FAILURE TO ACT

THE ECONOMIC IMPACT OF CURRENT INVESTMENT TRENDS IN ELECTRICITY INFRASTRUCTURE ★★★★

ASCE
AMERICAN SOCIETY OF CIVIL ENGINEERS

This report was prepared for the
American Society of Civil Engineers
by Economic Development Research
Group, Inc. in association with
La Capra Associates.

ASCE
AMERICAN SOCIETY OF CIVIL ENGINEERS

American Society of Civil Engineers
1801 Alexander Bell Drive
Reston, Virginia, 20191-4400
World Headquarters

101 Constitution Avenue, NW
Suite 375 East
Washington, DC 20001
Washington Office

reportcard@asce.org
www.asce.org/failuretoact

Economic Development
RESEARCH GROUP

Economic Development Research Group, Inc.
2 Oliver Street, 9th Floor
Boston, MA 02109

www.edrgroup.com

La Capra Associates
One Washington Mall, 9th Floor
Boston, MA 02108

www.lacapra.com

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PREFACE

The purpose of the *Failure to Act* report series is to provide an objective analysis of the economic implications for the United States of its continued underinvestment in infrastructure. The reports in the series assess the implications of present trends in infrastructure investment for the productivity of industries, national competitiveness, and the costs for households. The *Failure to Act* series analyzes two types of infrastructure needs:

1. Building new infrastructure to service increasing populations and expanded economic activity; and
2. Maintaining or rebuilding existing infrastructure that needs repair or replacement.

Every four years, the American Society of Civil Engineers (ASCE) publishes *The Report Card for America's Infrastructure*, which grades the current state of 15 national infrastructure categories on a scale of A through F. ASCE's 2009 *Report Card* gave the nation's energy infrastructure a D+. The present report answers the question of how the condition of the U.S. infrastructure system affects our nation's economic performance. In other words, how does a D+ affect America's economic future?

The focus of this report is on electricity, including generation, transmission, and the distribution infrastructure that provides electricity to our nation's homes and businesses. Most elements of electricity infrastructure are privately owned and publicly regulated utilities.

This is the third report in ASCE's *Failure to Act* series. The first report, *Failure to Act: The Economic Impact of Current Investment Trends in Surface Transportation Infrastructure*, encompasses highways, bridges, rail, and transit. The second report, *Failure to Act: The Economic Impact of Current Investment Trends in Water and Wastewater Treatment Infrastructure*, addresses the delivery of potable water and wastewater treatment. The next report will address airports and marine ports.

EXECUTIVE SUMMARY

This report illustrates the importance of electric power generation, transmission and distribution systems to the national economy. The analysis performed focuses on a *trend scenario* that presumes the mix of electricity generation technologies (e.g. electricity generation from oil, natural gas, coal, nuclear, hydro, wind, solar) continues to evolve as reflected in recent trends, including a long-term evolution towards smart grid technologies.[1]

Context

Electricity relies on an interconnected system that is composed of three distinct elements, as described below and illustrated by Figure 1:

1. Generation facilities—including approximately 5,800 major power plants and numerous other smaller generation facilities;[2]
2. High-voltage transmission lines—a network of over 450,000 miles that connects generation facilities with major population centers;[3] and
3. Local distribution systems that bring electric power into homes and businesses via overhead lines or underground cables. The first two elements are usually referred to as the bulk power system.

The United States' system of generation, transmission and distribution facilities was built over the course of a century. Centralized electric generating plants with local distribution networks were started in the 1880s and the grid of interconnected transmission lines was started in the 1920s. Today, we have a complex patchwork system of regional and local power plants, power lines and transformers that have widely varying ages, conditions, and capacities.

