THE SCOTTMADDEN ENERGY INDUSTRY UPDATE

RUNNING UP THAT HILL

Volume 20 - Issue 2

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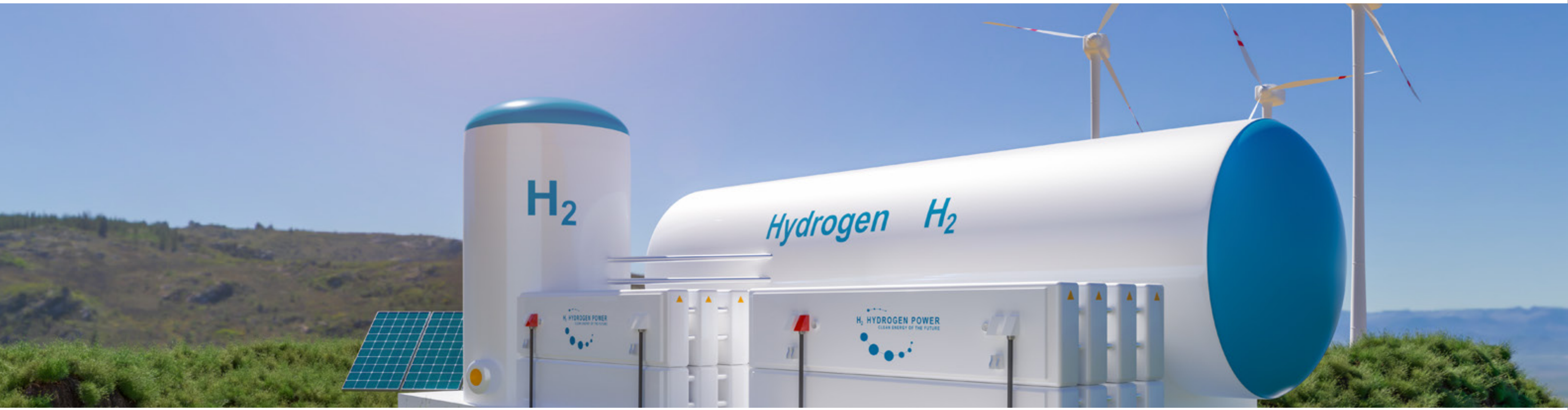
EXECUTIVE SUMMARY
RUNNING UP THAT HILL

So, what does Kate Bush's art pop hit of 1985 have to do with energy in 2020? In the midst of and beyond the COVID-19 pandemic, many efforts in the energy industry can feel like running uphill. Differences in policy and commodity preferences have pushed electricity markets to evolve in ways unanticipated when they were formed. The pandemic is forcing state utilities and regulators to answer tough questions about customer service and to prepare strategies for cost recovery. Notwithstanding the current "run up that hill," certain initiatives are gaining momentum. Many companies with net-zero carbon emissions goals are shifting focus from their long-term objectives to near-term steps to get there. Both the electric and gas industries are studying and testing hydrogen's potential role in a future energy system. Offshore wind energy offers unique advantages, some limitations, and is also gaining traction in the United States.

Some Highlights of This ScottMadden Energy Industry Update	
The New Technology Hill	▪ Use of hydrogen as a non-CO_2-emitting energy carrier has recaptured some interest among energy companies and policymakers. Its potential uses are numerous—end-use heating, power generation fuel, transportation, and a stored energy medium, to name a few. However, a potential move to a hydrogen-based energy economy poses physical, technical, and financial hurdles that must be addressed. ▪ Installations of offshore wind facilities are growing worldwide, and in the United States, ambitions for increased development are growing. Technology improvements are lowering energy costs and increasing potential capacity. But lengthy leasing processes, environmental concerns, supply chain nascency, and lack of transmission capacity are barriers to be dealt with.
The CO_2 Emissions Hill	▪ Net-zero carbon emissions and 100% clean energy commitments among electric utilities continue to accumulate. While carbon emissions have declined, much of the progress to date has been the gradual migration from coal- to gas-fired power generation. Net-zero will require more and different changes in resources, including renewables, storage, nuclear power, and demand-side alternatives. How quickly and costly this transition may be remains to be seen. ▪ Bid-based wholesale electricity markets are entering their third decade in the United States. Market structures designed for low cost and reliability are now being asked to consider factors like CO_2 emissions and possibly conflicting policy preferences. FERC, market administrators, and other stakeholders are now working through, with some friction, potential adaptation of current market approaches to reach a solution all parties can live with.
The Pandemic Hill	▪ The COVID-19 pandemic has presented an unprecedented change in energy demand and in the breadth and severity of challenges for utility customers. Utilities and regulators have put in place disconnection moratoria to accommodate cash-strapped customers. However, those costs along with other pandemic-related expenses (and savings) must be accounted for, for the long-term financial health of gas and electric utilities. To that end, utilities are well advised to work with regulators on approaches to recovery that will see them through this and future disruptions.



BACK TO THE FUTURE FOR HYDROGEN
TAKING ANOTHER RUN AT A HYDROGEN ECONOMY

Some in industry and government look for renewed opportunities to incorporate hydrogen into the energy system.

Renewed Interest

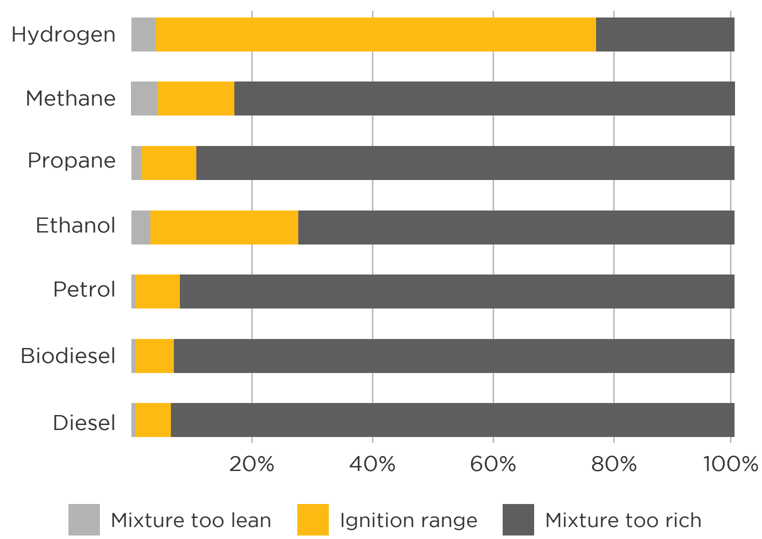
- There has been growing discussion of using hydrogen as an energy carrier across a number of applications, including blending with end-use gas, as a power generation fuel, and for transportation. The potential advantage of hydrogen is its lack of greenhouse gas emissions when used in its pure form.
- Various governments are developing hydrogen strategies and roadmaps.
  - In May 2020, the European Union released for comment a hydrogen strategy roadmap, focused on renewable hydrogen and decarbonization, followed by a hydrogen strategy in July.
  - Australia's Commonwealth Scientific and Industrial Research Organization has launched a research and development program and released a hydrogen roadmap that includes as a key element hydrogen exports to jurisdictions, particularly Pacific Rim countries lacking resource capabilities for large-scale hydrogen production.
  - The U.S. Department of Energy (DOE) has initiated a program called H2@Scale, which is studying the potential for hydrogen energy deployment across various sectors. In the summer of 2020, DOE issued a request for information, seeking comment on its research, development, demonstration, commercialization, and adoption of hydrogen and fuel cell technologies.
- Prior to DOE's recent activity, it last issued a hydrogen roadmap and strategy in 2002. A key question: How have the technology, business, and policy environments changed to warrant revisiting this potential energy resource?

Hydrogen's Unusual Nature

- Hydrogen is the simplest and most abundant element in the universe. It is also the lightest and smallest and tends to dissipate quickly when released in an open environment. It is colorless, odorless, tasteless, non-toxic, and non-poisonous, as well as gaseous at standard temperature and pressure. Apart from compounds, it does not exist in naturally large quantities.
- Compared with traditional hydrocarbon fuels, hydrogen has high-energy content per unit of mass. With about 120 megajoules/kilogram, hydrogen has three times the energy of gasoline and more than 2.5 times that of methane. Hydrogen, however, is not dense and requires more volume to carry the same energy as methane (more than three times the cubic feet for the same calorific value).
- Safety is a significant issue in dealing with hydrogen. While it is not dense, its flammability range is much wider compared to methane, ranging from concentrations with air as lean as 4% concentration and as rich as 75%. When it burns, its flame velocity exceeds three meters per second (nearly eight times that of methane), it burns hotter than methane (by about 154°C), and its flame is almost imperceptible in daylight. Unlike natural gas, which can be odorized for safety, other chemicals do not "follow" hydrogen well.
- In sum, while hydrogen has promise as an energy carrier, it is burdened with some technical and safety issues.

On August 10, the Electric Power Research Institute and the Gas Technology Institute announced the Low-Carbon Resources Initiative, a five-year effort to accelerate development and demonstration of low-carbon electric generation technologies and low-carbon energy carriers, such as hydrogen.

Ignition Range of Selected Fuels



Source: Shell, Fig. 4

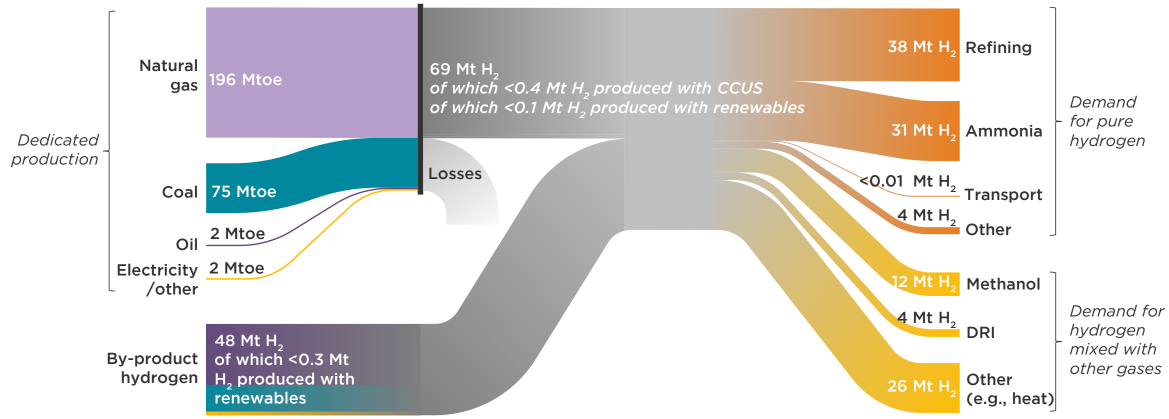
KEY TAKEAWAYS

- **Hydrogen as a carbon-free energy carrier is getting a new look from the energy industry and governments.**
- **There are a number of pathways being studied, including blending with natural gas, as an energy storage medium, as transportation fuel, and for power generation.**
- **Clean energy advocates have identified "green hydrogen"—produced with excess wind and solar energy—as a potential approach with fewer emissions implications than the current dominant method using hydrocarbons to produce hydrogen.**
- **Developing a hydrogen economy, however, has technical and cost hurdles that must be overcome.**

Hydrogen Today

- Today, hydrogen is used largely in industrial processes and the production of chemical compounds ammonia and methanol (methyl alcohol). Globally, 55% of hydrogen is used for ammonia in fertilizer production. Methanol, with a 10% hydrogen component, is used as a fuel in internal combustion engines and as a base for other compounds in the manufacture of resins, pharmaceuticals, and perfumes.
- About 25% of global hydrogen is used for petroleum refining (cracking and desulfurization), with other uses for steel production and other high-temperature applications.
- Much of current hydrogen production (95% in the United States) is derived from steam methane reformation (SMR), in which a hydrocarbon, such as natural gas or coal, is subjected to high-temperature water vapor, which breaks the hydrocarbon into hydrogen with residual carbon dioxide.
- Electrolysis, which uses electricity to separate water into hydrogen and oxygen, has not been a significant hydrogen production technique because of the relatively high cost of electrolyzers and electricity, as well as higher conversion losses as compared with hydrogen produced directly from natural gas. Only 1% of hydrogen is currently produced by electrolysis.
- To date, the use of hydrogen as a direct energy source has been limited. But a confluence of factors has prompted the energy industry to give hydrogen another look, including:
  - Ambitious decarbonization and net-zero emissions targets
  - Lower costs for increasing amounts of low- and zero-marginal cost emissions-free electricity for electrolysis
  - Storability

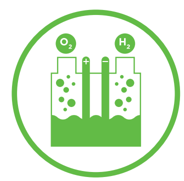
Today's Hydrogen Value Chains[1]



> **"Today's hydrogen industry is large, with many sources and uses. Most hydrogen is produced from gas in dedicated facilities, and the current share from renewables is small."**
>
> *–IEA*

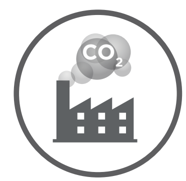
Source: IEA, Fig. 6

H_2 Lingo: Types of Hydrogen Production



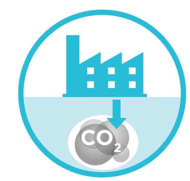
GREEN HYDROGEN

- Production from **water** and **green electricity** in an electrolyzer
- **Carbon neutral**



GREY HYDROGEN

- Production from **natural gas** or **coal** in a reformer
- **Emits CO_2**



BLUE HYDROGEN

- Production from **natural gas (typically)** in a reformer
- **CO_2 emissions captured** (typically 90%) and stored or used

Source: SNAM, Exh. 3

Prospective Pathways for Hydrogen Energy

- With a focus on less carbon-intensive energy sources, governments and industry are studying various end-use applications of hydrogen, looking at three principal areas: building end-use (particularly heating in large buildings), transportation, and power generation. A fourth area of future hydrogen application is expansion of industrial use in highly carbon-intensive processes, such as metals refining.
- A near-term opportunity is blending hydrogen into existing natural gas networks. This may be an attractive option in places where heat pumps or electrification applications are uneconomical or inefficient. Other potential applications (with higher concentrations of hydrogen) include district energy networks[2] (with longer-term potential for hydrogen gas boilers), although new infrastructure could be costly.
  - Some analyses indicate that a blend of up to 20% hydrogen is feasible in existing gas networks, although some modifications to existing pipelines may be needed to account for leak prevention and potential hydrogen-induced pipe embrittlement. In addition, because hydrogen's energy density is lower than that of natural gas, greater volumes would need to be delivered to meet the same energy need.
  - Some pilots are being conducted worldwide (see Enbridge case study at right), testing the cost and technical implications of blending, including effects on end-use appliances.
- Transportation has long been touted as a potential pathway for hydrogen.
  - Fuel cell vehicles (FCVs) are commercially available, although only 2,000 passenger vehicles were sold in 2019 and only 8,000 have been sold in the United States since 2012, a significantly smaller number than battery electric vehicles. There are 44 public hydrogen-fueling stations in the United States, 42 of which are in California. Key impediments to FCVs are the relatively high cost compared with internal combustion engines and the lack of refueling infrastructure.
  - Heavy truck and bus applications are seen as potentially benefiting from low-emissions fuel cell range extenders.
  - Hydrogen-based fuels for the maritime and aviation sectors are expected to become cost competitive in the longer term (2040 to 2050). With high-energy needs for compression or cooling to reduce hydrogen volume for large-scale mobile applications, using ammonia (NH_3) to replace fuel oil in ships or a methanized synfuel (hydrogen with reused CO_2) for aviation are alternatives to pure hydrogen use.

Enbridge Gas Proposes Low-Carbon Energy Project

Ontario-based Enbridge Gas Inc. (EGI) and Hydrogenics (manufacturer of electrolysis-based hydrogen generators) have proposed North America's first utility-scale power-to-gas plant. The plant is a 2.5-MW facility that can produce up to 1,000 kilograms/day (or 500 cubic meters/hour) of hydrogen at 99.99% purity.

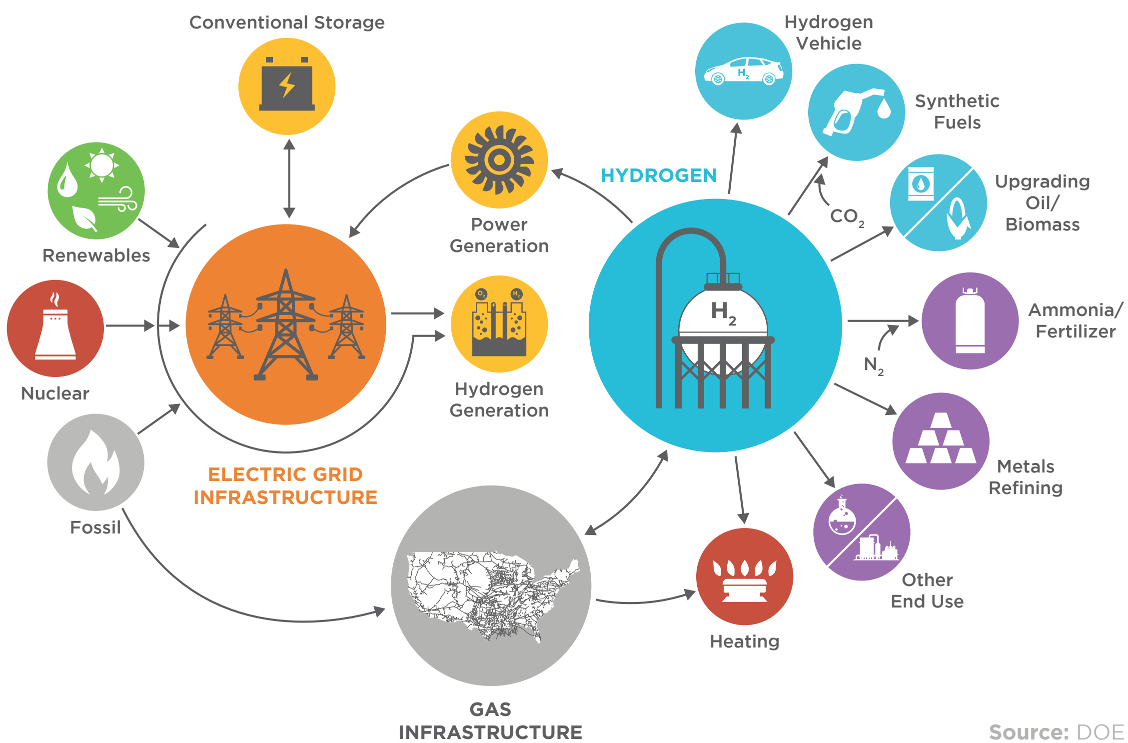
As part of this project, EGI has applied for approval to construct hydrogen/natural gas blending infrastructure and natural gas pipelines in the City of Markham, Regional Municipality of York.

The project will pilot the distribution of blended natural gas with up to 2% hydrogen by volume to approximately 3,600 existing customers.

One objective is to help the company prepare for the anticipated requirements of Canada's Clean Fuel Standard.

- While the use of hydrogen-based fuels in power generation is negligible today, some industry players see it as a fuel with the potential to reduce the carbon intensity of existing generation.
  - Hydrogen-based ammonia can be co-fired with coal to reduce emissions. With the use of ammonia as a fuel, additional attention needs to be paid to NOx emissions.
  - Existing gas turbine designs can accommodate 3% to 5% hydrogen fuel content. General Electric, Mitsubishi Hitachi, and Siemens, for example, have units that accommodate 30%+ hydrogen concentrations, and they are developing 100% hydrogen gas turbine technologies.
  - Finally, distributed combined heat and power applications using fuel cells provide flexible, albeit smaller scale, power options.
- Hydrogen, ammonia, and other hydrogen-based fuels can serve as large-scale energy storage, with low-cost excess energy creating hydrogen for storage and fuel for power production at another time.
  - Hydrogen-based storage options, however, can suffer from low round-trip efficiency. For example, using electrolysis to produce hydrogen, then converting it back into electricity via generation, loses about 60% of original electricity compared with battery storage.
  - However, compressed hydrogen is an attractive option for longer-discharge durations of 20 to 45 hours.
  - Critical to viability of hydrogen storage is the availability of geologic formations, such as salt caverns. Ammonia storage is a well-established technology, at least at industrial scale, but as with hydrogen, loses significant energy when converted and reconverted (if pure hydrogen for end use is required).

DOE's H2@Scale Concept for Wide-Scale Hydrogen Production and Utilization

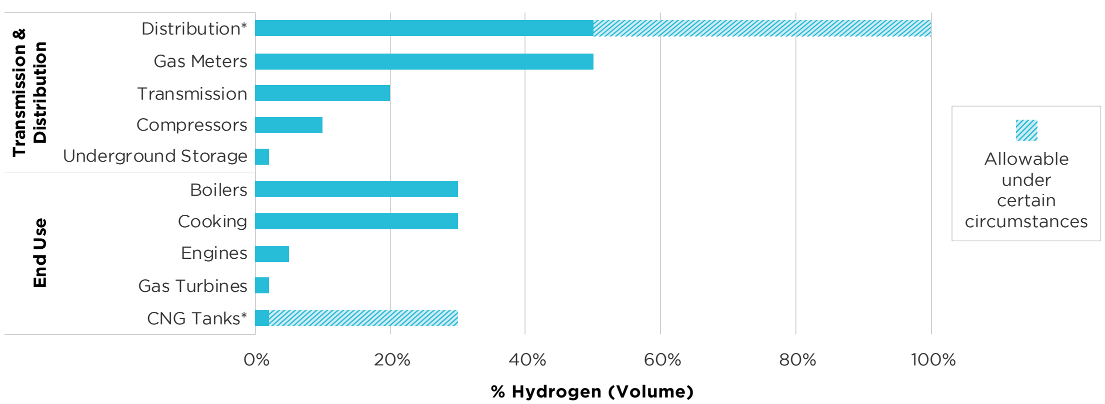


Source: DOE

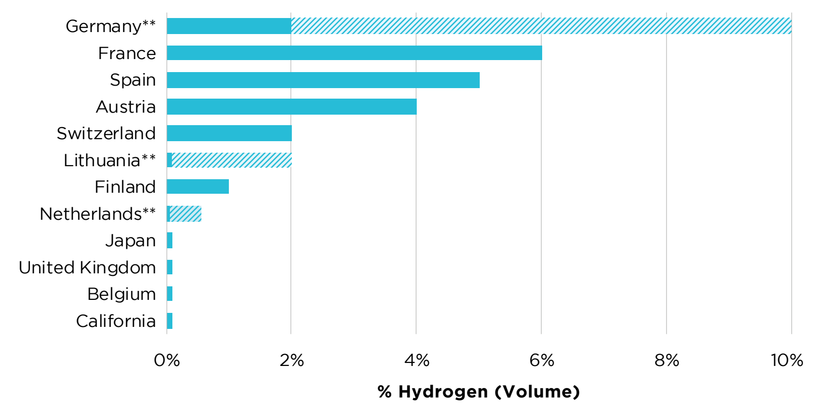
Challenges of Delivering Hydrogen

- Because it is a light molecule, hydrogen is subject to losses and dissipation when transmitted in its gaseous form. In addition, energy costs of conversion to and maintenance in liquid form are significantly higher than those of liquefying natural gas. Generally, transmission and distribution modes depend upon volume, distance, geography (supply and demand), required end use, and cost.
- Transportation as ammonia, a larger molecule, may be an alternative since it increases the energy density of the volumes transmitted and has a well-established pipeline network; however, it is a toxic chemical requiring special handling and may not be suitable for some end-use sectors.
- Currently, 85% of hydrogen is consumed on site, with the remainder transported via truck or pipeline. Pipelines are most cost effective for transmitting over distances of 1,500 kilometers (<1,000 miles) or less in large volumes. There are more than 1,600 miles of hydrogen pipelines in the United States, largely concentrated where large hydrogen users (e.g., petroleum refineries and chemical plants) are located, such as the U.S. Gulf Coast.
- Creating a new hydrogen pipeline infrastructure will be costly. Key design criteria would need to account for the embrittlement—and potential compromise—of steel and welds used to fabricate pipelines and the control of hydrogen permeation and leaks.
  - DOE and others are continuing research into fiber-reinforced polymer pipelines for hydrogen distribution.
  - Other research and pilots are testing the retrofit of existing natural gas pipelines to accommodate different levels of hydrogen.

