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MANAGEMENT CONSULTANTS

ENERGY INDUSTRY UPDATE

SAVED BY ZERO?

Volume 21 - Issue 1

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EXECUTIVE SUMMARY
Saved by Zero?

As The Fixx's 1980s hit says, "maybe someday, saved by zero." A growing number of commitments to net-zero targets have been made over the past several years, and federal policy is increasingly supportive. Before being "saved by zero," energy industry stakeholders are now shifting their focus from "whether" to "how" these commitments can be fulfilled. Energy and utility companies are now considering the actions, trade-offs, and complexities that are emerging in moving toward these goals. Those considerations include required effort and cost to achieve net-zero, potential strategies, and potential effects of transition.

Some Highlights of This ScottMadden Energy Industry Update	
Required Effort to Zero	▪ Massachusetts achieved its 2020 emissions-reduction targets. Now the state has created a cross-sector roadmap, outlining several potential pathways to reach its long-term emissions-reduction goals. Electric and gas utilities should look closely at this and other decarbonization roadmaps to understand various alternatives and scrutinize embedded assumptions.
Strategies to Zero	▪ As the power sector has significantly reduced its carbon emissions footprint, the transportation sector remains a meaningful contributor to carbon emissions. Fleet electrification could play an important role in a net-zero strategy. Electric utilities can be a key partner in this transition and should begin planning now. ▪ Transmission development is being recognized as a critical piece of the net-zero transition, linking large-scale renewable resources with demand centers. Many advocates for aggressive clean energy goals are highlighting the complementary roles played by large-scale clean energy development and power transmission expansion.
Potential Effects of Transition to Zero	▪ Recent weather events in California and Texas have exposed planning, process, and resource gaps in power systems. As the net-zero resource mix continues to change with increasing variable and gas-fired resources, resource planners may need to consider greater tail risk in their planning scenarios. ▪ Over the past several months, energy and utility companies have been discussing their 2020 performance and expectations for 2021 and beyond. Emerging themes include a refocus on core utility operations and pursuit of investment opportunities in clean energy.

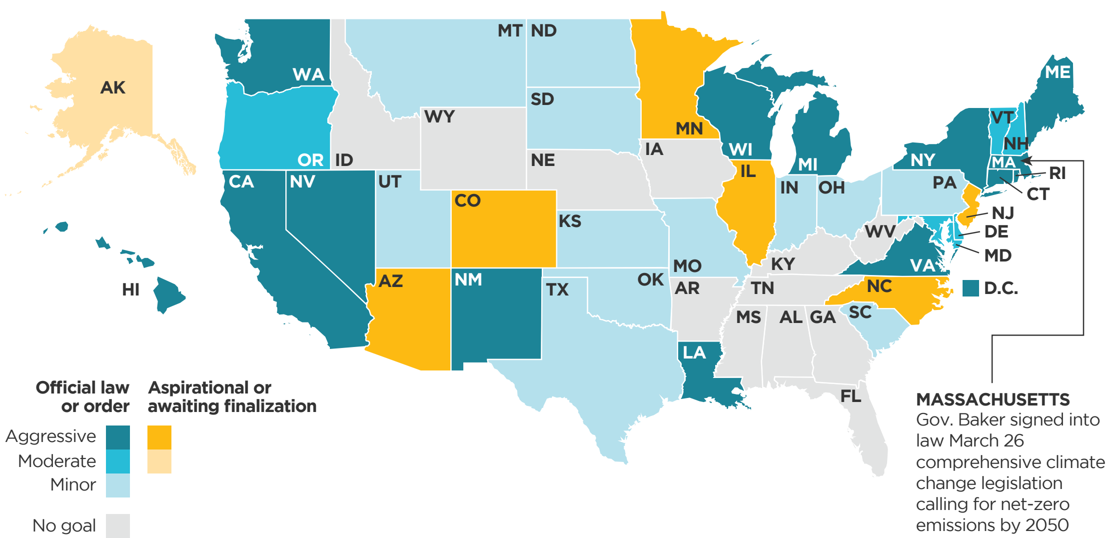
Massachusetts' Decarbonization Roadmap

Massachusetts outlines a comprehensive cross-sector carbon-reduction legislation, as it uses an analytical roadmap to evaluate options.

Decarbonization and Net-Zero Emissions: The Backdrop

- Certain U.S. states, municipalities, and utilities—along with emerging federal policy—press on with aspirations for decarbonization of the energy sector across all fuel types.
- To date, the focus has been on power sector decarbonization. But as a significant number of greenhouse gas (GHG) emissions reductions have been achieved in that sector in certain regions, attention is now turning to other sectors for (largely) energy-related GHG emissions reductions.
- In late 2020, Massachusetts proposed various pathways that would transition the Commonwealth to economy-wide net-zero emissions by 2050. This action follows on the heels of New York's well-publicized Climate Leadership and Community Protection Act enacted in June 2019.

Figure 1.1: **States Clean Energy and GHG Emissions Reduction Goals**



Note: Data as of April, 2021

Source: S&P Global Platts

KEY TAKEAWAYS

Recently, several studies have scoped out approaches to achieve net-zero GHG emissions by 2050. Massachusetts has taken the next step in its emissions-reductions journey, releasing a multi-sector 2050 roadmap for a net-zero emissions state economy.

The Commonwealth is looking to utilities to articulate the ways they are going to meet near-term goals and align plans with its decarbonization roadmap.

The Commonwealth has also issued for comment a policy outline for its 2030 interim target (45% below 1990 levels), consistent with its longer-term goals and approaches.

While these activities are intended to spur action, stakeholders will need to devote more attention to identifying specific actions and impacts, both intended and unintended.

Considering Long-Term Goals: The 2050 Decarbonization Roadmap

- Having achieved meaningful GHG reductions through the Global Warming Solutions Act's first milestone of 2020, the Commonwealth has now shifted focus to 2050. The 2050 Decarbonization Roadmap (the Roadmap), released in December 2020 by the Executive Office of Energy and Environmental Affairs (EEA), is an input in planning Massachusetts' go-forward strategy.
- The Roadmap envisions a net-zero emissions target and an 85% reduction of state GHG emissions from 1990 levels by 2050. Subject to finalization, the EEA asserts that the proposed Roadmap "identifies cost-effective and equitable pathways and strategies" to achieve the 2050 target. Analysis in the Roadmap includes:
  - Integrated, cross-sector energy system analysis exploring eight distinct net-zero emissions reductions "pathways" to 2050.
  - Sector-specific analyses focused on buildings, transportation, non-energy emissions, and the carbon sequestration potential of Massachusetts' natural and working lands, as well as a separate economic and health impact analysis.
- In tandem with the Roadmap, the Commonwealth has pursued aligned and inter-related policy and regulatory activities for the near term.
  - The MA EEA also released in December the interim Clean Energy and Climate Plan for 2030 (2030 CECP), a policy action plan to achieve the 2030 emissions limit while maximizing Massachusetts' ability to achieve net-zero by 2050.
  - Separately, Massachusetts' utility regulator, the Department of Public Utilities (DPU), initiated an inquiry (D.P.U. 20-80) in late October 2020 to examine the role of local gas distribution companies (LDCs) in achieving the 2050 climate goals.
  - Specifically, the DPU will explore strategies to enable transitioning to Massachusetts net-zero while safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs.
  - By early March 2022, an independent consultant's report will be submitted along with LDC-specific strategies to support GHG reductions, with each of these LDC-specific filings subject to a hearing and next steps.

An Introductory Roadmap Lexicon

- The structure of the Roadmap comprises four key elements: pillars, pathways, sectors, and strategies.
  - **Pillars:** Four key complementary "pillars of decarbonization" identified in previous deep decarbonization studies—specifically end-use energy (transitioned away from fossil fuels), energy efficiency and flexibility, energy supply decarbonization, and carbon sequestration.
  - **Pathways:** Different emissions-reduction scenarios/specific technological transitions to achieve net-zero by 2050; also used to evaluate different technological evolutions, advancements, and constraints.
  - **Sectors:** Key parts of the economy for which emissions reductions are targeted, but with a holistic view, recognizing current and future physical and technological interdependencies in such areas as transportation, buildings, energy supply, non-energy, and land use.
  - **Strategies:** Specific areas where actions can be taken to achieve 2050 (and 2030) goals within sectors, including light-duty transportation, residential and commercial buildings, electric and gas system changes, and natural carbon sequestration.
- The Roadmap outlines eight distinct emissions reductions pathways (see Fig. 1.6). Key distinctions between the pathways are the constraints on (or availability of) resource strategies, including efficiency, offshore wind, distributed energy resources, low-carbon piped gas, and thermal power generation.

Figure 1.2: **Selected Massachusetts Decarbonization Policy Activity (2008–2020)**

2008

The **Global Warming Solutions Act (GWSA)** and **Green Communities Act** are signed into law. Masschusetts becomes one of the first states in the nation to formally commit to a regulatory program requiring GHG emissions reductions (at least 25% below 1990 levels in 2020, and at least 80% below 1990 levels in 2050) and to comprehensively reform its energy policy and procurement framework to align with that goal.

2010

Publication of the **Clean Energy and Climate Plan for 2020**. The Commonwealth's first comprehensive climate action plan outlined an integrated portfolio of policies designed to ensure the achievement of the interim 2020 emissions limit.

2016

Governor Baker signs **Executive Order 569** establishing an integrated climate strategy for the Commonwealth and **An Act to Promote Energy Diversity** authorizing large procurements of offshore wind and hydroelectric resources.

2018

Governor Baker signs into law **An Act to Advance Clean Energy**, setting new targets for offshore wind, solar, and storage technologies.

2020

Publication of the **Decarbonization Roadmap to 2050** and the **Clean Energy and Climate Plan for 2030**, outlining the long-term strategies and near-term actions for the Commonwealth to achieve net-zero emissions.

2021

In March, Governor Baker signed comprehensive climate change legislation that codifies the Commonwealth's commitment to achieve **net-zero emissions in 2050**, updating the GWSA. It also authorizes the establishment of an emissions limit of no less than 50% for 2030 and no less than 75% for 2040.

Source: Massachusetts EEA

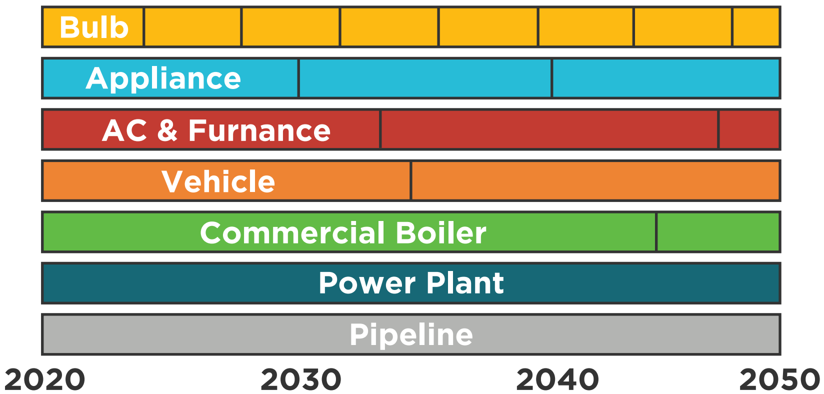
High-Level Findings and Observations of the Massachusetts EEA Roadmap

- The Roadmap looks across sectors with a view toward highest emissions-reduction gains. It dimensions emissions by sector: electricity (19% of GHG emissions), buildings (27%), transportation (42%; light-duty vehicles alone contribute 27%), industrial (5%), and other/non-energy (8%). Some common characteristics of net-zero strategies include the following, consistent with the aforementioned pillars:
  - Widespread electrification of vehicles and space heating/building services
  - A balanced portfolio of clean generation technologies—particularly offshore wind—across a New England regional footprint, as well as land-based and rooftop solar, significant amounts of imported, low-carbon electricity, energy storage, and new high-voltage transmission
  - Overall reduction in energy supply and demand (i.e., increased energy efficiency)
  - Negative emissions natural "sinks" in the form of the Commonwealth's forested land, as well as technologies such as direct air capture

  The report identifies some areas (aviation, marine, and rail, for example) that will be harder to decarbonize, certainly by 2050.

- Key findings of Roadmap investment and benefits include the following:
  - Substantial investment will be required over the coming decades, but the Roadmap assumes that approximately $4.5 billion in health and other benefits will more than offset this cost.
  - The analysis assumes shifting toward local non-emitting energy production will come with local economic benefits.
  - It does note that total required investment can be minimized by transitioning as existing capital stock reaches end-of-service life. However, as turnover points come infrequently (measured in decades) (see Fig. 1.3), the report notes that the pace of transformation "may feel uncomfortably fast."

Figure 1.3: **Assumed Lifetime of Common Energy-Related Infrastructure**



Source: Roadmap

The "All Options" Pathway as a Net-Zero Baseline

- When developing pathways, the Roadmap looks at a reference case (without net-zero targets); an All Options case, which assumes flexibility to employ the most economic decarbonization levers; and alternative cases, which selectively limit or expand those levers to show how technology evolutions or constraints could make the transition easier or more difficult.‡ A description of the cases and key characteristics is shown at Fig. 1.6.
- The All Options pathway is presented as a point of comparison rather than an endorsed pathway and may not be the most economical route. But the All Options pathway is presented by the EEA as a framework for discussion of sector strategies and additional policy engagement as stakeholders, regulators, and policymakers investigate possible actions.

Figure 1.4: **Key Assumptions in the Roadmaps "All Options" Pathway**

Massachusetts behind-the meter solar in 2050	7 GWs
Flexible end-use loads	Medium (load-shedding demand response, but less vehicle-to-grid, flexible space and water heading demand than DER Breakthrough pathway)
Building & industry electrification	High
Energy efficiency	High
Captured CO_2 export	No
Intraregional transmission cost	$5,600/MW-mile within New England; $9,400/MW-mile to Quebec
New gas power plants	None assumed in Massachusetts
New offshore wind power plants	Economic; assumes NREL Annual Technology Baseline "Low" offshore wind technology cost
New nuclear power plants	None assumed
Existing nuclear	Maintain
Use of fossil fuels	Constrained by emissions

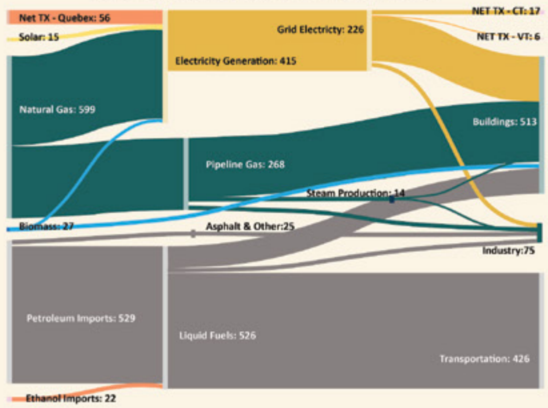
Figure 1.5: **Massachusetts Roadmap "All Options" Pathway Energy Projections for 2050**

Energy Flows* The Roadmap's All Options pathway assumes significant reduction in overall energy consumption by 2050, with a dramatic shift away from fossil fuel sources.

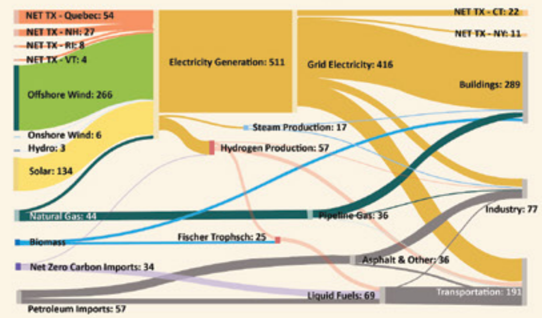
1. The Commonwealth shifts from being primarily powered by fossil fuels in 2020 to renewable resources in 2050. The main sources of energy in 2050 are offshore wind, solar, and electricity transmission imports.

2. The electrification of many end uses in the buildings and transportation sectors results in efficiency improvements and a reduction in overall energy demand. This is exhibited by the lower amount of primary energy sources in the figure with 2050 energy use.

2020 Commonwealth Energy Use (TBtu)



2050 Commonwealth Energy Use (TBtu)



3. Gas use declines significantly from 2020 to 2050 but is still used in 2050 for some electricity generation, building heating, and transportation uses.

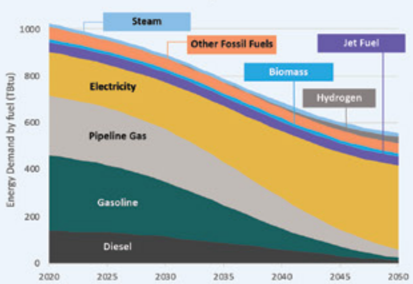
4. Sectoral coupling with flexible industrial loads (like steam and hydrogen production) help to balance the electricity generated by high levels of renewable energy.

Energy Demand and Supply Rapid transformation of the energy system has impacts on energy services and supply.

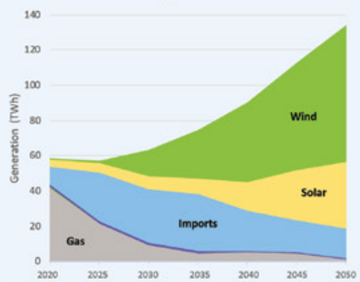
5. Over time, end uses in the buildings and transportation sectors are electrified resulting in efficiency savings and a reduction in overall energy demand.

6. Electrification results in growing demand for electricity. Solar and wind generation increase dramatically from 2025 through 2050.

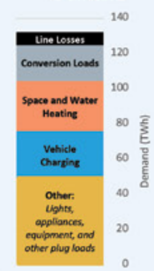
Energy Demand by Fuel



Electricity Generation by Source

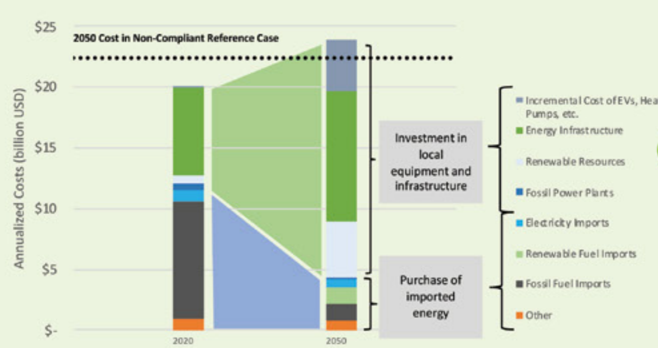


2050 Electricity Demand



Energy Costs Decarbonized energy system costs are not significantly higher than the costs associated with a 2050 fossil-based system.

Annual Statewide Energy System Costs



7. Investment in local equipment and infrastructure increases from 2020 to 2050, allowing decreased operating costs.

8. The purchase of imported energy decreases from 2020 to 2050 due to the replacement of imported fossil fuels with a diverse, largely regional, energy mix.

The Roadmap's All Options pathway (an "all of the above" strategy) projects signficant changes in the amount and type of energy supply and demand, as well as a modest increase in energy costs.

Notes: *The two figures above showing Roadmap energy flows illustrate key changes in energy supply and end use from 2020 to 2050. On the left of each figure are energy sources. The height of a bar indicates the relative quantity of energy used. The right of each figure indicates the energy use sectors like transportation and buildings. The middle of each figure shows energy transformations.

Source: Roadmap

Figure 1.6A: **Summary of Roadmap Pathways**

	Pathway	Key Characteristic	Difference from All Options Pathway	Research Question	Defining Assumptions	Key Finding of Roadmap Analysis
Least Cost	**All Options**	Baseline analysis—model selecting greatest number of economic resources to meet emissions limits using baseline cost assumptions		Under the most likely assumptions, what is the least-cost deployment of energy system technologies that achieves deep decarbonization?	"Benchmark compliant" decarbonization pathway, using midpoint assumptions across most technical parameters	Deep electrification and broad renewable buildout create a reliable energy system only marginally more expensive than today's.
	DER Breakthrough	High deployment of behind-the-meter solar and flexible loads	+10 GWs behind-the-meter solar	What are the impacts of greater deployment of behind-the-meter solar and flexible end uses?	▪ 17 GWs of behind-the-meter solar deployed in MA in 2050, as opposed to 7 GWs ▪ Higher level of flexible end uses, especially vehicle-to-grid	Additional demand flexibility lowers local electricity system upgrade costs; very high rates of rooftop solar reduce—but do not eliminate—the need for ground-mounted solar.
	Regional Coordination/ Expansion	Lower-cost electric transmission + export of captured CO_2	Intraregional transmission: ▪ $2,300/MW-mile within New England ▪ $4,700 (50% more) per MW-mile to Quebec	What can greater access to regional resources contribute as part of decarbonization?	▪ Lower transmission costs ▪ Captured carbon exports allowed for geological sequestration outside New England	Additional transmission increases access to, and the ability to share, additional low-cost clean energy resources across the Northeast, lowering overall costs.
	OSW Constrained	Region constrained to 30 GWs of offshore wind (near-shore siting difficult; high price; approvals delayed; etc.)	30 GWs Northeast cap, with mid (vs. low) technology costs; new nuclear is economical	What are the consequences of limited development in offshore wind?	Northeast offshore wind capacity is capped regionally at 30 GWs.	Clean resources, including new nuclear power, must be built to serve MA. Costs increased modestly.

