodity prices.

In Europe, demand resources are used to make the grid flexible less frequently than they are in other mature markets, such as the United States. Removing technical constraints (for instance, minimum size or duration) that limit access of demand response could accelerate the uptake of such solutions and increase the system's flexibility.

Finally, to address avoidable future bankruptcies that have raised costs for end users during the recent crisis, stakeholders may need to consider balanced interventions that protect consumers against volatility while avoiding excessive barriers to competition. These interventions could include strengthening the resilience of retailers through capital requirements (similar to those applied in the banking sector) or setting minimum backup levels, such as long-term supply contracts or hedging ratios for sales with fixed prices.

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The energy transition can unlock great benefits. These could include a cleaner and healthier environment, more affordable (and less volatile) energy costs for consumers and businesses, increased energy resilience and security, infrastructure investments, and significant job creation. However, realizing these benefits could entail far-reaching change, including institutional reforms, reviews of regulations, behavioral change, and large-scale capital outlays. EU policy makers recently introduced two reform proposals designed to help accelerate the transition.

First, the Green Deal Industrial Plan, announced in February 2023, aims to strengthen local supply chains and to support the affordability and adoption of clean technologies. This plan's ability to help ensure continued EU leadership in the energy transition will depend largely on the amount of financing, the ease of access to funds, and the simplicity of the policy instruments.

Second, a recent proposal aims to ease the weaknesses in the current design of energy markets by strengthening forward markets, developing and supporting liquid PPA markets for renewables, and introducing long-term markets for flexible resources.

Interventions in other areas could also be considered, including changes to the permitting process both for developing renewables and the grid infrastructure. Individual EU member states could consider simplifying administrative procedures and strengthening the capabilities required to comply with the maximum deadlines that the EU Council recently set for granting permits: three months for solar energy, compared with 12 months previously.

For the European Union, a successful energy transition amid geopolitical and macroeconomic turbulence would probably require sustained will, cooperation, and coordination among all stakeholders—including operators, regulators, investors, and society at large.

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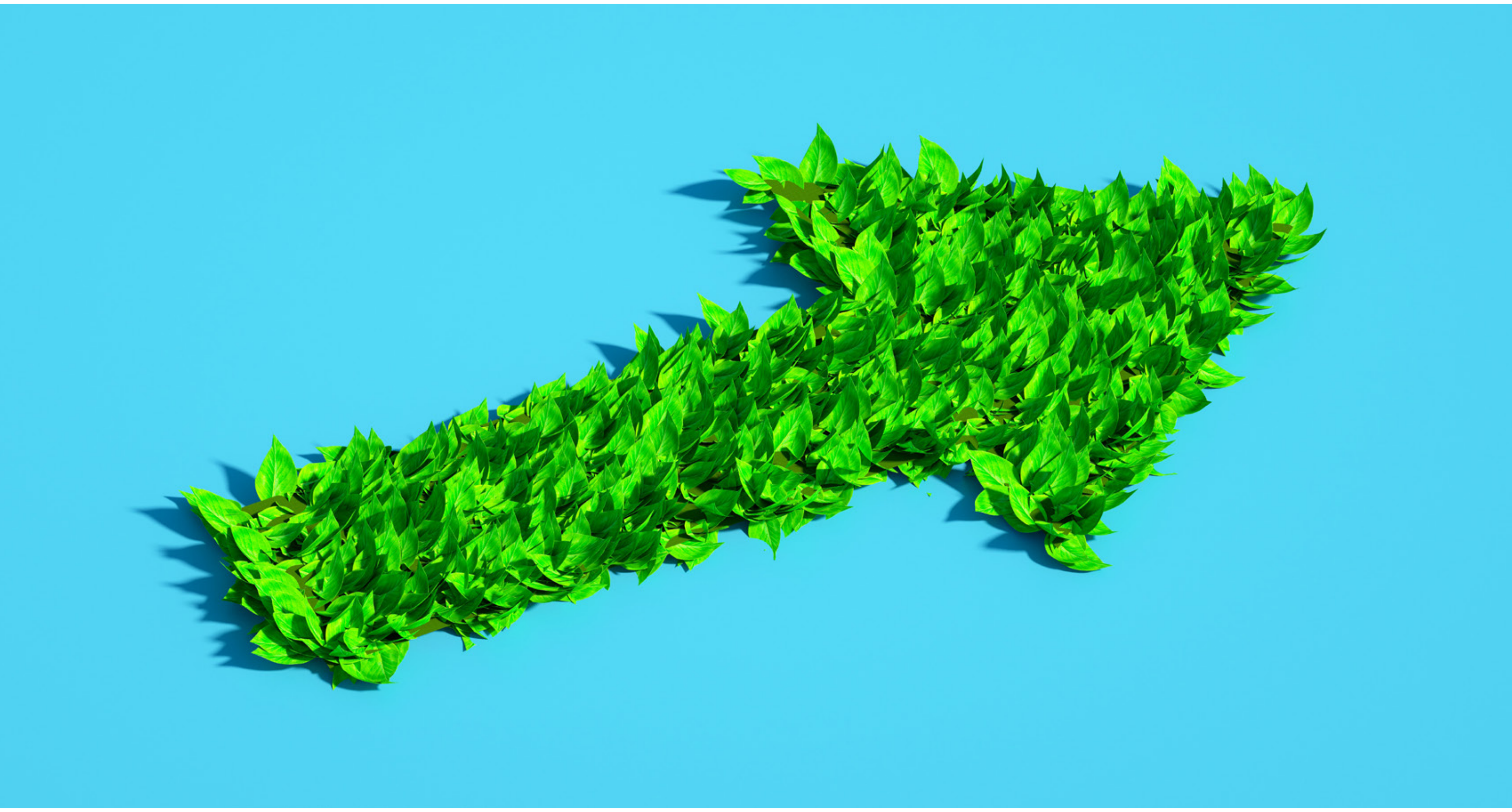
# Decarbonize and create value: How incumbents can tackle the steep challenge

While the task is not easy, incumbents—including those in hard-to-abate sectors—can decarbonize and generate value through a series of key actions.

*This article is a collaborative effort by Peter Crispeels, Dieuwert Inia, Henry Legge, Tomas Nauclér, and Philipp Radtke, representing views from McKinsey's Sustainability, Global Energy & Materials, and Advanced Industries practices.*



**The net-zero transition** could lead to the largest transformation of the industrial sector since the beginning of the Industrial Revolution. To reach net zero by 2050, about $275 trillion in cumulative spending on low-emissions assets will be required over the next 30 years—or approximately 7.5 percent of global GDP every year for 30 years.[1] Decarbonizing operations and product offerings presents many companies with the most significant opportunity in a generation: a potential $9 trillion to $12 trillion in annual sales by 2030 as capital and customer demand shift toward a low-carbon economy. On the flip side, failure to decarbonize could, on average, risk up to 20 percent in economic profit for companies by 2030, based on factors including stranded assets, increasing cost of capital, and loss of market share.[2]

In any case, decarbonization is a difficult transformation for most companies. The costs for scaling climate technologies and building new capabilities can be high. Access to financing can be challenging for businesses entering nascent, untested markets. Timelines for decarbonization can conflict with performance objectives and often stretch beyond the expected tenure of the current company executives. Meanwhile, entire supply chains are still being rewired from fossil fuel–based energy and feedstock to renewable sources, which could lead to major shifts in energy costs and the viability of current assets. In the current moment, leaders are also navigating the added complexity of inflation, disruptions to energy markets, supply shortages, and increased interest rates. To survive—and, ideally, create value—companies will need to think through their decarbonization strategy, keep up with a shifting landscape of market opportunities and policy (from subsidies and regulatory schemes to the organization's geographical footprint), and make swift decisions.

In some markets, start-ups have become early leaders in decarbonization (renewable energy, electric vehicles, and steel, for example). Start-ups often have a higher tolerance for risk-taking and the ability to operate at faster speeds with agility. But a set of incumbents has emerged as market leaders, too. These incumbents, including many in hard-to-abate sectors (such as chemicals and steel), have leveraged a few of their advantages, including long-term customer relationships and access to capital, talent, industry insights, and supplier networks. These established players, from industrial companies to logistics and consumer goods organizations, have been willing to take bold action and play offense to get ahead of their competitors.

How can more incumbents decarbonize *and* create value? Based on our experience, companies that are a step ahead in their decarbonization transformation tend to take action in three key areas. In this article, we explore the three key areas, a new tool that can help leaders build the business case for net-zero offerings, and reasons to move quickly.

## Decarbonize and create value: Three moves for incumbents

In our experience, incumbents that have created value through decarbonization have focused on three key areas of action:

— *Decarbonize and improve cost competitiveness.* Companies that reduce costs and emissions simultaneously can gain market share and finance further decarbonization efforts through the additional cash generated. Leading companies typically go after the first 20 to 40 percent of decarbonization while also reducing costs, leading to an improvement in EBITDA.[3]

— *Launch net-zero offerings.* Companies that are quick to offer zero-carbon offerings can leverage inherent supply–demand gaps in nascent markets and create value through value-based pricing strategies and price premiums.

— *Enter new value pools.* Companies that build new businesses along the current value

[1] "The economic transformation: What would change in the net-zero transition," McKinsey, January 25, 2022.
[2] "Playing offense to create value in the net-zero transition," *McKinsey Quarterly*, April 13, 2022.
[3] Based on net present value.

— chain—and tap adjacent value pools—have an opportunity to secure early demand for net-zero offerings and benefit from low-cost financing.

**Decarbonize and improve cost competitiveness**
In the past two to three years, we've seen an increasing number of companies set ambitious decarbonization commitments. To date, more than 6,000 companies have signed up through the Science Based Targets initiative to achieve an average reduction of 49 percent in Scope 1 and 2 emissions and 28 percent in Scope 3 emissions by 2030.[4] Now companies face the steep challenge of making the reductions a reality.

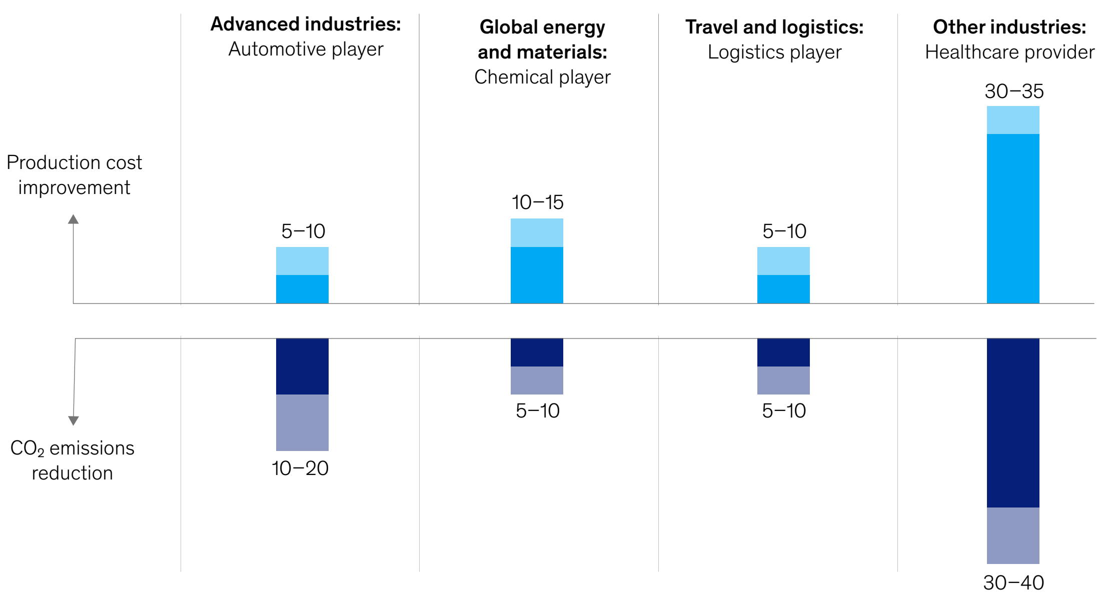
Many organizations have begun their decarbonization journey by looking to cut emissions from operations. Traditionally, some leaders have assumed there is a financial trade-off for reducing emissions in operations, and for good reason: decarbonizing operations can be complex and capital intensive. We've also seen companies try to decarbonize operations through a stand-alone program that isn't fully integrated with the core business, which can limit both the potential for emissions reductions and a healthy balance sheet.

Now, however, we see leading organizations integrate cost and carbon reductions simultaneously. Our analysis shows that companies are already seeing results: up to 40 percent reductions in emissions and up to a 15 percent improvement in financial performance (Exhibit 1). By 2030, incumbents can, on average, abate 20 to 40 percent of emissions while also reducing their production costs (Exhibit 2). A reduction

Exhibit 1

## Companies across industries can reduce carbon emissions and improve financial performance at the same time.

**Illustrative financial improvement and $CO_2$ reduction,** %

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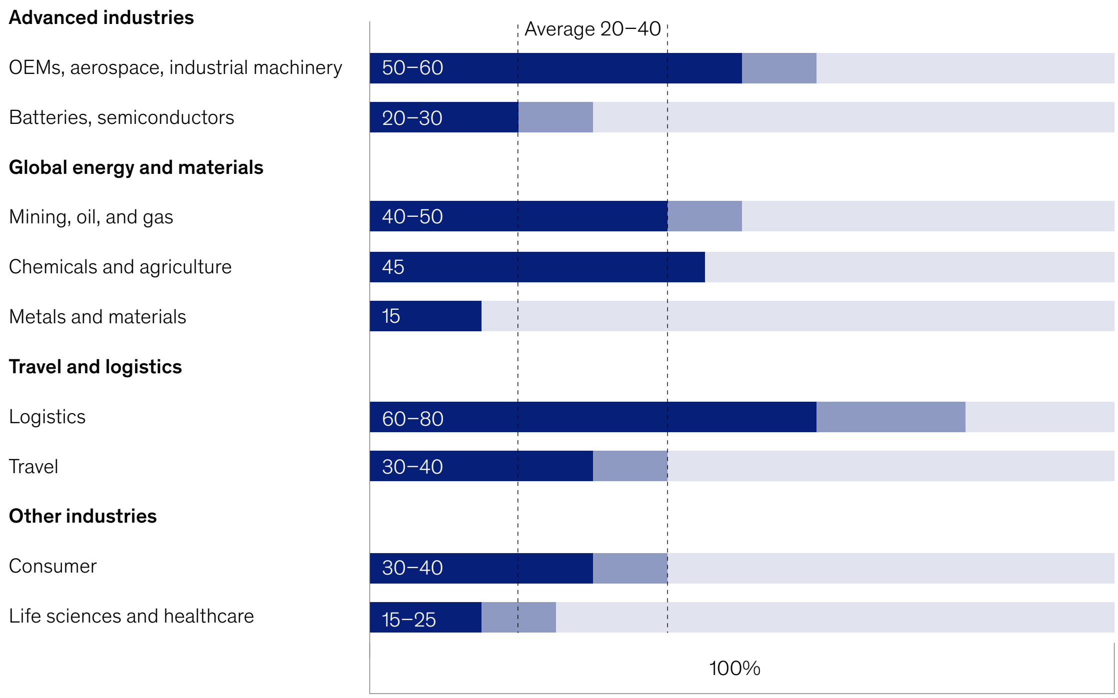
[4] Scope 1 emissions are direct emissions that occur from sources that are controlled or owned by an organization; Scope 2 emissions are indirect emissions associated with purchased energy; and Scope 3 emissions are indirect emissions resulting from activities along an organization's value chain. Science Based Targets initiative dashboard, accessed September 26, 2023; US Environmental Protection Agency.

Exhibit 2

## Incumbent companies can, on average, abate 20 to 40 percent of carbon emissions by 2030 while also reducing costs.

**Cost-effective emission abatement by 2030, by sector,[1] %**




[1]Includes Scope 1, 2, and 3 emissions. Based on net present value.
Source: McKinsey Catalyst Zero

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in production costs could be driven by energy efficiency, sourcing green energy, and variable cost reduction (yield and throughput increase, for example) of the manufacturing footprint. The potential for dual cost and carbon savings varies by industry. However, in some sectors, we see the potential to reduce emissions by as much as 60 to 80 percent while still having a favorable business case based on net present value. Reducing costs and carbon simultaneously can also free up cash to invest in new business opportunities that emerge from the ongoing net-zero transition.

Integrating cost and carbon reductions can also help companies gain market share. As both the public and private sectors increasingly set demands on sustainability, organizations that are ahead on decarbonization could be positioned to earn early contracts in growing markets and generate revenue faster than competitors. This advantage for early movers will likely fade as competitors catch up. However, as more market players decarbonize, global emissions should go down—a societal benefit—and end customers should experience more competitive pricing.

The dual task of cutting costs and carbon emissions is not easy. Decarbonizing operations often requires a transformation of processes and capabilities. There needs to be clear buy-in and accountability from leadership, as well as the ability for leaders to continuously reevaluate the decarbonization strategy as input costs change (energy prices, for example) and new technologies become commercially available. However, many incumbents—including those in harder-to-abate sectors—have advantages, such as the ability to engineer large-scale production processes, technological know-how, and investment flexibility. In our experience, companies successfully integrate cost and carbon reductions through a few approaches, from assessing carbon emissions on a granular level to embedding decarbonization in all processes:

— *Make fact-based decisions through full carbon transparency on an asset and product level.* Leading companies look for carbon and cost reductions on a granular level, down to all assets and product offerings, and operate with full carbon transparency for stakeholders and customers. For example, a leading chemicals player calculates detailed product carbon footprints for approximately 45,000 products, which enables the company to create viable decarbonization pathways and offer their customers a better understanding of a product's carbon footprint. Based on our analysis, such a granular approach can save companies an additional 10 to 20 percent in costs on average.[5]

— *Focus on capturing the first 20 to 40 percent of emissions.* We are seeing companies integrate cost and carbon reductions in several ways, from improving energy efficiency to reducing waste to designing products more efficiently.[6] However, companies often struggle to understand which measures will yield the most savings and how to focus engineering resources and financing. In our experience, leading companies focus on capturing an initial 20 to 40 percent of emissions while also reducing costs.

— *Embed decarbonization in all processes.* Eventually, decarbonization should be embedded in all critical processes. Incumbents will have different areas of focus, based on their sector and where they are in the value chain. Metals, chemicals, and mining companies might focus on plant design and related capital expenditures, whereas technology and component companies might emphasize product design and embedded emissions. For example, a large industrial-equipment manufacturer has set various decarbonization KPIs across all areas of the organization, from embedded emissions in procurement to share of recycled material in product design. Moving quickly to embed decarbonization objectives in all processes, in some cases, can help companies achieve cost efficiency faster and give the organization a head start on building new capabilities.

— *Stay agile in decision making and capital reallocation.* By 2050, about 90 percent of total global emissions can be reduced with existing climate technologies—however, many of these technologies are not currently cost competitive, and only 10 to 15 percent are considered commercially mature.[7] As markets evolve and new climate technologies become commercialized, leaders should remain flexible in their decarbonization plans and capital allocation, with an eye toward cost savings and value creation.

— *Use supply chain partnerships to accelerate the next wave of emissions reductions.* Companies can also build long-term strategic partnerships with technology providers to help them grow and capture economies of scale, which can, over time, lead to cost reductions on emerging climate technologies for the buyers. For example, electrolyzers, which are key to producing clean hydrogen, are increasingly in demand. Proactive companies are partnering

[5] Based on net present value.
[6] For more, see Laura Corb, Anna Granskog, Tomas Nauclér, and Daniel Pacthod, "Full throttle on net zero: Creating value in the face of uncertainty," McKinsey, September 20, 2023; and Peter Crispeels, Mikael Robertson, Ken Somers, and Eric Wiebes, "Outsprinting the energy crisis," McKinsey, April 21, 2022.
[7] International Energy Agency; McKinsey Sustainability Insights.

with electrolyzer providers to secure long-term supply at competitive prices.

### Launch net-zero offerings

Demand for net-zero offerings is surging—so much so that there could be shortages in certain sectors. According to our analysis, in steel, cement, and chemicals, for example, there could be up to a 60 percent supply–demand gap in 2030 for net-zero products. While such shortages could temporarily slow the net-zero transition, there is an opportunity for fast-moving players to capture the value of full decarbonization through value-based pricing strategies (moving away from a "cost plus" approach to one that factors in the value of decarbonization, for example) or earning a price premium on green goods and services. In some sectors, we're already seeing green premiums of 15 to 30 percent. In many markets, particularly in Europe, the ability to sell excess carbon allowances further strengthens the business case for green offerings. According to our analysis of green steel, for instance, producers in Europe that combine a green premium with the sale of excess carbon allowances could earn a 30 percent return on capital employed by 2035. Similar opportunities exist for many other products and services.

Another way to build the business case for net-zero offerings could be to use a marginal abatement revenue and cost curve (MARCC) on a product level. A MARCC, a new concept we have developed, shifts the discussion of offering net-zero goods and services from *only* cost to the total value of the opportunity. To create a MARCC, we start with the cost to decarbonize a product and then add the green premiums that we anticipate the net-zero version of the product can earn. Looking at just the costs of net-zero products, for example, shows that, on average, net-zero products incur an overall cost that is 10 to 30 percent higher than their more carbon-intensive counterparts.[8] These figures suggest that creating net-zero offerings would erode margins and destroy value for companies. However, a cross-sector MARCC for net-zero offerings, which captures the potential revenue upside of green premiums, reveals that incumbents can reduce emissions by up to 80 percent and create value (Exhibit 3).

Launching net-zero offerings successfully is not a given. A thorough market analysis and strategy is needed to identify the markets where net-zero products could generate green premiums, particularly if leaders set ambitious carbon abatement goals or foresee large capital expenditures. Companies often need to move quickly in markets where there are supply shortages, creating new markets and product categories, and working with partners across the value chain to maximize carbon reductions. However, incumbents that have existing production models, familiarity with a customer base, and experience with supply chains should have a leg up. The following are specific actions companies can take to help ensure a successful product launch:

— *Identify high-potential net-zero markets.* Leading companies start with a key question: What net-zero offerings can we provide in markets where there will be structural supply shortages for the foreseeable future?

— *Create new markets and rethink pricing strategies.* Many players who have successfully launched net-zero products have created and shaped new markets. They have achieved this in part through CEO-to-CEO sales (versus selling through the procurement organization). In these CEO-level conversations, leaders can secure early production offtakes and earn a price premium. For example, leadership at SSAB, which is developing fossil fuel–free steel made with hydrogen, has partnered with automotive incumbents to gain early sales. Companies that have identified new opportunities for greener products, like SSAB, have been able to capture a 20 to 30 percent premium.

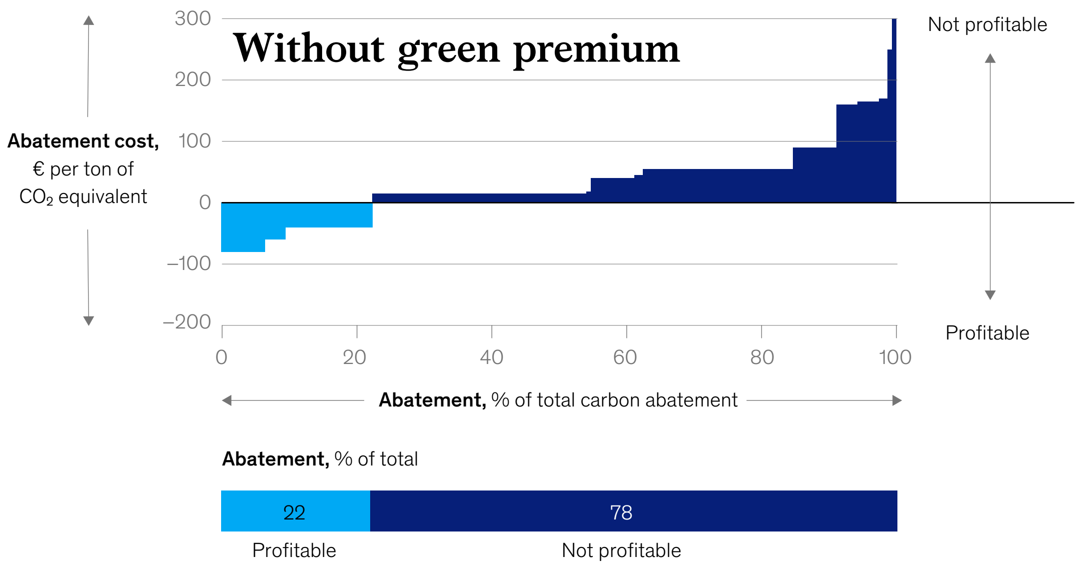
— *Secure green supplier partnerships for Scope 2 and 3 emissions.* Producing net-zero goods requires reducing emissions across the supply chain (Scope 2 and 3 emissions). Developing

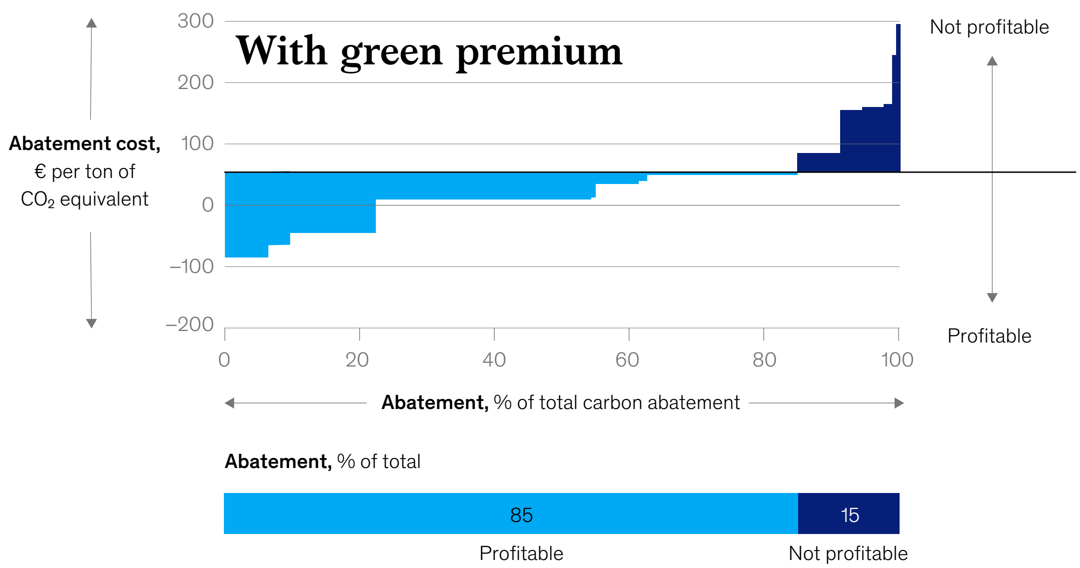
[8] *The net-zero transition: What it would cost, what it could bring*, McKinsey Global Institute, January 2022.

