FAILURE TO ACT

Electric Infrastructure Investment Gaps in a Rapidly Changing Environment

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EBP

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EXECUTIVE SUMMARY

Failure to Act: Electric Infrastructure Investment Gaps in a Rapidly Changing Environment

Electricity plays a key role in supporting the economy. Generation, transmission, and distribution systems that transmit electricity must be kept in a state of good repair to support the critical electricity needs that keep our homes, hospitals, schools, and businesses running.

Most of the nation's transmission and distribution lines were constructed in the 1950s and 1960s, with a 50-year life expectancy, meaning they have reached or surpassed their intended lifespan. Aging equipment stands to impact reliability of the electric grid – the nation's network of transmission and distribution systems.

A RAPIDLY CHANGING ENVIRONMENT

Since ASCE last issued its Failure to Act electricity report in 2011, the energy sector has vastly transformed. A combination of technology, markets, more severe storms, and policy changes at the state and federal level are driving this transformation. Key changes include:

1. Natural gas and renewable energy are growing as a percentage of the energy portfolio mix. In 2019, total renewable generation exceeded coal-fueled generation for the first time, a trend that is expected to continue. However, a greater adoption of solar, wind, and other renewable energy sources is changing electricity consumption patterns, subsequently requiring changes to be made across generation, transmission and distribution physical structures and control mechanisms.
2. Resilience and reliability concerns are increasingly driving infrastructure investment. While weather has always been the number one reliability threat, the number and intensity of disaster events and associated costs is accelerating.
3. The utility industry – and the economy as a whole – have become much more energy efficient, which serves as a constraint on the growth of electricity consumption. Demand is relatively flat and there are generally few concerns about the availability of adequate amounts of electricity. Instead, forecasted shortfalls in generation are the result of requirements that a certain share of the overall supply come from renewables.

WHAT IS ELECTRICITY INFRASTRUCTURE?

The United States' electric grid consists of a complex system of interconnected power generation, transmission, and distribution infrastructure.

- **Generation facilities** transform natural gas, coal, water, solar, wind, and other sources into electricity. There are about 10,000 generation facilities (i.e. power plants)[1] in the U.S., not including individual units such as residential solar panels or small-scale windfarms.
- Once generated, **transmission lines** transfer this electricity over long distances to distribution lines. There are more than 600,000 circuit miles of transmission lines, including 240,000 that are considered high-voltage. The transmission system can be thought of as the "interstate highway" of electricity delivery.
- **Distribution lines** provide electric power to homes and businesses. If transmission lines are the "highway" of the electric grid, distribution lines are the local roadways, carrying the electric power to its final destination. There are an estimated 5.5 million miles of local distribution lines or underground cables in the U.S.[2]

1 EIA FAQ , https://www.eia.gov/tools/faqs/faq.php?id=65&t=2#:~:text=As%20of%20December%2031%2C%202018,than%20one%20type%20of%20fuel.

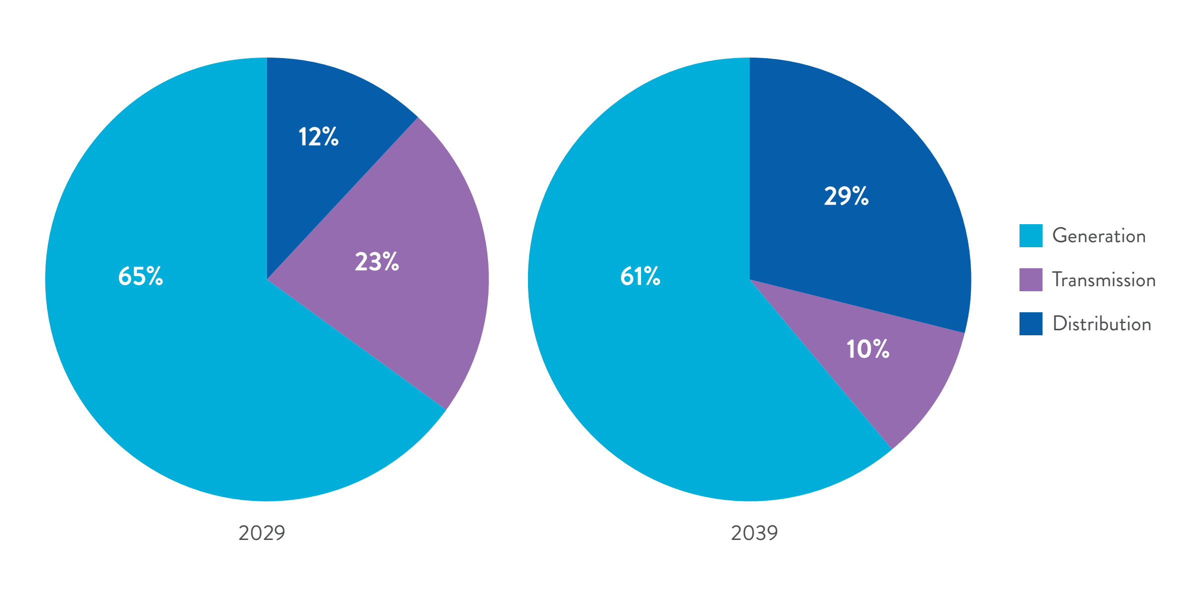
2 U.S. Dept. of Energy, Dynamic Line Rating: Report to Congress June 2019 https://www.eenews.net/assets/2020/01/27/document_ew_02.pdf

THE ELECTRICITY INFRASTRUCTURE INVESTMENT GAP

The estimated investment gap is the difference between projected trends of investments in electricity generation, transmission, and distribution infrastructure with estimated total needs. The needs are based on household and business demand for electricity, the age of current infrastructure, evolving mix of energy technologies, and state and federal policies that mandate conversions to renewable energy sources. **The total gap indicates that the U.S. is facing a $208 billion (in 2019 dollars) shortfall by 2029 and a $338 billion shortfall by 2039 in what is needed to ensure a reliable energy system.**

Driven by conversion to different energy sources to meet renewable portfolio standards and barring a significant increase of investment levels, generation will account for 65 percent of needed investment by 2029. When forecasting out to 2039, the gap in generation will shrink to 60 percent of the total, with distribution needs growing significantly to 29 percent of the overall share.

Share of U.S. Electricity Infrastructure Investment Gap—2029 & 2039



Totals may not add up due to rounding

Regional Differences in the Investment Gap

There are differences in projected investment gaps among the nine regions of the continental U.S. Overall, the West with its major land expanse and large population in California accounts for 33 percent of the total national investment gap, while the Northeast and Mid-Atlantic regions – with some of the oldest infrastructure in the U.S. – account for 43 percent of the gap. Moreover, the West, Northeast, and Mid-Atlantic regions generally have some of the more aggressive renewable energy targets, driving a need to develop renewable generation and the transmission infrastructure to support it.

Comparatively, investment gaps in Florida, the Southeast, and the Southwest are the smallest. All of Florida's needs are in distribution infrastructure. In the Southeast, modest generation and transmission investment are needed by 2029, and distribution will be needed to meet increasing population and business user demand. The Southwest and Midwest regions will require modest investments in generation, transmission, and distribution investments through 2039 to protect efficient electricity production and consumption.

Electricity Infrastructure Investment Gap ($2019 billions)

Region	Generation			Transmission			Distribution			TOTAL		
	2020-2029	2030-2039	2020-2039	2020-2029	2030-2039	2020-2039	2020-2029	2030-2039	2020-2039	2020-2029	2030-2039	2020-2039
Midwest	$2.2	$4.1	$6.3	$0.1	$0.2	$0.4	$2.1	$2.2	$4.3	$4.4	$6.6	$11.0
Southwest	$0.6	$2.7	$3.4	$0.1	$0.3	$0.4	$2.0	$2.1	$4.1	$2.8	$5.1	$7.9
Texas	$9.7	$13.4	$23.1	$0.6	$0.9	$1.5	$2.6	$2.8	$5.4	$12.9	$17.1	$30.0
Northeast	$38.3	$20.9	$59.3	$5.5	$3.3	$8.8	$6.1	$6.4	$12.5	$50.0	$30.6	$80.6
Mid-Atlantic	$25.9	$3.9	$29.9	$4.3	$0.8	$5.1	$13.9	$14.5	$28.3	$44.1	$19.1	$63.2
West	$50.8	$22.8	$73.6	$11.5	$5.7	$17.2	$10.6	$11.1	$21.7	$72.9	$39.5	$112.5
Southeast	$7.4	$0.0	$7.4	$2.2	$0.0	$2.2	$8.1	$8.4	$16.5	$17.7	$8.4	$26.1
Florida	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$3.3	$3.4	$6.7	$3.3	$3.4	$6.7
Total	$135.0	$67.9	$202.9	$24.4	$11.1	$35.5	$48.8	$50.9	$99.6	$208.1	$129.8	$338.0

Note: The tables above reflect the continental 48 states. An additional $830 million of distribution needs for the 2020-2039 period are estimated for Alaska ($6 Million) and Hawaii ($824).

Sources: Annual Energy Outplook, U.S. Energy Information Administration and electric Market Module of the National Energy Modeling System. Analysis by Daymark Energy Advisors Generation Gap Analysis and EBP.

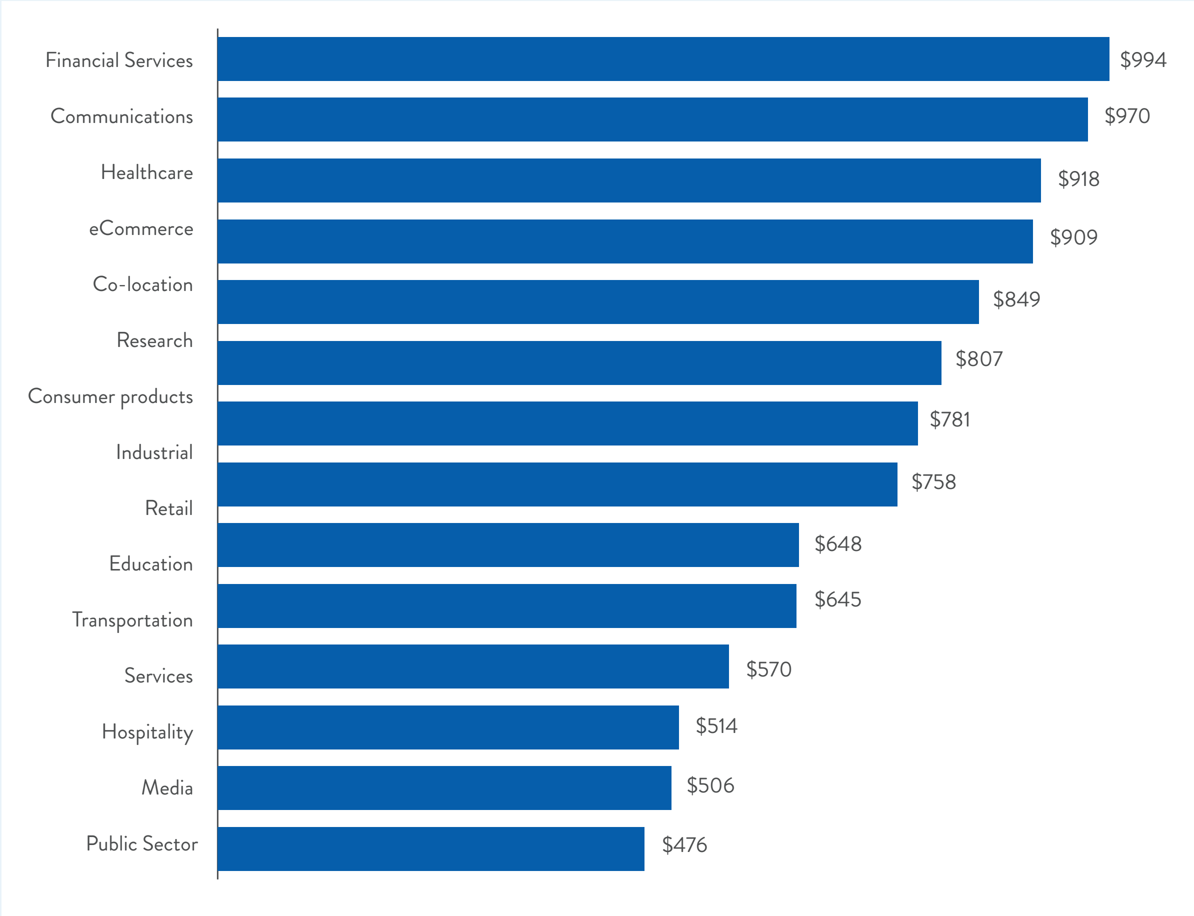
A Failure to Act hurts businesses and households

The impacts of investment shortfalls in electric infrastructure are multiple and interrelated. The grid's investment gap contributes to a greater incidence of electricity interruptions. Interruptions can be the result of equipment failures, capacity blackout or brownouts, power quality irregularities, or intermittent voltage surges. Electricity interruptions can vary in terms of frequency and duration. Ultimately, however, these system failures result in an unreliable electricity supply, which imposes direct costs on both households and businesses.

Costs incurred by both households and businesses can include damage to electronics from voltage spikes and surges, spoiled food that would otherwise be refrigerated, and additional costs incurred by an increased reliance on, and use of, backup generators. Consumers experience these electricity system failures as direct financial impacts to their households and businesses, as well as through larger effects on the nation's economy. The cost to residential customers from each electric interruption event is estimated at $6.68 using 2018 costs. This is about twice the cost for momentary events in 2011.

Meanwhile, businesses bear the consequences of downtime, labor, and lost productivity when the electicity grid fais. Outages are most damaging in the manufacturing sector, costing almost $42,000 per event on average in 2008. However, many different industries rely on data centers, and the average cost of an outage at one of these facilities increased from $505,000 in 2010 to $740,000 in 2016. That equates to incurred costs of $8,851 per minute the electricity grid is malfunctioning. Figure 8 lists cumulative impacts per year of data center disruptions due to electricity outages.

Cumulative Impacts Per Year of Data Center Disruptions due to Outages on Selected Industries (in $1000s)



Source: Ponemon Institute Cost of Data Center Outages, January 2016

The impacts from costs to businesses due to inefficiencies in delivery of electric power, including voltage spikes and surges, lost productivity, and added costs incurred by an increased reliance on secondary generators, monitoring equipment and backup strategies, as well as direct consumer costs (such as spoiled food), will result in lost household income. This lost disposable income is projected at $13 per household per year in 2020 but will grow to $563 by 2039 if the generation, transmission, and distribution investment gaps are not mitigated

The following table shows the total output losses by industry sector due to underinvestment in infrastructure from 2020 to 2029 and 2030 to 2039.