Tolerance of Selected Existing Elements of the Natural Gas Network to Hydrogen Blend Shares by Volume



Current Limits on Hydrogen Blending in Selected Natural Gas Networks



> **CNG tanks, turbines and engines have the lowest hydrogen tolerance. Minor adaptations could increase the grid's tolerance and exploit its transport capacity.**
>
> *–IEA*

> **Today most countries limit hydrogen concentrations in the natural gas network; modifying these regulations will be necessary to stimulate meaningful levels of hydrogen blending.**
>
> *–IEA*

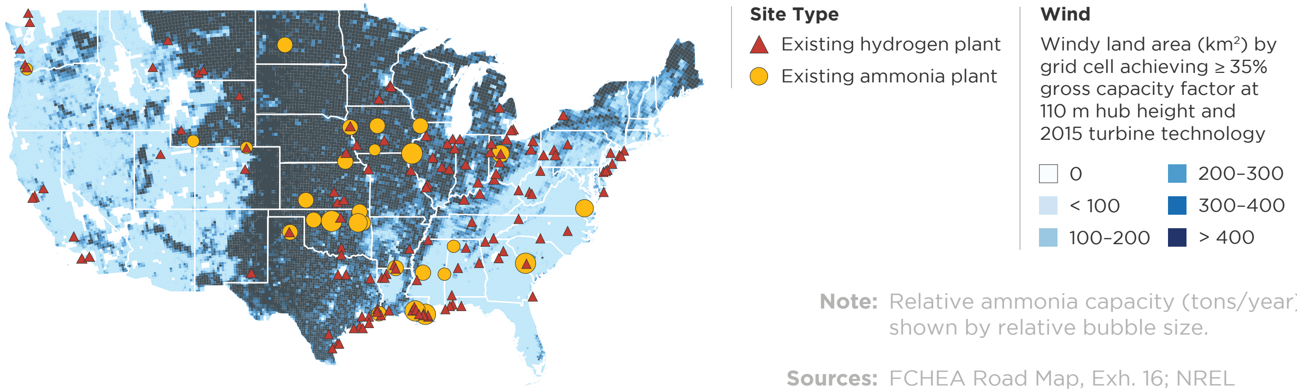
Notes: *The higher tolerance for distribution would require specific safety assessments; the higher tolerance of CNG tanks is for Type IV tanks (although the tolerance for CNG tanks may be as low as 0.1% depending on the humidity of the natural gas (United Nations, 2014). **Higher limit for Germany applies if there are no CNG filling stations connected to the network; higher limit for Lithuania applies when pipeline pressure is greater than 16 bar pressure; higher limit for the Netherlands applies to high-calorific gas.

Source: IEA

Opportunities in Hydrogen Production

- Interest in hydrogen is driven in part by lower costs of renewable energy, which have been declining over the past decade. As renewable resources have increased, there is an emerging seasonal and time-varying problem of overproduction from both wind and solar resources during low-demand, high-output periods. Grid operators can curtail this energy or it is left to sell at low or even negative prices.
- One approach to using this curtailed or low-priced energy is to employ it for hydrogen electrolysis, creating green hydrogen as a form of energy storage.
- Less flexible power generators, such as nuclear plants, could also provide non-emitting energy for hydrogen production during low-demand periods. Nuclear plants could provide energy for electrolysis or heat for either steam methane reforming or solid oxide electrolysis, although the latter has not yet been commercialized.
- Viability of this approach for any on-site production depends upon local resource availability (water or hydrocarbon feedstock) and nearby storage or takeaway capacity.

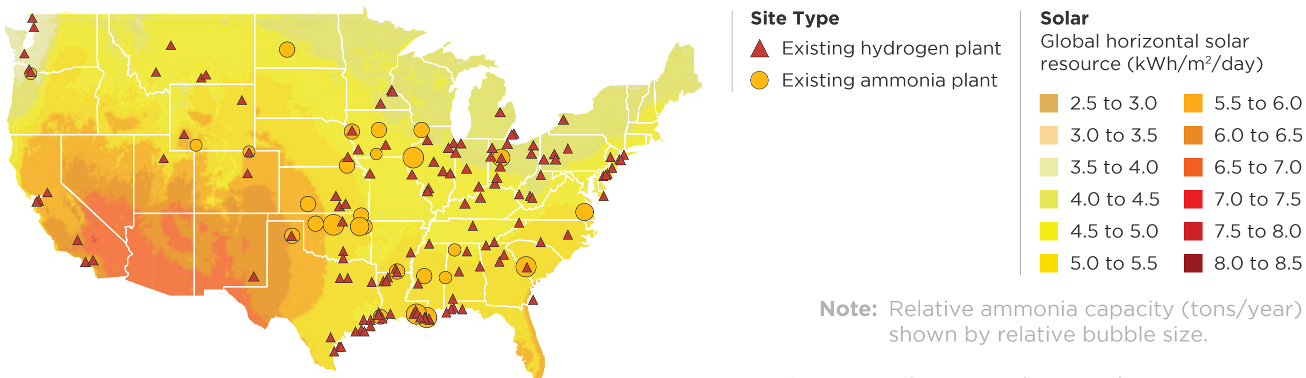
Continental U.S. Wind Power Potential and Current Ammonia and Hydrogen Production Sites*



Note: Relative ammonia capacity (tons/year) shown by relative bubble size.

Sources: FCHEA Road Map, Exh. 16; NREL

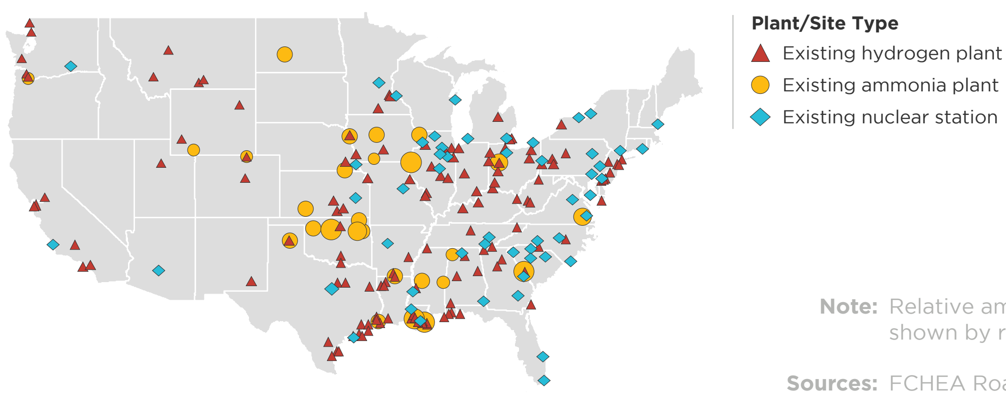
Continental U.S. Solar Power Potential and Current Ammonia and Hydrogen Production Sites*



Note: Relative ammonia capacity (tons/year) shown by relative bubble size.

Sources: FCHEA Road Map, Exh. 17; NREL

Continental U.S. Nuclear Power Plants and Current Ammonia and Hydrogen Production Sites*

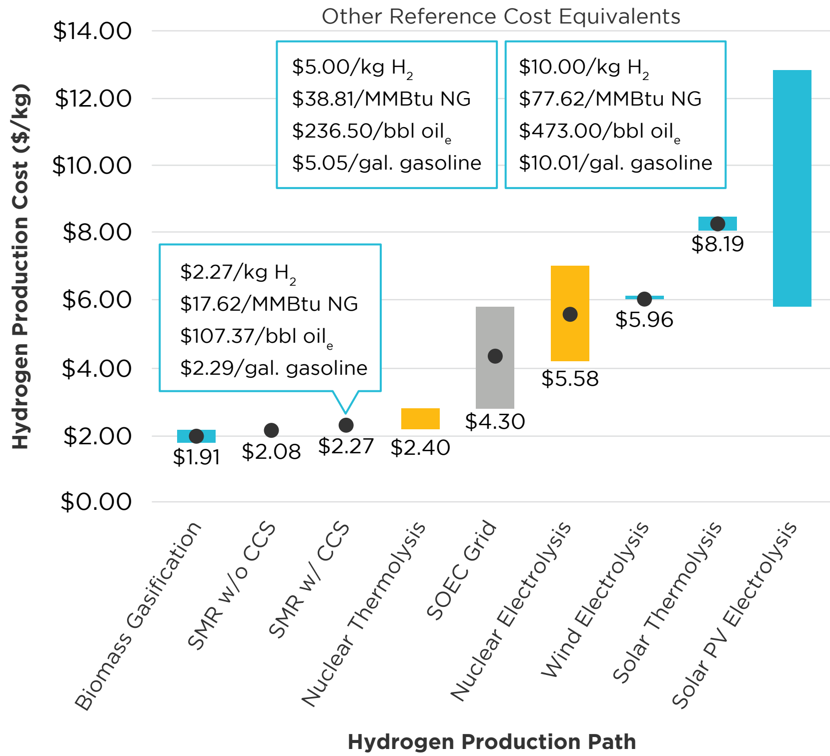


Note: Relative ammonia capacity (tons/year) shown by relative bubble size.

Sources: FCHEA Road Map, Exh. 16; EIA; NRC

Notes: *Sites per FCHEA as of May 2019. Nuclear stations as of October 2020.

Current Hydrogen Production Cost Ranges and Averages by Technology and Equivalent Prices for Fossil Sources with CO_2 Capture and Storage



Notes: NG means natural gas; oil_e means oil equivalent; SOEC means solid oxide electrolyzer cell

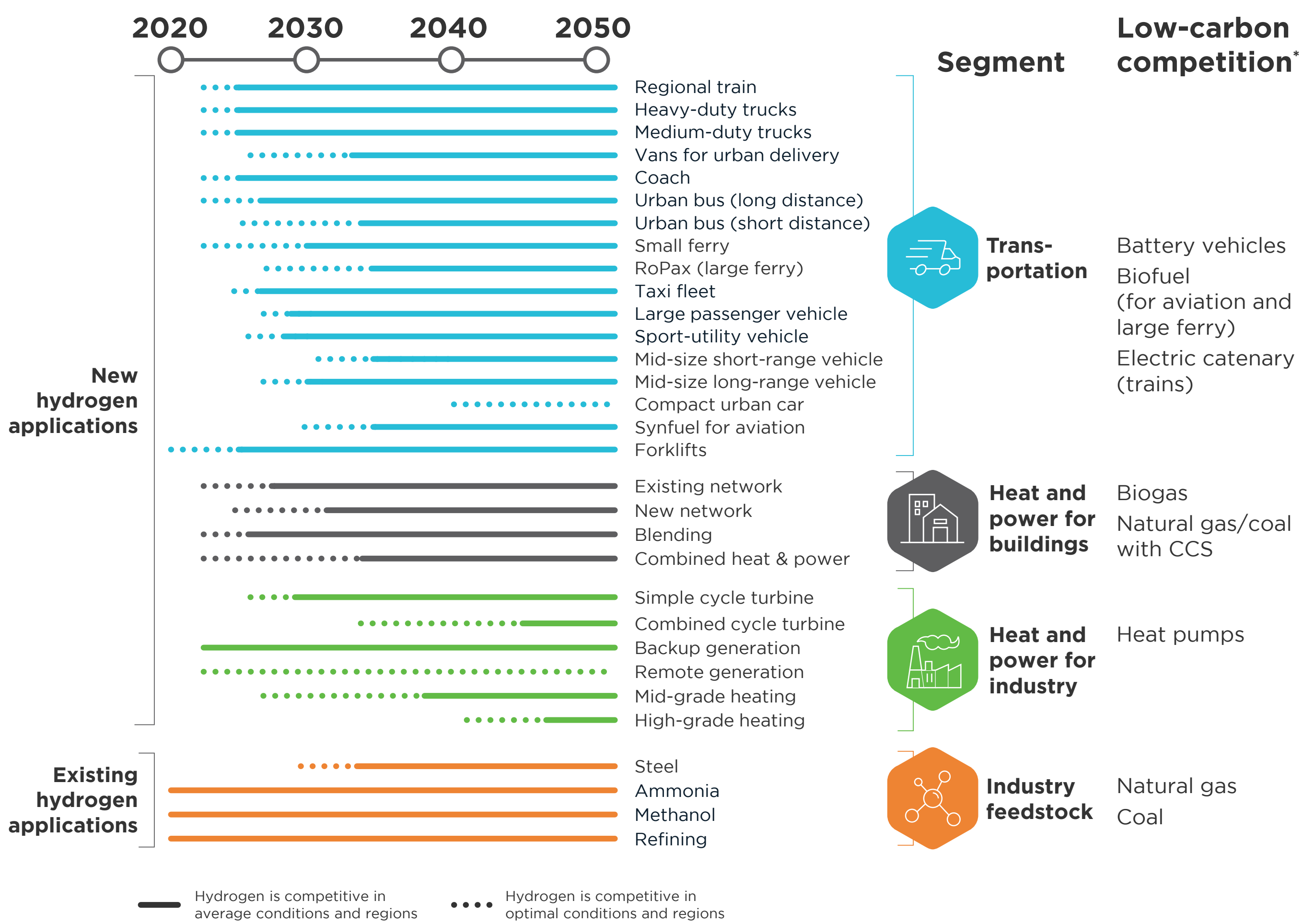
Source: DOE Hydrogen Strategy, Fig. 5

Cost: A Major Hurdle

- Costs of adapting or creating a hydrogen energy system have historically been a barrier to its pursuit. Those costs exist across the value chain.
- In production, cost drivers vary depending upon production method. For both SMR and electrolysis, the major driver is the cost of electricity for heat production or electrolysis. Availability of low-cost power, including renewable resources, is key.
  - For SMR, the cost of feedstock (e.g., natural gas) is the other major cost.
  - For electrolysis, the capital cost of electrolyzers, utilization rates, and efficiency are the other key drivers of production cost. The current cost of a proton-exchange membrane system is between $1,100 and $1,500 per kW. Some observers believe that a 60%+ reduction (toward $400/kW) could reduce costs of hydrogen by 2030 to between $2/kg and $3/kg compared to between $6/kg and $10/kg today. This does not account for any additional costs for feedwater and, as needed, desalination, or any water limitations that might reduce utilization rates.
  - Currently, however, with low gas prices and even with a CO_2 capture cost of about $0.30/kg, SMR with carbon capture and storage is estimated at $2.27/kg, assuming available use of sequestration destinations and the pipeline infrastructure to support CO_2 transportation. (Note: for comparison, $1/kg H_2 = ~$7.76/MMBtu of natural gas.)

- Some other cost considerations for the distribution and use of hydrogen include:
  - Cost of blending and of retrofitting pipeline materials, valves, and other leak-prone elements of existing natural gas infrastructure
  - Balance of investment between centralized and distributed production and use
  - End-use equipment turnover, such as appliances, boilers, and industrial process equipment
  - Additional NOx reduction equipment for power generation with hydrogen-based fuels
  - Capital required for transportation applications (rail, bus, medium- to heavy-duty vehicles, fleets), particularly cost and performance of fuel cells
  - Cost, siting, and utilization of vehicle-refueling systems

Cost Competitiveness Trajectories of Hydrogen Applications



Note: *In some cases, hydrogen may be the only realistic alternative (e.g., for long-range heavy-duty transport and industrial zones without access to CCS).

Source: Hydrogen Council, Exh. 6

Some Potential Requirements for a Hydrogen Transition

- The promise of hydrogen is stimulating activity across the energy sector with interest in decarbonizing hard-to-decarbonize power and thermal applications. But a transition to an energy sector with hydrogen as a key energy resource will involve a shift in scale from current activities. The United States produces about 10 million metric tons of hydrogen per year; worldwide production is approximately 70 million metric tons. Every million metric ton increase in annual demand equals an additional 415 Bcf of hydrogen gas (or 1.14 Bcf/day).[3]

Making the Hydrogen Transition Will Require a Few Enablers	
Scale	As mentioned above, scaling of infrastructure will be needed to meet any significant increase in hydrogen demand as well as to drive out costs through higher-capacity utilization, lower per-unit transportation costs, and lower installed costs of equipment.
Standards	Regardless of whether the fuel is hydrogen, ammonia, or another hydrogen-based energy carrier, agreement on purity, compression, equipment standards, and safety protocols will be needed.
Cost Reduction	To make hydrogen an affordable element of the energy mix, scale and learning curve effects must bring down the cost of hydrogen technologies. Also, the cost of developing hydrogen infrastructure must be compared with alternatives, such as electrification of certain energy applications.
Strategy and Transition Plan	Migrating to hydrogen-based energy is akin to changing the tires of a moving automobile. Industry players will have to consider how current infrastructure (e.g., gas pipelines) and the complementarity of applications and commodity form at various demand and supply points can be used to right-size infrastructure.
Resources	To produce hydrogen technically and economically, availability of resources by region will be important—e.g., availability of green and/or cheap electricity, low-cost hydrocarbons, substantial amounts of water for electrolysis, and access to suitable ports (for transportation).
Policy	Whether there is a net-zero carbon emissions goal or a carbon price—and the level of that price—will affect the attractiveness of hydrogen and hydrogen-based fuels. Further, regulations may hinder development of a hydrogen economy, so balancing safety and other concerns with barriers to infrastructure (e.g., development of hydrogen fueling stations) will be needed.

IMPLICATIONS

The energy industry will continue to be pressed into considering all low- or no-carbon emissions alternatives over the next decade or more. Hydrogen as a fuel will continue to garner interest. However, close attention should be paid to whether its cost, efficacy as an energy source, and potential infrastructure development challenges make it a core energy resource of the future or a niche play to incrementally lower CO_2 and other emissions.

Notes:

[1]Other forms of pure hydrogen demand include the chemicals, metals, electronics, and glass-making industries. Other forms of demand for hydrogen mixed with other gases (e.g., carbon monoxide) include the generation of heat from steel works arising gases and by-product gases from steam crackers. The shares of hydrogen production based on renewables are calculated using the share of renewable electricity in global electricity generation. The share of dedicated hydrogen produced with CCUS is estimated based on existing installations with permanent geological storage, assuming an 85% utilization rate. Several estimates are made as to the shares of by-products and dedicated generation in various end uses, while input energy for by-product production is assumed equal to energy content of hydrogen produced without further allocation. All figures shown are estimates for 2018. The thickness of the lines in the Sankey diagram are sized according to energy contents of the flows depicted.

[2]District energy systems supply heating and cooling to groups of buildings. When many buildings are close together, such as on a college campus or in a city, having a central heating and cooling plant that distributes steam, hot water, or chilled water to multiple buildings is sometimes more efficient. District energy systems may also produce electricity along with heating and cooling energy. District energy systems generally use fossil fuels (coal, natural gas, or fuel oil), although some use renewable sources of energy (biomass, geothermal, solar, and wind energy). (Source: EIA, at www.eia.gov/energyexplained/use-of-energy/commercial-buildings.php)

[3]1,000 kilogram = 1 metric ton. 1 kilogram = 415.26 BCF H_2 gas at 60°F and 1 atmosphere (see https://h2tools.org/hyarc/calculator-tools/hydrogen-conversions-calculator). Calculation 415.26 x 1000 (CF/ton) x 1,000,000 (tons per million metric tons).

CNG = compressed natural gas.

Sources:

https://h2tools.org/bestpractices/hydrogen-compared-other-fuels; IEA, The Future of Hydrogen (June 2019) (IEA); Hydrogen Analysis Resource Center, Lower and Higher Heating Value of Fuels, at https://h2tools.org/hyarc/calculator-tools/lower-and-higher-heating-values-fuels; DOE Hydrogen Program, A Comparison of Hydrogen and Propane Fuels (April 2009); Shell, Shell Hydrogen Study: Energy of the Future? (2017) (Shell); InsideEVs.com, at https://insideevs.com/news/392360/2019-sales-hydrogen-fuel-cell-cars-us/; Shell DOE Alternative Fuels Data Center, https://afdc.energy.gov/stations/states; SNAM, The Hydrogen Challenge: The Potential of Hydrogen in Italy (October 2019) (SNAM); “GE Unleashing a Hydrogen Gas Power Future,” *Power* (May 30, 2019); “Siemens’ Roadmap to 100% Hydrogen Gas Turbines,” *Power* (June 30, 2020); “How Much Will Hydrogen Based Power Cost?” *Power* (Feb. 27, 2020); Enbridge Gas; Government of Canada, at https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard.html; DOE Office of Energy Efficiency & Renewable Energy, Hydrogen and Fuel Cell Technologies Office, at https://www.energy.gov/eere/fuelcells/h2scale and https://www.energy.gov/eere/fuelcells/hydrogen-pipelines; “Hydrogen Towards Deep Decarbonization,” MITEI Spring Symposium (June 3, 2019), presentation by Emre Gencer; “Overview of Hydrogen and Fuel Cell Technologies,” MITEI Spring Symposium (June 3, 2019), presentation by Neha Rustagi; Fuel Cell & Hydrogen Energy Association, Road Map to a U.S. Hydrogen Economy (November 2019) (FCHEA Road Map); National Renewable Energy Laboratory (NREL), RE Atlas, at maps.nrel.gov/re-atlas (for solar resource); NREL, Wind Prospector, at maps.nrel.gov/wind-prospector (for wind resource); U.S. Nuclear Regulatory Commission, Map of Power Reactor Sites, at www.nrc.gov/reactors/operating/map-power-reactors.html; Nuclear Energy Institute, U.S. Nuclear Operating Plant Basic Information, at nei.org/resources/statistics/us-nuclear-operating-plant-basic-information; EIA, Energy Mapping System, at www.eia.gov/state/maps.php; Hydrogen Council, Path to Hydrogen Cost Competitiveness (Jan. 20, 2020) (Hydrogen Council); DOE Office of Fossil Energy, Hydrogen Strategy: Enabling a Low-Carbon Economy (July 2020) (DOE Hydrogen Strategy); ScottMadden research

OFFSHORE WIND ENERGY
BIG WAVE OF DEVELOPMENT EXPECTED

After a decade of starts and stops, offshore wind finally gains traction in the United States.

Offshore Wind: Unique Benefits, but Slow to Launch

- Offshore wind offers unique benefits compared to other renewable energy technologies, but the U.S. market has been slow to launch.
- Cape Wind—the first major offshore wind project in the United States—spent years overcoming fierce opposition to secure a federal commercial lease and power purchase agreements.
- In December 2017, the 488-MW project was canceled after failure to secure project financing resulted in termination of power purchase agreements.
- The high-profile collapse cast doubt on the U.S. offshore wind industry just as onshore wind and utility-scale solar were emerging as prominent sources of new generation.
- Despite these early challenges, offshore wind offers the following advantages compared to other renewable resources:
  - Significant wind resource exists alongside coastal regions with large loads.
  - Speeds of offshore wind are steadier than those of onshore wind, making the former a more reliable generation resource.
  - Offshore wind is typically strongest from midday to early evening, better aligning with peak load.
  - Due to these advantages, wind turbines can be sized larger for offshore projects, generating more energy per turbine.
- In fact, the tide may be turning in favor of offshore wind as demonstration projects come online, a strong pipeline of commercial-scale projects enter advanced development, and state policy support signals long-term market opportunities.