Exhibit 3

## Companies can build the business case for net-zero offerings by factoring a green premium into costs curves.

**Illustrative marginal abatement revenue and cost curve for net-zero offerings**

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long-term partnerships with suppliers to derisk procurement and substitute high-emissions inputs with low-emissions inputs is key, as well as ensuring carbon transparency across the value chain. For example, to decarbonize electricity at its plants and realize its goal of delivering net-zero products, chemical company BASF has worked with energy developers to support the construction of large offshore wind farms.

- *Tap financial partners and asset-level project financing.* To transform the core business around new net-zero offerings, many companies will need to build new plants and facilities. Creating this infrastructure could require billions of dollars in investment. Companies can rethink how they access funding. To finance the construction of its first plant project, H2 Green Steel has raised more than €1.8 billion in equity from a broad group of investors.[9] Energy company Ørsted has financed its transition to becoming the world's leading offshore-wind power producer through a strategy that includes operational cash flows, debt issuances, investment partners, and risk management.[10]

- *Finance new offerings by improving margins in the core.* New net-zero offerings can come with uncertainty in still-evolving markets. A stable and cash-generating core can help keep the business foundation stable while transitioning to the new offerings. To maximize this potential, companies can look to cut costs and improve margins in the core business.

- *Execute fast to capture premiums.* Green premiums won't be around forever. We anticipate that there will be shortages of green products in multiple industries through 2035 (for example, steel, copper, plastics, and cement). Getting ahead of value on the cost curve could set companies up for green premiums in the short term and robust market share going forward. We are already seeing green premium opportunities in steel and recycled plastics. For example, high-quality recycled plastics reached an average premium of up to 60 percent over virgin plastics.[11] One way to move quickly on new offerings is to do "parallel scaling"—that is, initiate additional growth waves before the first one is complete.[12]

**Enter new value pools**

The net-zero transition can generate vast business-building opportunities for organizations. Since 2015, six decacorns and 135 unicorns have been created within the sustainability space.[13] However, building green businesses isn't just a game for start-ups. As markets transition to green offerings, new value pools will emerge—in many cases, upstream or downstream of a company's current value chain position. There is an opportunity for incumbents to enter these new value pools, provided they move quickly and strategically.

Incumbents might not be naturals at building disruptive ventures. However, in recent years, we have seen incumbents flex a few advantages in building new green businesses, from securing strategic partnerships to attracting low-cost financing, while also embracing the speed and agility of a start-up.

That said, entering new value pools has challenges. It often requires, for example, a new set of capabilities and new types of risk management. Companies can consider a set of actions to mitigate risks while scaling new ventures:

- *Use the core business to secure captive demand.* A critical hurdle for new ventures is to find early-stage customers and partners to secure demand. Maersk, for example, has taken a few steps to create both supply and demand for green shipping fuels. The company has announced plans to invest in a green ammonia facility, along with ferry operator DFDS, and recently set up a green methanol company.[14] Such ventures support the company's

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9 "H2 Green Steel raises €1.5 billion in equity to build the world's first green steel plant," H2 Green Steel news release, September 7, 2023.
10 "Ørsted's renewable-energy transformation," McKinsey, July 10, 2020; "Funding strategy," Ørsted, accessed October 4, 2023.
11 Marcelo Azevedo, Anna Moore, Caroline Van den Heuvel, and Michel Van Hoey, "Capturing the green-premium value from sustainable materials," McKinsey, October 28, 2022.
12 For more, see Rob Bland, Anna Granskog, and Tomas Nauclér, "Accelerating toward net zero: The green business building opportunity," McKinsey, June 14, 2022.
13 McKinsey analysis of PitchBook and HolonIQ data.

# Making strategic moves now could be the difference between gaining market share and being stuck with higher costs for entry later on.

decarbonization ambitions and position the organization to gain market share in a nascent but growing market.

— *Secure low-cost financing based on secured demand.* Once captive demand is secured, established players can use their existing network and reputation to help their venture attract low-cost funding. For example, in 2017, Volvo Cars established Polestar as an independent electric-vehicle brand, leveraging its existing assets, capabilities, and customer and supplier relationships to swiftly develop a fully electric stand-alone brand. By utilizing platforms and technologies from Volvo Cars, Polestar was able to adopt an asset-light business model and efficiently create its first models. Volvo Cars' balance sheet, liquidity, and cash position can provide support to Polestar while simultaneously executing its own plans to transition into a fully electric-car company by 2030.

— *Run a stand-alone new business and recruit new talent.* Incumbents can consider providing assets, capabilities, and relationships to a new business. At the same time, incumbents should also consider keeping new ventures at arm's length operationally to establish a fast-paced, agile culture and operating model, while still enabling additional equity to be added by partners if needed. Additionally, companies can look to set up their ventures with new capabilities and talent to succeed, as new parts of the value chain might require new areas of expertise. These moves can help the new business scale faster and rapidly adapt to emerging opportunities.

## Now is the time to strike

Companies, for good reason, may hesitate to commit resources without complete clarity on their business case for decarbonization. However, our perspective is that now is the time to strike. Cost curves for green technologies are moving down across industries, and as we discussed earlier, some green premiums may have a shelf life. Making strategic moves now could be the difference between gaining market share and securing profitable growth, versus being stuck with stranded assets and higher costs for entry later on.

The three areas of action we have outlined are not a one-size-fits-all model, and implementing all three at once could indeed be a steep task. Leaders can prioritize based on factors including sector supply–demand dynamics, value chain opportunities, cost analysis, commercially available climate technologies, and evolving policy.

To decarbonize operations, leaders can swiftly act on the most cost-efficient moves that still help achieve decarbonization targets. As we noted earlier, launching net-zero products and services ahead of the competition has the potential to earn green premiums, a source of capital for scaling. When to enter a new value pool may depend on the pace of technological advancement, as well as regulatory changes. While it is impossible to predict

[14] "Maersk backs plan to build Europe's largest green ammonia facility," Maersk press release, February 23, 2021; Johannes Birkebaek and Jacob Gronholt-pedersen, "Shipping group Maersk sets up green methanol company," Reuters, September 14, 2023.

such developments, companies would be wise to anticipate change in these areas and be prepared to jump on opportunities—before the competitive landscape gets crowded. For example, last year's Inflation Reduction Act in the United States, which allocates about $370 billion for climate and energy spending, and multiple policy packages under the umbrella of the European Green Deal, could accelerate pockets of the net-zero economy and facilitate access to funding.

The net-zero transition presents challenges for incumbents, particularly those in hard-to-abate sectors. At the same time, established companies have a unique opportunity to decarbonize and create value. While there is no one universal approach, making timely moves across three key action areas could help companies create a competitive advantage in the years to come.

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# Renewables

# Enabling renewable energy with battery energy storage systems

The market for battery energy storage systems is growing rapidly. Here are the key questions for those who want to lead the way.

*This article is a collaborative effort by Gabriella Jarbratt, Sören Jautelat, Martin Linder, Erik Sparre, Alexandre van de Rijt, and Quan Han Wong, representing views from McKinsey's Industrials & Electronics Practice and McKinsey's Battery Accelerator Team.*


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**With the next phase** of Paris Agreement goals rapidly approaching, governments and organizations everywhere are looking to increase the adoption of renewable-energy sources. Some of the regions with the heaviest use of energy have extra incentives for pursuing alternatives to traditional energy. In Europe, the incentive stems from an energy crisis. In the United States, it comes courtesy of the Inflation Reduction Act, a 2022 law that allocates $370 billion to clean-energy investments.

These developments are propelling the market for battery energy storage systems (BESS). Battery storage is an essential enabler of renewable-energy generation, helping alternatives make a steady contribution to the world's energy needs despite the inherently intermittent character of the underlying sources. The flexibility BESS provides will make it integral to applications such as peak shaving, self-consumption optimization, and backup power in the event of outages. Those applications are starting to become more profitable as battery prices fall.

All of this has created a significant opportunity. More than $5 billion was invested in BESS in 2022, according to our analysis—almost a threefold increase from the previous year. We expect the global BESS market to reach between $120 billion and $150 billion by 2030, more than double its size today. But it's still a fragmented market, with many providers wondering where and how to compete. Now is the time to figure out where the best opportunities will be in the rapidly accelerating BESS market and to start preparing for them.

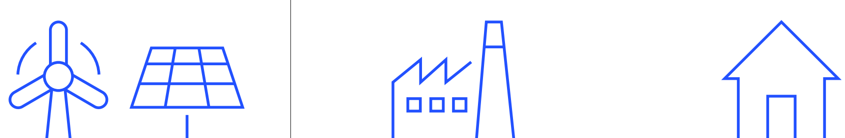
Here are some questions—and answers—to help BESS players formulate their strategies.

## What are the main opportunities?

The best way to get a sense of the opportunities associated with BESS is to segment the market by the applications and sizes of users. There are three segments in BESS: front-of-the-meter (FTM) utility-scale installations, which are typically larger than ten megawatt-hours (MWh); behind-the-meter (BTM) commercial and industrial installations, which typically range from 30 kilowatt-hours (kWh) to ten MWh; and BTM residential installations, which are usually less than 30 kWh (Exhibit 1).

Exhibit 1

**Battery energy storage systems are used across the entire energy landscape.**



| | **Front of the meter (FTM)** | **Behind the meter (BTM)** | |
|---|---|---|---|
| | **Electricity generation and distribution** | **Commercial and industrial (C&I)** | **Residential** |
| **Use cases** | • Price arbitrage<br>• Long-term capacity payments<br>• Ancillary service markets<br>• Derisking renewable generation<br>• Investment deferral | • Renewable integration (rooftop photovoltaic)<br>• Uninterruptable power supply (UPS)<br>• Power cost optimization<br>• Electric-vehicle (EV) charging infrastructure | Home integration of:<br>• Renewable integration (rooftop photovoltaic)<br>• EV charging infrastructure |

Source: McKinsey Energy Storage Insights

McKinsey & Company

We expect utility-scale BESS, which already accounts for the bulk of new annual capacity, to grow around 29 percent per year for the rest of this decade—the fastest of the three segments. The 450 to 620 gigawatt-hours (GWh) in annual utility-scale installations forecast for 2030 would give utility-scale BESS a share of up to 90 percent of the total market in that year (Exhibit 2).

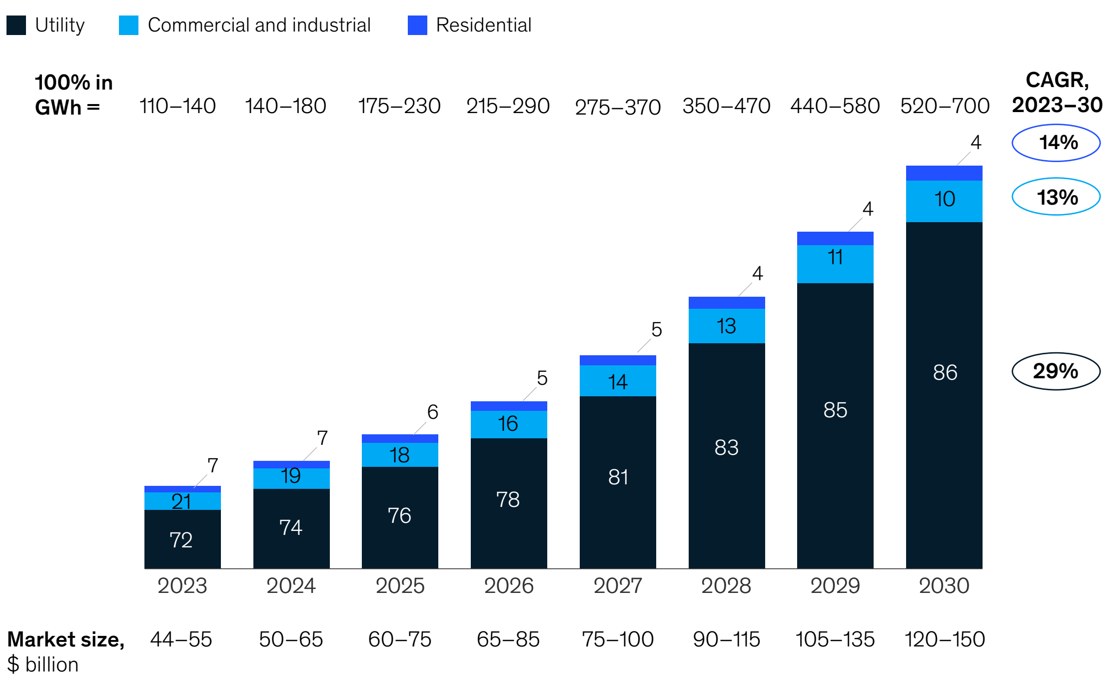
Customers of FTM installations are primarily utilities, grid operators, and renewable developers looking to balance the intermittency of renewables, provide grid stability services, or defer costly investments to their grid. The BESS providers in this segment generally are vertically integrated battery producers or large system integrators. They will differentiate themselves on the basis of cost and scale, reliability, project management track record, and ability to develop energy management systems and software solutions for grid optimization and trading.

BESS deployments are already happening on a very large scale. One US energy company is working on a BESS project that could eventually have a capacity of six GWh. Another US company, with business interests inside and outside of energy, has already surpassed that, having reached 6.5 GWh in BESS deployments in 2022. Much of the money pouring into BESS now is going toward services that increase energy providers' flexibility—for instance, through firm frequency response. In the long run, BESS growth will stem more from the build-out of solar parks and wind farms, which will need batteries to handle their short-duration storage needs.

Exhibit 2

## Battery energy storage system capacity is likely to quintuple between now and 2030.

**Annual added battery energy storage system (BESS) capacity,** %




Note: Figures may not sum to 100%, because of rounding.
Source: McKinsey Energy Storage Insights BESS market model

McKinsey & Company

Revenue models for FTM utility-scale BESS depend heavily on the dynamics of the regions that providers are entering. Most utility-scale BESS players pursue a strategy of revenue stacking, or assembling revenues from a variety of sources. They might participate in ancillary services, arbitrage, and capacity auctions. For instance, many BESS installations in the United Kingdom currently revolve around ancillary services such as frequency control. Italy has BESS players that have broken through by winning one of the country's renewables-focused capacity auctions. The opportunities in Germany revolve more around avoiding costly grid upgrades. The BESS players that have gotten traction in the FTM utility segment have understood the value of responding individually to countries and their regulations versus using one monolithic strategy.

## Where is the value in the commercial and industrial segment?

Commercial and industrial (C&I) is the second-largest segment, and the 13 percent CAGR we forecast for it should allow C&I to reach between 52 and 70 GWh in annual additions by 2030.

C&I has four subsegments. The first is electric vehicle charging infrastructure (EVCI). EVs will jump from about 23 percent of all global vehicle sales in 2025 to 45 percent in 2030, according to the McKinsey Center for Future Mobility. This growth will require rapid expansion of regular charging stations and super chargers, putting pressure on the current grid infrastructure and necessitating costly, time-consuming upgrades. To avoid this, charging station companies and owners may opt to put a BESS on their properties. Partnerships have already formed between BESS players and EV producers to build more EVCI, including in remote locations.

The next subsegment of C&I is critical infrastructure such as telecommunication towers, data centers, and hospitals. In this subsegment, lead-acid batteries usually provide temporary backup through an uninterruptible power supply during outages until power resumes or diesel generators are turned on. In addition to replacing lead-acid batteries, lithium-ion BESS products can also be used to reduce reliance on less environmentally friendly diesel generators and can be integrated with renewable sources such as rooftop solar. In certain cases, excess energy stored on a battery may allow organizations to generate revenues through grid services. Several telecommunication players and data center owners are already switching to BESS as their uninterruptible power supply solution and for the additional benefits BESS provides.

The third subsegment is public infrastructure, commercial buildings, and factories. This subsegment will mostly use energy storage systems to help with peak shaving, integration with on-site renewables, self-consumption optimization, backup applications, and the provision of grid services. We believe BESS has the potential to reduce energy costs in these areas by up to 80 percent. The argument for BESS is especially strong in places such as Germany, North America, and the United Kingdom, where demand charges are often applied.

The final C&I subsegment consists of harsh environments—applications for mining, construction, oil and gas exploration, and events such as outdoor festivals. The source of the growth will be customers moving away from diesel or gas generators in favor of low-emission solutions such as BESS and hybrid generators. A main factor driving adoption in this segment is upcoming regulations (including the European Commission's sustainability-focused Big Buyers initiative and Oslo's plan for net zero on construction sites by 2025). Many of the companies that make the switch will start by converting to hybrid genset solutions rather than immediately moving completely to BESS.

## What about the BESS residential consumer play?

Residential installations—headed for about 20 GWh in 2030—represent the smallest BESS segment. But residential is an attractive segment given the opportunity for innovation and differentiation in areas ranging from traditional home storage to the creation of microgrids in remote communities. From a sales perspective, BESS can be bundled with photovoltaic panels or integrated into smart homes or home EV charging systems. Tailored products will help residential customers achieve goals such as self-sufficiency, optimized self-consumption, and lower peak power consumption—and they may mean higher margins in this sector. Our recent consumer survey on alternative energy purchases suggests that interest in a BESS product will come down to a few factors, starting with price, safety, and ease of installation (Exhibit 3).

## How might we think about our strategic positioning?

In a new market like this, it's important to have a sense of the potential revenues and margins associated with the different products and services. The BESS value chain starts with manufacturers of storage components, including battery cells and packs, and of the inverters, housing, and other essential components in the balance of system. By our estimate, the providers in this part of the chain will receive roughly half of the BESS market profit pool.

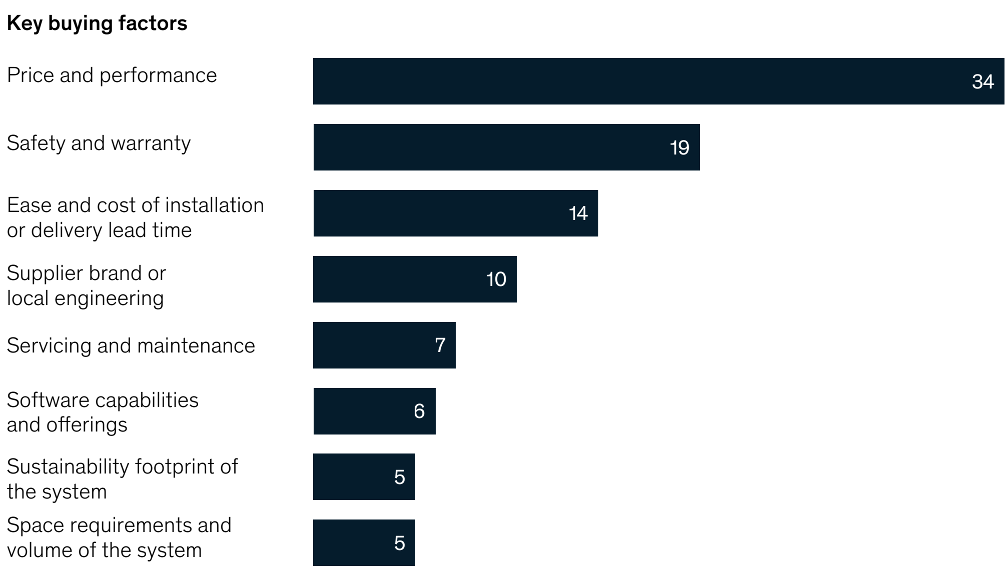
Then there are the system integration activities, including the overall design and development of energy management systems and other software to make BESS more flexible and useful. We expect these integrators to get another 25 to 30 percent of the available profit pool.

Finally, between 10 and 20 percent of the profit pool is associated with sales entities, project development organizations, other customer acquisition activities, and commissioning (Exhibit 4).

Exhibit 3

**Price, performance, safety, and good warranties top the list of what home buyers seek in a battery energy storage system.**

**2023 BESS[1] Germany Customer Survey, perceived as most important,** % of respondents




[1]Battery energy storage system.
Source: McKinsey BESS Customer Survey, 2023, German market (n = 300)

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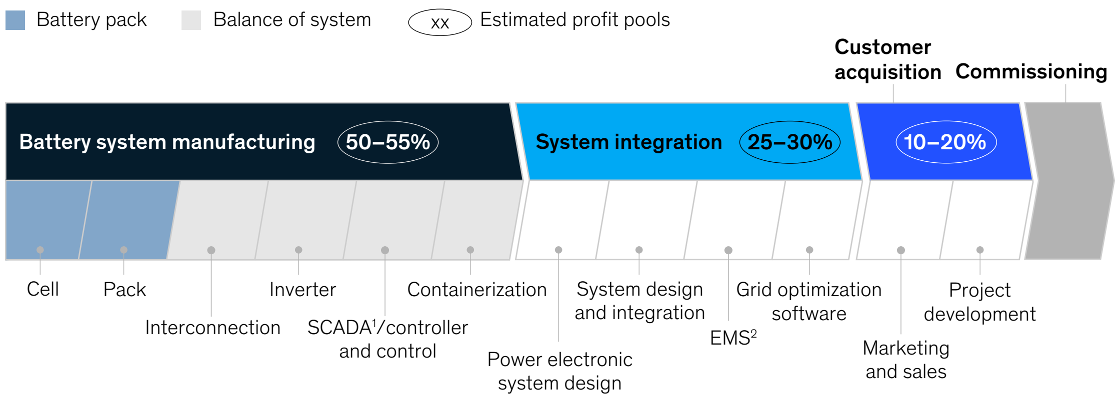
Exhibit 4

## The battery energy storage system value chain includes manufacturing, system integration, and customer acquisition.

**Value chain breakdown of battery energy storage systems** (hardware only)




[1]Supervisory control and data acquisition.
[2]Energy management system.
Source: GTM Research; McKinsey Energy Storage Insights BESS market model

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## What's going on in the area of battery technology that we need to know about?

From a technology perspective, the main battery metrics that customers care about are cycle life and affordability. Lithium-ion batteries are currently dominant because they meet customers' needs. Nickel manganese cobalt cathode used to be the primary battery chemistry, but lithium iron phosphate (LFP) has overtaken it as a cheaper option. (Lithium iron phosphate customers appear willing to accept the fact that LFP isn't as strong as a nickel battery in certain areas, such as energy density.) However, lithium is scarce, which has opened the door to a number of other interesting and promising battery technologies, especially cell-based options such as sodium-ion (Na-ion), sodium-sulfur (Na-S), metal-air, and flow batteries.

Sodium-ion is one technology to watch. To be sure, sodium-ion batteries are still behind lithium-ion batteries in some important respects. Sodium-ion batteries have lower cycle life (2,000–4,000 versus 4,000–8,000 for lithium) and lower energy density (120–160 watt-hours per kilogram versus 170–190 watt-hours per kilogram for LFP). However, sodium-ion has the potential to be less costly—up to 20 percent cheaper than LFP, according to our analysis—and the technology continues to improve, especially as manufacturing reaches scale. Another advantage is safety: sodium batteries are less prone to thermal runaway. There's also a sustainability case for sodium-ion batteries, because the environmental impact of mining lithium is high.

All of this makes it likely that sodium-ion batteries will capture an increasing share of the BESS market. Indeed, at least 6 manufacturers are expected to launch production of sodium-ion batteries in 2023. Clearly, providers will have to make decisions about which technology to bet on. Integrators may want to set up their systems so

# From a technology perspective, the main battery metrics that customers care about are cycle life and affordability.

that their transition to sodium-ion batteries is straightforward as the batteries become widely available.

## Is there a recipe for success in the BESS market? If so, what is it?

This is a critical question given the many customer segments that are available, the different business models that exist, and the impending technology shifts. Here are four actions that may contribute to success in the market:

— *Identify an underserved need in the value chain.* In a nascent industry such as this, it pays for companies to think about other products and services that they could get into, whether through organic moves or inorganic ones. For instance, is there anything to stop a system integrator from doing battery packaging in-house? Or from codeveloping a new cell chemistry with a battery manufacturer? For that matter, is there anything to keep a battery manufacturer from adding system-integration or service capabilities to appeal to a specific BESS segment, such as utilities?

  Software is a particularly critical area to explore. The value of storage systems will likely evolve from just hardware into the software that controls and enhances the system, unlocking the opportunity to capture larger customer segments and higher margins. BESS players need to develop these capabilities early.

— *Build resilience in supply chains.* Many critical BESS components (ranging from battery cells to semiconductors in inverters and control systems) rely on complex supply chains, which are susceptible to supply shocks from a multitude of sources, including raw material shortages and regulation changes. Strategic partnerships, multi-sourcing, and local sourcing are all levers to consider when defining a supply chain strategy, while not forgetting to plan for potential technology shifts. In addition to BESS components, another bottleneck for those in the market is engineering, procurement, and construction (EPC) capability and capacity, particularly for front-of-the-meter applications. Strategic partnerships with large EPC players ready for large-scale BESS installations are crucial to ensure successful execution of BESS projects.

— *Focus on the product features that matter most.* Product specifications should reflect what customers care about. Having a customer segment strategy that informs the road map will increase the odds that every feature matters to customers. Such an approach is especially important given that price competition is likely to remain a permanent reality in the BESS market. The right product road map will also increase the odds of having a unique selling proposition in any segment a company happens to be in. For example, making the right decision on system architecture and integrating with existing customer infrastructure (say, by coupling direct current with photovoltaic technology) could reduce the barriers to entry for many customers.

— *Think big and move fast.* With BESS in the spotlight and revenues starting to increase rapidly, now is not a time to play it safe. While it's true that the market is highly fragmented, it's also true that some bigger players are starting to amass market share. This raises the stakes for all companies, especially for small ones that may have started a decade ago as research projects and now find themselves sitting on top of valuable intellectual property. These companies will likely need to take some risks to have a chance of gaining share and avoid being muscled out by bigger companies.

The BESS market is in an explosive stage of development; players that don't move now will miss out. The winners in the market will be the companies that exhibit the four things required for success. These winners will create value in a new market as the energy transition accelerates.

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# Build together: Rethinking solar project delivery

Limited engineering and construction capacity could challenge America's ability to quickly grow renewables. To win in an undersupplied market, renewables players can rethink project delivery.