Aggregated Output Losses by Industry Sector ($2019 billions)

Sector	2020-2029	2030-2039	2020-2039
Manufacturing	$210	$736	$947
Health Care	$27	$134	$161
Professional Services	$72	$302	$374
Other Services	$47	$164	$211
Logistics	$45	$160	$204
Finance, Insurance and Real Estate	$96	$344	$439
Construction	$17	$54	$71
Retail trade	$24	$82	$107
Accommodation, Food and Drinking Places	$15	$53	$68
Transportation Services (excluding truck transportation)	$14	$50	$64
Mining, Utilities, Agriculture	$18	$63	$81
Information	$39	$167	$206
Educational Services	$4	$13	$17
Entertainment	$5	$16	$21
Social Assistance	$3	$10	$12
Totals	$637	$2,347	$2,984

Columns and rows may not add due to rounding.

Note: Losses and increases reflect impacts in a given year against national baseline projections. These measures do not indicate declines from 2019 levels.

Sources: EBP and LIFT model, University of Maryland, INFORUM Group, 2020.

Given current investment trends, capital investment needs, and changing trends in demand, the national losses in employment amount to 287,000 jobs in the year 2029 and 540,000 jobs in 2039. While employment impacts are expected to be relatively modest, the breadth of the impact touches many sectors in the economy. The following table shows the total jobs beneath the 2029 and 2039 national baseline.

Potential Employment Losses because of inadequate electricity infrastructure, 2029 and 2039

Sector	2029	2039
Manufacturing	36,700	61,700
Finance, Insurance and Real Estate	29,400	55,400
Professional Services	29,300	67,400
Other Services	37,800	71,600
Health Care	31,000	78,300
Construction	15,700	25,700
Information	8,100	13,900
Logistics	22,100	41,200
Retail trade	30,500	49,100
Mining, Utilities, Agriculture	7,400	12,900
Transportation Services (excluding truck transportation)	6,900	12,500
Accommodation, Food and Drinking Places	21,100	36,900
Entertainment	3,600	4,000
Educational Services	6,500	9,400
Social Assistance	1,000	300
Totals	287,200	539,800

Columns may not add due to rounding.

Note: Losses and increases reflect impacts in a given year against national projections. These measures do not indicate declines from 2019 levels

Sources: EBP and LIFT model, University of Maryland, INFORUM Group, 2020.

Rising incidences of voltage surges, and blackouts, and brownouts that disrupt production add costs to businesses that will make U.S. manufactured products less competitive in international markets. Consequently, between 2020 and 2039, U.S. businesses will lose $271 billion in the value of its exports, while businesses and households will pay an additional $142 billion for foreign imports.

CONCLUSION

The electricity sector is undergoing immense transformation and significant investments are needed to accommodate these shifts. While transmission infrastructure has benefited from increased investment over the last 10 years, continued modernization is needed to move large amounts of renewables across the grid. Across generation, transmission, and distribution, the U.S. is facing a $208 billion shortfall by 2029 and a $338 billion shortfall by 2039 in what is needed to ensure a reliable energy system.

If the needs identified in this report go unaddressed, business productivity will weaken, and wages and household incomes will fall. The impacts of underinvestment will be delayed but pronounced. About 77 percent of disposable income losses and total GDP losses and 79 percent of gross output losses are expected to occur between 2030 and 2039. Additionally, job loss will roughly double in the second decade of the study – a projected 287,000 jobs will be lost by 2029, compared to 540,000 jobs by 2039. By 2039, failing to close that investment will cost each American household $563 per year.

Reliable electricity is essential for today's economy and for 21st century living. By acting now to modernize the infrastructure that powers our homes, schools, hospitals, data centers, manufacturing plants and more, by investing in response to the evolving mix of energy technologies, and by easing permitting, impacts to American households and businesses can be mitigated.

About this Report

This *Failure to Act* report is about the electricity infrastructure that powers our nation's homes and businesses, including generation, transmission, and distribution systems. The report provides an objective analysis of the economic implications for continued underinvestment in infrastructure in the United States. Specifically, the report quantifies the cost of inaction for households, industries, and the overall economic competitiveness of the U.S. Additionally, this report touches on several seismic changes in the energy landscape that our electric infrastructure will need to accommodate.

OBJECTIVES AND LIMITATIONS OF THIS STUDY

The purpose of this study is to simulate the economic effects of various investment trends in America's energy infrastructure. This report does not address the availability, shortages, or changing prices of energy resources, nor the need or cost of exploration and extraction. It is also not intended to propose or imply prescriptive policy changes. Furthermore, the report does not address the fuels, or combination thereof, that are best suitable for the nation's energy future, nor the costs and benefits of energy fuel security. This study is limited to the infrastructure systems that generate electricity and convey it to businesses, institutions, and households.

ECONOMICS IN PANDEMICS: A NOTE ON COVID-19

The analysis in this report relies on baseline data that predates the COVID-19 pandemic. Data sets and economic models generally lag one to three years behind the present, to allow for data collection, validation, and publication. As a result, economic modeling does not yet account for COVID-19's domestic and global impacts.

However, COVID-19 has implications for the state of electricity infrastructure. With social distancing and stay-at-home mandates, worksite demand for electricity has declined, but household demands have increased. The U.S. Energy Information Administration's (EIA) latest Short-Term Energy Outlook, released in May 2020, predicts that retail sales of electricity in the commercial sector will fall modestly by 6.5 percent in 2020. Industrial retail sales of electricity are also expected to fall by 6.5 percent this year as many factories cut back production.[1] Meanwhile, payment deferral policies may lead to temporary revenue shortfalls for utilities, possibly affecting operation and maintenance. Shutdowns and slowdowns at manufacturing plants have interrupted supply chains, while stalled development could impact the construction of renewable generation and associated transmission facilities.

Up to the present time, energy infrastructure owners and operators have generally delivered a reliable supply of electricity in the face of shifting demand with little impact on prices paid. They have accomplished this despite aging infrastructure, evolving energy mixes, and other challenges discussed later in this report.

STUDY METHODOLOGY

ASCE worked with an economic research team that included EBP, Daymark Energy Advisors, and the Interindustry Forecasting Project (INFORUM) at the University of Maryland to develop this analysis. To estimate long-term national economic impacts, the researchers used the Long-term Interindustry Forecasting Tool (LIFT), housed at University of Maryland's INFORUM Group. LIFT is a dynamic interindustry-macro (IM) model that uses macroeconomic data to examine how changes in one industry will affect other industries and the national economy.

The Failure to Act series analyzes two types of infrastructure needs:

1) Building new infrastructure to service increasing and shifting populations and expanded economic activity; and

2) Maintaining or rebuilding existing infrastructure that needs repair or replacement.

The report includes projections generated for both 10-year (2029) and 20-year (2039) time horizons. The economic modeling is based on the 2019 national economy and used 2019 dollars, thus the economic impacts of the COVID-19 pandemic are not reflected in these projections.

1 EIA Short-Term Energy Outlook, May 12 2020

Introduction

The United States' electric grid consists of a complex system of interconnected power generation, transmission, and distribution infrastructure.

- **Generation facilities** transform natural gas, coal, water, solar, wind, and other sources into electricity. About 10,000 generation facilities (i.e. power plants) are in the U.S., not including individual units such as residential solar panels or small-scale windfarms.[2]
- Once generated, **transmission lines** transfer this electricity over long distances to distribution lines. The electricity network in the U.S. includes more than 600,000 circuit miles of transmission lines, including 240,000 that are considered high-voltage. The transmission system can be thought of as the "interstate highway" of electricity delivery.
- **Distribution lines** provide electric power to homes and businesses. If transmission lines are the "highway" of the electric grid, distribution lines are the local roadways, carrying the electric power to its final destination. An estimated 5.5 million miles of overhead and underground distribution lines are in the U.S.[3]

Electricity plays a key role in supporting the economy. Therefore, generation, transmission, and distribution systems that transmit electricity must be kept in a state of good repair to support the critical electricity needs that keep our homes, hospitals, schools, and businesses running. However, most of the nation's transmission and distribution lines were constructed in the 1950s and 1960s, with a 50-year life expectancy, meaning they have reached or surpassed their intended lifespan. Aging equipment stands to impact reliability of the electric grid – the nation's network of transmission and distribution systems.

A few key differences distinguish the energy grid from other infrastructure.

1. **Ownership:** Unlike our roads and bridges, most of our electric grid is privately-owned. For-profit, investor-owned utilities serve 72 percent of customers in the county, with publicly-owned utilities and rural cooperatives serving the rest. Privately-owned, independent power producers (IPP) also interface with the grid. Federal and state agencies have regulation authority over generation and transmission systems, while customer rates are generally regulated by state and local agencies.
2. **Technology:** The energy landscape is dynamic, and technologies evolve quickly. Innovation has transformed generation—including nuclear power, combustion of carbo-based fossil fuels such as coal, oil, diesel, and natural gas, and renewable power such as hydro, wind, solar, geothermal, or biomass. Meanwhile, behind-the-meter renewable generation by residential customers such as household solar panels are increasing.

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2 EIA FAQ, https://www.eia.gov/tools/faqs/faq.php?id=65&t=2#:~:text=As%20of%20December%2031%2C%202018,than%20one%20type%20of%20fuel.

3 U.S. Dept. of Energy, Dynamic Line Rating: Report to Congress June 2019 https://www.eenews.net/assets/2020/01/27/document_ew_02.pdf

3. **Renewable mandates:** Increasing awareness and concerns about climate change are driving states to enact mandates known as Renewable Portfolio Standards (RPS). An RPS requires utilities to incrementally increase the amount of electricity produced by renewable energy, including wind, solar, biomass, and other alternatives to fossil fuel and nuclear electric generation. Mandated RPS along with government subsidies have increased the percentage of renewables generated by utilities and have also stimulated market-based demand for renewable energy among business and residential customers. Subsequently, renewable energy generation has become more affordable. The combination of mandates and market demands, along with the geographical relocation of generation, amplify the need to build out new infrastructure to support a reliable, resilient, decarbonized electric grid, while maintaining our existing energy infrastructure at a high level.

CHANGES IN THE ENERGY LANDSCAPE

The energy sector has vastly transformed since ASCE last issued its Failure to Act electricity report in 2011 and will continue its transformation in the years ahead. A combination of technology, markets, and policy changes at the state and federal level are driving this transformation.

In the markets, natural gas and renewable energy are now competing with coal. In 2019, total renewable generation exceeded coal-fueled generation for the first time, a trend that is expected to continue.

Key technological developments have helped foster a more distributed, decarbonized electric grid. Relatedly, advancements in electricity storage, both by utilities and by customers, are better enabling solar and wind reliability. Solar and wind generation are often variable, meaning they do not always generate electricity at the time and in quantities needed. Improvements in storage make wind and solar more viable options within the electric markets.

However, a greater adoption of solar, wind, and other renewable energy sources is changing electricity consumption patterns, subsequently requiring changes to be made across generation, transmission and distribution physical structures and control mechanisms. For example, land-based and offshore-based wind generators require adequate transmission to reach distribution points. In another example, wind farms are being developed in the West as coal plants are decommissioned in the East, requiring transmission to move electricity in varying volumes and different directions than previously. Distributed networks may have multiple electric inputs and outputs, requiring much more sophisticated controls than were needed just a decade ago.

Additionally, resilience concerns are increasingly driving infrastructure investment, in both centralized and distributed configurations. While weather has always been the number one reliability threat, climate change has accelerated the number and intensity of disaster events and associated costs. These include fires, particularly in the western U.S., floods, sea level rise, and severe storm events such as Superstorm Sandy in 2012, and more recently, Hurricanes Irma, Harvey, and Maria in 2017; Michael in 2018; and Dorian in 2019. The devastating 2018 California wildfire season cost the state $400 billion in economic losses. NOAA estimates that over a four-year period studied, more than $1.7 trillion in losses were incurred by 273 major storms, fires and other natural disasters across the nation.[4] A separate U.S. Department of Energy (DOE) report estimates that power outages from weather-related events and other causes are estimated to cost the United States $28 to $169 billion annually.

McKinsey Company published a report in 2019 that examined the consequences of major events affecting 10 utilities in hurricane-prone states, the costs of storm damage, and preventive measures. Using data from the Fourth National Climate Assessment, McKinsey developed a baseline of likely costs per utility of $1.4 billion over a 2-year period. Meanwhile, the cost of preventive actions that would minimize or avoid damages for a typical South East utility was calculated at $700 million to $1 billion per utility.[5] Many of the resilience measures, such as increasing storage, hardening facilities, fostering distributed generation, building microgrids, and environmental management also serve the overall goal of decarbonizing the electric grid.

Finally, the utility industry – and the economy as a whole – have become much more energy efficient, which serves as a constraint on the growth of electricity consumption. The simplest way to measure energy use is to compare it to Gross Domestic Product (GDP). A 2015 report by the American Council for an Energy Efficient Economy explains more:

> From 1980 to 2014, U.S. energy use increased by 26 percent. However, over this same period, U.S. gross domestic product (GDP) increased by 149 percent. A common approach for looking at these two variables together is to examine energy intensity, defined as energy use per real dollar of GDP. Energy intensity declined from 12.1 thousand Btus per dollar in 1980 to 6.1 in 2014, a 50 percent improvement… Energy efficiency was an important contributor to this improvement. However, efficiency gains were also partly due to shifts in the U.S. economy away from some energy-intensive segments (e.g., heavy manufacturing). Based on available data, [estimates] conservatively [show] that about 40 percent of the improvement in energy intensity was due to structural shifts, and 60 percent was due to efficiency improvements. Energy efficiency savings in 2014 …sav[ed] US consumers and businesses about $800 billion in 2014 (based on the average 2014 energy price). This comes to about $2,500 per capita.[6]

4 *U.S. Billion-Dollar Climate Disasters 1980-2020 National Oceanic and Atmospheric Administration (NOAA)*, www.ncdc.noaa.gov/billions/events.pdf.