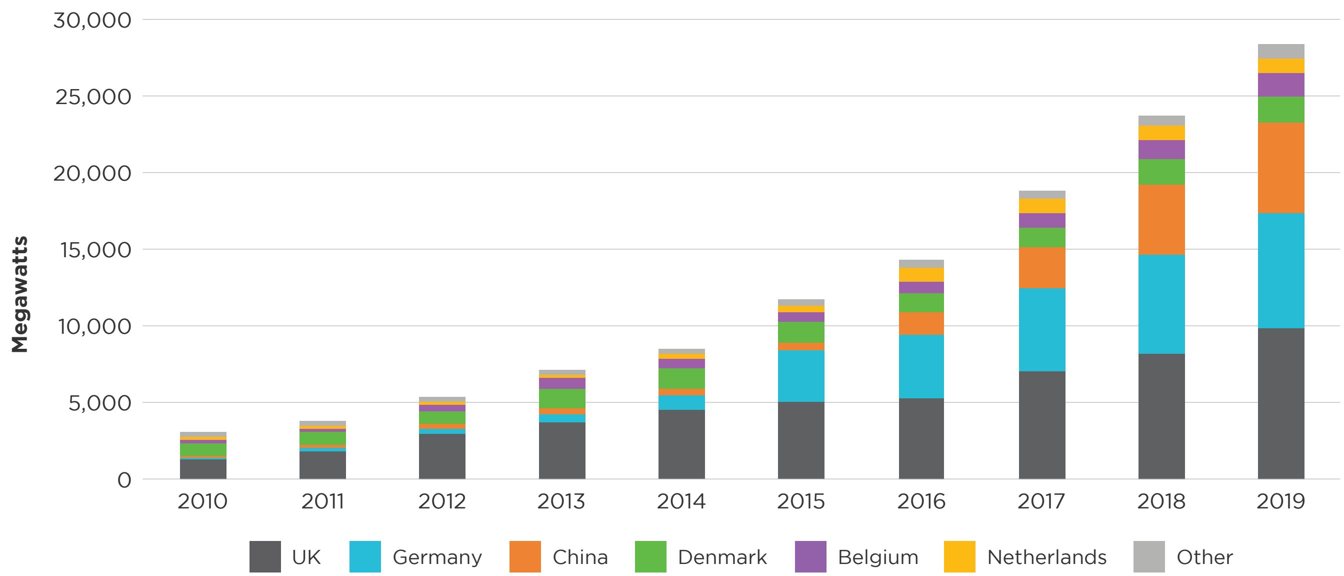
KEY TAKEAWAYS

- **The United States has steel in the water with one demonstration project near Rhode Island and another under construction off the Virginia coast.**
- **More is coming as 9 GW of offshore wind is in advanced development; the 800-MW Vineyard Wind project could be the first commercial-scale offshore wind project to become operational in 2023.**
- **The offshore wind market opportunity is even larger considering state procurement targets total 29 GW.**
- **However, challenges exist as the emerging industry works through a variety of growing pains, including high technology costs, logistical challenges, long regulatory approvals, and limited interconnection options.**

A Global Market Driven by European Development, Declining Costs, and Technology Advancements

- Cumulative global offshore wind capacity exceeded 28 GW in 2019, with the United Kingdom accounting for more than one-third of market (see chart below).
- The United Kingdom's success can be attributed to a favorable geography that includes strong winds and shallow water depths, coupled with policy support in the form of net-zero carbon emission targets and competitive auctions providing contracts for differences (CFDs) to offshore wind projects.
  - CFDs are private law contracts between an electric generator and a government-owned company called the Low Carbon Contracts Company (LCCC).
  - The CFD enables the generator to stabilize its revenues at a pre-agreed level (the strike price) for the duration of the contract. Under the CFD, payments can flow from LCCC to the generator and vice versa.
  - When the wholesale market price is below the strike price, LCCC pays a generator the difference between the market price and the strike price. Conversely, generators pay when wholesale prices are above the strike price, returning revenue in excess of the latter.
- In addition, the permitting process in the United Kingdom uses a project design envelope approach, allowing developers to identify a range of project design parameters for key components (e.g., number of turbines, foundation type, etc.). This approach allows developers the flexibility to make minor changes during the permitting process.

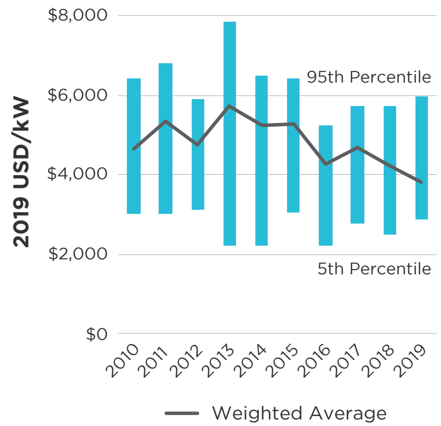
Cumulative Global Offshore Wind Capacity (MW)



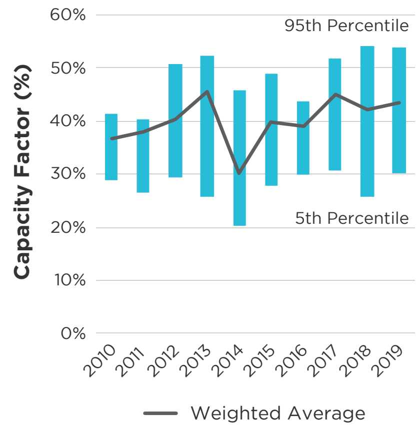
Source: International Renewable Energy Agency

- Improvements in offshore wind technology over time (notably, taller towers and larger blades) have resulted in slight declines in installed cost and, more notably, an increase in capacity factors (see charts at top right).
  - The result is the globalized levelized cost of energy (LCOE) from offshore wind's declining 29% from $161/MWh in 2010 to $115/MWh in 2019.
  - Offshore wind turbines continue to grow in turbine size and rating and swept area (output as a function of blade radius), leading to further reductions in levelized cost.
    - For example, in May 2020, Siemens Gamesa Renewable Energy announced development of a 14-MW offshore wind turbine that will be commercially available in 2024.
    - The International Renewable Energy Agency forecasts the LCOE offshore wind to drop to a range of $50/MWh to $90/MWh by 2030, in part as a function of increasing turbine size.
- The International Energy Agency forecasts offshore wind capacity to grow 15X from 2018 to 2040, with its $1 trillion in cumulative capital spend being comparable to the global capital spend for gas-fired and coal-fired capacity over the same time period.

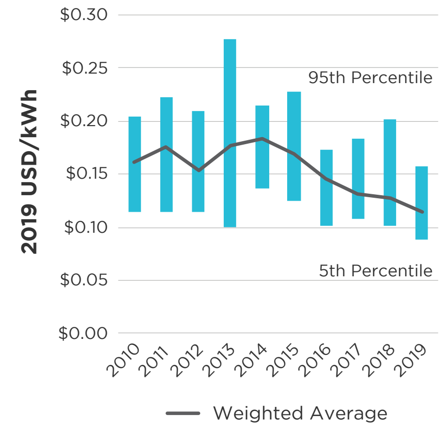
Global Installed Cost of Offshore Wind



Global Capacity Factor of Offshore Wind

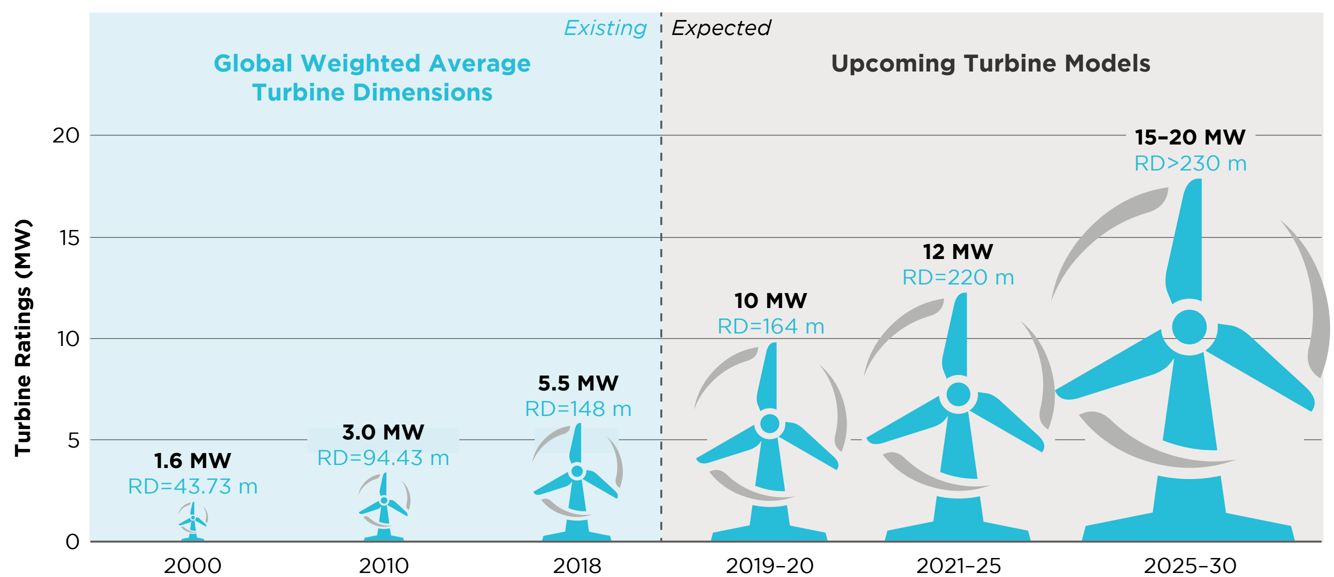


LCOE of Offshore Wind



Source: International Renewable Energy Agency

Global Weighted Average Size and Upcoming Offshore Wind Turbines



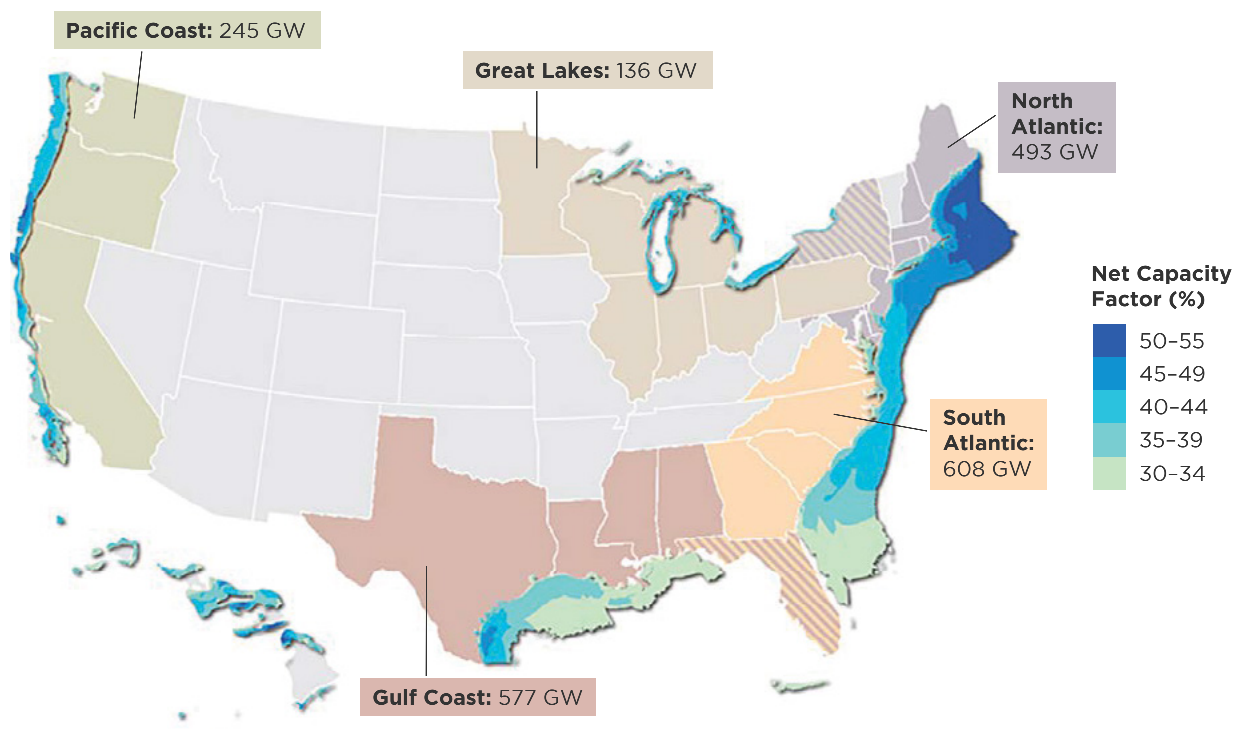
Note: RD stands for rotor diameter.

Source: International Renewable Energy Agency

Significant U.S. Offshore Wind Potential, but Lengthy Leasing and Approval Processes

- All coastal regions of the United States have access to significant offshore wind resource—the total technical capacity estimated to be in excess of 2,000 GW (see map below).
- While the technical potential is more than double U.S. electric demand, research firm Wood Mackenzie forecasts only 25 GW of capacity will be installed by 2030, rising to 37 GW by 2035.
- A key advantage is net capacity factors that can exceed 50%—a figure substantially higher than the average capacity factor of solar (25%) and onshore wind (35%).
- Offshore wind development is managed by the state or federal agency with jurisdiction over the submerged lands. State oversight can vary by location:
  - States bordering the Atlantic and Pacific Oceans have jurisdiction extending three nautical miles offshore.
  - Texas, Florida, and Louisiana have jurisdiction extending nine nautical miles offshore into the Gulf of Mexico.
  - Each state bordering the Great Lakes has jurisdiction out to the center of each lake abutting that state.

Net Capacity Factor (%) and Technical Potential of Offshore Wind by Region (GW)



Source: U.S. Department of Energy and U.S. Department of the Interior

- In federal waters, the Bureau of Ocean Energy Management (BOEM) administers the commercial leasing process. The process starts when a governor requests that BOEM form an intergovernmental renewable energy task force or when a company seeks to build offshore wind in federal waters. Once one of these undertakings is initiated, BOEM oversees a multi-year review process that includes four distinct phases (see graphic below).

BOEM Commercial Leasing Process

Planning and Analysis ~2 years

- BOEM delineates potential area or processes unsolicited application in coordination with intergovernmental task force
- BOEM publishes one or more federal register notices and determines whether competitive interest exists
- BOEM may further refine area and conduct necessary environmental reviews, evaluating lease issuance and site assessment

Leasing ~1-2 years

- If competitive interest exists, BOEM notifies the public and developers of its intent to lease through sale notices before holding a lease sale
- If competitive interest does not exist, BOEM negotiates a lease. Issuance may be combined with plan approval

Site Assessment Up to 5 years

- Lessee conducts site characterization studies
- Lessee submits site assessment plan (SAP)
- BOEM conducts environmental and technical reviews of SAP, eventually deciding to approve, approve with modification, or disapprove the SAP
- If SAP is approved, lessee assesses site (usually with meteorological tower(s) and/or buoy(s))

Construction (~2 years) and Operation (~25 years)

- Lessee may conduct additional site characterization
- Lessee submits construction and operations plan (COP)
- BOEM conducts environmental and technical reviews of COP, eventually deciding to approve, approve with modification, or disapprove the COP
- If COP is approved, lessee builds wind facility

Intergovernmental Task Force

- BOEM establishes intergovernmental renewable energy task forces in states that have expressed interest in development of offshore renewable energy.
- The role of each task force is to collect and share relevant information that would be useful to BOEM during its decision-making process.
- Task force meetings have identified areas of significant promise for offshore development and provided early identification of, and steps toward resolving, conflicts.

Source: BOEM

U.S. Offshore Wind by the Numbers

Category	MW
Operating	30
Under Construction	12
Advanced Development	9,100
State Procurement Commitments	29,193

Source: AWEA

Large Procurement Targets Drive Northeast and Mid-Atlantic Emergence as Offshore Wind Hub

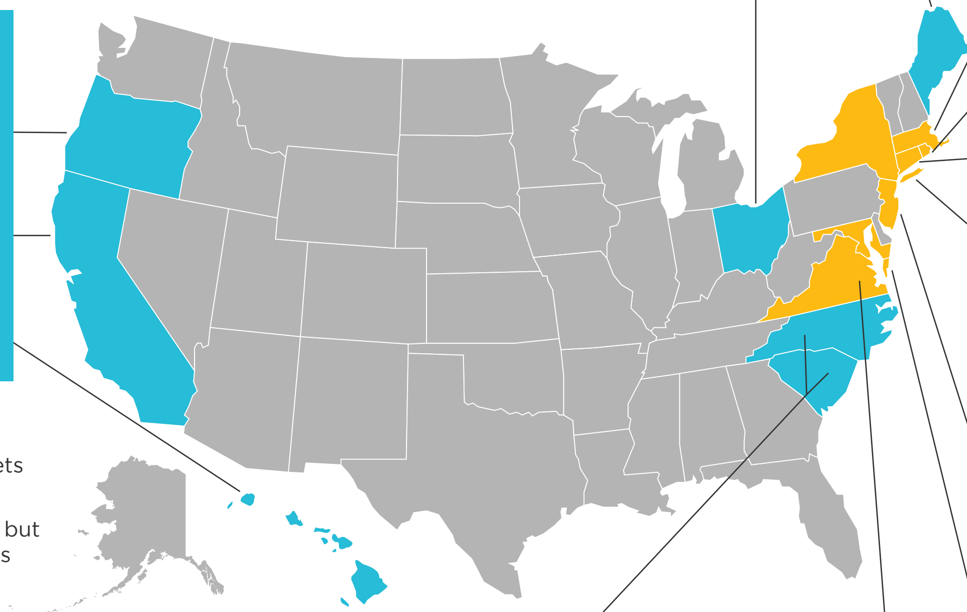
- The United States has one offshore wind project in operation—the 30-MW Block Island off Rhode Island—and another under construction—the 12-MW Coastal Virginia Offshore Wind.
- States have jockeyed for more than a decade to spur early offshore wind development, hoping to attract the economic development associated with building a new industry.
- The Northeast and Mid-Atlantic states are now leading this effort as seven states have committed to build more than 29 GW of offshore wind by 2035 (see table at left). These procurement commitments reflect a combination of legislation, conditional targets, and executive orders. New York has the largest target, committing to procure 9 GW of offshore wind.
- In addition, six states have issued competitive solicitations resulting in the selection of 6,297 MW of offshore wind projects (NY, MA, CT, and NJ have each selected more than 1,000 MW).
- The ensuing contracts are either the purchase of offshore renewable energy certificates (ORECs) or bundled power purchase agreements (PPAs) that buy energy and ORECs.
- With a growing pipeline of projects, the contracted price for offshore wind has started to decline even as the production tax credit phases out.
  - Offshore wind PPAs hit a new record low in February 2020 when the Massachusetts Department of Energy Resources (DER) recommended approval of a PPA with the 804-MW Mayflower Wind project at a levelized price in real 2019 dollars of $58.57/MWh.
  - This price beat out the 800-MW Vineyard Wind project, which, when priced in real 2019 dollars, was $67.59/MWh.
- Offshore wind projects that “start construction” (per IRS safe harbor rules) in 2020 and come online by the end of 2024 would qualify for a 60% production tax credit.
- Offshore wind is being explored in other regions of the United States (see map on next page), but the main activity remains in the Northeast and Mid-Atlantic.
  - Early winning auction bids for offshore parcels peaked at roughly $25,000/km^2.
  - In recent years, winning auction bids have increased considerably in New York (more than $125,000/km^2 in 2016) and Massachusetts (more than $250,000/km^2 in 2018).

Recent Offshore Wind Activities in the United States

Maine: In June 2019, the governor signed legislation requiring the PUC to approve a contract for Maine Aqua Ventus, the first-of-its-kind demonstration project of floating offshore wind in the United States.

Ohio: The Ohio Power Siting Board approved the 21-MW project in May 2020 and recently removed a provision that requires turbines to shut down at night between March and November to protect birds and bats.

Washington, California, and Hawaii: These states are challenged by deep waters, which require floating foundation technology. Nevertheless, BOEM has received unsolicited proposals from each state and is evaluating potential offshore wind areas known as "call areas."



Offshore wind activity and procurement targets

Offshore wind activity, but no procurement targets

Massachusetts: Legislation passed in 2016 and 2018 authorized utilities to procure a total of 3,200 MW of offshore wind by 2035. Utilities signed contracts with the 800-MW Vineyard Wind project in 2018 and the 804-MW Mayflower Wind project in 2019.

Rhode Island: In May 2018, the state selected 400 MW from the Revolution Wind project through a competitive procurement.

Connecticut: RFPs issued by the state resulted in utilities signing contracts with the 300-MW Revolution Wind project in 2018 and the 804-MW Park City project in 2020. Additional capacity is needed to comply with 2019 legislation requiring the state to procure 2,000 MW of offshore wind.

New York: Following an early offshore wind target of 2,400 MW, the Long Island Power Authority signed PPAs totaling 130 MW with the South Fork Wind Farm. In July 2019, legislation passed increasing the state target to 9,000 MW of offshore wind by 2035. In 2019, the state agreed to NYSERDA purchasing ORECs from the 880-MW Sunrise Wind project and the 816-MW Empire Wind project.

New Jersey: In May 2018, the state passed legislation establishing an offshore wind target of 3,500 MW by 2030. In June 2019, the state granted the first OREC award to the 1,100-MW Ocean Wind project. In November 2019, the governor issued an executive order to increase the offshore wind target to 7,500 MW by 2035.

North and South Carolina: Avangrid actively developing one site near Kitty Hawk. Otherwise, there has been limited activity at call areas identified by BOEM.

Virginia: In March 2020, Virginia passed a law requiring 5,200 MW of offshore wind by 2034. In June 2020, Ørsted and Dominion Energy finished installing the first turbines in federal water at the 12-MW Coastal Virginia Offshore Wind Project. Dominion Energy has announced plans to build and own another 2,640 MW of offshore wind by 2026.

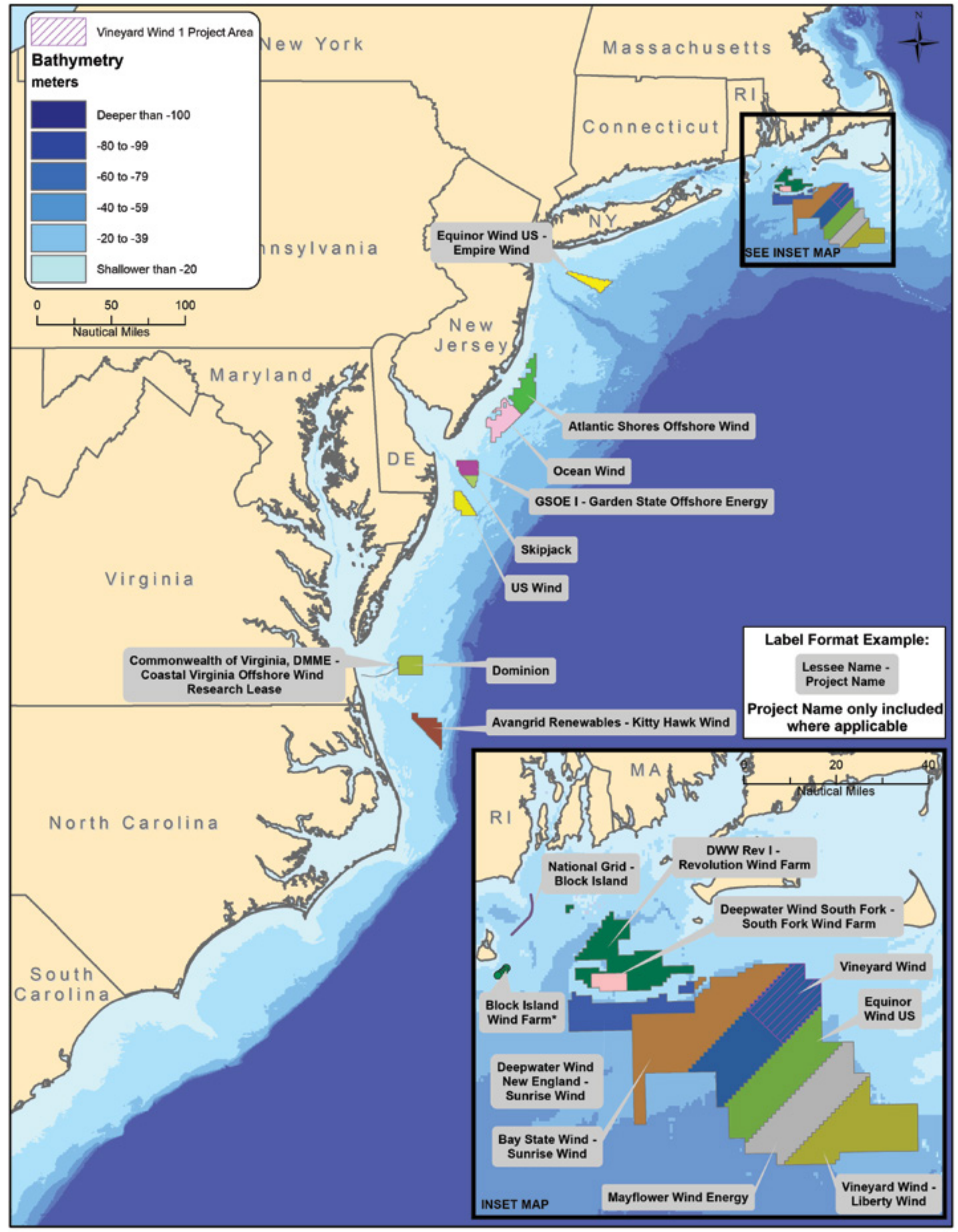
Maryland: In May 2017, the Maryland PSC awarded ORECs to the 269-MW MarWind project and the 120-MW Skipjack project. In May 2019, Maryland increased its RPS and passed an offshore wind mandate requiring 1,200 MW of offshore wind by 2030.