*This article is a collaborative effort by Katy Bartlett, Avery Black, David Frankel, Kevin Kroll, James Lambrou, Kimika Padilla, Dave Sutton, and Humayun Tai, representing views from McKinsey's Electric Power & Natural Gas Practice.*

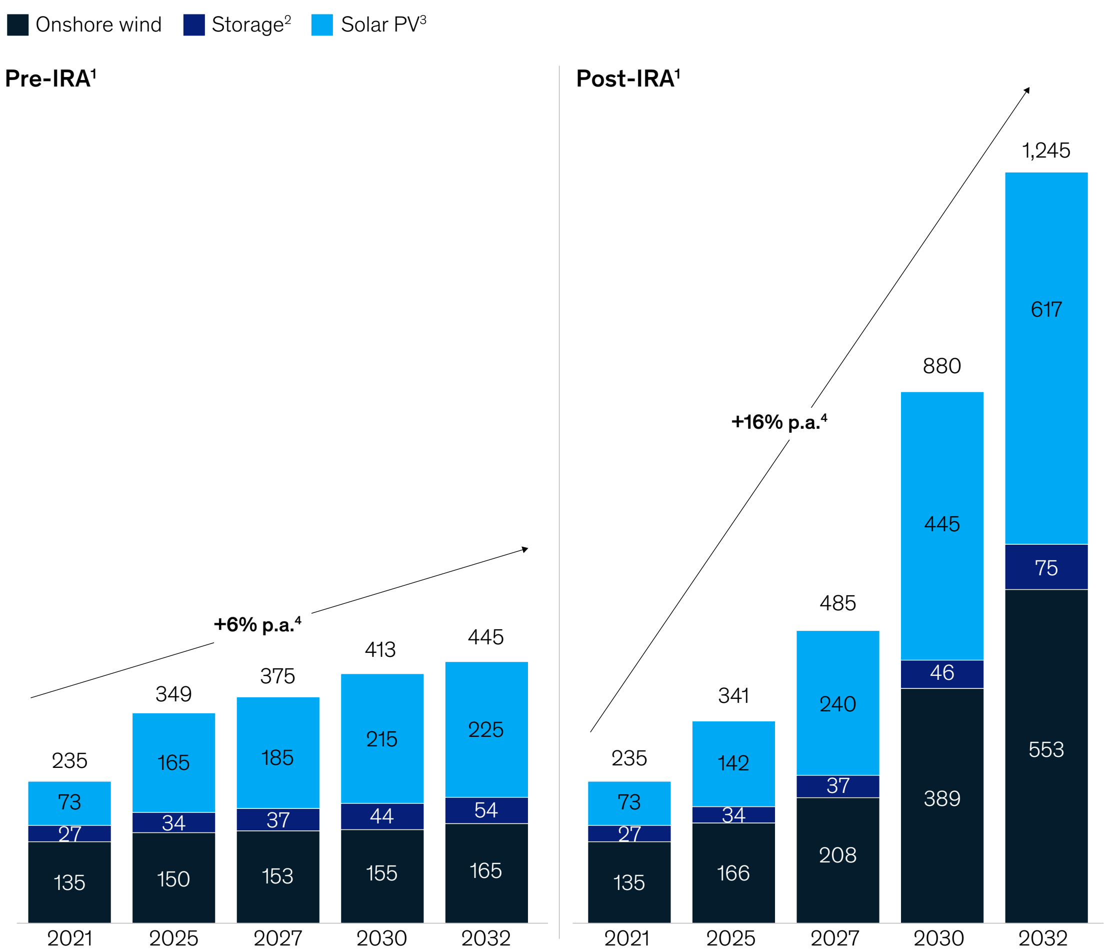
**The passage of** the Inflation Reduction Act (IRA) supports the growth of US renewables at an unprecedented pace. Solar, storage, and onshore wind capacity could reach more than 1,240 gigawatts (GW) over the next decade, growing 2.7 times faster than projected before the IRA took effect (Exhibit 1). The IRA is expected to stimulate domestic manufacturing of modules, subcomponents, inverters, trackers, and more, which could alleviate material shortages that had previously restricted project installation.

However, the solar industry faces significant construction and labor shortages that could worsen over the next three to five years. As solar projects grow in number and size, demand for engineering,

Exhibit 1

## The projected capacity of solar, storage, and onshore wind has almost tripled, thanks to the Inflation Reduction Act.

**Projections of US installed solar and wind capacity,** gigawatts




[1]Inflation Reduction Act.
[2]Includes lithium ion and existing hydro-pumped storage.
[3]Photovoltaics.
[4]Per annum.
Source: Inflation Reduction Act of 2022; McKinsey Power Solutions

McKinsey & Company

procurement, and construction companies (EPCs) and for the labor and materials required to build projects is expected to increase rapidly. Based on McKinsey analysis, EPC capacity to serve utility-scale solar projects would have to almost triple to meet the anticipated demand of approximately 50 GW installed in 2027.

These market dynamics produce strong incentives to rethink traditional industry practices and unlock more-efficient project delivery. The size of the prize for successful collaboration has never been bigger: US renewables could attract an estimated $700 to $800 billion in capital investments to build onshore wind and solar projects through 2030. To capture this value, solar project owners, developers, and EPCs should establish new approaches to partnerships, risk ownership and contracting, workforce development, and digital and technology adoption. The energy transition will depend on it.

## An undersupplied market persists as bottlenecks shift

To stimulate solar project development, the IRA extends old incentives and provides new ones. Chief among them are the revamped Investment Tax Credit (ITC), which offers a 30 percent tax credit on solar project capital cost, and the alternative Production Tax Credit (PTC), worth an estimated 2.75 cents per kilowatt-hour produced.[1] The IRA also created a new production tax credit that can be applied to domestically manufactured solar modules and subcomponents, including cells, wafers, polysilicon, and polymeric backsheets.[2]

However, despite these incentives, the solar industry still faces five critical challenges: EPC and labor shortages, limited access to land and permits, inflation and commodity price volatility, interconnection costs and timelines, and supply chain constraints. These are the main bottlenecks that make it difficult to deliver projects at a competitive cost and schedule, and they could potentially limit the rate at which the United States is able to grow its renewables to meet the economic incentives in the IRA.

— *EPC and labor shortages.* The IRA puts pressure on already constricted markets for EPCs and labor, which have not kept pace with rapid renewables growth. Moreover, demand for engineering and construction talent is growing in other industries, such as broadband, transportation, semiconductors, and public infrastructure, with support from federal legislation including the 2021 Bipartisan Infrastructure Law and the 2022 CHIPS and Science Act.[3] To expand capacity, solar EPCs must compete with higher-margin industries for engineering and construction talent. What's more, solar projects are often installed in rural areas where the overall labor pool is smaller to begin with, putting even more pressure on solar EPCs to ramp up their workforce development.

— *Limited access to land and permits.* Securing the land and approvals to install solar is a challenge for early-stage developers. A 100-megawatt (MW) solar project can require more than 500 acres of land, and interconnection and topographical constraints further limit the land available. Permitting is managed by local governments, producing a patchwork of different requirements and regulations that developers must navigate. In addition, permits can be difficult to obtain without community support.

— *Inflation and commodity price volatility.* Historically, solar module pricing has trended down as the technology has improved. However, the solar industry has not escaped recent inflationary pressures, and commodities such as steel, aluminum, and copper—which are used in modules, trackers, inverters, and bulk materials—have experienced record price volatility in the past 36 months. Going forward,

[1] Utility-scale projects can receive potential add-on tax credits for using domestic materials or for basing themselves in communities tied to traditional energy resources, such as former coal, oil, and natural-gas sites; see "Renewable electricity production credit amounts for calendar year 2022," Internal Revenue Service (IRS), November 10, 2022.
[2] "The Inflation Reduction Act," US Environmental Protection Agency, updated April 17, 2023.
[3] Garo Hovnanian, Adi Kumar, and Ryan Luby, "Will a labor crunch derail plans to upgrade US infrastructure?," McKinsey, October 17, 2022; "Semiconductor fabs: Construction challenges in the United States," McKinsey, January 27, 2023.

pricing trends could be more uncertain because of geopolitical dynamics, commodity price volatility, and the challenges of rebalancing supply and demand amid the diversification of solar panel manufacturing.

— *Interconnection costs and timelines.* Until an interconnection agreement is signed, grid connection can be one of the most uncertain costs for a renewables project. Additionally, in many regions, the interconnection process has become longer and more expensive. On average, US projects spend almost three years in interconnection queues, according to Lawrence Berkeley National Laboratory.[4] To reduce the number of speculative projects in queues, some independent system operators (ISOs) have implemented administrative fees that force developers to make larger bets on projects before reaching an interconnection agreement.

— *Supply chain constraints.* The IRA creates incentives for the US solar market to transition toward a more localized supply chain. US panel manufacturers could begin producing at scale within the next one to three years, relieving recent module availability challenges. However, the shortage of domestically manufactured wafers and solar cells is expected to persist, leaving panel manufacturers and their customers dependent on an international supply chain for these critical subcomponents. Other inputs, such as inverters, trackers, and racking, face an uncertain cost outlook, but significant shortages are not expected.

Many of these challenges have been ongoing, but a recent McKinsey survey suggests that they have shifted in order of priority.[5] Today, EPC and labor shortages are a top challenge for renewables players, overtaking other obstacles such as limited access to land and permits, inflation and commodity price volatility, and interconnection (Exhibit 2).

EPCs could remain in short supply for the next three to five years as the industry attempts to almost triple in size to build new utility-scale solar projects. This undersupplied market has given EPCs leverage to negotiate more favorable pricing and reduce their liability when materials or labor shortages cause schedule or cost overruns. At the same time, owners are struggling to secure EPC capacity and absorb risk from procurement uncertainty. Although some developers have established EPC partners, others—such as utilities that are just beginning to self-develop renewables—have arrived late to the matchmaking and need to catch up on solar-project-delivery capabilities. In this constricted environment,

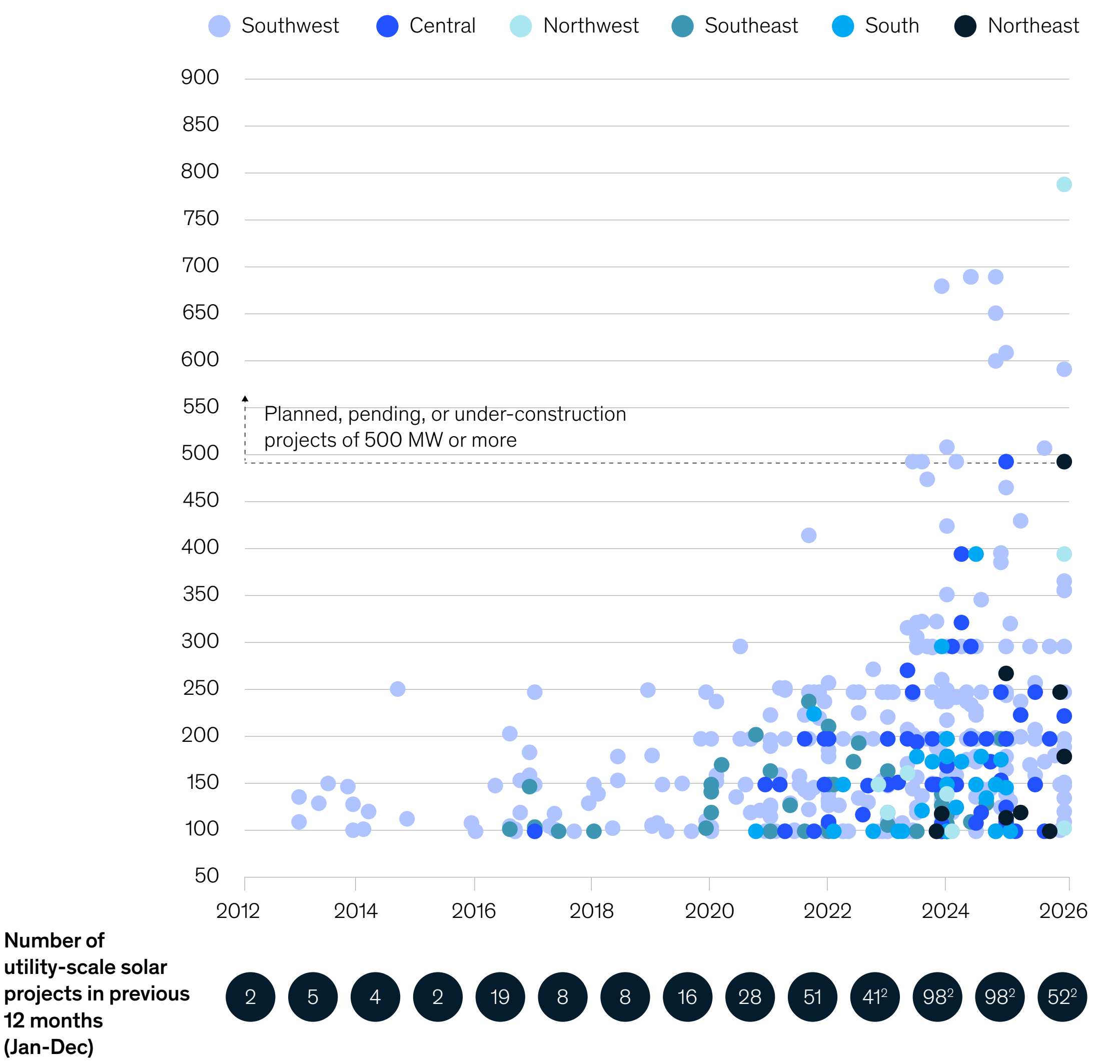
**Today, EPC and labor shortages are a top challenge for renewables players.**

[4] Will Gorman et al., “Queued up: Characteristics of power plants seeking transmission interconnection as of the end of 2021,” Lawrence Berkeley National Laboratory, April 2022.
[5] McKinsey Utility, Developer, and EPC Survey, December 2022.

Exhibit 2

## Utility-scale solar projects are expected to increase in number and size, driving high demand for qualified construction companies.

**US utility-scale solar projects of more than 100 MW,** by region[1]




[1]South = Alabama, Arkansas, Louisiana, Mississippi, Tennessee; Southwest = Arizona, California, Colorado, New Mexico, Nevada, Oklahoma, Texas, Utah; Northwest = Oregon, Washington, Idaho; Central = Iowa, Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Southeast = Florida, Georgia, North Carolina, South Carolina, Virginia; Northeast = Delaware, Maine, New Hampshire, New York, Pennsylvania.
[2]Pending, planned or under-construction projects include 242 projects: 45 pending regulatory approval, 69 planned for installation but without initiated regulatory approvals, 32 with regulatory approval received but not under construction, 6 with construction complete but not yet in commercial operation, and 90 under construction.
Source: EIA Monthly Electric Generator Inventory, March 2023

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project pipelines are at stake, along with a seat at the table amid growing demand for renewables. More than a dozen megaprojects of more than 500 MW each—enough to power the equivalent of more than 150,000 American homes—are already in the pipeline for 2023–26 (Exhibit 3).

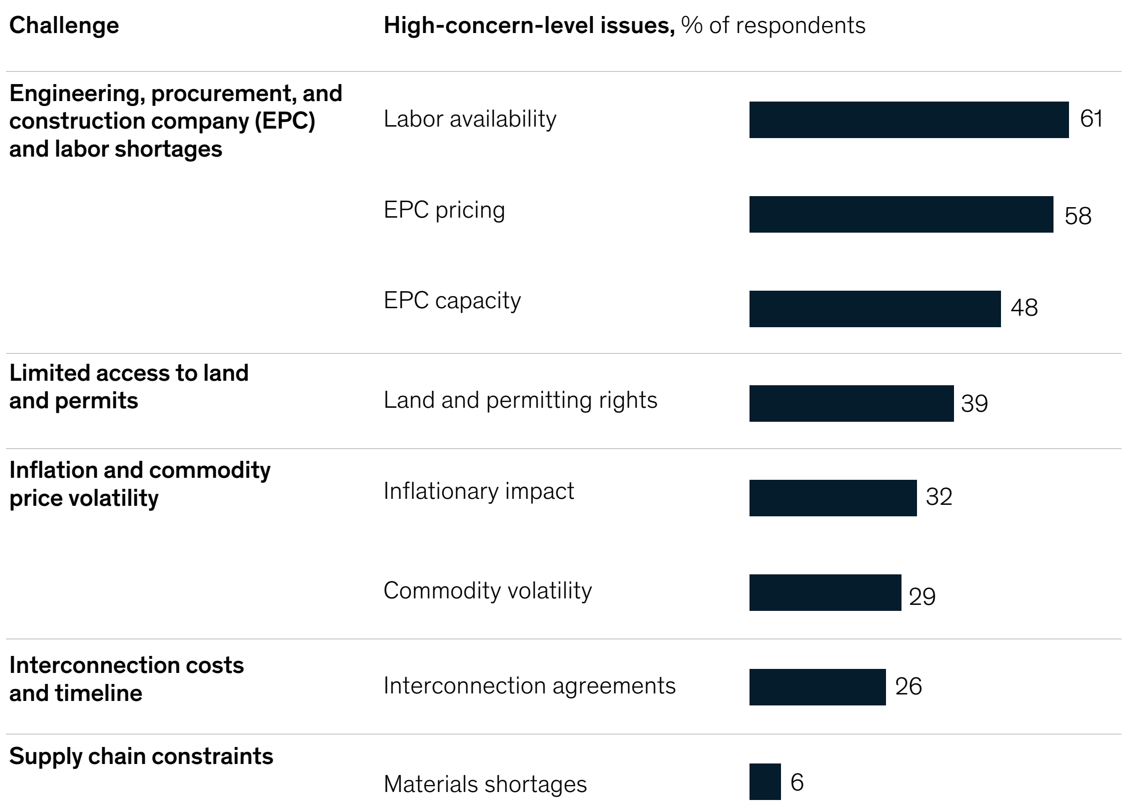
Capacity isn't the only challenge. Because solar construction is relatively simple, efficiency and consistency in installation are critical to preserving margins. There is already a significant performance gap, with smaller players' productivity lagging behind that of market leaders that have a dozen or more years of experience in the solar industry. And as project sizes grow, there is a shortage of EPCs that can achieve high productivity and deliver cost-efficient projects at greater scale.

## Rethinking solar project delivery

In the coming years, collaboration will be a major theme in renewables, achieved through new approaches to strategic partnerships, risk ownership and contracting, workforce development, and digital and technology adoption. Established

Exhibit 3

**Engineering, procurement, and construction company and labor shortages are a top challenge for developers and utilities.**




Note: High concern level = concern levels of 6–8, as rated by respondents.
Source: McKinsey Utility, Developer, and EPC Survey, Dec 2022, n = 42

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EPCs and developers can form tighter partnerships, such as by facilitating more integration between their respective engineering teams or promoting transparency on pricing and risk. And those without committed partners might entertain new options; for example, a utility developer might invest in building the capabilities of a regional contractor to install solar at scale.

Bold ambitions such as these could shift the market away from traditional contracting structures in which EPCs are treated purely as service providers that are compensated for delivering each project. Instead, owners and EPCs could pursue portfolio partnerships in which both sides have incentives to tackle supply chain and labor constraints together, unlocking additional value to be shared between them.

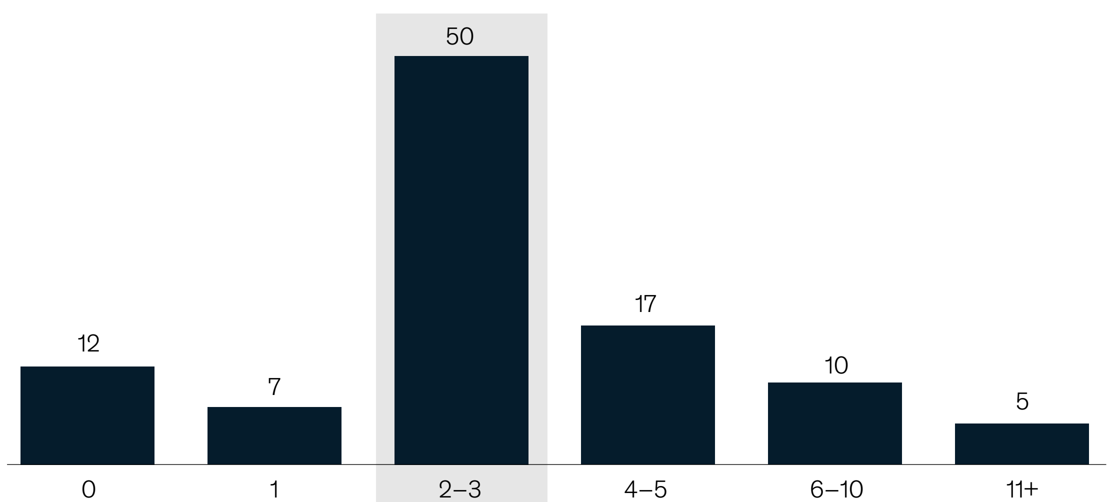
**Partnerships**

Partnerships have been a winning strategy in the solar industry for many years. Today, leading developers have locked in capacity with two or three core EPC partners on average, bringing benefits to both sides (Exhibit 4). The idea of a partnership extends beyond simply establishing a select set of EPCs that bid on or are awarded work on a project-by-project basis. They can range from nonbinding relationship-based commitments to formal master service agreements with bilateral contractual commitments. All partnership arrangements share common objectives, such as increased visibility and joint planning of project pipelines, early engineering involvement and continuous improvement of designs, and collaborative workforce attraction and development programs.

Exhibit 4

**Leading solar players have established an average of two to three partnerships each to achieve a broad array of benefits.**

**Number of partnerships per solar player,** % of companies




Source: McKinsey Utility, Developer, and EPC Survey, Dec 2022, n = 42

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Forming partnerships will continue to be a winning strategy in solar project delivery, but the landscape of partnerships is expected to change going forward. First, the industry could shift to include a broader set of stakeholders vying for committed partners. Second, new approaches to joint business growth and capability building could deepen partnerships and promote collaboration across larger and longer-term project portfolios.

*Expanding the industry.* Incumbents will expand their businesses to take advantage of IRA tailwinds, but rapid market growth also opens the door for other players to build a presence in renewables. For example, it has become potentially more attractive for regulated utilities to self-develop renewables, since they could not efficiently monetize the Solar Investment Tax Credit but can take full advantage of the alternative Solar Production Tax Credit created by the IRA. New types of EPCs could also enter renewables. A few large, diversified EPCs that serve other industries have begun expanding into solar. And as owners look for available talent pools to get projects in the ground, local or regional contractors could also be reskilled to install solar projects.

*Shifting to portfolio partnerships.* Contracting across a larger pipeline of projects can create flexibility to reallocate labor and materials to the projects that are ready to go. Shifting from one-off projects to larger pipelines also helps align incentives for partners to support each other's growth and productivity improvements over time. For example, to establish a multiyear solar portfolio, a utility developer might contract an EPC that currently serves the developer's other transmission assets but has ambitions to expand into renewables. The utility could procure equipment in-house—such as panels, inverters, trackers, and racking—to manage long lead times and leverage economies of scale across multiple projects while the EPC focuses on building the labor and technical skills to install solar. Greater cost transparency could allow the utility to monitor efficiency gains over time and set realistic expectations for the first few projects. The project load could also ramp up in stages, allowing the EPC to streamline the installation process and implement learnings on future projects.

*Co-investing in growth and capability building.* Players along the solar value chain can deepen partnerships through joint capability building and capacity expansion. For instance, a developer could co-invest with an EPC to build a workforce-training center to address the shortage of construction labor. The developer could use its community ties to assist with talent attraction, securing a skilled workforce to install its renewables projects. Meanwhile, the EPC could implement a training program that is compatible with the intended project pipeline and offer consistent, localized work to program graduates by collaborating with the developer on an efficient installation process and project sequencing. Joining forces with local government, unions, or a community trade school could also strengthen the partnership.

### Risk ownership and contracting

EPC availability has become a tighter bottleneck on project pipelines, pushing owners to engage EPCs earlier, consider less-experienced players, and absorb greater pricing risk for labor and materials. Stakeholders, including the owner, developer, EPC, and suppliers, can shift their contracting approach to reduce disruptions to their agreements and promote more-efficient project delivery. These stakeholders can revisit the allocation of responsibilities and risk, as well as engaging in more collaborative contracting.

*Adapting to new responsibilities.* The line between the responsibilities of the EPC and those of the developer is already blurring as some developers have shifted away from turnkey contracts. Our survey and interviews with industry experts indicate that an increasing number of owners are expanding in-house procurement capabilities over the next five years. Developers are already delivering projects with engineering, procurement, and construction management (EPCM) and project management contractor (PMC) models that enable more owner oversight and control, and some utilities are expected to follow suit.

*Revisiting the allocation of risk.* Risk ownership is another aspect of contracts that is ripe for revision. Recent contracts with EPCs have tended to shift more risk onto the project owner. However, instead of taking an adversarial approach to risk ownership, stakeholders can work together to align incentives so that both parties are mitigating risks that could lead to cost or schedule overruns. For example, project partners could set aside a common incentive pool that grows or shrinks based on overall project performance and negotiate allocation percentages as part of contracting. As suppliers or EPCs take on additional project risk, the project owner's percentage would decrease to compensate them. In another model, the contractor that carries the risk for materials and labor could receive progressive incentive payments for achieving costs or schedule below a predefined target. In such progressive incentive schemes, the contractor retains a higher percentage of the cost savings as the total cost savings increase (for example, 30 percent of the first $100,000 in cost savings, 35 percent of the next $100,000, and so on). This system can motivate the contractor to exceed targets and capture incremental savings beyond the low-hanging fruit.

*Embracing collaborative contracting.* Collaborative contracting could be a solution to anticipate demand, align on capacity for future projects, and unlock mutual growth. In other capital-intensive industries, collaborative contracting pilots have improved both costs and schedules by 15 to 20 percent versus traditional contracts, according to prior McKinsey research.[6] The right level of collaboration will depend on the nature of the partnership. For example, in aligned-incentives arrangements, cost and schedule overruns and underruns are shared. In integrated project delivery models, partners shape project scope, validate cost and schedule estimates together, and both share risk and profits. Stakeholders might operate under a single contract and a joint management structure that guides the execution of project.[7]

*Contracting with newer players.* Collaborative contracting is also beneficial in a market with newer, less-experienced players attracted by the rapid growth of renewables. Project owners who make significant bets on emerging EPCs could agree on a more "open book" approach with visibility into the underlying costs of delivering projects. Owners could monitor improvements over time and help structure contracts so that both the EPC and its workforce are rewarded for efficiency gains. Developers who scale their own in-house or joint capabilities, such as building late-stage engineering and design capabilities, can also reshape project delivery. For instance, moving away from a complete reliance on turnkey solutions could give developers flexibility to build projects with new contractors.

### Workforce development

The labor shortage has affected numerous sectors of the US economy, and renewables have not escaped the crunch. More than 92 percent of employers in the electricity generation sector are having difficulty hiring construction workers.[8] The rapid growth of renewables has led to many players competing for the same talent pools, and because solar installation has lower margins, it can be difficult to compete with rising wages in adjacent industries.[9]

To increase productivity—which is a main source of competitive differentiation in solar—effective training and talent retention are critical. A renewed approach to workforce development can help secure access to labor, enable high productivity and continuous improvement, and reduce unexpected changes in project schedules and costs.

*Attracting talent.* Talent attraction is the first step in growing the construction and engineering workforce. Solar project design and installation can provide jobs in rural parts of the country, but local people need to know those jobs exist. EPCs can partner with trade schools and local high schools to recruit new entrants to the workforce. In addition, dedicated efforts to attract historically underrepresented demographics would help expand workforce participation and make the growing industry more inclusive. Currently,

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[6] "Collaborative contracting: Moving from pilot to scale-up," McKinsey, January 17, 2020.
[7] Ibid.
[8] *United States energy & employment report 2022*, US Department of Energy, June 2022.
[9] "Will a labor crunch derail plans to upgrade US infrastructure?," October 17, 2022.