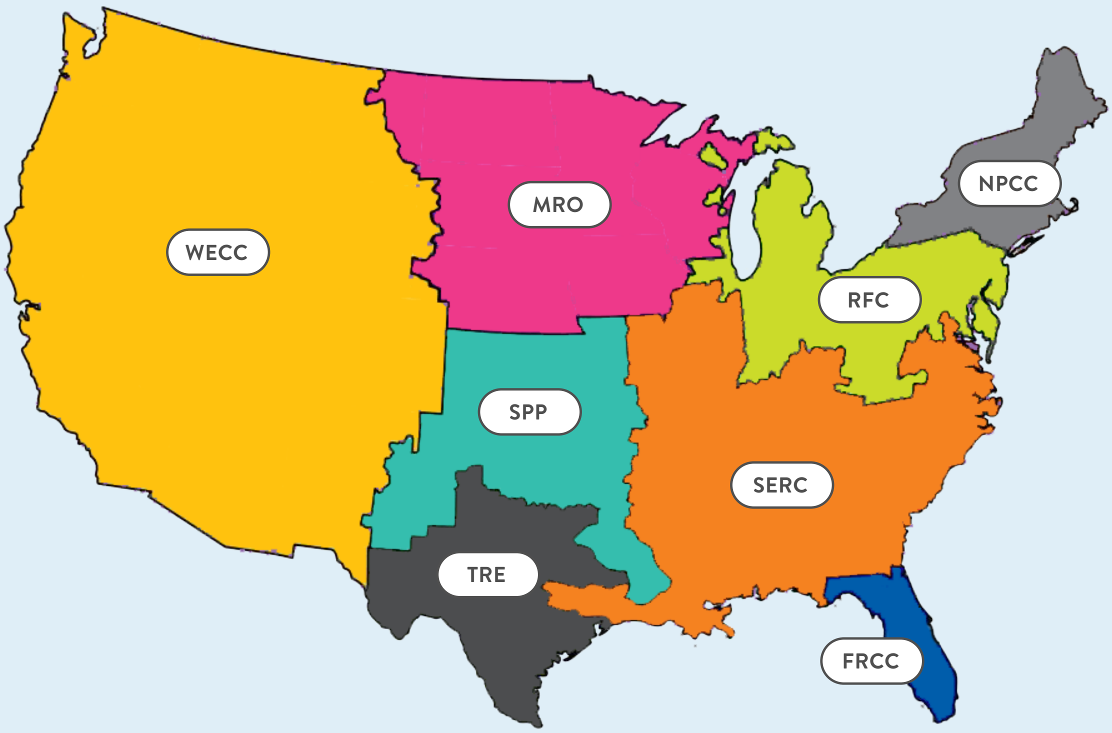
5 *Why and How Utilities Should start to Mange Climate Change Risk, Sara Brody, Matt Rogers, Giilia Siccardo, McKinsey, 2019*

6 *Energy Efficiency in the United States: 35 Years and Counting,* Steven Nadel, Neal Elliott, and Therese Langer June 2015 Report E1502.

ABOUT THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

The analysis in this report is frequently discussed in terms of North American Electric Reliability Corporation (NERC) regions. North America's interconnected power systems are subdivided into eight regional reliability organizations, which are mapped below in Figure 1 and referenced in the subsequent analysis. A non-profit corporation designated by the Federal Energy Regulatory Commission (FERC), NERC's objective is to ensure the reliability of the bulk power system in North America. The organization develops standards, trains and certifies personnel, and assesses reliability. Assessing reliability means NERC ensures that utilities have sufficient reserve margins to serve their customers over the next 10 years.

FIGURE 1. North American Electric Reliability Regions



KEY: **FRCC** = Florida Reliability Coordinating Council
MRO = Midwest Coordinating Organization
NPCC = Northeast Power Coordinating Council
RFC = Reliability First Corporation
SERC = Southeast Reliability Corporation
SPP = Southwest Power Pool Regional Entity
TRE = Texas Reliability Approach
WECC = Western Electricity Coordinating Council.

This is a representational map; many of the boundaries shown on this map are approximate because they are based on companies, not on strictly geographical boundaries. December 2010. In 2019 the FRCC was incorporated as a subregion of NERC. FRCC (Florida) is reported separately throughout this report to maintain consistency across years and for the purpose of geographical diversity.

Investment Gaps in Electric Infrastructure

GENERATION

Generation infrastructure transforms natural gas, coal, water, solar, wind, and other sources into electricity. Today, the U.S. energy grid is transitioning from a fossil-fueled central generation model to a more diversified and decentralized generation portfolio. Coal plants are rapidly retiring and being replaced mainly by combined cycle natural-gas fuel units, a development fueled by market conditions.[7] Wind and solar energy are increasingly contributing to the overall generation mix. These transitions require significant updates to our existing energy infrastructure. A longer-term concern is whether sufficient new generation will be in place when it is needed. Our analysis indicates there is a significant gap but the gap changes over time.

Demand Growth Is Slow

Net generation to meet electricity needs has been nearly flat for 20 years. That trend is expected to continue through 2050, with forecasts averaging no more than 1 percent growth annually.[8] Recent history supports this; despite a severe economic downturn in 2008 and 2009, followed by nearly a decade of sustained growth of 1.6 to 2.9 percent GDP annually, electricity generation rates remained stable.[9] EIA attributes stable demand to improved energy efficiency, increased behind the meter renewable generation by residential customers, such as household solar panels, and combined heat power (also known as cogeneration). Modest increases in peak demands are expected, driven by weather extremes leading to increased residential and commercial air conditioning usage.

When examining demand by region, Texas (ERCOT) projects the highest demand growth at 2 percent through 2039. New England (within NPCC) anticipates declines in summer demand mainly from increasing behind the meter solar. New England currently has 3,000 MW of solar installed, which affects summer peaks, making them occur later in the day when solar efficiency declines. Winter demand is increasing in the Northeast as the electrification of appliances, heat pumps, and other equipment take place. Of note, NERC qualifies its demand forecasts as somewhat uncertain because of the variety of factors that impact demand. Weather is the major influence and energy efficiency is highlighted as an uncertainty factor.[10]

Despite the projected slow demand growth, utilities continue to offer a variety of demand response programs. These include remotely managed residential and business lighting and air conditioning equipment and day-ahead capacity programs in which customers voluntarily reduce energy use during an 'event', a period of up to several hours coinciding with maximum demand on the utility's system.

Meanwhile, electric vehicles are continuing to penetrate the market. Demand increases due to charging

7 White House's 2020 Annual Economic Outlook.

8 EIA Annual Energy Outlook 2020

9 Bureau of Economic Analysis, reported by https://www.thebalance.com/us-gdp-by-year-3305543

10 NERC 2019 Long Term Reliability Assessment

electric vehicles (EV) is uncertain at this point, and depends upon a variety of factors, such as adoption curves for passenger vehicles, medium and heavy-duty trucks, and daily mileage. We expect utilities to construct rates that will drive charging to non-peak hours, which will affect most passenger vehicles and light duty trucks. The generation gap forecast included in this report considers 40 percent penetration of all segments of the new vehicle market by 2040.

Although managing power demand from EVs will be a challenge for distribution utilities, adequate electric capacity is expected to meet EV generation needs. Data shows that the electric grid can accommodate the anticipated growth in the electric vehicles, even with high EV penetration, as reported in a recent study completed by the U.S. Drive Grid Integration Tech Team (GITT) and Integrated Systems Analysis Tech Team (ISATT).[11]

The main concern for many utilities is timing charging demand so that it is minimally coincident with peak demand hours. This can be achieved primarily through regulatory processes where rates are structured to incentivize off-peak charging. Further, off-peak electric sales can benefit utilities that have unused or under-used capacity, providing new revenues from customer EV charging.

Electric vehicle charging infrastructure is a key enabler in the EV market. The number of EV charging stations within the U.S. has grown from 6,900 workplace, public, and direct current fast chargers in 2012 to approximately 61,000 by the end of 2017 for all vehicles.[12]

The Department of Energy's EIA anticipates energy consumption will grow at a slower rate than GDP as the economy becomes more efficient and less energy intensive[13]. Also significant, EIA's projections show generation will increasingly utilize renewables and natural gas, while coal is further reduced.

Planning Reserve Margins are not a concern through 2024

A reliable electricity generation system must have more capacity resources than anticipated peak demand, to account for unanticipated outages and higher-than-anticipated peak demand. The amount that capacity resources exceed peak demand is known as the planning reserve margin. NERC is primarily responsible for ensuring that planning reserve margins are maintained at a level sufficient to ensure system reliability.

NERC's 2019 Long Term Reliability Assessment provides required margin reserves for each region, ranging from 11.7 percent in the West, to 17 percent in the Midwest. Though 2024, all regions except Texas are expected to meet their required reserve margins. Texas could fall below its 13.5 percent margin to 8.5 percent in 2024. This is in line with the findings of the original ASCE 2011 Failure to Act report, which found most NERC regions – with the exception of Texas – had adequate reserve capacity.

The Generation Mix Is Evolving

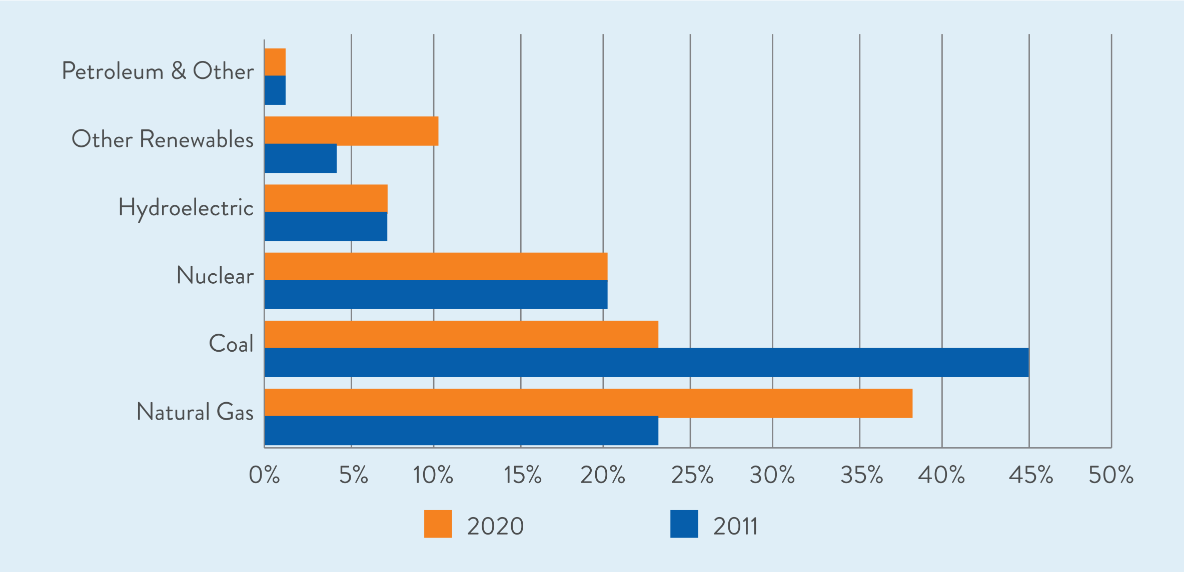
At the same time fossil fueled generation is transitioning from coal to natural gas, renewables are contributing increasing amounts to the overall generation mix. From 2009 to 2019, non-hydro renewables such as solar and wind increased from less than 4 percent to 11 percent of the energy portfolio (see Figure 2). This transition was driven in major part by advancements in renewable generation technology and manufacturing, which contribute to declining renewable costs. Technological impacts were enhanced by state policies aimed at reducing Greenhouse Gas (GHG) emissions, including directives to reevaluate the generation mix.

11 Grid Integration Tech Team and Integrated Systems Analysis Tech Team. "Summary Report on EVs at Scale and the U.S. Electric Power System." U.S. Drive: 2019 November.

12 Nicholas, Michael; Hall, Dale; Lutsey, Nic. "Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets." The International Council on Clean Transportation (ICCT): 2019 January. Web. <https://theicct.org/sites/default/files/publications/US_charging_Gap_20190124.pdf>

13 US EIA 2020 Annual Energy Outlook reference case https://www.eia.gov/outlooks/aeo/

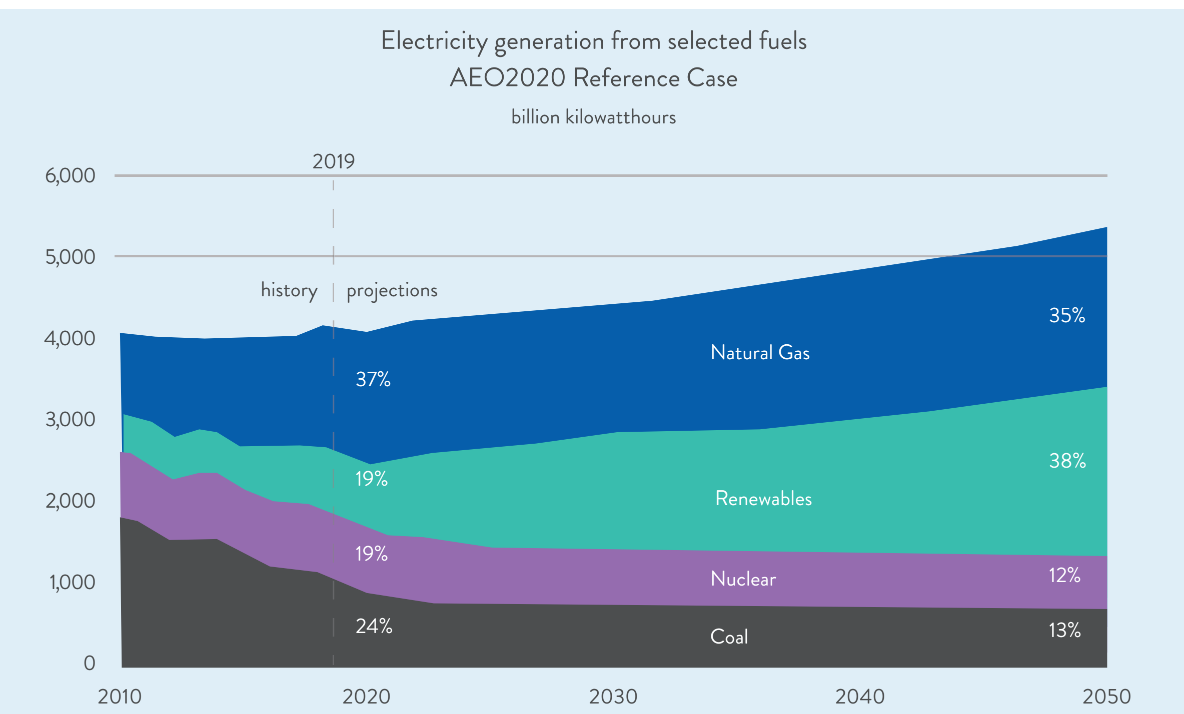
Figure 2. Fuel Sources of U.S. Electric Generation, 2009 and 2019



Source: U.S. Energy Information, 2009 and 2019

For the next 20 years or more, it appears natural gas will be the dominant fossil fuel. However, by about 2040, EIA projects that renewables will exceed natural gas generation. Meanwhile, EIA predicts nuclear energy will decline from 24 percent of electricity generation in 2020 to 13 percent by 2040. Similarly, coal will decline from 19 percent in 2020 to 12 percent in 2040. See Figure 3.

