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MANAGEMENT CONSULTANTS

ENERGY INDUSTRY UPDATE

UNDER PRESSURE

Volume 22 - Issue 1

CONTENTS

EXECUTIVE SUMMARY
Under Pressure

This Energy Industry Update examines how the combination of ambitious decarbonization targets, rising natural gas prices, policy mandates, and geopolitical events are combining to put pressure on the energy industry. This report examines the impact of multiple and sometimes conflicting pressures—between decarbonization aspirations and system reliability and flexibility, between demand for new energy resources and the complexity of integrating them into the grid, and between investment needs and affordability.

Some Highlights of This ScottMadden Energy Industry Update	
Cost Pressure	▪ Global energy markets continue to add significant amounts of renewables to their resource mix. However, fossil-fueled capacity remains a critical, dispatchable resource. And while the demise of coal-fired generation has been predicted, a recent run-up in natural gas prices has had the unintended consequence of increasing generation by those coal plants.
Decarbonization Pressure	▪ Multiple states and many utilities have set ambitious decarbonization goals to achieve partial reductions, net-zero or 100% carbon-free electricity generation within the coming decades. With interim targets now looming less than a decade away, some utilities are engaging in planning exercises that consider technology readiness, cost, and suitability for their particular circumstances. ▪ Reducing greenhouse gas emissions is top of mind for policy makers around the world. However, the clean energy transition doesn't happen overnight. Flexibility, optionality, and affordability are key. Recent geopolitical events remind us of the need for energy security, even during the transition. Europe has been pursuing decarbonization for more than a decade and may provide a glimpse into what other regions can expect and learn.
Investment Pressure	▪ Utilities, energy companies, and public and private investment firms are pursuing investments opportunistically in utility, power generation, and natural gas sectors. Additionally, private equity is playing a greater role in energy sector investment. Energy companies are using acquisitions for strategic objectives, such as business focus, increased scale, and growing their renewable resource portfolios. Finally, large capex needs provide investment opportunities, but utilities remain measured, keeping an eye on affordability and rate impacts. ▪ Many regions have a long and growing queue of power generation projects—many of which are wind and solar—seeking to connect to the bulk power system. Transmission operators and regulators are looking at potential approaches to manage this backlog, including grouping, increasing required levels of financial commitment, and process changes.

Capital Markets and Capital Needs

Utilities navigate capex objectives, portfolio choices, and capital needs.

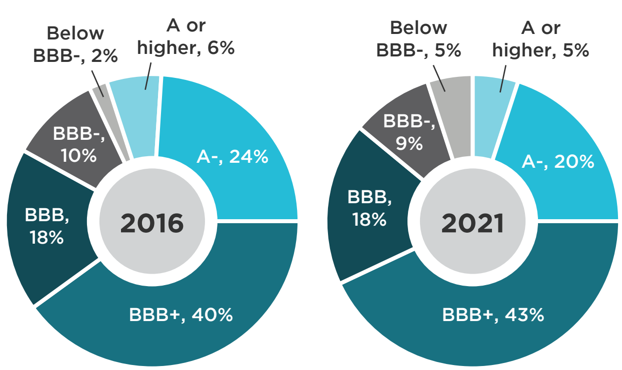
Mixed Investment Thesis on Utilities

- Investment analysts and rating agencies have mixed views on the current investment outlook in the utilities sector.
- Points of support for sector investment include attractive relative valuations (versus historical and the market); pursuit of lower-risk, regulated business models; and improving ESG tailwinds for some that have exited fossil generation businesses and/or seek rate base growth through decarbonization initiatives. Further, load profiles are expected to return to normal and in some cases have already done so, supporting revenue growth.
- However, some observe that utilities are out of favor along with other defensive sectors. Some sector-specific uncertainties and headwinds that utilities face include:
  - Focus on affordability and bill headroom, which are affected by higher natural gas and other commodity prices and inflation.
  - The sector's relatively small percentage of total market capitalization (3% of the S&P 500), considering the volume of share purchases driven by index fund flows.
  - Continued high capital spending and potential regulatory challenges, along with lower return on capital (6% a decade ago and closer to 4% today), pressuring credit quality (despite a higher rate base). Rate case activity is expected to be a significant driver for sector performance in 2022.
- While the potential for Fed rate increases could affect sector valuations, one analyst notes that utilities underperform on expectations of rate raises and tend to perform in line or sometimes outperform once those increases are effected.

Figure 1.1: **Year-End S&P Utility Credit Ratings Distribution for U.S. Investor-Owned Electric Utilities (Parent Level Only)**

"Industry credit quality generally improved over the past decade, although it experienced a slight decline, in aggregate, in each of the last three years...."

"The three major rating agencies remain somewhat divergent in their outlooks for 2022. S&P maintained a negative outlook, Moody's outlook remained stable and Fitch held its neutral outlook. While the agencies noted regulatory relations are broadly constructive, managing regulatory risk and financial metrics in an era of high capex and potentially rising costs were cited as concerns."



Source: Edison Electric Institute

KEY TAKEAWAYS

Capital spending continues apace, as investment in renewables and grid upgrades continues to grow.

The utilities sector remains attractive for investment, buoyed by attractive valuations. However, some investors remain cautious as higher capex could have implications for affordability and rate recovery.

An emerging trend is increasing private equity finding its way to utilities, including minority stakes. In some cases, utilities are opting for the higher valuations from this private capital versus equity raises in the public markets.

Energy and Utility Transactions: Targeted and Diverse

- Utility and renewable transaction activity continued into 2021, with power sector company level M&A up nearly 46% from 2020.
- Rationales for activity are varied, including opportunistic sales to fund capital investments (e.g., AEP sale of Kentucky Power), spin-off of businesses to provide more business focus, separation of businesses with distinct risks and revenue profiles (e.g., Exelon divestiture of Constellation Energy), and addition of assets into core businesses (e.g., Southwest Gas purchase of Dominion Energy's Questar Pipeline).
- Activist investors, not historically major players in the utilities sector, have begun to press some companies to pursue strategic reviews aimed at increasing shareholder value through sales and spin-offs and advancing clean energy transition activities.
- In several cases, utilities have sold minority stakes in selected subsidiaries rather than issuing equity or selling minority stakes in a holding company. Both Duke (Duke Energy Indiana) and FirstEnergy (utility assets) are examples of this phenomenon. One driver is that valuations of these stakes are more attractive to sellers than current public equity valuations.

Figure 1.2: **Selected North American Utility and Power Generation Asset and Company Transactions* (Pending and Completed)**

Buyer	Target	Industry	Announced	Status	Closed	Deal Value ($M)
Constellation Energy Corp	Exelon Corp. (Spin-off)	Electric Utilities	2/24/2021	Completed	2/1/2022	15,621
PPL Energy Holdings, LLC	Narragansett Electric Company	Electric Utilities	3/18/2021	Announced		5,270
Liberty Utilities Co.	Kentucky Power Company/AEP Kentucky Transmission Company	Electric Utilities	10/26/2021	Announced		2,846
Summit Utilities, Inc.	Arkansas and Oklahoma gas distribution assets	Gas Utilities	4/29/2021	Completed	1/10/2022	2,150
KKR & Co. Inc.	Clearway Community Energy	Multi-Utilities	10/25/2021	Completed	5/2/2022	1,900
NextEra Energy Partners, LP	2,520-MW portfolio	Renewable Electricity	10/22/2021	Completed	12/21/2021	858
Ontario Teachers' Pension Plan Board	Interest in 2,520-MW portfolio	Renewable Electricity	11/30/2021	Announced		849
Brookfield Renewable Partners L.P.	Three wind plants	Renewable Electricity	1/6/2021	Completed	3/24/2021	744
NextEra Energy Partners, LP	Four wind generation facilities	Renewable Electricity	4/19/2021	Completed	8/25/2021	733
Hearthstone Utilities Inc.	Hope Gas, Inc.	Gas Utilities	2/11/2022	Announced		690
Brookfield Renewable Corporation	Urban Grid Solar	Renewable Electricity	1/26/2022	Completed	2/7/2022	650
NextEra Energy Partners, LP	590-MW net interest portfolio of wind and solar projects	Renewable Electricity	7/23/2021	Announced		563

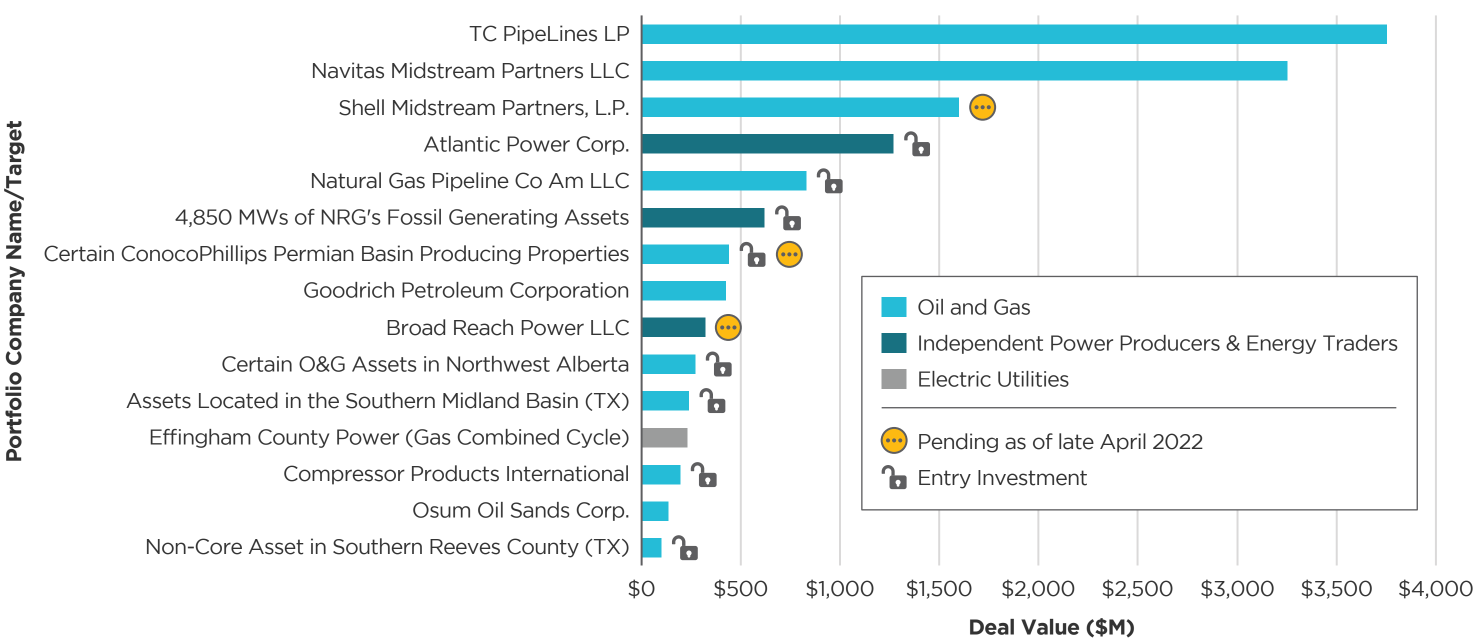
Notes: *Announced or completed between Jan. 1, 2021 and Feb. 14, 2022. Excludes private equity deals (as classified by S&P Global Market Intelligence). Status updated as of May 3, 2022.

Source: S&P Global Market Intelligence

Private Equity Steps In

- Another trend, reflected in recent acquisition and strategic activity, is the continuing interest of private equity in the utilities sector. The promise of steady, regulated returns for investment firms with pension and other clients seeking lower risk investments make utilities and other critical infrastructure assets more attractive.
- As solar and wind power is seen more as a utility-type investment with steady cash flows under a power purchase agreement, more private firms are buying renewable or sustainable assets. Some examples:
  - Ontario Teachers' Pension Plan Board announced the purchase of 50% of a 2.5 GW wind portfolio from NextEra Energy Resources.
  - KKR offered in October 2021 to purchase Clearway Energy's thermal business (thermal infrastructure assets that provide steam, hot water and/or chilled water, and in some instances electricity).
- "Recycling" by utilities of contracted renewables portfolios not within the regulated rate base is seen by some as a major source of M&A activity in 2022.
- Interestingly, private capital is also being invested in hydrocarbon businesses, including gas utilities, as well as fossil-fired power generation, as ESG sensitivities can constrain capital availability in those sectors from some investors. The acquisition of PSEG's fossil generation assets by ArcLight Capital Partners is an example of this trend.
- In some cases, private equity resources can be seen as an opportunity to modernize infrastructure and fund sustainability and clean energy initiatives (see Infrastructure Investment Funds' $8.1 billion buyout of gas utility South Jersey Industries in late February 2022).

Figure 1.3: **Selected U.S. and Canada Energy Sector Private Equity Energy Asset and Company Deals (Jan. 1, 2021–Feb. 14, 2022) ($ Millions)**



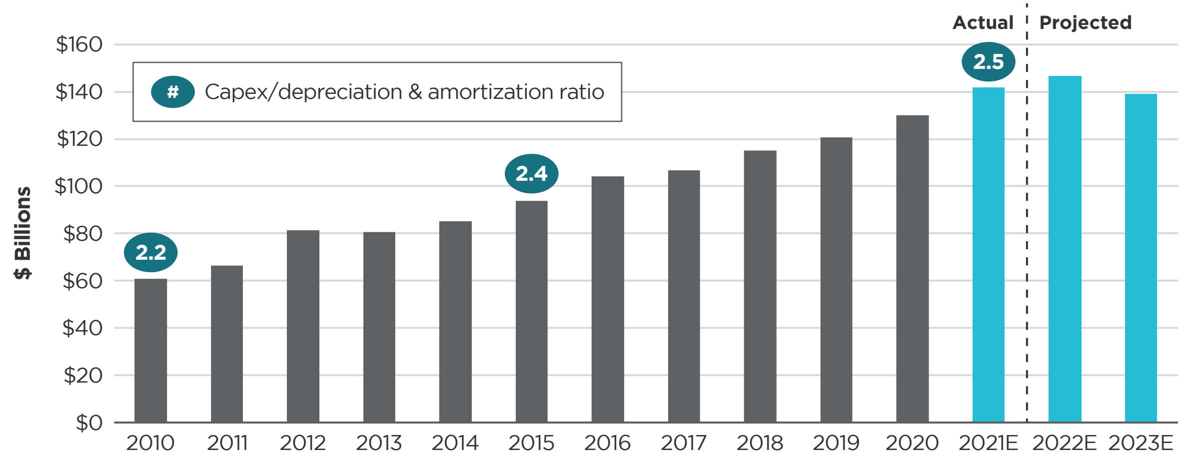
Notes: Includes divestitures. Deal value includes cash and other compensation as well as assumption of debt. Investor entry into asset/company investment as noted; all others are increases or decreases in existing stakes.

Source: S&P Global Market Intelligence

Where Is Capital Going?

- 2021 was a record year for U.S. utility capital expenditures. One estimate of 47 U.S. energy utilities projects that capital spending hit $141 billion in 2021. And 2022 capex is expected to grow by $5 billion among that group.
- Drivers of capex are not novel: upgrade of aging infrastructure (gas and electric transmission and distribution facilities), continued investment in non-carbon-emitting generation (especially renewables), and other energy transition investments. The Infrastructure Investment and Jobs Act, passed in November 2021, will serve as a catalyst for spending on policy-preferred projects under programs established or extended in that legislation.
- Utility investment in renewable energy appears to be pivoting from reliance upon contracted assets to interest in rate-based, regulated assets. AEP, for example, contemplates 16 GWs of regulated renewables by 2030, comprising more than $8 billion in its 2022-2026 capital plan.
- Key questions for capital investment are the effects of Fed rate increases on the cost of capital, the potential for sustained elevated inflation, and their combined effects on capital needs and customer bills.

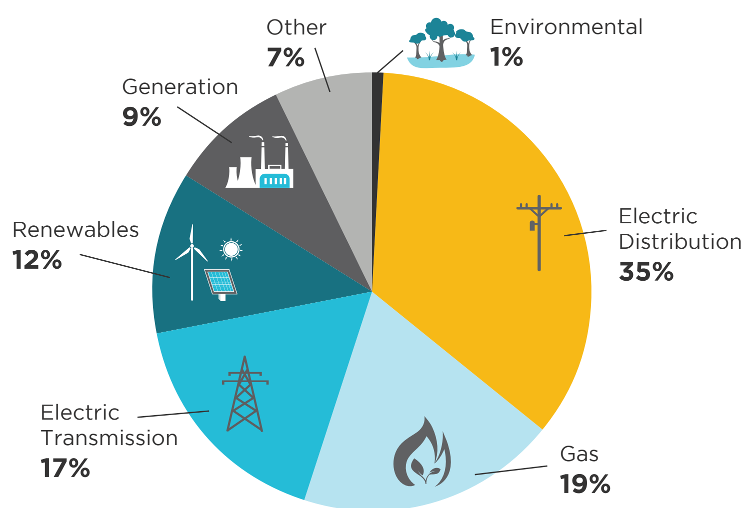
Figure 1.4: **Actual and Projected Selected* Energy Utility Capital Expenditures (2010–2023E) (in $ Billions)**



Notes: *Companies included are 47 investor-owned electric, gas, and combination utilities followed by S&P's Regulatory Research Associates. Analysis compiled Nov. 29, 2021.

Source: S&P Global Market Intelligence

Figure 1.5: **Projected Capital Expenditures by Category for Selected Energy Utilities (%)**



Notes: *Companies included are 47 investor-owned electric, gas, and combination utilities followed by S&P's Regulatory Research Associates. Analysis compiled Nov. 29, 2021.

Source: S&P Global Market Intelligence

IMPLICATIONS

Utility and energy companies are repositioning their asset portfolios to provide business focus and scale, pursue properties opportunistically, and achieve strategic goals such as growing renewable assets. Private equity continues to be interested in selected investments in the energy sector.

It is unclear how the cost of capital will evolve and perhaps impede this activity with expected central bank actions, but this trend seems durable in the near term.

Given the compressed timelines for acquisition due diligence, corporate development and strategic planning teams would be well served doing their homework in advance, having pre-screening criteria and scenario-planned integration strategies for assets and companies that might come to market.

Sources:

Citi Research; Barclays; J.P. Morgan; RBC Capital Markets; Morningstar; S&P Global Ratings; KKR; Ontario Teachers' Pension Plan Board; Platts *Megawatt Daily*; S&P Global Market Intelligence (SPGMI), "2022 Utility M&A to Focus on Renewable Asset Recycling, Minority Stake Sales" (Nov. 29, 2021); SPGMI, "U.S. Power Sector Company-Level, Asset Deals Surge in 2021" (Jan. 19, 2022); Reuters, "Energy M&A Trend: Minority Interest Sales in Regulated Utility Subsidiaries to Raise Equity Capital" (Jan. 3, 2022); SPGMI, "South Jersey industries Deal Reinforces Loft Gas Utility Valuations – Analysts" (Feb. 24, 2022); SPGMI, "$8.1B Buyout of South Jersey Industries to Speed Low-Carbon Transition, CEO Says" (Feb. 24, 2022); AEP 4th Quarter 2021 Earnings Release Presentation (Feb. 24, 2022); SPGMI, RRA Financial Focus, "Utility Capital Expenditures Update" (Nov. 30, 2021)

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Fossil Fuel Switching

Higher gas prices have revealed some regions' continued reliance on coal and oil.

Gas to Coal and Oil...and Back Again?