88 percent of the US construction workforce is White, and 89 percent is male.[10] Targeted career events, scholarships, and early-career mentorship and internship programs can help open paths for women and minorities to participate in the sector. To differentiate from other industries that are drawing from the same talent pool, solar EPCs should emphasize the mission-driven aspect of their work.

*Training talent.* Training programs can help new employees build the skills to work safely on jobsites and increase productivity. EPCs and project owners can collaborate on workforce development and ensure that localized training efforts are matched to a real pipeline of projects. Project owners can shift to a proactive approach, shaping talent development efforts around their needs. For example, to maximize efficient project delivery, an owner could co-invest in a training facility with a committed EPC partner and help tailor the curriculum to the owner's project pipeline, whether that be standardizing the module installation process or piloting new materials such as easy-install trackers.

*Improving the employment pipeline.* Once the trained workforce is in place, a consistent local pipeline of projects is critical for talent retention and productivity gains. Project owners and developers can help EPCs keep employees on a steady payroll. For example, a utility can sequence projects within its territory to ensure that the same workforce can service one after another. Project developers can also look for opportunities to standardize certain materials and designs across projects. In addition, productivity gains should be shared between contract parties. EPCs that achieve higher efficiency on later projects could be rewarded, with the initial baseline agreed on up front. Stipulations can also be made to ensure that every project meets the IRA's new prevailing wage and apprenticeship requirements.

### Digital and technology adoption

Adoption of digital software and technology has been slow in solar construction. Although some leading solar EPCs are beginning to pilot digital solutions and next-generation equipment in solar, widespread adoption remains elusive. However, project pipelines are growing quickly, and the additional value at stake has pushed solar companies to look for innovations that increase overall solar construction capacity. Such digital and technology solutions can help EPCs reduce costs, increase productivity, and track progress throughout project planning and construction.

*Adopting digital solutions.* A range of digital tools can help align project plans with reality on the ground. Generative scheduling uses advanced analytics to efficiently allocate labor, equipment, and materials during construction planning. Such tools generate hundreds of thousands of schedule and resource configurations. The programs then evaluate these configurations based on predicted schedule and cost outcomes. In other capital-intensive industries, generative scheduling has improved materials staging and distribution, increased equipment utilization, and alleviated labor constraints through better work sequencing. Remote monitoring can also benefit solar project construction. For example, drone-enabled digital twins can check construction progress against the schedule and flag any deviations from a project's design. Catching and correcting issues early can increase project quality and minimize costly rework. Some project tracking tools can not only forecast the schedule based on progress but can also test alternative scenarios and suggest adjustments to optimize future resource allocation.

*Achieving greater efficiency through technology.* Novel technologies have the potential to transform project engineering and construction, alleviating the labor shortage by allowing existing workers to become more efficient. For example, the latest solar tracker technologies are reducing the need for extensive earthworks on undulating terrain and enabling quicker and easier installation. Modular or preassembled solar components have also been tested in the field and are well positioned to scale. And automated earthworks equipment, which

[10] "Labor force statistics from the Current Population Survey," US Bureau of Labor Statistics, accessed March 10, 2022.

reduces labor time, is on the horizon. Start-up digital players and leading construction equipment manufacturers are testing autonomous bulldozers, excavators, and pile drivers with their partners. EPCs that adopt such technologies have the potential to capture higher margins from efficiency gains, and owners who create opportunities to pilot new equipment and materials on their projects can share in those benefits.

Strong tailwinds from the IRA have made certain market constraints facing US renewables more challenging, but the tailwinds also present a major opportunity for stakeholders to resolve EPC and labor shortages collaboratively. In a market that is expanding fast enough for both incumbents and emerging players to grow, owners can engage with EPCs in win–win partnerships that reach beyond adversarial contract negotiations to capture the growth opportunity. Our net-zero future depends on it.

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# 3 Generation

# What will it take for nuclear power to meet the climate challenge?

Nuclear power can be an important part of the energy transition. Scaling the industry to meet increasing electricity demand will require leaders to mobilize quickly and efficiently.

*This article is a collaborative effort by Chad Cramer, Bill Lacivita, Jennifer Laws, Muhammad Nabi Malik, and Geoff Olynyk, representing views from McKinsey's Electric Power & Natural Gas Practice.*

**The power sector** will play a critical role in the net-zero transition. Power generation contributes about 30 percent of global $CO_2$ emissions, primarily from combustion of fossil fuels. Many governments, utilities, and other companies are investing heavily in renewable sources of energy. As rapidly as renewables have scaled up in recent years, it's unclear whether wind and solar—along with other emerging solutions, including carbon capture, long-duration energy storage, and hydrogen—can grow fast enough to meet net-zero targets and projected increasing electricity demand.

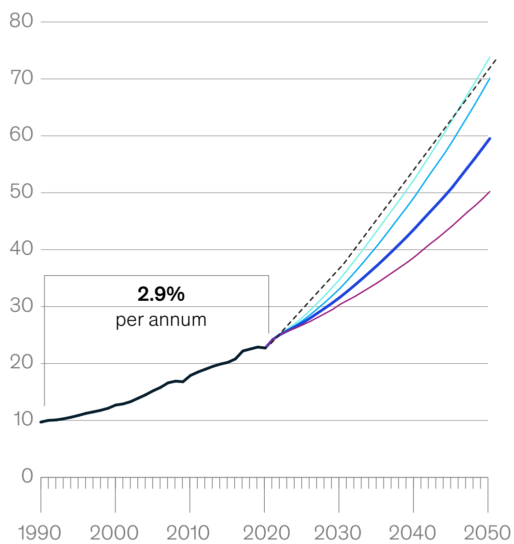
Nuclear power is a proven technology that can be called upon to play a bigger role in decarbonization. Its ability to scale up to meet rising demand, however, is in question.

According to McKinsey's Global Energy Perspective 2022, global power consumption could triple by 2050 (Exhibit 1). The expected increase in demand will stem largely from a shift away from fossil fuels toward electrification of end uses, including transportation (electric vehicles), building operations (electrifying heat), and industrial processes (low-carbon steelmaking). The resulting need for new low-carbon and zero-carbon generation will be unprecedented in the history of the global electrical grid.

Exhibit 1

### Electricity demand is expected to triple by 2050 across a range of scenarios.

**Global electricity demand,**[1]
thousands of terawatt hours




| Scenarios[2] | 2019–50 CAGR, % |
|---|---|
| **1.5°C pathway** Increased regulations and incentives to eliminate greenhouse-gas emissions create the need for extensive electrification across all sectors, including those that are hard to electrify today | 3.8 |
| **Achieved commitments** Technological advancement with strict regulations and targets further boost electrification even in sectors that are harder to electrify (eg, high-temp heat industries) | 3.8 |
| **Further acceleration** Technological advancement of proven solutions accelerates cost parity and triggers sooner and stronger electrification (such as heat pump adoption or electric vehicles) | 3.7 |
| **Current trajectory** Consensus view on the key drivers of electricity consumption: increasing living standards and consumption per capita, electrification across all sectors, and hydrogen uptake | 3.1 |
| **Fading momentum** Slower cost decline of zero-emissions technologies and lower fossil fuel price outlooks limit the fuel-switching trend | 2.6 |

[1]Including demand for green hydrogen production.
[2]Scenarios center around pace of technological progress and level of policy enforcement.
Source: World Energy Outlook 2021, IEA; Global Energy Perspectives 2022, Energy Insights, McKinsey

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Nuclear power—a proven, zero-carbon electricity source—currently contributes about 10 percent of global electricity generation.[1] As a firming, resilient, and dispatchable energy source, nuclear power can be generated at any time. It can also complement nondispatchable[2] power sources, such as wind and solar, to ensure that the total power supply meets grid demand. After construction of new nuclear power plants surged in Europe and North America in the 1960s and 1970s, it has been relatively stagnant globally, outside of China, Russia, and South Korea. The stagnation stems from construction challenges in the West, political and social perceptions of nuclear power in some regions,[3] and the overall transition to other clean technologies.

However, new developments suggest this period of stagnation may be ending. Factors such as energy security and resiliency, scarcity of top-quality land for renewables,[4] interconnection and new-build transmission timelines, and the ability to scale up the renewables and storage industries fast enough[5] have propelled nuclear power back into the energy transition discussion, while decades of progress in safety and waste-management practices[6] have helped to allay historical concerns. Recently, multiple countries have announced intentions to either slow the phaseout of their nuclear fleets or begin exploring construction of new plants. Advancing reactor technologies offer the promise of plants that will be more cost-effective to both build and operate. And policy makers, through legislation such as the Inflation Reduction Act in the United States,[7] are showing a willingness to offer incentives to accelerate the role of nuclear.

These developments indicate that nuclear power is emerging as a key component of decarbonization plans, but a big question remains: Can the industry reverse the trend of exceeding budgets and timelines while scaling up fast enough to rise to the climate challenge? In this article, we explore how much nuclear power could be essential in meeting net-zero targets, the current challenges in scaling nuclear, the promise of new technologies, and eight key actions for industry stakeholders.

## Up to 800 GW of new nuclear could be necessary to meet net-zero targets

In estimating the nuclear power needed to support the energy transition, we used techno-economic grid modeling[8] to project the overall power mix by 2050. Our scenario—based on "Further Acceleration" estimates from McKinsey's Global Energy Perspective 2022 for global energy mix, as well as anticipated supply and demand for power[9]—accounts for potential constraints on scale-up in renewables, such as scarcity of land, raw materials, and transmission limitations. Although our scenario does not rely on a full analysis of grid models and energy-transition scenarios, it does estimate roughly how much additional dispatchable, low-carbon generation will be needed to meet net-zero targets.[10]

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1 *Nuclear power and secure energy transitions*, IEA, June 2022. (The supply percentage reflects energy [TWh], not capacity [TW].)
2 Wind and solar are considered to be nondispatchable because they rely on external variables (wind or sun).
3 Environmental and safety concerns may affect public perceptions of nuclear power, but today's plants operate safely and reliably. A 2010 OECD report, *Comparing nuclear accident risks with those from other energy sources*, showed that releases of radioactivity are rare and that fatality risks related to nuclear power are low. After the 2011 accident in Fukushima, Japan, the United Nations Scientific Committee on the Effects of Atomic Radiation found that local residents did not experience radiation-related health effects (see *Sources, effects and risks of ionizing radiation: UNSCEAR 2020/2021 report*), even though displacement away from the Fukushima facility disrupted lives and livelihoods. Safety remains paramount when building and operating any nuclear facility.
4 "Renewable-energy development in a net-zero world," McKinsey, October 28, 2022.
5 Hauke Engel, Geoff Olynyk, and Daan Walter, "Failure is not an option: Increasing the chances of achieving net zero," McKinsey, June 2, 2022.
6 *Management and disposal of high-level radioactive waste: Global progress and solutions*, Nuclear Energy Agency and OECD, 2020.
7 Kathryn Huff, "Inflation Reduction Act keeps momentum building for nuclear power," Office of Nuclear Energy, US Department of Energy, September 8, 2022.
8 Techno-economic grid modeling is a tool that researchers and energy planners can use to determine the optimal mix of zero-carbon technologies in a given geography.
9 The scenario also incorporates middle-of-the-road assumptions in cost evolutions of key energy technologies, including solar, wind, and energy storage.
10 The existing nuclear fleet is also assumed to continue, but given that overall electrical generation globally roughly triples in net-zero scenarios, the newly required generation is projected to be substantially larger than that of the existing global fleet.

Our modeling reveals that the energy transition could require an additional 400 to 800 GW of new nuclear—which could represent up to 10 to 20 percent of future global electricity demand—to meet the need for dispatchable power (that is, not wind and solar) by 2050 (Exhibit 2).[11]

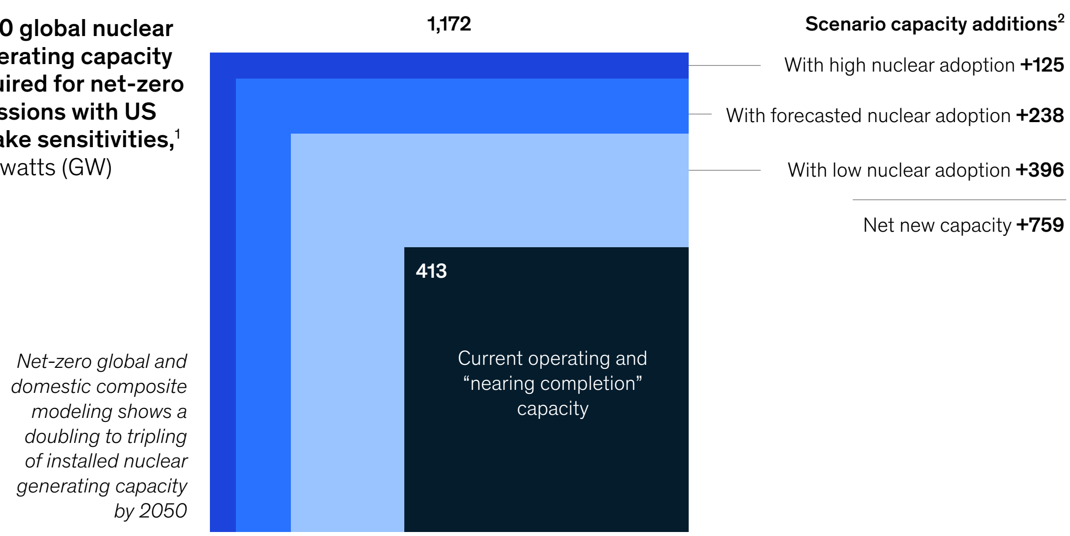
Notably, technology innovation, market dynamics, and construction costs could affect these projections significantly. In recent years, for example, the growth of renewables has consistently outperformed projections.[12] In addition, alternative dispatchable low- and zero-carbon technologies outside of nuclear power (long-duration energy storage,[13] geothermal, and tidal power, for example) could contribute to this potential need for dispatchable power. These technologies are at earlier stages of technical and commercial maturity, compared with nuclear, and each has different challenges in deploying at scale.

Can nuclear power provide this degree of additional electricity? Such a jump in nuclear capacity would be daunting for the industry, which at its peak has grown at a maximum of approximately 30 GW per year globally (a rate achieved in the 1980s but not since).[14] With assumptions that new reactors begin coming online by 2030 and reach scale by 2035,

Exhibit 2

**Demand for nuclear power is projected to double or even triple by 2050 based on today's capacity.**

**2050 global nuclear generating capacity required for net-zero emissions with US uptake sensitivities,**[1] gigawatts (GW)




[1]US required build-out modeling has explored nuclear sensitivities in more depth and shows that required capacity is highly sensitive to the build-out of renewables, transmission and distribution constraints, and the development of competing firming technologies, most notably carbon capture and underground storage.
[2]When accounting for the age of the current global fleet, an additional ~100 to ~250 GW of new builds could be required to replace retiring capacity, depending on plant life extensions.
Source: *Examining supply-side options to achieve 100% clean electricity by 2035*, National Renewable Energy Laboratory, Aug 2022; World Energy Outlook 2021, IEA; Net-Zero America Project, Princeton; McKinsey analysis

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[11]Excludes nontraditional off-takers (for example, hydrogen generation, industrial heat, and desalination).
[12] "Renewable-energy development," October 28, 2022.
[13] For more on the potential of long-duration energy storage technologies, see *Net-zero power: Long-duration energy storage for a renewable grid*, LDES Council in collaboration with McKinsey as a knowledge partner, November 22, 2021.
[14] Based on the International Atomic Energy Agency's Power Reactor Information System (PRIS) database, accessed December 13, 2022.

this uptick could require approximately 50 GW per year of new nuclear capacity (Exhibit 3).[15]

To scale nuclear power's capacity, numerous challenges must be addressed.

## Building nuclear power plants comes with a complex set of challenges

During the past 20 years, construction of new nuclear power plants has presented an array of challenges. These hurdles have been particularly acute in Western countries but are not necessarily unique to the nuclear industry, as other sectors face complex regulatory requirements or a scarcity of required skills in the labor force, for example. Our experience shows that the challenges in building new nuclear plants include but are not limited to:

— Complexity and variation in reactor designs, such that every plant is a "first of its kind," with little repetition of standard designs to capture project-over-project improvements.

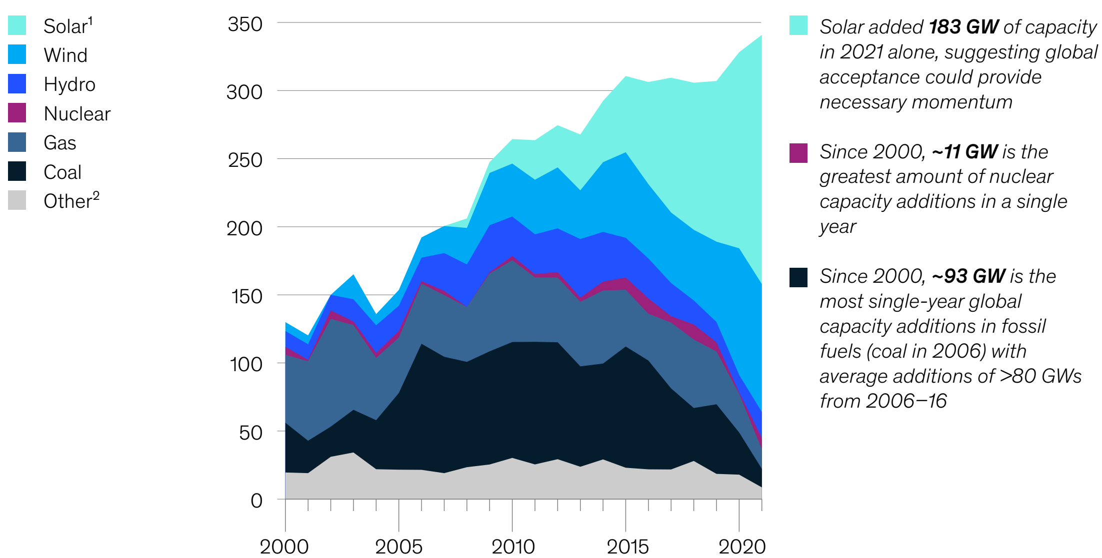
— Limited industrial base for materials, systems, and components, as well as a need for specialized manufacturing processes and rare materials.

— Scarcity of both skilled-craft and salaried workers who have the required expertise,

Exhibit 3

### The greatest amount of nuclear capacity added globally in a single year since 2000 was 11 gigawatts, a lower peak compared with other sources of energy.

**Global capacity additions by energy source,** gigawatts (GW)




[1]Data for solar capacity additions begin in 2007.
[2]Includes biomass, waste, oil, geothermal, and hydrogen.
Source: BloombergNEF; Global Wind Energy Council; International Atomic Energy Agency

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[15] Excludes nontraditional off-takers (for example hydrogen generation, industrial heat, and desalination).

compounded by an aging labor force of experienced nuclear professionals.

— Limits on the ability to execute construction effectively, without rework, to ensure on-time and on-budget delivery that meets stringent quality standards.

— Partnerships and construction contracts that do not reflect the extent of project risks inherent to the complexity of the technology.

— Complex and changing regulatory requirements for plant construction that are not consistent among governments.

This web of issues has created a vicious cycle for the industry. New-build projects experience construction delays and cost overruns—which can reach billions of dollars—and then future projects struggle to attract financing. Projects in Canada,[16] Finland,[17] France,[18] and the United States,[19] for example, have experienced significant delays, cost overruns, or prohibitively high bid costs for investors. These impediments have the compounding effect of constraining the parts of the industrial base that are key to supporting future construction and operations.

## The next generation of reactors have been designed with these challenges in mind

Nuclear reactors have historically been large, complex, costly projects that take many years—even decades—to complete. But emerging reactor technologies promise lower costs, faster build times, and other potential advantages.

Small modular reactors (SMRs), which are generally based on Gen III+ light water reactor (LWR) technology already in operation globally, are smaller in size and have a simpler, more modular design, which could help to reduce construction times and up-front costs. Other advanced reactor technology (Gen-IV) can be even smaller and could be deployed for microgrids, which power remote areas or a single facility. Additional advantages include lower operating costs, simplified systems that increase reliability, and better safety margins.

Gen-III+ SMRs are currently in the early phases of deployment, whereas Gen-IV reactors are primarily at a conceptual stage (outside of a few demonstration projects). In both cases, the required manufacturing and component supply chains would need to be scaled for broader deployment. However, greater investment in these technologies could, in the long run, significantly reduce the cost, timeline, and complexities of plant construction—and potentially speed up timelines for nuclear deployment. (For more on reactor technologies, see sidebar, "Innovations in reactor technology.")

## To meet the need for scale-up, industry stakeholders should consider eight key actions

Momentum for new-build nuclear is growing in many markets. For example, the US Department of Energy plans to award about $3 billion in the licensing, construction, and demonstration of two new Gen-IV plants through the Advanced Reactor Demonstration Program, in addition to the $1.4 billion cost-share for a new SMR plant.[20] Additionally, the Inflation Reduction Act in the United States provides either an investment tax

[16] Darlington Nuclear Generating Station; see *Management of delayed nuclear power plant projects*, International Atomic Energy Agency, September 1999.
[17] OL3 EPR plant; see "The regular electricity production of OL3 EPR will be postponed due to extension of turbine overhaul," TVO news release, August 20, 2021.
[18] Flamanville 3 project; see "Update on the Flamanville EPR," EDF, December 16, 2022.
[19] Vogtle 3 and 4 project; see *2022 second quarter report*, MEAG Power.
[20] *Nuclear energy projects: DOE should institutionalize oversight plans for demonstrations of new reactor types*, US Government Accountability Office, September 13, 2022; "Next-gen nuclear plant and jobs are coming to Wyoming," Office of Nuclear Energy, US Department of Energy, November 16, 2021; "DOE approves award for carbon free power project," Office of Nuclear Energy, US Department of Energy, October 16, 2020.

credit of up to 50 percent or a production tax credit up to approximately $30 per MWh for the first ten years of new-plant operation.[21] As of January 2023, GE Hitachi Nuclear Energy, Ontario Power Generation, SNC-Lavalin, and Aecon have signed a contract for the deployment of a BWRX-300 SMR in Ontario, Canada.[22] This is the first commercial contract for a grid-scale SMR in North America.

The United Kingdom recently announced an approximately $145 million fund to support new nuclear projects.[23] South Korea has also announced increased capacity.[24] In the United

[21] Inflation Reduction Act of 2022, H.R. 5376, 117th Congress.
[22] "Aecon partnership executes agreement to deliver North America's first grid-scale Small Modular Reactor for Ontario Power Generation," Aecon news release, January 27, 2023.
[23] "Future Nuclear Enabling Fund," Department for Business, Energy & Industrial Strategy, United Kingdom, May 2022.
[24] "Nuclear Power in South Korea," World Nuclear Association, updated November 2022.

## Innovations in reactor technology

**Nuclear reactor technology** is complex and comes in various forms. New designs promise lower costs, increased passive safety,[1] faster build times, smaller absolute size, more flexible locations, the ability to use nuclear waste as fuel, and other advantages. However, these designs are less proven, and supply chains for many of their parts have not yet been developed. The nuclear industry uses a standard classification of "generations" of reactors to categorize the technology. Today's large reactors are known as "Generation III+" (generations I to III are generally no longer built).

For nuclear power to scale up, we would expect the deployment of reactor technologies to progress, such that current Gen-III+ large light water reactors (LWRs) carry the load at first, Gen-III+ small modular reactors (SMRs) ramp up in the 2020s, and advanced Gen-IV reactors begin to play a role in the 2030s. Here is a brief overview of each generation of reactor technology:

— *Gen-III+ large LWR.* LWRs are the most common reactors globally ("light water" refers to the use of ordinary water as a moderator in the reaction process). They can generate more than 1 GW of electricity (enough to power 400,000 homes), can cost $5 billion or more for new plant construction, and may require at least five years to build. The up-front investment is high, but LWR designs are commercially ready and are being deployed today.

— *Gen-III+ SMR.* SMRs generate less power than the Gen-III+ large reactors, in the 100 to 300 MW electrical range (though smaller designs, down to about 20 MW, have been proposed). Their simplified designs and modularity can reduce construction time and up-front investment, compared with larger reactors. We believe that SMRs, which are in pilot development, could play the largest role in any near-term rapid scale-up of the industry.

— *Gen-IV reactor.* This category includes new and emerging technologies, such as liquid sodium cooled reactors, high-temperature gas reactors, and microreactors (1 to 50 MW of electrical output). Gen-IV reactors might solve key technical challenges (waste-burning, for example) and could create new use cases (such as microgrids that leverage microreactors or process heat from high-temperature reactors; high-temperature power for low-carbon hydrogen production). However, Gen-IV reactors are further away from commercialization and could require new supply chains for different materials or fuels.

While key factors such as cost and technical maturity might vary across these technologies, each could have a role going forward. Such factors influence each technology's scale-up potential.

[1] Safety functions that don't require active interventions from operators.

Arab Emirates, a plant has been in development for the past decade and is partially operational.[25] Globally, about 178 GW of capacity is under construction or planned.[26] According to the International Energy Agency, approximately 10 GW of new capacity has been connected to grids each year in recent years.[27] Achieving additional capacity of approximately 50 GW per year thus means a roughly fivefold scale-up for the industry from today's new-build activity levels, while maintaining existing nuclear plants online.

But the industry is at an impasse. Despite positive momentum for the first time in over a decade, the risk that initial construction will go over budget and over schedule may diminish chances that new nuclear will realize its full potential in supporting the energy transition at scale.

For the industry to scale up significantly, several near-term actions will need to be considered across financing, supply chain, and regulation. Industry players along the value chain—OEMs, plant operators, regulators, policy makers, and investors—would all play critical roles. We have identified eight key actions for stakeholders to consider.

1. *Source new financing for power plant construction across the value chain.* Financing will be critical in kick-starting the industry—we estimate that capital costs for a rapid scale-up to meet decarbonization targets could be roughly $500 billion per year. Private investment will need to support the development of new technologies, scaling of the industrial base, and construction of new reactors. Regardless of investment sources, managing cost risks will be vital. Policy support may be necessary to backstop financial risk as the industry scales up. Governments could offer guarantees or direct financing. Global power producers could consider spreading risks over large balance sheets. For example, the US Department of Energy Loan Program Office is available to provide low-cost financing, but such support is not consistent across all future nuclear nations.

2. *Ramp up the labor force for manufacturing, construction, and operation.* Today in the United States and Canada, for example, the nuclear industry provides approximately 130,000 direct jobs and nearly 600,000 total jobs (indirect plus direct). Our analysis suggests that the nuclear workforce in these two countries alone would need to grow to more than one million people—and to more than five million globally—for the industry to increase capacity to 50 GW per year. The industry and governments could coordinate on capability-building programs that include recruitment, training, apprenticeship, and placement, such as energy company EDF's efforts to train welders in anticipation of a new nuclear power station in the United Kingdom.[28]

3. *Establish streamlined global licensing processes.* Industry leaders, regulators, and policy makers could set up an industry consortium (or empower an existing one) to define global licensing requirements and proactively work with governments to lay out a road map for scaling up. In the natural gas industry, for example, the International Group of Liquefied Natural Gas Importers (GIIGNL)—often in cooperation with other organizations, such as the American Petroleum Institute—defines common technical standards for liquefied natural gas across the globe and works with governments to see those standards codified.