Sources: AWEA; BOEM; Greentech Media

Despite Advancements, Obstacles and Challenges Remain for a Nascent Industry

- While state procurement targets may jumpstart the industry, costs will need to decline for offshore wind to become competitive against alternatives.
  - Offshore wind may find early opportunities in the Northeast, where wholesale power prices are generally higher than in other regions.
  - Massachusetts DER found the Mayflower Wind project to provide an average 2.4¢/kWh (in real 2019 dollars) of direct savings to electric customers.
- The cumulative impacts of offshore wind development are receiving scrutiny in the permitting of the 800-MW Vineyard Wind project, which is on track to become the first commercial-scale offshore wind farm in the United States.
  - After postponing a final environmental impact statement (EIS) on the project's construction and operations plan, BOEM announced it would supplement the EIS to consider, in part, the cumulative impacts of the roughly 22 GW of offshore wind capacity planned along the U.S. East Coast (see map at right).
  - Issued in June 2020, the supplement found a net decrease in carbon emissions but major impacts to commercial fisheries, navigation, and vessel traffic.
  - BOEM is scheduled to release the final EIS in November 2020 and issue a decision on the Vineyard Wind project in December 2020.
  - The project could become operational in 2023 if final permits are issued by the Army Corps of Engineers and Environmental Protection Agency in March 2021.
  - The BOEM results will be closely watched, as approval is likely to pave the way for future projects, while rejection (or even additional delays) may stymie future development.

Outer Continental Shelf Renewable Energy Lease Areas (June 2020)



Source: BOEM

- The United States lacks the supply chain required to scale offshore wind development and is constrained by maritime laws.
  - Europe has relied on a fleet of specialized, purpose-built vessels (e.g., jack-up vessels) to move components from ports and conduct installation at project sites.
  - These vessels cannot be easily used in the United States because the Merchant Marine Act of 1920, commonly referred to as the Jones Act, requires vessels transporting goods between U.S. ports to be built, owned, managed, and crewed by Americans.
  - With offshore wind sites considered a "port" under the law, foreign-flagged vessels are prohibited from transferring components from a traditional port (i.e., dry land) to an offshore wind farm location
  - One approach to remain compliant is stationing specialized European vessels at the offshore wind site while having Jones Act compliant "feeder" vessels transfer components to the project site.
  - With global and U.S. demand for offshore wind vessels growing, a number of Jones Act compliant vessels are now under construction in the United States.

- Onshore interconnection capacity and transmission development remain a challenge that may require regional long-term planning.
  - ISO New England recently estimated only 5.8 GW of offshore wind could be interconnected using AC cable connections along the southern New England coastline before significant upgrades would be required to the onshore transmission network.
  - Meanwhile, PJM denied Anbaric Development Partners transmission injection rights for three projects with a combined transmission capacity of 3.4 GW, arguing the projects failed to meet certain requirements.
    - In November 2019, Anbaric filed a complaint with FERC, arguing PJM's procedures are unjust, unreasonable, and unduly discriminatory and prevent merchant offshore transmission.
    - FERC denied the complaint in June 2020, noting that Anbaric failed to demonstrate PJM's requirements—that merchant transmission facilities must use either direct current or controllable alternating current and be connected to another control area to receive transmission injection rights—are unjust and unreasonable.
    - FERC announced plans to hold a technical conference later in 2020 to discuss whether existing frameworks "can accommodate anticipated growth in offshore wind in an efficient and effective manner that safeguards open access transmission principles."
- Floating foundation technology must be developed to unlock wind resources in deeper waters.
  - More than 58% of the technical offshore wind resource is located in water depths greater than 60 meters that cannot be served by fixed-bottom foundations.
  - A number of floating foundation demonstration projects have been built in Europe and Japan, and at least 10 commercial projects are in development in Europe.

IMPLICATIONS

Despite a growing global offshore wind market, the U.S. market remains in early stages. The United States has one project in operation—the 30-MW Block Island off Rhode Island—and another under construction—the 12-MW Coastal Virginia Offshore Wind. A strong pipeline of projects in the advanced development (9 GW) and state procurement (29 GW) targets is spurring investment in an industry supply chain.

However, long-term success may hinge on overcoming a host of challenges, including the development of new technology (i.e., floating foundation technology), improving project economics with larger turbines, mitigating cumulative impacts of rapidly growing industry, and resolving interconnection and transmission challenges.

Sources:

International Energy Agency, Offshore Wind Outlook 2019 (November 2019); U.S. Department of Energy, 2018 Offshore Wind Technologies Report (August 2019); American Wind Energy Association, Offshore Wind Public Participation Guide (January 2020); Bureau of Ocean Energy Management; Department of Energy and Department of Interior, National Offshore Wind Strategy: Facilitating the Development of Offshore Wind in the United States (September 2016); International Renewable Energy Agency, Future of Wind: Deployment, Investment, Technology, Grid Integration and Socio-Economic Aspects (2019); International Renewable Energy Agency, Renewable Energy Statistics 2020 (July 2020); International Renewable Energy Agency, Renewable Power Generation Costs in 2019 (June 2020); Stoel Rives, The Law Wind: A Guide to Business and Legal Issues, Eighth Edition; *Journal of Commerce*; *Professional Mariner*; *Windpower Monthly*; S&P Global Market Intelligence, Massachusetts Department of Energy; U.S. Bureau of Ocean Energy Management (BOEM); Federal Energy Regulatory Commission; ISO New England; Greentech Media; *The Economist*; EMR Settlement Limited; ScottMadden analysis

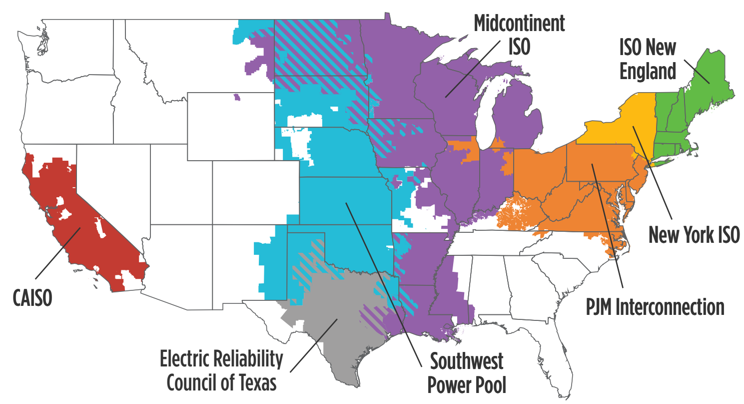
ELECTRICITY MARKETS: LOOKING BACK—AND AHEAD
WHOLESALE MARKETS SEEK TO ADAPT TO CHANGING PRIORITIES

As the restructuring of the wholesale power sector reaches its 25th anniversary, is an evolution pending?

Markets Feel Some Strain

- It has been nearly 25 years since FERC issued Order 888, establishing open access to the bulk transmission network and just more than 20 years since FERC promulgated Order 2000, calling for the establishment of regional transmission organizations (RTO).
- Over that time, large parts of the United States—as well as Canada—have established bid-based markets for energy and related services. These markets have encouraged technological innovation and asset turnover in the power generation sector and, along with declining fuel prices, helped lower power prices over the past 20 years. The non-RTO West has tested this construct through its competing imbalance markets.
- Setting aside issues and effects of the pandemic, as we entered 2020 some markets were feeling the strains of policy differences and commodity preferences among states, federal and state governments, and stakeholders in those markets. Key questions are: Can markets endure amidst these frictions, should they evolve, and, if so, in what way?

U.S. Regional Transmission Organizations/ Independent System Operators



Source: FERC

Capacity Markets: History and First Principles

- Capacity markets did not initially accompany the formation of bid-based markets in the late 1990s to early 2000s. Original expectations were that energy scarcity pricing would provide some signals of the need for additional capacity. Prior to that, in tight pools, members would demonstrate sufficient resources to meet expected obligations or purchase from other members who had excess.
- The theory motivating the establishment of competitive wholesale power markets was that competition would drive down prices, promote technology innovation (e.g., flexible combined-cycle natural gas units), and financially reward the most efficient units.
- However, in the early 2000s, concerns arose that reliance upon energy and ancillary services revenue had led to "missing money"—sufficient revenues beyond marginal cost to enable generators to meet long-run average total cost, entice new entrants, and ensure resource adequacy. PJM was the first to institute capacity markets, with projected capacity needs being procured years in advance to allow for retention or development of supply in time to serve as capacity resources.
- The nature of the resources was straightforward: installed capacity, adjusted for performance, at the lowest price, with procurement being "fuel agnostic."

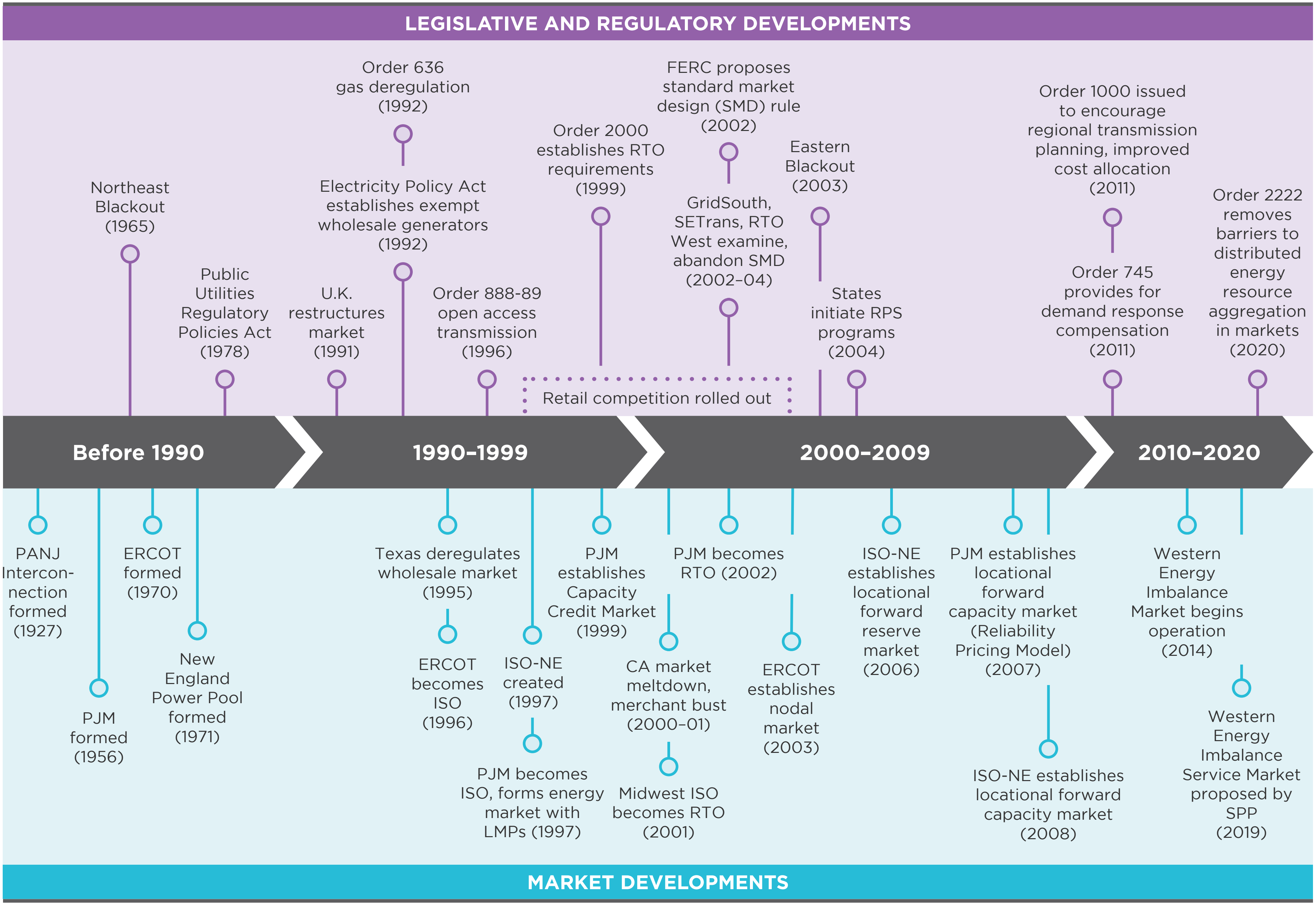
Market Evolution

- Markets have evolved and adjusted over time, trying to get rules and incentives right. Some markets have deep roots as tight power pools, pre-dating current constructs.
- Efforts at market standardization have been subject to more localized and regional interests and jurisdictional conflicts.
- Capacity markets are in varied states of adolescence. Will efforts to pull back from or adjust those markets be cost effective and achieve goals of reasonable rates, long-term average cost recovery (generator solvency); innovation and energy production efficiency; policy objectives (e.g., CO_2 emissions); and allocation of jurisdictional authority?

KEY TAKEAWAYS

- **Bid-based electricity markets are decades old, and have grown, expanded, and adapted with changes in policy, participant types, and resource and fuel costs.**
- **Designed to produce low prices and reliable energy supply, other considerations such as greenhouse gas emissions are now adding complexity in market design.**
- **Market administrators are looking for ways to accommodate different policy preferences while keeping transactions "in the market" to aid transparency and, in theory, lower prices.**
- **Many believe market adjustments are possible, but the journey may come with some contention. Time will tell what approaches will win the day.**

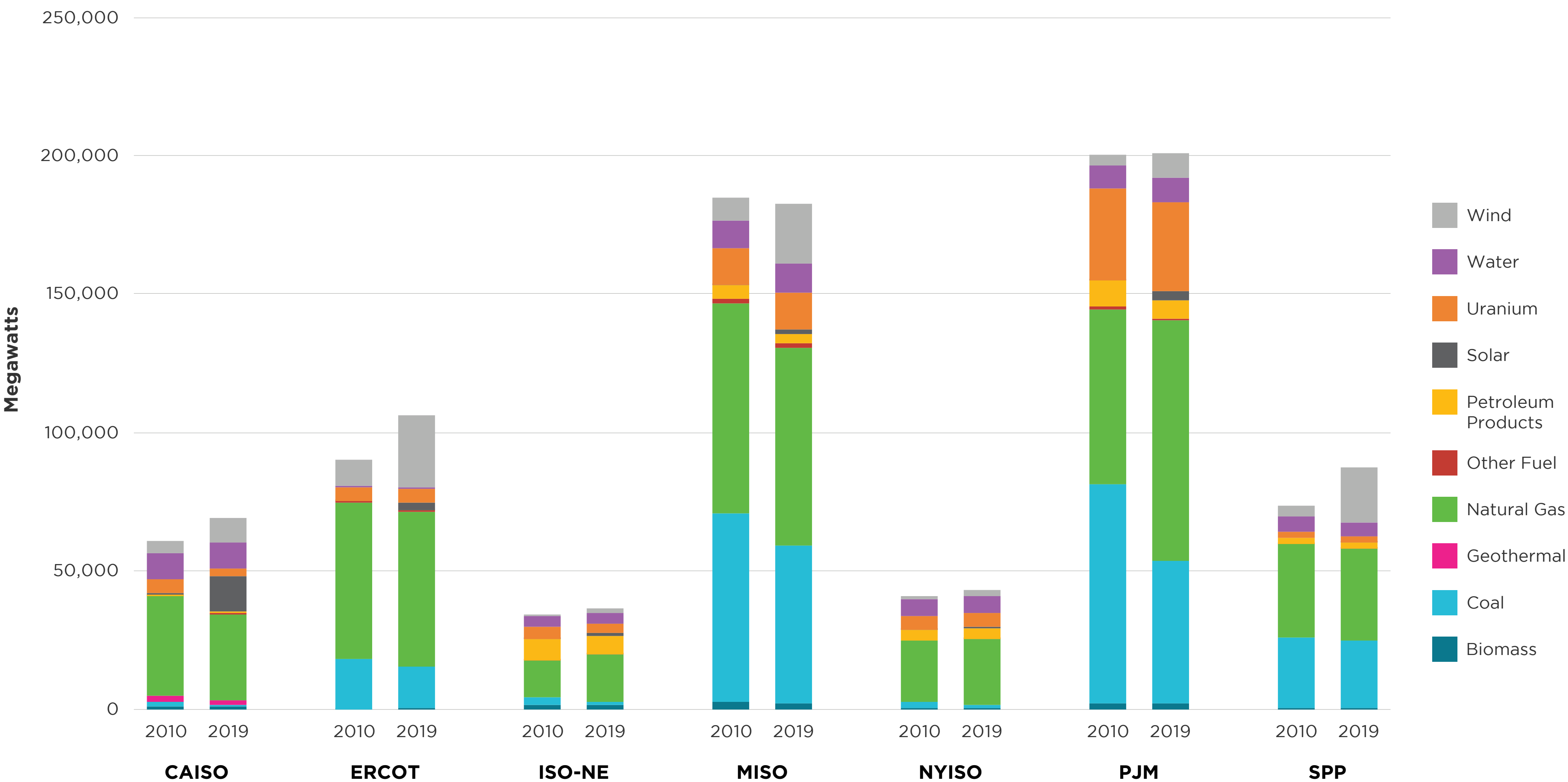
An Abbreviated and Selective History of U.S. Wholesale Electric Markets



Conflicting Priorities Causing Capacity Market Turmoil

- In recent years, increasing state interest in lowering greenhouse gas emissions and promoting renewable resources have been introduced as energy policy objectives in some jurisdictions. To support these policy objectives, some states have provided incentives—some guaranteed revenue to certain resources—to preserve certain fuel and emissions profiles.
- This has proven a conundrum for some market operators and regulators, who contend that subsidized resources artificially depress capacity prices, dampening the signals for resource adequacy. Other regulators, along with renewable and nuclear power advocates, contend states enjoy primacy over their energy mix that should not be stymied by market rules and pricing constructs.

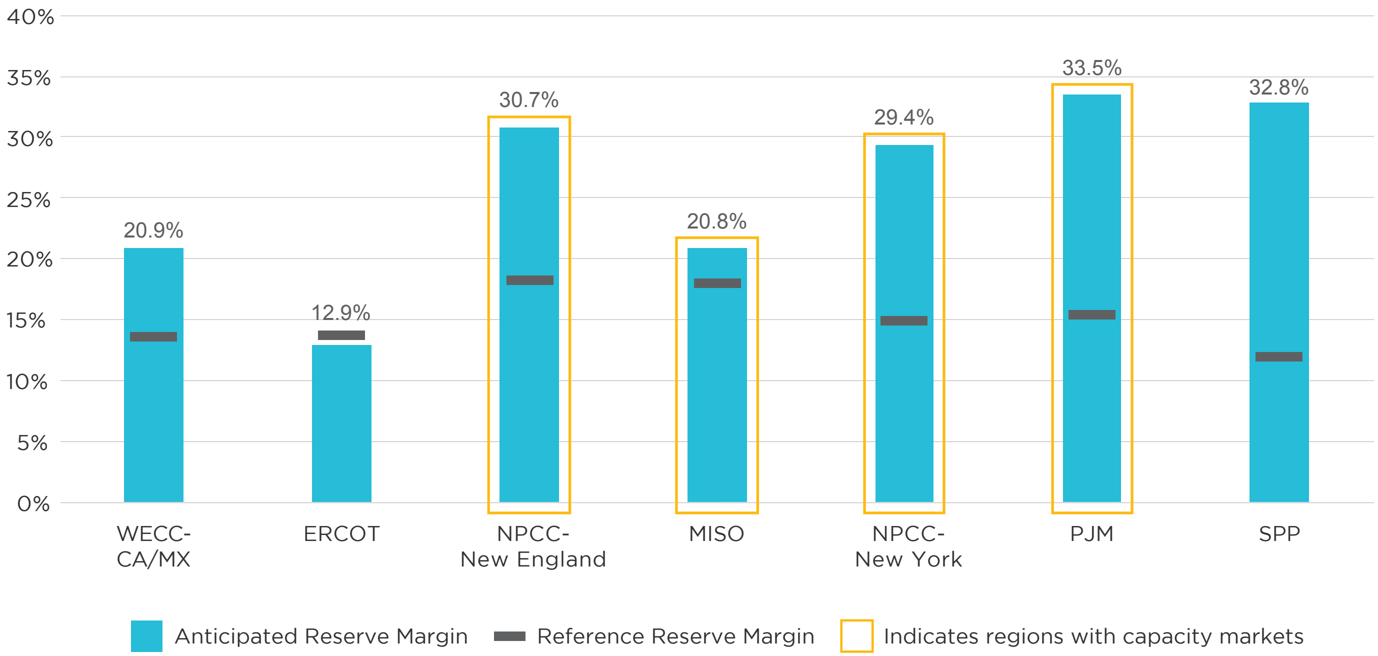
U.S. RTO/ISO Capacity Mix by Fuel Type (2010 and 2019) (in Megawatts)



Source: S&P Global Market Intelligence

- A longstanding flashpoint for this debate has been in the PJM Interconnection, where a minimum offer price rule (MOPR), originally intended to curb market power, is being applied to adjust prices to account for out-of-market payments (specifically defined "State Subsidies") and their potential price-suppressing effects on bids. To date, policy disagreement has postponed the past two annual base residual capacity auctions (slated for the summers of 2019 and 2020, respectively).
- States with subsidized, policy-supported resources are concerned that, as a result, customers will pay twice for capacity while supported generators may not clear the auction at all, eliminating a revenue source. The amounts are consequential: In 2018, capacity costs were $11.89/MWh, representing nearly 20% of an all-in wholesale cost of $59.96/MWh.
- Merchant generators, however, believe that the price adjustments level the playing field.

Summer 2020 Anticipated Reserve Margins and Reference (Target) Margin Levels for Selected Regions



Notes: Anticipated Reserve Margin is a metric, based upon available resource capacity, used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecasted peak demand. Anticipated resources include generators and firm-capacity transfers that are expected to be available to serve load during electrical peak loads for the season.