Source: Roadmap

Figure 1.6B: **Summary of Roadmap Pathways (Cont.)**

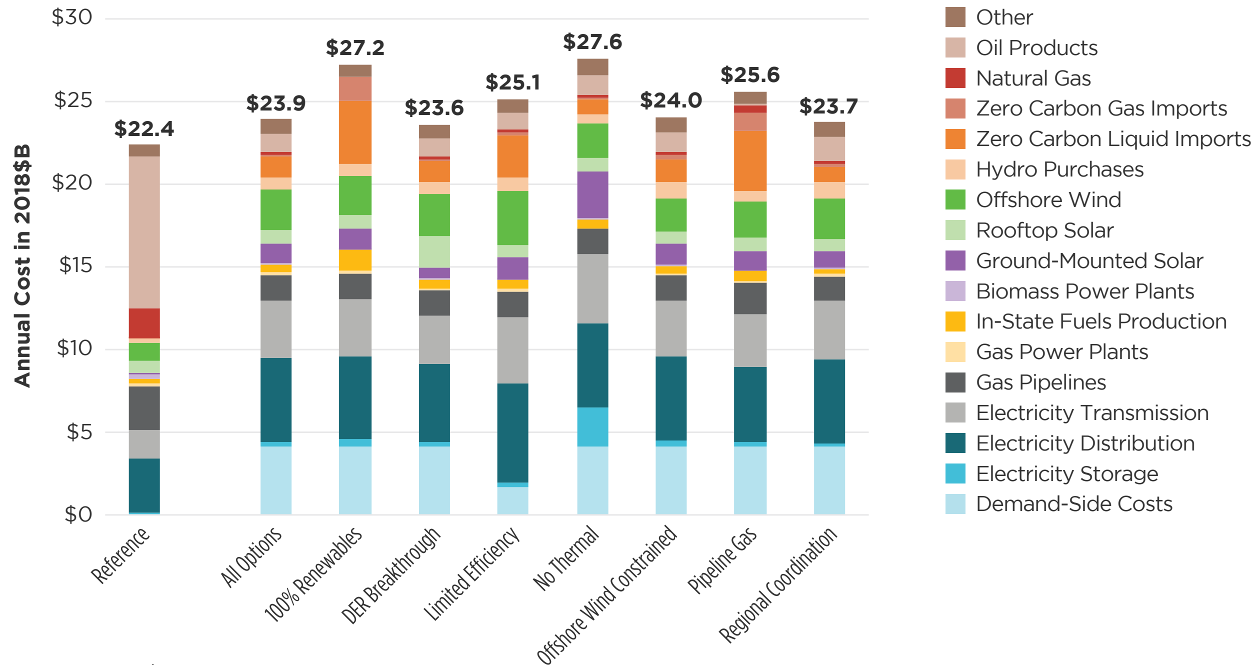
	Pathway	Key Characteristic	Difference from All Options Pathway	Research Question	Defining Assumptions	Key Finding of Roadmap Analysis
	Pipeline Gas	Low electrification of pipeline gas uses in buildings and industry	Low electrification of pipeline gas applications	What are the impacts of continued reliance on natural gas in buildings? What role can a decarbonized gas product play in a net-zero MA?	Building electrification is mostly limited to conversion from oil in the near term, with slower rates of gas-to-heat pump conversion in the long term.	Requires a substantial increase in imported low-carbon fuels, possibly above technically feasible quantities. Most of this fuel goes to high-value sectors to compensate for continued emissions from buildings using a fossil/clean fuel blend.
	Limited Energy Efficiency	Envelope efficiency gains remain at current levels	No efficiency gains across buildings, industry, and transportation	What are the energy, resource, and transmission and distribution needs that arise from deferring investments in efficiency?	Efficiency gains are reduced to about one-third of those achieved in the All Options pathway in buildings and aviation.	Limiting efficiency gains results in a higher demand for zero-carbon electricity and fuel resources. Costs increase significantly.
Highest Cost	**100% Renewable**	Fossil fuels fully replaced throughout economy with carbon neutral fuel; nuclear retired	All nuclear retired; no fossil fuels in 2050	What does a 100% renewable energy strategy across electricity and all fuels require in terms of resources, storage, and costs?	No fossil fuels allowed; zero-carbon combustion fuels allowed for electricity generation by thermal power plants.	Reliance on zero-carbon fuels needed for grid balancing and end uses leads to dramatically higher costs in 2050; demand may exceed feasible supply. It would likely require technological breakthroughs, yet to be identified, to meet resource constraints and contain costs.
Highest Cost	**No Thermal**	Forced retirement of all gas and oil electricity generation	New gas plants disallowed everywhere	What resources will be needed if thermal generation is not available to provide reliability services?	All thermal capacity retired by 2050.	Substantially higher reliance on solar power, particularly ground-mounted, and new, long-duration utility-scale energy storage to provide grid balancing, leading to dramatically higher costs.

Source: Roadmap

Early Analysis of Massachusetts Roadmap Costs

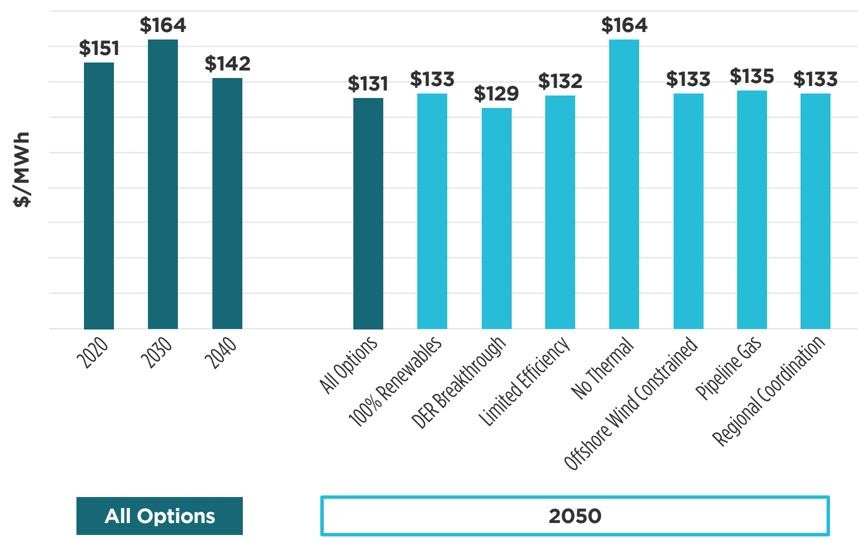
- As momentum toward decarbonization activities gathers in Massachusetts and elsewhere, utilities, regulators, and other stakeholders are increasingly considering the cost of developing or converting significant amounts of infrastructure to alternative energy sources.
- The Roadmap does not discuss costs except at a societal level and compared with projected health benefits. But the Roadmap technical report does identify costs in three ways:
  - **Gross cost:** Annual spending on energy, particularly comparing the reference case (no decarbonization) on fuels and capital versus a shift to new capital equipment (see Fig. 1.7)
  - **Net cost:** Compares annual costs for other pathways versus the All Options baseline scenario (not versus a no decarbonization alternative). The Roadmap's modeled diversion in costs between pathways tend to occur in the latter part (2040+) of the forecast period.
  - **Electric and gas rates:** Estimates a societal electricity rate, assuming greater electric volumetric demand and decreased gas volumes over time after an early period of significant capital investment (see Fig. 1.8). The rates it uses do not account for market-clearing prices and are averages of all customer classes.

Figure 1.7: **Gross Energy System Cost: No Decarbonization vs. All Options (Annual $ Billions)**



Source: Roadmap

Figure 1.8: **Roadmap Estimated Average Societal Electricity Rate Among Pathways ($/MWh)**



Roadmap estimated costs are highly assumptions dependent.

Source: Roadmap

Getting a Handle on Transition Cost: More Work Ahead

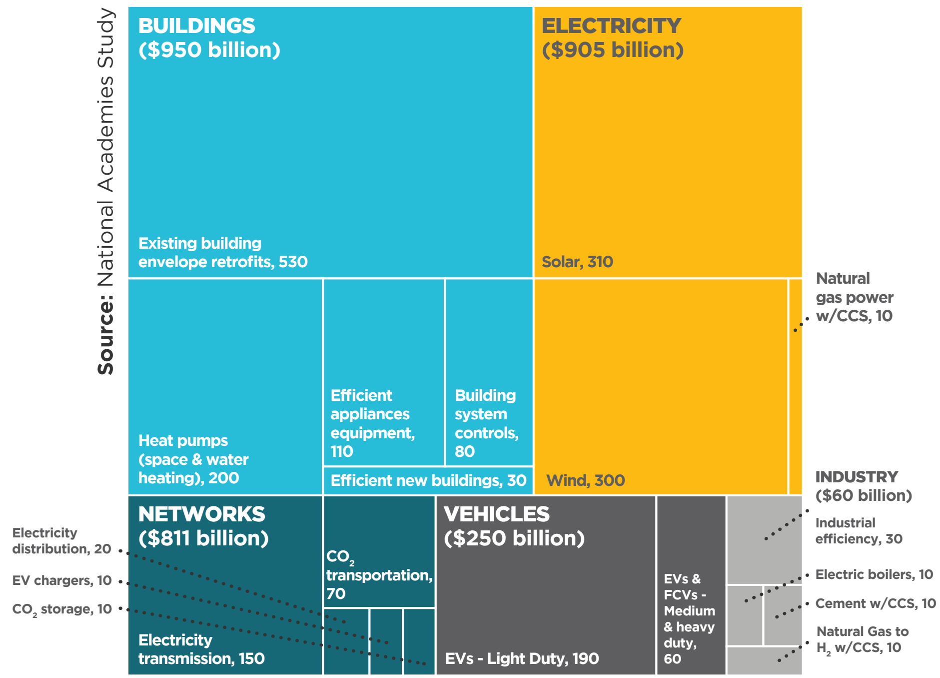
- The Roadmap report, as with other scenario analyses, raises questions about ultimate cost and affordability for customers.
- Several other recent studies have identified "deep decarbonization" pathways, some of which use the same EnergyPATHWAYS model used in the Roadmap. All contemplate significant capital investment, particularly in the next 10 years.
- A report by the National Academies of Sciences, Engineering, and Medicine, summarizing existing literature on U.S. net-zero pathways, estimates incremental capital investments of $2 trillion over the next decade, and $4 trillion to $6 trillion through 2050 beyond a $22.4 trillion "business-as-usual" baseline. Demand-side investment would comprise about 60% of the investment through 2030.

Figure 1.9 shows how near-term net-zero investment might be allocated. Near-term investment would be for five key actions:

- Improve efficiency and energy productivity
- Electrify energy services in the buildings, transportation, and industrial sectors
- Decarbonize electricity
- Build critical infrastructure
- Innovate to "complete the low-carbon toolkit"

- While higher than business as usual, the studies characterize the incremental cost as modest when compared with overall gross domestic product, typically about a percentage higher. Importantly, costs and trade-offs are based upon assumptions over a long-term horizon—for example, energy productivity gains, cost of existing and new technologies, and energy commodity prices. Those assumptions can drive significantly different visions of the energy system future state (see Fig. 1.10).

Figure 1.9: **Indicative 2021-2030 Capital Investment (National) for a Net-Zero Path (from Recent Studies) ($ Billions)**



Notes: Illustration as depicted in original report. Blocks are not to dollar scale. Totals indicated not fully represented by sector blocks.

Figure 1.10: **A Comparison of Indicators from Three Recent Decarbonization Studies**

		2030			2050		
Key Metric	**2015**	**EI**	**DDPP**	**NZA**	**EI**	**DDPP**	**NZA**
Final Annual Energy Demand (quads)	97	129	80	64–67	125	65	50–56
Percent Non-emitting electricity	18	60	55	62–77	100	85	98–100
Electricity share of final energy demand (percent)	28	44	32	21–25	73	60	38–51
Building energy demand (quads/yr)	18	17	16.4	18–19	11	13	13–15
EV share of light-duty vehicle stock (percent)	1	47	44	6–17	100	100	61–96

Source: National Academies Study (see Sources for this section for report acronym references)

Getting Myopic: Pursuing Decarbonization in the Next Decade

- As noted earlier, Massachusetts has other near-term activities focused on decarbonization. Its 2030 CECP, released for public comment, attempts to identify policy measures to move Massachusetts to its 2030 goal of 45% emissions reductions from 1990.
- The 2030 CECP proposes a suite of strategies that will yield reductions across sectors, with the potential reductions noted in Figure 1.11. Policy actions are focused on transportation, buildings, and energy supply, with modest activity in industrial and non-energy sectors and in land use. The EEA's proposed metrics and tools for emissions-reductions actions are more fully described in Figure 1.12.
- EEA notes that uncertainties for the 2030 policy are equipment stock lifespans and the potential for their replacement before the end of useful life and technology readiness.

Figure 1.11: **2030 CECP Targeted Emissions Reductions by Sector**

Sector	Gross GHG Emissions ($MtCO_2e$)			GHG Reductions in 2030 (from 2017)
	1990	2017	2030	
Transportation	30.5	30.5	22.5–22.7	7.8–8.1
Buildings	23.8	19.7	10.3	9.4
Electricity	28.1	13.6	8.5–9.4	4.2–5.1
Industrial & Non-Energy	12.0	9.2	7.8–9.7	(0.5)*–1.4
Total	94.5	73.0	49.1–52.1	20.9–23.9
% Reduction From 1990	-	23%	45%–48%	

*Negative reduction indicates an increase – this reflects partial mitigation of emissions growth

Source: 2030 CECP

Figure 1.12: **2030 CECP Reduction Strategies for Key Sectors**

Transportation	Buildings	Electricity
▪ \$130M for clean transportation systems ▪ 750,000 zero-emission vehicles (ZEV) on the road ▪ Rates and programs to allow for electric vehicle participation in electric markets ▪ ~20% reduction in carbon intensity of diesel fuel ▪ Pilot medium-duty/heavy-duty ZEV programs ▪ Stabilize vehicle-miles traveled, even with larger fleet	▪ Electric space heating in one million households and 300M-400M square ft. of commercial real estate ▪ ~20% reduction in fuel oil carbon intensity ▪ 5% reduction in pipeline natural gas carbon intensity ▪ Deep energy retrofit in 20% of building stock ▪ Passive, high-performance building envelope efficiency in new construction	▪ 7 GWs of clean energy projects, including 3.2 GWs solar, 3.2 GWs offshore wind, and 1 GW transmission to Quebec ▪ 2 $MtCO_2e$ limit on emissions from imported electricity ▪ Distribution-level grid upgrades
7.8–8.1 $MtCO_2e$ reduction	**9.4 $MtCO_2e$ reduction**	**4.2–5.1 $MtCO_2e$ reduction**

Source: 2030 CECP

Taking a Closer Look at Natural Gas Utility Implications

- The 2030 CECP acknowledges that it has not evaluated the cost of specific policies, but rather estimated them generally for suites of policies through the Roadmap.
- One area of particular focus for 2030 is thermal electrification in buildings, which has a direct and potentially significant impact on the natural gas industry. It is unclear, however, what this specific transition policy will cost and how those costs will be socialized.
- D.P.U. 20-80 is intended to address the implications of the Roadmap for natural gas utilities in the Commonwealth across proposed carbon-reduction pathways. Actions required under the proceeding include:
  - Quantify the costs and actual economy-wide emissions reductions in "transitioning the natural gas system"
  - Discuss potential mechanisms for cost recovery or responsibility for cost incurrence, as well as potential mitigation
  - Quantify electrification strategies, including key assumptions and GHG emissions-reduction calculations (including for power generation)
  - Discuss qualitative factors to consider, including public safety, reliability, economic development, equity, emissions reductions, and timing
  - Recommend specific initiatives, actions, and milestones to reduce GHGs from gas sale and distribution
- D.P.U. 20-80 will take some of the high-level analysis performed for the Roadmap and narrow the lens on gas utilities.

North Carolina: Different State, Different Regime, Different Approach

- In North Carolina, Governor Roy Cooper has relied on an executive order and stakeholder groups to shape and influence climate and energy policy.
- In October 2018, the governor signed Executive Order 80, which directed the state to address climate change and transition to a clean energy economy. In the near-term, the executive order set the following goals for the state by 2025:
  - Reduce statewide GHG emissions to 40% below 2005 levels.
  - Increase registered zero-emission vehicles (ZEV) to at least 80,000.
  - Reduce energy consumption per square foot in state-owned buildings by at least 40% from fiscal year 2002-2003 levels.
- The executive order also laid the foundation for more robust action by directing state agencies to develop longer-term targets and plans. With nearly 70% of GHG emissions coming from the electric power sector and transportation, notable directives included:
  - NC Department of Transportation to develop a NC ZEV Plan designed to increase the number of ZEVs to at least 80,000 by 2025, establish interstate and intrastate ZEV corridors, and increase installation of ZEV infrastructure.
  - NC Department of Administration to develop a NC Motor Fleet ZEV Plan that identifies the types of trips for which a ZEV is feasible, recommend infrastructure, and develop procurement options and strategies.
  - NC Department of Environmental Quality to develop a NC Clean Energy Plan that "fosters and encourages the utilization of clean energy resources...and development of a modern and resilient grid."
- Additional directives within the executive order tasked state agencies to produce the following additional reports: a climate risk assessment and resiliency plan; a GHG inventory; clean energy and clean transportation workforce assessments; and a comprehensive energy, water, and utility conservation program in state buildings.

Figure 1.13: **Selected Climate-Related Activities in North Carolina**

2018

- **October 2018:** Governor Roy Cooper signs Executive Order 80.

2019

- **September 2019:** DOA releases Motor Fleet ZEV Plan.
- **September 2019:** Duke Energy announces goal of achieving net-zero carbon emissions from electric generation by 2050.
- **October 2019:** DEQ releases NC Clean Energy Plan.
- **October 2019:** DOT releases NC ZEV Plan.

2020

- **July 2020:** NC Electric Cooperatives pledge net-zero carbon by 2050.
- **December 2020:** Stakeholder group releases NC Energy Regulatory Process Summary Report.

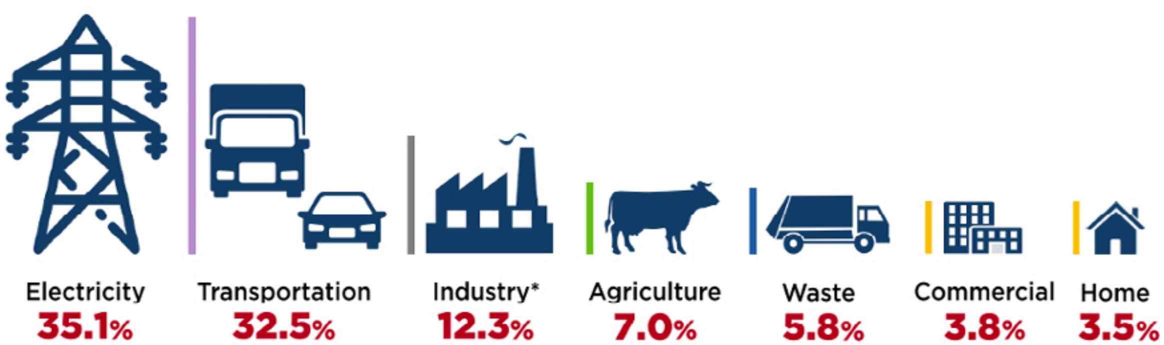
2021

- **March 2021:** Stakeholders discuss major energy legislation.