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[25] "Barakah Nuclear Energy Plant," Emirates Nuclear Energy Corporation, accessed December 7, 2022.
[26] Based on McKinsey analysis of the World Nuclear Organization database in February 2023 and recently announced projects from press search.
[27] "Nuclear power capacity additions and retirements in selected countries and regions by decade in the Net Zero Scenario," IEA, last updated October 26, 2022. Note that 10 GW of capacity has also been decommissioned; therefore, the total net energy produced from nuclear reactors has remained approximately constant.
[28] "Energy Minister opens new training centre to support Hinkley Point C," EDF, April 28, 2022.

4. *Implement individual-project best practices.* Applying best practices for large-scale investment projects can reduce the likelihood of cost and schedule overruns. In our experience, proven strategies and management tactics for successful megaprojects in other industries apply in the nuclear context in areas including site productivity; schedule optimization; cost control; commissioning and operational readiness; quality, project control, and risk management; and project organization and governance. Lessons from other industries will be invaluable if nuclear is to succeed.

5. *Implement industry-wide best practices for scaling up.* Toward that end, an asset-heavy industry can take several steps:

   - *Establish standard designs.* Create an industry body to identify and implement standards for plant systems and components, which could streamline regulatory processes, engineering, and supply chains.

   - *Use a replicable model for construction.* Building plants in rapid succession with a standard design will help workforce skills to remain relevant, the industrial base to scale up, and lessons from each build to inform successive builds.

   - *Repeat siting.* Historically, building multiple reactors at a single location has proved to significantly reduce costs for successive build-outs—by minimizing mobilization costs, utilizing shared buildings and structures, and maintaining the necessary workforce for follow-on units.

   - *Increase use of modular construction for standardized components.* In the 1960s, for example, the shipbuilding industry largely moved from bespoke, full-scale onsite construction to a more modular, "hull block" process, whereby sections are prefabricated in workshops and final assembly occurs in the drydock. For the nuclear industry, modular construction of plant sections can substantially drive down costs as processes become more predictable and repeatable, construction environments more controlled, workforces more stable, rework less frequent, and manufacturing times more efficient.

6. *Proactively coordinate and scale the industrial base.* Supply chain bottlenecks are likely to emerge if the industry scales up quickly. Potential bottlenecks could affect, for example, heavy forgings for reactor pressure vessels, instrumentation, and control systems, as well as specialized nuclear-safety-rated ("N-stamped") valves for critical control systems. More new-build program support by governments could boost investor confidence in building out supply chains for such components before construction begins. In addition, industry players can consider establishing centers of excellence to develop new manufacturing processes and help qualify more suppliers of components to meet the necessary performance and quality standards for the nuclear supply chain.

7. *Maintain the reliable and safe operation and maintenance (O&M) of current plants while continuing to improve financial performance.* Today's plants operate safely and reliably, but they face increasing economic challenges. For example, declining costs for wind and solar have forced nuclear providers in many markets to stay competitive on price, which has tightened margins. Maintaining today's nuclear capacity through safe, reliable, and cost-efficient operation of existing plants would help to keep them running (instead of shutting them down because of high operational costs) and potentially help preserve current supply chains and the workforce.

8. *Expedite development of next-generation reactors.* Accelerating commercial deployment of Gen-III+ and Gen-IV technologies could, over time, reduce capital costs and speed up plant build-outs through "learning by doing," more efficient supply chains, and other benefits.

Reactor technology owners could refine their equity stories for investors, with an emphasis on getting pilots right. Nuclear industry players could also consider public–private consortiums to expedite technology development.

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The promise of nuclear energy is needed now more than ever to meet global net-zero targets. Scaling up the nuclear industry will be a significant undertaking that requires overcoming a substantial set of roadblocks. Even an optimistic scenario for an expanded nuclear economy would be likely to involve a complex, global web of policies, in addition to uneven cost levels, as technologies and the supporting industrial base emerge on different timelines. However, we believe a nuclear scale-up is achievable. It's time for the industry to meet the challenge.

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# 4 Trading

# How traders can capture value in sustainable fuels

The sustainable-fuel market is nascent, complex, and growing fast. Traders that develop an in-depth understanding across different fuels, feedstocks, and regions can gain a competitive advantage.

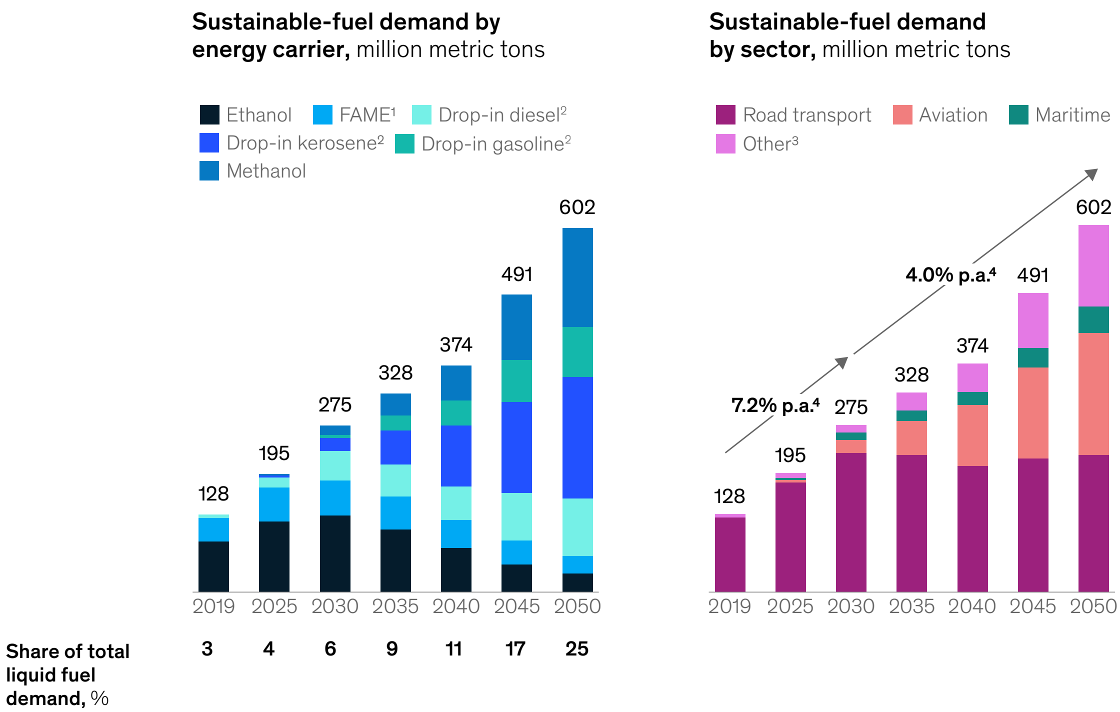
*by Tapio Melgin, Agata Mucha-Geppert, Xavier Veillard, and Andrew Warrell*

**As countries around the world** seek to limit their carbon emissions, sustainable fuels will play an important role. This category consists of a broad range of low-carbon fuels, including biofuels, e-fuels, and chemical by-products (see sidebar, "Know your sustainable fuels"). Because sustainable fuels can fill gaps in decarbonization and complement electrification, demand is expected to triple over the next 20 years, reaching approximately 600 million metric tons (Mt) by 2050 (Exhibit 1).[1] To date, completed advanced-biofuels projects and announced investment pipeline in sustainable-fuel capacity have reached $100 billion.[2]

The sustainable-fuel market is still mostly nascent, characterized by complex regulations and interdependencies across sectors. Physical

Exhibit 1

## The contribution of sustainable fuels to liquid-fuel demand could double by 2030.




[1]Fatty acid methyl ester.
[2]Drop-in fuels include 100% blend fuels, such as hydrotreated vegetable oil (HVO), hydrotreated esters and fatty acids (HEFA), and power-to-liquid (PtL) diesel or kerosene.
[3]Rail, building, chemicals, industry, and other.
[4]Per annum.
Source: McKinsey Sustainable Fuels Cost Model, Achieved Commitments scenario, Apr 2023

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[1] Based on the Achieved Commitments scenario from the McKinsey Global Energy Perspective 2023 (forthcoming). For more on the market outlook, see Nathan Lash, Tapio Melgin, Agata Mucha-Geppert, and Ole Rolser, "Charting the global energy landscape to 2050: Sustainable fuels," McKinsey, July 7, 2022.
[2] McKinsey Sustainable Fuels capacity tracker, May 2023.

## Know your sustainable fuels

**Sustainable fuels differ** by feedstock, application, and production methods.

**Conventional biofuels**
Biofuels produced from organic matter, including food crops and organic-residue materials, are typically blended with conventional fossil fuels at low percentages (given the constraints of engines to accommodate fuel with certain properties).

Ethanol is produced through fermentation of plant-based materials. First-generation ethanol uses feedstocks such as corn, while second-generation ethanol is produced from residues such as bagasse, which requires more processing. Ethanol is used primarily in gasoline blends (for example, E10) and additives (for example, ethyl tert-butyl ether), improving fuel characteristics such as octane number and lowering greenhouse gases (GHGs) at a modest cost (for first-generation ethanol).

Fatty acid methyl ester (FAME) is a type of biodiesel derived from renewable sources such as vegetable oils or animal fats. FAME is commonly blended with fossil diesel fuel (such as B7 and B20). Traded products on the market reflect the underlying feedstock: for example, FAME and cooking oil can combine to create used cooking oil methyl ester, or UCOME.

Biomethanol is a type of methanol produced from biomass or renewable feedstocks, such as agricultural residues, woody biomass, or side-stream extracts from pulp mills. It can be used as a fuel in dedicated engines—for example, as a gasoline additive (methyl tert-butyl ether)—or as a feedstock for the production of chemicals.

Biogas is produced through the anaerobic digestion of waste streams such as corn stover, manure, wastewater sludges, or food waste. It is often produced on a small scale, contains roughly two-thirds methane and one-third other gases, and can be combusted to produce electricity and heat. When upgraded to biomethane, it becomes a drop-in fuel and tradable commodity.

**Drop-in sustainable fuels**
Drop-in sustainable fuels can be produced from edible or residue biomass sources by using low-carbon hydrogen or by synthesizing sustainable captured carbon and low-carbon hydrogen. They are compatible with existing engines and fossil-fuel infrastructure. Drop-in fuels have already been a replacement for diesel, jet fuel (currently, the blend limit is 50 percent), and compressed and liquefied natural gas. In addition to having a positive impact on GHG emissions and a low carbon-intensity score, these fuels typically have lower particulate-matter and nitrogen oxide emissions.

Products currently on the market or expected to go to market soon include renewable diesel (hydrotreated vegetable oil) or e-diesel, sustainable aviation fuel (such as HEFA[1] and e-SAF), biomethane and synthetic methane (sustainable natural gas), and e-gasoline. These fuels are often traded and blended with conventional fuels in the country of use.

**E-fuels or hydrogen-based fuels (non-drop-in)**
E-fuels are manufactured using hydrogen from low-carbon electricity sources (such as renewable or nuclear energy) and captured carbon. The production of low-carbon hydrogen through electrolysis based on renewable or nuclear energy can be traded as gaseous hydrogen or liquid hydrogen. When hydrogen is combined with acceptable sources of carbon (such as biogenic carbon[2] or carbon derived from direct air capture) or nitrogen, it can form e-fuels such as e-methanol or e-ammonia. However, some hydrogen derivatives are not compatible with existing engines and infrastructure.

[1] Hydrotreated esters and fatty acids (synonymous with the hydrotreated-vegetable-oil process).
[2] Biogenic carbon is $CO_2$ sequestered from the atmosphere during the growth of feedstock and released during biofuel combustion.

and regulatory constraints on feedstocks have resulted in price volatility; supply chain and infrastructure bottlenecks, variations in pricing across regions, and import and export rulings have added to this volatility. The mix of fuel types will evolve through 2050: road fuels have represented most of the demand and growth to date, but in the 2020s categories such as sustainable aviation fuel (SAF), renewable natural gas and synthetic natural gas, and bio- and e-methanol will make up a larger share. During the 2030s, technological advancements could spur growth in new advanced-biofuel pathways and e-fuels, complicating the global market while injecting much-needed capacity and liquidity.

With such complex market fundamentals, sustainable-fuel traders should seek to understand which markets will increase in liquidity, which arbitrage plays to explore across products, which storage hubs to invest in, and which offtakes to secure to gain access to supply. Winning traders will build and enhance selected capabilities to keep pace with the market's evolution.

## Current market and development factors

A fascinating but challenging aspect of the sustainable-fuel market is the broad range of categories it encompasses (Exhibit 2). Biofuels account for the vast majority of the current market, but drop-in sustainable fuels and hydrogen-based e-fuels could reshape the landscape in the coming decades. The development of these fuels will be nonlinear: they will mature at different paces, and their specific uses could replace fossil fuels at different rates.

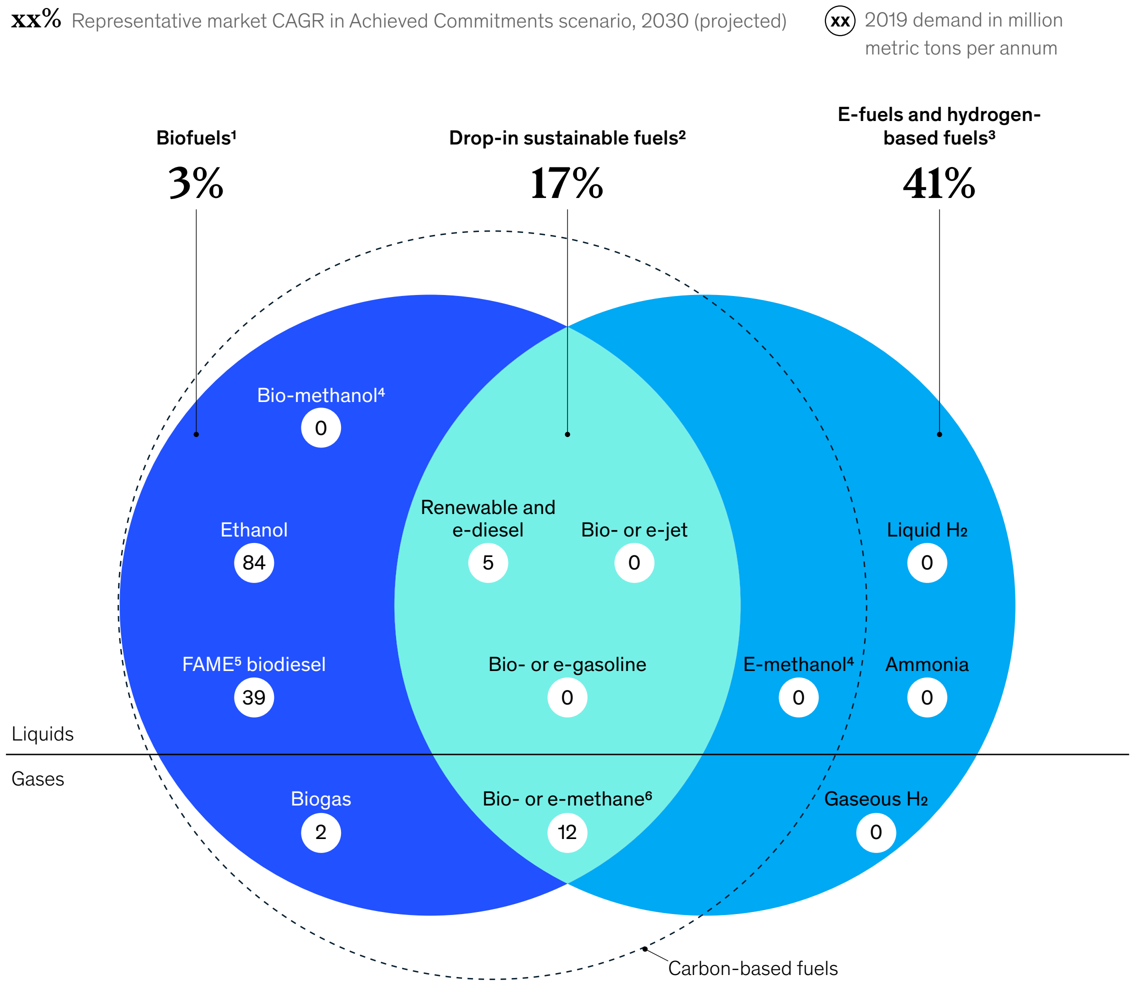
Several factors will shape the market's development over the next few decades.

**Winning traders will build and enhance selected capabilities to keep pace with the market's evolution.**

Exhibit 2

## The market for sustainable fuels includes a broad range of categories.

### Overview of sustainable liquid and gas energy carriers




Note: Pure hydrogen and other decarbonization vectors do not meet the “drop in” requirement.
[1]Bio-based with compatibility restrictions (blend walls) with existing combustion engines.
[2]Fuels that require new infrastructure or engines.
[3]Fuels that are fully compatible with existing infrastructure (blended up to 100%) and that can be produced from either bio-based or hydrogen-based sources. Liquid and gaseous hydrogen only includes green and blue hydrogen.
[4]Methanol can be upgraded to various drop-in fuels but is not a 100% drop-in fuel by itself.
[5]Fatty acid methyl ester.
[6]Renewable natural gas.

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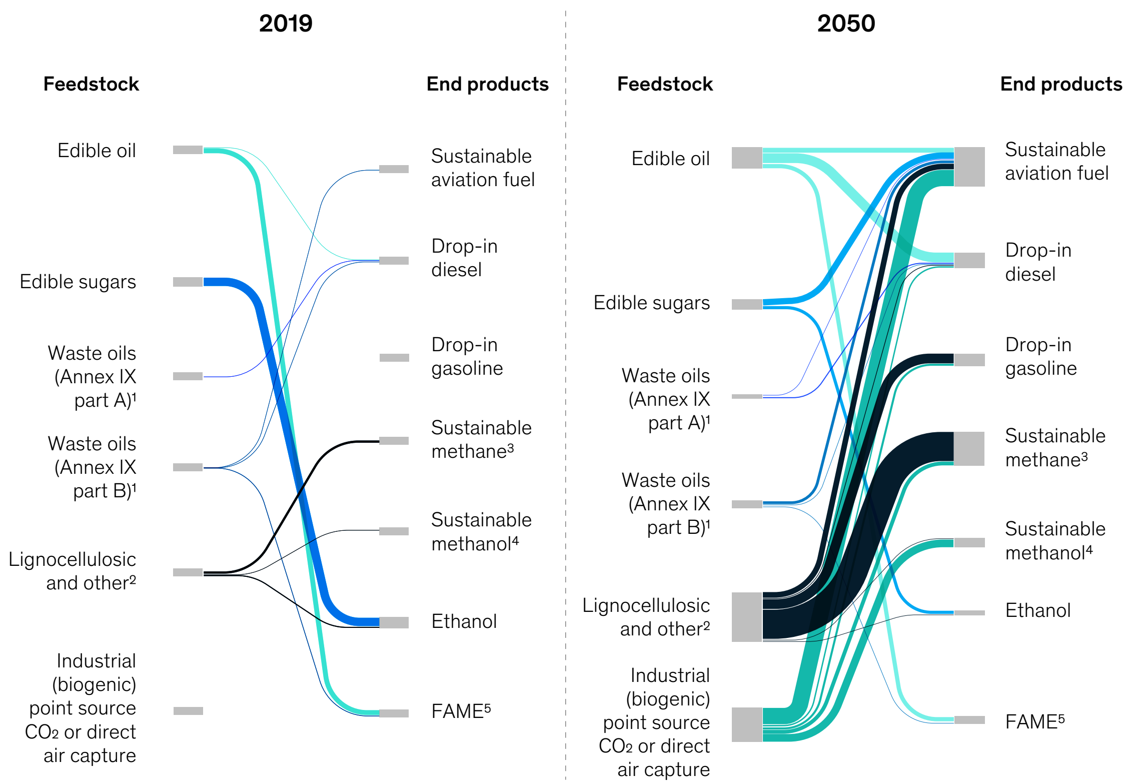
### The rise of e-fuels

In the coming years, constraints on sustainable biomass feedstocks are expected to create a gap between demand for and supply of fuels with existing technologies. Although biomass feedstocks, notably lignocellulosics, have significant potential for energy production,[3] practical constraints on their collection mean the global community likely won't be able to achieve net-zero targets without a shift to e-fuels and dedicated biomass production on marginal lands or surplus agricultural land (Exhibit 3).

Exhibit 3

## Over the next 30 years, achieving net zero will require a fundamental shift in the way sustainable fuels are produced.




[1]Availability could potentially be expanded with purposely grown volumes of low indirect land-use change and cover crops. See Renewable Energy Directive (2018/2001), European Commission, Dec 2018.
[2]Includes all relatively unconstrained feedstock technologies; ie, power-to-X (PtX), gasification, alcohol-to-jet (AtJ), bio-based or synthetic methane, green hydrogen for refinery use, or more hydrotreated vegetable oil (HVO) if more feedstock is unlocked. Decreasing demand for ethanol from edible sugars could result in retrofitting ethanol plants to AtJ, practically meeting part of "Lignocellulosic and other" demand.
[3]Sustainable methane includes synthetic methane, biomethane, and biogas. The biogas demand estimation is based on McKinsey's *Global Energy Perspective 2022* outlook.
[4]Includes methanol as a fuel in transport and as a feedstock in chemicals.
[5]Fatty acid methyl ester.
Source: McKinsey Sustainable Fuels Cost Model, Achieved Commitments scenario, Apr 2023

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[3] Göran Berndes et al., "Chapter 2: Bioenergy" in *Renewable energy sources and climate change mitigation*, Intergovernmental Panel on Climate Change, 2011.

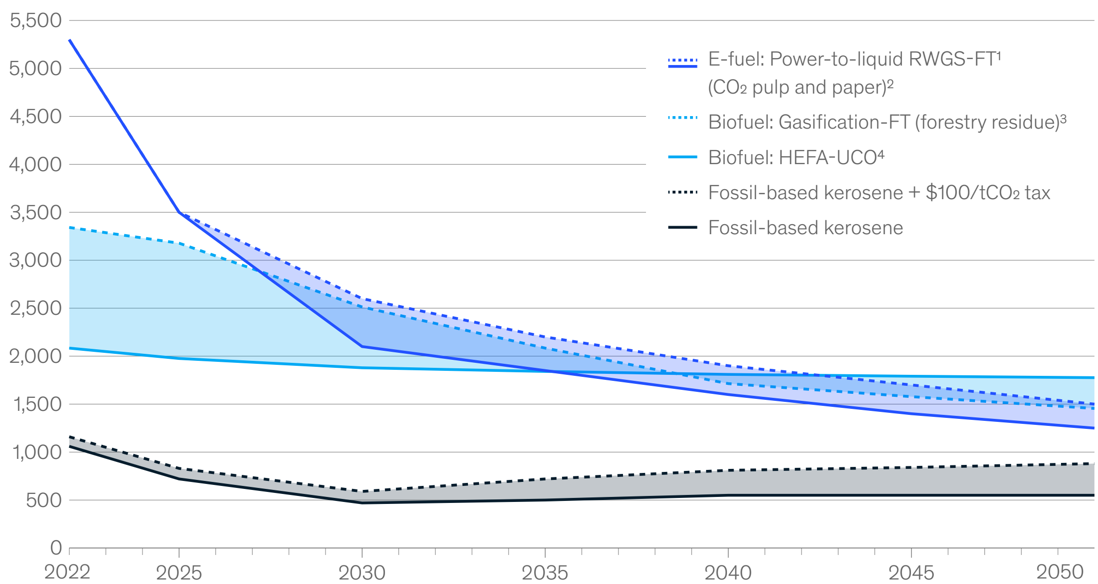
E-hydrocarbon markets could still emerge in the late 2020s, but volumes will likely not become significant compared with bio-based production until the following decade. In addition, the cost competitiveness of different production pathways continues to be uncertain given the limited adoption and the potential to reduce production costs of some of the pathways over time (Exhibit 4). EU regulators have taken the strongest long-term view on the role of e-fuels, introducing proposals to mandate the use of RFNBOs[4] in the transport sector with specific quotas for the aviation and marine sectors.[5] These mandates seek to create a market for those products.

The business case and location choices for e-fuel production are affected by access to affordable renewables, availability of sustainable carbon (e-ammonia, which doesn't contain carbon, is an exception), and integrated production costs of hydrogen derivatives (which are affected by rules such as temporal correlation, requiring storage

Exhibit 4

## Many emerging advanced aviation fuels could become cost competitive with HEFA in the 2030–40 period.

**Unit cost projections for sustainable aviation fuel in European OECD countries,**
$ per metric ton (t) of kerosene




[1]Reverse water–gas shift via FT process.
[2]Hydrogen costs are a range because of high uncertainty in cost-down trajectory and the impacts of regulation (eg, EU correlation on firming costs).
[3]Fischer–Tropsch process.
[4]Hydroprocessed esters and fatty acids produced from used cooking oil.
Source: McKinsey Sustainable Fuels Cost Model, Achieved Commitments scenario, Apr 2023

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[4] Renewable liquid and gaseous fuels of nonbiological origin, a category defined by the European Union's Renewable Energy Directive.
[5] *Proposal for a directive of the European Parliament and of the Council amending Directive (EU) 2018/2001 of the European Parliament and of the Council, Regulation (EU) 2018/1999 of the European Parliament and of the Council and Directive 98/70/EC of the European Parliament and of the Council as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/652,* Council of the European Union, July 15, 2021.

of electricity or hydrogen to produce compliant fuels). Classifications vary by type of hydrogen (for example, carbon intensity or whether electricity source includes nuclear in addition to renewables) and carbon (such as carbon derived from fossil, biogenic, or direct-air-capture sources) and can affect a product's value in the market. Currently, future producers are concentrating primarily on nonfossil carbon sources such as ethanol, pulp and paper, and waste-to-energy plants.

Production can provide opportunities in regions with a high potential for renewables and biogenic-carbon availability, such as Latin America, North America, and parts of Asia and Europe. Africa, Australia, and the Middle East could be major producers of e-ammonia and potentially e-hydrocarbons for markets that allow the use of fossil carbon in e-fuels. The high cost of direct air capture needs to fall dramatically to be competitive with carbon capture from industrial sources.

**Competing policy approaches to support market development**

Multiple countries and regions are active in the global sustainable-fuel market. The European Union and North America are at the forefront in drop-in sustainable fuels. Meanwhile, an established significant market for conventional biofuel has experienced growth over the past 30 years, with bioethanol in Brazil, China, and India and biodiesel (fatty acid methyl ester [FAME]) from palm and soybean oil in Latin American and Southeast Asian countries.[6] Asia–Pacific, Australia, China, Japan, India, Singapore, and South Korea are emerging as potential demand hubs for drop-in fuels such as SAF as well as e-methanol and e-ammonia to serve as energy carriers or fuels for the marine sector.