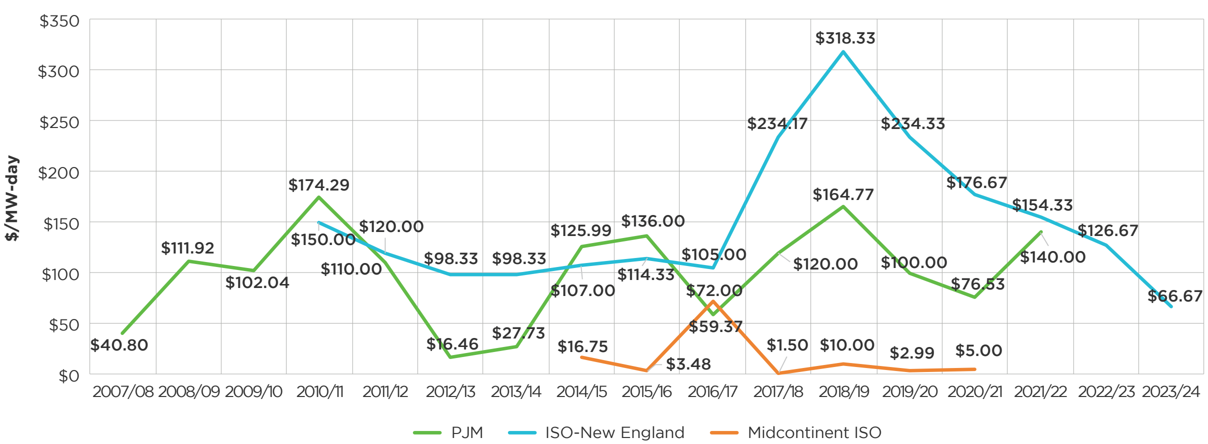
Source: NERC

- Summer reserve margins have been tightening in MISO and especially in ERCOT.
- While projected in June to have adequate reserve margins, excessive heat in California, combined with gas-fired generator outages and reduced imports, stressed reliability this summer. California does not have a capacity market, relying instead upon reliability must-run arrangements and CAISO's capacity procurement program. Generators had proposed a capacity market back in 2018, but that effort was unanimously rejected by FERC. The events of this summer are being examined for root cause analysis and lessons learned.
- ERCOT, which uses scarcity pricing in its energy markets to encourage resource development, continues to see tight reserve margins. In summer 2019, ERCOT hit the region price cap of $9,000/MWh for several hours. This should provide incentives for peaking units to be ready and available.

States Investigate Exiting the PJM Capacity Market

- FERC Commissioner Glick, who has dissented in many of FERC's recent PJM-related rulings, has publicly questioned the need for capacity markets if they do not adequately accommodate state policy priorities.
- In response, New Jersey, Maryland, and Illinois have been studying the possibility of exiting the PJM capacity market. In lieu of market participation, states (and load-serving utilities) would use an existing alternative to centralized procurement known as the Fixed Resource Requirement (FRR).
- Under FRR, utilities provide their own capacity procurement plans for their resource adequacy needs, which states may design as they wish. One complication is that PJM assesses capacity adequacy factoring in transmission constraints. Depending upon the location of the generation resources and the load delivery area, utilities under the FRR might need to shore up resources in their load delivery areas. However, critics of the current PJM process assert there is over-procurement, with reserve margins under that construct estimated as 22% versus the 15% to 16% they would be under FRR.
- Cost is a major factor of debate. How much an FRR approach might cost a load-serving utility depends on assumptions of whether internal (to the load footprint) capacity is procured first and then imported resources or whether the most inexpensive deliverable resources (in or outside the footprint) are procured first. These assumptions matter, as one of two competing analyses said that FRR could increase costs by up to $386 million, while the other claimed it would save $270 million by 2025. New Jersey's utility commission is evaluating the cost of PJM's FRR option.
- While only PJM has this FRR arrangement, a move by a sufficiently significant amount of load and resources to the FRR construct may render the PJM capacity market more like the New York Independent System Operator (NYISO) and Midcontinent ISO, which have significant amounts of their resource requirements met outside of auctions. If utilities go forward with FRR, it is unclear what impact that will have on pricing and capacity resource availability. Moreover, does this portend a partial reintegration of utilities in states with these capacity support programs?

Indicative Capacity Prices in Selected Jurisdictions by Delivery Period ($/MW-Day)*



- PJM and ISO-New England conduct forward-capacity auctions three years in advance of anticipated delivery year. As shown here, PJM and ISO-NE prices can vary significantly from year to year. Because of the ongoing debate over PJM's MOPR for subsidized resources, it has not yet conducted auctions for 2022/23 and 2023/24 delivery years.
- By contrast, much of MISO's capacity is locked up through self-scheduling or a fixed resource adequacy plan (FRAP), with about 5.5% offered in its most recent capacity auction that has not been self-scheduled. It is difficult to determine what those self-scheduled and FRAP prices are.

Note: *PJM prices reflect annual auction results for RTO in Base Residual Auction; MISO figures reflect the predominant price among zones; there is no MISO-wide price and no averaging was performed. ISO-NE prices reflect system-wide prices and do not depict higher prices in selected zones in delivery years 2016/17 through 2018/19. ISO-NE prices are reported in $/kW-month; these have been converted to $/MW-day based on a 30-day month.

Sources: PJM; Midcontinent ISO; ISO-New England

Working Out Carbon Market Kinks

- State policy and priority mismatches on carbon pricing for energy have been a point of contention for market and pricing structures, beyond the capacity issues noted above.
- California has implemented a carbon border adjustment of sorts, subjecting imports to California's cap-and-trade regulation—in particular, compliance costs under that program. It is unclear whether those costs will reduce the amount of imports into California from certain resources.
- To address some states' concerns about leakage, PJM is studying potential rule changes and whether and how to implement border price adjustment mechanisms. Leakage refers to importing or exporting less-expensive, higher-emitting generation into or out of a region that has a carbon-pricing scheme.
- In parallel and partially in response to interest of key players, including utilities, generators, and one natural gas industry organization, FERC conducted a technical conference in late September 2020 to address carbon pricing in organized electricity markets. Issues discussed included:
  - Whether integration of state-set carbon pricing into RTO/ISO markets and their potential rate impacts are just, reasonable, and not unduly discriminatory or preferential under the Federal Power Act, FERC's governing authority.
  - An overview of how RTO/ISO markets currently incorporate carbon pricing under state and regional initiatives and technical and policy challenges of leakage.
  - Operational and market design issues from integrating carbon pricing into energy and ancillary service markets.
- It is unclear where the industry and FERC will proceed to from here. However, FERC issued for comment a draft policy statement encouraging efforts to incorporate a state-determined carbon price into RTO/ISO markets. Some considerations it noted were impacts on market design, price transparency, price formation, dispatch effects, and economic or environmental leakage.

New York: Single Policy, Adjustments Still Required

NYISO's buyer-side market power mitigation rules require new resources to bid at an offer price floor, subject to certain exemptions. To accommodate New York's renewable resource policies, NYISO proposed qualified exemptions to the offer floor for policy resources (i.e., non-CO_2-emitting generation).

FERC found that the NYISO proposal was "unduly discriminatory because it does not provide sufficient justification for prioritizing the evaluation of Public Policy Resources before non-Public Policy Resources, independent of cost" and that the two types of resources are "similarly situated resources in that they must adhere to similar requirements for interconnection and for participation in the NYISO [installed capacity] market."

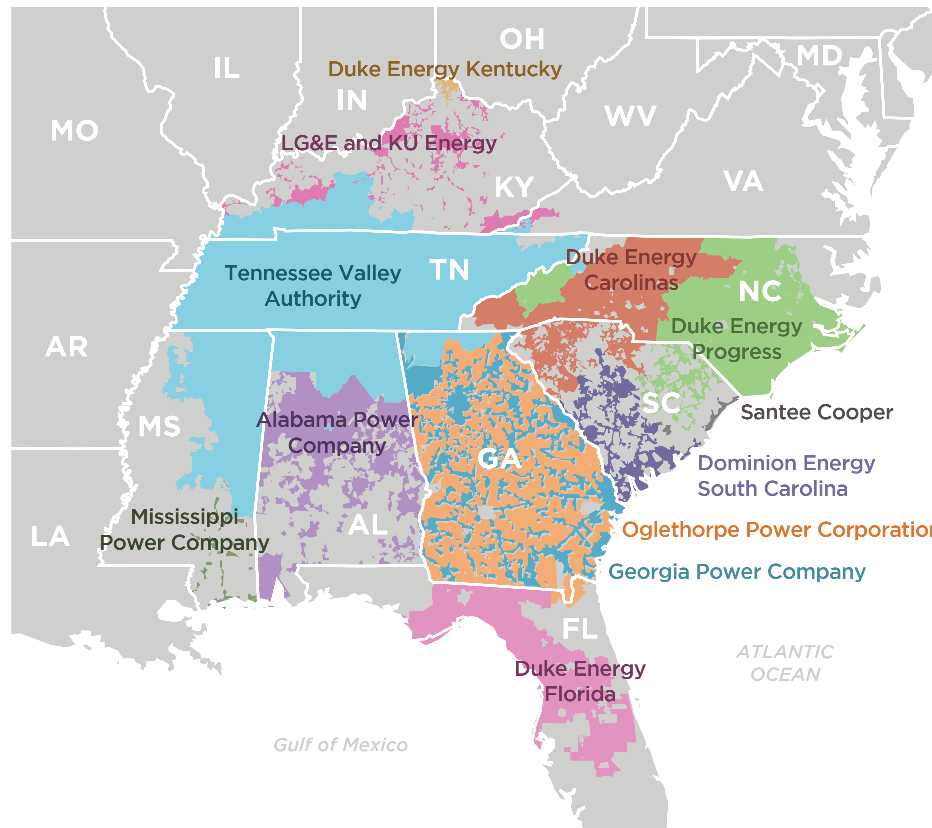
Commissioner Glick, in a strongly worded dissent, stated that the interpretation of NYISO's buyer-side market mitigation rules created "unnecessary and unreasoned obstacles aimed at stalling New York's efforts to transition the state toward its clean energy future."

The discussion illustrates that the debate over capacity rules, particularly offer prices, transcends those areas where states have policy differences such as PJM, even including states and markets in which there is policy alignment. However, while capacity market issues remain in those markets, those policies may still be achieved through carbon pricing.

A Possible Southeastern Energy Exchange

- Nearly two decades ago, a couple of southern U.S. utility groups proposed RTOs—SeTrans and GridSouth. Those efforts were motivated by Order 2000, which called for formation of RTOs nationwide to enhance wholesale competition to lower prices and address issues of resource adequacy.
  - FERC pursued this goal through a proposed standard market design (SMD), which sought to use PJM as a template for bid-based markets with location-based pricing and financial hedging against congestion.
  - These efforts were eventually abandoned as FERC terminated its SMD efforts amid resistance from state regulators and other stakeholders over jurisdiction, cost, and fallout from the California price spikes of 2000–01, among other concerns.
- Against this backdrop, in mid-July 2020, Duke Energy Corporation, Southern Company, and the Tennessee Valley Authority confirmed they, and others, were discussing the potential for a centralized, automated energy market, currently termed as the Southeast Energy Exchange Market (SEEM).
  - SEEM would be a 15-minute energy exchange, with the goals of lowering costs, optimizing renewable energy resources, and bolstering reliability.
  - Though still early in the discussion stage, it would operate like an energy imbalance market (EIM), although it is not envisioned to be as costly as other EIMs, such as the Western EIM, nor administered centrally via a third party, such as an ISO.
- Renewable energy advocates are lobbying for consideration of even greater integration in the form of a full-blown RTO, arguing that there would be savings through integrated dispatch over a wider geographic footprint, better use of lower-marginal cost resources, and lower emissions.
- Given the complications of integrating state policies and variable energy resources into other bid-based markets, it is unclear whether southeastern regulators and utilities will consider an RTO anytime soon. Costs, benefits, and ratepayer impacts would have to be considered and studied as well as other policy priorities and preferences (e.g., state vs. federal regulatory primacy and accountability).
- This market would be a small but meaningful first step in optimizing the growing number of renewable resources, particularly solar, in the Southeast. It could also support export of other resources, including existing excess dispatchable resources to "firm up" those resources.

Utilities in Talks for Southeast Energy Exchange Market (as of July 2020)



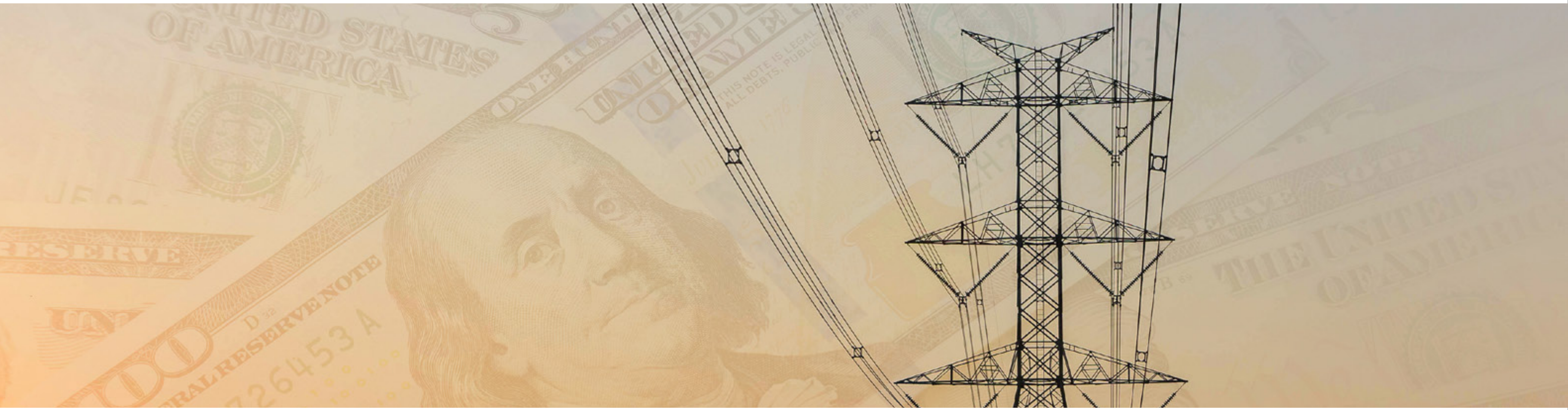
Sources: S&P Global Platts Analytics; S&P Global Market Intelligence

IMPLICATIONS

Electricity markets will likely see further development and change, regardless of the political environment. Stakeholders—especially power market participants—will need to remain flexible and adaptable as potential new rules and markets for carbon emissions, demand-side participation, and market expansion (such as the Southeast Energy Exchange Market under discussion), among others, are developed.

Sources:

S&P Global Market Intelligence; Utility Dive; *Power* magazine; Platt's *Megawatt Daily*; PJM Interconnection; Southwest Power Pool; ISO-New England; Midcontinent ISO; New York ISO; California ISO; Electric Power Supply Association; M. Farmer & R. Gramlich, "Whether to FRRExit: Information States Need on the Costs and Benefits of Departing the PJM Capacity Construct" (May 2020); Answer of Monitoring Analytics, LLC, Independent Market Monitor for PJM, Investigation of Resource Adequacy Alternatives, New Jersey Board of Public Utilities, Docket No. EO20030203 (July 15, 2020); "Standard Market Design: What Went Wrong, What's Next," *Electricity Journal* (July 2003); "FERC Rejects Southern RTO, Approves GridSouth," *Oil & Gas Journal* (March 15, 2001); FERC Order Rejecting Tariff Revisions, Docket No. ER20-1718-001 (Sept. 4, 2020); Resources for the Future, "Buyer-Side Mitigation in the NYISO: Another MOPR?" (March 6, 2020); North American Electric Reliability Corp., 2020 Summer Reliability Assessment (June 2020); FERC Technical Conference, Carbon Pricing in Organized Wholesale Electricity Markets, Docket No. AD20-14-000 (Sept. 30, 2020), and Notice of Proposed Policy Statement (Oct. 15, 2020); ScottMadden analysis



REGULATORY RESPONSES TO COVID-19
TRACKING IMPACTS AND PREPARING STRATEGIES FOR RECOVERY

Tough questions: How to help customers and how much financial protection should be provided for utilities?

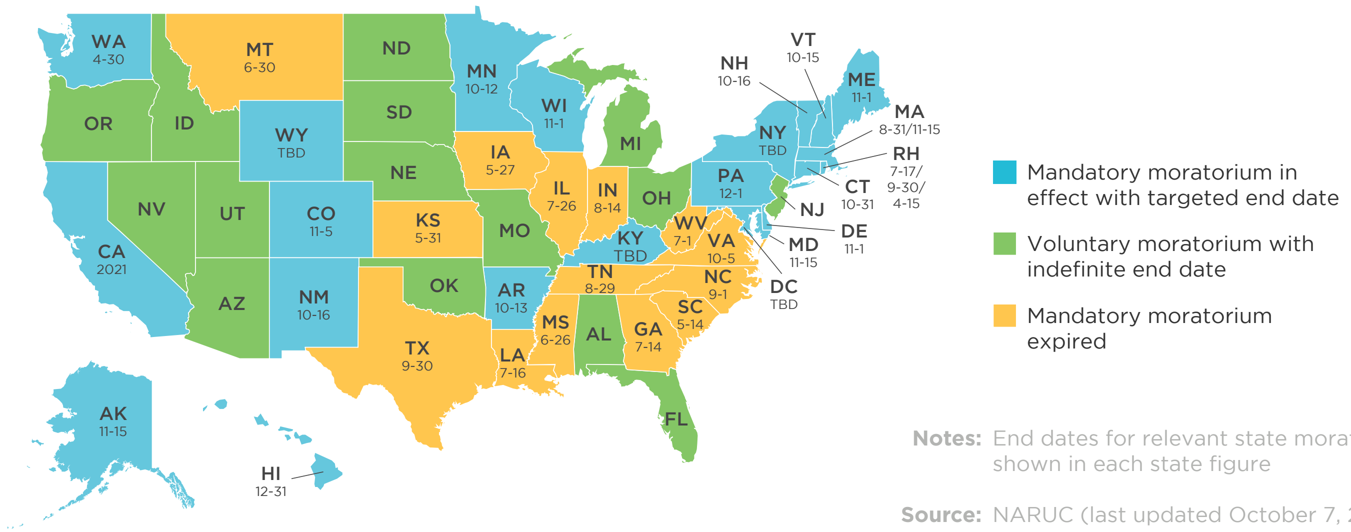
Tracking COVID-19-Related Expenses (Net of Savings) and Lost Revenue

- Starting in mid-March, state legislatures, governors, public service commissions, and utilities across North America began to address the various impacts that COVID-19 is having on customers and utilities. Emergency stay-at-home orders, accompanied by voluntary or mandated moratoria on service disconnections, were initiated to help relieve customers' suffering from the pandemic, as well as the subsequent economic turmoil.
- Utilities and regulators took proactive steps to better understand and measure the financial impacts of COVID-19. In many jurisdictions, these steps included granting utilities the ability to track unusual, unanticipated, and uncontrollable expenses associated with the virus response—such as collection forbearance and disconnection moratoria—through deferred regulatory asset accounting mechanisms, anticipating pursuit of future cost recovery.
- However, with little precedent for this type of pandemic event, the specific actions have varied greatly. Most commissions have offered generic guidance for utilities to track expenses the latter view as prudent. A few jurisdictions have explored potential issues around the appropriate treatment for lost revenue from the service disconnection moratoria, operational expenses and savings, and financing costs to maintain liquidity during the crisis. Most, however, have deferred those discussions until later.
- There is no clear consensus for how stakeholders should respond to these events. As the full extent and duration of the economic consequences associated with the pandemic are understood, utilities and stakeholders will assess how risks and costs should be shared among shareholders and customers, recognizing that the magnitude and characteristics of those risks will vary by jurisdiction.

KEY TAKEAWAYS

- **Utilities are tracking incremental costs, savings, and lost revenue from the pandemic, but most prudency determinations have been deferred, adding to the uncertainty about regulatory recovery.**
- **Utility service disconnection moratoria have been extended in some jurisdictions, while allowed to expire in others. Moratoria may be revisited if the economic crisis does not abate soon.**
- **For those jurisdictions that have provided guidance to date, eligibility for recovery of specific categories of COVID-19 costs varies widely.**
- **Utility strategies for recovery of COVID-19-related costs will depend on timing and each utility's situation. A reevaluation of the regulatory construct may help prepare utilities for the next disruption.**

Status of U.S. COVID-19 Utility Service Disconnection Moratoria



Notes: End dates for relevant state moratoria shown in each state figure

Source: NARUC (last updated October 7, 2020)

Status of Utility Service Disconnection Moratoria: Extend or Allow to Expire?

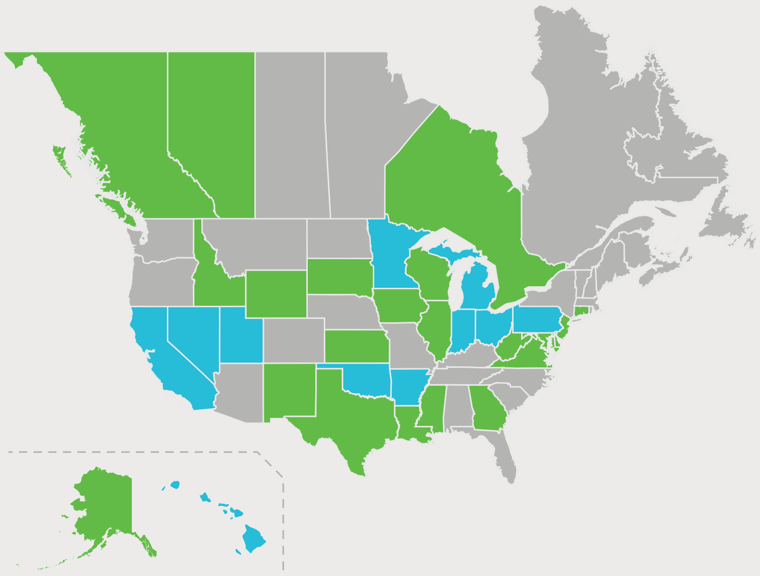
- Service termination moratoria have been implemented in all 50 states, as well as the District of Columbia and Puerto Rico. The moratoria are, or were, voluntary in 19 jurisdictions and mandated by the governor, legislature, or a regulatory commission in the others. The latter includes states where one or more utilities initially suspended service disconnections voluntarily, but policymakers subsequently issued a directive mandating a moratorium.
- Today, as the COVID-19 crisis continues amid concerns of subsequent "waves" of infection and continued economic disruption, regulators and utilities are considering whether to extend mandatory or voluntary utility service termination moratoria.
- Service moratoria that were in place in 11 states—Illinois, Indiana, Iowa, Kansas, Louisiana, Missouri, Montana, Ohio, Rhode Island, South Dakota, and West Virginia—have expired since May. Moratoria in 15 other states are set to expire before the end of 2020. Even as mandated moratoria expire, some utilities have indicated that they will voluntarily continue to forego utility service disconnections and provide flexible payment options for customers unable to pay bills. Others have argued that extending moratoria for too long increases the risk of default and termination should customer arrearages become unmanageable.
- Regulators have expressed concern as well. The Virginia State Corporation Commission, for example, stated that the "moratorium on utility service disconnections for nonpayment is not sustainable" and could result in costs being "unfairly shifted to other customers." The commission also said the moratorium could have disproportionately negative impacts on smaller, less-capitalized utilities and member-owned electric cooperatives, while larger utilities with strong balance sheets would have more flexibility to absorb the cash flow impacts of the moratoria.