State Agencies and Stakeholder Groups Map the Path Forward

- The NC ZEV Plan organized actions in four categories: education, convenience (e.g., fast charging), affordability, and policy. Early actions include coordinating ride-and-drive events, facilitating fast charging collaboration, and establishing consistent wayfinding signage.
- The NC Motor Fleet Plan used telematics data to identify 572 traditional, gas-powered vehicles that could be replaced by electric vehicles, thereby saving the state an estimated $3.8 million and reducing emissions by 22,000 metric tons over the lifetime of the vehicles.
- As for the electric sector, the NC Clean Energy Plan established a goal to reduce GHG emissions 70% below 2005 levels by 2030 and to attain carbon neutrality by 2050.
    - An overarching theme across the wide-ranging recommendations was an interest in establishing a "21st century regulatory model that [incentivizes] business decisions that benefit both the utilities and public in creating an energy system that is clean, affordable, reliable, and equitable."
    - An ensuing stakeholder process arose to design specific policy recommendations. The group reached general agreement and recommended the following legislative package:
        - Adopt a performance-based regulatory framework that includes a multi-year rate plan, revenue decoupling, and performance incentive mechanisms (PIMs).
        - Expand securitization to electric utilities to retire undepreciated assets, in addition to current authorization related to storm recovery costs.
        - Study the benefits and costs of wholesale market reform and their impacts on the North Carolina electricity system.
        - Expand procurement practices to utilize competitive procurement as a tool for electric utilities to meet energy and capacity needs identified in integrated resource plans.
- Stakeholders have since begun negotiating major energy legislation to be considered by the North Carolina legislature.

Figure 1.14: **North Carolina Greenhouse Gas Emissions by Sector**



Note: *Industry includes fossil fuel combustion, natural gas and oil processes, and industrial processes.

Source: NC Dept. of Environmental Quality

Key Observations Concerning North Carolina's Approach

- The actions and ensuing targets set by Governor Roy Cooper create short-, medium-, and long-term goals. Achieving incremental milestones will require continuous improvement and investments in both ZEV infrastructure and renewable or net-zero technologies.
- The focus on the electric power and transportation sectors addresses the largest sources of GHG emissions but also reduces the number of stakeholders that must pursue near- or medium-term actions.
- Despite being initiated by an executive order, the process has aligned stakeholders on a set of policy reforms that may institutionalize new electric utility business models with performance-based ratemaking, decoupling, and PIMs.
- Despite the absence of a legislative mandate, major electric utilities serving North Carolina customers, notably Duke Energy and North Carolina Electric Cooperatives, have announced the goal of net-zero carbon by 2050. What makes their voluntary commitments notable is that these utilities accounted for nearly 85% of the state's retail electricity sales in 2019.

What This Means for Energy and Utility Companies

- While the Roadmap and similar analyses serve as tabletop exercises for envisioning decarbonization, the real work is left to the energy and utility industries to assess growth opportunities, potential costs, and deployment actions needed to implement policy directives.
- Utilities should look closely at proposed transition actions and ask:
  - What assumptions are driving different pathways? Do they assume technology breakthroughs? Some examples:
    - Availability and deliverability of imported clean energy
    - Behavioral changes (e.g., EV adoption, ridesharing)
    - Stock turnover and ability and cost to retrofit
    - Availability of resources, including trained personnel, at scale during the contemplated timeframes
    - Heat pump efficiency
    - Dispatchability and capacity availability of different power generation resources
  - What opportunities for investment (and returns) can come from transition?
  - How will the costs of transition investments be allocated among customer classes or socialized more broadly, and what new rate or pricing schemes are required?
  - How much capital is needed to fund energy system investments, and where will it come from?
- In addition to addressing the questions above, and others, utilities will need to consider long-term targets as they make investment and business model decisions over the next decade.

Potential Actions for Utilities Considering Decarbonization

- **Opportunities:** Consider where investment might afford business opportunities to roll out new products and services, generate higher margins, improve system performance, or otherwise grow the business.
- **Interim Targets:** Identify interim “no-regrets” strategies that preserve real options as technology and other transitional aspects evolve.
- **Signposts:** Articulate key indicators that could serve as status markers of whether transition cost, difficulty, or timing are different than originally contemplated and require plan adjustment.
- **Scope, Cost, and Prioritization:** Prioritize “bang-for-the-buck” investments with a capital plan and resource allocation strategy.
- **Rate Strategy:** Identify key features of existing regulatory and rate structures that require readjustment to provide net-zero utility and customer incentives.

IMPLICATIONS

It is a long road to 2050, and pressure is building in some states to reconfigure infrastructure in key energy-consuming and producing segments of the economy. Near term, utilities should look closely at proposed policy roadmaps to determine recommended actions and embedded assumptions, considering implementation issues, including customer cost, expected pace of action, and possible barriers. They should also identify potential growth opportunities as the energy system is reconfigured.

Notes:

‡Analysis started with the end-state emissions goal and used "back-cast" modeling to understand the transformations needed to get to 2050. It modeled pathways, taking into account energy supply and demand and emissions input/output on an hourly and annual level, cost assumptions, and expected turnover of capital stock (power plant, boilers, vehicles, etc.).

Sources:

www.mass.gov/service-details/global-warming-solutions-act-background; www.mass.gov/info-details/ghg-emissions-and-mitigation-policies; www.mass.gov/service-details/gwsa-implementation-progress; Massachusetts S.2995, passed Jan. 4, 2021; Massachusetts Executive Office of Energy and Environmental Affairs (EEA), Massachusetts 2050 Decarbonization Roadmap Study (Dec. 2020) (includes the Roadmap Report and associated technical analyses) (Roadmap); EEA, Interim Clean Energy and Climate Plan for 2030 (Dec. 30, 2020) (2030 CECP); Massachusetts Dept. of Public Utilities, D.P.U. 20-80, *Vote and Order Opening Investigation into the Role of Gas Local Distribution Companies as the Commonwealth Achieves Its Target 2050 Climate Goals* (Oct. 29, 2020); National Academies of Sciences, Engineering, and Medicine, Accelerating Decarbonization of the U.S. Energy System (Feb. 2, 2021) (National Academies Study); *Megawatt Daily*; NRDC; Foley Hoag; North Carolina Executive Order 80 (signed Oct. 29, 2018); NC Department of Administration, NC Motor Fleet ZEV Plan (Sept. 2019); NC Department of Transportation, North Carolina ZEV Plan: A Strategic Plan for Accelerating Electric Vehicle Adoption in North Carolina (Oct. 2019); NC Department of Environmental Quality, NC Clean Energy Plan: Transitioning to a 21st Century Electricity System (Oct. 2019); and RMI and RAP, North Carolina Energy Regulatory Process: In Fulfillment of the North Carolina Clean Energy Plan B-1 Recommendation (Dec. 2020); WRAL, "Secret Talks Underway on Potential Major NC Energy Bill" (Mar. 10, 2021);

Reports referenced in Figure 1.10 are: Energy Innovation, "Net-Zero Emissions Scenario" (2020), Policy Solutions, available at https://us.energypolicy.solutions/scenarios/home (EI); Evolved Energy Research, U.S. Deep Decarbonization Pathways Project, 350 PPM Pathways for the United States (2019) (DDPP); Larson, et al. Net-Zero America by 2050: Potential Pathways, Deployments and Impacts (forthcoming), Princeton University (Dec. 2020), preliminary results summary available at https://www.dropbox.com/s/kyz1d2b6h90vjyn/Preliminary%20Results.pdf?dl=0 (NZA). All reports were cited in the National Academies Study referenced above.

Energy and Utility Sector Themes

Cost control and increasing capex emerge as cross-energy sector priorities.

Turning the Corner

- Over the past several months, energy and utility companies have been discussing their performances in 2020 and expectations for 2021 and beyond.
- In our review of selected companies' comments to investors, almost all companies discussed two significant common items:
  - First, most acknowledged the efforts of the workforce in performing well despite the constraints of the COVID-19 pandemic. Many said that financial performance was better than expected given the circumstances.
  - Second, firms are increasingly referencing environmental, social, and governance (ESG) strategies. Many discussed social justice and equity activities and workforce diversity initiatives. Most referenced clean energy and GHG emissions-reduction objectives as well, with some focused on frameworks for reporting climate performance.
- More detailed discussion of company priorities and strategies appears on the following pages.

KEY TAKEAWAYS

After a difficult pandemic year, utilities hope for improving conditions and increasing revenues from commercial and industrial customers.

Many companies deployed cost control measures in 2020 and hope to maintain cost discipline going forward.

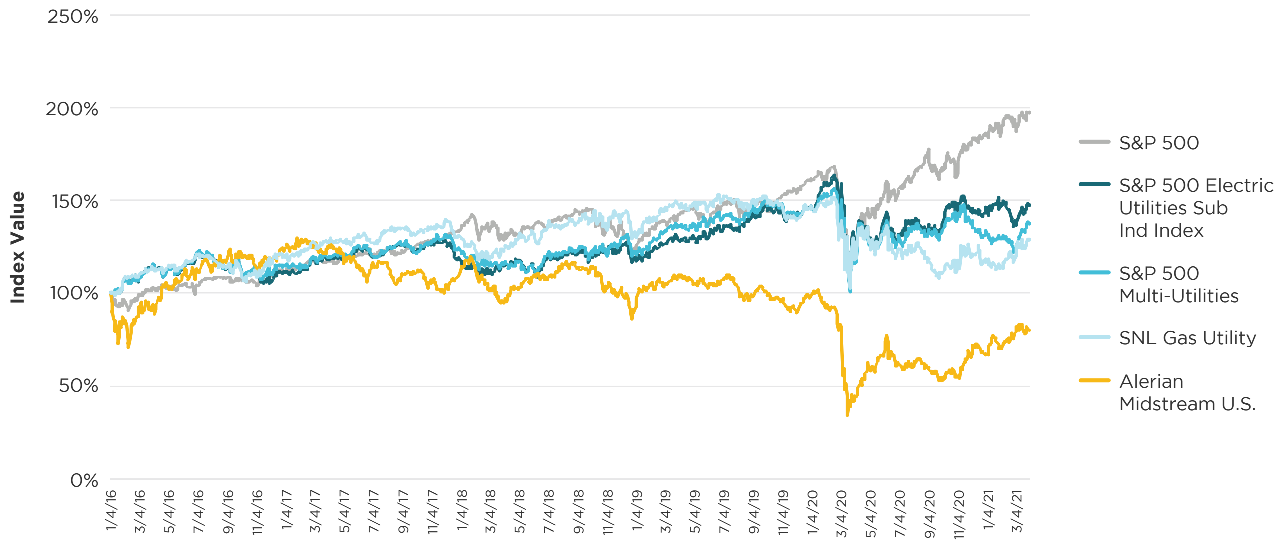
The energy and utility sector continues to deploy capital strategically and reposition business portfolios, many to pure-play, rate-regulated operations.

While capital investment has continued to grow for infrastructure upgrades and GHG reduction initiatives, some analysts see downside risks if energy demand growth disappoints, if regulatory lag becomes an issue, or if balance sheets are weak.

Looking for Stock Price Growth

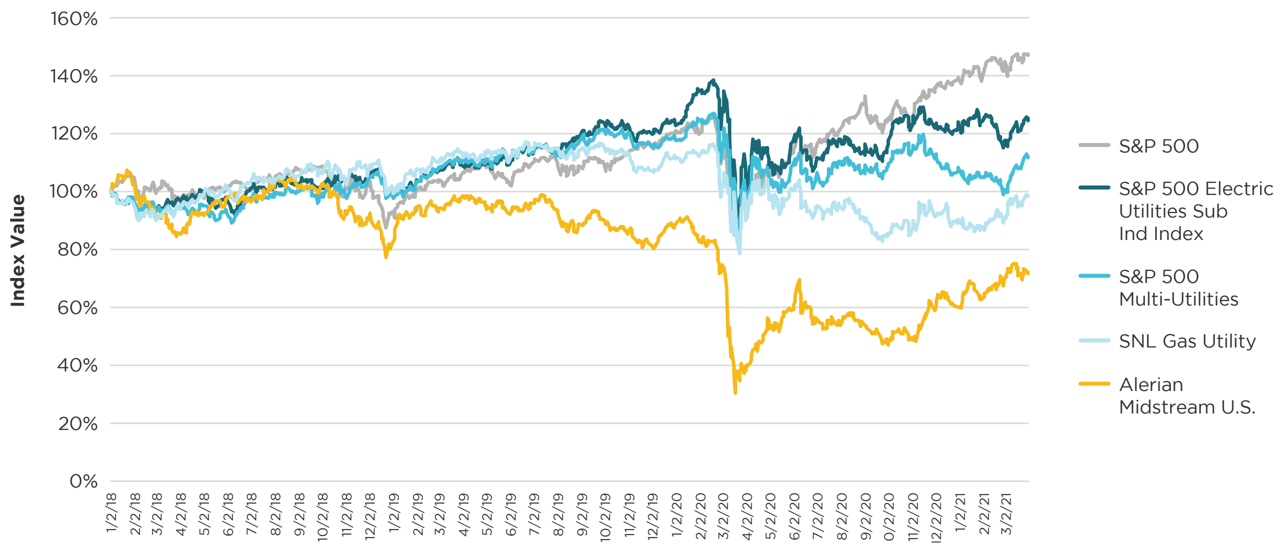
- Setting aside the unusual economic conditions of the past year, utilities have been lagging the overall market index as well as higher growth sectors such as financials, technology, and healthcare.
- Relatively strong economic growth over the past few years and recent bullish outlooks for economic rebound have caused some observers to believe that utilities' defensive characteristics—absent a growth story—may cause valuations to continue to lag other sectors.
- A look back at relative energy and utilities' index values versus the broader S&P 500 index is shown on Figures 2.1 and 2.2.
- Looking ahead, Figure 2.3 captures estimated EPS growth in selected U.S. utilities versus their forward (2022) price-earnings multiple. This analysis indicates that many utilities may be undervalued.

Figure 2.1: **Selected Energy Sector Normalized Equity Indices - Five Years (1/1/2016–3/31/2021) (Jan. 1, 2016 = 100%)**



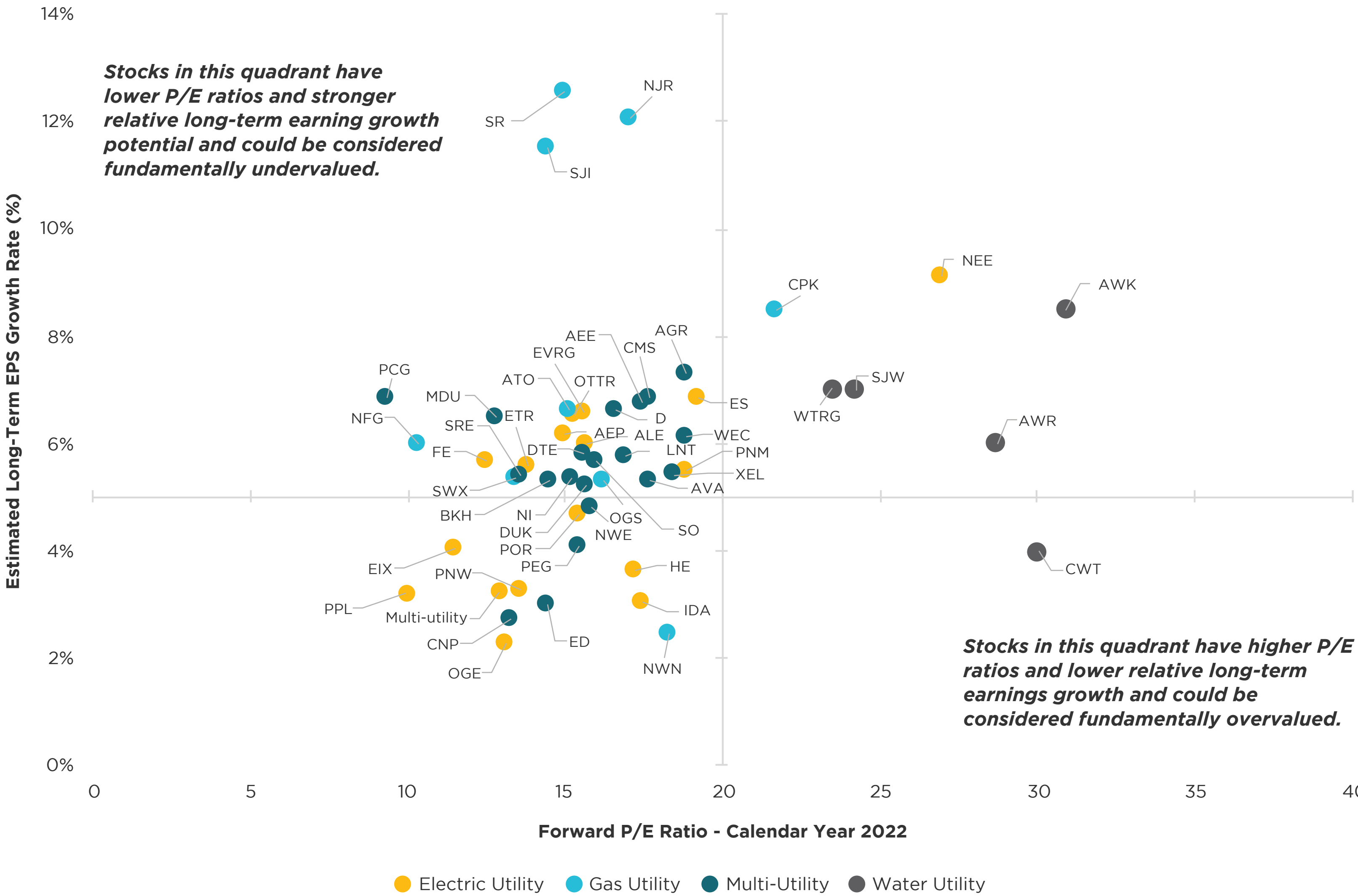
Sources: S&P Global Market Intelligence data; ScottMadden analysis

Figure 2.2: **Selected Energy Sector Normalized Indices - Three Years (1/1/2018–3/31/2021) (Jan. 1, 2018 = 100%)**



Sources: S&P Global Market Intelligence data; ScottMadden analysis

Figure 2.3: **Earnings vs. Price/Equity Multiple Outlook for Selected U.S. Utilities**



Notes: For the 12 months ended Dec. 31, 2022. As of Feb. 26, 2021. Comments are per S&P.

Source: S&P Capital IQ

Deploying, and Redeploying, Capital

- Despite the challenges of the COVID-19 pandemic, capital spending in the utility industry continued apace in 2020 (see Fig. 2.4). According to U.S. government figures, the annual amount of electric power industry construction in 2020 did not dip below $73B (Fig. 2.6).
- Among investor-owned electric utilities, year-end capex projections as of October 2020 projected a 3% increase over 2019 levels. Spending among functional areas was relatively steady, with a slight decrease in the generation portion of spend and a slight increase in the distribution segment (see Fig. 2.5).
- Meanwhile, with significant amounts of liquidity in the financial system and continued low interest rates, transaction activity has largely been smaller asset-by-asset transactions, punctuated by larger spinoffs, divestitures, and strategic minority investments by private equity players (see Fig. 2.7). These transactions reflect movement toward simpler pure-play, rate-regulated businesses for some, while acquirors may see opportunity to pick up potentially undervalued unregulated businesses and fossil fuel assets.