- For more than a decade, a combination of factors—tightening environmental restrictions, carbon emissions reduction objectives, and low natural gas prices resulting from increased domestic production from hydraulic fracturing—has combined to shift significant amounts of oil- and coal-fired power generation to gas-fired units across many regions.
- This trend continued as recently as 2020. However, the progressive tightening of gas supply that resulted in an increase in natural gas prices in the second half of 2021 had negative impacts on demand. That led to a slowdown in consumption growth, power generation fuel switching from gas back to coal, and gas demand destruction.
- U.S. coal consumption for power generation increased by an estimated 19% in 2021, showing net increases year-over-year in every month from January to October—and the first increase in coal-fired generation since 2014. Gas consumption for generation declined in most months and a 3% year-over-year decrease for the year in 2021.
- Europe has seen a similar trend, with coal-fired generation increasing by 11% in 2021, while gas-fired generation output declined by 1% for the year. This has driven carbon prices on the European Union's Emissions Trading System up more than 200% since the start of 2021, as higher-carbon emissions from coal generation increased demand for permits.
- Fuel switching also occurred in favor of oil for peaking needs in some markets (see page 15 for more on New England) as LNG spot prices reached record levels in Q4 2021. High gas prices in the United Kingdom have also prompted a switch to oil, as coal only accounts for 2% of power capacity, amid tight electricity supplies this winter.
- However, S&P and other analysts have noted that the trend is expected to reverse in 2022, with more coal-to-gas switching rather than gas-to-coal switching, although that had yet to be observed through early March 2022.

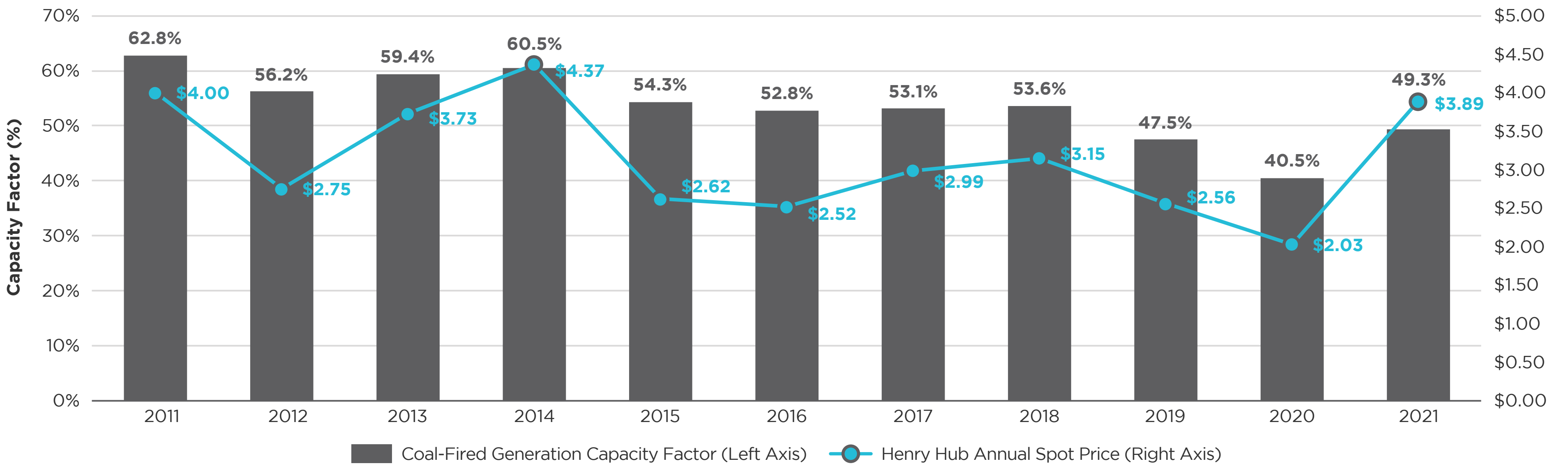
KEY TAKEAWAYS

High gas prices have reversed the long-term trend toward coal-to-gas switching for power generation and even promoted more oil-fired generation. This dynamic is being seen in Europe as well.

It is unclear whether this is a long- or short-lived phenomenon, but fuel production has responded to the uptick in demand.

Recent geopolitical events (i.e., Russia-Ukraine conflict)—and the possibility of future events—drive home the need for fuel diversity and resource flexibility as part of a not-so-straight line toward energy transition.

Figure 2.1: **U.S. Coal-Fired Power Generation Annual Capacity Factor (%) and Annual Henry Hub Spot Natural Gas Price ($/MMBtu) (2011–2021)**



Source: EIA

Figure 2.2: **U.S. Monthly Year-over-Year Generation Change (2021 vs. 2020) (in TWh)**

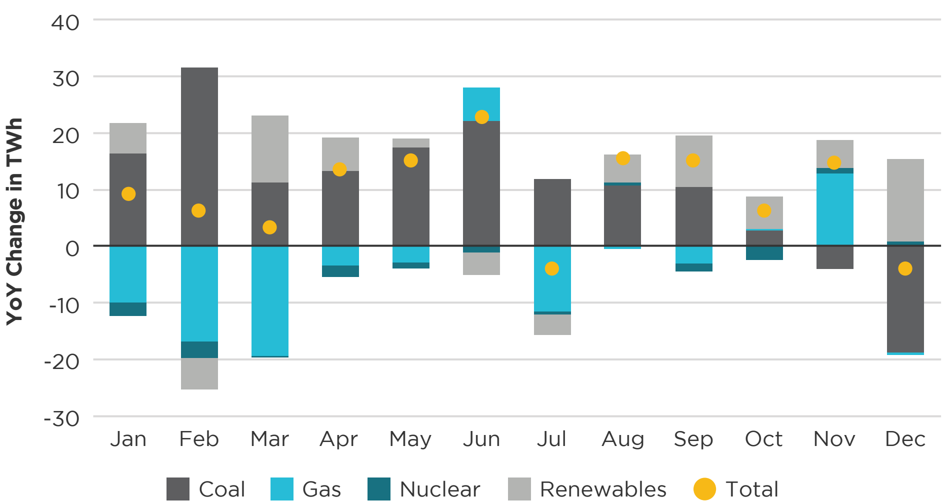
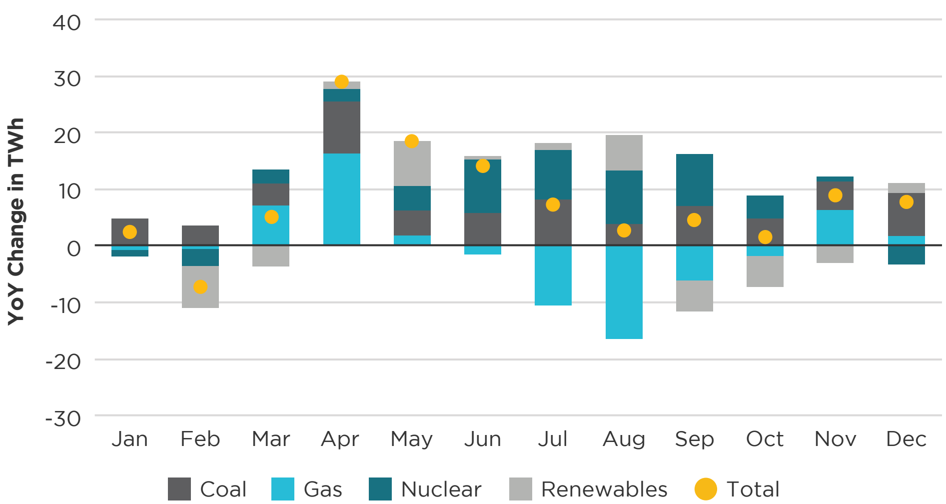


Figure 2.3: **Europe Monthly Year-over-Year Generation Change (2021 vs. 2020) (in TWh)**



Sources: IEA analysis based on EIA (2022) and ENTSOE (2021); ScottMadden analysis

The Supply Response: Higher Prices Prompt Production

- After declining in 2020, the combined production of fossil fuels in the United States, including natural gas, crude oil, and coal, increased by 2% in 2021.
- As of early 2022, EIA expects U.S. fossil fuel production to continue increasing in 2022 and 2023, surpassing 2019 production levels, to all-time highs in 2023. This production is driven in part by high prices, inventory replenishment, and exports.
- Dry natural gas production increased by 2% in 2021, and it is expected to increase by 3% in 2022 and 2% in 2023.
- U.S. coal production increased by 7% in 2021 after declining in 2020 to its lowest level in more than 50 years. It is expected to increase by 4% in 2022 and by a smaller 1% in 2023. Coal producers are replenishing inventories from the strong 2021 power burn and to meet strong export demand, although demand in the electric power sector is expected to decline.
- Global coal consumption reached a record in 2021 and was on track to rise further in 2022.
  - As in the United States, increases in natural gas prices in 2021 led to increased coal-fired generation in the European Union, China, and India. Coal-fired capacity is expected to increase, especially in Asia, as developing countries see it as a “transition fuel.”
  - Mining companies had been reducing or spinning off their coal activity. Those that remain, such as global giant Glencore, continue to expand operations to meet continued demand, and BHP is reconsidering its retreat from thermal coal given the current high prices and changing investor attitudes.
- High oil prices are also expected to lead to increased production of oil around the world. Crude oil production in the United States declined by an estimated 1% in 2021, but it is expected to increase by 6% in 2022. Other oil producers have also suggested that output may ramp up in response to current prices.

Figure 2.4: **U.S. Fossil Fuel Production (2000–2021 Actual/2022-2023 Forecast) (in Quadrillion Btu)**

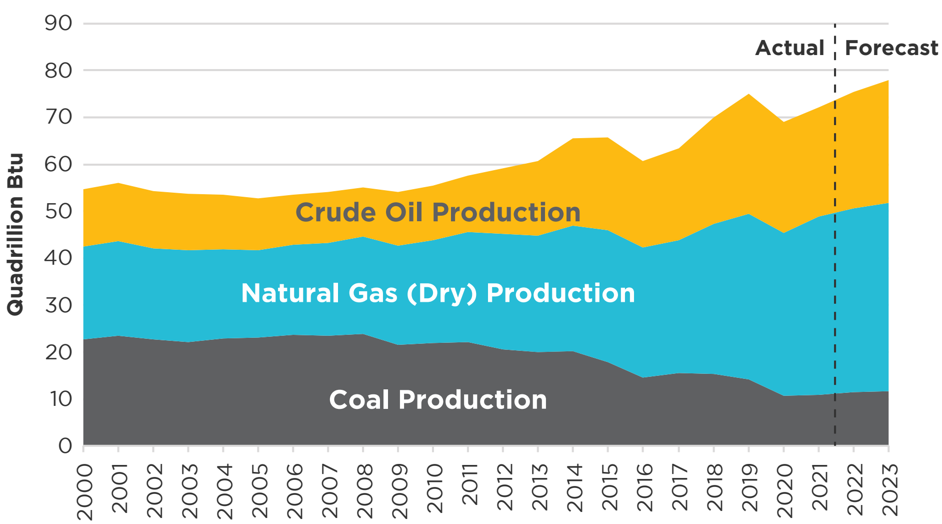
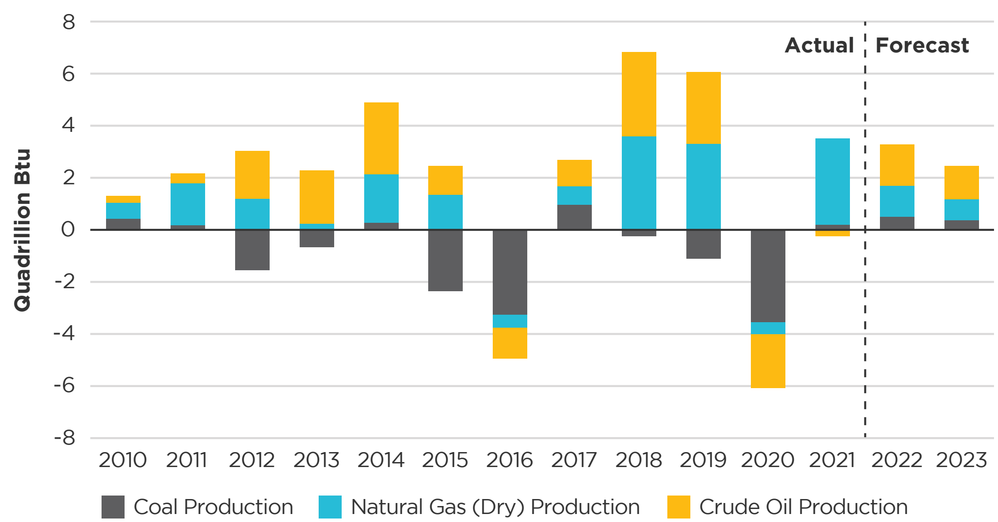


Figure 2.5: **Annual Change in U.S. Fossil Fuel Production by Product (2000–2021 Actual/2022-2023 Forecast) (in Quadrillion Btu)**



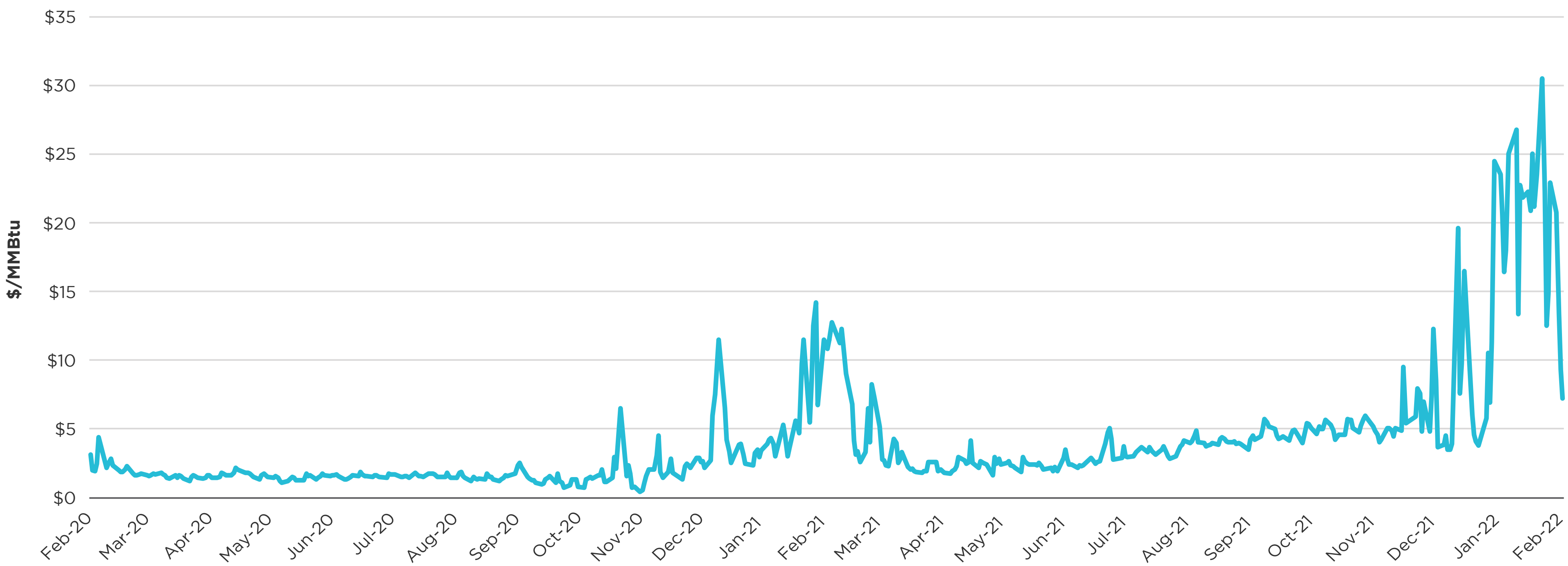
Note: Forecast from EIA as of January 2022.

Source: EIA

New England’s Persistent Reliance on Oil at Odds with Carbon Initiatives

- Insufficient natural gas infrastructure may pose a near-term challenge to the decarbonization efforts in New England states, as high gas prices have made oil-fired generation less expensive than gas-fired generation, despite oil being 40% more carbon intensive than gas.
- With limited ability to import gas from neighboring regions where it is produced and demand for gas in New England increasing—both for home heating and gas-fired generation capacity—winter weather events regularly drive high gas prices, as heating demand competes with demand for power generation. In the lead-up to a winter storm in mid-January, regional spot prices for gas reached an average of $29.26/MMBtu with the Algonquin Gates spot price reaching a high of more than $30/MMBtu in late January.
- Overall demand for gas and oil combined in New England is expected to stay relatively flat, while oil takes a larger share in response to high gas prices.
- In January alone, ISO New England dispatched 1.03 million MWhs of power from oil-fired generators—more than four and a half times the amount for the whole year in 2021 and more than it has dispatched in any year since 2011. With crude oil approaching the highest prices since 2014 at the time, that has driven costs and emissions of carbon dioxide and other pollutants higher in the region.

Figure 2.6: **New England (Algonquin City Gates) Natural Gas Price Index (Feb. 10, 2020–Feb. 10, 2022) (in $/MMBtu)**

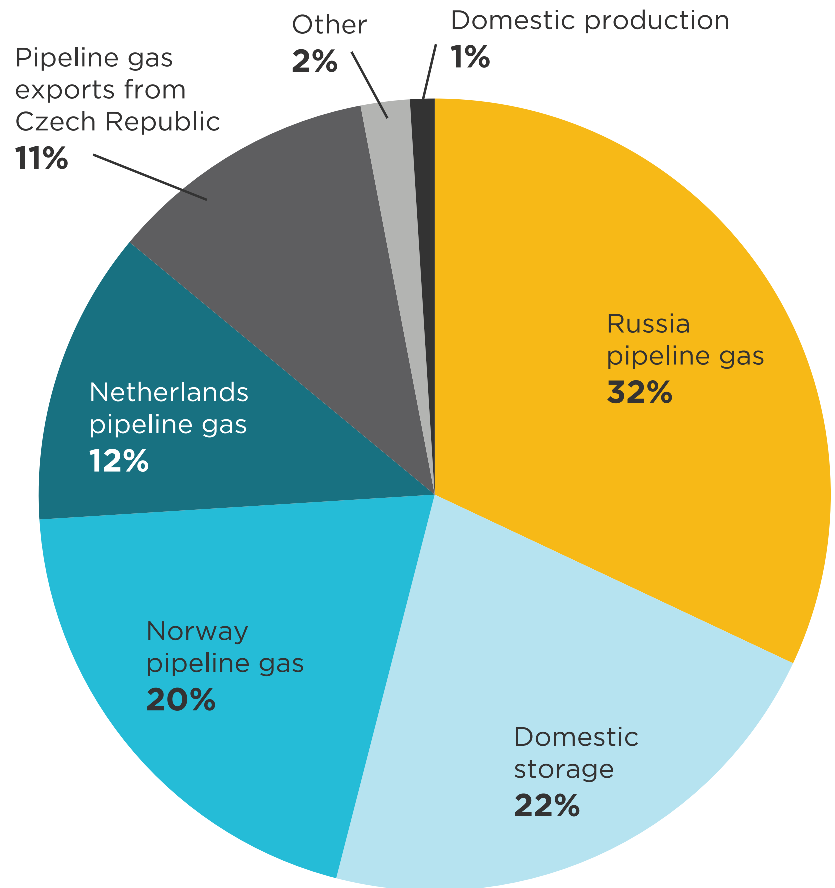


Source: S&P Global Market Intelligence

Energy Security Concerns and Geopolitical Developments Complicate Policies

- In response to high gas and electricity prices in 2021, the European Commission published a toolbox for action and support in October, including short-term actions to alleviate the impact of rising prices and mid-term consideration of revising security of supply regulation to ensure effective functioning of gas storage facilities.
- Recent Russian military action in Ukraine has led to sanctions against Russia, a key hydrocarbon provider to Europe. Among the sanctions in response to the unfolding crisis, Germany's suspension of and sanctions against the Nord Stream 2 pipeline may have the most significant impact on international energy markets.
- Though many of the other sanctions levied on Russia have been designed to avoid disrupting the flow of coal, gas, and oil from the country to its neighbors, particularly those in Europe, there are other signs that dependencies with Russia are being loosened.
- Germany's chancellor announced in late February that his government would accelerate the construction of two new LNG import facilities and add to Germany's gas storage reserves.
- European oil majors have also recently announced divestitures of Russian-backed oil and gas production ventures, led by BP's announcement that it would sell its partial ownership share in Rosneft.
- The continuing crisis in eastern Europe shows that events can sometimes overcome desired energy market outcomes. Further, adjustments to policies and infrastructure can take years. For example, the IEA proposed a 10-point plan to the European Union to reduce reliance on Russian gas supplies. But many of the prescriptions—e.g., replacement of gas sources; energy efficiency improvements; power system fuel diversity—will take months or years to execute.
- These geopolitical events are also further complicating an already challenging energy transition. In the United Kingdom, for instance, disruption in the gas market comes at a time when prices were already spiking amid higher reliance on the commodity due to lower wind output.