- In other cases, governors, state legislatures, or public utility commissions have agreed to extend mandatory moratoria—many on a limited or month-to-month basis—until COVID-19 has abated and the economy recovers. Groups representing customer interests have raised questions about customers' ability to pay and argued that service disconnections could endanger the fight against the spread of COVID-19.
  - In Wisconsin, the public service commission moved back the moratorium's expiration date set for October 1 to November 1, the second one month extension in as many months. November 1 will mark the beginning of the cold weather moratorium period in the state.
  - In North Carolina, the utilities commission issued an order on July 29 authorizing utilities to resume disconnections effective September 1, but certain utilities have indicated that they would voluntarily continue to forgo shutoffs beyond that date.
- Utilities in almost all jurisdictions have implemented some form of flexible payment for distressed customers, in some instances extending repayment plans for as long as 24 months. Flexible repayment plans are generally the initial avenue for recouping arrearages associated with the pandemic that utilities must explore before seeking treatment as bad debt. At the same time, regulators have encouraged the full use of available economic assistance funds and considered other creative solutions, such as applying security deposits to delinquent accounts.

Eligible Expenses: Just and Reasonable, Incremental and Necessary

- Because most states simply provided a blanket statement regarding their requirement that utilities demonstrate "just and reasonable" and "incremental and necessary" expenses to be considered for future rate recovery, there is little certainty about which categories will ultimately be eligible for recovery. However, some commissions have provided specific guidance. There are four general approaches with future cost recovery supported by:
  - Past practices and orders
  - Customer benefits
  - Incurrence of "extraordinary, non-recurring, incremental expenses"
  - Prudence and reasonableness of the deferred expenses
- Each of these approaches may provide some additional degree of certainty of recovery if the utility expenses can be demonstrated to be consistent with the relevant language in their jurisdiction. The figure at right outlines the breadth of accounting deferrals by state and province in the United States and Canada, and it provides details from an illustrative review of the language in commission orders.
- Anticipating potential issues this coming winter, gas utilities may benefit from reviewing the impact and responses from electric utility neighbors. To date, gas utilities have experienced less disruption, as the U.S. heating season was mostly complete before the onset of the virus, whereas electric utilities have been impacted to a greater degree, as summer peak demands coincided with the economic disruption.

COVID-19 Accounting Deferral Orders in the United States and Selected Provinces in Canada



Narrowly defined eligible expenses | More broadly defined eligible expenses

Sources: State PUC filings; ScottMadden analysis

Illustrative Review of State Commission Orders on COVID-19-Related Expenses

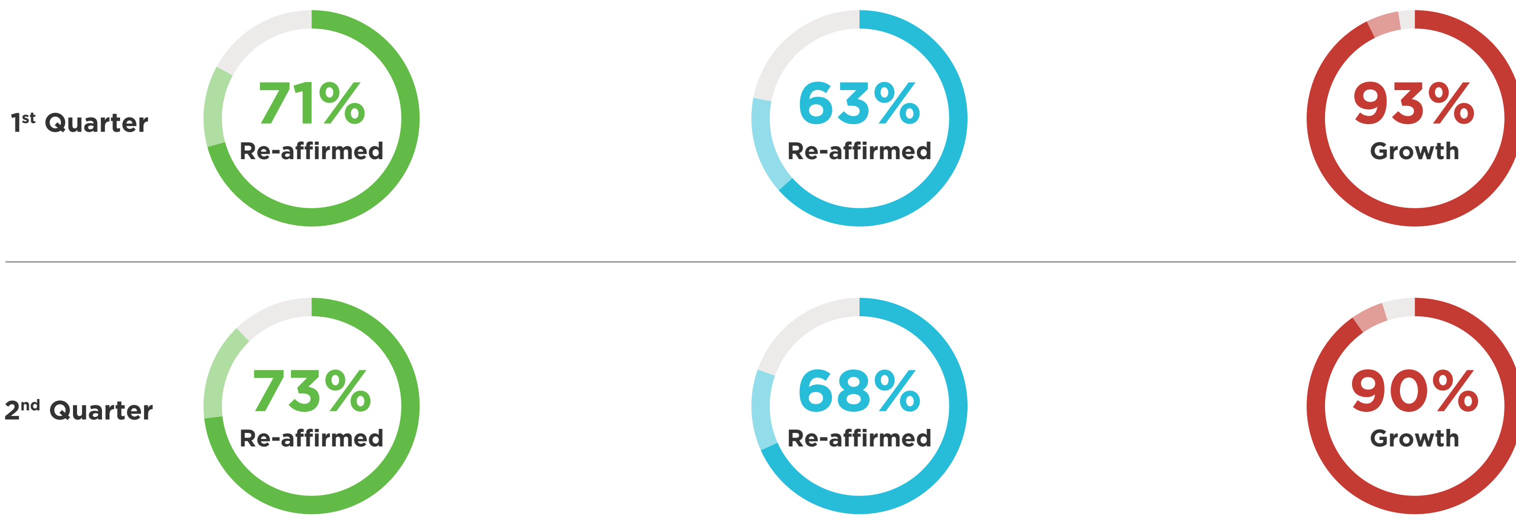
State Commission	Eligible Expenses	Ineligible Expenses	Key Quote
Idaho 	✔ Suspended late fees in excess of 2019 baseline ✔ Bad debt expense exceeding 2019 levels ✔ Incremental COVID-related operations and maintenance costs	✕ Carrying or financing costs ✕ Reduced sales from customers (potential for recovery to be determined later)	"Actual recovery amounts and terms of recovery will be determined after a review of the prudency and reasonableness of these deferred expenses in the next rate proceeding."
Indiana 	✔ Suspended fees (late, convenience, reconnection, etc.) ✔ Setup costs for extended repayment programs ✔ Incremental bad debt expense	✕ COVID-related operations and maintenance costs ✕ Additional pension costs ✕ Carrying or financing costs ✕ Lost revenue due to loss of load	"The Commission has the responsibility of balancing the right of the utility's investors to recover costs and the opportunity to earn a fair rate of return against the right of the public to pay no more than reasonable rates for the utility's service."
Pennsylvania 	✔ Incremental bad debt expense ✔ Extraordinary, nonrecurring incremental expenses incurred, subject to detailed recordkeeping	✕ No other COVID-related expenses are authorized for deferral	"With the exception of the separate regulatory authorization afforded uncollectible expenses below, this Secretarial Letter does not grant authorization for utilities to defer any other potential COVID-19-related expenses."
Wisconsin 	✔ Suspended fees (late, convenience, disconnection, etc.) ✔ Bad debt expense above what is already included in rates ✔ COVID-related administrative and general expenses ✔ Carrying costs at approved short-term rates	✕ Lost revenue from loss of load	"Accurate documentation and reporting will be essential as utilities file future rate applications seeking recovery of deferred balances; however, the Commission recognizes that reporting places further demands on utilities' resources and time."

Sources: State PUC filings; ScottMadden analysis

Early Returns on Earnings Impacts from COVID-19 Costs

- A review of quarterly earnings reports from 41 U.S. electric and gas utilities over the first two quarters of 2020 reveals that the majority of utilities expected to deliver on previously communicated targets in the first quarter, with a slight second quarter increase in the number as more utilities reaffirmed 2020 guidance.
- The figure below details the findings from the earnings conference call presentations. Earnings and capex guidance increased from the first to the second quarter from 71% to 73% and 63% to 68%, respectively. The vast majority of utilities in the sample (93%) confirmed expectations of dividend growth, and that number declined slightly in the second quarter.
- In addition to the COVID-19-related costs incurred by utilities, some also have offsetting cost reductions from such actions as furloughs of non-essential employees, reductions in travel and training expenditures, and reductions in operating costs from other scaled-back operations during the pandemic (e.g., reduction in lower-priority operations and maintenance expenses, etc.).

Earnings and Capex Guidance and Dividend Growth for Selected Electric, Gas, and Combination Utilities (Q1 vs. Q2 2020)



Earnings Guidance	Q1	Q2
Re-affirmed	29	30
Lowered (or Re-affirmed Lower Q1 Range)	5	6
Withdrawn or None Provided	7	5

Capex Guidance	Q1	Q2
Re-affirmed	26	28
Lowered	6	5
Not Available/No Comment	9	8

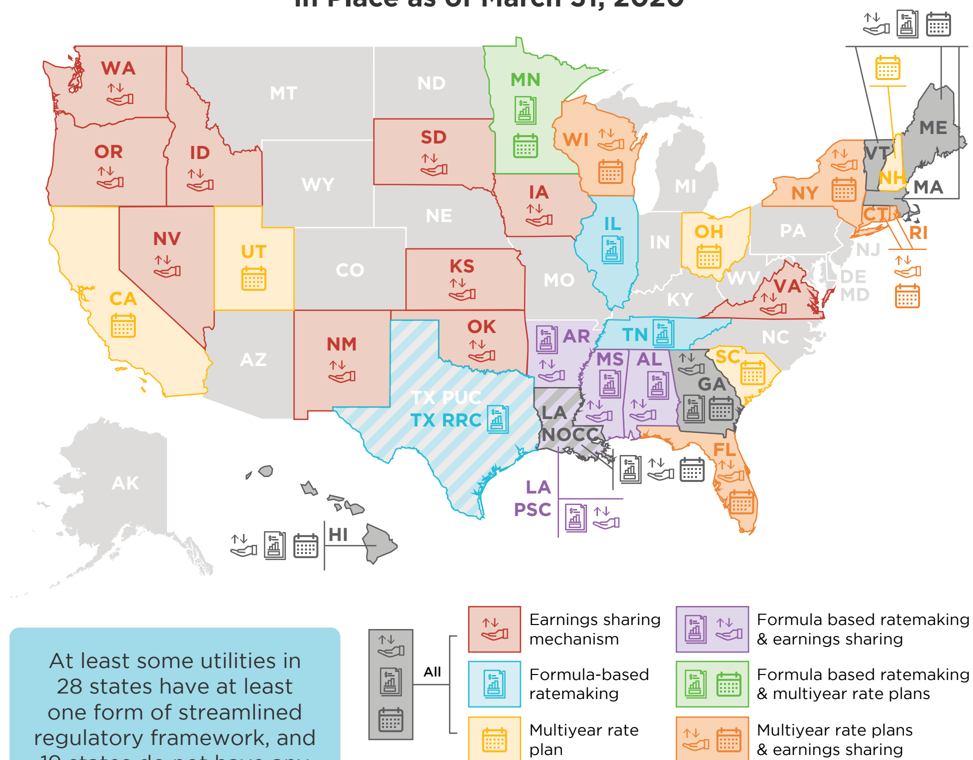
Dividend Growth	Q1	Q2
Positive Growth	38	37
Zero Growth	2	2
Reduced	1	2

Sources: Company earnings reports and press releases from Q1 and Q2 2020; ScottMadden analysis

Utility Strategies for Achieving COVID-19 Cost Recovery

- **Short Term:** Assuming the underlying regulatory construct is not going to change in most jurisdictions, utilities' options for seeking short-term recovery will be limited to such traditional mechanisms as emergency rate increases, limited issue riders, or waiting to incorporate COVID-19-related costs into their next base rate case. Utilities should take advantage of deferral orders, if available, to shore up income and then carefully consider the trade-offs between these options before determining how to proceed for recovery of any COVID-related regulatory assets and non-deferred costs.
- **Emergency Rate Increases:** Regulators are unlikely to approve any immediate or drastic rate increases through surcharges, at least until after the COVID-19 health emergency has subsided. With expectations that economic fallout from the pandemic will be relevant for the foreseeable future, this option seems to be an unlikely path for most utilities.
- **Limited Issue Riders:** Typically used to remediate one-time costs from unique events, such as extreme weather, these riders may or may not allow utilities to recover their full cost of capital in carrying costs. Securitization of COVID-19 expenses could reduce recovery risk for utilities and will allow utilities to deploy capital elsewhere, while minimizing rate impacts for customers by locking in a lower interest rate as opposed to a higher combined cost of capital.
- **Base Rate Case:** This provides an opportunity for a comprehensive recovery of unexpected pandemic costs within a discussion of broader revenue requirement issues. However, the process may be drawn out, as commission resources may be overwhelmed with requests once the health crisis is over and should interveners aggressively contest any rate increases.
- **Medium to Long Term:** In the medium to long term, utilities may choose to consider altering the regulatory construct. Utilities operating in jurisdictions with alternative ratemaking provisions in place—such as full- or partial-revenue decoupling, formula-based rate making, and/or earnings sharing mechanisms (see map at right)—may be somewhat insulated from the worst financial impacts. Utilities operating in jurisdictions without such mitigating mechanisms could consider requesting such features as part of their recovery filing.

Jurisdictions with Streamlined Regulatory Frameworks in Place as of March 31, 2020



At least some utilities in 28 states have at least one form of streamlined regulatory framework, and 19 states do not have any streamlined regulatory frameworks in place.

Source: Regulatory Research Associates, a division of S&P Global Market Intelligence

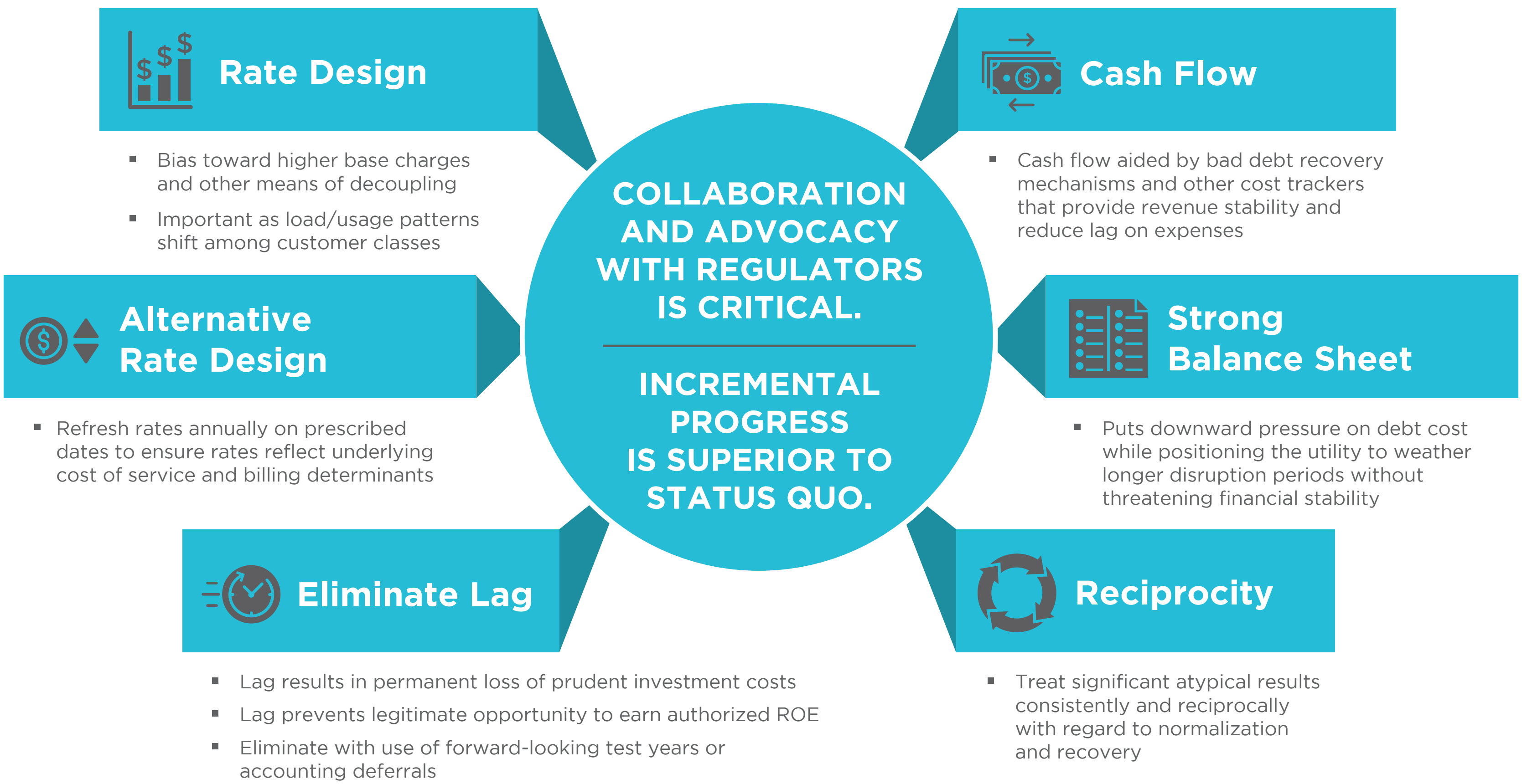
Definitions for Key Terms Above:

- **Revenue Decoupling** – Separates volumetric charges from certain fixed costs, generally to incentivize efficiency and conservation. In some cases, it can be used to offset unexpected changes in demand due to macroeconomic factors.
- **Formula-Based Ratemaking** – Provides annual true-up mechanisms to maintain a target return on equity, rate of return, and capital structure if actual performance differs from expectations.
- **Earnings Sharing Mechanisms** – Allows balancing of over- or under-earning within an approved bandwidth so investors and customers share costs as well as benefits.

Preparing for the Next Disruption

- As utilities reflect on the current COVID-19 crisis and the magnitude of the financial impacts continue to come into focus, the moment is an appropriate one in which to revisit and rethink the regulatory construct more holistically. By examining all levers available to protect against potential negative impacts from future disruptions, utilities may be better prepared for the next event. The figure below provides a framework for considering all the key aspects of the regulatory construct.

Preparing for the Next Disruption:
Key Aspects of Regulatory Construct to Reduce Negative Impacts in the Future



IMPLICATIONS

With prudency determinations for recovery of COVID-19-related costs deferred in most jurisdictions and widely variable in jurisdictions that have provided guidance to date, utility strategies for recovery will need to be catered to the timeframe and each utility's unique situation. While options may be somewhat limited in the short term, a reevaluation of the regulatory construct may help utilities identify alternative ratemaking provisions to help insulate them from the next disruption.

Sources:

NARUC; Regulatory Research Associates (RRA), a division of S&P Global Market Intelligence, "RRA Regulatory Focus: State Regulatory Evaluations" (Aug. 19, 2020); RRA, "Gas Utilities Become More Exposed to COVID-19 as Winter Approaches" (Sept. 22, 2020); RRA, "Regulators Seesaw on Shut-off Policy, Move Slowly on COVID-19 Cost Recovery" (Oct. 5, 2020); company earnings reports and investor presentations from Q1 and Q2 2020; various utility regulatory filings; ScottMadden analysis

100% CLEAN ENERGY AND NET-ZERO STRATEGIES
LOOKING AT TRANSITION STRATEGIES

The near-term path to 100% clean energy boosts renewables and depends on natural gas for reliability.

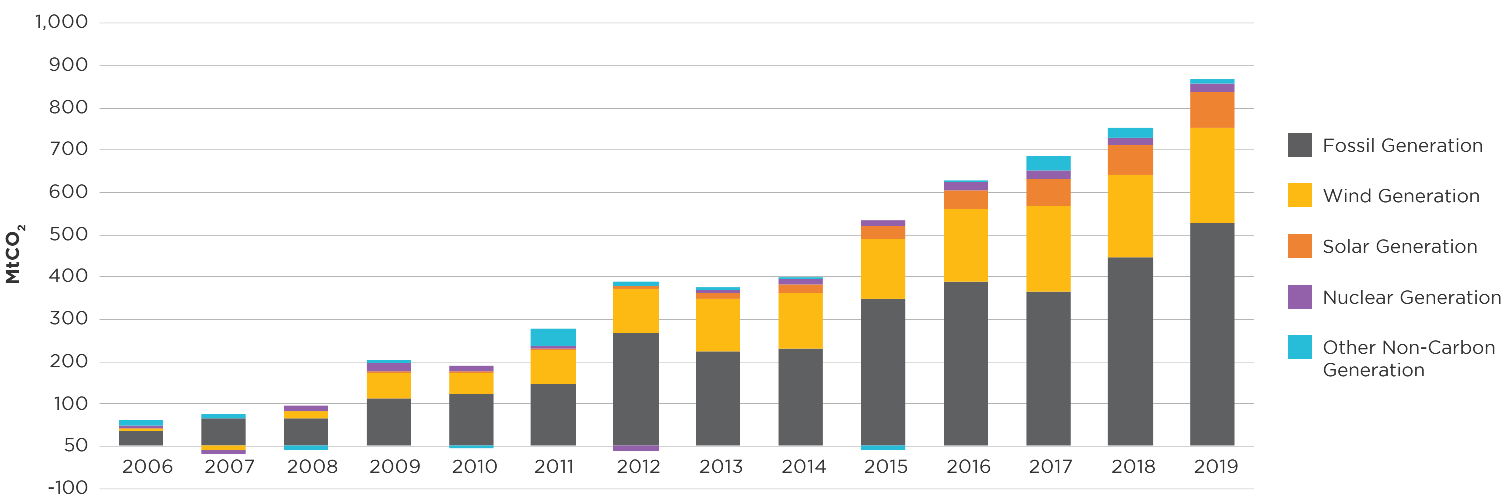
100% Clean Energy Commitments Become More Common

- Eight states have enacted legislation, and more than a dozen U.S. electric utilities have announced 100% clean energy commitments.
- A “100% clean energy” commitment could mean serving customers with one of the following:
  - 100% renewable energy (including hydro)
  - 100% carbon-emissions-free electricity (e.g., renewables, hydro, and nuclear)
  - 100% net-carbon-neutral electricity (e.g., renewables, hydro, nuclear, and fossil with carbon capture and sequestration)
- These are ambitious goals that will require massive capital investments, reliance on new technologies, and changes to grid operations.
- To further explore current and future drivers impacting carbon dioxide (CO_2) emissions, we examined historical reductions in energy-related CO_2 emissions to understand the past and reviewed recent utility integrated resource plans (IRPs) to provide insights into the future.
- As discussed in greater detail later in this section, natural gas has been an important source of CO_2 reductions to date, but renewable energy resources and battery storage are likely to drive the next chapter of the energy transition.

Since 2005, Natural Gas-Fired Power Generation Has Been the Primary Driver of Energy-Related CO_2 Emissions Reductions

- ScottMadden analyzed energy-related CO_2 emissions from 2005 to 2019 ("study period") to understand the technologies and states that have provided the greatest reduction contributions.
  - We chose the year 2005 because President Obama, under the Paris Climate Agreement, committed the United States to reduce overall greenhouse gas emissions by 26% to 28% below 2005 levels by 2025.
  - The Paris Climate Agreement is an international environmental accord designed to substantially reduce global greenhouse gas emissions in an effort to limit the global temperature increase to two degrees Celsius above pre-industrial levels.
  - In June 2017, President Trump announced the United States would exit the Paris Climate Agreement; the United States may officially withdraw in November 2020.
- During the study period, the United States reduced energy-related CO_2 emissions by a total of 5,486 million metric tons through changes in fossil generation (i.e., shifting primarily from coal to natural gas) and growth of non-carbon resources (see figure below).
  - Changes in fossil generation accounted for 61% of the cumulative reduction, while wind and solar accounted for 27% and 6%, respectively.
  - While nuclear and hydro generation provide the majority of non-carbon electricity in the United States, they are not prominent in the results because output from these resources did not change significantly during the study period.