Figure 3. Projected Mix of Generation Fuels, 2010-2050



Source: EIA Annual Outlook 2020

Renewable Portfolio Standards and the Growing Generation Gap

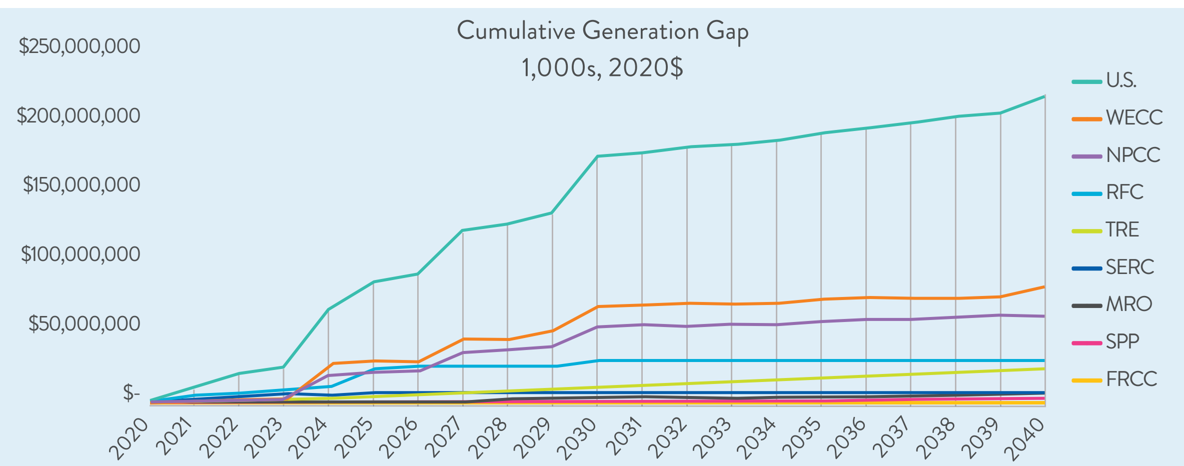
States began enacting Renewable Portfolio Standards (RPS) in the late 1990s. Today, 29 states have RPS mandates and another six states have voluntary goals. Most mandates were originally enacted to diversify energy resources, but over time these statutes have shifted to include climate change mitigation strategies.

RPS renewable percentage requirements and rules vary greatly. Some states require just 10 percent of the overall generation portfolio come from renewables. In many states – but not all – the renewables percentages increase annually. Other states may set a cap on the percentage of overall generation coming from renewables. In the past year in particular, a number of states have revised RPS goals and rules, with several aiming for 50 percent renewable components or more as early as 2030, including New York, New Jersey, Connecticut and California.[14] Market penetration of renewables has also been spurred by recent years by low interest rates, tax credits, and constantly improving renewable energy economics, especially land-based wind.

By 2039, it is estimated that approximately 45.4 gigawatts (GW) of solar and 32.5 GW of wind resources are needed across the continental U.S to meet existing renewable portfolio standards.[15] Despite projections of very modest electric demand growth, a gap between the amount of generation available and the generation needed will emerge. Using publicly available data on energy requirements from NERC and a variety of industry sources, **we project the generation investment gap to grow to a cumulative $203 billion by 2039.** This projection assumes there will be a 40 percent penetration of electric vehicles, including buses and trucks, in the market by 2039.

Figure 4 shows the annual generation gap by NERC region from 2020-2039. The difference between regions is in large part due to the presence (or absence) of Renewable Portfolio Standards requirements. Florida (FRCC) has no RPS in place but also reports some of the highest solar activity. The actual generation gap, therefore, is minimal because Florida is in the process of replacing much of its fossil generation with renewables, even in the absence of a formal standard. The generation investment gap in the Western U.S. (WECC) and the Northeast (NPCC) comes from the need to meet expressed standards. The leveling off indicates periods of stable investment needs.

Figure 4. Annual Generation Gap by NERC Region



Sources: Annual Energy Outlook, U.S. Energy Information Administration and electric Market Module of the National Energy Modeling System. Analysis by Daymark Energy Advisors Generation Gap Analysis, April 2020.

14 National Conference of State Legislatures, State Renewable Portfolio Standards and Goals, Retrieved on August 13, 2020 https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

15 NERC establishes annually revised standards, called Long Term Reliability Assessments, for the amount of generation capacity required in each region to meet the region's projected needs, plus a margin to ensure sufficient generation capacity in the region to accommodate typical situations such as power plant maintenance and less common situations such as the demand for air conditioning during heat waves.

TRANSMISSION

Transmission is part of the "bulk power system," and is almost exclusively used for wholesale market transactions. Only a few very large customers access the transmission system directly. It is critical for moving electricity from sources of generation, including remote renewable generation not previously tied into the transmission network, to the distribution grid.

The three tables below are taken from the U.S. Department of Energy Annual Transmission Review from March 2018. As of the end of 2016, more than 300,000 miles of transmission lines were in place throughout the U.S. Much of those lines were in the smaller 100-299 KV ranges as shown in Table 1 below.

Table 1. Existing Transmission Mileage by NERC Region
Existing Circuit Miles

Existing Circuit Miles	Florida	Midwest	Northeast	Mid-Atlantic	Southeast	Southwest	Texas	West
100-199 kV	3,956	21,933	13304	32,683	60,916	19,365	20,818	38,252
200-299 kV	6,203	7,501	1,612	6,862	22,828	3,224	-	38,167
330-399 kV	-	8,542	5,580	13,650	3,868	6,653	14,838	10,673
400-599 kV	1,201	139	-	2,431	9,093	94	-	13,826
600-799 IN	-	-	190	2,201	-	-	-	-

Source: Annual Data Review, 2018, U.S. Department of Energy

Transmission construction projects by NERC region expected to be completed in 2020 and planned for 2021-2025 are provided in Table 2 and Table 3, respectively.

Table 2. Construction Projects Expected to be Completed by 2020
Circuit Miles to be Completed

Circuit Miles	Florida	Midwest	Northeast	Mid-Atlantic	Southeast	Southwest	Texas	West
100-199 kv	132	1,892	368	534	257	189	217	387
200-299 kv	363	123	2	187	174	112	-	730
300-399 kv	-	1,124	116	154	-	1,171	77	198
400-599 kv	-	380	-	5	60	-	-	825
600 kv+	-	-	-	-	-	-	-	-

Source: Annual Data Review, 2018, U.S. Department of Energy

For future planning, the Florida region has been incorporated as a subregion of the Southeast (Southeast Reliability Corporation). With the assistance of staff from NERC, DOE and LBL, the Florida totals have been separated from Southeast and presented to maintain consistency with the rest of this report.

Table 3. Circuit Miles Planned, 2021-2025

	Florida	Midwest	Northeast	Mid-Atlantic	Southeast	Southwest	Texas	West
	FRCC	MRO	NPCC	RF	SERC	SPP-RE	TRE	WECC
100-199 kv	164	293	227	99	46	0	98	474
200-299 kv	278	8	-66	24	84	0	0	732
300-399 kv	0	2189	717	0	0	0	127	232
400-599 kv	150	0	0	0	0	0	0	1533
600 kv+	0	0	0	0	0	0	0	0

Sources: Source: Annual Data Review, 2018, U.S. Department of Energy and North American Electric Reliability Corporation (NERC). http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

Transmission Age and Condition Continues to be a Concern

The age and condition of transmission components, highlighted in ASCE's 2011 Failure to Act report, continues to be a concern. Aging transmission components can contribute to higher failure rates, more widespread outages, and longer recovery times. Outages contribute to financial loses not only for a utility company, but businesses and customers that rely on this power. A 2015 Department of Energy report found that 70 percent of transformers and transmission lines are 25 years or older, and 60 percent of circuit brakers are 30 years or older.[16]

Transmission investment has increased in past 10 years

According to Edison Electric Institute's (EEI) 2018 Annual Property & Plant Capital Investment Survey, annual transmission spending in the United States increased from $15.6 billion in 2012 to $22.2 billion in 2018. While more recent data is not yet available, increased spending was projected through 2020 before flattening off through 2022.[17] EEI's survey of its member investor-owned utilities and stand-alone transmission companies found that the surge in investment was related to providing access to clean energy and increasing the grid's reliability, security, and resiliency. Spending also reduced congestion, eased resource pricing, and helped to better meet current and future customer needs.[18]

Under the Energy Policy Act of 2005 and FERC's subsequent Order 1000, FERC provided incentives for utilities to build needed transmission lines, encouraging more participation by merchant builders as a means of speeding the process. Merchant Builders are design/build companies that own the transmission they build but work cooperatively with utilities. These entities may be better positioned to use standardized designs in multiple situations for example, gaining economies of scale. In addition to utility incentives in rates, $10 billion in federal grants and matching funds was provided by the American Resource and Recovery

16 Quadrennial Technical Review 2015, U.S. Department of Energy

17 Edison Electric Institute. 2018 Financial Review: Annual report of the U.S. Investor-Owned Electric Utility Industry. https://www.eei.org/issuesandpolicy/Finance%20and%20Tax/Financial_Review/FinancialReview_2018.pdf at pp 52-53.

18 Ibid.

Act (ARRA) toward transmission projects. These actions spurred transmission investment that continued through the past decade, which is why the projected gap for transmission investment is relatively small.

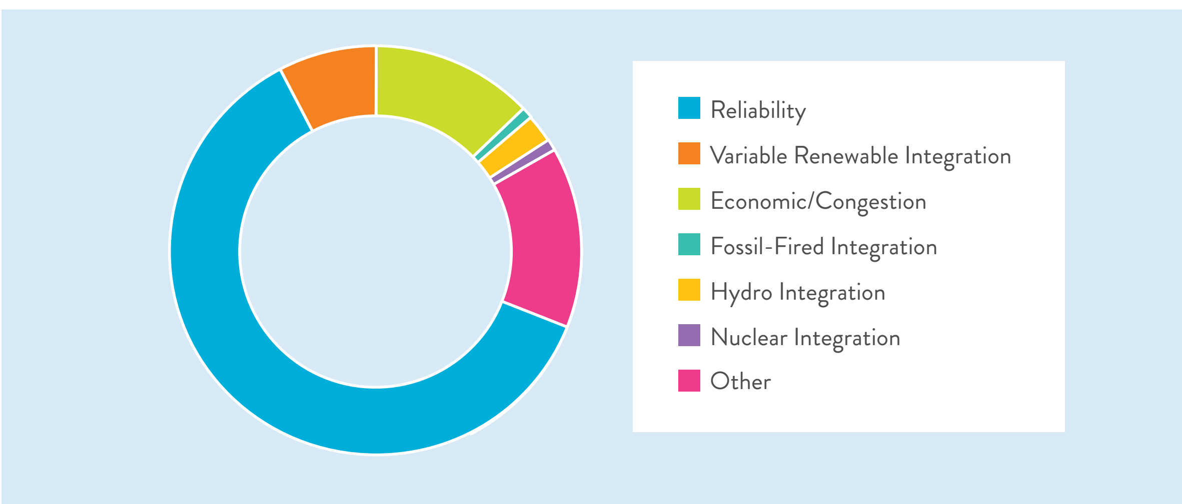
The U.S. Energy Information Administration notes that the surge in transmission investment has been spread across the country. However, while all regions have seen some growth, transmission investment has been most robust in the eleven-state region of the Western Electricity Coordinating Council (WECC), and least substantial (at least when measured by dollars) in the Florida Reliability Coordinating Council (FRCC), the Midwest Coordinating Organization (MRO) and the Southwest Power Pool Regional Entity (SPP). WECC expansion has been guided by 10- and 20-year regional studies, much of which focused on increasing renewable resources and the need for adequate access to them. Somewhat similarly, PJM (originally standing for Pennsylvania, New Jersey and Maryland) performs integrated planning across their vast network, achieving economies of scale, although state approvals, mostly for siting, are still required for projects. PJM is the largest Regional Transmission Organization in the country serving 13 states and the District of Columbia, including NERC's Midwest, Mid-Atlantic and Southeast Regions. Overlapping jurisdictions make comparisons among NERC jurisdictions more complex but it appears from PJM's plans that reliability and access to renewables are primary drivers of transmission investment.

While recent investment appears to be sufficient to serve the existing system, trends suggest a near-term leveling off of transmission spending for typical maintenance and replacement construction.

Determination of the transmission investment funding gap considers both expected shortfalls to meet traditional transmission investment needs, as well as needed investment in new transmission to serve renewable generation. This includes isolated land-based and off-shore wind generators, as well as necessary infrastructure to accommodate expected electric contributions from two-way distributed energy networks.[19]

Figure 5 below illustrates the primary purposes of proposed transmission construction miles from 2019-2029. Of note, reliability concerns drive about 70 percent of construction, while economics/congestion issues and renewable integration are the second and third drivers of investment.

Figure 5. Primary Motivations for Transmission Construction



Source: NERC, 2019 Long Term Reliability Assessment

19 Currently distributed networks primarily receive power from the bulk transmission network and do not play in the bulk market as a generating source. This may change as distributed generation develops further.

Permitting Remains a Major Barrier

Transmission systems are regulated at the federal level by FERC. However, oversight and approvals for specific transmission construction are made by state governments in almost all instances, which means that proposed transmission crossing multiple state lines must be approved in each state. Where federal lands are involved, additional permits may be required from the federal agency with oversight.