Figure 2.4: **Investor-Owned Utility Historical and Projected Capex (as of Oct. 2020)**

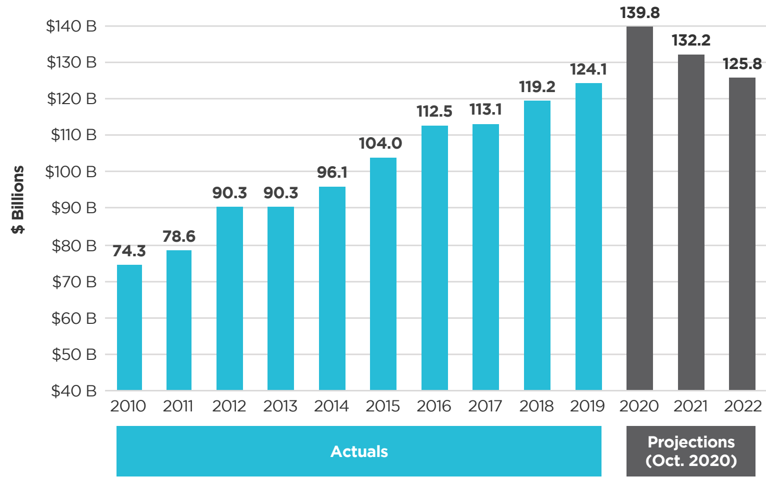
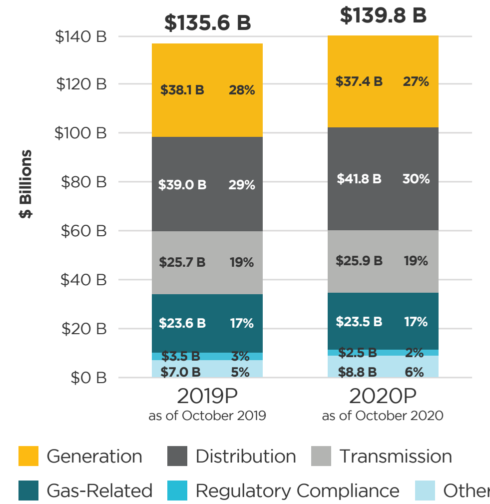


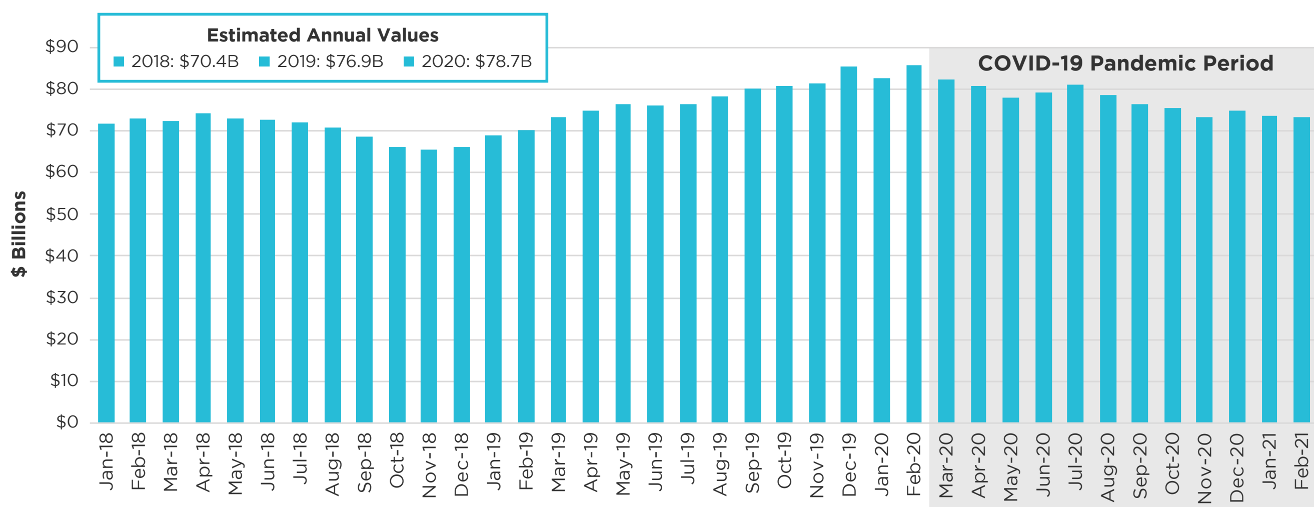
Figure 2.5: **Investor-Owned Utility 2019-2020 Projected Functional Capex**



Notes: According to EEI, at the industry level, projected capex is consistently overestimated for the first year's projection (by 5%-7%) and underestimated in the second year (by 6%-10%) and in the third year (by 20%-25%). Each annual functional projection above is compiled during the reported calendar year and not revised to align with actual total. So 2019 totals do not align between the EEI charts above. Data as of October 2020.

Source: EEI

Figure 2.6: **Monthly Value of Private Construction Put in Place – Electric Sector**



Note: These are estimated annual rates based upon monthly activity.

Sources: U.S. Census Bureau; ScottMadden analysis

Figure 2.7: **Selected Significant ($1B+) Asset, Spinoff, and Corporate Transactions (Jan. 2019-Apr. 2021)**

Legend		
Industry	**Transaction Type**	**Buyer Type**
Combination utility	**A** – Asset acquisition	**CU** – Combination utility
Electric utility	**C** – Corporate acquisition	**EU** – Electric utility or affiliate
Gas utility	**M** – Acquisition of minority stake	**F** – Financial investor
Renewable energy	**S** – Spinoff or split-off	**GU** – Gas utility or affiliate
		M – Merchant energy provider
		Muni – Municipality
		O&G – Integrated oil & gas company

Notes: Transaction value includes purchase consideration such as assumed debt. Transaction status as of April 8, 2021.

Sources: S&P Global Market Intelligence; ScottMadden analysis

CEO Themes: Messages to Stakeholders

- A selected sample of messages from investor presentations and earnings calls revealed a few themes, slightly differentiated by sectors, as shown in Figure 2.8.

Figure 2.8: **Utility Management Themes, Priorities, and Strategies by Sector**

Gas Local Distribution Companies	Midstream Gas Companies	Combination Delivery-Only Utilities*	Combination Utilities**	Integrated Electric Utilities
▪ Natural gas is not going away anytime soon. But we are reinvesting today to prepare for and capitalize on the transition toward **decarbonization**. ▪ Our north star and vision forward is being a **carbon-neutral** energy provider by 2050. ▪ We continue to execute our well-established **regulatory strategy** focused on annual filing mechanisms, which mitigate the incremental impact of customer bills while **reducing [regulatory] lag**. ▪ As innovation like **RNG and hydrogen scale**, the existing gas distribution system will deliver more and more decarbonized fuel, dramatically reducing emissions without a massive build-out of new infrastructure. ▪ Safety, reliability, and affordability make natural gas a **preferred fuel source**. Eight out of 10 homeowners in our service territory prefer natural gas.... There is a strong recognition that natural gas is affordable, efficient, and preferable to electricity for heating and cooking. ▪ Over the last 10 years, we have invested more than $11B company-wide to **modernize our pipeline infrastructure**, more than 80% of which was allocated to safety. ▪ We have not seen any **bans**… across our service territory. We stay in close contact through our **stakeholder engagement** strategy, our local public affairs and operating teams with our city jurisdictions, [and] our state legislators as well.	▪ Dramatically improved credit metrics, with “strong cash generation and capital discipline moving toward goal to **improve leverage metrics**.” ▪ Actively researching opportunities that will complement extensive midstream assets and **enhance role in a future transition to a low-carbon economy**, including electrification of compression assets, potential carbon capture and storage opportunities, and long-term opportunities like hydrogen transportation and storage. ▪ Maintaining cost discipline, achieving expense and sustaining capital savings, getting **more efficient and cost effective**. ▪ **Diversification** across multiple commodities, **magnitude** of transportation and storage assets, depth of **marketing activities**, and **cost control** efforts.	▪ Significant [emissions-reduction efforts] to the region [are] customers’ **energy efficiency** initiatives,… significantly expand[ing] **zero-emissions vehicle charging infrastructure and reduc[ing] the number of homes heated with oil**. Most significant,…at least 4,000 MWs of **offshore wind** facilities. ▪ Strengthen **core utility delivery business**; grow existing clean energy businesses and **pursue additional clean energy growth opportunities** consistent with our risk appetite; and pursue additional **regulated growth opportunities** to add value in the evolving industry. ▪ Announced a series of integrated transactions intended to **simplify our energy infrastructure businesses** under one growth platform…intended to create **scale and strategic alignment** …[and] selling a non-controlling interest to a **strategic partner**…. [W]e’re **allocating capital into the lower-risk portion of the energy value chain** in…cross-border **renewable opportunities**, large-scale integrated **LNG projects**, and other investments in **energy networks**.	▪ Reducing or unwinding exposure to the midstream gas sector; simplifying to **focus on pure-play state-regulated utility operations**. ▪ Sale of two gas LDC businesses as an efficient way to **recycle capital** and invest in growth accretive to utility businesses. ▪ Future growth from the **new clean energy future investments** behind-the-meter, to infrastructure opportunities supporting **electrification of transportation** and a growing mix of **renewables in the distribution system**, to expanding the existing **aging infrastructure replacement** programs. ▪ Kicked off **grid enhancement projects**, including securing a **mechanism for recovery**.	▪ Actively manage our portfolio of assets and companies to enable this movement [to clean energy], while ensuring our balance sheet and credit metrics strength… **Asset optimization** will continue as we focus on core growth opportunities. ▪ As we mature in our continuous improvement efforts, we aspire to **permanently reduce O&M costs** and redeploy those resources. ▪ Develop innovative solutions that include **large-scale battery storage, carbon capture and sequestration, and hydrogen-based strategies**. ▪ Long-term capital investment plan includes annual projected rate base growth at our state-regulated utilities of >5%, with a continued emphasis on **transmission, transportation and distribution, modernization, and resilience**. ▪ Stability of **multi-year rate plans** allows focus on efficiency in the business…while [maintaining] strong credit ratings and balance sheet [and]…consistent access to the capital markets. ▪ Substantial **economic decarbonization** of the electricity, transportation, and industrial sectors is possible, which represents a **potential investment opportunity of trillions of dollars** in the coming decades.

Notes: *Combination delivery-only utilities deliver gas and electricity but do not own and operate power generation facilities. **Combination utilities are electric and gas utilities that own and operate power generation and transmission facilities that serve customers in a traditional integrated utility structure or as provider of last resort supplier.

Sources: Selected utility earnings calls and investor presentations

Word on "The Street"

- Rating agencies and investment analysts have provided relatively restrained outlooks for energy and utility sectors. In part, they cite continued effects of the pandemic on both demand and potential regulatory lag as headwinds to growth.
- Many outlooks also depend upon policy outlooks, which were uncertain earlier and continue to evolve, including both state and federal regulatory approaches to the pace and price of investment.
- Figure 2.9 shows the outlook of one rating agency across several sectors, including key assumptions, and risk and opportunities around their base case. Figure 2.11 (at page 31) shows a number of comments of investment bank analysts about the North American utilities sector in particular.

Figure 2.9: **S&P Ratings Views of Selected Energy and Utility Sectors**

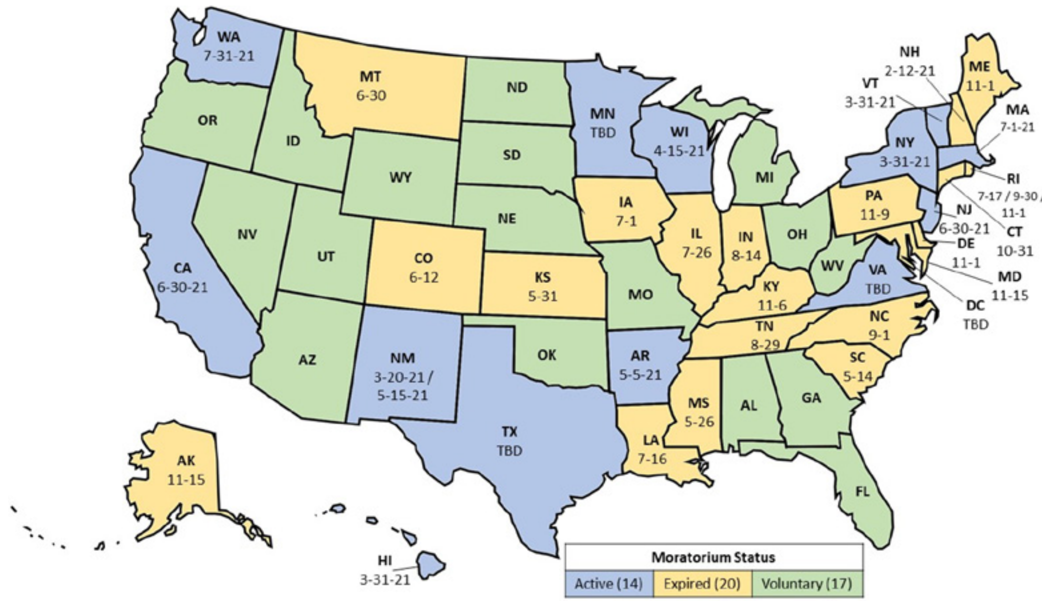
	North American Regulated Utilities	North American Merchant Power	Midstream Energy
	Negative Outlook Despite Predictable Cash Flows	*Resilient, but Pandemic Risks Linger*	*More Stable Road Ahead, as Long as Companies Avoid the Potholes*
Assumptions About 2021 and Beyond	▪ Robust capital spending ▪ COVID-19 subdues electric deliveries to commercial customers ▪ Strategic focus on simpler business model	▪ Lower natural gas production ▪ COVID-19's lingering effect on commercial customers ▪ Renewable proliferation, not COVID-19, drives power market	▪ Lower capital spending ▪ Focus on climate policy and environmental regulation ▪ Increase in discretionary cash flow
Key Risks or Opportunities	▪ O&M cost reductions ▪ Effective management of regulatory risk ▪ ESG risks	▪ Cost reductions and deleveraging ▪ Capital allocation decisions will be key ▪ ESG risks	▪ Counterparty credit risk weaker than expected ▪ Delayed upstream recovery ▪ Accelerated energy transition

Source: S&P Global Ratings

COVID-19 Effects: Still Parsing Outcomes

- Even as North America recovers from the worst of the pandemic, many state disconnection moratoria remain in place (aided in sentiment by the Centers for Disease Control) as well as voluntary utility moratoria (see Fig. 2.10).
- For utilities, it is too early to say what will be the amount, timing, and collection of delinquent payments as a result of past and current collection bans. Bad debt is typically recoverable as a cost of service, but these are unusually high amounts given the extraordinary nature of the pandemic.
- Utility commissions have granted deferrals to some utilities, but those do not improve cash flow, and recovery is not guaranteed.
- Rating agencies have cited regulatory lag as an issue in 2020, but see reopening and better conditions in 2021 as commissions return to regular order.
- Some questions that will likely need to be addressed:
  - Where will the burden ultimately fall—delinquent customers, other customers, shareholders, taxpayers?
  - How will customers prioritize utility payments vs. other arrearages (housing costs, student loans, car payments)?
  - Over what time frame will collection of delinquent bills or regulatory assets (if a state has ordered such treatment) occur?
  - Is securitization an option?
  - How does the presence (or lack thereof) of alternative mechanisms impact recovery?

Figure 2.10: **Status of Disconnection Moratoria (as of Mar. 23, 2021)**



Source: NARUC

Figure 2.11: **Selected Investment Analyst Comments on North American Utilities**

ESG

"We note varied investor views over utility coal plant exposure and the role utilities play in energy transition. Generally, ESG investors seem content to own utilities with coal under a clear strategy to retire those assets in the near term. However, some mandates must adhere to coal exposure below pre-defined threshold…"

Post-Texas Impacts

"Earnings season was essentially divided between pre- and post-Texas. For companies that reported before the storm, questions often focused on more big picture topics…Looking ahead, we think the ripple effects from Texas will be a key theme throughout the year, as utilities grapple with recovery implications, potential balance sheet pressure, and overall heightened regulatory scrutiny."

Transmission

"Companies have flagged cost allocation in particular as the largest hurdle to current [transmission development] efforts, noting current dynamics of incremental system additions likely result in higher costs to customers. Overall, meaningful electrification and current renewables targets likely require significant system investment; however, long project lead times and these policy issues weigh on the opportunities' current scope."

Decarbonization

"Questions remain surrounding the details of Biden's climate policy, but general agreement on its aggressive approach…Importantly, management emphasized the connection between pace and price; to the extent that the overall decarbonization pace is accelerated, price to customers will also accelerate."

Canada

"We continue to see interest in core [Canadian] infrastructure from private capital providers, which has resulted in higher transaction activity. Both interest and valuations have been buoyed by low interest rates and the ability to add debt leverage beyond what is 'acceptable' by public equity investors."

Transition Investment

"Overall, we noticed generally favorable [utility] commissioner feedback on local utilities, specifically related to execution throughout the pandemic and need for continued investment to manage the energy transition. Separately, while we believe generation transition presents a compelling opportunity for utilities to highlight greener attributes, we observed growing investor concern regarding stranded asset risk."

Natural Gas

"Thematic issues include pushback against local bans on new natural gas connections, with [legislative] bills supportive of continued gas system investment."

Sources: JP Morgan; RBC Capital Markets

IMPLICATIONS

As many utilities adopt lower carbon profiles, they need to focus on capital needs to fund asset portfolio changes as well as investment for growth and modernization. Examining strategic options will likely be a part of this process. Utilities will need to manage capital and cash carefully, with effective cost reduction and containment, constructive regulatory outcomes, disciplined capital allocation processes, and an openness to alternatives.

Sources:

Yardeni Research, Inc.; Charles Schwab Corp.; S&P Global Market Intelligence; Alerian; U.S. Census Bureau; Edison Electric Institute (EEI); Platts *Megawatt Daily*; J.P. Morgan; RBC Capital Markets; company earnings calls, investor presentations, and shareholder letters; S&P Global Ratings; S&P Capital IQ; National Association of Regulatory Utility Commissioners (NARUC); ScottMadden analysis

Source: Proterra

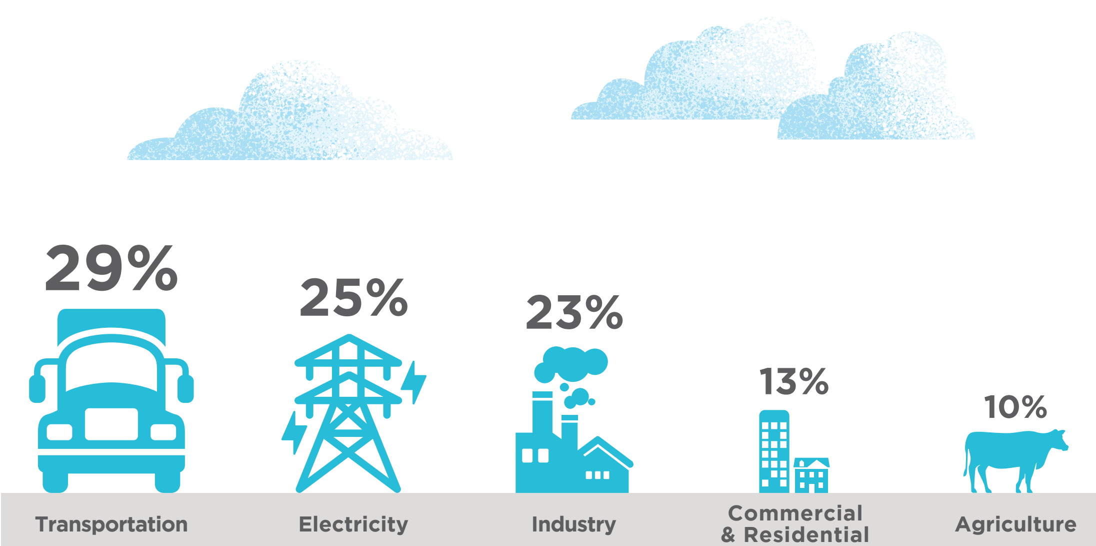
Fleet Electrification

Electric vehicle fleets will require new approaches and offer unique opportunities for utilities.

Transportation as a Critical Component to Net-Zero Carbon Ambitions

- In 2017, transportation surpassed the electric sector as the largest source of GHG emissions in the United States.
- Efforts to achieve cross-sector decarbonization, such as those seen in Massachusetts, will require stakeholders to focus on the deployment of zero-emission vehicles (ZEVs).
- While ZEVs may include multiple technologies (e.g., electric, hydrogen), most ZEVs are electric vehicles (EVs). EV technology can be further categorized as battery EVs and plug-in hybrid EVs.
- Much of the early EV focus has been on consumer adoption and public charging infrastructure, but now the electrification of vehicle fleets is spurring change.
- Fleet owners are finding EVs can meet the needs of a growing number of duty cycles, while saving money and contributing to sustainability goals.
- Electric utilities can be a key partner in this transition and should begin planning now for how they will serve this new class of electric customer.

Figure 3.1: **Total U.S. Greenhouse Gas Emissions by Economic Sector in 2019**



Source: U.S. EPA

KEY TAKEAWAYS

The number of available EV models is increasing across all vehicle classes (i.e., light-duty, medium-duty, and heavy-duty). At the same time, states and fleets are establishing ambitious zero-emission transportation goals.

The transition to electric fleets may pose a challenge for electric utilities, as new concentrated loads will likely require expensive and time-intensive infrastructure upgrades.