Figure 2.7: **German Gas Supply by Source**



Source: Reuters

Volatility in Commodity Markets Amid a Bumpy Energy Transition

- One unintended consequence of the energy transition has been higher CO_2 emissions in the short term, as high gas prices have made more carbon-intensive fuels more attractive. Some have suggested that this phenomenon may be temporary and that high costs for all fossil fuels may accelerate renewables development in the medium to long term.
- While governments and businesses continue to invest in low-carbon energy sources like renewables, the world remains deeply reliant on fossil fuels and will likely continue to do so for years to come. A poorly managed transition may lead to volatile energy prices and other disruptions that, in turn, threaten to undermine support for policies to reduce greenhouse gas emissions.
  - Coal and oil retirements are expected to continue in the United States. No decisions around planned retirements have been changed, although there have been a few temporary deferments.
  - Fuel-switching options will continue to shrink accordingly as additional coal and oil capacity is retired, and flexibility will have to come from other sources.
  - One emerging risk is the higher cost and lower availability of capital to legacy fossil energy firms and assets, discouraging operation, before flexible, low-carbon options are available.
- S&P recently increased its outlook for wind, solar, and energy storage development in the United States in response to recent high prices for fossil fuels, but the challenge to managing the energy transition smoothly will be timing.
  - The timelines around retirement of specific coal and oil units are flexible in the near term, but that capacity will not be available after it is retired from service—and the time needed to deploy sufficient renewables to replace retiring capacity can be long and uncertain.
  - The current environment of high and volatile fuel commodity prices driving concerns about shortages, energy security, and resource adequacy at different times in various regions may herald challenges to come as the energy transition gains momentum.

IMPLICATIONS

Utilities and policymakers will need to be adaptive as market dynamics and energy economics shift in potentially unanticipated ways. Whether these shifts are long lived remains to be seen. But, as we have seen in prior transitions such as the "dash to gas" in the early 2000s, fuel diversity and operational flexibility will continue to be important during the much-discussed energy transition.

Note:

See related discussion in "Energy Transition: What Are We Learning?" in this Energy Industry Update.

Sources:

U.S. Energy Information Administration (EIA); International Energy Agency (IEA), Gas Market Report Q1 2022 (Jan. 2022); "Europe's carbon price nears the 100 Euro milestone," Reuters (Feb. 6, 2022); EIA, Short-Term Energy Outlook (Feb. 8, 2022 and Mar. 8, 2022); IEA, Coal 2021 (Dec. 2021); "Glencore's Message to the Planet," *The Economist* (Jan. 1, 2022); *Natural Gas Week*; S&P Global Market Intelligence; ISO New England; "New England Power Plants Burn Most Oil Since 2011 as Gas Soars," Bloomberg (Feb. 22, 2022); "Nord Stream 2 Could File For Insolvency After Sanctions Hit," OilPrice.com (Mar. 1, 2022); "German LNG Import Terminal Plans Put on Fast Track," MarineLog.com (Mar. 5, 2022); IEA, 10-Point Plan to Reduce the European Union's Reliance on Russian Natural Gas (Mar. 2022)

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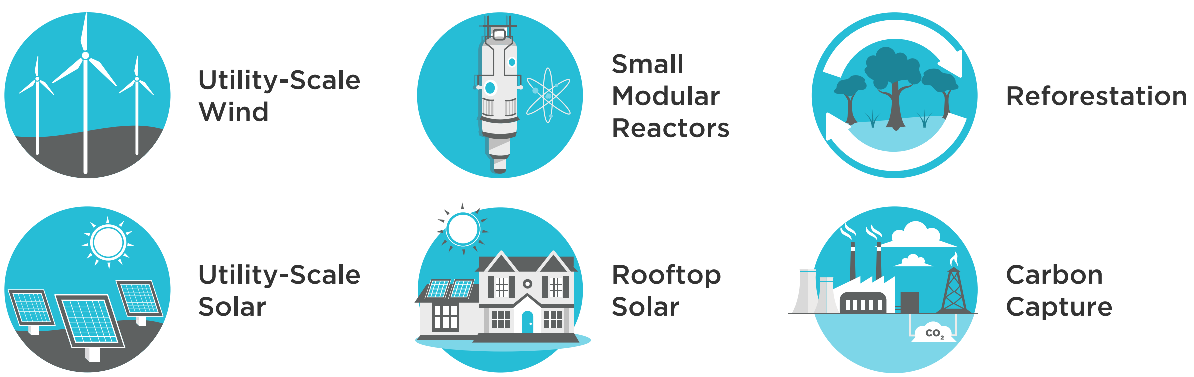
Utility Decarbonization Portfolios

Companies begin to turn net-zero commitments into resource plans with all-of-the-above strategies.

From Net-Zero Goals to Net-Zero Plans

- Many energy utilities in North America have committed to net-zero goals, whether driven by independent action, stakeholder pressure, or state and local targets or mandates.
- However, achieving those goals—interim and long term—may require an expansive view of potential technologies and approaches to be applied to carbon emissions reduction and sequestration.
- As utilities consider an all-of-the-above approach, they face several challenges:
  - **Multitude of options:** The approaches and technologies available are many and varied and their costs are changing. Some time is required to identify, research, and assess technology options.
  - **Immature, pre-commercial, or theoretical technology:** Several utilities have admitted that their commitment to a net-zero target by 2050 depends upon development and commercialization of technologies not currently available or economic.
  - **Context and suitability:** Many carbon-reduction technologies may not be well-suited to a particular region because of policy preferences, climate, geology, or the required scale of reduction.
  - **Conflicting regulatory mandates:** Without a national or state mandate or other policy that explicitly values carbon-free resources, utilities must continue to plan for the least-cost resources, which may be at odds with potentially higher costs of greenhouse gas (GHG) reduction investments.
- Despite these challenges, companies must develop decarbonization resource portfolios and roadmaps at a more granular level—decarbonization resource plans—to achieve their objectives.

Figure 3.1: **Decarbonization Technology Examples Being Investigated by Some Utilities**



KEY TAKEAWAYS

Net-zero targets are ambitious and require a wider lens of potential technologies and approaches to reach those objectives.

Decarbonization resource portfolios must balance considerations of technology maturity, potential GHG reduction impact, cost, and dispatchability (for energy producing assets).

Traditional integrated resource planning modeling approaches are instructive but because they are optimizing nascent or evolving technologies should be considered directional and not definitive.

Figure 3.2: **Net-Zero Commitments – Utilities and Utility Parent Companies**

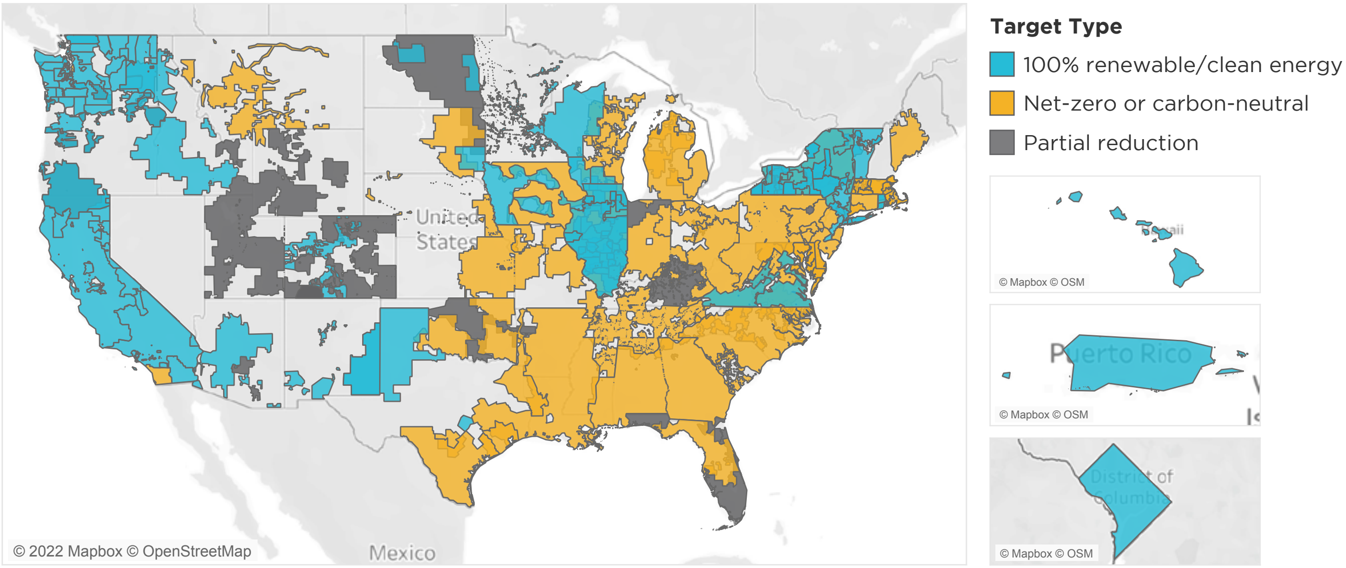
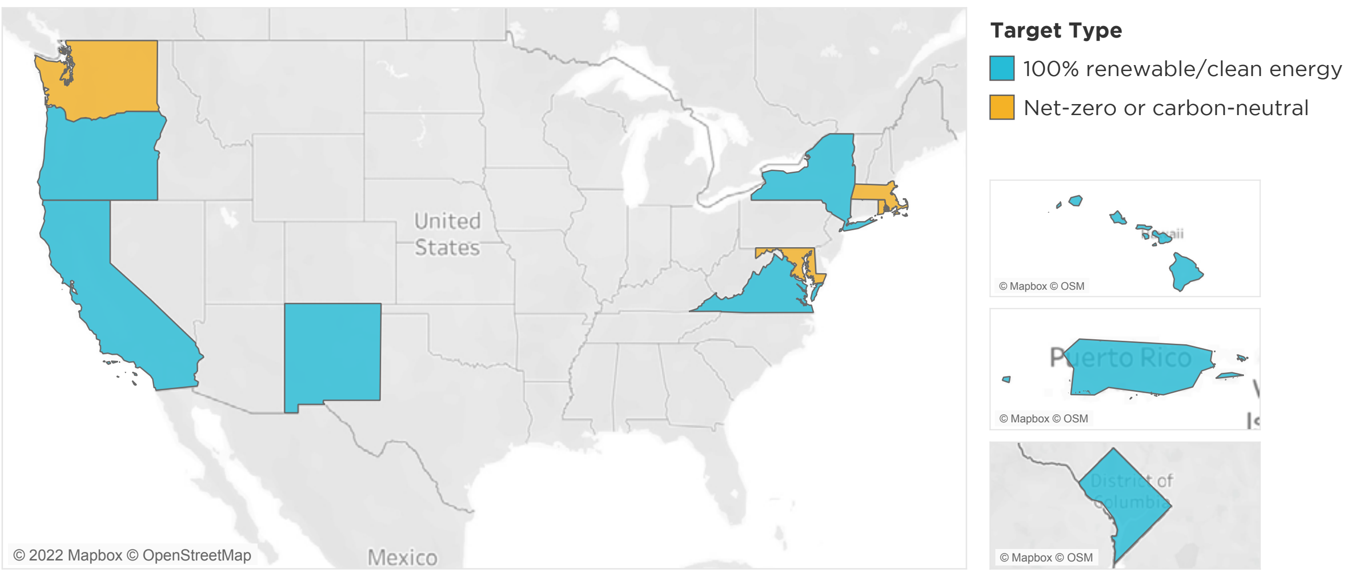


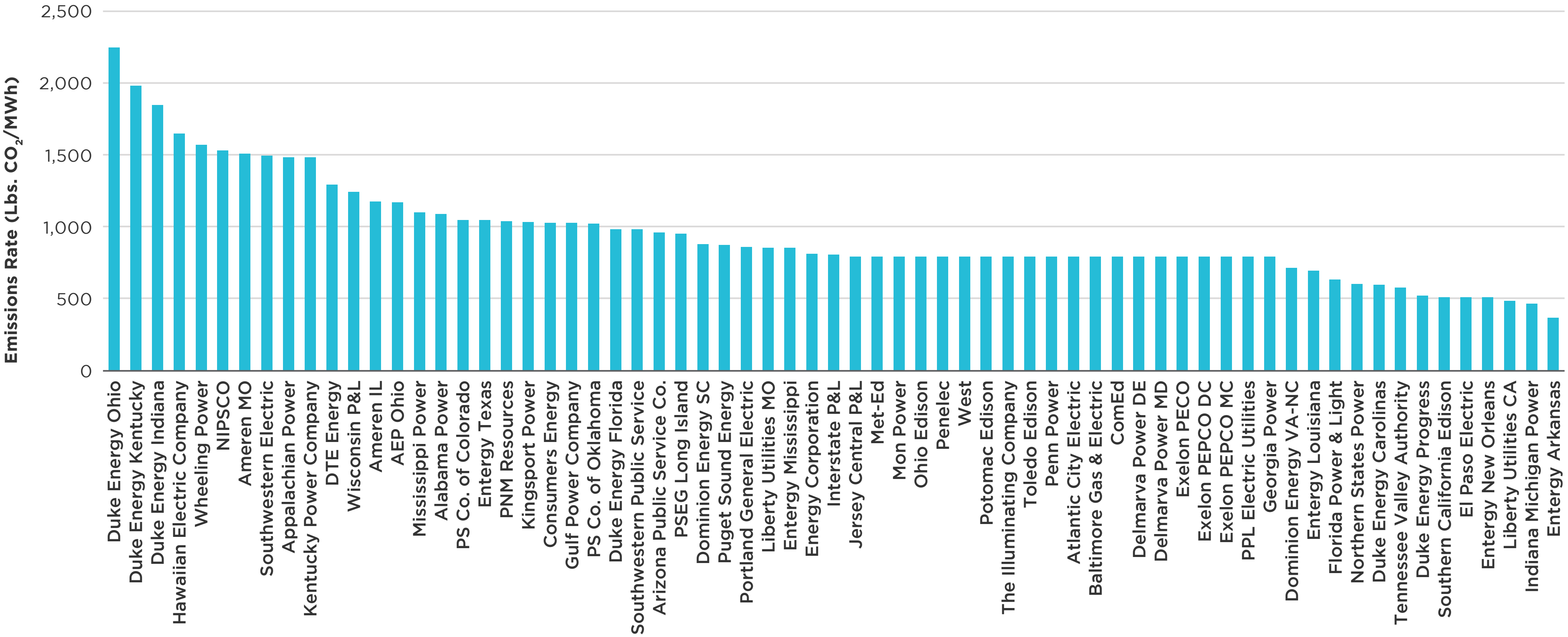
Figure 3.3: **Net-Zero Commitments – 100% State Requirements**



Notes: Figure 3.3 displays U.S. states that have established a binding 100% clean or renewable energy standard, or a binding net-zero requirement that applies to electric distribution utilities. These requirements can apply to specific utilities, to specific types of utilities, or economy-wide. Related state policy actions that are less enforceable, including executive orders and non-binding goals, are not displayed.

Source: Smart Electric Power Alliance

Figure 3.4: **2020 Utility Average CO_2 Emissions Rates* of Selected Reporting Operating Companies (Pounds of CO_2/MWh)**



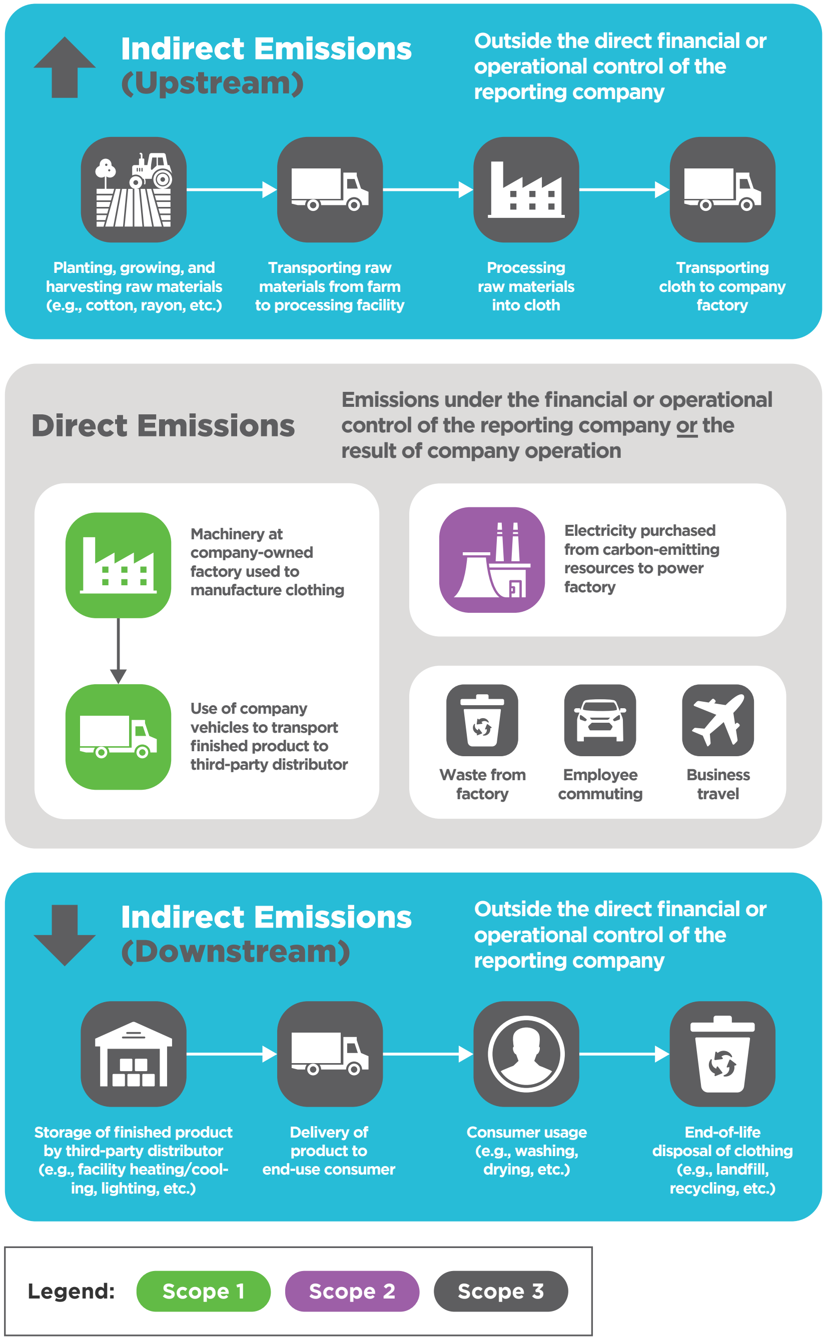
Notes: *All are average emissions rates except Utility Specific Residual Mix Emissions Rates used for Southern Company and Alliant Energy Corp. subsidiaries. The utility-specific residual mix emissions rate is the average annual emissions rate (in lbs. per MWh) of electricity delivered to customers, including renewable generation for which renewable energy certificates are retained by the utility and retired in the reporting year, with accounting adjustments made for specified green energy products where another entity (e.g., a customer or different electric company) owns the renewable attributes.