A recent example of the complexity of this issue is the Northern Pass proposal, intended to bring 1,090 Megawatts of Canadian hydroelectric power through New Hampshire to Massachusetts to serve the state's two largest utilities. Approval was required from DOE to import power. The proposed routes (there were three possibilities) crossed national forest and state park lands in New Hampshire. The U.S. Department of Interior, which manages the national forests, approved the plan. However, residents and conservation groups raised concerns about degrading the environment of wild areas where the transmission line was proposed. As mitigation, the utilities suggested downgrading the voltage to be carried to bury a portion of the transmission line. Further complicating the project were issues of eminent domain where private lands were to be crossed. A fierce campaign in northern New Hampshire led to the state's Site Evaluation Committee's disapproval of the project. Utility appeals to the New Hampshire Supreme Court were not successful and the project was abandoned seven years after its initial proposal.[20]

Siting transmission on federal lands may follow a different path. In a legislative change under the Energy Policy Act (EPA) of 2005, several federal agencies such as Departments of Energy, Interior, Agriculture, and Commerce have a role in designating transmission corridors on federal lands. In these special cases, and in some extreme congestion situations, FERC has a role in transmission approval.

Financing transmission can be another barrier. Utilities generally find credit for capital expenditures readily available. However, transmission projects have added risk from the uncertainty of the permitting approval process. Some parties find that upfront permitting and approvals costs can be as high as 50 percent of project construction costs. By contrast, actually constructing approved transmission usually involves overhead expenses around five percent. The length and expense of approval processes is seen as increased risks by potential transmission project financers.[21]

Congestion and Constraints

Transmission congestion occurs when there is insufficient transmission capacity to deliver lower-cost generation resources to consumers, requiring the use of higher-cost generators closer to customers. This increases the price of electricity in congested areas, as reflected in higher locational marginal prices and higher electricity prices for consumers. These costs are significant. A 2019 analysis shows that congestion costs increased across the nation about 9 percent from 2016 to 2017 and 22 percent from 2017 to 2018, for a total of just over $5 billion in 2019. Table 4 shows cost changes by year for each region.[22]

20 Source: New Hampshire Public Radio

21 *Suffering from Lack of Transmission*, Rose Fulbright, Washington DC, recorded August 9, 2018, https://www.projectfinance.law/publications/suffering-from-lack-of-transmission

22 *Congestion Costs in RTOs*, , Grid Stratefies LLC, in Watt Transmission. https://watt-transmission.org/2019/09/17/transmission-congestion-costs-in-the-u-s-rtos/

Table 4. Transmission Congestion Costs ($2019 millions)

RTO*	2016	2017	2018
ERCOT Texas	$497	$976	$1,260
ISO-New England 6 New England States	$39	$41	$65
MISO Midwest System Operator	$1,400	$1,500	$1,400
NYISO New York Independent System Operator	$529	$481	$596
PJM Pennsylvania, New Jersey, Maryland + 8 other states	$1,024	$698	$1,310
SPP Southwest Power Pool	$274	$405	$381
Totals	**$3,763**	**$4,101**	**$5,011**

*RTOs and ISOs control and operate wholesale electric markets, covering one state or multiple states. The largest, PJM, serves 11 states + District of Columbia

Source: Transmission Congestion Costs in US RTOs, Jesse Schneider, Grid Strategies LLC
https://watt-transmission.org/2019/09/17/transmission-congestion-costs-in-the-u-s-rtos/

Several strategies are common for dealing with congestion costs. The first set of strategies can be undertaken by customers themselves. Customers can mitigate congestion costs by building their own internal generation, increasing their energy efficiency, or by purchasing financial hedges, called Congestion Revenue Rights, which provide some measure of certainty about fluctuating costs.

The second strategy is building more transmission to serve lower cost generation. However, this has the potential for unintended consequences. For example, the midwestern MISO region had the highest congestion costs in recent years. Area wind farms were producing very low-cost power and injecting it into a network that was already severely congested. Additionally, four coal plants in the area were retired, further throwing off the balance of transmission loading. The Mark Twain transmission project was conceived in 2014 to ease congestion and allow more wind capacity from Iowa and Missouri to travel east into Illinois. Once completed at the end of 2019, the transmission line eased congestion in Iowa, but increased it downwind in Illinois. As a result, costs increased for downwind customers, partially a result of those customers needing to secure more locally-sourced electricity.[23]

The third strategy is investing in new technology that improve the efficiency of existing transmission. A prime example is modernized information sensors that provide system operators with additional information required to dispatch electricity as the system requires, such as real time information on power flows. Transmission becomes more efficient as temperature falls allowing more power to be transmitted, and less efficient as temperature rises, a likely growing concern with climate change impacts.

23 *Could Ameren's New Transmission Line Make Congestion Worse?* Elliot Gordon, Greentech Media, January 15, 2020.

Higher voltage transmission lines – those even higher than maximum voltage lines in current use – can carry increased capacity without requiring new rights of way. These sorts of lines are in use in the European Union and elsewhere but are not yet present in the U.S.

To alleviate complications associated with connecting generation to distribution, several other technological options can be considered, including increasing energy efficiency and demand management, batteries, and creating microgrids.

Outages and momentary interruptions continue to be a concern.

Somewhat paradoxically, despite the growth in transmission investments made in recent years, interruptions in the bulk system continue. According to EIA and other sources, not only are transmission interruptions increasing, but costs per event are increasing as well.

EIA tracks transmission events greater than 200 MW per event by year for all utilities, reported on a voluntary basis. Among 638 events reported from 2014-2018, severe weather was cited as the cause of 50 percent of outages, systems operations were responsible for 18 percent of outages, and transmission disruptions/interruption were cited as the cause of 32 percent of outages. Transmission disruptions/interruptions are essentially unexpected failures. In 2019, a much higher percentage of transmission outages – 46 percent – was attributed to transmission disruption/interruption. This was perhaps at least partly the result of the unusually heavy fire season in the Western U.S.[24] Increasing numbers and intensities of fires are one effect of climate change in drier, hotter regions, a trend that's expected to accelerate. As an aside, utilities submit events to EIA on a voluntary basis, meaning all events may not be captured. Also important to note - the reported events are located on the bulk transmission system. The local distribution network incurs significant outages and interruptions, discussed later in this report.

In addition to tracking events, EIA also collects data on the duration of outages. The group reported the national average duration of an event in 2017 was 7.8 hours, including major storms. When excluding major storms, the average duration of an outage was about half that duration. The transmission outages are not evenly distributed across the nation. The Southeast (SERC) and Western (WECC) regions show the greatest number of events over the five-year period, at 151 and 130 events respectively. Three FERC regions or subregions – the Midwest (MRO), Puerto Rico, and the Southwest (SPP), reported 20 events or fewer.

However, these transmission outages are not the full outage story. Later in this report, we mention that customer losses result from both transmission and distribution problems, and sometimes a combination of failures in both.

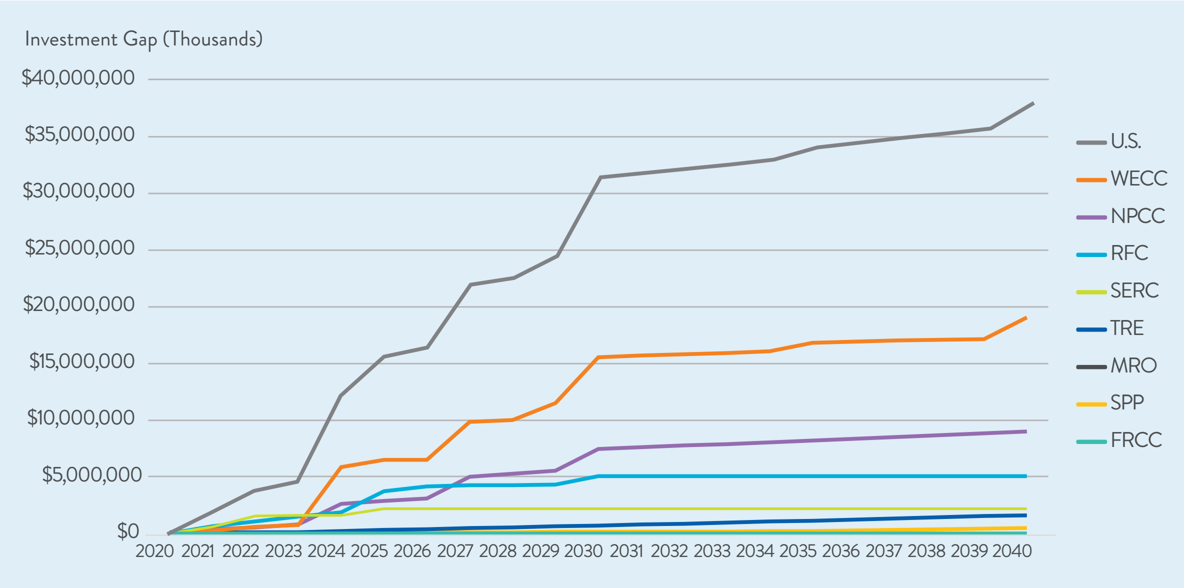
Recent Investment Upticks

As noted above, recent years have seen a significant uptick of investments in transmission systems. Transmission investments increased from $15.6 billion in 2012 to an average of $21.0 billion from 2013 through 2021.[25] However, an investment gap persists, compounded by the system's needs, over the next 10 years, to accommodate new renewable energy generation. The projected investment gap through 2039 is $35.4 billion. Figure 6 summarizes this cumulative transmission investment gap by region.

24 EBP analysis of EIA reported Electric Disturbance Events, 2014-2019

25 Edison Electric Institute. 2018 Financial Review: Annual report of the U.S. Investor-Owned Electric Utility Industry. https://www.eei.org/issuesandpolicy/Finance%20and%20Tax/Financial_Review/FinancialReview_2018.pdf.

Figure 6. Cumulative Investment Gap by Region



Source: Improving estimates of transmission capital costs for utility-scale wind and solar projects to inform renewable energy policy, Lawrence Berkeley National Laboratory, October 2019 and state Renewable Portfolio Standards. Calculations by Daymark Energy Advisors.

Microgrids[26]

Microgrids come in a variety of control capabilities, applications, and sizes. However, the distinguishing characteristic of microgrids, no matter their size or location, is that they either are or can be isolated, and that at minimum they control loads within their boundaries.[27] Microgrids are characterized as basic, intermediate, and advanced. Basic microgrids, which are popular in the Southwest and Northeast, operate in an islanded mode, providing firm service in a limited area.[28] In 2016, 31 percent of basic microgrids were in remote locations, with the majority in Alaska.[29] Intermediate microgrids provide integration of local resources, multiple Distributed Energy Resources (DERs), and optimize performance within the grid boundary. Sophisticated systems participate in markets outside the microgrid and power flow is two-way with the outside. DOE notes that advanced microgrids are still in active development and the technology is likely to continue evolving.

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26 Much of the information in this section is taken from Microgrid Guide For Publicly Owned Critical Infrastructure, by the US Department of Energy, no publication date given

27 Ibid.

28 Surveys by Navigant and GTM (now Wood McKenzie), commissioned by NREL found different numbers of microgrids in roughly the same proportions with the exception of basic microgrids in Alaska. Differences in access, count and classification appeared to account for the differences.

29 Surveys by Navigant and GTM (now Wood McKenzie), commissioned by NREL found different numbers of microgrids in roughly the same proportions with the exception of basic microgrids in Alaska. Differences in access, count and classification appeared to account for the differences.

DISTRIBUTION

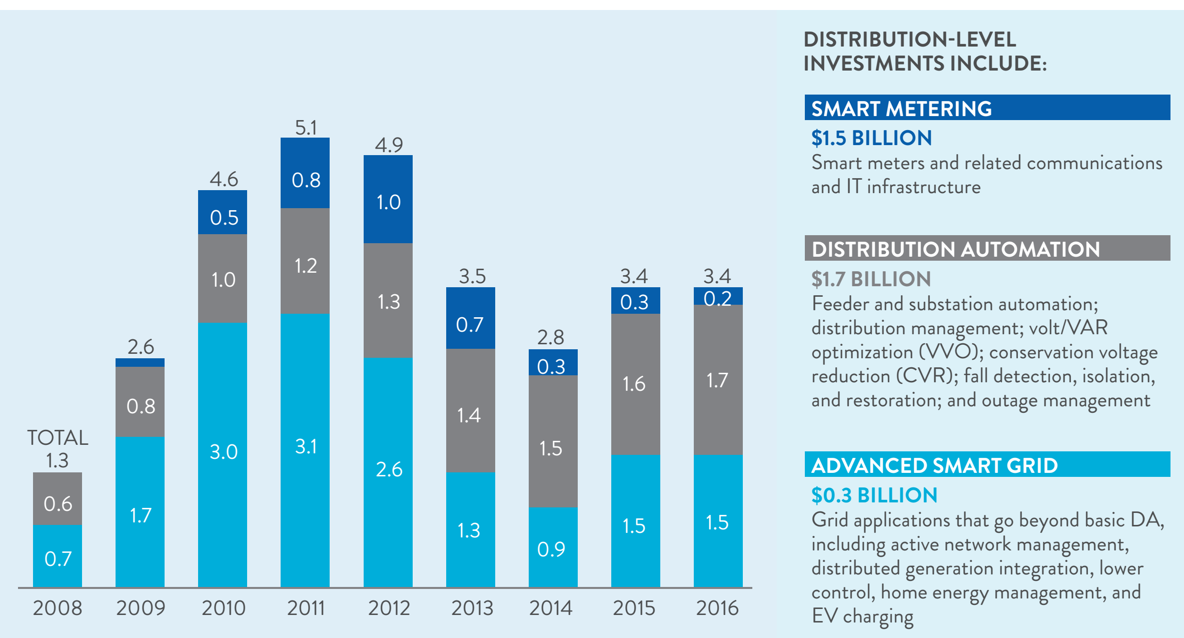
The distribution system is the "last mile" of the electric delivery system, consisting of lower voltage electric lines, neighborhood substations, and individual customer services and meters, among other components. Distribution is a key failure point in the electric grid with respect to system reliability. The lightning strike that blacks out a neighborhood, or the storm-driven flooding that shuts down transformers are usually happening on the distribution system. The increasing number and severity of natural events requires hardening and islanding (isolating a region to remain in service). As distributed energy resources become factors in local distribution, security of the control mechanisms on the distribution networks must be enhanced.