Annual Energy-Related CO_2 Reduction by Source (2005–2019)



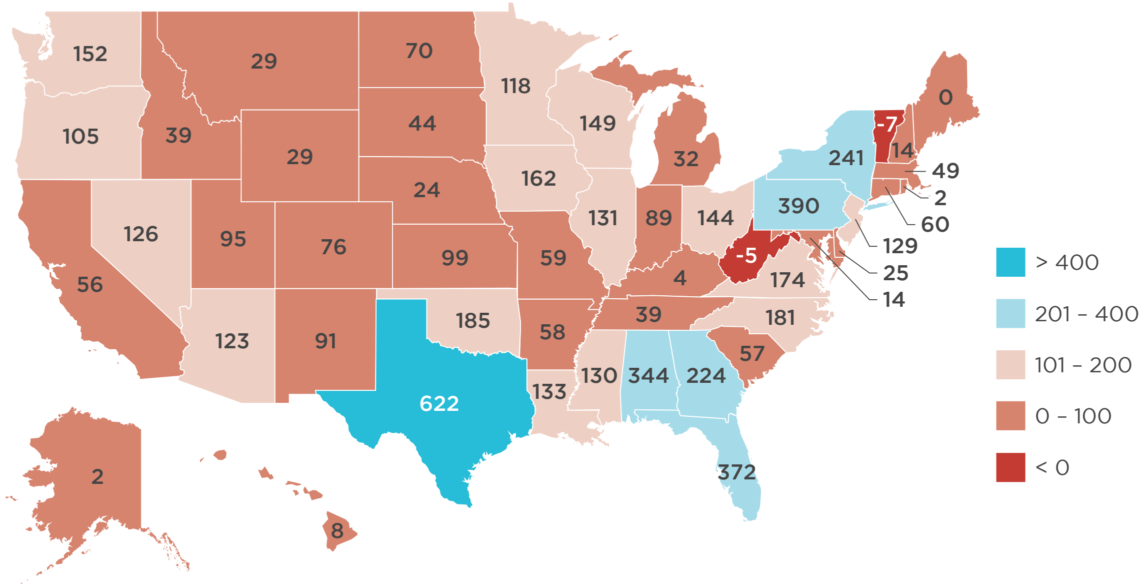
Sources: EIA; ScottMadden analysis

KEY TAKEAWAYS

- **Since 2005, the shift from coal to natural gas drove the majority of energy-related CO_2 emissions reductions in the United States.**
- **Recent integrated resource plans from electric utilities pursuing 100% clean energy indicate the next step is to significantly scale up the deployment of renewable energy and battery storage capacity.**
- **The cost increases associated with these renewable and storage portfolios are estimated to be comparable to or even lower than inflation, yet natural gas will still be required to ensure electric grid reliability.**
- **Deeper decarbonization (80% carbon reduction or greater) will require new technologies, such as long-duration storage or small modular nuclear reactors, that currently are not widely available nor cost effective.**

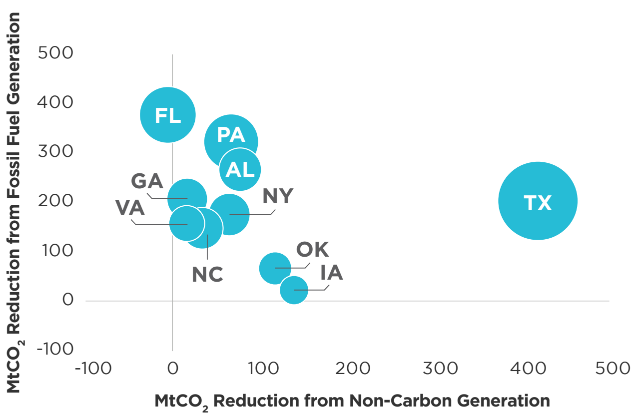
- The states producing the largest carbon reductions have large electricity markets or started with high carbon intensities.
  - Due to its large electricity market and abundant wind energy, Texas has contributed the largest CO_2 reduction of any state (see map).
  - A review of the other states with the largest CO_2 reductions shows that most of these originated from shifts in fossil generation (see bubble chart at lower left).
  - This dynamic results in many Southeastern states' contributing greater CO_2 reductions than California—a state with long-standing energy policies focused on climate change.
  - Even in the 30 states with mandatory renewable energy portfolio standards (RPS), changes in fossil generation fuel types provide significantly greater CO_2 emissions reductions than non-CO_2-emitting generation deployments (see chart at lower right).

Cumulative Energy-Related CO_2 Emission Reductions by State (in $MtCO_2$) (2005–2019)



Sources: EIA; ScottMadden analysis

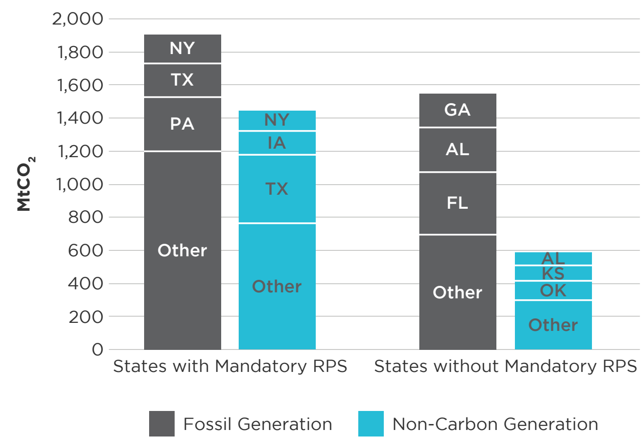
Top 10 States for Energy-Related CO_2 Reductions by Source (2005–2019)



Note: Size of bubble reflects electric retail sales.

Sources: EIA; ScottMadden analysis

Cumulative Energy-Related CO_2 Reductions by Renewable Portfolio Standards (RPS) (2005–2019)

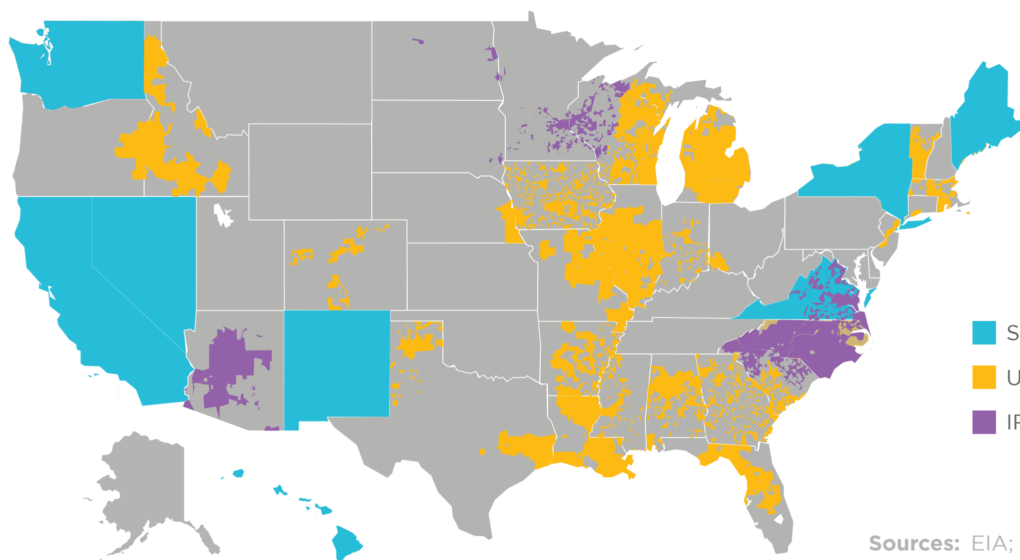


Sources: EIA; ScottMadden analysis

Utility Integrated Resource Plans: A View into the Future

- In December 2018, Xcel Energy was the first major utility to announce plans to pursue a 100% clean energy goal. Many utilities have followed suit, and their initial announcements often outline the path to 100% clean energy in general terms.
- Some of these utilities have recently released IRPs, providing a detailed view into the changes in energy resources planned over the next decade or longer. In addition to affordability and reliability, securing carbon reductions becomes an elevated criterion in this new class of IRPs.
- ScottMadden reviewed five recent IRPs to understand how some electric utilities are planning to pursue decarbonization over the next 15 years. The themes and strategies that span these IRPs may provide a roadmap—or some pointers—to other electric utilities considering CO_2 reduction goals or strategies.
- More specifically, ScottMadden reviewed the IRPs from the following vertically integrated, investor-owned electric utilities:
  - Arizona Public Service Company's (APS) IRP, covering its Arizona service territory
  - Xcel Energy Inc.'s Northern States Power Company's IRP, covering its Upper Midwest service territory in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin
  - The Duke Energy Carolinas' (DEC) and Duke Energy Progress' (DEP) IRPs, covering their North Carolina and South Carolina service territories
  - Dominion Energy, Inc.'s Virginia Electric and Power Company's IRP, covering its Virginia service territory
- Each IRP was published after the parent company announced a commitment to achieving 100% clean energy. In Virginia, Dominion Energy is also subject to a state law requiring 100% clean energy, more specifically requiring 30% of energy from renewables by 2030 and the closure of all investor-owned, utility-owned CO_2-emitting power plants by 2050.

States and Electric Utility Service Territories with 100% Clean Energy Commitments



States and D.C.
Utilities
IRPs Evaluated

Sources: EIA; SEPA; Center for American Progress; Sierra Club; ScottMadden analysis; S&P Global

Future CO_2 Emission Reductions Driven by Massive Deployment of Renewable Energy and Energy Storage

- While the accompanying tables provide an overview of each IRP, several trends emerge across the planning documents.
- A clear focus across all the reviewed IRPs is the intent to significantly expand renewable energy and battery storage capacity.
  - Most capacity additions are planned in later years, based upon the assumed continued decline in the cost of renewables and battery storage.
  - IRPs that evaluated multiple carbon reduction portfolios (i.e., modest reductions versus rapid decarbonization) showed similar near-term actions, indicating renewables and storage are the key next step in the 100% clean energy journey for these utilities.
- The renewable energy and storage build-outs will cost electric customers more than new natural gas-fired generation, but in most cases, the cost increases are lower than the rate of inflation.
  - Natural gas generation is the predominant addition in IRPs that provide a traditional least-cost scenario (i.e., APS, Dominion Energy, and Duke Energy).
  - In these instances, renewable energy and battery storage scenarios show greater carbon reductions, but they produce a cost premium compared to least-cost scenarios dominated by natural gas.
  - In many cases, the cost increases associated with the carbon reduction scenarios are forecast to be below the rate of inflation (projected by the utilities) over the planning periods (typically 10 to 15 years). For example:
    - Xcel Energy notes that its preferred scenario achieves its carbon goals for a nominal customer cost increase of 1.1% per year over the planning period—significantly lower than its inflation assumption of 2.4%.
    - APS reports the average annual increases in generation and transmission system costs are 1.3% and 1.7% in two of the three CO_2 reduction scenarios—notably less than its inflation assumption of 2.5%.
    - Duke Energy finds its base case with carbon policy results in residential bills incurring an average annual increase of 1.5% through 2035; an inflation assumption is not provided in the IRP.
- With the exception of scenarios that intentionally eliminate natural gas generation, all IRP scenarios use it to ensure power grid reliability. Some utilities expect to keep natural gas capacity relatively constant (e.g., Xcel Energy), while others expect to add incremental natural gas capacity (e.g., Duke Energy), during the IRP planning periods.
- The IRPs show a clear trade-off between affordability and more aggressive carbon reductions.
  - Scenarios with deep carbon reductions require greater renewable energy and battery storage capacities or technologies that are not available or cost effective today (i.e., long-duration storage or small modular nuclear).
  - Faster-than-expected technology declines could mitigate the cost of deeper carbon reductions. Conversely, the failure to cost-effectively deploy emerging technologies could make aggressive carbon reductions more costly for electric customers.
- All of the IRPs examined depend on existing nuclear capacity. The planning outlooks anticipate nuclear energy will remain an important source of non-carbon-emitting electricity, spurring many of the companies to seek nuclear license extensions.

Northern States Power Company (Xcel Energy Inc.)

IRP Details

Report Title

- Upper Midwest Integrated Resource Plan

Date Filed

- July 1, 2019

Study Period

- Covers 2020 to 2034

Portfolio Analyzed

- Evaluated 15 "baseload study scenarios" to develop, select, and refine a preferred plan

Clean Energy Goals

Current State

- Reduced carbon emissions 38% company wide from 2005 levels

Interim Goal

- Reduce carbon emissions company wide by 80% from 2005 levels by 2030

End Goal

- 100% carbon-free electricity by 2050

Resource Mix

Preferred Plan

- **Coal:** Retire last coal plant by 2030
- **Nuclear:** Extend the license of Monticello nuclear plant to 2040 and continue to operate Prairie Island nuclear plant
- **Renewables:** Add 4,000 MW of utility-scale solar and 1,400 MW of wind
- **Natural Gas:** Acquire 760 MW at Mankato Energy Center (MEC) and build an additional 800 MW in mid-2020s
- **Load-Supporting Resources:** 1,700 MW addition of firm, dispatchable load-supporting resources (utility-scale storage expected to be an integral resource)
- **Energy efficiency:** Annual average savings of more than 780 GWh
- **Demand response:** 1,500 MW of incremental demand response

Notable Observations

Generation Transition

- Significant resource additions do not occur until 2025, allowing the company to respond to changing customer needs and regulatory policies.
- Coal retirements represent approximately a quarter of current total capacity.
- Natural gas on the system remains largely unchanged as MEC is an existing resource through power purchase agreements and the new plant replaces retiring units elsewhere.

Ensuring Reliability

- Reliability planning is centered on meeting a 6,400-MW winter peak-load obligation with sufficient firm, dispatchable resources.
- Core tenets to meeting reliability include nuclear resources, combined-cycle natural gas plants, and firm, dispatchable load-supporting resources deployed in the latter part of plan.
- When renewables are abundant, Xcel Energy can confidentially operate at 60% renewable penetration, but the company is cautious about going much beyond this point at this time.

Bill Impacts

- Preferred plan is expected to keep annual bill increases at or below the rate of inflation.
- Modest cost increases are possible due to the strategy of making use of existing assets and deferring resource additions until later in the plan.

Long-Term Outlook

- "The last stretch of total carbon reduction—from 80 to 100 percent—will require technologies that have not yet been developed or deployed economically."

Virginia Electric and Power Company (Dominion Energy, Inc.)

IRP Details

Report Title

- Virginia Electric and Power Company's Report of Its Integrated Resource Plan

Date Filed

- May 1, 2020

Study Period

- Covers 2021 to 2035

Portfolio Analyzed

- Four portfolios called Plan A, Plan B, Plan C, and Plan D
- Plan A represents a traditional least-cost scenario but does not represent a realistic state of Virginia laws

Clean Energy Goals

Current State

- Reduced CO_2 emissions from power generation serving VA customers by 38% from 2000 to 2019

End Goal

- Net-zero CO_2 and methane emissions by 2050 (across electric and natural gas operations)

Resource Mix

Plan B

- **Coal:** Retirement of more than 1,400 MW of existing coal
- **Solar:** Add nearly 16,000 MW (1,000 MW of which is "distributed solar" defined as less than 3 MW)
- **Offshore Wind:** Add more than 5,000 MW of offshore wind which the Virginia Clean Energy Act (VCEA) finds in the public interest if certain cost and development timelines are met
- **Storage:** Add 2,714 MW of energy storage which the VCEA found to be in the public interest if development timelines are met
- **Natural Gas:** Add 970 MW of gas-fired combustion turbines
- **Nuclear:** Extending licenses for Surry and North Anna nuclear plants

Notable Observations

State Requirements

- Signed into law in April 2020, the VCEA requires 100% clean energy from the company's generation fleet by 2045.
- The law requires closure of Chesterfield Units 5 and 6—totaling more than 1,000 MW of coal capacity—by 2024 and all CO_2-emitting units by 2045.
- VCEA also directs the development of 5,200 MW of offshore wind, 16,100 MW of onshore renewables, and 2,700 MW of energy storage by 2035.

Ensuring Reliability

- Natural gas combustion turbines serve as a "placeholder" to address potential reliability issues from growing renewable energy and coal retirements.
- The company notes additional analysis is needed to understand reliability impacts from retiring traditional generation and potential transmission and distribution needs.

Bill Impacts

- Customer bills are expected to increase 2.9% on a compound annual basis through 2030 using year-end 2019 bill as a baseline.

Long-Term Outlook

- Long-term goals "will require supportive legislative and regulatory policies, technological advancements [such as large-scale storage, hydrogen, or advanced nuclear], grid modernization, and broader investments across the economy."
- Achieving net-zero emissions may require balancing CO_2 emissions with carbon capture and sequestration, reforestation, or negative-emissions technologies such as renewable natural gas.

Arizona Public Service Company

IRP Details

Report Title
- 2020 Integrated Resource Plan

Date Filed
- June 26, 2020

Study Period
- Covers 2020 to 2035

Portfolio Analyzed
- Analyzed three portfolios: Bridge, Shift, and Accelerate
- Technology Agnostic Portfolio (which did not restrict natural gas) included for cost reference

Clean Energy Goals

Current State
- Reduced CO_2 emissions by 26% from 2005 to 2019

Interim Goal
- Provide 65% clean energy (i.e., non-CO_2 energy sources) by 2030
- Provide 45% renewable energy by 2030
- End coal generation by 2031

End Goal
- Provide 100% clean, carbon-free electricity by 2050

Resource Mix

Bridge Portfolio
- **Coal:** Retire all coal by 2031
- **Renewable Energy:** Add 6,450 MW of utility-scale wind and solar
- **Storage:** Add 4,850 MW of energy storage
- **Natural Gas:** Add 1,859 MW of merchant PPA or hydrogen ready combustion turbines
- **Distributed Energy:** Add 1,585 MW of rooftop solar
- **DSM:** Add 1,602 MW of demand-reducing resources
- **Demand Response:** Add 693 MW of demand response
- **Nuclear:** Keep Palo Verde nuclear plant as an important source of non-carbon generation

Notable Observations

Generation Transition
- Energy storage will be used to meet peak summer demand and provide the "backbone" replacement capacity and energy as the company looks to exit coal.
- The company notes storage at scale has not yet been demonstrated, but it is likely feasible and reasonable to reflect in the IRPs.
- Demand-side management will be used to shift customer's consumption into the midday peak solar hours and reduce the use during peak demand hours.
- Renewable energy additions will include wind and solar, with exact capacities determined through an all-source RFP procurement process.
- APS is also working with California ISO (CAISO) in the design of a new Extended Day-Ahead Market that takes advantage of the existing CAISO and Energy Imbalance Market.

Ensuring Reliability
- Natural gas is a source of reliable-system capacity that will allow the fleet to transition while "maintaining a reliable safety net" should new resource projects be delayed.
- Natural gas will also help the company negotiate the best possible prices for new resources by providing flexibility in capacity timing.

Bill Impacts
- In its Bridge Portfolio, annual costs for generation and incremental transmission (which does not include all components of customer rates) grow at 1.3% per year, "well below" APS's assumed rate of inflation.

Long-Term Outlook
- Long-term generation resources to be considered include small modular nuclear, advanced forms of long-duration energy storage, hydrogen, and carbon capture and sequestration.

Duke Energy Carolinas and Duke Energy Progress

IRP Details

Report Title

- Duke Energy Carolinas (DEC) Integrated Resource Plan 2020
- Duke Energy Progress (DEP) Integrated Resource Plan 2020

Date Filed

- September 1, 2020

Study Period

- Covers 2021 to 2035

Portfolio Analyzed

- Base case without carbon policy (i.e., least-cost portfolio) plus five alternatives reflecting a range of potential future resource scenarios

Clean Energy Goals

Current State

- DEC: Reduced CO_2 emissions by 36% since 2005
- DEP: Reduced CO_2 emissions by 41% since 2005

Interim Goal

- Reduce CO_2 emissions by at least 50% from 2005 levels by 2030

End Goal

- Achieve net-zero by 2050

Resource Mix

Combined DEC and DEP: Base Case with Carbon Policy

- **Solar:** Add 8,375 MW of utility-scale solar
- **Wind:** Add 750 MW of onshore wind
- **Storage:** Add 2,200 MW of battery storage
- **Natural Gas:** Add 7,350 MW of incremental capacity
- **EE and DR:** Total contribution of 2,035 MW by 2035
- **Coal:** Retire all units that operate exclusively on coal by 2030
- **Nuclear:** Renew licenses for 11 units at six plants in the Carolinas

Notable Observations

Generation Transition

- Base case with carbon policy assumes a price on carbon emissions from power generation, with pricing in line with current and past policy proposals, to incentivize lower carbon resource selection.
- Partnered with National Renewable Energy Laboratory on an integration study, finding the value of solar without storage suffers diminishing returns, especially for scenarios with solar penetrations at or above 20% on an annual basis.
- IRP analysis allowed the selection of onshore wind located in central Carolinas because of lower-transmission costs, in addition to the traditional coastal regions that have better wind resources.
- All portfolios examined keep Duke Energy on a trajectory to meet its interim and long-term carbon goals.
- Developing an integrated system and operations planning framework that will optimize capacity and energy resource investments across generation, transmission, distribution, and customer solutions.

Ensuring Reliability

- Winter peak is expected to grow 1,650 MW for DEC (equaling an annual growth rate of 0.6% per year) and 1,850 MW for DEP (equaling an annual growth rate of 0.9% per year).
- Reducing carbon emissions by 70% in 2035 would require “unprecedented levels of storage… given that there is no utility experience for winter-peaking utilities in the United States or abroad with operation protocols to manage this scale of dependence on short-term energy storage.”

Bill Impacts

- In its base case with carbon policy portfolio, residential bills increase an annual average of 1.5%; however, figures do not reflect efficiencies or costs elsewhere in the business.
- By comparison, the earliest practicable coal retirement portfolio produces only slight improvements to carbon reductions (64% reduction vs. 62% reduction) and bill impacts (1.4% annual increase vs. 1.5% annual increase) by building additional incremental natural gas.

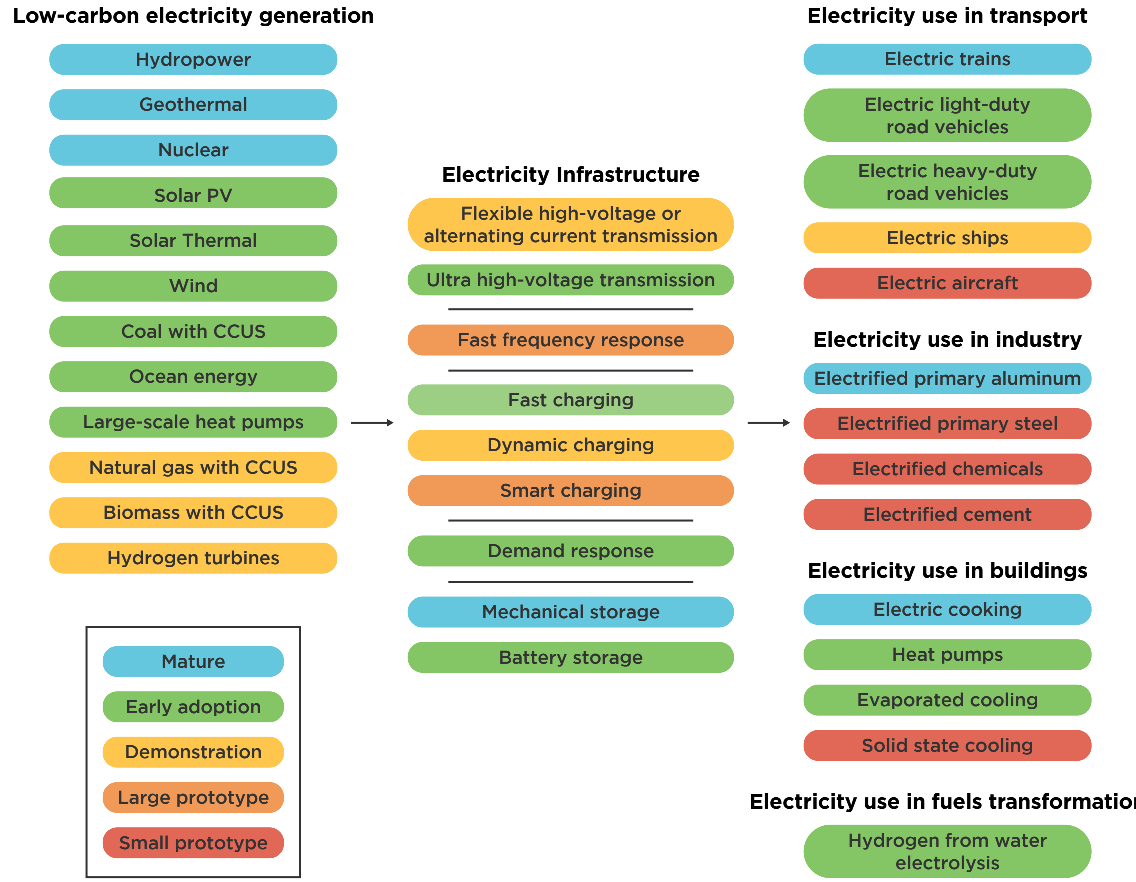
Long-Term Outlook

- “Public policies and the advancement of new, innovative technologies will ultimately shape the pace of the ongoing energy transformation.”