Source: Edison Electric Institute

Identifying High-Leverage Decarbonization Levers

- For utilities, especially those with fossil generation, the primary objective of the portfolio is reduction of Scope 1 emissions, which tend to overshadow Scopes 2 and 3 emissions. Scope 1 emissions are categorized as direct GHG emissions that occur from sources that are controlled or owned by an organization (e.g., emissions associated with fuel combustion in boilers, furnaces, vehicles).
- Constructing a decarbonization portfolio to achieve those reductions requires a comparative evaluation of technology options. In particular, several factors that are useful to characterize options include:
  - **Maturity (readiness for deployment):** Technologies are evaluated using a technology readiness framework specifying where in the development and commercialization process the technology sits. Due to the long-term nature of these plans, technologies in the earliest stages of their development must be considered.
  - **Scale of potential abatement (potential impact):** Different abatement options have different potential reduction profiles, including dependence in some cases (such as carbon capture, utilization, and storage) upon existing emitting resources.
  - **Cost of abatement:** Research and resource planning modeling are used to estimate the cost per ton of CO_2 abated (or potential increased cost per MWh) of the targeted resource.
  - **Dispatchability:** Different resources allow varying levels of control over the production of energy (e.g., stand-alone solar vs. solar + storage vs. small modular reactors).
- A first order analysis groups abatement or sequestration options into categories and identifies some likely technology candidates that can then be modeled in different portfolios that can be assessed, like integrated resource plan (IRP) scenarios, based upon cost, carbon reduction, timing, and feasibility.

Figure 3.5: **Illustration of Scope 1/2/3 Emissions**



Source: ScottMadden white paper, "Carbon Reduction Begins with Carbon Accounting" (July 2021)

Figure 3.6: **Department of Energy Technology Readiness Levels Framework (Defined)**

Closer to Commercial Readiness

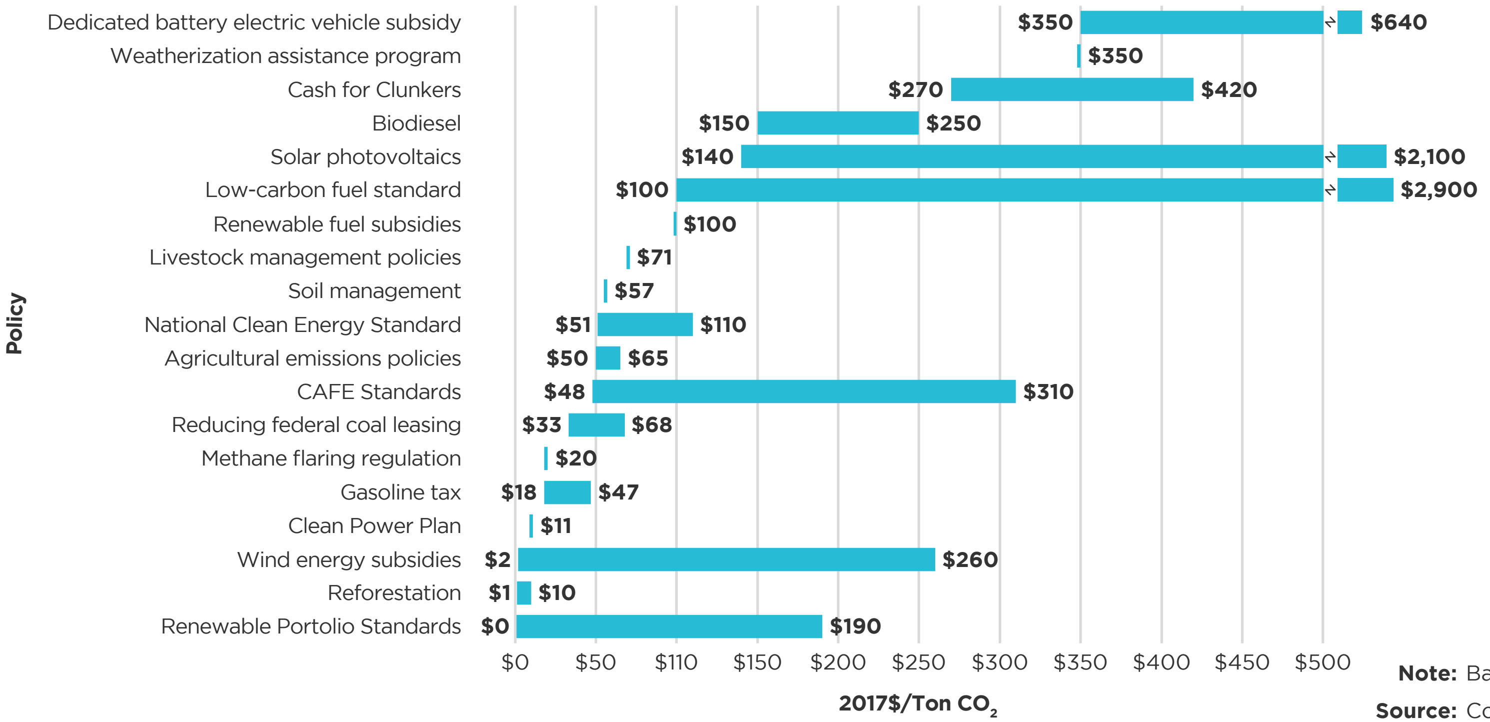
Relative Level of Technology Development	Level	Title	Description
System Operations	TRL-9	**Normal Commercial Service**	**Scale:** full-scale implementation. Enforceable performance guarantees, including capacity, material use/production, and energy use/production
System Commissioning	TRL-8	**Commercial Pilot Plant:** deployment of the technology in its final form and under expected conditions	**Scale:** size/capacity no less than about 25% of the capacity required for full-scale implementation
	TRL-7	**Pilot Plant:** integrated, fully functional prototype that incorporates all the features of the anticipated full-scale operational environment	**Scale:** size/capacity no less than about 5% of the capacity required for full-scale implementation. Include all components or unit processes expected at full scale
Technology Demonstration	TRL-6	**Process Development Unit:** a unit consisting of prototype components in a relevant environment	Prototype components are those which design and function are essentially the same as expected for full-scale deployment
Technology Development	TRL-5	**Component Validation:** pertinent technology components are validated in a relevant environment	Component-level assemblies are designed and function independently as a unit
	TRL-4	**Component Validation in a Laboratory Environment**	Laboratory studies that physically verify the engineering/scientific assumptions of the analytical studies
Research to Prove Feasibility	TRL-3	**Proof of Concept**	Laboratory studies that physically verify the engineering/scientific assumptions of the analytical studies
	TRL-2	**Formulation of the Application**	Practical applications of basic physical principles are "invented" or identified
Basic Technology Research	TRL-1	**Basic Principles Observed and Reported**	Observation of material properties or other physical/chemical phenomena

Source: Adapted from Department of Energy

Abatement Cost Estimates: Emerging Alternative Approaches

- Many industry participants and observers are familiar with the marginal (CO_2 emissions) abatement cost (MAC) curve, which plots the marginal costs of achieving a cumulative level of emissions abatement sequenced from the lowest to the highest cost measure. This is typically represented as cost in dollars per metric ton of CO_2-equivalent abated.
- However, like levelized cost of energy (LCOE), this MAC analysis is relevant for abatement costs of various approaches in isolation—that is, when selecting among abatement alternatives *independent of existing emissions sources* being displaced or reduced.
  - A critique of traditional MAC curves is their static cost estimates, which may reflect only short-run reductions and not account for learning-by-doing and scale economies as some nascent technologies mature. Further, there can be diminishing returns for carbon reduction as a particular technology is deployed.
  - Also, MAC curves do not necessarily reflect what energy sources are displaced and how those displacement terms interact or limit each others' opportunity. Some observers say that MACs underestimate transition costs and do not fully represent required transition investments.
- Some alternatives proposed include an updated MAC curve that shows annual emission reductions from measures relative to a baseline scenario as a function of marginal abatement cost. However, that "MAC 2.0" approach is focused on economy-wide options rather than electricity specifically.

Figure 3.7: **Recent Static Economy-Wide Marginal Abatement Costs of Past and Present U.S. Policies (2017$/Ton CO_2)**



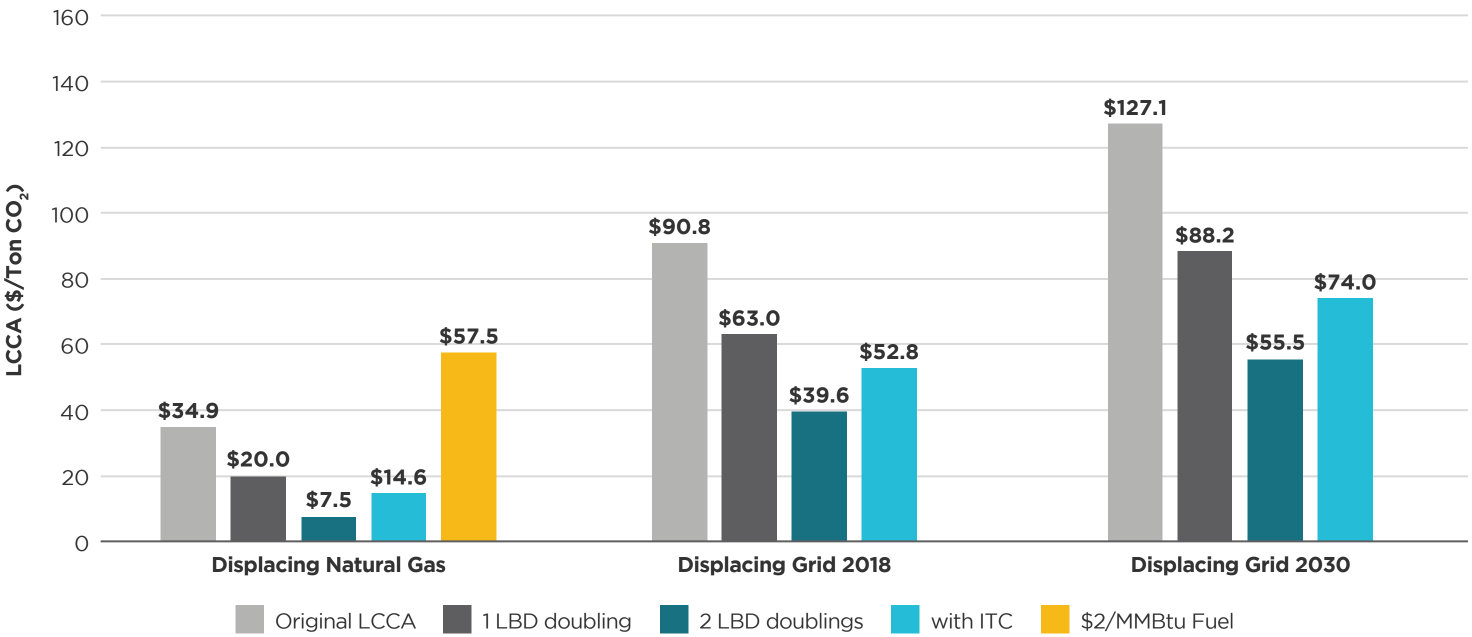
Note: Based upon a compilation of economic studies.

Source: Columbia/SIPA Center on Global Energy Policy

Abatement Cost Estimates: Emerging Alternative Approaches (Cont.)

- Another proposed approach is the levelized cost of carbon abatement (LCCA), which is the difference in annualized costs between the decarbonization measure (e.g., utility-scale solar) and an original configuration (e.g., fossil generation), divided by the difference between emissions in the original configuration and emissions in the displacement configuration. Some observations:
  - Lower annualized fuel costs of an existing configuration will increase the numerator and thus increase the LCCA.
  - Emissions from displacement of a low-emitting resource will reduce the denominator, also increasing the LCCA.
- While the LCCA construct is not yet widely used, it points to the need for more tailored abatement cost estimates that reflect "the real, all-in costs of a policy and the real, all-in impacts on emissions. These costs and impacts can vary depending on the contexts and details of geography, existing infrastructure, timing, and other factors." All-in costs can extend beyond the plant and land. For example, at scale, solar produces additional costs such as those for grid upgrades to manage reactive power and overproduction export, costs which are not incorporated into estimates such as LCOE.

Figure 3.8: **Illustrative LCCA for Utility-Scale Solar Displacing Various Existing Sources in Central California ($/Ton CO_2)**



LCCA decreases with:

- Higher-cost resources in the system's original configuration
- Higher-emissions resources in the system's original configuration
- Greater or accelerating learning-by-doing efficiencies projected for the decarbonization measure

Notes: Since displacing hydropower effectively yields infinite LCCA value, it is excluded.
ITC means investment tax credit. LBD means learning-by-doing or experience efficiencies.

Source: Columbia/SIPA Center on Global Energy Policy

Modeling Potential Portfolios

- To assess potential portfolios, IRP resource models can be employed with modifications to determine GHG emissions constraints. This allows for evaluation of scenarios with different decarbonization portfolios and first-order determination of high-leverage actions.
- Portfolios, rather than individual technologies, should be evaluated since the technology levers employed have interactions with current resources and are dependent on how those decarbonization levers affect higher-emitting resources. It also promotes discussion of possible scenarios, related constraints, and timing of achievement of GHG emissions reductions against internal or statutory targets.
- Uncertainty needs to be recognized and incorporated into the modeling. For example, there may be significant confidence in cost forecasts of mature and currently commercially available technologies. For newer or not-yet-developed technologies, modelers must use a wide band of potential costs. Further, IRP models are designed to work with well-known parameters compared with the technology portfolios that utilities are analyzing. This creates the opportunity for false precision in the analysis.
- When optimizing the potential portfolio, some care must be exercised to limit certain potential variables so the results make real-world sense.
  - For example, left to optimize inputs, because they may be deemed a relatively cheap action, demand-side options could result in theoretical adoption of those measures beyond what has been historically or might be realistically expected.
  - Further, left unconstrained, storage becomes a major tool for decarbonization, but the model does not recognize grid and land constraints that limit the quantity of storage deployed. It is also difficult to model which resources are charging those storage assets.
  - Finally, interim targets should be used, or the model heuristics could wait until near the end of the forecast period and then designate huge changes to the resource mix all in the forecast's final years.

Figure 3.9**: Results of Modeling**

The results of modeling provide some directional guidance on where to focus time and capital for carbon reduction as well as additional initiatives to consider the following:

Required infrastructure, including grid enhancements

Land and water needs

Additional analysis of preferred technologies

Environmental studies

Potential rate impacts and regulatory models

Implementation considerations (customer and stakeholder planning)

Signposts to monitor (especially for immature technologies)

Complications and Considerations: Lessons Learned

From our work in assisting clients in developing these studies and plans, we have observed the following:

Risk tolerance or aversion matters in building and selecting a decarbonization portfolio, particularly where a utility commits to technology before full maturity.

An optimal portfolio must consider affordability and rate "step changes" to avoid rate shock. In addition, the potential timing and cost of stranded assets must be considered.

While sequestration options such as afforestation and reforestation may be potential technologies for adoption, state policy preferences in some cases may limit these projects to within the state's territorial footprint.

Local geography (including elevation) and geology matters for technologies such as solar, wind, and pumped storage and for carbon capture and storage.

Possible grid impacts of changes in resource profiles—e.g., system stability, VAR/voltage support, network upgrades and reactive support, need for additional transmission capacity—are typically not modeled but must be studied scenario by scenario.

Non-intuitive issues may arise because of interactions of technologies. For example, stand-alone batteries may be carbon positive (charge and discharge) based upon round-trip inefficiencies, but they may be carbon negative when paired with or displacing a fossil-fired peaking unit.

IMPLICATIONS

While much has been made of state, municipal, and utility commitments to net-zero targets, the specifics of how to achieve them have been deferred. With interim targets now looming less than a decade away, utilities must engage now in planning exercises that consider existing and future options and related technologies and develop assessments of various resource portfolios that are suitable for the utility's circumstance and reflective of its (and its regulators') risk tolerance.

Sources:

U.S. Environmental Protection Agency, *Scope 1 and Scope 2 Inventory Guidance*, at https://www.epa.gov/climateleadership/scope-1-and-scope-2-inventory-guidance (accessed Mar. 13, 2022); K. Gillingham & J. Stock, "The Cost of Reducing Greenhouse Gas Emissions," *Journal of Economic Perspectives* (Fall 2018); Evolved Energy Research, Marginal Abatement Cost Curves for U.S. Net-Zero Energy Systems (July 2021); S. Friedmann, Z. Fan, Z. Byrum, E Ochu, A Bhardwaj, and H. Sheerazi, "Levelized Cost of Carbon Abatement: An Improved Cost-Assessment Methodology for a Net-Zero Emissions World," Columbia/SIPA Center on Global Energy Policy (Oct. 2020); "Levelized Cost of Carbon Abatement — New Tool For Investors And Policy Makers," CleanTechnica (Oct. 20, 2020), at https://cleantechnica.com/2020/10/20/levelized-cost-carbon-abatement-new-tool-for-investors-and-policy-makers/; ScottMadden analysis

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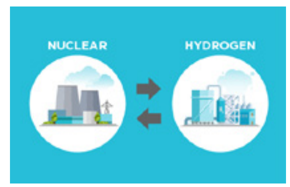

ARTICLE

The Case for Hydrogen and Nuclear Cogeneration

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Interconnection Queue Reform

Long lines and slow reviews hamper the energy transition.

Interconnection Queues Hold Back Hundreds of Gigawatts of Renewable Generation

- The current processes for interconnecting generation to transmission systems were designed to connect a modest number of large, central station generators to the grid, not the much more numerous, smaller wind and solar projects now being developed in the United States.
- As a result, the total capacity active in interconnection queues is growing year-over-year with more than 1,000 GWs of generation and an estimated 420 GWs of storage capacity in interconnection queues at the end of 2021.
  - Solar (676 GWs pending) accounts for a large and growing share of generator capacity in the queues. Additionally, substantial wind capacity (247 GWs) is also in development, 31% of which is for offshore projects (77 GWs).
  - In total, about 1,350 GWs of zero-carbon capacity (i.e., renewables and storage) is currently seeking transmission access as is 75 GWs of natural gas capacity.
- Much of this proposed capacity will ultimately not be built.
  - Among a subset of queues for which data are available, only 23% of the projects seeking connection from 2000 to 2016 have subsequently been built. These completion percentages appear to be declining and are even lower for wind and solar than other resources.
  - The completion rate may have increased temporarily after the 2010-2012 queue reforms, but it appears to be declining for projects proposed from 2014-2016. Trends for projects proposed in 2017 and after cannot yet be determined, as most of them are still active.