Investments – particularly in "smart grids" – have increased

Distribution investments can be roughly sorted into automated metering, distribution automation, connections to distributed generation and storage, and smart grid investments. Smart grid spending represents a portion of total distribution investment. The U.S. DOE Smart Grid System Report shows historical smart grid spending obtained from Bloomberg New Energy Finance World Factbook, 2017. Smart grid spending as a percentage of total distribution spending. The smart grid share was only 5 percent of spending in 2008. It was as high as 22-23 percent in 2010 – 2012, driven by a temporary uptick in smart grid projects funded by the American Recovery and Reinvestment Act of 2009 (ARRA). After ARRA projects were exhausted, Smart Grid spending has leveled out at 12-15 percent of total distribution investment. The chart showing a spending breakdown by smart grid component (smart metering, distribution automation, and advanced smart grid) is reproduced as Figure 7 below.

In general, distribution expenditures have increased dramatically. In 2018, EIA reported that spending on electricity distribution systems by major U.S. electric utilities had risen 54 percent over the past two decades, from $31 billion to $51 billion annually. Figure 8 shows the overall spending patterns. From 1996 to 2017, annual capital investment by these utilities for electric distribution systems nearly doubled.

Figure 7. Smart Grid Spending Breakdown, 2008-2016 (billions)

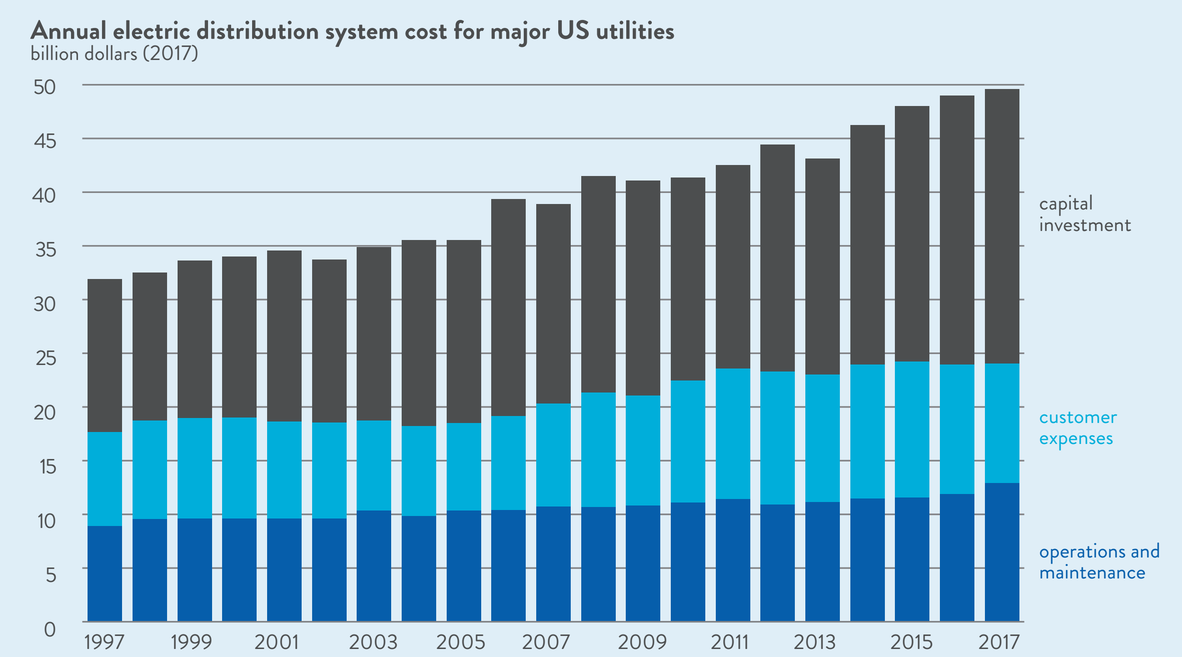


Source: Bloomberg New Energy Finance World Factbook, 2017

The term "smart grid" broadly refers to a modernization of the electricity delivery system so that it monitors, protects, and automatically optimizes the operation of its interconnected elements. A truly smart grid can accommodate both centralized and distributed generation, move electricity from the high-voltage transmission network to the distribution system, and take advantage of energy storage installations to balance power quality within the distributed network. Some distribution networks have the capability to sell electricity back into the bulk transmission system, becoming active players in electric markets. Other distribution networks have the ability to become islanded amid catastrophic events such as hurricanes, tornados, or blizzards, maintaining service to customers. A small number are built to serve only the distributed network, oftentimes in a configuration or in areas where there is no access to bulk transmission. Ultimately, a smart grid optimizes the flow of power to consumers' thermostats, electric vehicles, appliances, and other household devices. Automation at the distribution level has existed for many years, but the smart grid introduces new levels of communication and capability to meet demand and maintain stability.

Smart grid investments will better enable increasing amounts of distributed generation – such as homes and businesses outfitted with solar panels and energy storage by batteries before or behind customer meters – to be connected and to contribute directly to the larger grid system. Therefore, upgrading the distribution system to be a "smart grid" capable of managing more complex operations has become a priority for some utilities and state regulators in the last 10 years. The primary drivers initially were state regulators, but utilities have much to gain in adopting smart grid technologies at the grid level as well as in their customer-facing operations. Smart grid innovations should increase utility efficiency at serving customers.

Figure 8. Spending by U.S. on Distribution System Components



Source: U.S. Energy Information Administration, Federal Energy Regulatory Commission (FERC) Financial Reports, as accessed by Ventyx Velocity Suite

As in the bulk power system's transmission components, capital investments for utilities in large part consist of upgrading aging equipment. Specifically, poles, wires, and substation transformers are being upgraded with advanced materials and new technology to better withstand extreme weather events, allow easier frequency and voltage control during system emergencies, and to accommodate greater use of variable renewable generation such as customer-sited wind and solar.

Over the past decade, investment in overhead poles, wires, devices, and fixtures such as sensors, relays, and circuits has risen by 69 percent, and spending on substation transformers and other station equipment has increased by 35 percent. Investment in customer meters has more than doubled over the past 10 years as utilities have upgraded to smart meters that can be accessed remotely, communicate directly to utilities, and support smart consumption and pricing applications using real-time or near real-time electricity data.

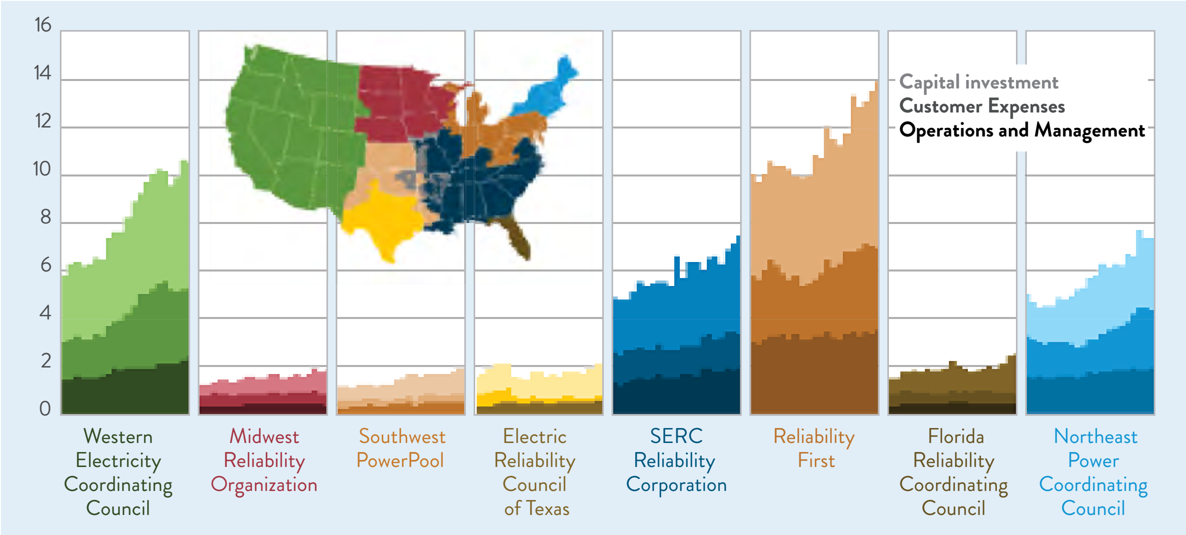
Although expenditures related to customer accounts and sales have decreased, spending on customer services and information systems has more than doubled over the past decade in an effort to better inform customers about outage locations and durations and to develop better customer outreach tools. Operations and maintenance expenses have also increased as electric distribution systems experience stress from several factors, including more customers, variable generation, and the effects of storms, wildfires, and flooding. Managing a grid with increasing amounts of customer-sited variable generation increases wear and tear on the distribution equipment required to maintain voltage and frequency within acceptable limits and to manage excessive heating of transformers during reverse power flow.

A Shortfall in Distribution Investment is Expected Despite Recent Increased Expenditures

Though substantial investment has already been made in distribution grid infrastructure in many parts of the country, a significant gap still exists between current investment levels and the level required for adequate reliability and performance. **This analysis projects a cumulative spending gap of $100 billion through 2039.** This estimate primarily focuses on the amount of investment that will be required to upgrade and transition the system to smart grid. As with transmission, some investment will be required to maintain wires and poles, transformers, meters, and similar equipment that are usually the responsibility of the local utility. Those costs are included in the total estimate and are characterized as reliability needs in the baseline projections.

Figure 9 shows investments by NERC region. The largest spending increases have occurred in the older, more populated systems, which include the Northeast Power Coordinating Council (New York City and Boston), Reliability First (Chicago, Detroit, Philadelphia, Baltimore-Washington, DC), and the Western Electricity Coordinating Council (Los Angeles, San Francisco). Each region's expenditures appear in three shades. The lightest shade is for capital expenditures, medium is for customer-related expenditures and the deepest shade is for operations and maintenance

Figure 9. Major Utility Distribution System Investments by NERC Region, 1996-2016 ($2016 billions)



Source: U.S. Energy Information Administration, Federal Energy Regulatory Commission (FERC) Financial Reports, as accessed by Ventyx Velocity Suite

The projected regional level of total distribution investment shows a more varied picture, resulting from differences in need. By 2039, RFC, WECC and SERC are projected to make cumulative investments of $28.1 billion, $27.3 billion and $16.4 billion, respectively. In other regions projected spending is substantially less.

CUMULATIVE INVESTMENTS

Table 5 shows the U.S. average and range of expenditures in generation, transmission, and distribution for 2013-2019 (adjusted to be constant 2019 dollars). On average, annual capital expenditures for all three electricity segments during the years considered was $87 billion.

Table 5. Annual Capital Expenditures for Electricity Infrastructure, 2013-2019

Type of Expenditures ($2019 billions)	Average Annual	Low Annual	High Annual
Generation	$35	$32	$42
Transmission	$20	$17	$24
Distribution	$31	$22	$36
Annual Average, Low and High Spending	**$87**	**$74**	**$95**

Note: Annual totals represent expenditures per year from 2013-2019, and not the sums of low or high annual spending by type.
Source: Edison Energy Institute

The Potential Investment

The estimated investment gap is the difference between projected trends of investments in electricity generation, transmission, and distribution infrastructure and the estimated total needs. The needs are based on household and business demand for electricity, the age of current infrastructure, the evolving mix of energy technologies, and state and federal policies that mandate conversions to renewable energy sources. The total gap indicates that the U.S. is facing a $208 billion (in 2019 dollars) shortfall by 2029 and a $338 billion shortfall by 2039 in what is needed to ensure a reliable energy system (see Table 6). This equates to a gap of approximately $120 per household per year for 20 years.

Understanding the gap requires a look at each of the three components and the nine regions of the continental United States (see the note under Table 6 for Alaska and Hawaii). Overall, the West with its major land expanse and large population in California accounts for 33 percent of the total national investment gap, while the Northeast and Mid-Atlantic regions – with some of the oldest infrastructure in the U.S. – account for 43 percent of the gap. Moreover, these regions generally have some of the more aggressive renewable energy targets, driving a need to develop renewable generation and the transmission infrastructure to support it (almost 50 percent of the transmission gap is in the West). By region, Florida, the Southeast and the Southwest will require the least additional investment. All of Florida's needs are in distribution infrastructure. In the Southeast, modest generation and transmission investment are needed by 2029, and distribution will be needed to meet increasing population and business user demand. The Southwest and Midwest regions will require modest investments in generation, transmission, and distribution investments through 2039 to protect efficient electricity production and consumption.

Table 6. Electricity Infrastructure Investment Gap ($2019 billions)

Region	Generation			Transmission			Distribution			TOTAL		
	2020-2029	2030-2039	2020-2039	2020-2029	2030-2039	2020-2039	2020-2029	2030-2039	2020-2039	2020-2029	2030-2039	2020-2039
Midwest	$2.2	$4.1	$6.3	$0.1	$0.2	$0.4	$2.1	$2.2	$4.3	$4.4	$6.6	$11.0
Southwest	$0.6	$2.7	$3.4	$0.1	$0.3	$0.4	$2.0	$2.1	$4.1	$2.8	$5.1	$7.9
Texas	$9.7	$13.4	$23.1	$0.6	$0.9	$1.5	$2.6	$2.8	$5.4	$12.9	$17.1	$30.0
Northeast	$38.3	$20.9	$59.3	$5.5	$3.3	$8.8	$6.1	$6.4	$12.5	$50.0	$30.6	$80.6
Mid-Atlantic	$25.9	$3.9	$29.9	$4.3	$0.8	$5.1	$13.9	$14.5	$28.3	$44.1	$19.1	$63.2
West	$50.8	$22.8	$73.6	$11.5	$5.7	$17.2	$10.6	$11.1	$21.7	$72.9	$39.5	$112.5
Southeast	$7.4	$0.0	$7.4	$2.2	$0.0	$2.2	$8.1	$8.4	$16.5	$17.7	$8.4	$26.1
Florida	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$3.3	$3.4	$6.7	$3.3	$3.4	$6.7
Total	$135.0	$67.9	$202.9	$24.4	$11.1	$35.5	$48.8	$50.9	$99.6	$208.1	$129.8	$338.0

Note: The tables above reflect the continental 48 states. An additional $830 million of distribution needs for the 2020-2039 period are estimated for Alaska ($6 million) and Hawaii ($824 million). Hawaii is undergoing a massive transformation from petroleum to renewable generation. In 2018 about 40 percent of generation was renewable and climbing.

Sources: Annual Energy Outlook, U.S. Energy Information Administration and electric Market Module of the National Energy Modeling System. Analysis by Daymark Energy Advisors Generation Gap Analysis and EBP.