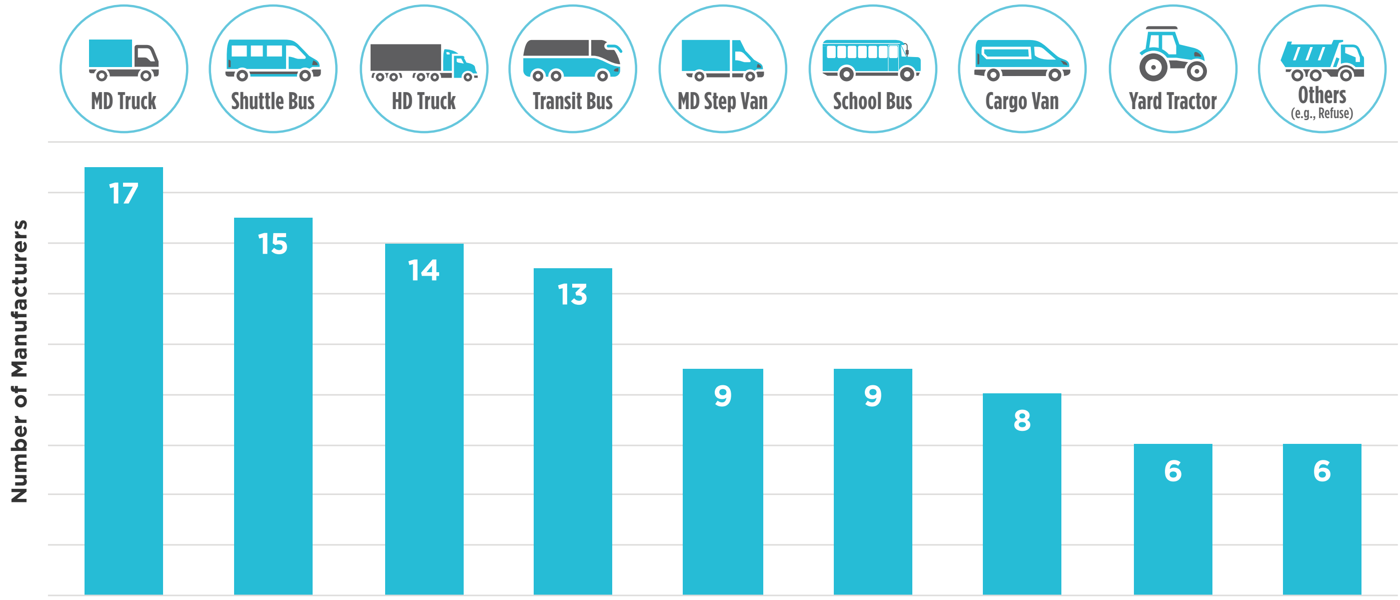
Electric utilities may support fleet electrification by forming an internal EV organization, developing an EV regulatory strategy, designing EV infrastructure planning, and providing fleet electrification support.

However, benefiting from fleet electrification will require utilities to view fleets as a new customer class.

Driving EV Fleet Adoption: Public Policy, Fleet Targets, and More Models

- States are starting to drive changes in transportation through public policy and long-term goals.
  - California is the most notable example with an executive order directing that, by 2035, new passenger cars and trucks sold in the state must be ZEVs. Similar targets have been considered or evaluated by Massachusetts, Washington, Colorado, and New Jersey.
  - Medium- and heavy-duty (MD/HD) vehicles are on a similar trajectory. The California executive order also directs that, where feasible, 100% of MD/HD operations be ZEVs by 2045 (target for drayage is 2035). In addition, 15 states and the District of Columbia signed a memorandum of understanding to make all sales of new MD/HD vehicles zero emissions by 2050.
- Meanwhile, EV options are growing rapidly as manufacturers continue to announce EV commitments and enhance EV offerings.
  - In the United States, there are currently 66 models of EV passenger cars and light trucks available to consumers. This number is expected to roughly double by 2025, with many of the new models sporting longer ranges and price points that rival internal combustion engine vehicles.
  - More MD/HD vehicles are also becoming available. In North America, more than 210 ZEV models are expected to be available by 2023—up from 176 in 2020. In addition, more manufacturers plan to offer electric options (see Fig. 3.2).

Figure 3.2: **Number of Manufacturers Projected to Release Available Medium- and Heavy-Duty ZEV Models (by Vehicle Type) in the United States and Canada by 2023**



Source: CALSTART

Driving EV Fleet Adoption: Public Policy, Fleet Targets, and More Models (Cont.)

- As technology and model availability improves, many large fleets in the United States have committed to significant electrification goals. Some examples include:
  - **Federal:** President Biden signed an executive order directing federal officials to develop a procurement plan that will transition the 645,000 vehicles owned by the federal government to ZEVs. The American Jobs Plan (i.e., Biden's infrastructure proposal) calls for investing $174 billion in EVs and related infrastructure (see sidebar for more details).
  - **Commercial:** Several firms plan to electrify their delivery vehicle fleets. For example:
    - FedEx will replace 100% of its pickup and delivery fleet with ZEVs by 2040. FedEx Express purchases will be 100% electric by 2030.
    - Amazon expects to have 10,000 custom electric delivery vans built by Rivian on the road by 2022. A total of 100,000 of these vehicles will be in service by 2030.
    - UPS has also ordered 10,000 electric delivery vans from the UK-based start-up, Arrival.
  - **Municipal:** Mayor Bill de Blasio signed an executive order mandating that New York City operate with a 100% electric fleet by 2040, and Los Angeles Sanitation & Environment will transition all refuse trucks to zero emissions by 2035.
  - **Utility:** Several utilities (e.g., Duke Energy, Exelon, AEP, Xcel, PSEG, Alliant, and CenterPoint) plan to replace 100% of their light-duty vehicles by 2030. In addition, Ontario Power Generation, Iberdrola, and PG&E have all joined EV100, a campaign launched by the Climate Group.
- With new EVs capable of serving a growing number of duty cycles, fleet operators can benefit from lower total cost of ownership (i.e., lifetime cost of the vehicle). Initial costs may be higher, but with the right electricity rates and duty cycle, EVs may be able to produce savings through lower maintenance and fuel costs.

Biden Infrastructure Plan Revs Up EV Spending

In March 2021, the Biden administration outlined the American Jobs Plan. With a broad definition of infrastructure, the plan proposes spending more than $2 trillion on infrastructure ranging from highways, roads, and bridges to the care economy. EVs are prominent in the proposal with $174 billion going to:

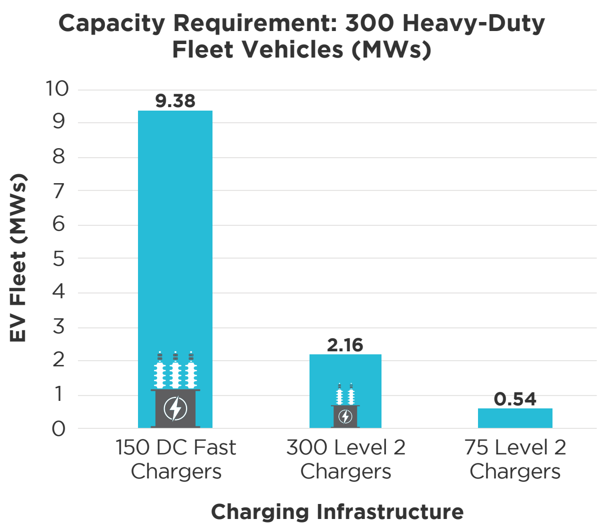
- Enable automakers to spur domestic supply chains from raw materials to parts, retool factories to compete globally, and support American workers to make batteries and EVs.
- Provide consumers point-of-sale rebates and tax incentives to buy American-made EVs.
- Establish grant and incentive programs for state and local governments and the private sector to build a national network of 500,000 EV chargers by 2030.
- Replace 50,000 diesel transit vehicles and electrify at least 20% of the school bus fleet through a new Clean Buses for Kids Program.
- Utilize the vast tools of federal procurement to electrify the federal fleet, including the U.S. Postal Service.

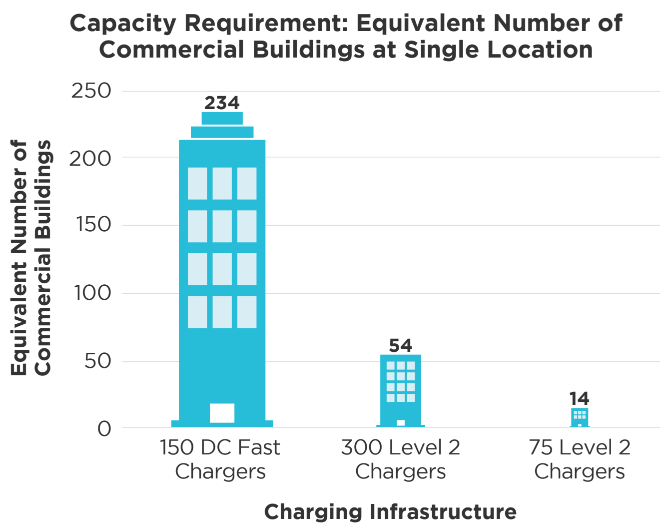
Source: The White House

Electric Utilities Need to Start Preparing Now for EV Fleets

- Fleet operators currently have on-site fueling stations or rely on public gas stations for fleets dependent on gasoline or diesel. With limited public chargers and longer charging times, EV fleets will require their own charging infrastructure in the near term.
- The load from EV fleets will be unlike other types of load for several reasons:
  - **Scale:** MD/HD fleets may have significant energy and capacity requirements, even when optimized (see graphic at Fig. 3.3).
  - **Mobility:** Fleets may do most of their charging at depots, but unlike stationary load, they are also capable of charging at different locations while performing a duty cycle.
  - **Concentration:** Most fleet vehicles will return to a depot, concentrating charging load. In addition, multiple fleets within industrial zones may electrify, resulting in costly infrastructure upgrades.
  - **Vehicle-to-Grid (V2G):** Technology is still being developed, but V2G technology could one day allow fleets to export electricity to the grid in sizeable quantities.
- Current utility distribution planning processes may struggle to keep pace with rapid fleet adoption.
  - Distribution planning typically follows an annual cadence for general system-load growth.
  - Customer-specific load growth for new or expanded service triggers design reviews, which can take weeks or years depending on the size of the project.
  - Utility lead times may be unacceptable to many fleet operators accustomed to buying and quickly integrating new vehicles.
  - In addition, customers may be responsible for costs associated with the required infrastructure upgrades, potentially leading them to abandon or scale back fleet electrification efforts.
- Electric utilities may miss a revenue opportunity if fleet owners forego EV adoption or relocate to other service territories.
- To avoid missing an opportunity, electric utilities need to begin outreach efforts to work proactively with fleets to right-size charging infrastructure and provide make-ready infrastructure at sites for future EV fleets.

Figure 3.3: **Capacity Requirement Under Different Charging Scenarios for Quantity and Level of Chargers**





Comparing capacity requirements with more traditional demand sources, such as commercial buildings, illustrates significant point capacity needs.

Notes: Analysis assumes all chargers are used at the same time. DC Fast Charger output is assumed to be 62.5 kW. Level 2 charger output is assumed to be 7.2 kW. Commercial building is assumed to have peak demand of 40 kW. Battery capacity is assumed to be 500 kWh per vehicle. Vehicles assumed to operate 250 days a year and charge 70% of battery capacity per day. Annual energy consumption is constant across all scenarios.

Fleet Electrification Should Be Part of a Comprehensive Approach to EVs

- As EVs become more popular, utilities will need to develop a comprehensive approach to support individual and fleet customers.
- Figures 3.4A-B highlights key capabilities that should be developed by utilities and underscores the enhanced services that can be provided to fleet customers.

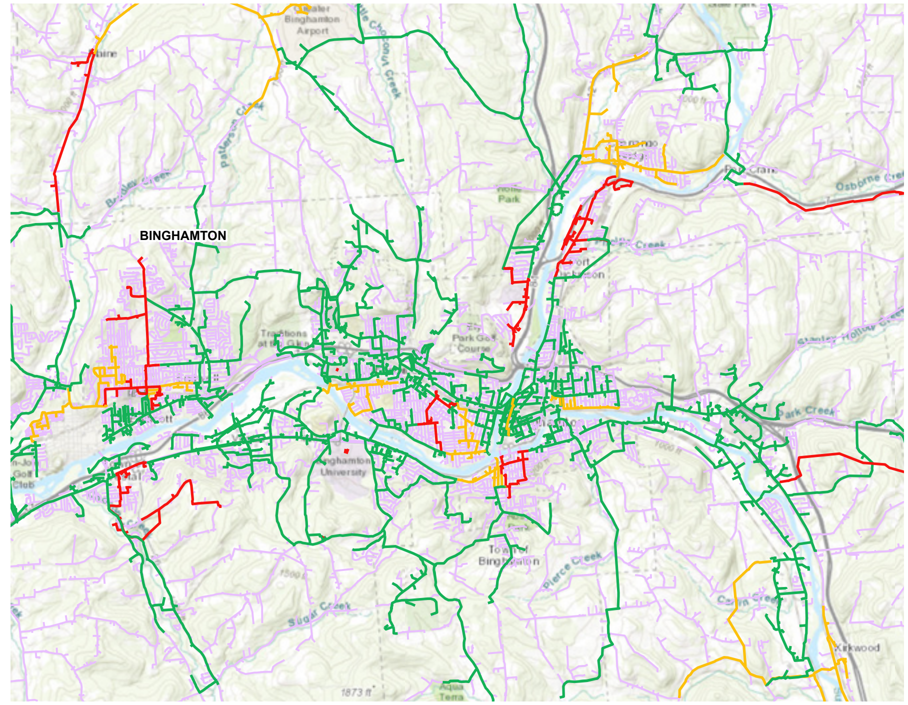
Figure 3.4A: **Comprehensive Approach to EVs for Electric Utilities**

Capability	Opportunity	Potential Activities	
Utility EV Organization	Create an internal EV organization to coordinate EV programs across internal organizations and interface with fleets, charging developers, and EV customers	▪ Identify where the utility's EV group will reside in the company's organizational structure ▪ Develop group roles and responsibilities ▪ Incorporate organization into existing processes and procedures related to EVs and EV infrastructure development	▪ Identify and develop processes and procedures needed to implement EV-charging programs, infrastructure programs, and outreach activities ▪ Drive EV awareness and manage company EV programs and incentives ▪ Monitor EV vehicle availability, battery advancements, and charger technology developments
EV Regulatory Strategy	Develop EV strategies to meet state and/or company decarbonization goals. Advocate for EV programs in rate cases and regulatory proceedings	▪ Develop and communicate the company's EV strategy ▪ Propose EV supportive rate structures ▪ Determine cost recovery methods for EV programs and infrastructure ▪ Support regulatory program reporting	▪ Design EV programs to implement the company's EV strategy ▪ Support EV-related regulatory filings ▪ Perform cost-benefit analysis/ratepayer impact analysis of EV programs and proposals
EV Infrastructure Planning	Design and implement EV infrastructure programs	▪ Develop and implement public-charging incentive programs ▪ Develop and implement workplace charging programs ▪ Develop and implement make-ready infrastructure programs	▪ Design the EV infrastructure planning process ▪ Coordinate the development of load-serving capacity maps ▪ Design an infrastructure future-proofing process
Fleet Electrification Support	Assist customers in planning for the electrification of their vehicle fleets by providing feasibility assessment, rate analysis, and infrastructure planning support	▪ Provide information, such as load-serving capacity maps, to fleet customers and charging developers to facilitate the development of charging infrastructure in low-cost areas on the electric system (see map at Fig. 3.5) ▪ Engage proactively with fleets through customized, event-based efforts, such as Ride & Drive events, fleet operator town halls, etc. ▪ Engage fleets to understand their electrification plans and potential impact to the system	▪ Work with fleets to optimize duty cycles and develop a managed charging plan: consider sequenced charging and operational impacts ▪ Right-size charging infrastructure collaboratively with customers; incorporate physical space available, on-route charging options, charging window ▪ Help customers understand the variables that drive total cost of ownership (e.g., charging options, battery specifications, fleet size, etc.) and develop tools to support their analysis and payback period

Figure 3.4B: **Comprehensive Approach to EVs for Electric Utilities (Cont.)**

Capability	Key Considerations	Examples
Utility EV Organization	▪ How many FTEs are needed to support the company's EV objectives and requirements? ▪ Where does an EV organization fit into the organizational structure? ▪ What skills/capabilities are needed? ▪ What is the governance?	▪ Pacific Gas & Electric Co. ▪ Southern California Edison ▪ San Diego Gas & Electric Co.
EV Regulatory Strategy	▪ Is there an upcoming rate case? ▪ Is there an ongoing or anticipated EV proceeding? ▪ Does the company have plans for EVs that need to be reviewed with the regulator?	▪ NY Electric Vehicle Supply Equipment proceeding ▪ NJ Board of Public Utilities petitions ▪ California PUC proceedings
EV Infrastructure Planning	▪ How does EV infrastructure planning differ from traditional new business processes? ▪ What types of programs are most suitable for the utility's service territory? ▪ How much EV adoption is forecast? ▪ Will customers charge publicly or at home? ▪ What infrastructure costs will the utility pay versus charging station owners?	▪ Orange & Rockland Utilities ▪ Pacific Gas & Electric Co.
Fleet Electrification Support	▪ How many fleets operate in the utility's service territory? ▪ Where are the fleets located and are they geographically concentrated? ▪ How large are the fleets? ▪ What classes of vehicles will be electrified? ▪ When do fleets plan to electrify? ▪ How, when, and where will charging take place? ▪ Are fleets aware of specialized rates or incentive programs?	▪ Orange & Rockland Utilities ▪ National Grid (MA) ▪ Pacific Gas & Electric Co.

Figure 3.5: **EV Load Capacity Map**



Source: NYSEG & RGE's EV Load Capacity Portal

NY EV Circuits (3 Phase)

- >1.5 MW Capacity Remaining 3P Lines
- 600 kW to 1.5 MW Capacity Remaining 3P Lines
- < 600 kW Capacity Remaining 3P Lines

NY EV Circuits (non-3 Phase)

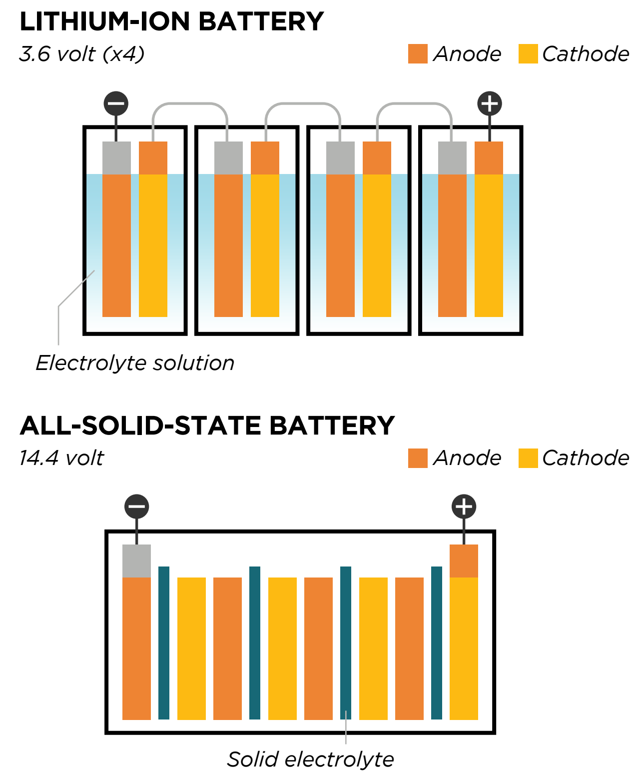
- One and Two Phase Lines

Ascertaining specifically where system capacity is constrained and demand is expected will be important for fleet electrification.

A Distinct Customer Class Offering Utilities New Opportunities

- It would be easy to categorize electric fleets as incremental commercial or industrial load. This approach is simplistic because EV fleets will have distinct energy and capacity demands, load profiles, geographic concentrations, and infrastructure requirements. Instead, electric utilities should view and approach electric fleets as a separate customer class.
- An early focus should be on tariffs and rate design. In some cases, the operational cost savings (i.e., lower maintenance and fuel costs) associated with EV fleets can be offset by high-demand charges. Electric utilities should consider tariffs and rate structures that are specifically tailored to support EV fleet deployment.
- Electrification presents utilities with an opportunity to partner with fleets to manage upfront and ongoing costs that benefit their customers. Meanwhile, failure to optimize charging infrastructure may lead to higher-than-necessary costs, which will slow EV adoption. Fleet operators may also pursue behind-the-meter solutions (e.g., on-site storage or generation).
- Throughout the transition, utilities will need to remain nimble, as recent market developments highlight the potential for innovation and disruption:
  - Multiple automakers are exploring solid-state batteries as a way to reduce charge times and improve energy density (see Fig. 3.6).
  - In China, the car manufacturer NIO has swapped battery packs from light-duty vehicles more than one million times at specially designed stations. In the United States, Ample is piloting similar efforts in San Francisco with Uber drivers.
  - In the Netherlands, Shell is testing on-site battery storage coupled with EV-charging infrastructure to avoid expensive infrastructure upgrades.
  - In the United Kingdom, a BP subsidiary is partnering with a U.S. start-up, FreeWire Technologies, to install EV chargers that fully integrate battery storage.
  - Other companies are exploring distributed-charging hubs to service EV fleets.