An examination of the EU and US markets highlights the complex and varied landscape across regions as well as different approaches to spurring adoption of sustainable fuels.

*European Union.* The European Union has set ambitious targets for reducing carbon emissions and is using legislation to support demand. For example, the "Fit for 55" package of legislation, which aims to decrease the European Union's greenhouse-gas emissions by at least 55.0 percent by 2030, establishes targets for the use of renewable energy in the Renewable Energy Directive amendment (29.0 percent for the transport sector by 2030) and specific feedstocks (5.5 percent for advanced biomass and RFNBO by 2030, of which minimum 1.0 percent RFNBO).[7] Proposed legislation would lay the foundation for SAF demand, mandating a 2 percent share of SAF supply in 2025, 6 percent in 2030, and 70 percent in 2050 (of which 35 percent would be RFNBO).[8] By providing long-term demand signals, including compliance mechanisms, EU leaders have sought to create prerequisites for investment decisions.

On the supply side, the European Union and its member states have imposed bans and restrictions on feedstocks that can be used for biofuels. The region is shifting from food crops (such as palm, soy, and corn) to waste and residue streams for advanced biofuels.[9] In addition, it is defining sustainability criteria for e-fuels, favoring biogenic or direct-air-capture carbon and green or low-carbon hydrogen that meets stringent criteria (as laid out in the RFNBO delegated act).[10] A recent proposal to allocate some EU Emission Trading System (ETS) funds from aviation to support SAF adoption could also introduce incentives similar to those found in the US Inflation Reduction Act (IRA).[11]

6 "Biofuels," in *Renewables 2021: Analysis and forecast to 2026*, International Energy Agency, December 2021.
7 "Council and Parliament reach provisional deal on renewable energy directive," Council of the European Union, March 30, 2023; "Interinstitutional File: 2021/0218(COD)," Council of the European Union, June 19, 2023.
8 "Infographic – Fit for 55: Increasing the uptake of greener fuels in the aviation and maritime sectors," Council of the EU and the European Council, last reviewed July 26, 2023; "Fit for 55: Parliament and Council reach deal on greener aviation fuels," European Parliament, April 25, 2023.
9 "Biofuels—updated list of sustainable biofuel feedstocks: Annex," European Commission, May 12, 2022.
10 "Commission sets out rules for renewable hydrogen," European Commission, February 13, 2023.
11 "Directive (EU) 2023/958 of the European Parliament and of the Council of 10 May 2023 amending Directive 2003/87/EC as regards aviation's contribution to the Union's economy-wide emission reduction target and the appropriate implementation of a global market-based measure," *Official Journal of the European Union*, May 16, 2023, Volume 66.

*North America.* The passage of the IRA in 2022 signaled a dramatic shift for the United States. The act features $370 billion in tax credits for the renewable-energy industry, including a credit of $1.75 a gallon for SAF through 2026 and a production tax credit of $3.00 per kilogram (kg) of hydrogen that has GHG emissions below 0.45 kg $CO_2$ per kg $H_2$ (such as onshore wind or nuclear). By attracting investment, the IRA seeks to scale up SAF production to at least three billion gallons a year by 2030, with the goal of 100 percent blending by 2050.[12]

These tax credits could significantly boost manufacturing capacity. However, a high share of projects have yet to clear the financial-investment-decision (FID) stage. Twelve major North American passenger and cargo airlines have made SAF commitments through 2030, but their offtakes are still far from meeting future demand, and few of those offtakes can be considered fully binding.

The North American market also has several policies to support the use of sustainable fuels. For example, the US Renewable Fuel Standard (RFS) and the state-level Low Carbon Fuel Standard (LCFS) programs affect pricing and create markets for credits.

**Aligning market supply and demand**

The different policies and approaches could lead to supply-and-demand imbalances across regions in the medium term. The market could snap back into balance in multiple ways, including the following:

— If capacity ramps up faster than projected demand, additional voluntary use could result—especially in markets with subsidized supply, such as the United States.

— Fuel producers might choose to recalibrate their product slate—for instance, by producing more renewable diesel instead of SAF or more bio-naphtha for the chemicals sector.

— Many projects that have yet to clear the FID stage, particularly those with limited access to feedstock or financing, might not launch or could be delayed for several years. Further, few offtakes and credit schemes are contractually binding for the next seven to 15 years, which is often the payback time required to achieve positive returns in the highly capital-intensive advanced-biofuels and e-fuels pathways.

— Insufficient demand could cause a significant decline in average use of production capacity, leading to compressed margins and slower capacity growth until the market rebalances through growth in demand.

— In the long term, e-fuels or e-crude could become the "new oil," assuming renewable energy production is not constrained, sustainable-carbon trading develops, or the cost of direct air capture approaches that of carbon capture.

**The different policies and approaches could lead to supply-and-demand imbalances across regions in the medium term.**

[12] *Sustainable aviation fuel: Agencies should track progress toward ambitious federal goals*, US Government Accountability Office, revised May 17, 2023.

## Outlook on global trade flows through 2050

The development of sustainable fuels will proceed at different paces depending on category and region. However, based on trends to date, we can make a few observations about how global trade flows could play out through 2050. Currently, a significant share of production and consumption takes place within regions, shaped by various mandates, incentives, and trade rules. Some interregional trade also takes place, notably of feedstocks and fuels—for example, from Asia–Pacific hubs to Europe and North America. Producers outside the United States are increasingly looking to the European Union as a potential export market. Therefore, many of the feedstocks and fuels can be considered as partially global commodities.

Although the recent IRA package in the United States is intended to meet local demand, it is starting to attract more investment to the region. This activity may be contributing to the widening gap in pricing among regions. Some demand patterns are also shifting; for example, airlines refueling with SAF have access to cheaper prices in California than in the European Union. Further, proposed book-and-claim schemes could lead to global or regional optimization of demand volumes based on local incentives.[13]

Looking toward the future, long-term scenarios will likely be shaped by high demand growth beyond the European Union and United States, the increased interest in securing supply, regional and local feedstock constraints, greater market complexity, and the partial commoditization of markets such as renewable diesel and SAF. On one hand, feedstock shortages could lead to the adoption of more expensive or capital-intensive production pathways, such as the conversion of lignocellulosic feedstocks. Differences in sustainability criteria across regions may result in the growth of regional markets and product differentiation based on sustainability criteria.

On the other hand, the rise of e-fuels combined with a scarcity of the biomass needed to support 2050 net-zero scenarios may lead production to concentrate in the global south, depending on the cost of direct air capture and requirements for nonfossil carbon sources. As an alternative, production could be more regional, with sustainability criteria differing by region. The resulting long-term outcome will likely be a mix of global commoditization and local fragmentation, creating opportunities for a range of feedstock, technology, and fuel combinations.

**Although the recent IRA package in the United States is intended to meet local demand, it is starting to attract more investment to the region. This activity may be contributing to the widening gap in pricing among regions.**

[13] When SAF isn't available on a given flight or route, a book-and-claim system enables a company to pay for SAF to be supplied for another aircraft somewhere in the world. This system enables companies to claim the $CO_2$ reduction of SAF on its climate accounting toward Scope 3 emissions while also boosting demand for SAF. For more, see Laura Hutchinson et al., "Clean energy 101: Book and claim," RMI, May 30, 2023.

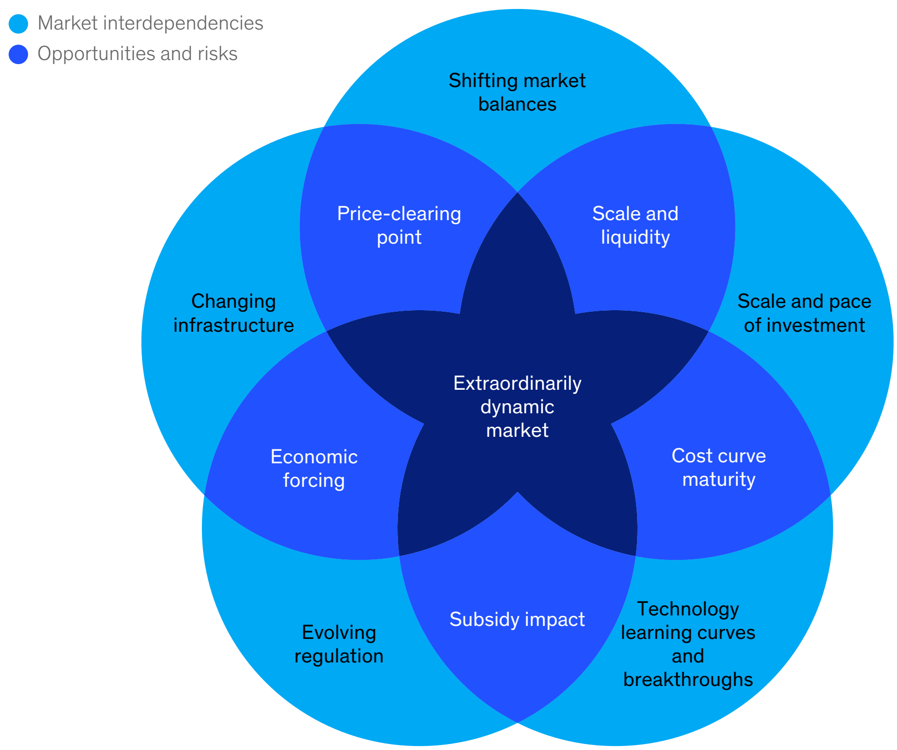
## How traders can win in sustainable fuels

The sustainable-fuel market is poised to ramp up significantly in both scale and complexity. Five interdependent areas will shape the market in the coming years (Exhibit 5). To better identify value creation opportunities and risk, market participants will need to understand how these areas influence one another and how to keep pace with advances. For example, traders that have a good grasp of the shifting market balances but lack an understanding of the pace of investment in new technology platforms could be at a disadvantage.

Given the number of imbalances expected to arise across product categories, traders must develop or enhance several core capabilities to be competitive.

Exhibit 5

**Companies in the dynamic sustainable-fuel market can derive value by understanding the interdependencies in five key areas.**

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### Build a regulatory intelligence team

The regulatory landscape varies dramatically among countries and regions and is evolving rapidly. Traders that develop a deep understanding of local market regulations, credit qualifications, future trends, and potential changes will be better able to shape their trading strategies and secure offtakes or supply arrangements.

The economics of sustainable fuels such as renewable diesel, which has relatively high production costs, are highly dependent on regulatory incentives and vulnerable to regulatory uncertainty. For example, the cost of SAF from HEFA-UCO[14] in Europe without incentives was recently about $2,200 per metric ton, 100 to 150 percent more than the cost of producing fossil-based kerosene today.[15] That means users either rely on substantial credits (such as LCFS, Renewable Identification Numbers,[16] Blenders Tax Credit, or the new IRA credit stack in the United States) to break even or customers pay the required price for mandated volumes and pass those costs on to customers (the primary mechanism in the European Union).

The outlook for many of these programs could be affected by regulatory changes, which will influence the price of subsidized fuels in the years ahead. For example, multiple IRA credits will expire after several years. The RFS program has also historically been volatile, with the price of RINs often driven by legislative outcomes and market perception of new targets set by the US Environmental Protection Agency.

### Develop global trade flow models

Gaining an understanding of global trade flows, while feasible in the current context, will be far more difficult in the coming years given the level of uncertainty, lack of transparency (including the dearth of trade categories for some products), and complexity in the sustainable-fuel market. Optionality is especially critical in this environment. Winning traders will model how fast each commodity will grow and in which market it will likely clear (including within-year demand dynamics) as well as anticipate shifts and monitor key changes in logistics capability and access within regions.

### Enhance origination capabilities

Traders will need robust origination functions to secure offtakes or supply agreements for specific feedstocks and products that offer competitive flow advantages. Successful traders will structure these agreements to balance price, volumetric flexibility, and logistics to enhance optionality and derisk volume flows if market dynamics change. Traders also have opportunities to rent or buy blending facilities, acquire sustainable fuels (including certificates) and fossil fuels, perform blending, and detach sales of molecules and credits—essentially creating a secondary market in a given country for the certificates or "tickets."

Commodity trading organizations attracted to sustainable fuels by their dynamic nature and growth could try to anticipate how the market will evolve and identify inconsistencies in pricing across products or over time, offering opportunities for market arbitrages. Successful traders look for areas of greatest transactional volume and seek to build scale around these opportunities. Often, they will use scale to continue to capture value when margins collapse as the gaps start to close.

### Strengthen the trading team

The interdependencies of feedstock, fuel, and credit prices within sustainable fuels and across other sectors are complex. Successful traders will need to model correlations among products and explore arbitrage opportunities across specifications, locations, and timing. For example, as demand grows for second-generation feedstocks for drop-in fuels, the prices of advanced waste and oils could become more volatile. Through 2021 and part of

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14 Hydroprocessed esters and fatty acids produced from used cooking oil.
15 Giulia Squadrin, "European SAF market takes flight," Argus Media Group, April 17, 2023; "Jet Fuel Price Monitor," International Air Transport Association, accessed August 18, 2023.
16 The US Environmental Protection Agency's Renewable Identification Numbers system is used to enforce and track compliance with the Renewable Fuel Standard program.

2022, for example, soybean oil prices exhibited high volatility in response to intensifying competition from both renewable diesel and FAME producers in the United States amid limited supply from export markets. Feedstocks with limited or scattered availability and competing demand for alternative uses are at greatest risk of such volatility.

The trading team will need to have a broad level of expertise across many different commodities and understand the interplay of those commodities in different markets and products. Specialist trading across high-volume commodities will still exist, but because each market will be influenced by a growing array of factors, traders will need far broader commodity knowledge to be effective.

In the coming decades, the sustainable-fuel market will be transformed by increased demand, substantial investment, disparate policies across regions, and technological advancements. Despite the many factors that will shape the market, rapid growth and volatility could offer enticing opportunities to capture value. Winning traders will develop new capabilities to track regulatory changes, monitor global trade flows, improve origination, and build out their trading teams to navigate this complex trading landscape.

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The authors wish to thank Cherry Ding, Mikołaj Krutnik, and Nathan Lash for their contributions to this article.

# 5 Grid

# Smart scheduling for utilities: A fast solution for today's priorities

AI-driven schedule optimizers are alleviating long-standing headaches for utility companies by reducing employee downtime, improving productivity, and minimizing schedule-related service disruptions.

*by Sohrab Rahimi, Zachary Surak, Jackie Valentine, and Akshar Wunnava*

**Utilities today are** squeezed across multiple priorities—including reliability, cost, and safety—and are facing increasing challenges related to labor shortages, regulatory scrutiny, and a post-COVID-19 hybrid work environment. Companies have generally taken on efforts to address their priorities individually, and this one-metric focus often leads to the inaccurate perception that there is a trade-off among reliability, cost, and safety. As a result, significant optimization improvements remain for those who are ready to take a more holistic, end-to-end approach.

Our experience in process transformation efforts across utilities indicates that the largest drivers of execution waste relate to the initiation of work orders, planning and scheduling handoffs, and information silos. Many of these issues can be traced back to traditional work management processes, which rely heavily on many time-consuming and inconsistent manual processes.

Smart scheduling involves analytics-powered algorithms and user-centric interfaces that can be deployed in a matter of months and within existing systems to build better, faster schedules. AI-enabled smart scheduling that efficiently matches resources with work can transform companies' ability to drive long-needed improvements across multiple competing priorities. It can free up scheduler time, boost worker utilization, and increase productivity by 20 to 30 percent. These additional resources can then be used to reduce overtime, insource contractor spend, or reduce job backlogs.

In our experience, successful deployment of smart-scheduling tools requires utility companies to learn five key lessons:

— Data are crucial but should not be a barrier to starting.

— Technology must work in conjunction with processes.

— Businesses must clearly specify their optimization criteria.

— Piloting, followed by intentionally scaling, a "light tech" scheduling solution is vital to increasing adoption.

— Solutions must be user-friendly and holistic.

## Deploying new technologies can significantly improve scheduling

In a previous, industry-agnostic article, we laid out how optimizing work management—starting with smart scheduling or scheduling optimization—can improve grid reliability, the efficiency of capital deployment, cost, safety, and employee engagement.[1]

**AI-enabled smart scheduling can transform companies' ability to drive long-needed improvements across multiple competing priorities.**

[1] Jorge Amar, Sohrab Rahimi, Nicolai von Bismarck, and Akshar Wunnava, "Smart scheduling: How to solve workforce-planning challenges with AI," McKinsey, November 1, 2022.

Schedule optimization, however, is one of the most challenging optimization problems due to variations in types of work and operations. This variation makes solutions hard to generalize and therefore hard to scale. Additionally, the mathematical complexity of optimization equations and the number of decision variables mean models take a long time to run. To be truly useful, optimization models need to operate in almost real time so that they can react to changes such as employee sick days and unexpected demand surges.

While classic optimization models have been around for decades, the advent of new technologies in AI and cloud infrastructure allows for the rapid development and deployment of tools that bring deep analytics and optimization engines to the scheduling process. These tools have also reduced the cost of deploying an end-to-end schedule optimization solution and can sit on top of existing work management systems. Additionally, using AI improves the quality and functionality of scheduling in a number of ways:

— offering the most optimal solution given a range of interdependent constraints and dynamic, ever-changing demand

— providing a consistent, systematic approach with no human bias

— delivering significantly faster computation than manual processes, which improves the ability to adapt to unexpected changes in operations

— lowering HR requirements, which frees up capacity to focus on other areas

## Smart scheduling offers benefits for utility companies

For electric and gas utilities, scheduling is a central function that matches demand for services with the crews, materials, and equipment needed to perform those services. Utilities have a variety of different work types—including emergency jobs, short-cycle jobs, and long-cycle jobs—with varying scheduling dynamics. Smart scheduling provides benefits for each work type:

— Emergency jobs have high importance but low predictability and may require a crew to be immediately reallocated from another work site. These schedule "break-ins" require real-time juggling of crews and often cause churn and rework for schedulers. Smart scheduling can help block off capacity for these emergent break-ins via dynamic schedule loading. For example, only 60 to 70 percent of capacity may be allocated in a given week if algorithms predict, based on historical data, that 30 to 40 percent of time will need to be spent on emergency jobs. Smart scheduling can also identify the optimal crew to address the emergency job based on factors such as geographic proximity and the priority and state of the crew's current job.

— Short-cycle jobs can typically be completed within the day. They range in complexity: some jobs may require one crew for an hour or two, while others—such as hydro-vacuum excavation—may require several crews for a full day alongside coordination with third-party contractors. The scheduled duration for a short-cycle job may often be several hours more or less than the actual requirement, leading to either a schedule backlog or underutilization. Smart scheduling can better estimate the durations of these jobs using a combination of historical performance and factor-driven adjustments. For example, data on local soil composition can be used to estimate the time needed to dig.

— Long-cycle jobs may require multiple days to complete, and the main challenge is to ensure continuity by scheduling the same crews for the whole duration. These jobs often come with multiple crews and pieces of equipment, plus third-party contractors, which means that smart scheduling can ease the significant mental burden on schedulers.

Schedulers need to coordinate the availabilities of crew, materials, and equipment ahead of time to ensure that all components are ready on the day when the work is to be done. Depending on the type of job, schedulers may need to create crews of different sizes—generally one to four full-time equivalents (FTEs). Additionally, crews may be qualified only for certain types of jobs, and some jobs (particularly those related to electrics) may also require materials that are not in stock and that have a long lead time once ordered. Most gas jobs, on the other hand, can be done with the materials readily found on trucks. Finally, jobs may require special equipment such as backhoes or diggers.

One of the largest pain points for crews is job delays or "false truck rolls," which occurs when a job cannot be started or completed on time due to the unavailability of the right crew, materials, or equipment. Smart scheduling can help ensure all job components are ready before jobs are incorporated into the schedule.

**The tangible benefits of smart scheduling for a US utility**

In our previous article, we laid out the significant, tangible benefits accrued by a US electric and gas utility after it piloted a machine learning–based schedule optimizer[2]:

— *Lowered HR requirements for scheduling.* Scheduler productivity increased by 10 to 20 percent, which is the equivalent of freeing up one to two scheduler hours per day.

— *Increased automation for flexibility.* AI models automate initial schedule builds and ongoing optimization and can react to changes in the system (for example, COVID-19, seasonalities, or workforce changes) within one to two days. Manual schedulers may take much longer to adjust to such shifts.

— *Reduced waste.* Over the six-week pilot, dynamic schedule loading and a decreased number of prematurely scheduled jobs meant that break-ins were down by 75 percent, job delays by 67 percent, and false truck rolls by 80 percent.

— *Increased crew utilization and field productivity.* Prior to the pilot, crew members at one of the utility's sites spent 44 percent of their time actually working on jobs (as opposed to being unassigned, training, or traveling). In the automated, optimized schedules, crews could expect to spend 65 percent of their time on jobs. Overall, the pilot achieved an approximate 20 to 30 percent increase in field productivity (Exhibit 1).

## Five lessons for utility players in deploying a smart-scheduling solution

Based on our experience, there are five core lessons to keep in mind during the development and deployment of smart-scheduling solutions in a utility context.

**1. Data are crucial but should not be a barrier to starting**

Many utilities often delay analytics-based scheduling efforts due to a lack of trust in data quality. Most leaders have a misperception that data need to be rich and easy to digest to begin to get value from AI-based tools, but the opposite is true: a small amount of data can yield disproportionate insights. In fact, new data-processing methods can take existing data and make them usable for AI models. To achieve optimal results, utility players will need to map their data landscape and find resolutions to any issues that compromise the quality or usability of the data (see sidebar, "Mapping the data landscape"). This process frequently highlights the relative importance of specific data that can then be prioritized for better data governance and stewardship, which can further increase the accuracy of AI outputs.

These processes can be conducted in as little as three weeks, but space must be built into any smart-scheduling rollout timetable. This time is used to prepare and process data related to timesheets, HR, and job backlogs, as well as to evaluate data quality and to run preprocessing modules to prepare data sets to be used by the AI engine.

**2. Technology must work in conjunction with processes**

Smart scheduling will be effective only if it works for the end user. Therefore, new technologies

[2] "Smart scheduling," November 1, 2022.

Exhibit 1

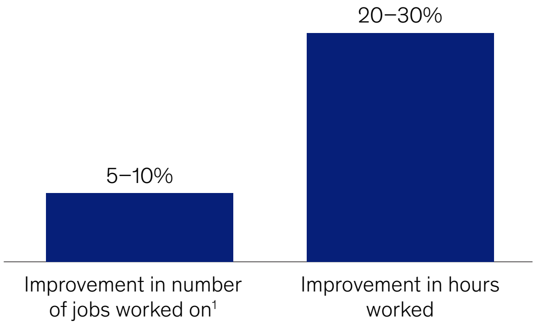
## Smart scheduling at an electric utility improved field productivity and reduced waste by 20 to 30 percent.

**Improved field productivity and reduced field waste over a 6-week pilot**

**80%**
reduction in false truck rolls

**75%**
reduction in break-ins

**67%**
reduction in job delays




[1]Increase occurred during peak training time, Omicron variant outbreak, and winter weather.

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## Mapping the data landscape

**Utility players** will need to map their data landscape—that is, understand data quality and relationships between data sets—to identify resolutions to any potential data issues.

**Potential data and operational issues**

— Changes to work orders are not tracked over time.

— Schedules are not locked, making tracking adherence challenging.

— Travel time may not be accurately coded.

— Job duration estimates are inaccurate.

— Too many data sources can be overwritten by human inputs.

**Potential resolutions**

— locking schedules to allow for better metric tracking

— updating job duration estimates

— estimating travel time based on typical patterns

— identifying unknown gaps in crew timesheets to improve quality of crew metrics must be developed in conjunction with efficient scheduling processes, which should be codesigned with frontline employees. Digital tools, such as smart-scheduling engines, codify the underlying processes, meaning that organizations that do not optimize their processes in tandem with the development of technical tools are at risk of codifying inefficiencies.

Getting the most out of new digital tools may require some or all of the following process improvement initiatives:

- clear job readiness checklists that take into account the specificities of each electric or gas job
- break-in management processes that reduce nonemergency break-ins and quickly reorder the schedule to address emergencies
- efficient handoff meetings to align stakeholders such as schedulers, field supervisors, and warehouse managers
- prejob walkthroughs to ensure site readiness

Additionally, the successful deployment of digital tools requires continuous maintenance of the technical models. This work will require a number of different skills profiles, including capable data scientists, data engineers, and cloud engineers.

**3. Businesses must clearly specify their optimization criteria**

A smart-scheduling engine can optimize frontline schedules based on several evaluation criteria. For example, the engine could maximize the number of jobs scheduled, minimize operating costs related to shifts or travel time, or maximize service levels by reducing customer wait times. To achieve the best results, it is imperative that business leaders feed clear objectives into their smart-scheduling engine.

**4. Piloting, followed by intentionally scaling, a "light tech" scheduling solution is vital to increasing adoption**

Smart-scheduling solutions can be developed as "light tech" overlays on top of existing systems and do not require platform overhauls ("heavy tech"). Algorithms can often be tested in an isolated testing environment to pilot the efficacy of a scheduling optimization solution. This piloting, which should be done in conjunction with schedulers, is essential to train the model for the specific utility company and context. For example, variations in regulations or union-specific requirements can have a significant impact on the details of an optimized schedule.

**To achieve the best results, it is imperative that business leaders feed clear objectives into their smart-scheduling engine.**

A key metric during the pilot period is the frequency of manual schedule overrides by schedulers. These overrides can indicate an issue with the underlying model and should therefore happen as seldom as possible. However, some manual intervention will always be required to address last-minute contextual changes such as sick days or employee holidays.

In our experience, it takes at least four to six weeks for smart-scheduling algorithms to reach a 70 to 80 percent match with the final schedules previously created by schedulers, as measured by the percentage of jobs and crew pairings that are the same in each (Exhibit 2). While an optimal schedule is unlikely to exactly match the existing manual schedule, a relatively close match is a good indication that the new algorithm is factoring in the right parameters and will not require frequent manual overrides.

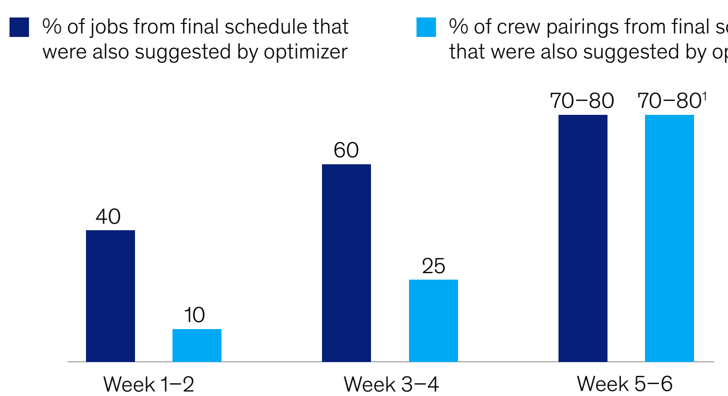
Pilots can also be an important way to build support for the new scheduling methods within the organization, which can make the subsequent rollout easier. In the US utility example used above, schedulers—who were spending four to seven hours a week building and updating the manual schedule—saw that the new technologies could build automated schedules that closely matched their own within minutes.