KEY TAKEAWAYS

The current transmission interconnection system was built for an era when large, dispatchable generators were the primary capacity connecting to transmission. Current interconnection regulations can pose a challenge for smaller, renewable projects.

FERC and RTOs have recognized the issues and strategized various solutions. FERC introduced Order 845, allowing greater ease of interconnection to renewable projects, while RTOs are moving toward clustering interconnection studies.

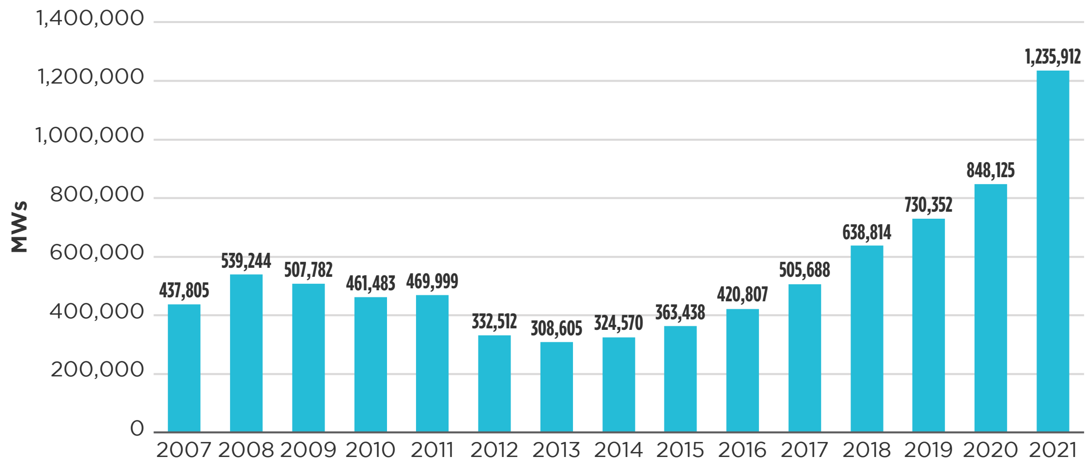
None of these solutions, however, addressed one of the main challenges—participant funding—which inefficiently allocates network upgrade costs to a single renewable project.

Participant funding has been a topic of controversy as FERC seeks input on potential solutions in its recent ANOPR.

Interconnection Queues Hold Back GWs (Cont.)

- Moreover, wait times are on the rise: in four ISOs and one utility, the typical duration from interconnection request to commercial operation date increased from ~2.1 years for projects built in 2000-2010 to ~3.7 years for those built in 2010-2021. This has led to growing calls for queue reform to reduce cost, lead times, and speculation by players who pre-emptively grab queue positions.
- A review of interconnection agreement (IA) data shows variations between markets.
  - Among projects *without* signed IAs through 2020, those in SPP (median = 915 days) tend to have spent the longest time in the queues, followed by MISO (612 days) and NYISO (602 days).
  - Among projects *with* signed IAs through 2020, those in CAISO (median = 2,072 days) tend to have spent the longest time in queues, followed by SPP (1,645 days), and West (non-ISO) (1,555 days).

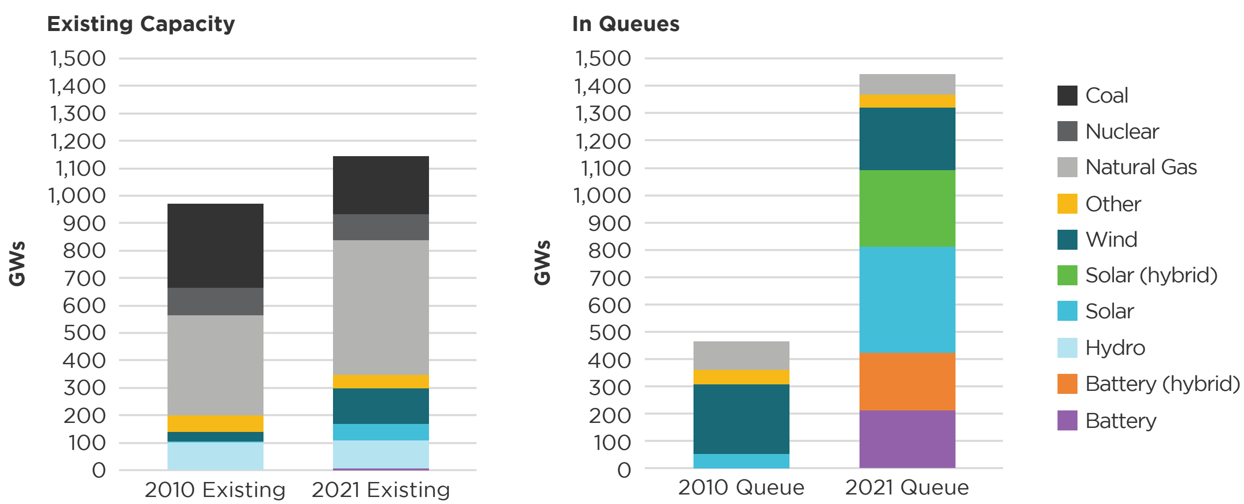
Figure 4.1: **Generation, Storage, and Hybrid Capacity in Interconnection Queues: Total U.S. Capacity in Interconnection Queues (2007–2021) (in MW)**



Notes: Excludes battery capacity from hybrid projects. Battery storage and all hybrid categories data are from 2018 through 2021. ERCOT queue data includes only projects that have requested a full interconnection study (FIS).

Source: Lawrence Berkeley National Laboratory

Figure 4.2: **Generation, Storage, and Hybrid Capacity in Interconnection Queues: Existing Capacity vs. Capacity in Interconnection Queues (2010 and 2021) (in GW)**



Source: Lawrence Berkeley National Laboratory

A recent Berkeley Lab survey shows:

"A total of 1.44 terawatts (TW) in interconnection queues, which is greater than the existing capacity of the U.S. power generation fleet. The queue has grown by nearly a TW in the past decade, indicating both great interest in development and a congested process of interconnection.

Most of the projects in queues are proposed solar, storage, and wind power plants. At current estimated capex prices, these projects represent more than $2 trillion in potential investment.

Based on past completion rates, only about a quarter of proposed projects are likely to come online. Even so, this volume of proposed plants indicates an ongoing and substantial shift in electricity generation toward renewable resources."

Current Interconnection Policy Framework Was Built for a Different Era

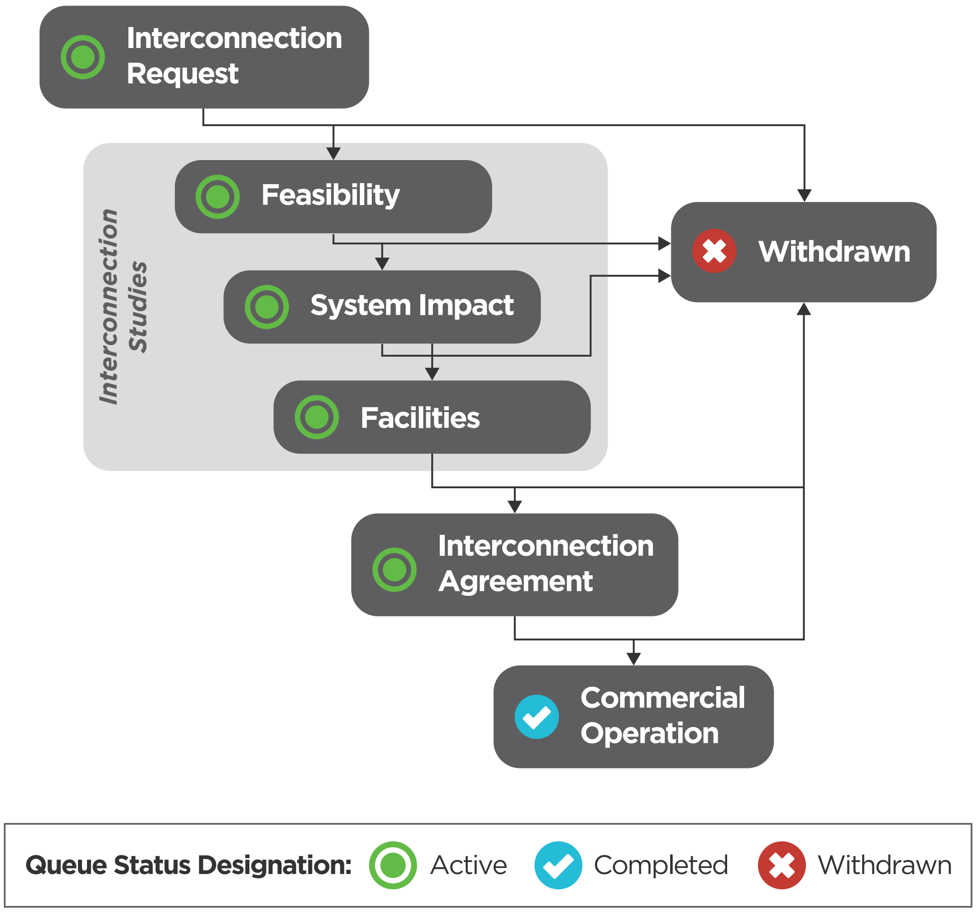
- Current generator interconnection policy was established in the early 2000s and designed to connect gas-fired generation, which made up the vast majority of new capacity at the time.
- Gas generators have the ability to interconnect with the transmission system at a wide variety of locations, depending upon the availability of gas infrastructure. Because of the locational flexibility, scale of the generator, and, in organized markets, price signals for siting new generation, transmission impacts were straightforward and economically manageable.
- Early policies were focused on increasing efficiencies for this type of interconnection. In 2003, FERC issued Order 2003 in an effort to standardize interconnection procedures and agreements for generators more than 20 MWs. The order standardized Large Generator Interconnection Procedures (LGIPs) and Large Generator Interconnection Agreements (LGIAs). FERC determined that RTOs could propose participant funding for generation interconnection upgrades (i.e., where interconnecting generators are entirely responsible for network upgrade costs). Additionally, the policy applied a serial approach to reviewing interconnection projects individually and in the order that they entered the queue.
- By definition, renewable resources are more location specific and sometimes more distant from load than large, central station thermal resources. In the late 2000s, growing wind capacity began to overload interconnection queues. In certain areas, when the existing transmission network reached capacity, the next project in line would be faced with the exceedingly high costs of a substantial network upgrade. Seeing the comparatively large price of their interconnection, many projects would drop out of the queue until another project decided to bear the cost of the upgrade.

Source: Photo courtesy of FERC

Regional Transmission Organizations Look at Backlogs (Part One)

- Through the late 2000s into the 2010s, many RTOs experienced similar interconnection queue congestion with rising rates of renewable generation development. In 2008, FERC ordered RTOs to investigate solutions to address the backlogs.
    - MISO held multiple stakeholder forums and, in 2016, proposed tariff revisions to minimize re-studies and the implementation of new milestones to improve project readiness. In 2018, it added to these changes by eliminating fully refundable milestone payments and requiring site control demonstration.
    - SPP, experiencing similar backlog, produced reforms such as a "first-ready, first-served" policy and a greater use of cluster interconnection studies. In 2013 and subsequently 2019, SPP continued to refine its interconnection process, eventually requiring a three-stage study process with financial deposits required at each stage.
    - PJM held similar processes, which led to extending the length of the queue cluster to avoid queue study overlap and to create a separate queue for smaller projects seen as more likely to drop out.
    - CAISO's policy evolution led it to combine its small and large generator interconnection procedures in 2010, and later in 2012, to integrate the transmission planning process and generation interconnection procedures.
- The individual RTO efforts did not address the underlying issue causing queue backups—the continuation of participant funding combined with the rise of location constrained generation.

Figure 4.3: **Simplified Interconnection Study Process**



Source: Lawrence Berkeley National Laboratory

FERC's Attempt at Renewable Interconnection Improvements

- By the late 2010s, the growth in proposed renewable generation facilities and other new technologies, such as energy storage since Order 2003, had led to delays due to backlogs and long timelines for interconnection queues as well as delays for interconnection re-studies due to late-stage project queue withdrawals. Lack of cost and timing uncertainty was deemed a problem for financing of projects and a risk that some interconnection customers were less able to absorb unexpected and potentially higher costs.
- In April 2018, FERC issued Order 845, intended to improve the efficiency of processing interconnection requests, to maintain reliability, to balance the needs of interconnection customers and transmission owners, and to remove barriers to resource development. The order sought to accomplish these goals by revising FERC's pro forma LGIPs and LGIAs. In February 2019, FERC issued Order 845-A to explain how the rules outlined in the original order should work.

Key Provisions of Order 845

- Requiring transmission providers to maintain base case data and network models and underlying assumptions.
  - Order 845-A clarified that transmission providers may use the Commission's critical energy/electric infrastructure information regulations as a model in study modeling and assumptions.
  - FERC further clarified that the network model information should reflect the system conditions currently used in interconnection studies, not the real-time interconnection systems.
- Providing more leeway for generation facilities to exercise the option to build transmission upgrades with respect to interconnection facilities regardless of whether the transmission provider can meet the established deadline for the project, which was previously a prerequisite.
  - Order 845-A clarified that transmission providers may recover oversight costs if the option to build is exercised and that the option to build does not apply to stand-alone network upgrades on non-transmission electric systems that may be affected by proposed interconnection.
- Modifying the pro forma LGIPs to allow interconnection customers to request interconnection service in an amount that is less than a resource's full capacity.
  - Order 845-A clarified that if a customer chooses service below the facility's capacity and later seeks to increase its service, the transmission provider must provide reasoning for any determination to require additional studies prior to granting such a request.
  - FERC also held that an interconnection customer may propose control technologies at any time during the interconnection process to request service below the generating facility's maximum capacity.
- Modifying the pro forma LGIP to require transmission providers to report interconnection study performance data on their OASIS sites on a quarterly basis.

Lesson: Despite incremental improvements and increased transparency, the provisions from Order 845 did not fully reform or alleviate interconnection challenges.

FERC Seeks a Broader Solution to Interconnection Woes

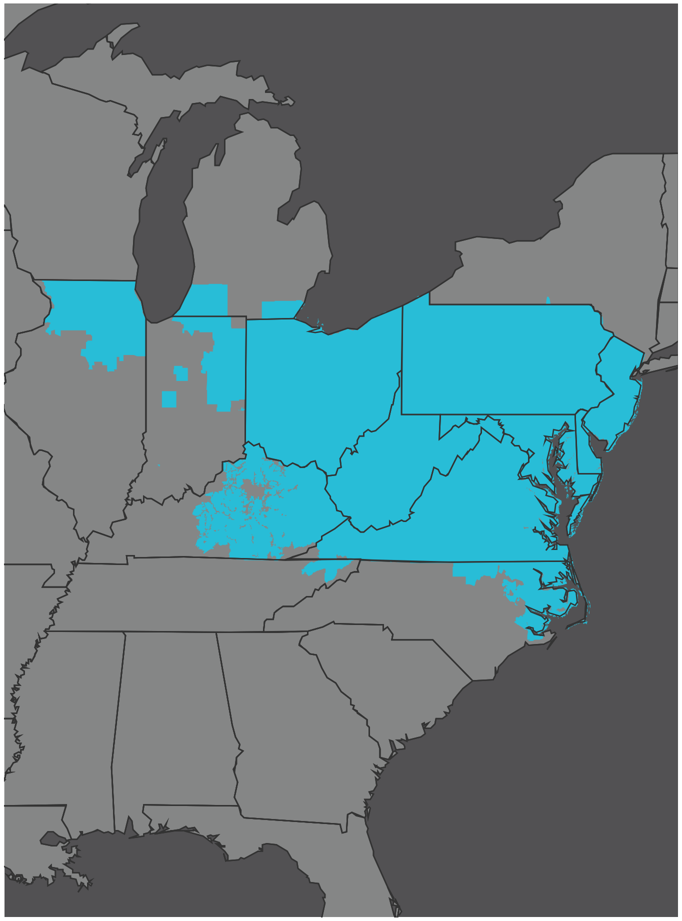
- FERC's recent Advance Notice of Proposed Rulemaking (ANOPR), "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," seeks input on the most pressing issues of the current interconnection process.
- Notable potential reforms presented by the ANOPR include reducing procedural and informational barriers as well as adjusting cost-allocation methods for transmission network upgrades. Participant funding has also been controversial, as the ANOPR seeks to reform the allocation of costs for transmission interconnection established in a 2003 order.
  - Under the existing cost-allocation structure, generating facilities bear the full costs of transmission network upgrades. However, the current interconnection environment is dominated by smaller, more distributed resources. While many entities receive benefits from network upgrades, assigning the entire cost to one entity leads to significantly increased near-term costs and therefore underinvestment.
  - The goal of the ANOPR's interconnection section is to consider potential reforms that better align costs and benefits of network upgrades potentially through requiring longer-term planning requirements to better capture the scope of the benefits and beneficiaries of network upgrades.
  - The ANOPR has teed up issues, including:
    - How to appropriately identify and allocate the costs of new transmission infrastructure in a manner that is aligned with estimated benefits.
    - Whether the generator interconnection process should be reformed to ensure (i) a more purposeful integration with the regional transmission planning and cost-allocation processes, (ii) a more efficient queueing process, and (iii) a more efficient and cost-effective allocation of interconnection costs.
- Another consideration of the ANOPR is whether participant funding is "unjust and unreasonable" and if pro forma crediting should be used instead. This would allow costs of transmission network upgrades paid by generating facilities to be offset by credits against future transmission service bills.

Regional Approaches Will Determine Success of Interconnection Queue Reforms

- Ultimately, the success of interconnection reform will depend on the rules and processes developed within each market.
- The following tables (Figs. 4.4–4.6) provide selected interconnection reform developments in select markets.

Figure 4.4: **PJM Interconnection Summary**

Current Process and Challenges	▪ New interconnection projects are taken in at six-month intervals and processed in the order in which they are received. ▪ Projects in the queue receive a feasibility study, a system impact study, and a facilities study before executing final agreements. ▪ Network upgrade costs—identified during the system impact study—can be shared across queue cycles. ▪ The volume of new generation project requests has tripled in the past three years, causing the number of queue projects under study to increase along with the number of projects that are backlogged. - As of December 2021, there were 288,609 MWs in PJM's interconnection queue, almost half of which were solar. - About a third of the projects in PJM's backlog have been in the interconnection queue for more than 500 days. - In addition, 166 projects have been in the queue for more than three years.
Proposed or Approved Reforms	▪ Cluster/cycle-based queue windows that are synced with the progress of previous studies conducted and phases reached. ▪ New financial and site control requirements intended to limit and remove more speculative projects. ▪ A review queue that prioritizes projects by construction readiness, including financing agreements, secured off-takers, and hardware availability. ▪ Network upgrade costs contained within one cycle, creating greater certainty around possible costs required to interconnect a project.
Expected Results and Next Steps	▪ PJM has proposed that the review of new project applications be deferred until late 2025 in order to clear out backlogged projects and transition to the new review process. ▪ Backlogged projects will be cleared out using two transition review cycles, with the first finishing by mid-2025 and the second wrapping up a year later. ▪ Under the new process, PJM expects interconnection applications could be completed in less than two years. ▪ PJM expects to file its interconnection reform proposal to FERC for review in May 2022, pending approval from two more of its stakeholder committees. ▪ If approved by FERC, the reform plan could take effect October 2022.