Figure 3.6: **Understanding Solid-State Batteries**



Sources: Toyota; Inside Climate News

Solid-state batteries replace the liquid electrolyte inside lithium-ion batteries with a solid electrolyte. Solid-state batteries can offer a higher energy density and a better safety profile than lithium-ion batteries.

IMPLICATIONS

Electric utilities need to view EV fleets as a new class of electric customer. This customer class will grow rapidly in the near term as fleet owners find that EVs can make good sense—for sustainability and business. Electric utilities should engage with fleet operators early to understand and inform their electrification plans. Specific opportunities include providing site feasibility assessments and rate analyses for EV fleet owners. Failure to assist customers with this transition will result in higher costs, slower EV adoption, or behind-the-meter solutions. Utilities must also remain nimble and respond to changing public policy and technological advancements.

Sources:

Atlas Public Policy, Atlas EV Hub; CALSTART's Drive to Zero, Zero-Emission Technology Inventory; U.S. Environmental Protection Agency, Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2019 (Apr. 2021); industry news; ScottMadden analysis

Weather and System Performance: Test Cases

A heat wave in the West and a cold snap in Texas force planners and policymakers to re-examine resources and operations.

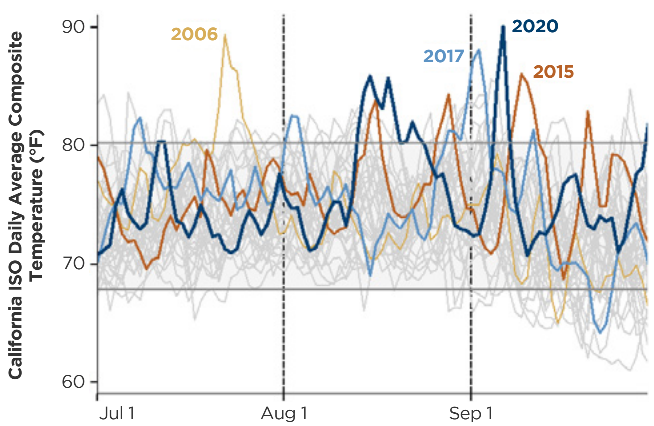
California in Transition

- California is in the midst of a transition to 100% clean or net-zero energy by 2045 as well as targeting renewables to supply 60% of retail sales by the end of 2030. Part of this effort has focused on increasing energy storage and renewable resources, retiring fossil fuel and nuclear generation, and increasing energy efficiency.
- As solar generation has become a larger resource on the system, the California system has experienced "duck curve" effects—dramatic falloffs in solar generation in the early evening while loads increase with increased residential usage as residents return home (at least pre-pandemic).
- California has a state-led integrated energy demand planning process as well as a California Public Utilities Commission (CPUC)-led resource adequacy (RA) planning process, among others, all evolving to accommodate system changes driven by the state's policy goals.

August and September 2020 Hot Spell

- With the foregoing as a backdrop, in mid-August and again in early September, California and much of the U.S. West experienced extended temperatures in the 80s and 90s, which led to high loads across the region. This led to actual system load peaks exceeding 1-in-2-year peak demand forecast (which is used for RA planning) on seven days in those time periods.
- On August 14 and 15, CAISO was forced to institute rotating outages around 6:30 p.m. each day. More than 490,000 customers were affected on August 14 for 15 to 150 minutes, with about 1,000 MWs of load shed on that date. On August 15, load curtailment totaled about 500 MWs, affecting 321,000 customers for 8 to 90 minutes.
- There was similar high expected demand August 17–19 and again September 5–7 and expected capacity shortfall. But in both cases, no load was shed, in part, because of conservation efforts.

Figure 4.1: **California July, August, and September Temperatures (1985–2020)**



Source: Root Cause Analysis

KEY TAKEAWAYS

Recent multi-hour and multi-day extreme weather events have exposed planning, process, and resource gaps in power systems. California's and Texas' weather events in the past nine months highlight these issues.

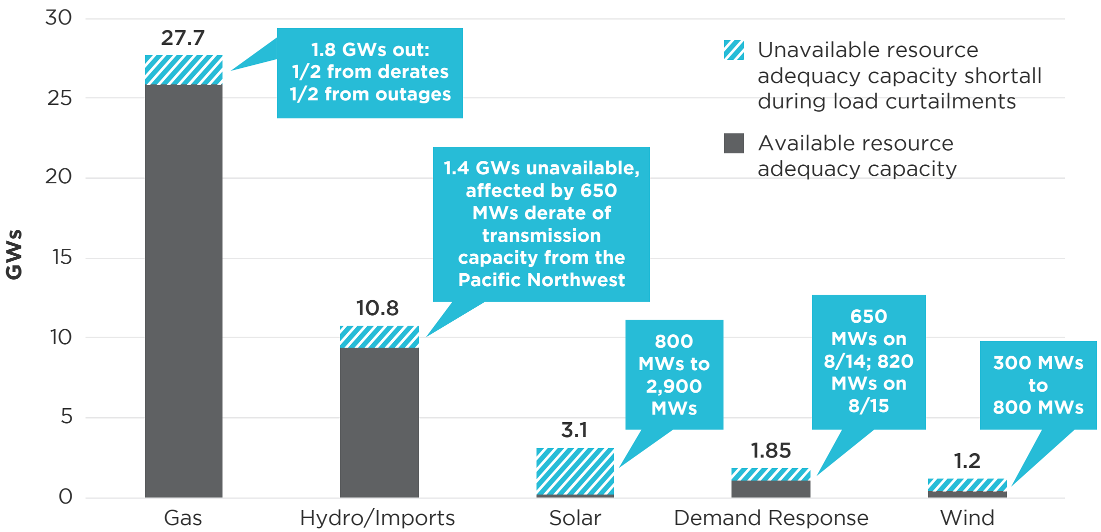
A changing resource mix, especially with high-solar penetration, requires more time-dependent considerations and multiple, flexible options on both supply and demand.

In determining resource needs, system planners must consider long-duration events and more extreme (1-in-N) scenarios. In addition, they will need to consider more contingencies and perhaps enhance their tabletop simulations to be able to anticipate that wider range of such possible events, including common mode failures and resiliency planning.

Root Cause Analysis: A Series of Unfortunate Events

- Energy regulators and CAISO, as well as CAISO's market monitor, conducted analyses of the August heat wave and its effects on the California market. In its report, CAISO, the CPUC, and the California Energy Commission found that there were three major factors contributing to the outages:
  - The heat wave resulted in power demand exceeding existing resource adequacy and planning targets.
  - In transitioning to a "reliable, clean, and affordable resource mix," resource planning targets‡ have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours.
  - Some practices in the day-ahead energy market exacerbated supply challenges under stressed conditions.
- To some extent, CAISO in its May 2020 Summer Loads and Resources Assessment contemplated potential load-shed conditions during a heat wave with peak shifting to later in the day, lower than normal hydro conditions, and increased reliance on imports.
- Current California RA planning standards are based on 1-in-2-year loads plus 15% reserve margins. Actual system conditions exceeded that level.
- Resource availability and performance during the event were key issues (see Fig. 4.2). Some resources counted on for reliability were derated because of ambient conditions, and some solar and wind resources were not available during the early evening hours when load was curtailed. Moreover, some demand response resources did not arrive.
- Finally, because of certain market practices and under-scheduling of load (more than 1.3 GWs during net peak demand), exports from CAISO, unsupported by physical resources, were able to be scheduled and were not curtailed. After August 15, CAISO modified its practices and enabled changes in treatment of exports to "improve the alignment of export self-schedules with real-time system conditions."

Figure 4.2: **CA's Resource Shortfalls During Critical Hours (Aug. 14–15)**



- 12% to 16% of resource adequacy capacity was not bid or self-scheduled into the California real-time market at crucial hours on August 14–15.
- **Note:** Curtailment totaled about 1,000 MWs on August 14 and 500 MWs on August 15.

Sources: Root Cause Analysis; Market Monitor Report

Some Things That Worked

- On August 16, California's governor declared a state of emergency, which freed up more potential supply (e.g., auxiliary ship engines) and fuel sources. The messaging included conservation messaging, which is estimated to have reduced peak demand by as much as 4 GWs.
- The Western Energy Imbalance Market (EIM) assisted CAISO during the crisis, providing about 1.3 GWs and 0.5 GWs during load curtailment intervals on August 14 and 15, respectively. EIM imports were limited, however, by limited GHG-emitting supply available to be transferred into California during the period after August 15, although with conservation efforts, there was less need for those resources.
- While some utility demand response did not perform as well as expected, it provided some support, and special "reliability demand response resources" of 800+ MWs were dispatched to meet peak demand.

Learning Lessons and Developing a Policy Response

- The heat wave of August–September 2020 and the subsequent power system response triggered inquiries into causes and potential changes in policy, process, and decision rules. The CPUC initiated an emergency rulemaking proceeding in November 2020, seeking action for additional firm resources as well as potential demand reduction approaches in advance of summers 2021 and 2022. Regulators are using an "all of the above" approach, touching on many of the gaps that emerged during August 2020.
- The CPUC has initially focused on additional supply, citing a longer lead time required for its procurement. In January 2021, the CPUC authorized procurement of at least 3.3 GWs of incremental RA capacity and renewable integration resources, with 50% of that due by summer 2021. Resources are limited to incremental capacity from existing plants, contracts with generation at risk of retirement, and incremental energy storage. The CPUC is also looking at demand resources under resource adequacy procurement standards that consider availability during the net demand peak period (i.e., hours past the gross peak when solar production is very low or non-existent).
- Priority actions on demand management have included a new media campaign for Flex Alert conservation measures, increased compensation for and expanded participation in investor-owned utility demand response programs, and a new five-year pilot of an emergency load reduction program.
- Some critics argue that capacity was not the issue during the heat wave and maintain that reforms in ISO procedures (such as those that enabled exports during the crisis) should be prioritized. The CPUC is addressing these issues, and CAISO has proposed market enhancements with the targeted implementation date of June 2021 (see sidebar at right).

CAISO's Proposed Market Improvements to Address Gaps Arising from August 2020 Heat Wave

- Export, load, and wheeling priorities*
- Western Energy Imbalance Market coordination and resource sufficiency test review
- Import market incentives during tight system conditions
- Real-time scarcity pricing
- Reliability demand response resource dispatch and real-time price impacts
- Resource adequacy provisions for enhanced storage resource management during tight supply conditions
- OASIS report and interconnection process

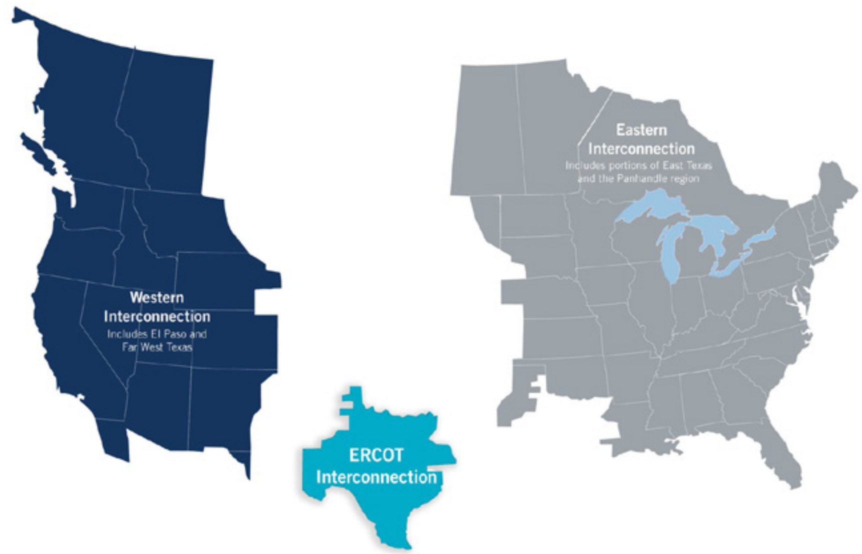
Implementation expected in June 2021 except as indicated by an * expected in July 2021.

Source: CAISO, Summer 2021 Reliability Monthly Report (Mar. 12, 2021)

Deep Freeze in Texas

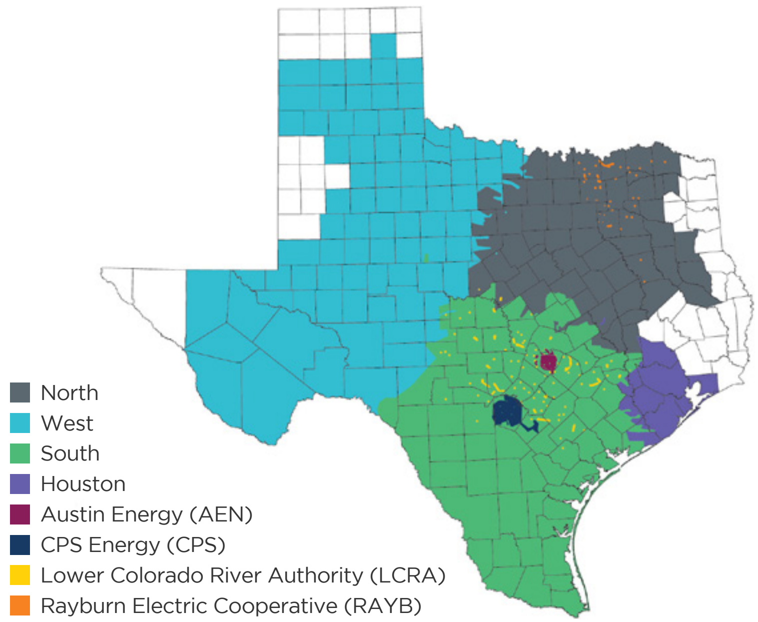
- In mid-February 2021, a polar vortex pushed down through the Midwest as far south as Texas. While Texas occasionally experiences cold weather, on this occasion, record-setting low temperatures and wind chills prevailed, and some places remained below freezing for nearly six (Dallas) to almost seven days (Austin) beginning Sunday, February 14.
- A combination of snow, freezing rain, and persistent frigid temperatures overwhelmed the Texas grid as both thermal and renewable resources faced equipment failures. At its worst point, 52.3 GWs of generation was unavailable (about 49% of a system with 107.5 GWs installed capacity). Thermal generation made up the bulk of these unavailable resources; some wind equipment became inoperable, but wind accounted for only 2 to 3 GWs of non-performing generation.
  - With high demand and low supply availability, ERCOT was forced to shed up to 20 GWs of load beginning Monday, February 15, for three consecutive days, saying it was less than five minutes from cascading grid collapse and months to recover.
  - More than 60% of Texas homes have electric space heating, exacerbating demand as well as the effects of the outages. Moreover, outages affected the state's natural gas production and delivery infrastructure, severely limiting the supply of a key generation fuel.

Figure 4.3: **NERC Interconnections**



Source: ERCOT

Figure 4.4: **ERCOT Load Zones**

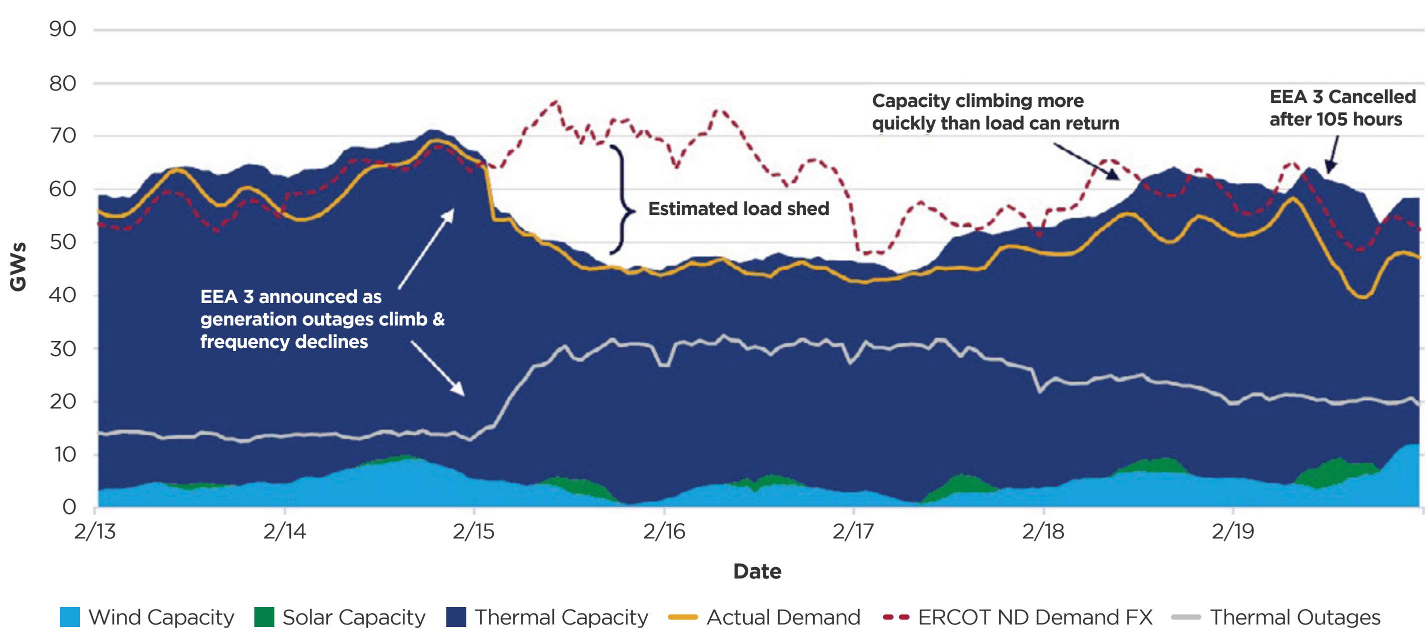


Source: ERCOT

Investigating Causes and Examining Decisions

- The event was as much a gas interruption event as a power system event. The Texas power system is highly dependent upon in-state natural gas: about 50 GWs of forecasted 82 GWs peak load was expected to be served by natural gas. Texas gas production and delivery, however, were impeded by power outages and freezing wellheads, compressors, and instruments. Dry gas production was down 10 BCF/d, or about one-third of January 2021 daily production. Note that Texas gas is liquids-rich, making it more susceptible to freezing. Moreover, many gas-fired plants have interruptible gas supply contracts, and local gas distribution companies are required to prioritize "human needs" end-use customers, such as hospitals and residences.
- While these conditions were intense and of relatively long duration, extreme cold in Texas is not unheard of. Cold weather events in February 2011 and December 1983 were precursors, although the composition of the Texas energy system is different today. After the February 2011 event, which also involved load shed, NERC and FERC investigated and found gaps in winterization. Given the similarity in outcomes in this 2021 event, winterization will likely be an area of inquiry.

Figure 4.5: **ERCOT's Available Capacity and Demand (Feb. 13–19, 2021)**



Sources: Wood Mackenzie; ERCOT; P. Cramton, "Lessons from the 2021 Texas Electricity Crisis" (Mar. 22, 2021 draft), at http://www.cramton.umd.edu/papers2020-2024/cramton-lessons-from-the-2021-texas-electricity-crisis.pdf

- ERCOT plans for only 2 GWs of renewables in its extreme winter scenario (out of more than 37 GWs installed).
- ERCOT only plans 14 GWs of thermal outages in that scenario—as of Feb. 15, 30+ GWs were out.
- 2.8 GWs of planned outages were in effect, including seasonally mothballed capacity.
- While this analysis focuses on capacity, a key part of the review will need to focus on generation (energy production) as well.

Investigating Causes and Examining Decisions (Cont.)

- In the meantime, much of the media and Texas' political attention is on money—who pays and how much. During the emergency, ERCOT pegged prices at the market cap of $9,000 (the value of lost load) during and after the outages. The goal was to coax more resources online, but stakeholders are debating whether sustaining those prices was appropriate. And for available gas generation, market prices for gas ranged from $200/MMBtu to more than $1,000/MMBtu, compared to more recent prices of $2 to $3. In an energy-only, retail choice market that relies on scarcity pricing to incentivize resources, effects are being felt by generators, fuel suppliers, utilities, and customers alike.
- As with California, the policy response will depend upon findings of the state and federal inquiries spawned by this event. Fact finding and root cause analysis beyond the early "quick takes" will likely examine the following (including but not limited to):
  - Performance of different power system resources (including fuel types) during the event
  - Compulsory winterization and seasonal preparation
  - Interconnectivity of ERCOT with adjacent regions and whether resources could have been supplemented from outside ERCOT
  - ERCOT's market design and market and pricing processes during reliability events
  - Gas-power market interdependence; in particular, gas infrastructure performance and preparation
- On February 18, NERC and FERC initiated a joint investigation into the event. Separately but timely, FERC has scheduled a technical conference in June 2021 on climate change impacts relating to grid reliability and frequency of extreme weather. On February 22, FERC also commenced an enforcement proceeding to examine any potential market manipulation with spiking gas and power prices.