After a successful pilot, it is important to execute a well-thought-out scale-up plan. This plan should take into account factors such as overall deployment speed, deployment across work types (that is, there may be different considerations for electric versus gas jobs or for short-cycle versus long-cycle jobs), the differing challenges of rural and urban service centers, and resourcing the scale-up (for example, potentially hiring change champions or trainers). Tools and processes can be scaled up in an agile fashion because making iterative improvements over time is generally preferable to trying to perfect the algorithms during the pilot period.

Exhibit 2

**Schedule optimizers can improve to build 70 to 80 percent of the final weekly schedules in just four to six weeks.**

**Typical improvements in scheduling by AI-driven schedule optimizer**




[1]Improvement of about 50 percentage points from week 3–4, driven by favored crew pairings.

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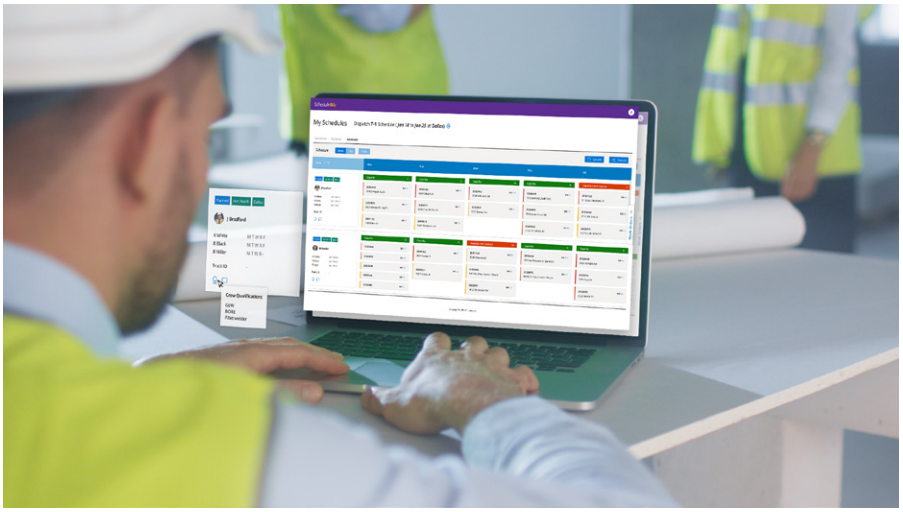

Scheduling interfaces could have several user-friendly features.

**5. Solutions must be user-friendly and holistic**

To operate successfully, schedule optimization needs to be integrated into a user-friendly, end-to-end digital solution. The final, holistic solution must update constantly, forecast accurately, and incorporate an easy-to-use, interactive front-end interface. Many schedules are currently based in Microsoft Excel, and the benefits of the automated, AI-optimized schedule can be multiplied if companies can incorporate features such as daily or weekly drag-and-drop schedules and a metrics dashboard.

Scheduling interfaces should incorporate user-friendly features, which could include the following:

— preloaded, optimized schedule

— prioritized work orders

— simple and real-time edits

— precise information display

— flexible crew management

Inflation, supply chain issues, and ongoing labor disruptions are making work optimization—which has long been one of the most challenging problems for consumer-facing industries such as utilities—even more complex. When deployed thoughtfully as part of a holistic solution, AI-driven schedule optimizers can significantly improve work management processes, smooth out operations, and boost overall productivity.

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# Winner takes all? Digital in the utility industry

With the utility industry so fragmented across North America, can digital platforms enable it to consolidate at scale, resulting in lower prices, better service, and more satisfied customers?

*by Adrian Booth, Eelco de Jong, Ben Elder, and Aditya Pande*

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**Load growth is slow,** energy prices are soaring, inflation is rising, and grid reliability and resiliency is becoming an ever-present concern—North America's population is under pressure and would welcome an easing on their wallets from the utility industry. Meanwhile, most utilities' bold aspirations to reduce their carbon footprint to net zero over the next few decades are being met with capital, labor, and materials challenges that make achieving this goal uncertain. For public utilities, these challenges are only further amplified by earnings pressure amid a volatile energy market. And the grid is only getting more complex to operate as distributed energy resources introduce an influx of new information and variables into the system.

## Key questions to be asked

With these issues in mind, solutions need to be sought. The North American utility industry is massively fragmented—over 3,000 electric utilities and many more gas and water ones—across three primary ownership models that are either investor- or municipal-owned utilities or cooperatives.[1] This raises questions:

*Why hasn't the industry consolidated more to take advantage of scale and best practices to deliver a better product at a lower price with higher customer satisfaction?* At this stage, it is very difficult to prove that they can provide this. Many proposed M&A strategies run into well-meaning, state-based utility commissioners, city managers, or cooperative shareholders who may wish to protect local communities and potentially disallow the typical M&A deal synergies—such as reducing corporate overhead costs and operational expenses that could risk service levels or other actions, leading to lay-offs, higher customer rates, or reduced service levels. When trying to compare utility performance, discussions often quickly get lost in the nuanced differences of each utility—such as whether it is urban, suburban, or rural and overhead or underground; weather and vegetation variations; historical capital-spend levels per customer; or age of assets.

*What if there were a way to build a utility that could demonstrably prove that it could provide a better product and service at lower rates?* Digital disrupting business models across industries are increasing rapidly. This began with entirely new sectors being created (such as search or social media); some of the companies in those sectors are now among the world's most valuable. Then disruption moved to mostly "asset-light" industries: those where the product or service was primarily based on information or data such as banking, media, or insurance. The disruption then traveled to industries where physical products were involved, for example, e-commerce. Now the disruption is increasingly blurring the lines between physical and digital such as Tesla and Peloton Interactive—where the combined digitally-infused physical product is fundamentally superior to alternatives. Despite this, the utility industry barely takes advantage of digital.

*What if monopoly-based sectors could use digital to disrupt the monopoly structure?* As digital has not yet fully infiltrated the utility industries, what would happen if the regulated utility networks of electric, gas, and water businesses could use digital to deliver electrons and gas or water molecules in an alternative fashion? At present, there is little evidence that the industry is pursuing such innovation at the same scale and pace seen in other industries, so why not flip the question on its head and ask: If digital could enable a utility to provide a fundamentally better product and services at lower rates, what could that do to the utility industry's underlying structure?

In this article, we explore answers to these questions, expose the significant opportunities that the space presents, look at what is needed to build a digital utility platform, and identify six key factor for success.

[1] *United States Electricity Industry Primer*, Office of Electricity Delivery and Energy Reliability, US Department of Energy, July 2015.

## A modern digital platform: A once-in-a-generation consolidation opportunity

Digital could open an exciting consolidation opportunity for fast-moving companies that create digital platforms to meet their customers' needs. The pace of technological change is increasing—look at the fast-decreasing cost of cloud computing, the growing availability of powerful machine-learning (ML) and AI capabilities, the rapidly evolving tools to deal with persistent and chronic data issues, and the increased intelligence in smart phones.

While more utilities are starting to adopt many of these digital trends, the rate of adoption is not keeping up with the pace of innovation. The opportunity gap to improve key outcomes by deploying technologies and methodologies that have been utilized in successful transformations increases every day.

The evidence for digital is clear. When working with leading utilities, we have seen exceptional step-change improvements in select use cases such as:

— a 25 to 30 percent field productivity improvement from AI-powered scheduling

— up to an 80 percent capital reallocation based on ML insights in asset health

— more than a 30 percent improvement on customer satisfaction in select journeys

— a 2 to 5 percent increase in heat rate or yield for fossil as well as renewable generation assets

— more than a 30 percent improvement in reliability and resiliency outcomes within existing spend levels

If the "product" is defined as clean, reliable, resilient, safe, easy-to-do-business with, and an affordable energy or water service, then a step change in every dimension is possible. This can be done by looking at a collection of already-achieved impacts from utilities using select digital use cases.

## A digital platform on top of an available technology foundation

What would happen if a digital platform that deploys every known high-impact use case to its full extent was built on top of a flexible, extensible, available technology foundation that could "bolt on" additional utilities?

While almost all major utilities are utilizing digital, data, and analytics in some fashion, it appears that few executive teams can articulate a cohesive strategy on how a comprehensive digital, data, and analytics platform could provide "best-in-class" outcomes across reliability, safety, resiliency, affordability, and customer experience—with no trade-offs.

In our perspective, if a cohesive strategy is not devised within a three-to-five-year timeframe, likely no one will "break out of the pack" and the industry will continue on its linear improvement trajectory.

However, bold industry companies that adopt a digital platform could achieve a step-change performance ahead of peers and, more important, use the once-in-a-generation opportunity to fundamentally restructure the entire industry. The value at stake is massive for those that take action. They could invite energy regulators, customers, and communities to join an unbeatable deal—a digital utility platform that provides the best reliability, safety, resiliency, affordability, and customer experience. Those jurisdictions and utilities that connect to the platform could be set up to tackle the energy transition from a position of strength. If the core utility product can be offered at lower cost and better customer experience, it will create more headroom to invest in carbon-free technologies or improvements in grid resiliency, or both.

Many stakeholders would need to be involved to achieve this, including customers, investors, policy makers, and regulators. The regulatory relationship would be critical, given the authority that regulators generally have in approving (or disallowing) investments. For the vision to succeed, it would require an open utility and regulator relationship, with both willing to explore a new partnership based on transparency and verifiable outcomes.

## What it will take

Building a base that can serve as a comprehensive multi-utility platform will require a detailed, layer-based framework and associated design elements. These layers can collectively transform legacy utility architecture into a "digital-native-style," secure, and inter-operable platform that allows business services to be scaled across utilities (exhibit).

## How to build it: A new approach and new leadership

Most utilities are already building parts of these features across some layers of their tech-stack; in other words, these features are being built on a use-case by use-case scenario—think of it as "drip irrigating" a farm with new elements. While these enable specific use cases, the escape velocity that is needed for all the layers to be in place will take too long to deliver an efficient model quickly. Moreover, this is an optimistic outcome that will require a lengthy history of delivering cross-business use cases, alongside a visionary enterprise architecture team that can enable the organic build-out to collectively scaffold this cross-layer end state.

Building the multilayer future state will require a cross-functional team and a close partnership with the enterprise architecture organization. The team needs to set the intention to focus on creating and delivering this future state, while the rest of the IT organization delivers nearer-term use cases and other "must-do" regulatory or systems migrations.

### A platform architecture road map

Building such a platform will be a multiyear endeavor, and utilities will need the ambition and the resolve not only to embark on the journey but to stick with the aspirational vision over a three-to-five-year horizon, and buttress against shifting priorities throughout. Various key enablers are necessary to have in place upfront to put utilities on the path to success when making this leap.

*A strong business case backed by estimates of measurable business value* will be needed to develop a long-term road map and strategy and return value to the utility. The road map could include the series of strategic investments required to deliver the transformative business-enablement platform, and an estimate of the necessary foundational investments. Further, leadership will need to keep front of mind the necessity for significant new talent and partnerships to create the blueprint and execute the build-out of this platform.

*New technical capabilities and skillsets* will be required, including cloud engineering, DevOps, and data science. Digital skills like these will be critical to deliver the target state platform. Utilities will need to ensure that best practices around core cloud and software engineering capabilities are in place—for example, Infrastructure as Code, cloud FinOps, automated testing, and cybersecurity.

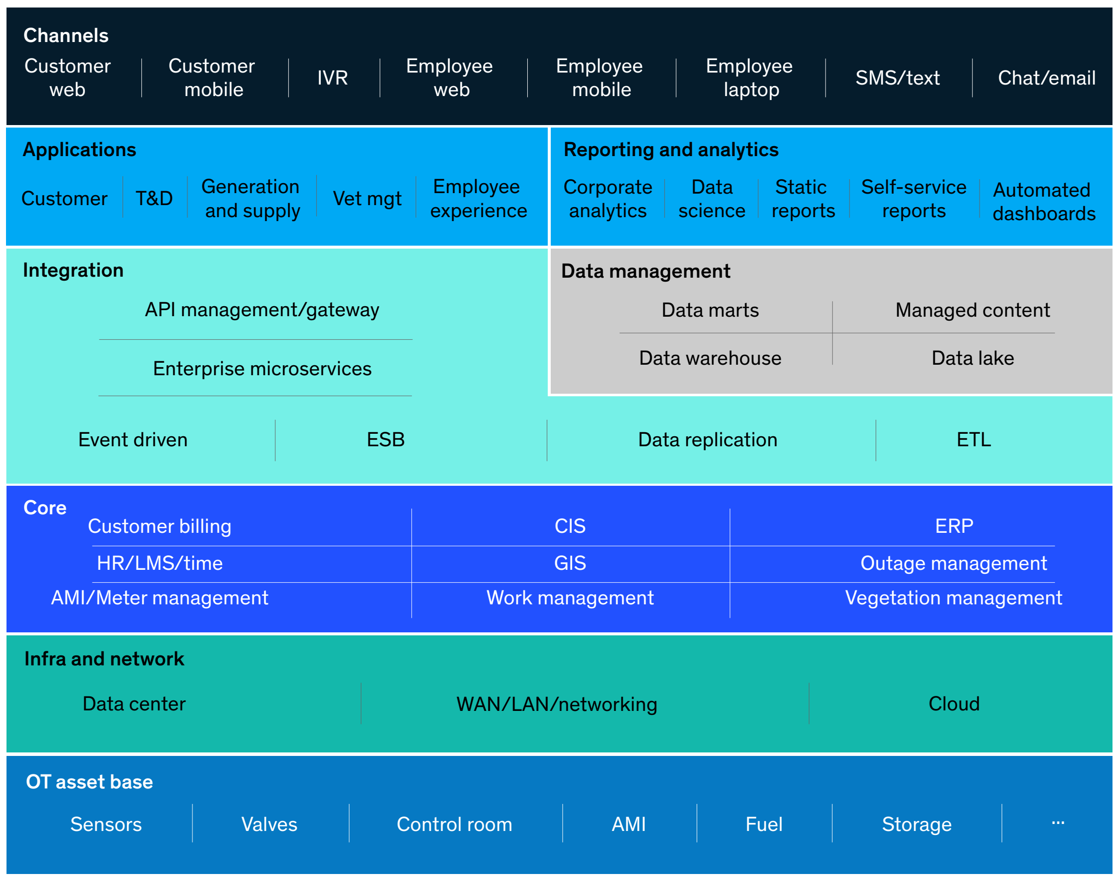
*A well-defined set of foundational architecture principles and a lean tech governance mode*l will be necessary to ensure that maximum value from the investment is returned to the business. This is essential to steer strategic design decisions made along the way. An architecture governance model, backed by a shared set of principles and guardrails, could drive delivery consistency through the use of acceptable patterns, streamline technical decision making, and empower delivery teams by giving them the autonomy to move at pace with agility.

*Strong organizational cooperation and commitment by multiple stakeholders* will be essential, beginning with the C-team and board. As this transformation is a multiyear journey, dedication and support from top-level leaders will be important to stay the course, with frequent and consistent communication at all levels. The

Exhibit

## Adopting a digital platform architecture model could enable a utility to forge ahead of competitors.

**Components of a digital platform architecture model**




### Key characteristics

- **Unified user experiences:** fragmentation of experience across apps and tools is one of the most common pain points for utility field workers today. Reusable UX components and cross-platform development help deliver consistent and seamless experiences in the field.
- **Analytics ready:** empowering citizen development through analytics sandboxes and self-serve reporting.
- **Enterprise APIs and microservices:** a well-defined catalog of domain-driven APIs enables utilities to build fit-for-purpose omnichannel solutions on top of, but decoupled from, core enterprise systems.
- **Robust core system integration:** most utilities struggle to access and leverage the data in their core enterprise systems (eg, assets, work orders, customer, etc.). A modern platform will provide near real-time integration to read from and write back to core systems for analytics and app use cases.
- **Cloud native:** moving workloads to the cloud and leveraging elastic scale for storage and compute is helping utilities drive down capital and O&M costs across BUs.
- **Leveraging the Internet of Things data explosion:** the abundance of data from AMI and smart sensors has largely gone untapped by utilities. A modern platform will curate and synthesize this data for predictive modeling use cases.

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development of the target state platform needs to be a collective effort—it cannot be achieved in isolation. Business stakeholders could consider partnering with the whole IT function to ensure the alignment of goals and outcomes, address dependencies, and reduce risk.

## Three phases of transformation

We have observed that a successful transformation to a digital utility platform takes place over three phases.

**Phase 1: Developing foundational patterns for integration architecture**

The first step in implementing a target state platform model is to establish foundational patterns for system integration and platform consumption. The integration layer is a vital starting point—getting it right means fewer headaches during large system upgrades or consolidations in the future. Getting it wrong, however, can lead to multiyear overruns of large system modernization efforts.

A sound integration architecture could decouple user-facing systems of engagement from the backing core IT systems, thereby reducing dependencies and eliminating sizeable tech debt. This often accrues when utilities build business functionality within rather than on top of core IT systems. With this layer of abstraction in place, future M&A efforts could be simplified and consolidations made easier. Applying the architecture principles from the lean governance model at the integration layer could serve as a replicable blueprint for scaling and expanding the platform over time.

We recommend beginning by focusing on use cases within work, asset, or customer management as these core IT systems are central to many digital value cases. Organizations can start with one or two foundational use cases (such as customer payment journey or asset analytics) to prove end-to-end platform integration. For these use cases, the integration patterns can take two forms: operational integrations and analytics. Operational integrations can exist as managed enterprise APIs, designed to provide abstracted, consumable interfaces to read from and write back to core systems themselves. Analytical integrations can serve to build out of the "enterprise data hub," replicating data from core systems—often in streams or real time—for analytical use cases.

Successful delivery of this foundational integration architecture layer requires a combination of strategic guidance from enterprise architecture to help steer teams on key design decisions. Additionally, new or underrepresented skillsets, such as data engineering, may be needed in the organization for it to scale, as well as a sound cloud strategy and infrastructure automation capability.

**Phase 2: Establishing consumable interfaces, integration points, and self-service tooling**

With the foundational integration patterns in place, the next step comprises the development of consumable interfaces and integration points, and the associated self-service tooling roll out. Socialization of the enterprise APIs, data marts, and available integration points through living documentation artifacts (like Swagger or wiki-hosted data catalogs) could open the doors for business as consuming apps, dashboards, automation bots, and other products begin leveraging the platform's offerings. A self-service model is ideal, where consuming teams have everything they need at their fingertips to find, connect to, and communicate with points of integration across the platform. Sandbox environments (secure, isolated areas for experimentation with data and integrations) could be set up to encourage citizen development—a safe way to explore new use cases for harnessing the data within the platform.

**Phase 3: Incrementally scaling to additional domains and expand off-the-shelf accelerators**

Once the first end-to-end use cases are delivered for a given domain, phases 1 and 2's processes can be repeated to expand the API and data catalogs with additional business domains, data sets, or system integrations. These could be based on use cases and prioritized by business value. In addition, the integration patterns defined in phase 1 could be applied to additional core systems (such as planning, scheduling, and outage) to bring new read or write capabilities to consuming apps and user-facing products. As the platform delivery initiatives scale and capabilities mature over time, efforts could be focused on the development of assets and capabilities to accelerate platform adoption for consuming use cases. For example, this could include software development kits (SDKs) for easy platform integration or reusable components for engagement-layers (including dashboard widgets, mobile and web libraries, forms, and more). Assets like these can accelerate development and help speed up the adoption of tools across business or customer workflows. More advanced acceleration use cases may include cross-platform services like event hooks or notification services.

Within the data and analytics space, an open-source library of baseline analytics models could help kick start new teams or inspire new citizen-development experiments to unlock untapped value from existing data sources.

## Beyond IT: What also has to be true to transform the industry

Building a comprehensive digital utility platform is much easier said than done. Taking key lessons learned from other sectors, we have uncovered six significant factors that could lead to success.

1. *A strong CEO and executive team backed by a board willing to stay the course.* While achieving a better product and service is likely a technical certainty, the path can be rocky. Data privacy, cybersecurity, model drift leading to adverse outcomes, critical talent leaving, and many other issues can derail short-term efforts. Yet an organization with a strong CEO and high-performing executive team committed to the vision will likely overcome such obstacles. Technology talent, however, is vital for a successful team—utilities are often run by engineers, lawyers, and accountants without the necessary technical expertise to guide change.

2. *Product and platform agile operating models combined with lean management principles.* More legacy companies, from automotive to energy, are realizing that they need to adopt a new agile operating model and product development culture. For a successful utility platform to be built, a fundamental change needs to happen across the enterprise from the frontline, back office, the executives, and the board room.

   IT and business siloes need to be completely broken down into sustained, impact-oriented product teams, with platforms carefully separated into systems of record versus product that represent systems of insight and engagement. Correspondingly, the product manager's or product owner's role will become more important. A large utility will likely need to hire or train more than 30 product managers—a quick search online across major utilities indicates the current dearth of product-manager or product-owner roles.

   Beyond digital products and platforms, the rest of the utility organization needs to accelerate more than 30 years of lean management system into three to five years. Here's the opportunity for utilities to move waste and variability, improve frontline problem solving and accountability, enable performance dialogues, and operate a utility with a cohesive operating system—all enabled by lean management system thinking. The combination of lean plus digital is critical: research shows that the hardest part of digital transformations is not talent, technology, or data (although those are difficult enough) but driving operating-model changes that ultimately ensure that the intended business outcomes are achieved.

   To enable this new operating model, winners will hire more employees like agile coaches, ML engineers, or full-stack developers—people who are in great demand globally. Utilities need to attract this talent by creating compelling career paths linked to the opportunity to build an industry-leading digital platform that drives industry consolidation and plays a meaningful role in the energy transition. Companies could consider "acquihiring" a lot of talent at once by buying one or more small software start-ups.

3. *Key differentiators that are built, not bought.* Building a comprehensive digital utility platform is not just about upgrading to the latest management system. Research shows that reliability, safety, resiliency, affordability, and customer experience, among others, have to be internally developed for organizations to achieve best-in-class levels of insight and action and industry-leading differentiation.

4. *Domain-based and design-led customer service and workflows.* Domains need to be at customer-care level, electric-distribution asset management, workforce management, and supply chain. Core utility customer journeys (such as paying bills or reporting an outage) and utility workflows (for instance, vegetation or asset management) can be reimagined by using design thinking to create better products and service. While all domains are important, the most critical is getting supply chain right—this will enable industry consolidation. Utilities spend substantial amounts of capital on supply chain but, due to the incredibly fragmented industry, wield almost no buying power. The winning industry consolidator will most likely have a meaningfully better, digitally enabled, supply chain.

5. *Recognizing the importance of cloud.* A 100 percent cloud-based platform that recognizes the flexibility and AI-powered capability of cloud far outweighs any capital-expenditure or operating-expenditure accounting treatment. "The digital utility platform needs to be in the cloud," is not a technical statement anymore. Whether the IT infrastructure is in a data center or the cloud is irrelevant—what is important is that cloud capabilities far surpass what is generally available in an on-premises data center—as shown by the pace of available data science and ML and AI capabilities that major cloud providers (such as AWS, Azure, and Google Cloud) have released in the past few years. Regarding the global utility industry in this space, an important milestone was reached in 2019 when Enel (Italy's national entity for electricity) became first large utility to be 100 percent cloud-based.[2]

6. *Developing stakeholder skills to enlighten and empower regulators, legislators, the workforce, and other stakeholders.* Historical or legacy regulatory requirements that were mostly put in place in reaction to, or in anticipation of, historical events can hinder progress. Radical transparency is required to educate all stakeholders, partially enabled by a much more rigorous approach to data.

When a utility is transformed by both digital and lean management using the principles above, three things will likely be true. First, the utility could be higher performing (for example, across reliability, resilience, customer satisfaction, safety, and compliance) and more affordable. Second, with a rich focus on data and analytics, the utility could have the ability to prove better performance and cost outcomes to third parties, which would enable an M&A strategy. Third, the digital platform and operating model will be extensible so that acquired utilities could be "bolted on" to improve the utility's performance.

## The path ahead

It's not clear yet whether any utility in the North American industry has transformed enough digitally to impact the fundamental industry structure. A number of utilities have digital transformation strategies underway in various forms—some are standing-up digital units (for example, using the digital-factory concept), some are systematically

[2] "Enel 'full cloud': All the advantages of being the pioneers," Enel, July 11, 2019.

upgrading their core systems, and others have made great progress in specific journeys or domains. While it's difficult to estimate exactly how much investment is required, it is likely to be between $500 million and $1 billion. A winner with across-the-board, industry-leading performance and a compelling M&A platform could build a $200-billion-plus value company—one that consistently delivers top-quartile reliability and customer experience while keeping customer rates among the lowest in the industry.

This is a once-in-a-generation moment. Significant step change in performance could be achieved in a consolidated, regulated industry that is asset intensive, engineering focused, and safety conscious. The first few leaders who recognize the end-to-end opportunity in a greenfield digital utility platform—one that drives an M&A strategy to bring a better and more affordable energy product to millions of customers—could accrue disproportionate value. Why wait?

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6

# CAPEX

# Europe’s €10 billion savings opportunity to deliver onshore wind and solar

With Europe’s demand for wind and solar photovoltaic (PV) power set to more than double by 2030, the industry will be hard-pressed to scale up in time—unless it finds a new way to deliver capital projects.

*This article was a collaborative effort by Antoine Engerand, Alessandro Gentile, Jochen Latz, Igor Stepanishchev, and Benjamin Thaidigsmann, reflecting views of McKinsey’s Operations practice.*

**The total EU capital expenditure** for the energy transition could reach €1.7 trillion by 2030, with around 45 percent going towards onshore wind and solar photovoltaic (PV) capacity. Accordingly, between 2023 and 2030, annually installed onshore wind capacity would need to more than double over the levels achieved between 2018— and 2020—and solar PV capacity would need to more than triple.

Companies involved in capital projects for these renewables would likewise need to double or triple their project pipeline in a very short time—and do so efficiently. Can the construction industry manage this unprecedented growth? Today, Europe's renewables construction sector is facing serious challenges. These must be overcome if the region is to meet its energy transition targets.

## Challenges facing the renewables ramp-up

Ramping up organizations quickly often comes at the cost of productivity. Added to this is the fact that onshore wind and solar PV are not yet fully mature industries, with limited examples of successful, quick ramp-ups. To achieve fast scale-up, companies can no longer rely on individual experts to deliver results—instead, they need a more standardized approach so that best practices can be consistently followed in capital project delivery.

There is a talent shortage for the scale-up of renewables projects in the European Union (EU).[1] By 2030, the full-time equivalent (FTE) requirements for renewable energy sources (RES) in the EU will be triple the 2020 levels. Additionally, the renewables sector faces high competition with other growing infrastructure sectors that have similar FTE skill requirements, such as grids, telco, and rail.