Net-Zero's Global Technology Challenge

- The infrastructure challenge of achieving net-zero emissions targets is globally recognized. As the International Energy Agency (IEA) has said: "Reaching net-zero emissions by 2050 would require rolling out clean energy technologies and enabling infrastructure at unprecedented scale."
- Moreover, while electricity is a big target for a long-term transition to a 100% clean energy goal, other sectors, including passenger vehicles, transportation (airplanes, ships, trucks, buses, etc.), industrial processes, and building end-use, will also need to reduce emissions to meet ambitious emissions goals.
- Technology development will be critical. Indeed, some technologies the industry discussed 15 years ago—such as hydrogen; carbon capture, utilization, and storage; and bioenergy—are getting another look.
- The chart at right shows IEA's view of technology maturity, illustrating the challenge ahead in the electricity sector.

Global Technology Readiness Level of Technologies along the Low-Carbon Electricity Value Chain*



Source: IEA

> **"Not all parts of the low-carbon electricity value chain are at commercial scale today; some technologies in end-use sectors and in electricity infrastructure are at demonstration or large prototype stage."**
>
> *–IEA*

Notes: *CCUS = carbon capture, utilization and storage. Each technology is assigned the highest technology readiness level of the underlying technology designs. For more detailed information on individual technology designs for each of these technologies and designs at small prototype stage or below, see: www.iea.org/articles/etp-clean-energy-technology-guide.

IMPLICATIONS

The coming decade will be an important transition period for electric utilities looking to meet 100% clean energy commitments. Companies embarking on this journey expect to significantly expand renewable energy and battery storage capacity. At the same time, natural gas will remain an important resource ensuring reliability. This transition period will also require the development of new cost-effective technologies to ensure continued progress in the following decade. The industry will continue to closely watch these early movers for future successes, challenges, and updated IRPs.

Notes:

Methodology for historical CO_2 reductions based on Energy Information Administration's report: "U.S. Energy-Related Carbon Dioxide Emissions, 2018." ScottMadden expanded the methodology by allocating CO_2 reductions to individual non-carbon technologies (e.g., wind, solar, etc.) and individual states. The non-carbon resource allocation was based on each technology's pro-rata contribution to the change in total non-carbon generation in a 2005 baseline year. If a non-carbon technology generated less than the amount generated in the 2005 baseline year, it would be allocated a negative carbon-reduction value (i.e., carbon emissions increase) via a similar pro-rata method. For state allocation, changes in fossil generation and non-carbon generation reductions were calculated based on a pro-rata translation of the state's contributions to U.S. total emissions reductions.

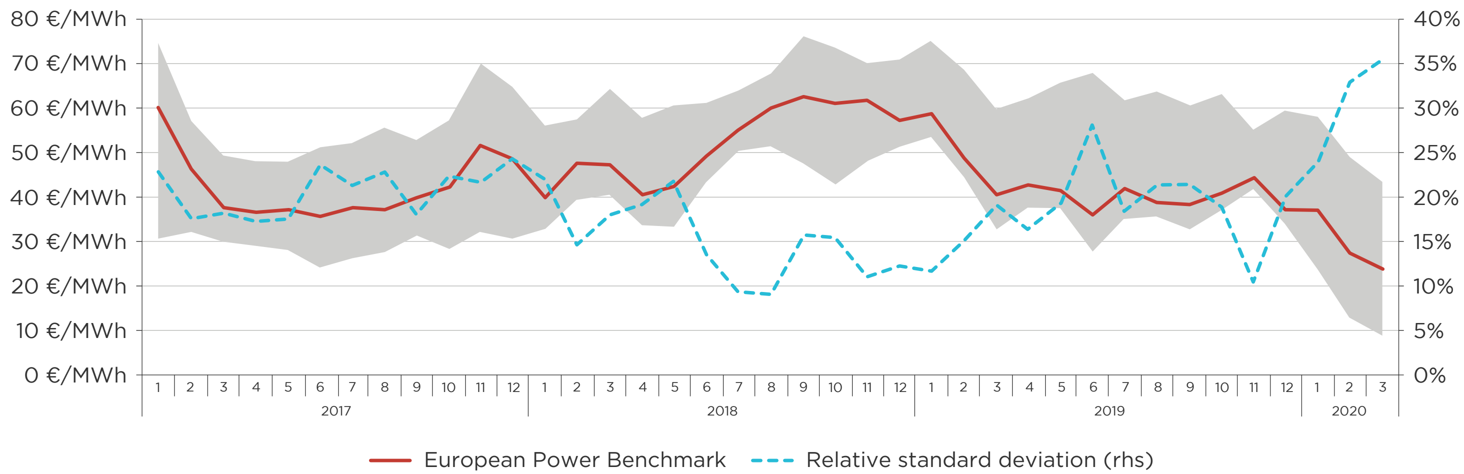
Sources:

Energy Information Administration; company integrated resource plans; Natural Resource Defense Council; International Energy Agency; https://www.greentechmedia.com/articles/read/virginia-100-clean-energy-by-2050-mandate-law; ScottMadden analysis

THE ENERGY INDUSTRY IN CHARTS

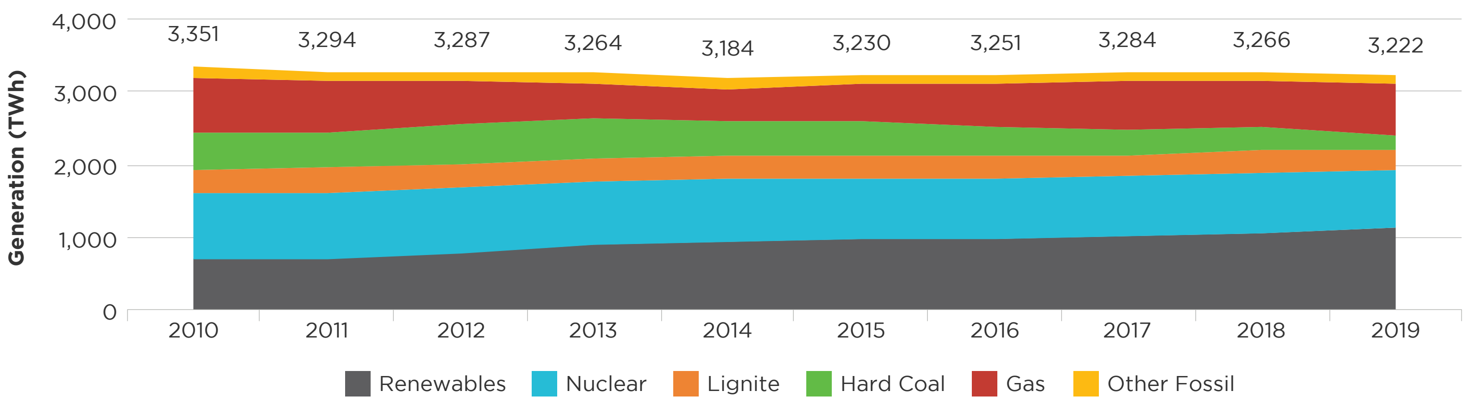
Recent and Long-Term Trends in the EU Power Sector—Wholesale Prices and Fuel Mix

Lowest and Highest Regional Wholesale Electricity Prices in European Day-Ahead Markets (in €/MWh*) and Relative Standard Deviation of Regional Prices (2017–Q1 2020)



Source: European Commission

EU-28** Electricity Generation by Fuel Type and Year (TWh)

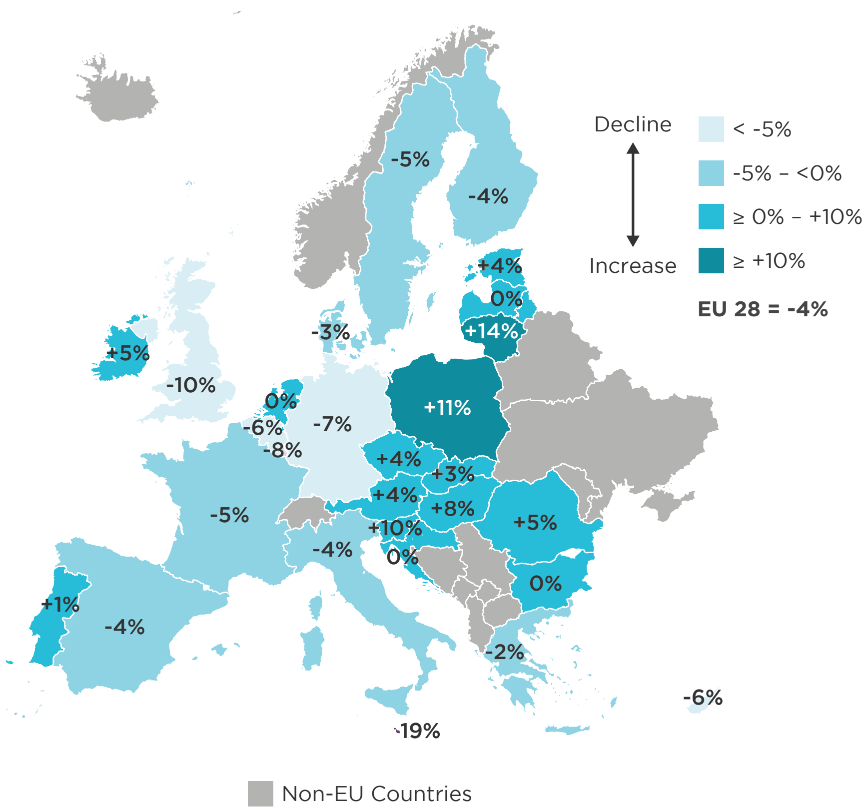


Source: Agora Energiewende & Sandbag

- COVID-19-related demand reduction and wind generation at historically high levels (up 43%) year-over-year led to instances of renewables comprising more than 50% of power production and greater occurrences of negative prices. These lower prices led to lower fossil-fueled power production and even ramping down of nuclear units. In France, nuclear power was the main source of flexibility during Q1 2020.
- This reduced consumption intensified an ongoing trend of lower electric demand in western Europe and Scandinavia.
- Other trends continue, including reduction in emissions, wholesale price volatility, and generally higher household electricity prices.

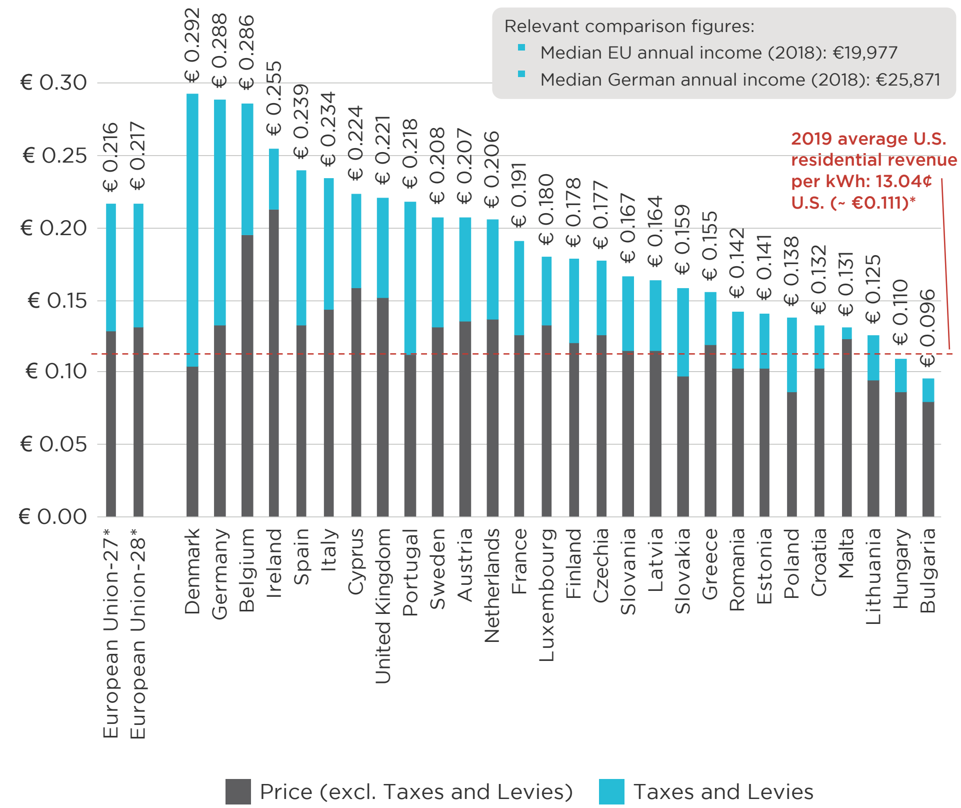
Recent and Long-Term Trends in the EU Power Sector—Consumption and Residential Retail Prices

Change in Electricity Consumption (2010 to 2019)



Source: Agora Energiewende & Sandbag

Average Household Electricity Prices Including All Taxes and Levies (Price Per kWh) in 2nd Half of 2019

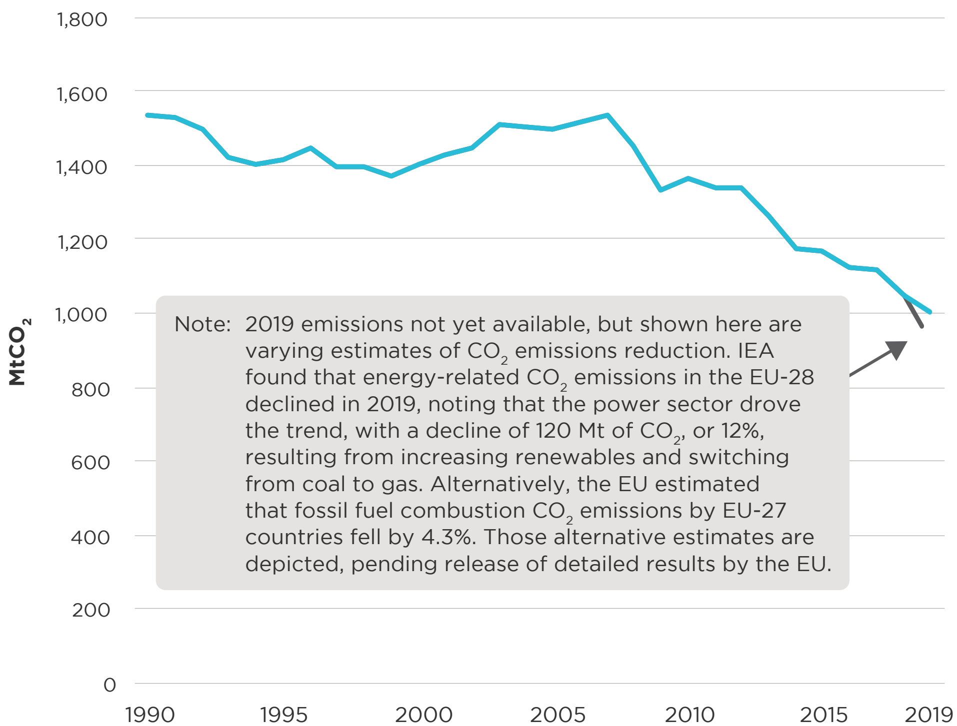


Sources: Eurostat; EEI

- EU regulators have mused that combined effects of COVID-19-related demand reduction and higher amounts of renewable generations "could be seen as a precursor of things to come and an opportune moment to evaluate and plan for a future that might not be as distant as previously thought."

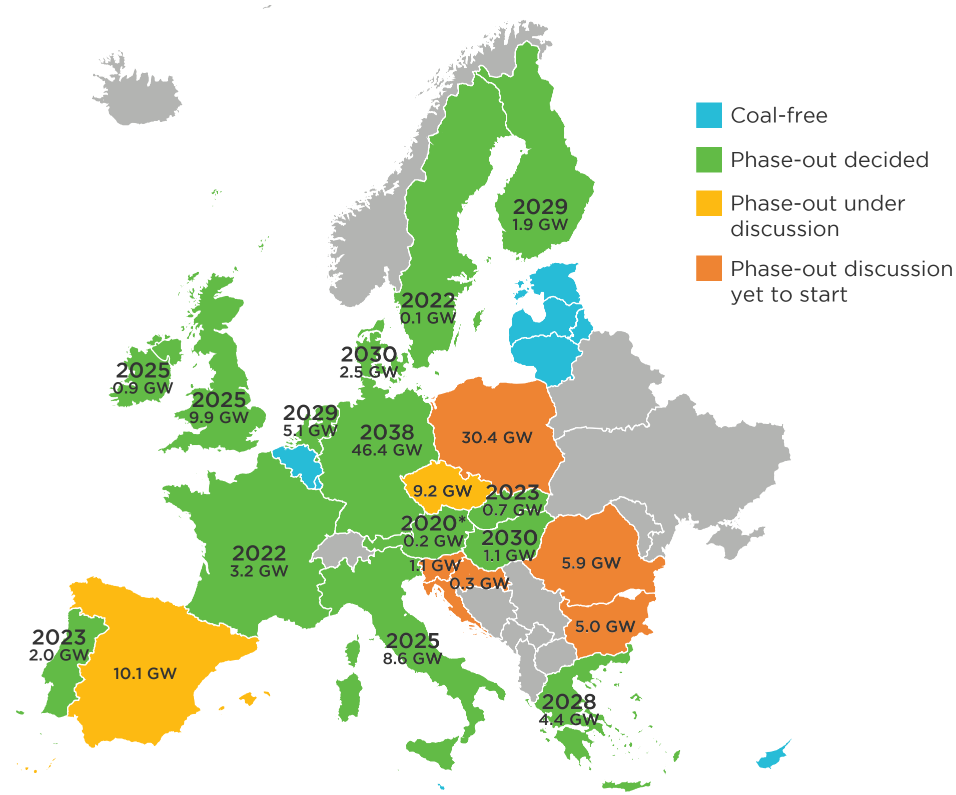
Recent and Long-Term Trends in the EU Power Sector—CO_2 Emissions and Coal Power Plant Retirements

European Union-28* CO_2 Emissions from Fuel Combustion by Electricity and Heat Producers (1990–2019 Est.) (in Millions of Metric Tons)



Source: Agora Energiewende & Sandbag

Coal Phase-Out Dates and Remaining Coal Capacity (GW)



Source: Agora Energiewende & Sandbag

Notes: *The European Union (EU) currently counts 27 EU countries. The EU 28 includes the United Kingdom, which withdrew from the EU on Jan. 31, 2020. EU countries include Austria, Belgium, Bulgaria, Croatia, Italy, Cyprus, Czechia, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, and Sweden.

**For reference, €1 = U.S. $1.17 as of Sept. 29, 2020 (per xe.com).

Sources: European Commission, Quarterly Report on European Electricity Markets: Market Observatory for Energy, Q1 2020 (July 2020); Agora Energiewende and Sandbag, The European Power Sector in 2019: Up-to-Date Analysis on the Electricity Transition (February 2020), Figs. 1-2, 2-2, and 5-4; Eurostat New Release, "Energy prices in 2019: Household energy prices in the EU increased compared with 2018" (May 7, 2020); Eurostat, Mean and median income by household type - EU-SILC and ECHP surveys [ILC_DI04] (data last updated Sept. 9, 2020), at https://ec.europa.eu/eurostat/databrowser/view/ILC_DI04/default/table, accessed Sept. 23, 2020; Edison Electric Institute, Statistical Yearbook of the Electric Power Industry (August 2020), at Table 8.9 (Average Revenue per Kilowatthour Sold, by Year & Class of Service, Total Electric Industry 2008-2019); IEA, "Global CO_2 emissions in 2019" (Feb. 11, 2020); EU Eurostat New Release, "In 2019, CO_2 emissions from energy use in the EU estimated to have decreased" (May 6, 2020); IEA data and statistics, at https://www.iea.org/data-and-statistics?country=EU28&fuel=CO2%20emissions&indicator=CO2%20emissions%20by%20sector

GLOSSARY

€
Euro (currency)

A&G
administrative and general

bbl
barrel

Bcf
billion cubic feet

BOEM
U.S. Bureau of Ocean Energy Management

CAISO
California ISO

capex
capital expenditures

CCS
carbon capture and storage

CCUS
carbon capture, utilization, and storage

CNG
compressed natural gas

CO_2
carbon dioxide

DOE
U.S. Department of Energy

DRI
direct reduced iron

DSM
demand-side management

EIA
U.S. Energy Information Administration

EIS
environmental impact statement

ERCOT
Electric Reliability Council of Texas

FERC
Federal Energy Regulatory Commission

gal.
gallon

GW
gigawatt

H_2
hydrogen

IEA
International Energy Agency

IRP
integrated resource plan

IRS
U.S. Internal Revenue Service

ISO
independent system operator

ISO-NE
ISO New England

kg
kilogram

km^2
square kilometers

kW
kilowatt

kWh
kilowatt-hour

LCOE
levelized cost of energy

LMP
locational marginal price

m
meters

MISO
Midcontinent ISO

MMBtu
million British thermal units

Mt
million metric tons

$MtCO_2$
million metric tons CO_2

Mtoe
million metric tons of oil equivalent

MW
megawatt

MWh
megawatt-hour

NERC
North American Electric Reliability Corporation

NH_3
ammonia

NOx
nitrogen oxides

NPCC
Northeast Power Coordinating Council, a reliability reporting region

NRC
U.S. Nuclear Regulatory Commission

NREL
U.S. National Renewable Energy Laboratory

NYISO
New York ISO

OREC
offshore renewable energy credit

PPA
power purchase agreement

PSC
public service commission

PUC
public utilities commission

PV
photovoltaic

RFP
request for proposals

RPS
renewable portfolio standard

RTO
regional transmission organization

SMR
steam methane reforming

SPP
Southwest Power Pool

TWh
terawatt-hour

USD
U.S. dollar

WECC-CA/MX
Western Electricity Coordinating Council, California and Northern Baja Mexico subregion, a reliability reporting region

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Strategy & Services	▪ Integrating ESG Issues into Corporate Strategy ▪ 2019 ScottMadden Corporate Responsibility Report ▪ The Nexus of COVID-19 Recovery and ESG Performance ▪ The Use of Scenario Planning to Develop Workforce Strategies Following COVID-19
Supply Chain	▪ How Can Supply Chains Prepare for the “Next Normal”?
Transmission & Distribution	▪ Atlantic Coast Pipeline Closure and Dominion Energy Divestiture Highlight Impact of Environmental Factors on Utilities

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ENERGY PRACTICE
SCOTTMADDEN KNOWS ENERGY

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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.

Stay Connected

ScottMadden will host a free webcast based on this report on **Thursday, November 19, from 1-2PM EST** to further explore the future of electricity markets, ambitions for hydrogen in the energy system of the future and plans and progress made with net-zero CO_2 emissions. We look forward to sharing our views and fielding questions related to these issues.
If you are unable to attend the live event or would like to replay the session at a later date, the on-demand recording can also be accessed.

Contact Us

Brad Kitchens
President and CEO
sbkitchens@scottmadden.com
919-781-4191

Cristin Lyons
Partner
Energy Practice Leader
cmlyons@scottmadden.com
919-781-4191

Jim Stephens
Partner
Rates & Regulation Practice Leader
jstephens@scottmadden.com
508-202-7918

Greg Litra
Partner
Director of Research
glitra@scottmadden.com
919-781-4191