IMPLICATIONS

The incidence of high-impact events affecting energy systems appears to be on the rise. Electrification is expanding, variable generation is becoming a larger part of the energy mix, potential limits on interregional energy movement can occur, and system complexity continues to grow. This will push regulators and resource planners to contemplate greater tail risk in their scenarios, while challenging them to think more broadly about current reliability levers and to look to develop new ones such as energy storage.

Notes:

‡The reliability requirements and resource adequacy programs provide resource (supply or demand response) deliverability criteria that each load-serving entity must meet and provide rules for counting resources that must be made available to CAISO.

Sources:

2021 SB 100 Joint Agency Report (Mar. 2021); CAISO Dept. of Market Monitoring, Report on System and Market Conditions, Issues, and Performance: August and September 2020 (Nov. 24, 2020) (Market Monitor Report); Joint Report of CAISO, CPUC, and CEC, Root Cause Analysis: Mid-August 2020 Extreme Heat Wave (Jan. 13, 2021) (Root Cause Analysis); CAISO, 2020 Summer Loads and Resources Assessment (May 15, 2020); CPUC, *Proposed Decision of ALJ Stevens, Agenda ID #19115*, Rulemaking 21-11-003 (Jan. 8, 2021); CPUC, *Proposed Decision of ALJ Stevens, Agenda ID #19272*, Rulemaking 21-11-003 (Mar. 5, 2021); Clean Coalition, "What CAISO Didn't Tell You About the August 2020 Blackouts" webinar (Jan. 28, 2021); CAISO, Summer 2021 Reliability Monthly Report (Mar. 12, 2021); ERCOT, Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation (Feb. 24, 2021); White & Case Client Alert, "The Texas Blackout: A Regulatory Perspective and Future Outlook" (Mar. 2021); International Ass'n of Energy Economics webinar, "Texas and Other Markets After the Big Freeze: Diagnosis and Prognosis" (Mar. 19, 2021); Texas Railroad Comm'n website, January 2021 gas production, at https://rrc.texas.gov/oil-and-gas/research-and-statistics/production-data/texas-monthly-oil-gas-production/; Wood Mackenzie webinar presentation, "Spring 2021 Outlook: The Sun Will Come Out Tomorrow" (Feb. 24, 2021); FERC press releases, Feb. 18, Feb. 22, and Mar. 16, 2021

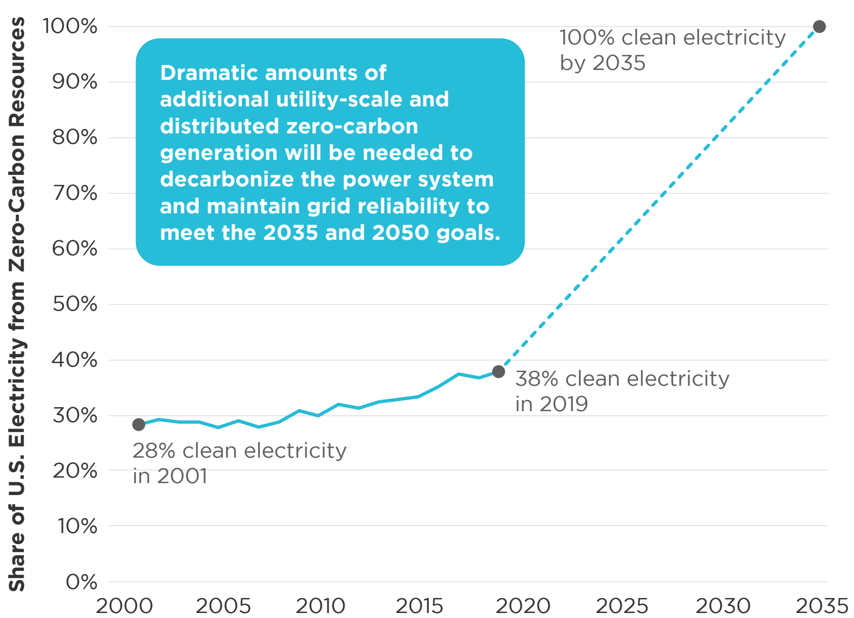
The Critical Role of Transmission in the Net-Zero Transition

Breaking the transmission logjam is becoming an urgent priority for many clean energy proponents.

Changed Context, New Priorities

- Eighteen U.S. states and territories have adopted mandates or goals to achieve 100% carbon-free or renewable energy, with some setting targets as early as 2030. Further, electric utilities have also made their own clean energy commitments, and corporate buyers are increasingly making voluntary commitments to purchase renewable energy.
- The U.S. Energy Information Administration projects that solar energy, wind energy, and battery storage will comprise 80% of the new capacity installed in 2021, further accelerating the deployment of variable renewable energy on the electric grid.
- Rather than a massive build-out of additional transmission capacity to integrate those new resources, many current transmission projects are smaller in scale and scope and more local in issues addressed. This suggests a disconnect between today's transmission planning processes and the increasingly aggressive clean energy goals of states, utilities, and corporations.

Figure 5.1: **Pace of Clean Electricity Additions to Increase Dramatically**



Note: Clean electricity refers to electricity that does not have carbon emissions as a byproduct of generation.

Source: ESIG Study

KEY TAKEAWAYS

The context for transmission has changed, and several recent studies point to the need for and benefits of a national backbone of a long-haul high-voltage transmission grid to enable clean energy goals.

The pace and scale of transmission development may be insufficient to meet integration needs, as renewable resources continue to dominate power supply additions.

Activity in jurisdictions such as New York suggests that policy and regulatory alignment can begin to plan needed transmission to reach aggressive policy goals, but much work is required to achieve policy objectives.

Developing large transmission projects across states and regions has proven much more challenging than developing smaller, intrastate and intraregional projects. A newly constituted FERC has expressed willingness to play an active role in deploying transmission to support state and federal clean energy agendas.

Changed Context, New Priorities (Cont.)

- Numerous studies have pointed to some important benefits of long-haul high-voltage transmission, many significantly outweighing the cost of developing new transmission, including:
  - Ability to deliver the lowest marginal cost resource to load
  - Access to non-correlated variable resources, thereby reducing variability
  - Flexibility to respond to increasingly dynamic fluctuations in supply and demand
  - Opportunity to scale to accommodate a surge in demand from electrification
- But challenges remain. As the Energy Systems Integration Group (ESIG) notes in a recent policy paper: “No single entity has the responsibility or authority to direct the building of transmission that serves national policy goals. Transmission has been constructed to meet incremental needs, but the pace of transmission needed to facilitate the clean energy transition is lacking.”
- With Order 1000, FERC attempted to address challenges to interregional transmission planning by requiring all regional transmission organizations to establish an interregional planning process. In practice, given the fact that few, if any, projects have been developed through those processes, many industry observers believe that Order 1000 needs to be revisited.
- Importantly, the new leadership at FERC has indicated an interest in supporting transmission to advance renewables development.

Recent Studies Highlight Needed Transmission

- Recent analyses from a variety of industry groups and stakeholders have reinforced and highlighted the importance of transmission in the energy transition. Among the headline-grabbing numbers where consensus is emerging, achieving the goals of the Biden administration may require doubling or tripling the size and scale of today's U.S. transmission system.
- The studies also align on the finding that, of today's technologies, wind and solar enabled by storage and transmission are the lowest cost options available to meet clean energy targets and that the pace of their deployment will need to accelerate dramatically to be able to meet those targets.
- The ESIG paper (noted earlier) synthesized the findings from six recent studies and outlined two areas of agreement across the body of work:
  - Transmission smooths all time scales of weather variability by providing access to wider areas and more remote resources that are less correlated.
  - A cross-country transmission network is critical to minimizing the electric system's cost and maximizing its flexibility.
- The possibility of developing a national "macro grid" made of a national-scale, long-haul transmission backbone connecting resources from coast to coast has inspired recent interest. And several of the studies demonstrate that, though it may be costly, investing in a massive-scale transmission system may also be cost effective. In outlining its macro grid concept, ESIG highlighted three key components to a well-designed macro grid:
  - A national transmission planning authority to develop engineering power system analyses to serve the entire nation's needs for reliable, economic, rapid, and full economy-wide decarbonization.
  - Identification of renewable energy zones that can support high levels of wind and solar development concentrated in favorable locations with the availability of large-scale transmission facilities and interconnection capacity.
  - A network of multi-regional transmission infrastructure that can be integrated into a macro grid to allow sharing of renewable resources across the country.

Figure 5.2: **Selected Energy Transformation Studies' Assessment of Renewable Needs**

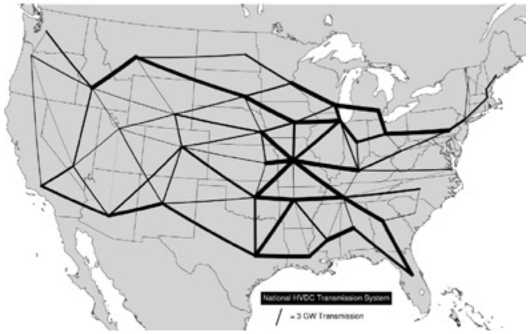
Study	Region Assessed	Renewable Capacity	Clean Energy Level(s)	Annual Electricity Demand	Target Year
The 2035 Report	United States	1,100 GWs (wind and solar)	90% clean electricity	4,500 TWhs	2035
Electrification Futures Study	United States and Canada	600 GWs (wind) 1,000 GWs (solar)	23% to 75% renewable energy	7,000 TWhs	2050
Interconnection Seam Study	United States (except Texas) and Canada	600-900 GWs (wind and solar)	63% to 95% carbon free electricity	4,900 TWhs	2038
MIT Study	United States	1,200 GWs (wind) 1,100 GWs (solar)	100% clean electricity	5,000 TWhs	2040
Renewable Integration Impact Assessment	United States - Eastern Interconnection	411 GWs (wind) 677 GWs (solar)	Up to 100% clean electricity	2018 demand	N/A
VCE ZeroByFifty	United States	1,100 GWs (wind) 1,000 GWs (solar)	100% clean energy	9,000 TWhs	2050

Note: Clean energy generally refers to renewables and other net-zero energy resources.

Source: ESIG Study

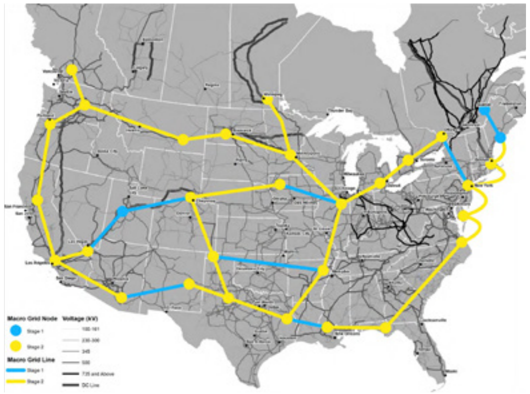
Figure 5.3: **Conceptual Maps of High-Voltage Transmission in a Low-Carbon Grid from Recent Studies**

VCE ZerobyFifty (2021)



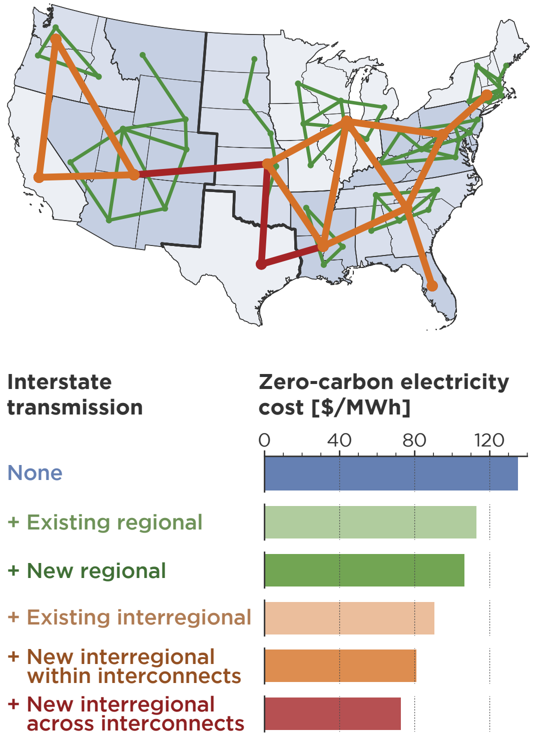
Source: VCE Study

ESIG (2021)



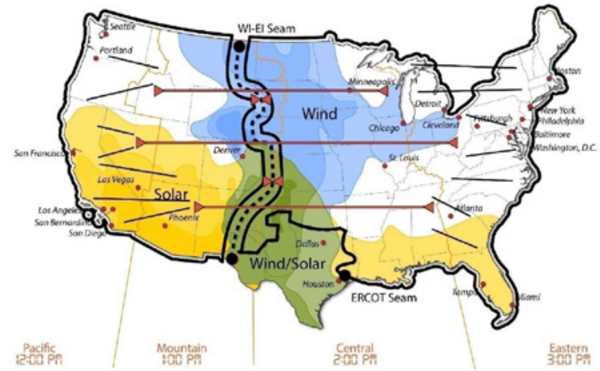
Source: ESIG Study

MIT (2021)



Source: MIT Study

NREL Seams (2018)

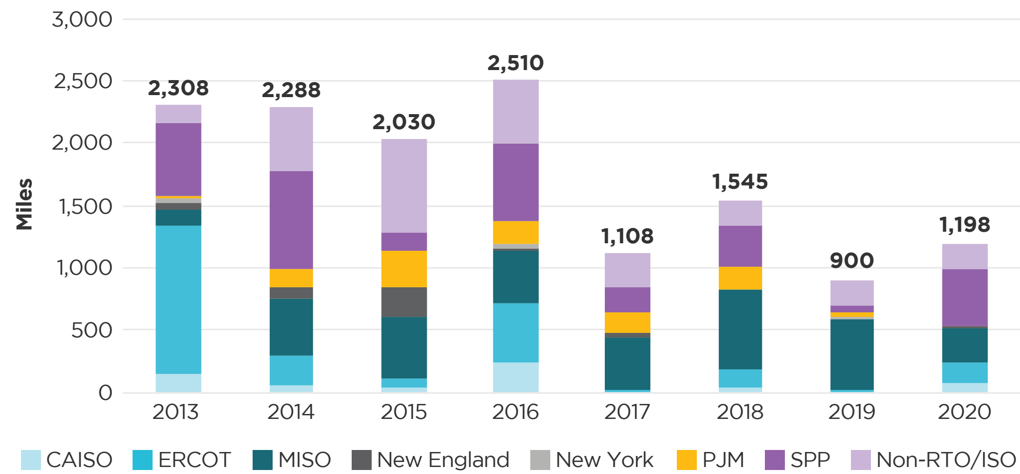


Source: Interconnection Seams Study

Are Plans for Transmission Development Enough?

- Approximately 160,000 miles of transmission are currently operating in the United States, and approximately 14,000 miles of those lines (less than 10% of the total) have been added since 2013, including nearly 350 discrete projects establishing new transmission paths between substations over that timeframe. As Figure 5.4 illustrates, the number of new miles added each year has declined markedly over the past four years compared to the 2013-2016 period.
- If recent history is an indicator of the pace of new transmission development going forward, significant intervention and acceleration may be required to achieve policy objectives related to deployment of clean energy (e.g., less than 10% over the past 8-9 years vs. 200% to 300% needed in the next 15 years).
- Today, S&P estimates that approximately 300 projects representing approximately 18,000 miles of transmission lines are in varying stages of development in the United States, from announced to under construction, but that figure is far short of the estimated needs outlined in recent studies.
- A large and growing number of renewable projects are being withdrawn from interconnection queues due to the lack of grid capacity, resulting in high interconnection costs. The Sustainable FERC Project's recent analysis of the MISO queue is telling.
  - From 2016 through October 15, 2020, developers withdrew 278 wind, solar, and battery storage or hybrid solar-storage projects from the queue. These projects had reached advanced stages of the interconnection process, representing nearly 35 GWs of capacity.
  - Clean energy developers are pulling their plans from the queue, as they are required to pay for grid upgrade costs too high for a single project to bear. In MISO West, for example, high-voltage grid upgrade costs assigned to developers have increased the total cost of some projects by more than 60%.

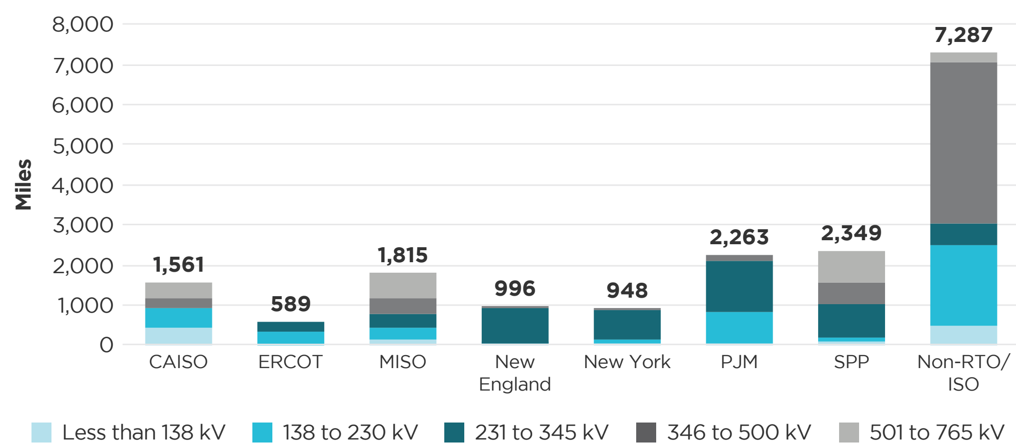
Figure 5.4: **Miles of New Transmission Added in the U.S. Since 2013 by Originating Region**



Note: Includes all projects greater than or equal to 115 kV and longer than 10 miles.

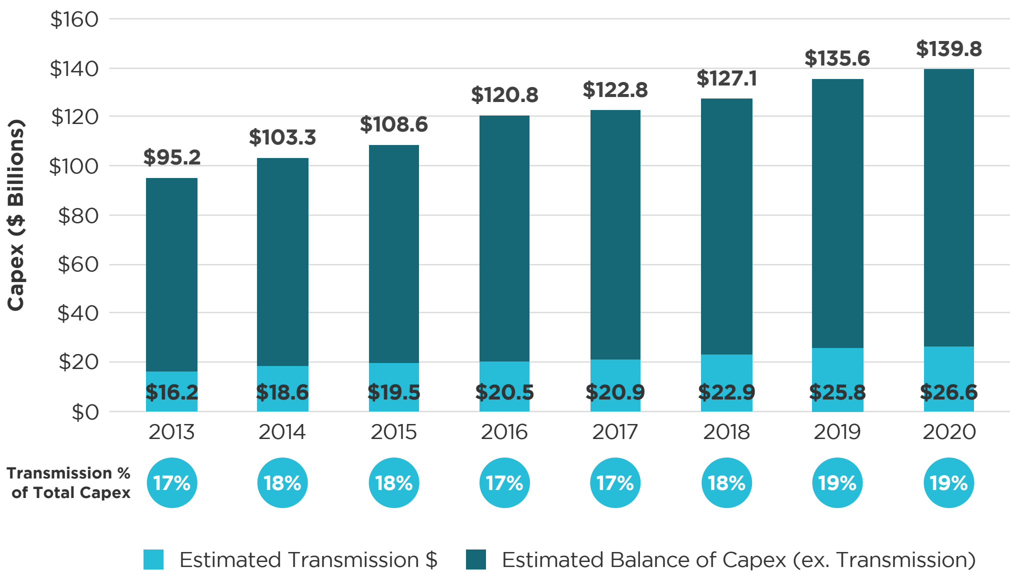
Sources: S&P Global Market Intelligence; ScottMadden analysis

Figure 5.5: **Miles of New Transmission Planned in the U.S. Today by Originating Region and Voltage**



Sources: S&P Global Market Intelligence; ScottMadden analysis

Figure 5.6: **Projected Capital Expenditures by Function ($ Billions)**



Source: EEI

Grid-Enhancing Technologies (GETs)

GETs include a portfolio of technology solutions that increase the capacity of the existing transmission system to accommodate more power flows across existing lines. While there are a variety of different types of GETs, one recent study for the Working for Advanced Transmission Technologies Coalition (WATT) examined the combined impact of three technologies in a targeted region of the Southwest Power Pool (SPP):

- **Advanced Power Flow Control** – Injects voltage in series with a facility to increase or decrease effective reactance, thereby pushing power off overloaded facilities or pulling power onto under-utilized ones.
- **Dynamic Line Ratings (DLRs)** – Adjust thermal ratings based on actual weather conditions, including ambient temperature and wind, in conjunction with real-time monitoring of resulting line behavior, expanding real-time capacity, improving safety, and maximizing capacity available to interconnect renewables.
- **Topology Optimization** – Automatically finds reconfiguration alternatives to re-route flow around congested or overloaded facilities while meeting reliability criteria.