Sources: FERC; EIA; ArcGIS

Figure 4.5: **MISO Interconnection Summary**

<table>
<tr><td>Current Process and Challenges</td><td>

In 2017, MISO implemented a three-phase Definitive Planning Phase (DPP) process to study and review interconnection requests:

Projects pass through three phases: preliminary system impact study, revised system impact study, and final impact study.
A facilities study begins in Phase II, but it is not completed until the conclusion of the final impact study.
Generation Interconnection Agreement (GIA) negotiations begin after the completion of the facilities study.
The DPP process is expected to take 505 days.

MISO states that although its current DPP process has performed reasonably well since its adoption in 2017, the overall length of the process has become an issue.

</td></tr>
<tr><td>Proposed or Approved Reforms</td><td>

In March 2022, FERC approved, in part, the following interconnection reforms:

Interconnection customers may choose between a Default Path and Optional Path.

The Default Path allows interconnection customers to execute a GIA before the facilities studies are competed.
Offering less risk and more certainty, the Optional Path begins GIA negotiations after facilities studies are completed.

Revise model building and updating process while retaining firm timelines for model reviews.
Align interconnection timelines with MISO Transmission Expansion Plan (MTEP) study cycle.

MISO and SPP also conducted a Joint Targeted Interconnection Queue (JTIQ) which aims to identify opportunities for transmission network upgrades along the seams to enable new generator interconnections.

</td></tr>
<tr><td>Expected Results and Next Steps</td><td>

MISO's interconnection reforms are expected to deliver the following benefits:

Shorten the length of the generation interaction process (i.e., 505 days to 373 days for the Default Path)
Increase the overall efficiency of the generator interconnection study process
Improve the alignment between the generator interconnection process and MTEP process

Meanwhile, the MISO-SPP JTIQ study, released in March 2022, found collaboration would allow an additional 28 GWs to 53 GWs of improved interregional generation enablement to be available to new generator interconnection projects near the seam. The study identified a seven-project JTIQ portfolio, costing an estimated $1.65 billion and providing a $724 million benefit in the MISO footprint and $247 million benefit in the SPP region.

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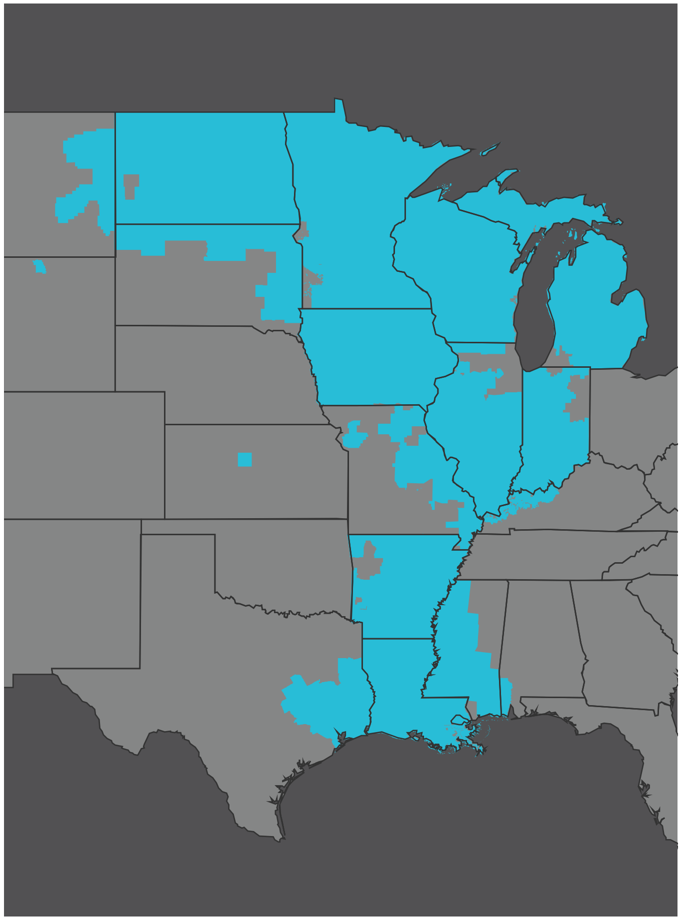
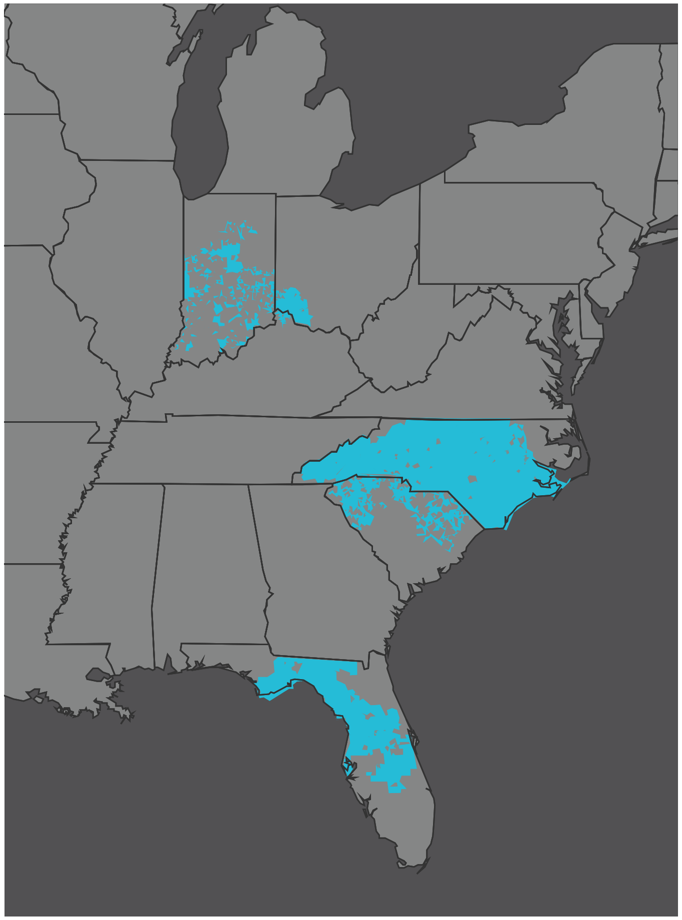


Sources: FERC; EIA; ArcGIS

Figure 4.6: **Duke Energy Interconnection Summary**

Current Process and Challenges	▪ New generation projects applying for interconnection were reviewed serially, one at a time, with little consideration given to projects' readiness in prioritizing their reviews. - The interconnection queue process consisted of three to four studies, including a facilities study, before the final IA. - Network upgrade costs were assigned to the project that triggered the need for an upgrade, preventing developers from sharing costs when large upgrades were required. ▪ In 2019, Duke Energy's utilities in North and South Carolina had 14 GWs of solar and wind projects in their interconnection queues. - In 2020, a Duke witness testified that "because the interconnection queue and study complexities continue to increase, the current serial study process is not sustainable." - Lack of cost sharing for large network upgrades resulted in many projects being forced to withdraw from the queue.
Proposed or Approved Reforms	▪ Duke plans to clear the existing interconnection queue by the end of 2022 in order to begin the process of queue reforms addressing the inefficiencies of the current system. Reforms were approved by the North Carolina Utilities Commission, the South Carolina Public Service Commission, and FERC in 2021 and include: - The creation of timing and payment requirements for projects to be included in the review window. Projects that meet the requirements will then be grouped by location. - A transition from the serial review process to a process that reviews projects in clusters. ▪ Each cluster goes through a combined transmission and distribution load flow study. ▪ Clusters are then processed based on whether they have a transmission impact, a shared distribution impact, or no impact.
Expected Results and Next Steps	▪ The existing interconnection queue is planned to be cleared by the end of 2022, allowing for the implementation of reforms which are expected to have the following effects when Duke begins processing interconnection requests under the reformed process in 2023: - Duke expects timing and payment requirements to remove speculative projects from the queue. - Duke expects the cluster review process to enable more predictability (including cost predictability) and improved efficiency.



Source: S&P Global

Transmission Owner's Ability to Earn

- Another result of the growth of renewable generation and, subsequently, the increase in network upgrades is the debate over transmission owner's ability to earn a rate of return on network upgrades for interconnecting generation.
- Historically, interconnecting generators pay for the network upgrades required to connect to the transmission system, so despite the fact that transmission owners own and operate the system, they are not entitled to earn on the investment.
- However, the growth of renewables has led to increased spending on network upgrades. In 2021, PJM forecast that because of network upgrades, transmission owners would not be entitled to earn on 4% of total transmission assets within the next few years. With the expected growth of renewables, this number will only increase.
- Transmission owners argue that if a growing portion of their business is to be owned and operated on a non-profit basis, it will lead to increased risk for shareholders and be harder to attract investment.
- This discussion has the potential to shift the deadlock on who pays for network upgrades. The possible movement away from participant funding could open the door for transmission owners to take part in funding network upgrades and consequently bolster the argument for their ability to earn a rate of return on those assets.

IMPLICATIONS

Historical interconnection approaches ill-suited for currently proposed resources have led to significant interconnection queue backlogs and delays in renewable energy development. In recent years, RTOs and FERC have begun to acknowledge this issue and have sought out efficient means of remedying its underlying causes.

Changes such as clustering applications, providing interconnecting generators the option to build transmission upgrades, and modifying the system study process have been the first attempts to create a more efficient interconnection process. More recent discussion in FERC's transmission ANOPR has posed the question of whether a necessary step to increase efficiency will be to rework one key cause of underinvestment—participant funding.

Proposed changes seek to better align costs and benefits and to aid a shift toward an economically optimal level of investment. With a large transmission build-out expected to continue in the coming decades, changes in policy will be a key factor to enable efficient and economical progress.

Notes:

FERC released a Notice of Proposed Rulemaking (NOPR) on April 21, 2022.
Any notable differences between the ANOPR (discussed in the text) and NOPR are not addressed in this section.

Sources:

Lawrence Berkeley National Laboratory, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2021 (April 2022); Lawrence Berkeley National Laboratory, *Generation, Storage, and Hybrid Capacity in Interconnection Queues*, at https://emp.lbl.gov/generation-storage-and-hybrid-capacity (accessed April 22, 2022); Lawrence Berkeley National Laboratory, Queued Up v2: Extended Analysis on Power Plants Seeking Transmission Interconnection as of the End of 2020 (February 2020), at https://emp.lbl.gov/sites/default/files/interconnection_update_2_18_22.pdf; R Street Institute, "Pruning the thorns in transmission and generator interconnection reform" (March 8, 2022); Brattle, "FERC ANOPR Reform: The Need for Improved Transmission Planning and Cost Allocation" (November 3, 2021); Morgan Lewis, "FERC Rulemaking to Reform Regional Transmission Planning and Cost Allocation" (July 16, 2021); Covington, "FERC Rulemaking to Reform Regional Transmission Planning and Cost Allocation" (July 20, 2021); Troutman Pepper, "FERC Issues Advance Notice of Proposed Rulemaking on Potential Reforms for Electric Transmission Planning, Cost Allocation, and Generator Interconnection Processes" (July 21, 2021); Troutman Pepper, "FERC Revises and Clarifies Order No. 845 Large Generator Interconnection Reforms" (February 27, 2019); Stoel Rives, "Helping the Hook-Up: FERC's Generator Interconnection Procedures Reform Seeks to Improve Information Flow, Recognizes Changing Technology and Opens Further Opportunities for Storage" (April 30, 2018); The National Law Review, "FERC Reforms Generator Interconnection Procedures to Accommodate Energy Storage" (February 25, 2019); LexisNexis, "Pratt's Energy Law Review" (June 2019); Americans for a Clean Energy Grid, Disconnected: The Need for a New Generator Interconnection Policy (January 14, 2021); FERC; PJM Interconnection; Midcontinent ISO; Duke Energy Corporation; ScottMadden analysis.

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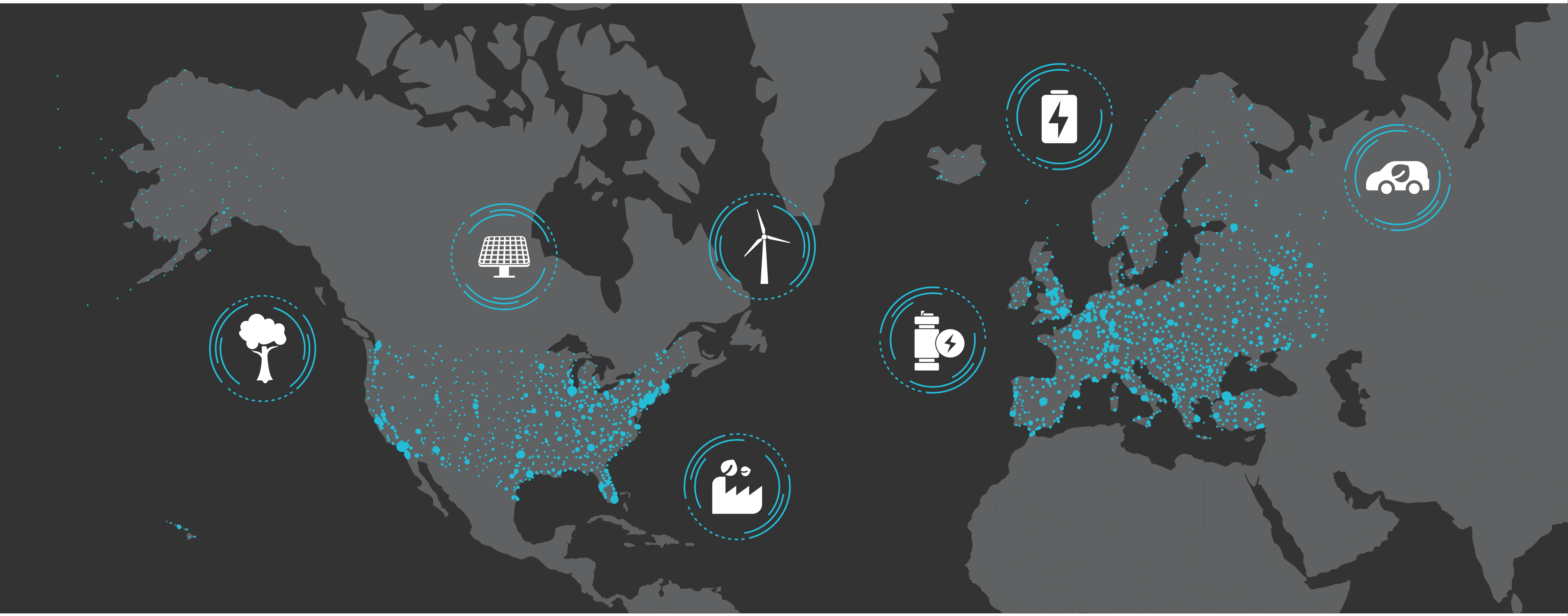


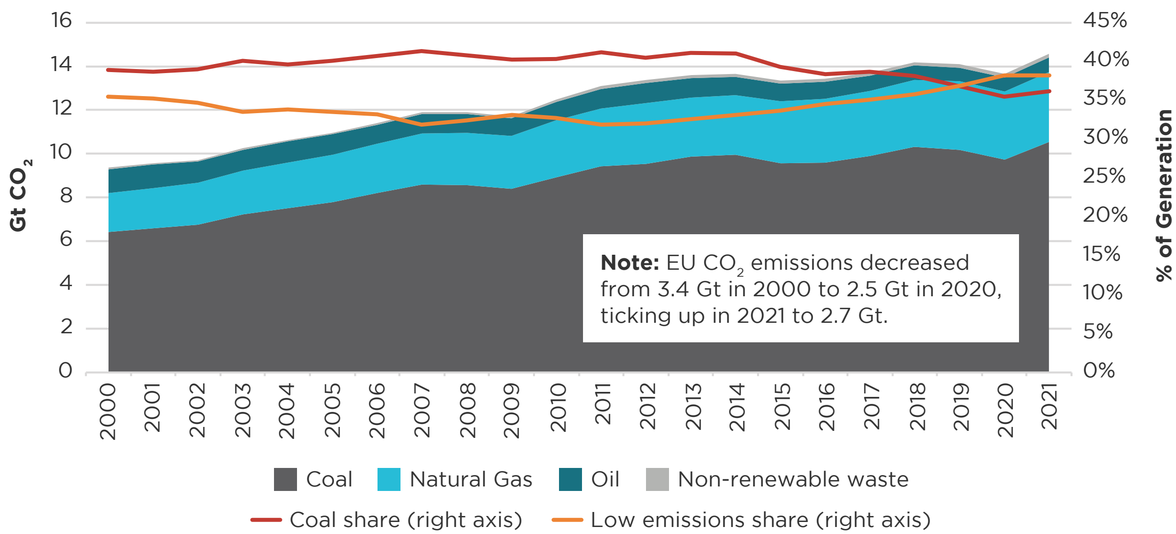
Energy Transition: What Are We Learning?

A look at some trends in Europe as a potential window on North America's energy transition.

Moving Down the Emissions Curve

- The European Union (EU) instituted its GHG emissions trading system in 2005, launching economy-wide efforts to reduce emissions, with a focus on more emissions-intensive industries such as power generation.
- Since then, European states have implemented additional policies, including the EU's "Fit for 55" legislation targeting 55% reduction in emissions by 2030 and the Green Deal, which aims for carbon neutrality by 2050.
- While no longer part of the EU, the United Kingdom has continued down its path of GHG emissions reduction through national policies promulgated by multiple governmental departments. It most recently adopted its own Net Zero by 2050 Strategy, aimed at achieving ambitious emissions reduction objectives under its 2019 net-zero by 2050 legislation.
- Transitioning to lower and ultimately net-zero carbon emissions has not been without challenges. Some concerns about the transition to date have been the following:
  - Falling short of emissions targets set to date
  - Concerns about energy security and system performance
  - Increasing energy price volatility and higher prices of certain energy sources such as natural gas

Figure 5.1: **Annual Global CO_2 Emissions from Electricity and Heat Production by Fuel and Generation Share by Fuel (Gt CO_2)**



Source: IEA

KEY TAKEAWAYS

The EU, like several regions of the United States, is pursuing ambitious GHG reduction goals.

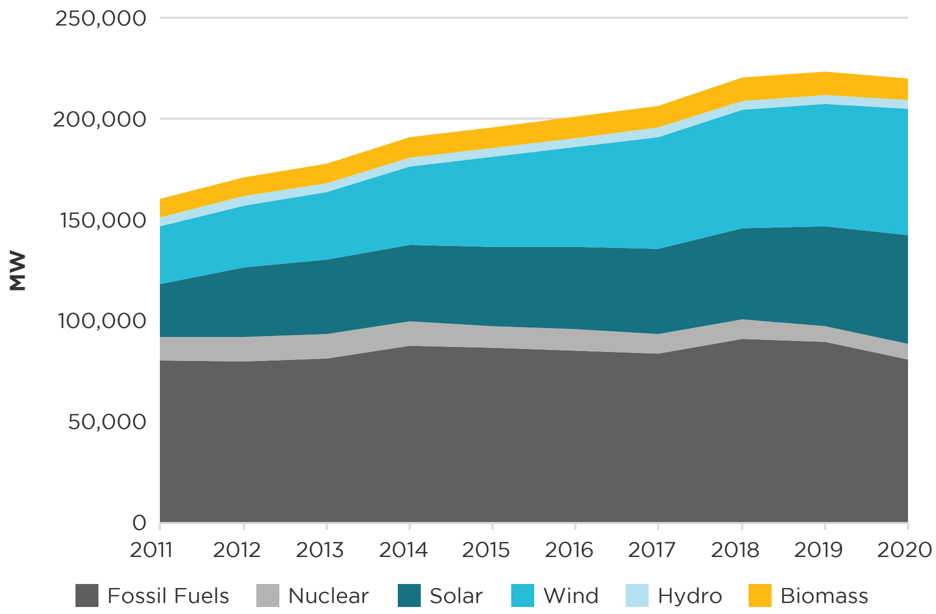
However, transition to those goals has been complicated by increasing natural gas prices, attrition of emissions-free nuclear generation, strong post-pandemic demand, erratic weather patterns, and, more recently, geopolitical events in Ukraine.