In short, drivers of investment vary by geographic region. For example, Hawaii invests to reduce its high electric rates and to increase distributed renewable energy. Infrastructure owners in the Midwest, by comparison, invest in decarbonization efforts, as well as for improved grid integration and distribution system resilience. Each respective region has its own policy levers and system-wide challenges and opportunities.

In general, states with higher energy costs have historically paid more attention to energy issues. You can see this most clearly in utility energy efficiency programs, where states that now lead, including Massachusetts, California, Rhode Island, Minnesota, Connecticut, Vermont, Oregon, Washington, and New York, have been leaders since the 1980s. Renewable energy grew up alongside energy efficiency as the more attractive sibling, with a certain amount of rivalry. Over time the goals – and in some cases programs – merged. For example, getting state solar subsidies in some places first requires addressing energy efficiency.

Driven by conversion to different energy sources to meet renewable portfolio standards and barring a significant increase of investment levels, generation will account for 60 percent of the total gap by 2039, with transmission and final distribution representing 10 percent and 29 percent respectively (totals do not add to 100 percent due to rounding). In the shorter term — by 2029 — generation accounts for 65 percent of needed investment. Distribution is expected to account for 23 percent of the gap through 2029, while transmission is projected to account for 12 percent through 2029.

Economic impacts of investment gaps on business and households

The impacts of investment shortfalls in electric infrastructure are multiple and interrelated. In general, the grid's investment gap contributes to a greater incidence of electricity interruptions. Interruptions can be the result of equipment failures, capacity blackout or brownouts, power quality irregularities, or intermittent voltage surges. Electricity interruptions can vary in terms of frequency and duration. Ultimately, however, these system failures result in an unreliable electricity supply, which imposes direct costs on both households and businesses.

Costs incurred by both households and businesses can include, but are not limited to: 1) damage to electronics from voltage spikes and surges; 2) spoilage of food kept refrigerated or in otherwise controlled conditions; 3) lost productivity when production processes are temporarily idled at manufacturing and service facilities; and 4) added costs incurred by an increased reliance on, and use of, backup generators, power quality monitoring and conditioning equipment, or researching of production shifts. Consumers experience these electricity system failures as direct financial impacts to their households and businesses, as well as through larger effects on the nation's economy.

The cost of interruption events to residential customers has doubled since 2011.

This study uses the 2018 Interruption Cost Estimate (ICE) model developed for EIA to conservatively estimate that **nationwide, residential and business customers will experience $85 billion in annual losses from unreliable electricity.**[30] The ICE model measures the impacts of voltage surges, outages, and brownouts on industries and households. Table 7 shows the projected losses among different electric customers over the next two decades. The annual dollar increase over time is commensurate with annual EIA demand forecasts and the two percent forecasted growth of real GDP.[31]

Table 7. Direct Losses to Electric Customers by Class, 2020 – 2039

Customer Class	Losses in Billions $2019				
Year/Period	2029	2039	2020-2029	2030-2039	2020-2039
Residential	$2	$3	$20	$24	$44
Commercial	$53	$65	$487	$593	$1,080
Large Comm/Ind	$49	$60	$448	$546	$995
Totals	$104	$127	$954	$1,164	$2,119

30 The ICE model was used to calculate $82 billion of impacts in 2016 dollars and the BEA deflator was used to update the dollars to 2019 value.

31 Annual energy Outlook 2020 Electricity Reference Case. However reports by Eaton and others indicate that the costs of service interruptions and disruptions are in fact increasing well beyond annual demand rates but the existing data are not comprehensive and we do not have sufficient data to project a reliable trend at this point in time.

The EIA ICE econometric model quantifies that the cost to residential customers from each electric interruption event is $6.68 using 2018 costs. This is about twice the cost for momentary events in 2011. Given the model's conservative estimate, the residential customer's loss per interruption event is not only expected to increase over time, but its current value is likely an underestimate of total impacts. Residential customers experience inconvenience losses, such as sitting in the dark or lack of computer access, as well as out of pocket losses, such as spoiled food and damaged electronic equipment.

Costs of outages for industries – especially those that rely on data centers – has grown.

Businesses bear the consequences of downtime, labor, lost productivity and other impacts differently based upon their sector and size, which was documented by Lawrence Berkeley National Laboratory (LBNL).[33] In 2008, LBNL estimated losses for events for broadly defined industries as a consequence of energy disruptions, which is provided to present a general order of magnitude.

Table 8 illustrates the variations of the extent to which major industry sectors are impacted by electric power outages. Outages are most damaging in the manufacturing sector, costing almost $42,000 per event on average in 2008. The cost to U.S. manufacturing per event was more than twice the impacts on mining, more than three times higher than public administration, and almost five times higher that telecommunications and utilities, the next three largest impacted sectors. Agriculture was reported as the least effected sector by electric outages at about $1,000 per event, while costs to wholesale and retail trade, construction, services, finance, insurance and real estate and services varied from almost $3,000 to $6,000 per event.

Table 8. Losses by Event Type and Duration by Industry (2008)

Outage Characterisitic	Number of Reported Outages	Average
Season		
Winter	1,729	$11,129
Summer	11,871	$15,628
Day		
Weekend	1,359	$2,249
Weekday	12,241	$16,478
Region		
Midwest	1,474	$12,294
Northwest	2,315	$3,552
Southeast	4,338	$23,797
Southwest	1,983	$5,946
West	3,490	$18,166
Industry		
Agriculture	187	$1,063
Mining	170	$18,501
Construction	129	$3,663
Manufacturing	3,620	$41,691
Telco. & Utilities	1,023	$8,837
Trade & Retail	3,390	$2,818
Fin., Ins. & R.E.	585	$5,790
Services	3,690	$4,810
Public Admin.	270	$12,239

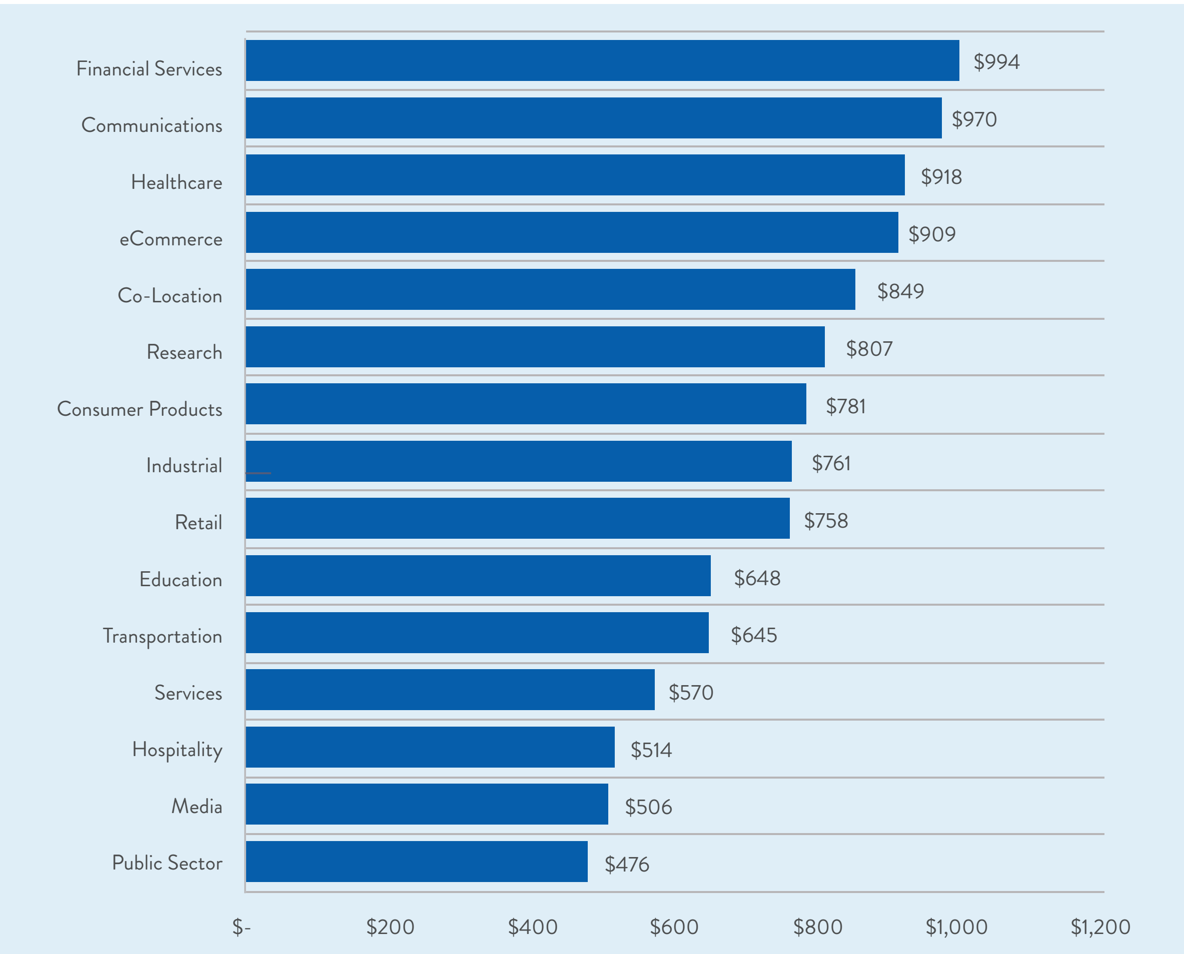
Source: Lawrence Berkeley National Laboratory

33 Estimated Value of Service Reliability for Electric, Lawrence Berkeley National Laboratory, LBNL-2132E 2008

As business and industry sectors become more interconnected, they increasingly rely upon data centers to perform day-to-day functions and plan for the future. Therefore, even momentary fluctuations such as voltage drops or surges impact various industries in different ways. A 2016 study based on 63 data centers estimated the mean-average cost of a U.S. data center outage is $8,851 per minute, compared to $5,617 in 2010[33]. The average length of a 2016 disruption was 95 minutes, which was down slightly from the 97 minutes in 2010. While the duration of impacts has stayed roughly the same, the average cost of outages at data centers increased from $505,000 in 2010 to $740,000 in 2016.

Figure 10 shows an annual distribution of the cumulative financial impacts by industry type due to outages at data centers. While the sample size is small, the study shows the industries facing the most damaging impacts are financial services, communications (media), health care and ecommerce. These industries are all reliant on telecommunications – and relatedly, the grid – to power computers, phones, and other electronics.

Figure 10. Cumulative Impacts Per Year of Data Center Disruptions due to Outages on Selected Industries (in $1000s)



Source: Ponemon Institute Cost of Data Center Outages, January 2016

33 Ponemon Institute Cost of Data Center Outages, January 2016

Data center operators have developed a variety of storage and backup emergency power to ensure that data centers are not catastrophically interrupted. However, uninterruptible power supplies typically fall short in being able to provide adequate cooling during outages, meaning equipment can sustain permanent damage. Backup power may not initiate quick enough to prevent such damage, requiring increased capabilities.[34] Developing and maintaining such systems imposes further costs on businesses and institutions.

Impacts of Disposable Income Losses Delayed, But Severe

The impacts from costs to businesses due to inefficiencies in delivery of electric power, including voltage spikes and surges, lost productivity, and added costs incurred by an increased reliance on secondary generators, monitoring equipment and backup strategies, as well as direct consumer costs (such as spoiled food), will result in lost household income. **This lost disposable income is projected at $13 per household per year in 2020 but will grow to $563 by 2039 if the generation, transmission, and distribution investment gaps are not mitigated.** In other words, if the electricity investment gap is left unaddressed, the impacts to disposable income will increase 40-fold over the next 20 years. Over the 2020-2039 span of this study, each household will lose on average $5,800 in disposable income.

34 *How to Manage Data Center Cooling During an Outage.* https://lifelinedatacenters.com/data-center/data-center-cooling-power-outage/

Impacts to the U.S. Economy

If adequate investments do not occur to rehabilitate, replace, and modernize our nation's electric generation, transmission, and distribution systems, then both households and businesses will incur costs. These may occur in the form of higher rates for electric power, costs incurred because of power unreliability, or costs associated with adopting more expensive industrial processes. Ultimately, they all lead to the same economic impacts: diversion of household income from other uses and reduction in the U.S. business competitiveness in world economic markets.

Total Economic Output Slows[35]

Total output represents total economic activity in producing and providing goods and services. Table 9 shows the total output losses by industry sector due to underinvestment in infrastructure from 2020 to 2029 and 2030 to 2039. The 15 sectors shown in Table 9 and in subsequent industry tables are consolidated from 64 industries within the LIFT model.[36]

As shown in Table 9, the impact on manufacturing output is especially impacted by electricity underinvestment. The production of manufactured goods – everything from paper, paints, rubber, and asphalt to electronics, automobiles, and appliances – requires energy. Unreliable electricity creates inefficiencies in the production process, as workers wait idled for machines to turn back on, or companies incur costs associated with backup generators and conditioning equipment.

35 Output represents gross production of U.S. industries. According the U.S. Bureau of Economic Analysis, gross output consists of both the value of what is produced and then used by others in their production processes and the value of what is produced and sold to final users—that is, final product. Industry "value added" is defined as the value of the industry's sales to other industries and to final users minus the value of its purchases from other industries. Value added is a nonduplicative measure of production that when aggregated across all industries equals gross domestic product (GDP) for the economy.

36 The full concordance table of the industries shown to the full list of 64 are shown in the appendix.

Table 9. Aggregated Output Losses by Industry Sector ($2019 billions)

Sector	2020-2029	2030-2039	2020-2039
Manufacturing	$210	$736	$947
Health Care	$27	$134	$161
Professional Services	$72	$302	$374
Other Services	$47	$164	$211
Logistics	$45	$160	$204
Finance, Insurance and Real Estate	$96	$344	$439
Construction	$17	$54	$71
Retail trade	$24	$82	$107
Accommodation, Food and Drinking Places	$15	$53	$68
Transportation Services (excluding truck transportation)	$14	$50	$64
Mining, Utilities, Agriculture	$18	$63	$81
Information	$39	$167	$206
Educational Services	$4	$13	$17
Entertainment	$5	$16	$21
Social Assistance	$3	$10	$12
Totals	**$637**	**$2,347**	**$2,984**

Columns and rows may not add due to rounding.

Note: Losses and increases reflect impacts in a given year against national baseline projections. These measures do not indicate declines from 2019 levels.