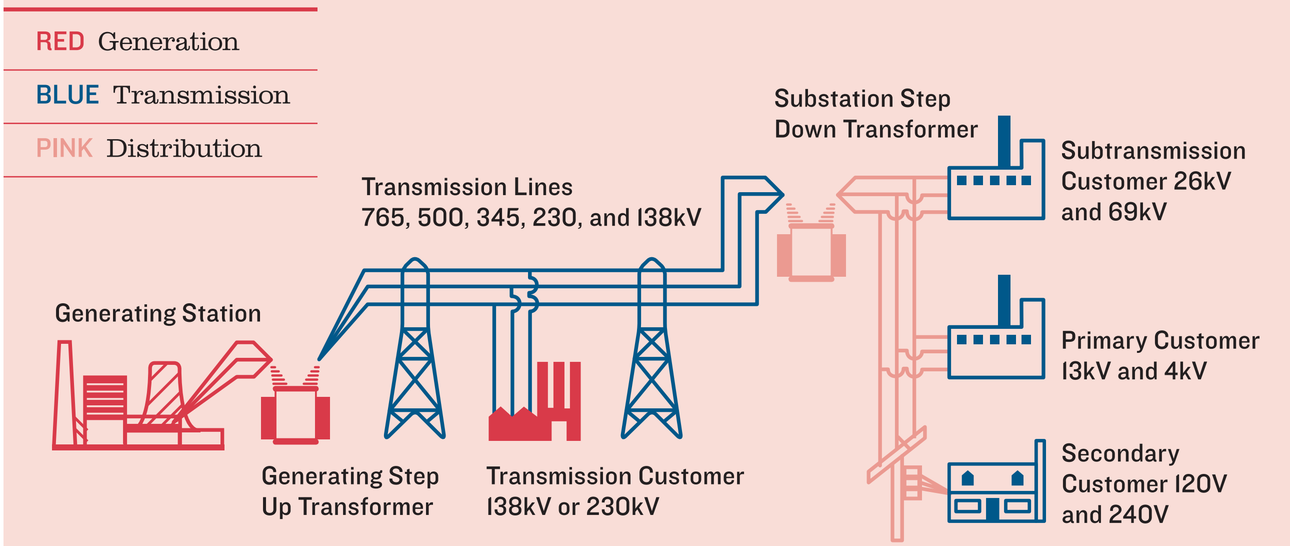
The aging of equipment explains some of the equipment failures that lead to intermittent failures in power quality and availability. The capacity of equipment explains why there are some bottlenecks in the grid that can also lead to brownouts and occasional blackouts. These concerns make it critical to understand what investments may be needed to keep the system in a state of good repair, and what implications any shortfall could have on the nation's economy.

During the past decade, electric energy infrastructure has improved through an upturn in investment, and the negative economic impacts noted in studies of 10 and 20 years ago have been partially mitigated. However, more investment is needed to further reduce the incidence of service disruptions to households and businesses. The needs to maintain and update existing electric energy infrastructure, to adopt new technologies, and to meet the demands of a growing population and evolving economy over the next 30 years will impose significant requirements for new energy infrastructure investment.

Projected Demand for Electricity

In the near term, there is close to adequate capacity to meet demand. Over the short term from 2011 through 2020, national growth in generation is expected to be 8% and demand for electricity in all regions is expected to average 8% or 9% based on projections from the U.S. Energy Information Agency. Divergence across different areas in the United States is not expected until the 2021-2040 period. Over the long-term there is expected to be significant regional differences as use is expected to increase by 39% in Florida, 34% in Western states and 20% in the Mid-Atlantic area.

FIGURE 1 ★ Elements of Generation, Transmission, and Distribution Systems



SOURCE Federal Energy Regulatory Commission, 2006.

Recent Investment Trends

Investment in electricity infrastructure has increased in the past decade. From 2001 through 2010, annual capital investment averaged $62.9 billion, including $35.4 billion in generation, $7.7 billion in transmission, and $19.8 billion in local distribution systems (in 2010 dollars).

The average rate of this investment is used as the basis for calculating the gap between investment rates and expected future increases in investment needs. However, it is important to note the widely varying annual investment levels from 2001 to 2010, which ranged from $44 billion to $101 billion. Spending for generation showed the widest range, while distribution was the most narrow in range. Over the recent ten year period, estimated investment in electric generation facilities varied from $18 billion to $72 billion, while transmission and distribution investments varied from $6 billion to $10 billion and $17 billion to $22 billion, respectively (all dollars adjusted to 2010 value).