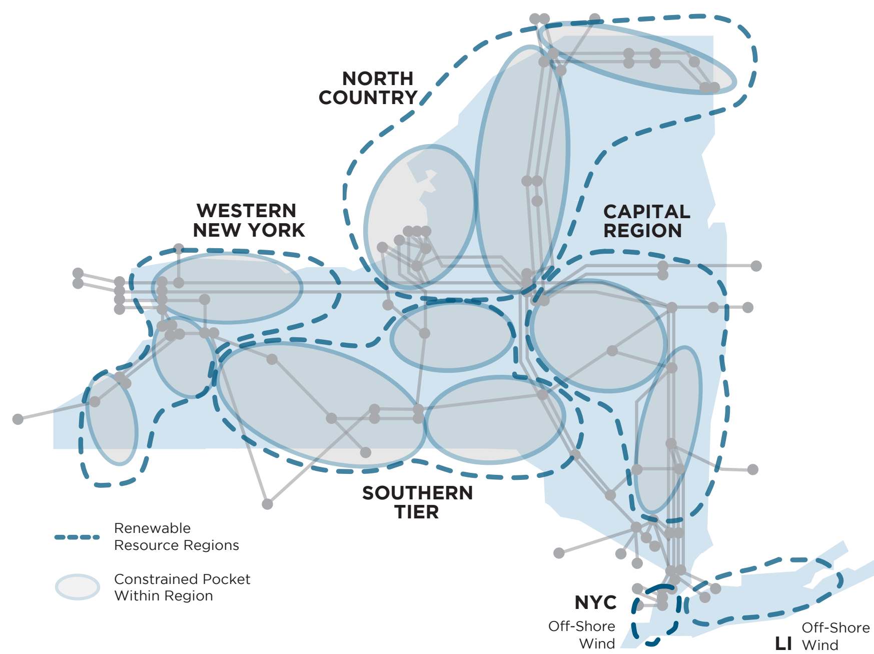
The WATT study also sought to quantify the combined benefits of all three technologies if deployed in concert in SPP: specifically, how much more renewable capacity could be accommodated, as well as its associated economic benefits and carbon-emission reductions.

- The study found that more than twice the amount of additional new renewables could be integrated with deployment of GETs, and it found that the cost of installing the technology ($90M) was dwarfed by the $175M annual production cost savings.
- Additional benefits included land lease costs and tax revenues, three million tons of incremental annual carbon reductions, and creation of 650 long-term jobs.

New York Links Climate and the Grid

- New York has been pursuing decarbonization, initially through its clean energy standard and other GHG reduction initiatives. New York's Climate Leadership and Community Protection Act (CLCPA), enacted in 2019, targets an 85% reduction in GHG emissions by 2050, 70% renewable generation by 2030, and 100% emissions-free electric supply by 2040. The CLCPA also envisions 9 GWs of offshore wind by 2035.
- In May 2020, pursuant to complementary legislation, NYPSC commenced a proceeding to develop a comprehensive power grid study to identify transmission and other grid improvements needed to achieve CLCPA targets. It also focused on local transmission and distribution (LT&D) capital plans and development of a state-wide bulk transmission plan.
- As part of the NYPSC proceeding, a joint New York utilities working group report recommended adapting existing LT&D planning processes and accelerating selected projects to facilitate achievement of CLCPA objectives. The report noted that achievement of clean energy mandates will require expanded planning objectives and changes to planning processes and to existing practices concerning cost allocation and cost recovery.
- The NYPSC accepted that traditional decision-making frameworks may not be adequate for the emerging requirements of the CLCPA. The commission solicited "practical proposals" for a process to guide future utility investment, including:
  - Transparent planning process
  - Approach to account for CLCPA benefits in utility planning and investment criteria
  - Approach to prioritizing recommended projects in context of other capex and CLCPA time frames
  - Benefit/cost analysis for LT&D upgrades
  - Cost containment, cost recovery, and cost allocation methodologies

Figure 5.7: **Renewable Generation Pockets in the New York ISO Region**



Source: New York ISO

New York Power Grid Study Identifies Gaps

- NYISO , the state, and a joint group of utilities commissioned reports on potential grid impacts from climate change and a net-zero power system, especially with high-renewables penetration.
- Released in January 2021, one such study (the Power Grid Study) prepared for NYPSC reviewed and distilled three other studies. Some important observations about the studies and the requirements of the future transmission system in the Power Grid Study are:
  - **Resource uncertainty:** Different studies make different assumptions about capacity, resource types, load growth trends, and imported and exported energy (e.g., hydro). Importantly, the uncertainty surrounding which new resources will come online, in which location, and when has implications for grid investment needs.
  - **Need for integration with LT&D:** Some scenarios assumed little or no renewable curtailments or congestion. However, they did not account for potential lower-voltage congestion, emphasizing the importance of integration across the entire grid, from source to sink.
  - **Energy storage is an essential variable:** The availability of storage impacts analyses insofar as it affects response to renewable overproduction, long- and short-duration seasonal and intraday underproduction, the need for thermal generation (including plants fired by hydrogen or renewable natural gas), and required upgrades at the local level, as well as overall system and energy cost.
  - **Optionality is a consideration:** In the case of offshore wind integration, the Power Grid Study opined that a meshed offshore network is superior for a large offshore wind development, providing insurance against cable outages. But in the interim, a radial connection could be acceptable if designed to later be converted to a meshed network.
  - **Advanced technologies:** Technologies like dynamic line ratings and power-flow control technologies, among others, should be considered when cost effective, but benefits may need to be discounted for additional risk of these new technologies.
  - **Coordinated planning processes are required:** As noted above, improvement of planning processes, including planning coordination among LT&D, renewable resource investments, and bulk power transmission infrastructure, is needed.
- Note that New York is a special case with its own self-contained ISO and single state regulator. Issues become thornier in regional, multi-state systems with different regulatory approaches and priorities. In deregulated markets with various entities that own or control resources, planning and coordination are more difficult.
- A separate look at potential resilience issues during transition was prepared last fall (see next page).

NYISO's Climate Change Impact and Resilience Study: Some Observations

- Climate disruption scenarios involving **storms and/or reductions in renewable resource output** (e.g., due to wind lulls) can lead to loss of load occurrences.
- The **variability of meteorological conditions** that govern the output from wind and solar resources presents a fundamental challenge to relying on those resources to meet electricity demand.
- Battery storage resources help fill voids created by reduced output from renewable resources, but periods of reduced renewable generation **rapidly deplete battery storage** resource capabilities.
- In many months, the distributed energy resources needed to balance the system must be significant in capacity, be able to come **online quickly**, and be flexible enough to meet **rapid, steep-ramping needs**.
- An assumed increase in inter-zonal transfer capability **enables a renewables-heavy resource mix** and improves reliability, but also **increases vulnerability to certain climate disruption scenarios**.
- Cross-seasonal differences in load and renewable generation could provide opportunities for **renewable fuel production**.
- The current system is heavily dependent on **existing fossil-fueled resources to maintain reliability**. Eliminating these resources from the mix will require an **unprecedented level of investment** in new and replacement infrastructure and/or the emergence of a **zero-carbon fuel source** for thermal generating resources.
- Overall, the key reliability challenges are associated with both **how the resource mix evolves between now and 2040** in compliance with the CLCPA and the impact of climate change on meteorological conditions and events that introduce additional reliability risks.
- Comparing **different resource pathways** reveals key differences in how the system makeup in 2040 can affect reliability outcomes.

Source: Climate Change Impact Study (emphasis added)

A Key Enabler: FERC's Policy Focus

- FERC is poised to play a pivotal role in the new administration's ambitious plans to address climate change and reduce GHG emissions from the U.S. electric power sector. Early signals suggest that the commission's new leadership is keen to use its statutory authorities to support the deployment of renewable resources.
- Ten years after Order 1000, the policy has yet to deliver on the early promise of increased interregional transmission development, and the new leadership has signaled a willingness to revise or revisit the order.
- One recent study, prepared on behalf of the American Council on Renewable Energy, summarized confidential interviews with industry stakeholders about the current policy framework, especially Order 1000. Recurring themes among the responses included:
  - Order 1000 requires grid operators to engage in interregional coordination, but it stops short of requiring interregional planning across regions.
  - The order also left many of the more complex details to be worked out by grid operators, including aligning planning processes and cost-benefit methodologies to enable joint project evaluation across regions.
  - "At present, there is no mandate for centrally coordinated interregional planning or an 'overlay study' to determine the optimal interconnection points for interregional renewable integration," the study noted. "As a result, opportunities for efficiencies from intercontinental transmission are being missed."
- In addition to revisiting Order 1000, FERC has other tools at its disposal to encourage the development of new transmission. These include using or delegating its authority to designate national transmission corridors and coordinating with federal power agencies to develop transmission projects on federal lands in the United States.
- Despite persistent challenges to developing inter-regional transmission, FERC's staff recently highlighted two important developments:
  - MISO/PJM – In a first for both grid operators, MISO recently joined PJM in approving an interregional project near the Indiana-Michigan border. Reported costs in 2020 for wires-related transmission projects in MISO and PJM were $2.4B and $3.6B, respectively.
  - MISO/SPP – In late 2020, MISO and SPP announced the launch of a new study group tasked with identifying cost-effective transmission projects along the Nebraska-Kansas seam between the two systems.

IMPLICATIONS

Transmission development is being recognized as a critical piece of the clean energy transition. Those seeking to achieve aggressive clean energy goals are becoming aware of the complementary roles played by clean energy development and new transmission development and expansion. The Biden administration and the new FERC leadership appear to be embracing a more muscular role for the federal government in clearing the logjam in regional and national transmission development. The questions will be how much and how far they can go, and whether other industry stakeholders embrace the changes needed.

Notes:

As of Apr. 12, 2021, states and territories with 100% clean or renewable energy goals include CA by 2045, CO by 2050, CT by 2040, DC by 2032, HI by 2045, LA by 2050, ME by 2050, MA by 2050, MI by 2050, NJ by 2050, NM by 2045, NV by 2050, NY by 2040, PR by 2050, RI by 2030, VA by 2045/2050, WA by 2045, and WI by 2050.

The Power Grid Study Report summarized and critiqued findings of the Joint Utilities Report, the Siemens PTI Report, and the DNV GL Report.

Studies summarized by the ESIG Study include The 2035 Report, Electrification Futures Study, Interconnections Seams Study, the MIT Study, the MISO RIIA, and the VCE Study (see references in Sources below).

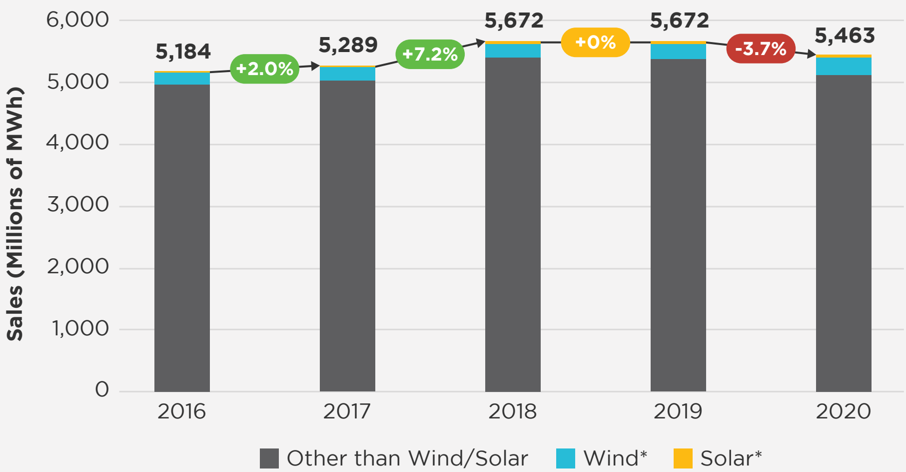
Sources:

FERC Staff Report, State of the Markets 2020 (Mar. 18, 2021) (State of the Markets Report); EIA[xi] , *Today in Energy*, "Renewables account for most new U.S. electricity generating capacity in 2021" (Jan. 11, 2021), available at https://www.eia.gov/todayinenergy/detail.php?id=46416; University of California, Berkeley, The 2035 Report (June 19, 2020), available at https://www.2035report.com/ (2035 Report); National Renewable Energy Laboratory (NREL), Electrification Futures Study: Scenarios of Power System Evolution and Infrastructure Development for the United States (Jan. 2021), available at https://www.nrel.gov/docs/fy21osti/72330.pdf (Electrification Futures Study); NREL, The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study (Oct. 2020), available at https://www.nrel.gov/analysis/seams.html and https://www.nrel.gov/docs/fy21osti/76850.pdf (Interconnection Seams Study); P. Brown & A. Botterud, "The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System," *Joule*, Vol. 5, Issue 1 (Jan. 20, 2021), available at https://www.cell.com/joule/fulltext/S2542-4351(20)30557-2 (MIT Study); Midcontinent Independent System Operator (MISO) Renewable Integration Impact Assessment (Feb. 2021) (MISO RIIA), available at https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/#nt=%2Friiatype%3AReport&t=10&p=0&s=Updated&sd=desc; Vibrant Clean Energy, ZeroByFifty: United States Zero Emission Economy-wide by 2050, available at https://www.vibrantcleanenergy.com/media/reports/zerobyfifty/ (VCE ZeroByFifty); Working for Advanced Transmission Technologies Coalition (WATT), Unlocking the Queue with Grid-Enhancing Technologies: Case Study of the Southwest Power Pool (Feb. 1, 2021), prepared by The Brattle Group; Americans for a Clean Energy Grid, Macro Grids in the Mainstream: An International Survey of Plans and Progress (Nov. 18, 2020), prepared by Iowa State University; Energy Systems Integration Group, Transmission Planning for 100% Clean Energy (Feb. 18, 2021) (ESIG Study); American Council on Renewable Energy, How Transmission Planning & Cost Allocation Processes are Inhibiting Wind & Solar Development in SPP, MISO, and PJM (Mar. 25, 2021), prepared by Concentric Energy Advisors; NYPSC, *Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Case 20-E-0197 (May 14, 2020) (Study Order), at pp. 1-2; Initial Report on the New York Power Grid Study (Jan. 19, 2021), prepared by NYDPS, NYSERDA, The Brattle Group, and Pterra Consulting for NYPSC (Power Grid Study); Joint Utilities, Utility Transmission and Distribution Investment Working Group Report (Nov. 2, 2020) (Joint Utilities Report); Siemens Power Technologies, Inc., Zero-Emissions Electric Grid in New York by 2040 (Siemens PTI Report); DNV GL Energy Insights, PowerGEM & WSP Global, Offshore Wind Integration Study: Final Report (Dec. 2020), prepared for NYSERDA and NYDPS (DNV GL Report); NYISO, Climate Change Impact and Resilience Study – Phase II (Sept. 2020), prepared by Analysis Group (Climate Change Impact Study)

THE ENERGY INDUSTRY
IN CHARTS

- COVID-19 affected power demand, but wholesale power sales remained above 2017 levels.
- We highlight a few key statistics from 2020 below.

Figure 6.1: **Annual U.S. Wholesale Power Sales by Type (2016-2020) (Millions of MWhs) and Year-over-Year Growth**



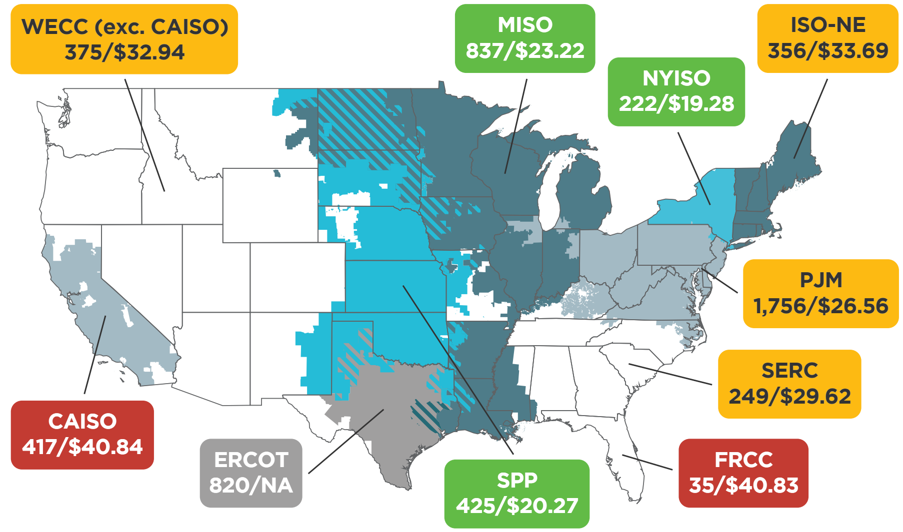
2016–20 CAGR
- **Total:** 1.3%
- **Wind**: 10.7%
- **Solar:** 25%

2020 % of Total
- **Solar:** 1.1%
- **Wind**: 5.1%
- **Other than Wind/Solar:** 93.8%

Notes: *Utility scale. Utility-scale wholesale sales from wind and solar facilities that are for the most part facilities above 20 MWs in size. Annual figures calculated by aggregating quarters.

Sources: S&P Global Platts (from FERC quarterly data); ScottMadden analysis

Figure 6.2: **2020 Wholesale Power Sales by Region (Millions of MWhs) and Average Value ($/MWh)**



$/MWh Legend
- $0-$25.00 (green)
- $25.01-$35.00 (yellow)
- $35.01+ (red)

REGION
Sales MWhs / Average $/MWh

Notes: MWh values are rounded to nearest million MWhs. NA means not available. Low average values may result from tolling or exchange agreements. ERCOT data is not comprehensive and is based on filings where data is available. ERCOT sales for Calpine, NextEra, NRG, OE Holdings, Talen, and Tenaska are for sales from generation only. Average price is for all regions ex-ERCOT. Totals include an estimate for data not filed at FERC as of March 7, 2021. CAISO totals include an estimate for Pacific Gas and Electric and Southern California Edison CAISO sales for Q4 2020 which are reported one quarter late.

Sources: S&P Global Platts (from FERC quarterly data); ScottMadden analysis

GLOSSARY

B
Billion

CAISO
California ISO

capex
capital expenditures

CCS
carbon capture and storage

CECP
Massachusetts' Clean Energy and Climate Plan

CO_2
carbon dioxide

CPUC
California Public Utilities Commission

DEQ
N.C. Department of Environmental Quality

DOA
N.C. Department of Administration

DOT
N.C. Department of Transportation

EEI
Edison Electric Institute

EIA
U.S. Energy Information Administration

EPS
earnings per share

ERCOT
Electric Reliability Council of Texas

ESG
environment, social, and governance

EV
electric vehicle

FERC
Federal Energy Regulatory Commission

FRCC
Florida Reliability Coordinating Council

FTE
full-time equivalent employees

GHG
greenhouse gas

GW
gigawatt

IOU
investor-owned utility

ISO
independent system operator

ISO-NE
ISO New England

kW
kilowatt

kWh
kilowatt-hour

LDC
local gas distribution company

LT&D
local transmission and distribution

M
Million

MISO
Midcontinent ISO

MMBtu
million British thermal units

$MtCO_2e$
million metric tons CO_2-equivalent

MW
megawatt

MWh
megawatt-hour

NARUC
National Association of Regulatory Utility Commissioners

NERC
North American Electric Reliability Corporation

NREL
U.S. National Renewable Energy Laboratory

NYISO
New York ISO

NYPSC
New York Public Service Commission

OASIS
open access same-time information system

O&M
operations and maintenance

P/E
price-to-earnings

PIM
performance incentive mechanism

PJM
PJM Interconnection

PSC
public service commission

PUC
public utilities commission

RA
resource adequacy

RTO
regional transmission organization

SERC
SERC Reliability Corporation

SPP
Southwest Power Pool

T&D
transmission and distribution

TWh
terawatt-hour

V2G
vehicle-to-grid

WECC
Western Electricity Coordinating Council

ZEV
zero-emissions vehicle

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ScottMadden will host a free webcast based on this report on **Thursday, June 10, 1-2 PM ET**, to further explore the advancement of fleet electrification and why electric utilities should start preparing now, Massachusetts' recently released decarbonization roadmap, and the role transmission can play during the transition to net-zero. 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.

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