Germany and the United Kingdom, and European governments more broadly, are looking at new energy sources and considering extending current options like nuclear to ease near-term burdens of the clean energy transition.

Germany: Unintended Detours on the Way to Net-Zero

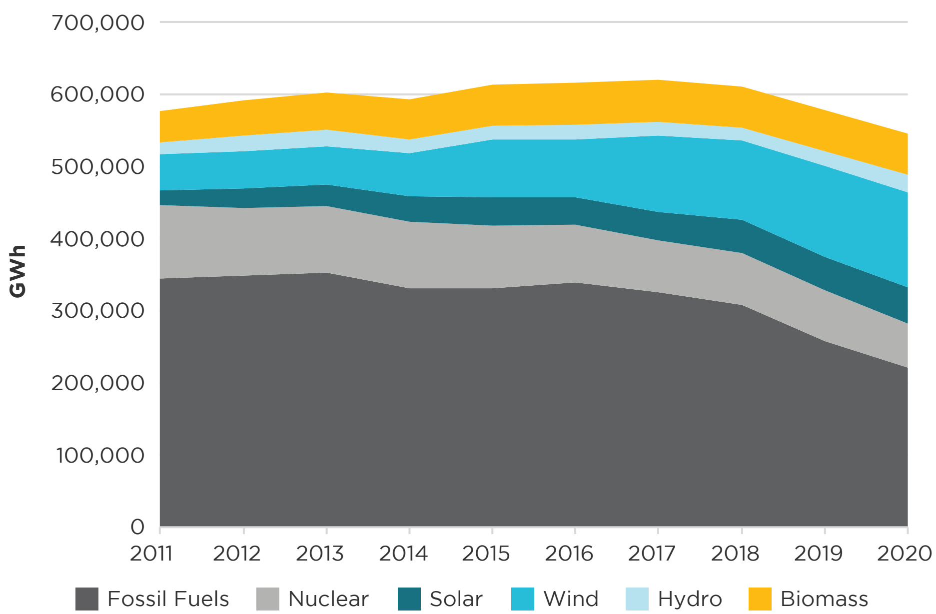
- Through its Energiewende (or Energy Transition) policy, Germany has pursued an aggressive expansion of renewable generation in tandem with an accelerated phase-out of nuclear power by 2022 and planned phase-out of coal-fired power generation by 2038, recently accelerated to 2030. Its goal was to secure half of its energy supply from renewables by 2030.
- In 2020, renewable resources comprised 60% of capacity and 48% of energy generated, nearly meeting Germany's 2030 goal. Renewable power production was also affected by an unusually windy Q1 and much lower energy consumption due to the COVID-19 pandemic. However, in 2021, its first "normal" year after the pandemic, Germany found itself confronted by several developments that challenged its progress toward its transition objectives:
  - Increased demand, as energy usage and economic activity recover from the COVID pandemic
  - A low wind year, challenging for a nation whose installed capacity is 28% wind
  - High retail costs (43% more than the EU average), 50% of which are taxes and fees
  - A pending shortfall of capacity (~4.5 GWs) between 2022 and 2025 as the nation's last nuclear plants are retired
- The shortfall in wind resources, winding down of nuclear assets, and high natural gas prices caused higher demand for Germany's coal fleet, with coal-fired power generation increasing by nearly 21% in 2021, after a large decrease in 2020. This increase occurred despite EU emissions allowances under its emissions trading scheme costing twice what they cost in 2020.

Figure 5.2: **German Capacity by Fuel Type (MW)**



Source: EIA

Figure 5.3: **German Generation by Fuel Type (GWh)**

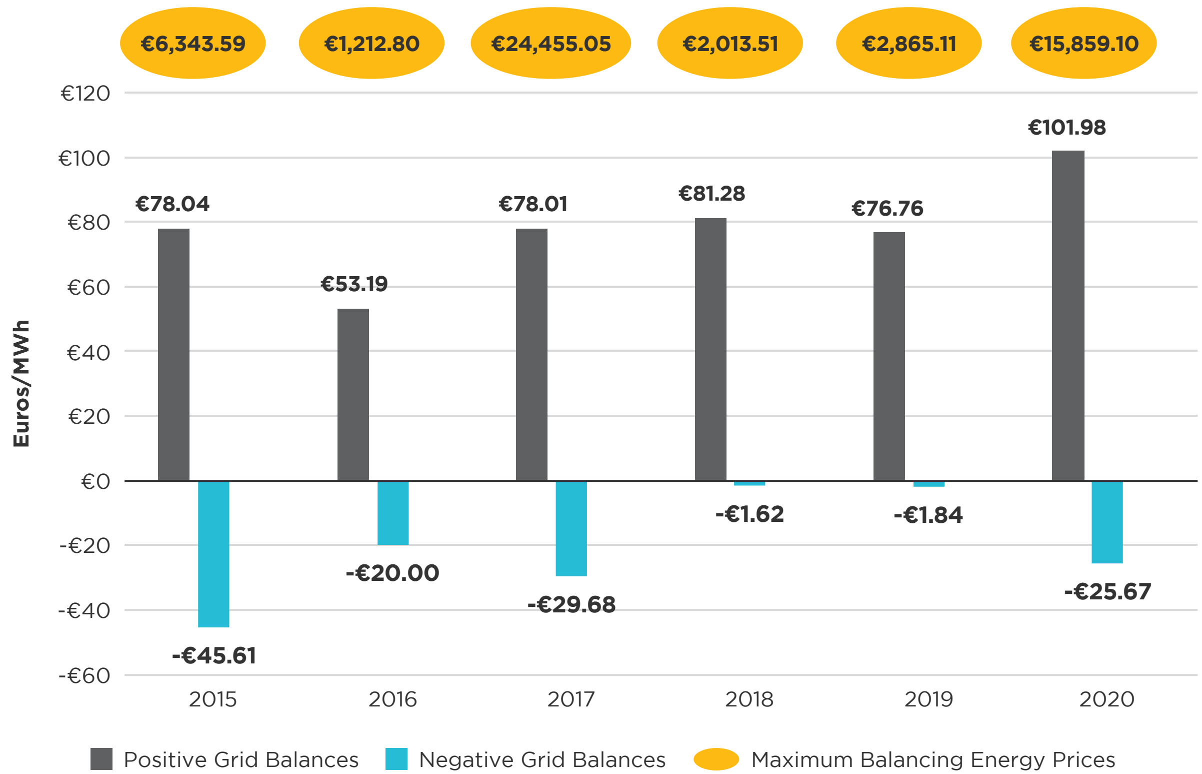


Source: EIA

Germany: Unintended Detours on the Way to Net-Zero (Cont.)

- As Germany's nuclear fleet faces retirement, it confronts the challenge of satisfying future demand at the same time it now seeks to increase the share of renewable energy to 80% by 2030, a 120% to 150% growth in renewables from current levels. One effect of this changing mix to date has been a growth in system balancing costs, which were about €102/MWh in 2020 versus a range of €53 to €81/MWh from 2015 to 2019.
- And more investment (and rate pass-throughs) await, as the EU and Germany look to increase grid connectivity to reduce overall system costs. Germany estimates that nearly $100 billion in grid enhancements will have to be made by 2030.
- Significant reliance on non-domestic Russian energy resources and the recent run-up in prices of hydrocarbons, which still provide a significant portion of German energy, have caused the new German government to consider diversity of supply and suppliers.
  - Some measures include consideration of pushing back coal retirement dates, developing LNG receiving terminals, and postponing scheduled 2022 retirement of its remaining nuclear plants.
  - But those potential measures are controversial as some advocates and government officials have recently been discussing accelerating renewable energy commitments to 100% by 2035.

Figure 5.4: **Average Volume-Weighted and Maximum Balancing Energy Prices (Euros/MWh)**



Notes: Balancing is for 15-minute intervals. Positive control area balance reflects undersupply (i.e., consumption is reduced by control reserve providers or feed-in of energy is increased). Negative balances reflect oversupply. (Source: *Monitoringbericht* 2021, at pp. 218-19.)

Source: German Federal Network Agency

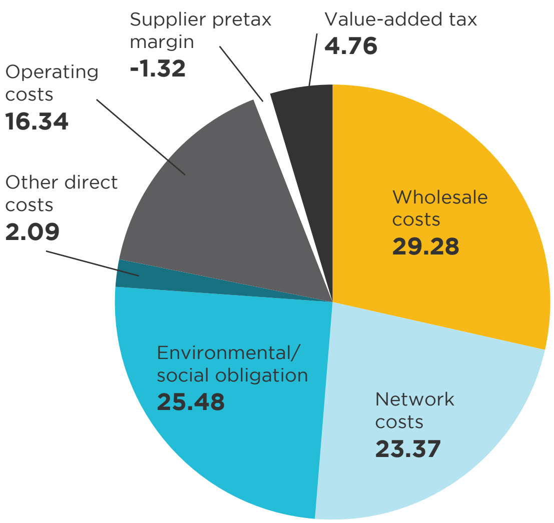
The United Kingdom: Gas as a Linchpin

- The United Kingdom has continued to pursue a decarbonization agenda for nearly a decade. Its regulatory framework was established in its 2013 Energy Act, which along with energy market reform, aimed to transform the U.K. electricity system to ensure energy supply is secure, low carbon, and affordable. In 2019, the United Kingdom became the first major economy to pass legislation that commits the country to a legally binding target of net-zero GHG emissions by 2050.

- Like Germany, U.K. power production capacity has seen increasing levels of renewable resources, which comprised 47% of installed capacity in 2020 and 43% of energy. Meanwhile, baseload coal and nuclear capacity has been declining in both capacity and output. Coal output, in particular, has declined precipitously with the introduction of a carbon price floor in 2013. It has been replaced largely with gas-fired generation, which share of electricity production has hovered around 40%.

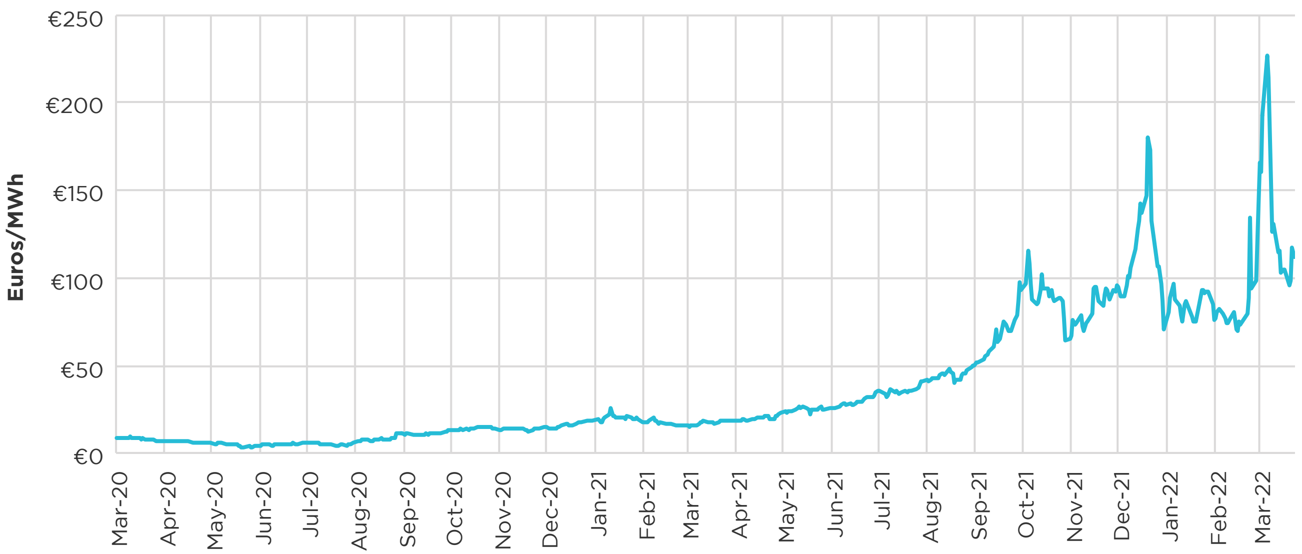
- Reliance of both the gas and electric systems on large amounts of imported gas has contributed to high and volatile energy prices for households. This had several effects:
  - Gas price spikes for home heating and retail electricity (retail markets are unbundled) bumped up against a price cap mechanism established in 2018 by the U.K. energy regulator Ofgem, leading to failure of 30 small retail providers serving 4 million customers.
  - Higher gas prices undermined the economics of electricity- and gas-intensive industries such as fertilizer, steel, chemical, and glass production.
  - Older coal plants such as Drax have been called into service as unplanned nuclear outages, reduction of power imports from France due to cable issues, and low wind output combined to force consideration of a wider variety of resources.

Figure 5.5: **U.K. Retail Electricity Bills: Breakdown by % of Total Bill**



Source: Ofgem

Figure 5.6: **TTF (Dutch) Front-Month Closing Natural Gas Prices (March 2020–March 2022) (Euros/MWh)**

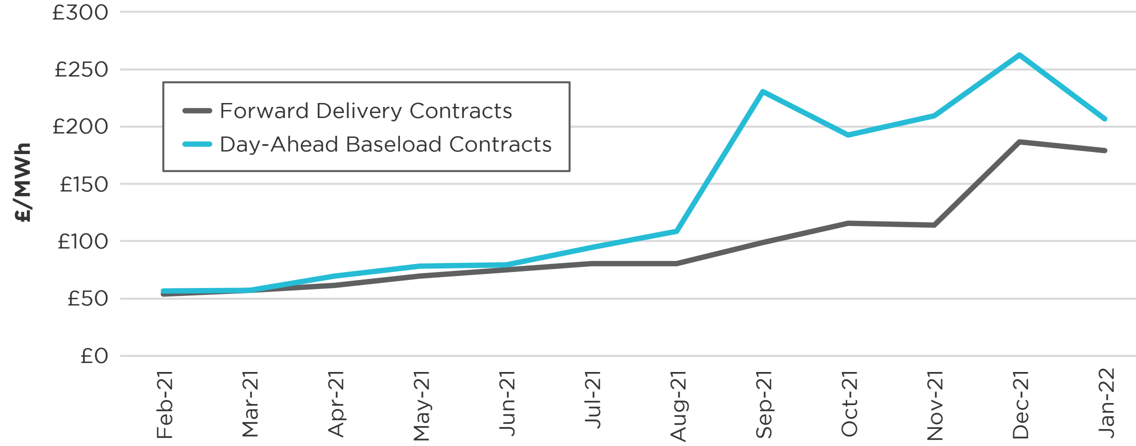


Source: Yahoo! Finance

The United Kingdom: Gas as a Linchpin (Cont.)

- Some headwinds remain for U.K. energy security and price stability and its emissions-reduction goals.
  - Nuclear units are retiring, with only one new unit, Hinkley Point C, slated to replace them.
  - Despite its heavy reliance on gas, the United Kingdom has very little gas storage and gas fracking has been banned, leading to heavy reliance upon imported LNG.
  - The U.K. government announced in June 2021 that it would bring forward the complete phase-out of unabated coal-fired power generation by one year to October 2024, although that announcement predated the significant run-up in natural gas prices beginning in August 2021.
- The U.K. government is considering varied actions, some more likely and near term than others:
  - Less likely but under debate, delaying the capping of the nation's last major gas fracking well.
  - Developing offshore wind, which current pipeline of 86 GWs is 8 times current operational capacity.
  - Encouraging further U.K. North Sea oil and gas development, subject to net-zero by 2050 commitments, with potential to fast-track six licenses. There has also been discussion of developing an offshore hydrogen hub.
  - Increasing interconnection capacity with Ireland, Norway, and continental Europe of 8.5 GWs between 2022 and 2025.
  - Revisiting the price cap construct, with an expected increase in spring 2022.

Figure 5.7: **U.K. Wholesale Electricity Prices (£/MWh)**



Source: Ofgem

Figure 5.8: **U.K. Capacity by Fuel Type (MW)**

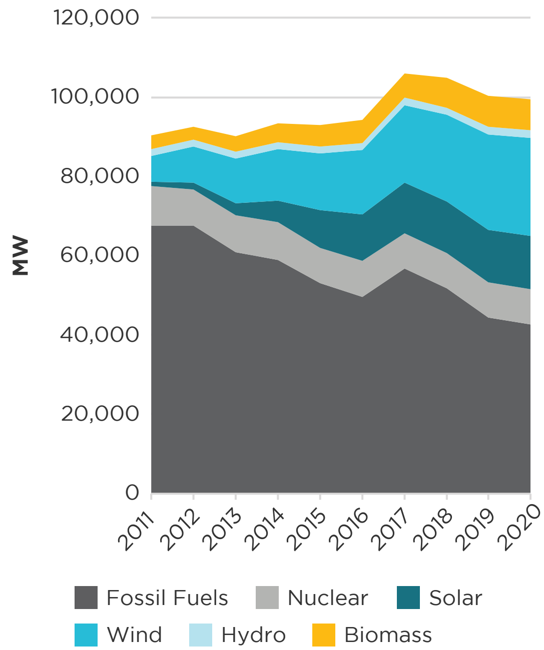
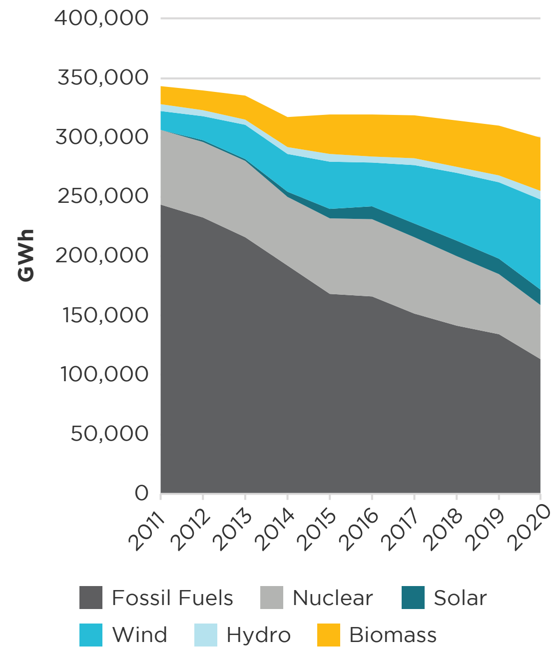
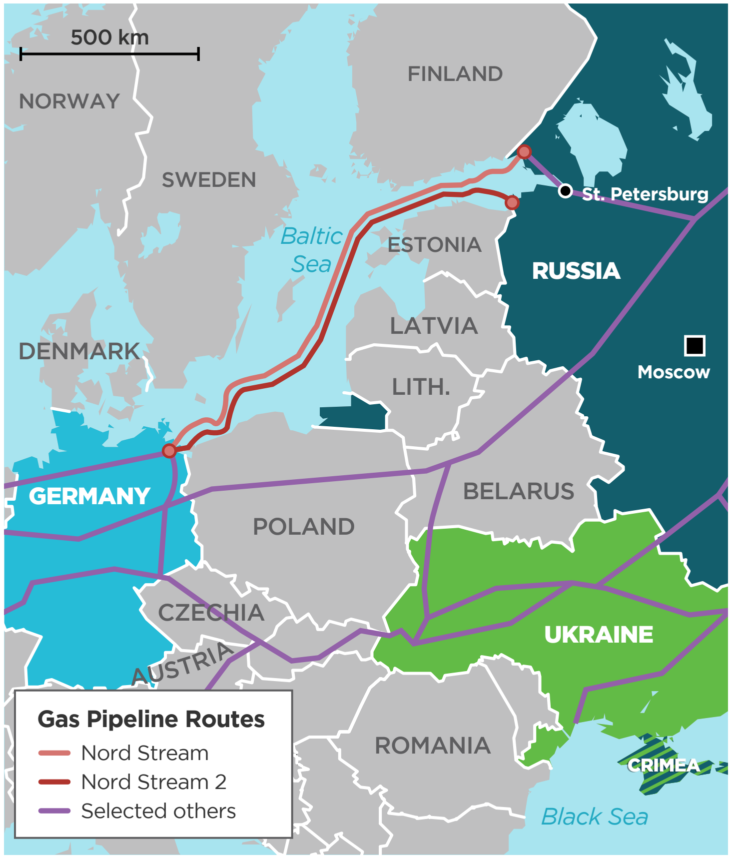


Figure 5.9: **U.K. Generation by Fuel Type (GWh)**



Source: EIA

Figure 5.10: **Selected Eastern European Major Gas Pipelines**



Source: Economist

Ukraine Conflict Complicates Transition and Energy Security in Europe

- Russia's invasion of Ukraine has complicated significantly the already challenging natural gas situation in the European energy transition.
- Before the conflict, Europe (including Turkey) imported more than one-third of its gas from Russia. Germany is particularly energy dependent upon Russia. It imports more than 50% of its natural gas, one-third of its oil, and 57% of its hard coal from Russia.
- While Germany has suspended certification of Nord Stream 2 (55 billion cubic meters (BCM)/year), as of this writing, Europe had not imposed any embargo or sanctions on Russian energy. And Nord Stream 1 (58 BCM/year), through the Baltic Sea, and other gas import routes remain operational. However, the EU has been discussing the inevitability of sanctions on Russian oil and gas at some point and has approved a ban on Russian coal imports to take effect in August.
- Uncertainty about future developments in Ukraine, the potential for disruption of gas supplies transiting that country, and the possibility of a ban on Russian gas has led to high prices and market disruption with no easy or quick solution.
- As discussed elsewhere, Europe remains dependent on fossil fuels for energy security and grid balancing through its clean energy transition. So what is to be done?