The Potential Investment Gap for Electric Infrastructure

Nationally, extending current trends leads to funding gaps in electric generation, transmission, and distribution that are projected to grow over time to a level of $107 billion by 2020, about $11 billion per year, and almost $732 billion by 2040, as shown in Table 2, and the flow of annual expenditures through 2040 is illustrated by Figure 2.

Today, we have a complex patchwork system of regional and local power plants, power lines and transformers that have widely varying ages, conditions, and capacities.

TABLE 1 ★ Annual Average Construction Expenditures for Generation, Transmission, and Distribution: 2001–10 *(in billions of 2010 dollars)*

TYPE OF EXPENDITURES	AVERAGE ANNUAL	LOW ANNUAL	HIGH ANNUAL
Generation	35.4	17.7	71.6
Transmission	7.7	5.6	10.2
Distribution	19.8	16.9	22.3
Average TOTAL	**62.9**	**44.2**	**101.0**

NOTE Low and high annual "total" expenditures represent the average total spending from 2001 to 2010, and are not sums of the annual average expenditures of the three components of the electric infrastructure system.

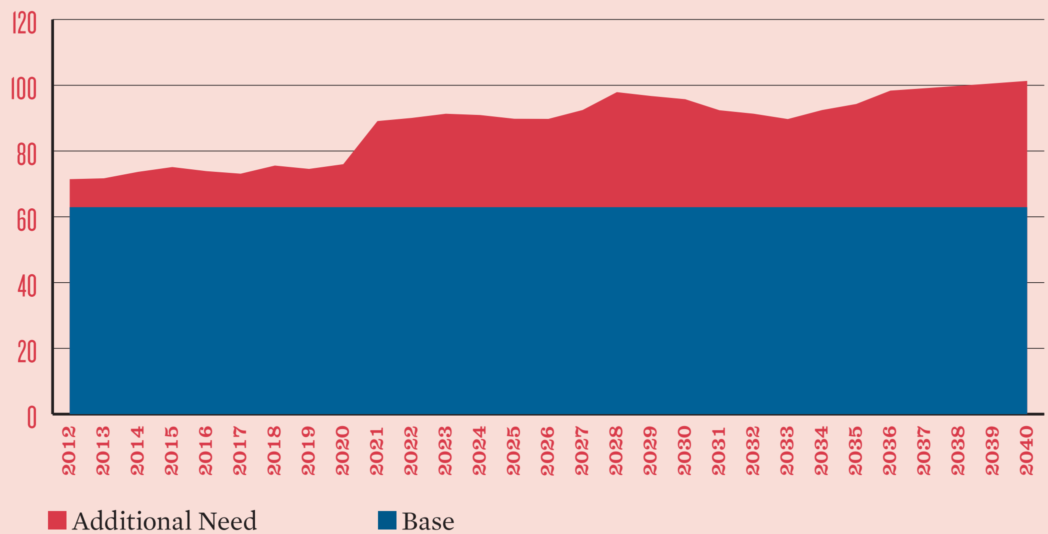
SOURCES Transmission and distribution numbers from Edison Electric Institute, *2012 Report*, table 9–1; generation investment was estimated from reporting forms of the EIA and Federal Energy Regulatory Commission, with averages applied for investment cost per kWh for applicable generating technologies.

TABLE 2 ★ National Electricity Infrastructure Gap: Estimated at $732 Billion by 2040 *(in billions of 2010 dollars)*

TYPE OF INFRASTRUCTURE	CUMULATIVE NEED 2020	CUMULATIVE NEED 2040
Generation	12.3	401.1
Transmission	37.3	111.8
Distribution	57.4	219.0
U.S. TOTAL	**107.0**	**731.8**

SOURCES EIA, NERC, Eastern Interconnection Planning Collaborative, Phase I Report, December 2011, Renewable Energy Transmission Initiative Electric Power Research Institute and Federal Energy Regulatory Commission. Calculations by La Capra Associates and EDR Group.