Alongside the talent scarcity, there are also land shortages for wind and solar farms, as well as long and unpredictable timelines for obtaining relevant development permits. Large-scale grid infrastructure is equally important: renewables projects may wait for months or even years before getting connected to the grid.[2]

The entire supply chain, including original equipment manufacturers (OEMs) and engineering, procurement, and construction (EPC) firms, faces those ramp-up challenges as well as added pressures. Scarcity of hard-to-substitute rare-earth metals—such as neodymium and praseodymium, used in wind turbines—raises prices and slows production. Price spikes for more common materials, such as copper, silicon, gallium, and iron, further strain budgets. For solar in particular, supply constraints add to the complexity of meeting the ever-growing demand.[3] In 2020, the EU estimated that China accounted for more than 70 percent of the global value chain for solar components value chain, including 89 percent of global production of solar wafers.

Given these challenges and the massive ramp-up in the industry, any expectation that capital expenditure in the industry would decrease as technologies develop appears misplaced. The remaining lever available for companies looking to accelerate profitable growth in renewables is to push further on project delivery performance. In this article, we focus on how to bridge the performance gap between existing and best practices, which recent benchmarking has identified.

## The performance gap

We recently performed an EPC benchmarking analysis that revealed where capital expenditure performance can improve in Europe. Around two gigawatts (GW) of onshore wind and two GW of solar assets were analyzed in detail to assess capital expenditure on a cost-per-megawatt (MW) basis (see sidebar, "Methodology").

### Finding the €10 billion opportunity

The study, conducted using data from 2020–21 (before the sharp rise in inflation across much

[1] "Renewable-energy development in a net-zero world: Overcoming talent gaps," McKinsey, November 4, 2022.
[2] "Renewable-energy development in a net-zero world: Land, permits, and grids," McKinsey, October 31, 2022.
[3] "Building resilient supply chains for the European energy transition," McKinsey, October 17, 2022.

## Methodology

**Fifteen companies** and their recent onshore wind and solar projects—around four gigawatts in total—across the EU were assessed, with a focus on both qualitative and quantitative components. The qualitative component included an assessment of each company's operating model and practices. This was measured across eight EPC value levers: contracting strategy; risk-based decision making; design-to-value; market intelligence; sourcing strategy; optimized terms and conditions; contract execution; and risk and claims management. The quantitative assessment compared capital-expenditure performance based on three main steps:

1. *Scope delineation.* To ensure data comparability, all study participants used the same definitions of cost categories across their plants.
2. *Normalization.* A should-cost methodology was used to scale the cost of each of the assets on a granular, sub-cost-category level. This enabled a true like-for-like comparison between projects, by adjusting for drivers that cause significant differences in cost without being under full control of the asset owner—such as labor-cost differences across countries, cost of raw materials over time, or the size of the plant. For example, if the reference point is a plant with 50MW capacity and the grid interconnect cost is 20 percent lower per MW for a project with 100MW, the 20 percent cost advantage needs to be removed from the 100MW plant to make the two plants comparable in the benchmark.
3. *Benchmarking for a broad set of metrics.* The focus of the study was the performance based on capital expenditure per MW along the main cost categories. After the projects were normalized, they were all compared using normalized capital expenditure on a granular level. Capital expenditure performance was analyzed not only as total capital expenditure but also by cost category, such as collector systems and grid interconnection. Other key performance metrics analyzed alongside this were schedule adherence and contingencies, and safety performance.

of the world), found a wide variance in capital expenditure performance between top-quartile and bottom-quartile averages—about 20 percent for onshore wind and more than 30 percent for solar PV in Europe. If lower performers could improve their capital expenditure performance in line with top performers, onshore wind projects could save around €6 billion, and solar PV projects could save roughly €4 billion—a total of about €10 billion a year at an industry level in Europe (Exhibit 1).

In onshore wind, the variance in performance between top- and bottom-quartile performers is mainly caused by the large variability in wind turbine generator (WTG) cost and balance of plant (BoP) cost. For solar PV, BoP—including electrical and mechanical installation cost, piles, trackers, and the like—shows the highest deviation among the cost categories, despite being smaller in absolute terms than costs for PV equipment (primarily modules and inverters).

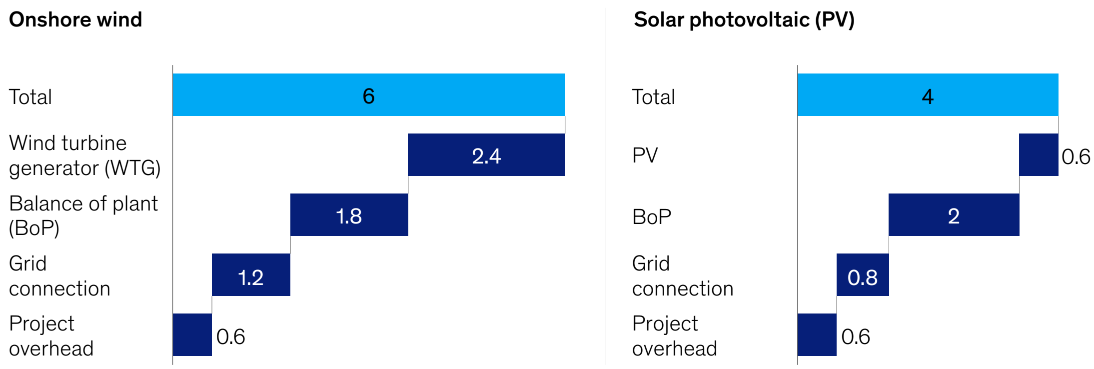
### Choosing the right capital-expenditure delivery model

Another key finding of the study was that, on a project-by-project basis, top performers use delivery models that are consistent with their internal capabilities. Under the most advanced owner-integrated models, companies acquire in-house capabilities and invest heavily in capability-building. Organizations that do not have in-house skills, and don't plan to ramp up internal capabilities, usually do better with turnkey models. This means there is no silver-bullet model—it is

Exhibit 1

## European onshore wind and solar photovoltaic projects show a €10 billion annual capital expenditure opportunity.

**Average capital expenditure (capex) opportunity by project category,[1]** € billion (estimated)




[1]Gap between average capex and top-quartile capex of projects commissioned 2019–2021; value per category estimated based on total capex opportunity and relative contribution per category; based on projects commissioned 2019–2021.
Source: McKinsey Onshore Wind and Solar PV EPC Benchmark, EU wave

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possible to be a top performer in terms of capital expenditure both with an owner-integrated model and with a turnkey model (Exhibit 2).

Avoiding a one-size-fits-all approach across their portfolio better accounts for internal capabilities in different regions and asset types, and achieves higher, more consistent results. Companies that selectively chose their operating model all scored in the first or second quartile, while those that chose a default operating model ran the full range of performance from top to bottom.

**Building—or acquiring—capabilities**
Although choosing the most suitable operating model based on in-house capabilities is a powerful way to increase capital expenditure performance, the analysis shows that companies with better in-house skills do tend to attain higher capital expenditure performance; capabilities and performance correlated directly across both the wind and solar industries in Europe (Exhibit 3). Scaling up wind and solar plants is therefore not just a question of growing the physical assets—growing team capabilities matters, too, whether by reskilling and upskilling employees, hiring the right people, or exploring international

## Actions to fill the performance gap

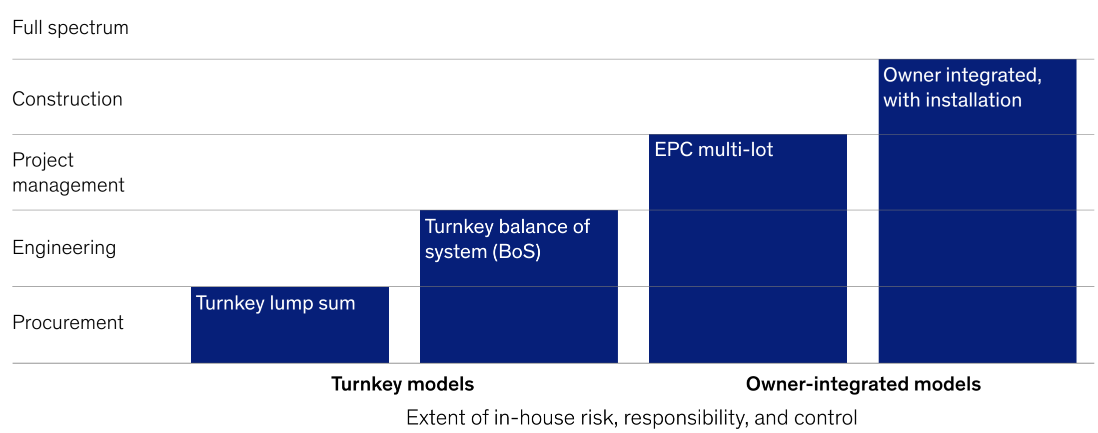
By focusing their capital performance strategies and execution on levers that help them bridge the gap to top-quartile performance, companies can reap large benefits while sustaining growth.

*Expanding workforce.* Companies can leverage multiple solutions to expand their workforces amid labor shortages. For example, they can attract talent by partnering with schools and universities to develop tailored research programs and by providing mentoring and internship opportunities. Reskilling employees in adjacent industries that are scaling down, such as coal, could also be a pathway for increasing the talent pool. Companies can also play an active role in training their own workforces and those of their key contractors. For example, joint investments in manufacturing capacity—perhaps accompanied by volume guarantees— can provide critical support for contractors to achieve

Exhibit 2

## There is a wide spectrum of engineering, procurement, and construction (EPC) contract models, involving varying levels of risk and required capabilities.

**EPC models, by internal capabilities**




Source: McKinsey Onshore Wind and Solar PV EPC Benchmark

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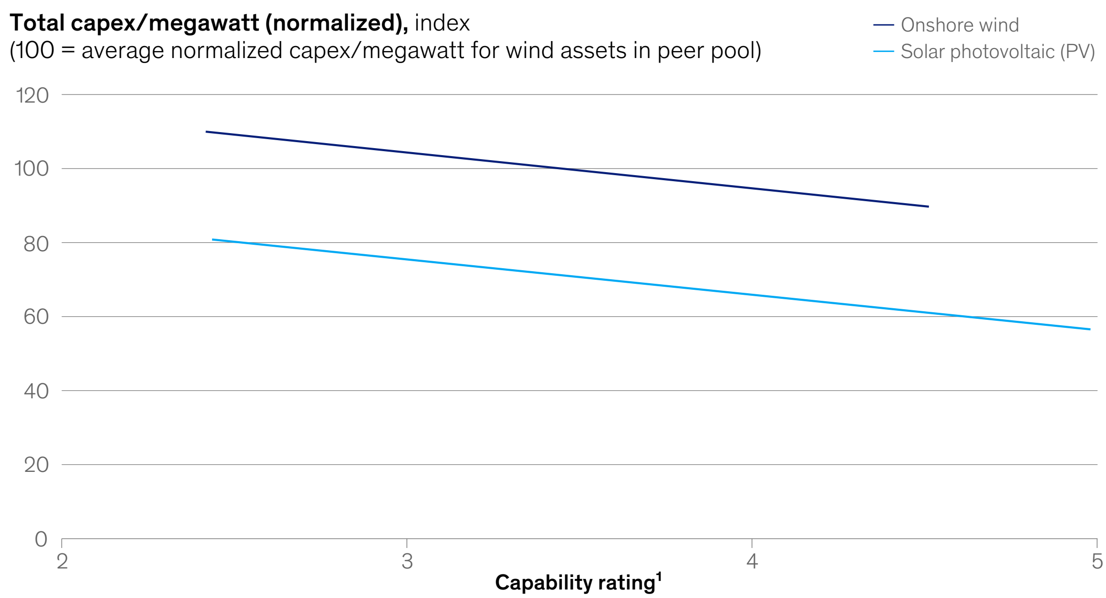
Exhibit 3

## Capabilities matter in both onshore wind and solar photovoltaic.

**Total capex/megawatt (normalized),** index
(100 = average normalized capex/megawatt for wind assets in peer pool)




[1]Average score across eight value levers assessed in qualitative operating model assessment.
Source: McKinsey Onshore Wind and Solar PV EPC Benchmark

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scale. Another option is to co-invest with partners in training facilities that are tailored to the partners' respective project pipelines.

*Design excellence.* Design processes could be further standardized to reduce reliance on the small groups of individuals who have, so far, been responsible for progress. The digitization of these processes would enable advanced analytics, adding to performance improvements while making more effective use of the resources needed to deliver. Optimizing from a total cost of ownership (TCO) perspective— using value engineering at the portfolio level, for example—allows for more informed trade-offs between individual project performance and overall portfolio value.

*Procurement excellence.* The development of more flexible framework agreements, rather than requiring rigid price and delivery terms, can secure supplies, reduce lead times, and enable productivity enhancements, such as design standardization. In parallel, this helps suppliers attain scale benefits, such as advanced planning for procurement and manufacturing capacity, which makes their work smoother. Best-practice expediting processes include closely monitoring supply chains and manufacturing at contractor sites to manage supply chains and avoid surprises on delays and extended lead times.

*Collaborative contracting models.* Newer collaborative contracting models can drive productivity as well—and involve a mindset shift from "owner and contractor trying to individually optimize their results" to "we can only win together." Here, both sides need to make continuous efforts to establish collaborative ways of working across project execution, for example by aligning incentives arrangements in which cost and schedule overruns and underruns are shared, instead of focusing on claims.

*Project execution.* Lean construction and project portfolio management can be injected into all projects. Stage-gate processes can be enhanced to enable cross-functional visibility and minimize waste. Construction activities can be optimized and standardized to upgrade performance across contractors. Additionally, claims management can be upgraded, enhancing claims defense and the effectiveness of counterclaims.

*End-to-end digitization.* Data can be used for meaningful conversations about performance, especially by digitizing the project stage-gate process with an eye on creating value and driving cross-functional collaboration. It can also help companies benchmark their projects as a basis for continuous improvement. Through a digital project control tower and a digital backbone, the necessary elements can be provided to all stakeholders, including suppliers.

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The build-up of onshore wind and solar PV projects is a major lever to keep pace with EU decarbonization plans. This once-in-a-lifetime growth opportunity for companies also comes with challenges that require organizations to find quick solutions and scale up their capabilities. Missing the boat on tackling those challenges now, as a joint effort across the EU, will put at risk all EU decarbonization targets. With the expected boom in demand for renewable energy, and the need to increase supply it infers, the time to assess and improve capital expenditure performance is now.

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# Capital projects are critical for a green future

Constructing new decarbonization assets can help achieve net-zero targets—but doing so requires fundamentally rethinking project costs to accelerate development.

*by Zak Cutler and Sam Linder*

**Capital is critical** to tackling climate change. According to McKinsey analysis, meeting net-zero targets will require spending $9.2 trillion a year on physical assets between now and 2050, up from $3.5 trillion today.[1] By then, the energy mix would also include nascent energy technologies such as clean hydrogen; battery storage; and carbon capture, utilization, and storage (CCUS).

Capital projects, including those crucial to the energy transition, typically take many years and many hands to design, build, and launch. The number and scale of projects in the current pipeline will not suffice. Labor costs are increasing as raw materials and components remain in high demand, and the global supply chain has strained to keep pace, making the transition to newer technologies with different cost structures even more challenging. And, by definition, nascent technologies don't have a track record of lessons learned to inform cost productivity improvements to accelerate scaling.

That said, investment in the energy transition is accelerating. As an example, when the Inflation Reduction Act was signed in 2022, the US federal government released $370 billion in funding to provide tax credits for clean-energy projects.[2] With this in mind, the challenge moving forward will be securing the right people, resources, and physical space while overcoming supply chain constraints and financing for nonestablished players.

The time is now for industry players to fundamentally rethink how they approach projects to deliver them faster, cheaper, and more efficiently than ever.

## A once-in-a-generation call for capital investment

McKinsey analysis suggests that global annual capacity needs to be drastically increased across four areas—renewables, hydrogen, battery storage, and $CO_2$ captured—in the next 30 years (Exhibit 1). Each of these decarbonization technologies will be critical to tackling climate change.

In some areas, such as solar and wind, the global industry has already made significant strides in expanding installed renewable capacity. But other areas, such as carbon capture technologies, are still in early stages.[3]

Batteries are projected to see a meteoric rise in demand in the coming decades if the industry can overcome ongoing challenges in securing the raw materials, such as lithium, copper, and nickel, needed to produce at scale. On this point, recent McKinsey estimates show that meeting global demand for copper and nickel alone could require capital expenditures of $250 billion to $350 billion by 2030, both to grow new capacity and to replace depleted existing capacity.[4]

The pathway for hydrogen perhaps best illuminates the challenges of scaling new energy technologies. McKinsey estimates that by 2050, two primary fuels—electricity and hydrogen—will make up an estimated 50 percent of the global energy mix.[5] This growth will be seen across different forms of hydrogen, including renewable "green" hydrogen, which is produced via the electrolysis of water.

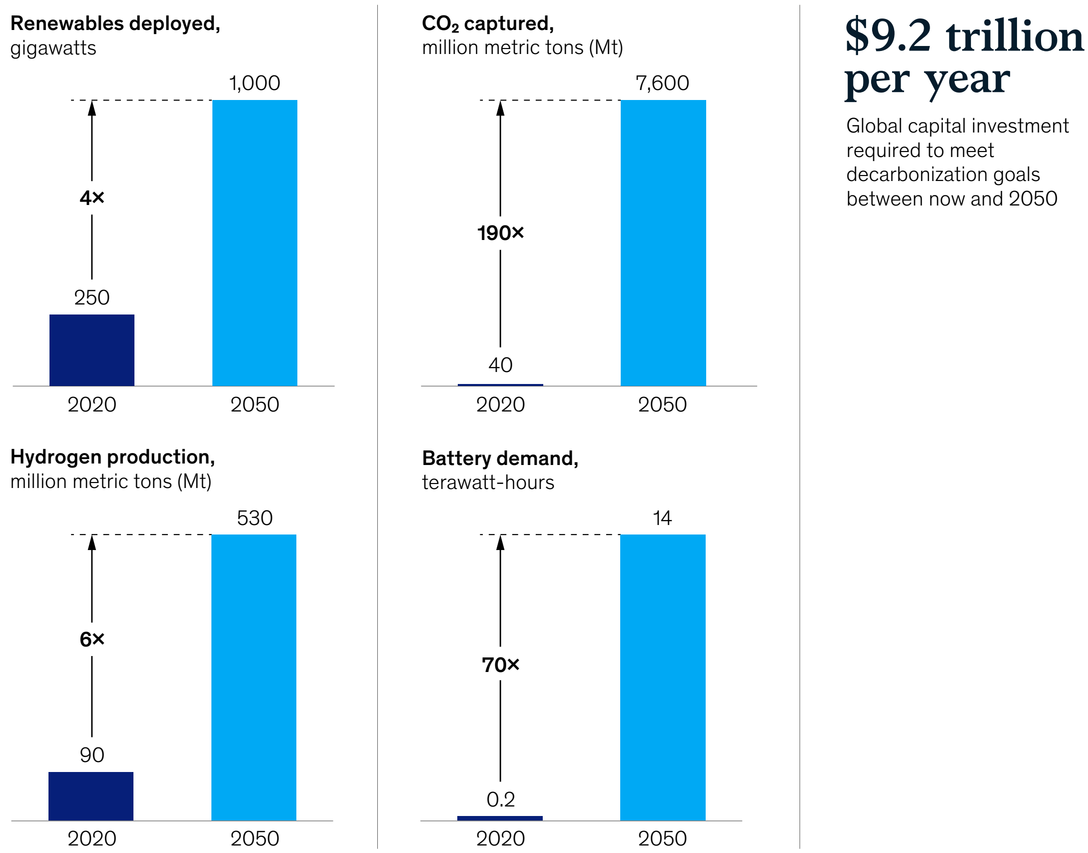
Recently announced projects would add about 22 million metric tons of capacity, but their financing is still unclear—and collectively they would account for only 15 to 20 percent of the estimated 2035 need.[6] Regarding cost parity, improvements are possible in terms of the levelized cost of hydrogen,[7] but this will require the industry to rapidly improve electrolyzer systems, increase hydrogen plant capital expenditures, and lower electricity costs (Exhibit 2).

[1] "The net-zero transition: What it would cost, what it could bring," McKinsey Global Institute, January 2022.
[2] "Here's how the Inflation Reduction Act is impacting green job creation," World Economic Forum, March 14, 2023.
[3] "Scaling the CCUS industry to achieve net-zero emissions," McKinsey, October 28, 2022.
[4] "The raw-materials challenge: How the metals and mining sector will be at the core of enabling the energy transition," McKinsey, January 10, 2022.
[5] *Global Energy Perspective 2022,* McKinsey, April 26, 2022.
[6] Ibid.
[7] The levelized cost of hydrogen refers to the methodology used to calculate the capital and operating costs of producing hydrogen, allowing for the comparison of different production routes.

Exhibit 1

## The opportunity in green capital expenditures is massive; investment needs to triple by 2050 to reach decarbonization goals.

**Global annual capacity required to decarbonize**




Source: International Energy Agency; "The net-zero transition: What it would cost, what it could bring," McKinsey Global Institute, January 2022

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In an accelerated scenario, clean hydrogen could account for approximately 95 percent of total supply by 2050, helping to meet the anticipated fivefold increase in demand driven by the road transport, maritime, and aviation industries.[8] Thus, significant scale-up in renewable-energy production, electrolyzers, and CCUS is needed to make hydrogen, renewable fuels, and other clean technologies cost competitive with conventional-energy production, particularly in transport, which is expected to account for more than 50 percent of demand growth by 2050.

### The path forward: Rethinking capital project costs

Considering the starting points of technologies such as hydrogen, batteries, and CCUS, their

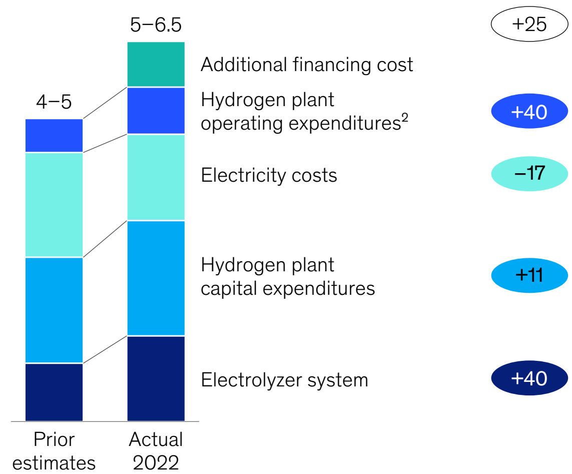
[8] *Global Energy Perspective*, April 26, 2022.

Exhibit 2

## In 2022, the levelized cost of green hydrogen increased by approximately 25 percent.

**2022 alkaline water electrolysis plant approximate LCOH[1] (1 GW),** $ per kilogram of hydrogen

**Approximate change vs prior estimates,** %




Note: Levelized cost of hydrogen 2022 estimates for a 1 GW alkaline water electrolysis plant in the United States.
[1]Levelized cost of hydrogen.
[2]Includes operations and maintenance, stack refurbishment, and water consumption.
Source: Hydrogen Council; McKinsey analysis

McKinsey & Company

respective growth potentials are high. Effective hyperscaling—that is, large-scale and repeatable new-asset development—would require project owners to increase their metabolism while rethinking the cost of project delivery. The "plant as a product" approach, which uses manufacturing methodology to help companies scale green capital expenditures quickly and make construction projects repeatable, can help owners and builders deliver these projects more efficiently and cheaply.

Several projects currently underway could produce hydrogen at a cost of $6 to $8 per kilogram. For hydrogen to be economical, however, it will need to be produced at roughly $3 per kilogram for most applications.[9] This means industry leaders need to fundamentally rethink capital costs for future projects. Some of the necessary efficiency will come from experience, reducing costs—particularly for electrolyzer system improvements for power density and efficiency—and some will come as more projects are built and others are scaled. However, cost competitiveness won't happen within the necessary time frame if industry players don't approach things differently.

With this in mind, the following decisions throughout the project life cycle can help facilitate the required timelines, costs, and levels of efficiency of green projects.

### Rethink the approach to project design

Moving forward, players—particularly incumbents accustomed to large-scale capital projects with massive specifications and scale—can help make these projects economical by rethinking how they

[9] Yuanrong Zhou, "Can the Inflation Reduction Act unlock a green hydrogen economy?," International Council on Clean Transportation, January 3, 2023.

are designed for the minimum technical solution. This can be done in part by taking a radical approach to design and standardization. For example, Tesla claims that it has been able to reduce the capital expenditures per gigawatt-hour of its gigafactories by 70 percent, which has led to knock-on benefits of standardized materials and supplies.[10] In addition, this approach has been facilitated by the creation of an ecosystem of partners and suppliers that are aligned on aspirations related to speed, massive scale, and low costs.

**Engage in collaborative contracting**

Players can pursue strategic partnering models across the value chain with suppliers that are new to the industry. Companies can also consider investing time and energy into building more collaborative partnerships with contractors rather than relying on transactional bid–buy relationships. One option is developing an ecosystem of contractors, for which shared incentives and partnerships can be improved with each subsequent build, as opposed to changing up contracts each round. Our analysis shows that undertaking multiple projects in parallel and using the same contractors can improve performance by an additional 15 to 20 percent beyond the average.

**Build next-generation capabilities**

Simply put, the industry needs more people with clean-energy expertise. Although training can help upskill current employees and ensure they're ready to tackle climate change on the ground, more skilled workers will be needed. On this point, players can partner with unions, trade schools, and vocational schools to build their talent pools. For instance, in 2018 Quanta Services acquired Northwest Linemen College, which focuses on the electric power industry. This allowed Quanta to create a pipeline for certified line technicians, who are in high demand. As another example, Ontario's Express Entry Skilled Trades Stream has removed requirements for domestic experience for foreign nationals with experience in skilled trades. Now, those with the right work experience can transfer their accreditations by passing an exam.

**Apply digital tools**

Project owners can build smart, data-driven setups across the value chain and life cycle. Advanced analytics and digital twins are now table stakes; including them from the outset will help optimize the system as a whole. Digital twins in particular are needed not only for operations but also for optimizing or right-sizing project designs and delivering the lowest life cycle costs needed to make projects economical. Advanced analytics or an AI-enabled digital twin can add 5 to 15 percent savings over so-called basic techno-economic models. This is achieved by subcomponent granularity, a look "inside" the chemical or physical properties, and increasingly accurate dynamic optimization. In addition, if the digital twin is set up correctly during the design phase, it can serve as the basis for a variety of use cases throughout the plant life cycle, ranging from operations and maintenance to strategic investment.

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Without a large pool of project examples to learn from, many project owners may feel that they're starting from scratch, and they may be tempted to take it slow and steady. But at the current pace, the world will never hit its 2050 goals. Capital project leaders have a range of options to reconsider how they approach project costs, from project design to future-proofing the partnerships and capabilities that will provide the foundation for hyperscaling.

[10] *Global Energy Perspective,* April 26, 2022.

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