- **Europeans are investigating alternatives to Russian energy:**
  - Europe's gas reserves, particularly the Groningen field in The Netherlands, have been declining and there is widespread opposition to hydraulic fracturing.
  - While Europe has some LNG import capacity, it is pursuing expansion of LNG import capacity, although that could take years to complete.
  - While a proposed pipeline (EastMed) from Israel to southern Europe has been blocked, Israel and Turkey are discussing increased pipeline exports to Europe from the south via Turkey's pipelines.
- **Germany is considering how to make the most of the gas it has, including the following:**
  - Scheduled and orderly shutdown of industrial plants with high gas consumption
  - Mandated higher fill levels of gas storage, particularly into fall 2022, in preparation for winter 2022-23 gas demand (Germany's storage capacity is 25% to 30% of annual gas demand)
- **Finally, Europeans are redoubling their clean energy deployment, specifically:**
  - Accelerating renewables deployment and energy efficiency improvements
  - Maximizing generation from existing low-emission sources (biomethane and nuclear)

Lesson: Transitioning energy systems must consider over-reliance on single sources of energy, build in flexibility and optionality, and consider energy independence as a strategic goal.

Lessons Learned from European Experience to Date

- Some observers believe that recent challenges to energy transition in Europe are largely a result of the Ukranian conflict and the geopolitical turmoil it has created. That said, the standoff with Russia and other exogenous events (low wind, a cold winter, pandemic, etc.), are facts that have accelerated and focused attention on the joint—and sometimes competing—goals of energy security, energy transition, customer affordability, and price stability.
- Some important learnings from the past are described in the table below. As the United States and Canada continue their transition journey, policymakers, regulators, and utilities will need to study, learn, and apply those lessons to their unique situations and challenges.

Redundancy	▪ During transition, resource redundancy may be needed to contend with uncertainty as non-dispatchable resources become a larger part of the fuel mix. ▪ While duplicative infrastructure is not necessarily a desired outcome for policy, retaining existing, low-embedded cost infrastructure (e.g., fossil-fired power plants) over a longer-than-expected time may be required to preserve optionality and ensure system reliability. ▪ While Germany is expected to move ahead on planned retirements of its nuclear fleet, Belgium has decided to push back its exit from nuclear energy by 10 years in light of energy supply dislocations. Interestingly, the EU Commission in February proposed including gas and nuclear energy in the EU's sustainable finance taxonomy, a system for labelling certified climate-friendly investments. This proposal is still being discussed and could be rejected or be classified as "amber" for less "green" investments that can aid transition.
Flexibility	▪ Even as forecasting performance of variable resources improves, flexible resources will be more in demand to manage physical perturbations affecting resource performance and intra-day price volatility. ▪ Peaking resources as well as energy storage, demand response, and improved interconnection (discussed below) may need to have differentiated values. Until storage technology duration and scale are more fully developed, natural gas-fired generation resources will continue to be the near-term flexible resource. In the United Kingdom, there is some movement to fund carbon capture and storage for power generation. ▪ Also, resource planning approaches will need to consider flexibility so that such flexibility is well managed and both performance and pricing expectations are well understood.
Interconnection	▪ Increased integration with adjacent systems provides a larger pool of resources for balancing as well as access to renewable resources in other regions. Transmission developers in both Germany and the United Kingdom are investing significant amounts in power transmission to increase capacity with neighboring systems. ▪ Interconnection with other fuel markets, including LNG, also provides redundancy and price alternatives.
Contend with Volatility	▪ Exogenous events will continue to affect energy markets: weather, hydrology, and geopolitics, to name a few. ▪ While energy intensity has been declining, energy consumption is still expected to grow. But average demand is expected to be lower with shorter periods of higher peak consumption. And broad, economy-wide electrification remains a wild card. ▪ With more intermittent supply, gas demand and prices (at least in the medium term) will be volatile. To manage this, grid planners must understand fuel supply vulnerabilities, contracting and procurement approaches for both average and peak demand, and supply diversification strategies.
Price Cushion	▪ Wholesale and retail prices have been increasing in these markets as has price volatility. While U.K. regulators have been revisiting pricing approaches, those efforts have been in response to a moving target. Working with regulators to dampen and smooth out effects of higher and more volatile costs during transition will be necessary. But those approaches must provide adequate compensation to encourage participation of needed resources.

Sources: Reuters; Rabobank; Oxford Institute for Energy Studies; EU Agency for the Cooperation of Energy Regulators; ScottMadden analysis

IMPLICATIONS

Clean energy transition is a process, and perhaps a longer than expected one, that will in the intermediate term require flexibility and optionality in energy sources to assure relatively low and stable prices, affordability, energy security, and reliability while continuing to move the needle on GHG emissions reductions. Recognizing and managing concentration risk whether by generation technology or source of fuel will not only continue to support resource diversification strategies but may provide a more sustainable path for reducing carbon emissions.

There will always be unforeseen events that complicate long-term energy resource plans. North American utilities and policymakers should continue to look to Europe for ongoing lessons on reacting to those events while ensuring resilience and adaptation as European stakeholders steer toward their net-zero objectives.

Sources:

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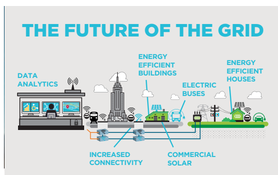

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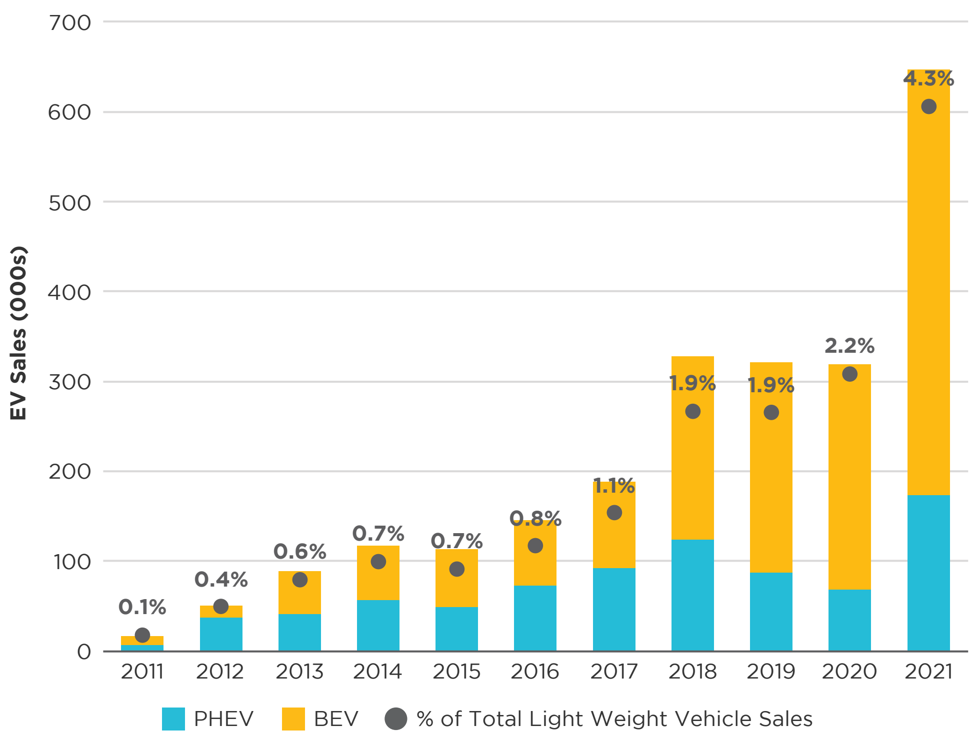
Electric vehicle (EV) sales ticked up substantially in 2021.

Figure 6.1: **U.S. Annual Light Duty EV Sales (in Thousands of Units) and as % of Total Light Weight Vehicle Sales (2011-2021)**

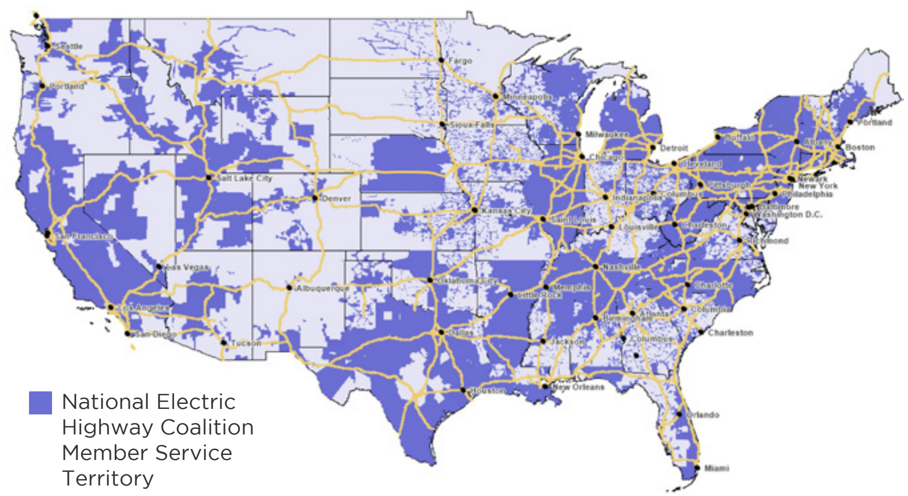


Note: EVs include hybrid electric vehicles for purposes of calculating % of total sales.

Sources: Alliance for Automotive Innovation (EV sales); Federal Reserve Bank of St. Louis (total light weight vehicle sales); ScottMadden analysis

Many electric utilities—both investor-owned and public power—are pursuing the development of a fast-charging network along major highway corridors in the United States.

Figure 6.2: **National Electric Highway Coalition**



Note: As of 3/14/22

Source: EEI

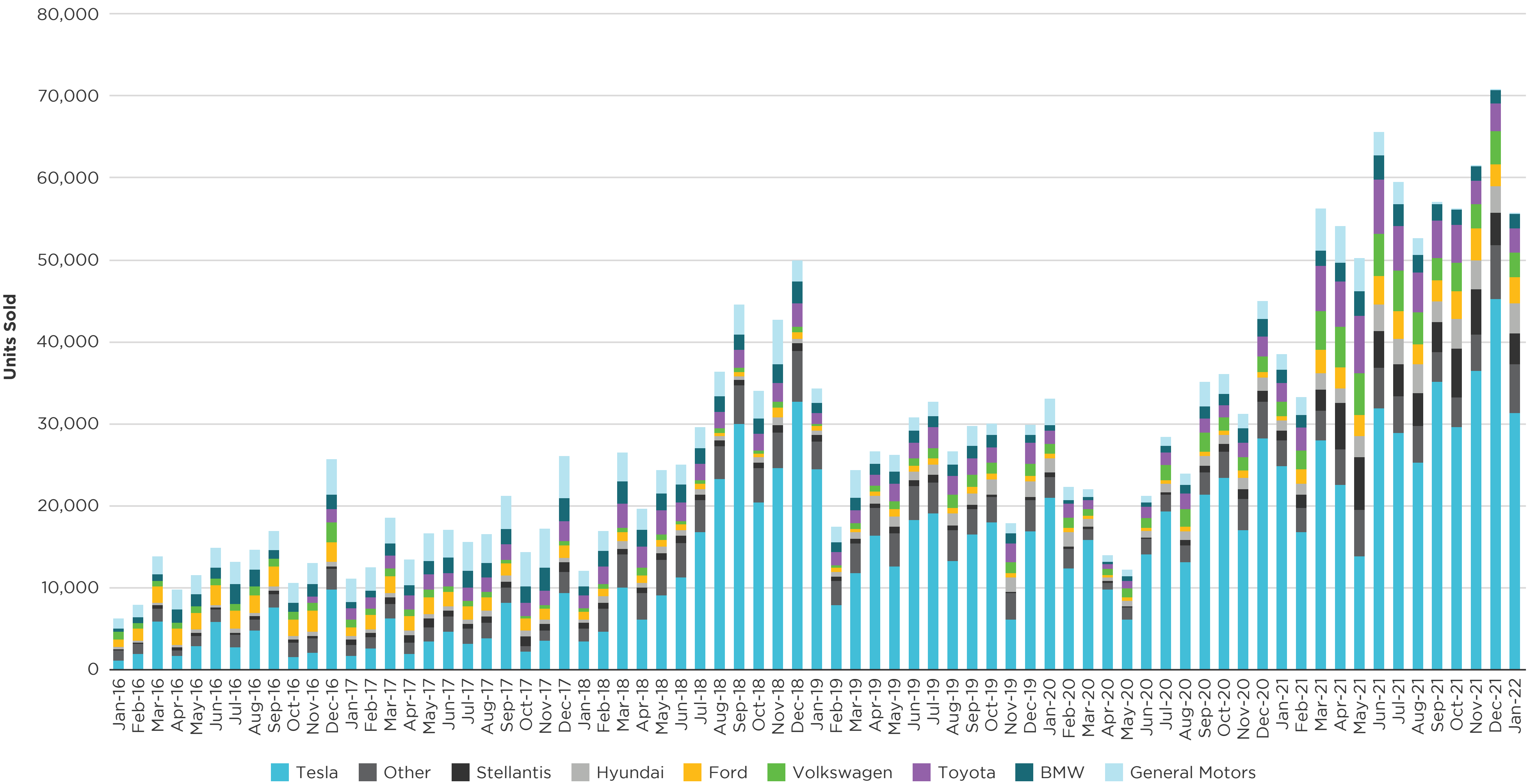
Want to Dive Deeper into Recent Electric Vehicle Developments?

Check out our interactive infographic to learn more.

www.scottmadden.com/insight/ev-recent-developments/

While EV models are proliferating globally, most U.S. sales in the past few years have been concentrated in a few makes, with Tesla the dominant seller, capturing more than half of 2021 EV sales.

Figure 6.3: **U.S. Monthly BEV and PHEV Sales by Manufacturer (Jan. 2016-Jan. 2022)**



Notes: BEV is battery electric vehicle. PHEV is plug-in hybrid electric vehicle. Stellantis N.V. is the product of the 2020 merger of global automaker FCA and PSA. FCA's brands included Abarth, Alfa Romeo, Chrysler, Dodge, Fiat, Fiat Professional, Jeep, Lancia, Ram, and Maserati brands. PSA was the second largest car manufacturer in Europe and its brands included Peugeot, Citroën, DS, Opel, and Vauxhall.

Sources: Atlas EV Hub; Stellantis N.V. U.S. Prospectus

GLOSSARY

ANOPR
advanced notice of proposed rulemaking

BCM
billion cubic meters

BEV
battery electric vehicle

CAISO
California Independent System Operator

capex
capital expenditures

CO_2
carbon dioxide

DOE
U.S. Department of Energy

EEI
Edison Electric Institute

EIA
U.S. Energy Information Administration

EPA
U.S. Environmental Protection Agency

ERCOT
Electric Reliability Council of Texas

ESG
environment, social, and governance

EU
European Union

EV
electric vehicle

FERC
Federal Energy Regulatory Commission

GHG
greenhouse gas

Gt
gigaton

GW
gigawatt

GWh
gigawatt-hour

IEA
International Energy Agency

IRP
integrated resource plan

ISO
independent system operator

kW
kilowatt

kWh
kilowatt-hour

LCCA
levelized cost of carbon abatement

LCOE
levelized cost of energy

LGIA
large generator interconnection agreement

LGIP
large generator interconnection procedure

LNG
liquefied natural gas

MAC
marginal CO_2 emissions abatement cost

MISO
Midcontinent Independent System Operator

MISO-SPP JTIQ
MISO-SPP Joint Targeted Interconnection Queue

M&A
mergers and acquisitions

MMBtu
million British thermal units

MW
megawatt

MWh
megawatt-hour

NERC
North American Electric Reliability Corporation

NOPR
notice of proposed rulemaking

NREL
U.S. National Renewable Energy Laboratory

NYISO
New York Independent System Operator

OASIS
open-access same-time information system

PHEV
plug-in hybrid electric vehicle

PJM
PJM Interconnection, LLC

PUC
public utility commission

RTO
regional transmission organization

SPP
Southwest Power Pool

T&D
transmission and distribution

Tcf
trillion cubic feet

TW
terawatt

TWh
terawatt-hour

VAR
volt-ampere reactive, a unit of measurement of reactive power

ENERGY PRACTICE
ScottMadden Knows Energy

About ScottMadden

We know energy from the ground up. Since 1983, we have served as energy consultants for hundreds of utilities, large and small, including all of the top 20. We focus on Transmission & Distribution, the Grid Edge, Generation, Energy Markets, Rates & Regulation, Enterprise Sustainability, and Corporate Services. Our broad, deep utility expertise is not theoretical—it is experience based. We have helped our clients develop and implement strategies, improve critical operations, reorganize departments and entire companies, and implement myriad initiatives.

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