Sources: EBP and LIFT model, University of Maryland, INFORUM Group, 2020.

Employment Losses are Modest, But Widespread

Underinvestment in our electricity infrastructure will increase production costs, and therefore prices. This leads to a reduction in domestic demand, has implications on foreign demand, and reduces U.S. competitiveness. In turn, domestic production volumes fall, leading to lower levels of employment, as shown in Table 10.

Table 10. Losses on Total U.S. Economy due to Inefficient Electricity Delivery, 2020-2039 ($2019 billions)

Year	Business Sales (Output)	GDP	Disposable Income	Jobs
Losses in the Year 2029	$132	$79	$38	287,000
Losses in the Year 2039	$331	$185	$84	540,000
Cumulative Losses 2020-2029	$637	$394	$185	N/A
Cumulative Losses 2030-2039	$2,347	$1,341	$634	N/A

Columns may not add due to rounding.
Note: Losses and increases reflect impacts in a given year against national baseline projections. These measures do not indicate declines from 2019 levels.
Sources: EBP and LIFT model, University of Maryland, INFORUM Group, 2020.

Given current investment practices, capital investment needs, and changing trends in demand, the national losses in employment amount to 287,000 jobs in the year 2029 and 540,000 jobs in 2039. Job impacts are significantly less pronounced than dollar effects. By 2039, the job impacts amount to three-tenths of one percent of the projected national baseline, representing about half the rate of lost GDP and output.

Of note, the need for firms to lower costs by reducing employment is mitigated, in part, by the tendency for wage rates to fall as labor productivity weakens. As wages drop, the immediate employment shock seems severe as firms adjust staffing levels to reflect lower wages and lower productivity.

While employment impacts are expected to be relatively modest, the breadth of the impact touches many sectors in the economy. Table 11 shows the total jobs beneath the 2029 and 2039 national baseline; Table 11 illustrates the spread of expected job losses by sector in 2039.

Table 11. Potential Employment Losses because of Inadequate Electricity Infrastructure, 2029 and 2039

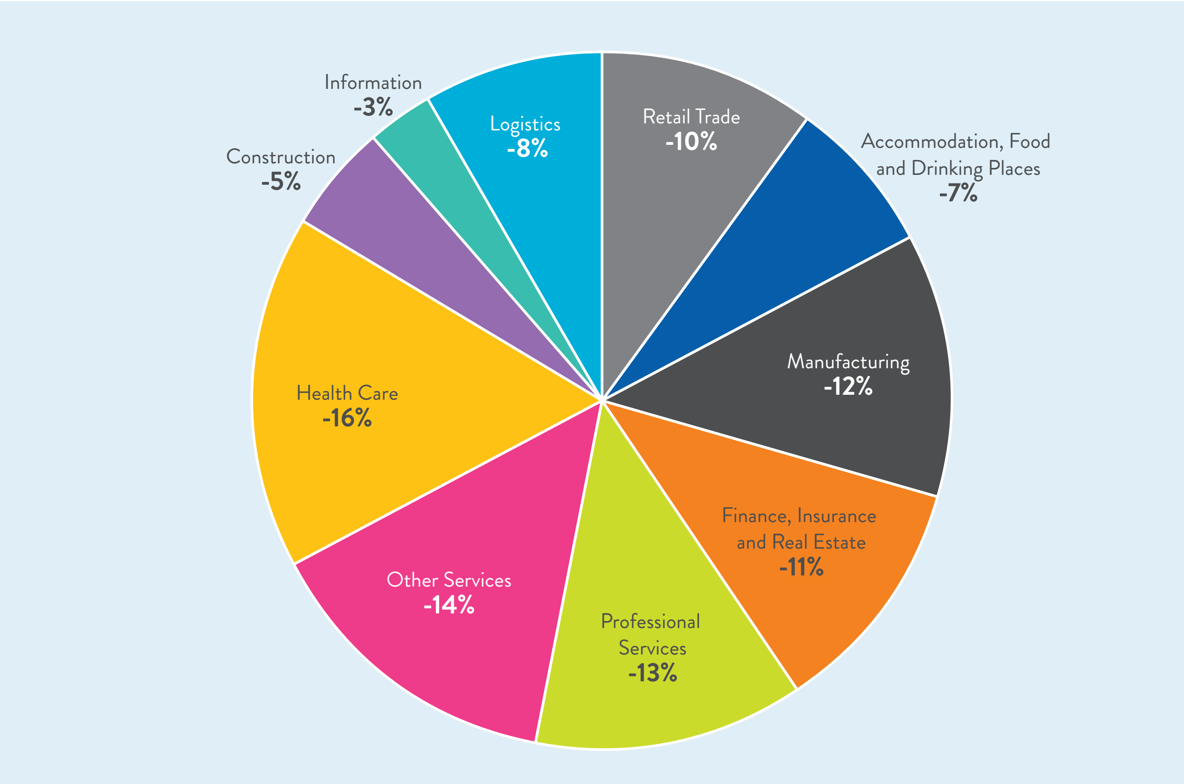
Sector	2029	2039
Manufacturing	36,700	61,700
Finance, Insurance and Real Estate	29,400	55,400
Professional Services	29,300	67,400
Other Services	37,800	71,600
Health Care	31,000	78,300
Construction	15,700	25,700
Information	8,100	13,900
Logistics	22,100	41,200
Retail trade	30,500	49,100
Mining, Utilities, Agriculture	7,400	12,900
Transportation Services (excluding truck transportation)	6,900	12,500
Accommodation, Food and Drinking Places	21,100	36,900
Entertainment	3,600	4,000
Educational Services	6,500	9,400
Social Assistance	1,000	300
Totals	**287,200**	**539,800**

Columns may not add due to rounding.

Note: Losses and increases reflect impacts in a given year against national projections.
These measures do not indicate declines from 2019 levels

Sources: EBP and LIFT model, University of Maryland, INFORUM Group, 2020.

Figure 11. Sectors as Percent of Total Jobs Beneath the 2039 National Baseline



Note: Percentages are based on the proportion of jobs projected to be lost in 2039 shown in Figure 12. Sectors that account for 2 percent or less of the expected losses are combined as "other" (transportation services, excluding trucking; mining, utilities and agriculture; entertainment; educational services; and social assistance).

Sources: EBP and LIFT model, University of Maryland, INFORUM Group, 2020.

Less Competitive in International Markets

Rising incidences of voltage surges, blackouts, and brownouts that disrupt production add costs to businesses. These costs will make U.S. manufactured products less competitive in international markets. Consequently, between 2020 and 2039, U.S. businesses will lose $271 billion in the value of its exports, while businesses and households will pay an additional $142 billion for foreign imports. Table 12 shows the cumulative trade effects by quantifying the degree to which of exports are expected to decrease and the amount by which imports are expected to increase. By 2029, exports are likely to show an aggregate loss of approximately $51 billion, compared with expected increases of $24 billion to the cost of imports. In 2039 alone, due the economic costs imposed by failing to address investment shortfalls, exports are predicted to be $34 billion beneath the baseline, while imports are estimated to be $17 billion above the forecasted baseline.

Table 12. Cumulative Trade Effects ($2019 billions)

Period	Cumulative Export Losses	Cumulative Import Increases
2020-2029	$51	$24
2030-2039	$220	$118
2020-2039	$271	$142

Columns and rows may not add due to rounding. Losses and increases reflect impacts in a given year against total national export projections. These measures do not indicate declines from 2019 levels.
Sources: EBP and LIFT model, University of Maryland, INFORUM Group, 2020.

The LIFT model traces 121 goods and services commodities, including commodities sold by U.S. companies to international markets. Table 13 lists the 10 exported goods and services that stand to lose the most money through 2029 and 2039 due to underperforming electricity infrastructure.

Table 13. Potential U.S. Export Reductions in Goods and Services by 2029 and 2039, Ten Largest Affected Sectors ($2019 billions)

Export Sector	2029	Export Sector	2039
Wholesale trade	$4.8	Wholesale trade	$25.8
Aerospace products and parts	$3.5	Aerospace products and parts	$17.3
Pharmaceutical products and other chemicals	$2.6	Pharmaceutical products and other chemicals	$19.3
Royalties	$2.2	Royalties	$12.0
Petroleum and coal products	$1.8	Architectural, engineering, and related services	$10.8
Architectural, engineering, and related services	$1.8	Software	$10.5
Software	$1.7	Fabricated metal products	$10.0
Fabricated metal products	$1.7	Petroleum and coal products	$9.3
Other financial investment activities	$1.5	Other financial investment activities	$8.8
Scientific research and development services	$1.4	Scientific research and development services	$8.5

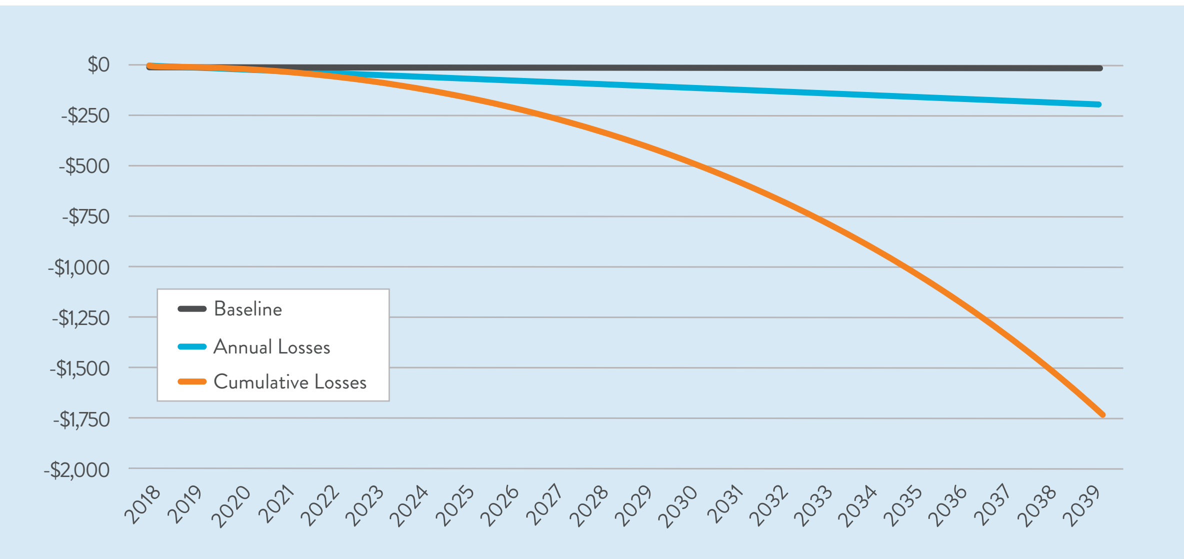
Note: Changes reflect impacts in a given year against national baseline projections by year from 2020 through 2039. These measures do not indicate changes from 2019 levels. Totals for pharmaceutical products and other chemicals are the sums of two commodity groups, "Pharmaceutical products" and "Other chemicals".
Sources: EBP and LIFT model, University of Maryland, INFORUM Group, 2020.

Competitiveness at Stake

Of the total impacts projected from 2020-2039, more than half occur during the second decade of this study. About 77 percent of disposable income losses and total GDP losses and 79 percent of gross output losses are expected to occur between 2030 and 2039. Additionally, a projected 287,000 jobs will be lost by 2029 and 540,000 jobs lost by 2039 due to inefficient electricity delivery, roughly a projected doubling in second decade.

As time goes on, the disadvantages that insufficient investment in energy infrastructure cause are compounded. Over the next 10 years, economic dislocation is observed, but that dislocation worsens from 2030 to 2039. The delayed impact of underinvestment in electricity infrastructure is harmful to much of the U.S. economy, including manufacturing and aerospace. Our competitive hinges on adequate investment in generation, transmission, and distribution infrastructure. Our findings indicate that if the needs identified for 2020-2029 are not addressed and electric infrastructure does not become more modern, reliable and resilient, business productivity will weaken, and wages and household income will fall. As a consequence, domestic goods are expected to become more expensive to produce and U.S consumers will have less purchasing power. These two factors will create a downward economic spiral that will intensify over time.

Figure 12. U.S. GDP Impacts From the Gap in Electricity Infrastructure Investment, 2019-2039 ($2019 billions)



Note: Losses reflect impacts in a given year against national baseline projections (shown as 0). These measures do not indicate declines from 2019 levels.

Sources: EBP and LIFT model, University of Maryland, INFORUM Group, 2020.

Conclusion

The U.S. electricity sector is undergoing rapid changes that have immediate and long-term implications. Renewables are making up a larger percentage of the overall generation portfolio, partially because of market demands and partially the result of state and federal legislation and regulations.

To accommodate this shift, significant investments in the electricity grid are needed. While transmission infrastructure has benefited from increased investment, continued modernization is needed to move large amounts of renewables across the grid. Generally, the electric industry is moving in a positive direction and is poised to be able to meet customer and societal needs. However, distribution segments still struggle with reliability, a problem that is likely to accelerate as storm intensity grows.

Reliable electricity is an essential need for household and the nation's economic activity. The lack of reliability is already hurting households — each electric interruption event costs residential customers $6.88, a figure that has doubled since 2011. As the international economy continues to use increasingly sophisticated technology, including computerized controls and sensitive electronics, the need for reliable electricity is becoming even greater. This growing need is mitigated but not eliminated by continuing advances in the efficiency of new electric equipment and in the management of both supply-side and demand-side resources.

To obtain the needed electric power, households and businesses depend on maintaining and updating the three key elements of electricity infrastructure: (1) generation plants; (2) transmission lines; and (3) local distribution equipment. For the entire system to function, generation facilities need to meet load demand, transmission lines must be able to transport electricity from generation plants to local distribution equipment, and the far-reaching distribution networks must be kept in good repair to ensure reliable final delivery. Connections among the different elements of this broader system are crucial for meeting regional and national energy needs as well as for supporting emerging changes in the spatial pattern of power sources and population centers. Deficiencies or shortfalls in any one of these elements of electricity infrastructure can affect the network's efficiency, domestic jobs, international competitiveness of our industries and, and as a result, our overall standard of living.

About this report

This is one of four reports in ASCE's Failure to Act series. Additional reports include analyses of the nation's water, wastewater and stormwater systems, surface transportation, airports and marine ports/inland waterways. Finally, a summary report will combine the research and findings of the specific sector studies to assess implications for the national economy based on combined need and investment trends.

EDP US WISHES TO THANK

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