FIGURE 2 ★ Projected Needs and Gap by Year Compared with 2001–10 Average Investment Levels *(in billions of 2010 dollars)*



SOURCE EIA Annual Energy Outlook 2011 (years 2008-2035) and NERC 2011 Long-term Reliability Report, Eastern Interconnection Planning Collaborative, Phase I Report, December 2011, Renewable Energy Transmission Initiative Electric Power Research Institute and Federal Energy Regulatory Commission. Calculations by La Capra Associates and EDR Group

TABLE 3 ★ Regional Breakdown of Electric Distribution Investment Gap, 2020 and 2040 *(billions of 2010 dollars)*

REGION	CUMULATIVE GAP ESTIMATE BY REGION	
	2011–2020	2011–2040
Texas	14.6	56.0
Florida	4.2	18.2
Midwest	4.4	45.3
Northeast	8.0	51.2
Mid-Atlantic	18.2	130.3
Southeast	29.7	225.6
Southwest	2.4	9.2
West	25.5	196.0
U.S. Total	**107.0**	**731.8**

NOTE Regional descriptions are approximations of NERC Regions.

SOURCE EIA Annual Energy Outlook 2011 (years 2008-2035) and *NERC 2011 Long-term Reliability Report*.

In 2020, distribution and transmission infrastructure are expected to account for more than 88% of the investment gap while generation infrastructure represent roughly 11.5%. By 2040, however, generation infrastructure is potentially the most costly element of the gap, accounting for 55% of the total, with transmission accounting for 15%, and distribution accounting for 30%. This is a reversal from 2020, when generation is expected to be the best funded element of electricity infrastructure.

The cumulative total investment gap adds the generation, transmission, and distribution infrastructure gaps. Those results are shown by region in Table 3, and indicate that the investment funding gap will be highest in the Southeast, the West, and the Mid-Atlantic area, and lowest in the Southwest and Florida. Growth alone does not appear to be driving the gap, but rather a combination of supply, technologies, and demand.

Estimate of Future Costs Incurred

A projected investment gap will be some combination of aging equipment and capacity bottlenecks that lead to the same general outcome—a greater incidence of electricity interruptions. The interruptions may occur in the form of equipment failures, intermittent voltage surges and power quality irregularities due to equipment insufficiency, and/or blackouts or brownouts as demand exceeds capacity for periods of time. The periods of time can be unpredictable in terms of frequency and length, but the end result is a loss of reliability in electricity supply which imposes direct costs to households and businesses.

TABLE 4 ★ **Cumulative Impacts by Region, 2012, 2012–20, and 2012–40**
(in billions of 2010 dollars)

REGION	2012	CUMULATIVE, 2012–20	CUMULATIVE, 2012–40
Texas	0.5	18	80
Florida	0.7	8	32
Midwest	0.8	9	59
Northeast	2.0	17	79
Mid-Atlantic	3.0	36	194
Southeast	5.0	59	297
Southwest	0.5	6	18
West	4.0	44	239
TOTAL	**17**	**197**	**998**

NOTE Regional descriptions are approximations of NERC Regions.

SOURCES Calculations by La Capra and EDR Group based on data from EIA and Electric Power Research Institute.

TABLE 5 ★ Effects on U.S. GDP and Jobs, 2011–40

ANNUAL IMPACTS	2020	2040
GDP	-$70 billion	-$79 billion
Jobs	-529,000	-366,000
Business Sales	-$119 billion	-$159 billion
Disposable Personal Income	-$91 billion	-$86 billion
AVERAGE YEAR	**2012–2020**	**2021–2040**
GDP	-$55 billion	-461,000
Jobs	-461,000	-588,000
Business Sales	-$94 billion	-$180 billion
Disposable Personal Income	-$73 billion	-$115 billion
CUMULATIVE LOSSES	**2012–2020**	**2021–2040**
GDP	-$496 billion	-1.95 trillion
Jobs	NA	NA
Business Sales	-$847 billion	-$3.6 trillion
Disposable Personal Income	-$656 billion	-$2.3 trillion

NOTE Losses in business sales and GDP reflect impacts in a given year against total national business sales and GDP in that year. These measures do not indicate declines from 2010 levels.

SOURCES EDR Group and LIFT model, University of Maryland, INFORUM Group, 2012.

A failure to meet the projected gap will cost households $6 billion in 2012, $71 billion by 2020, and $354 billion by 2040. It will cost businesses $10 billion in 2012, $126 billion by 2020, and $641 billion by 2040. Annual costs to the economy will average $20 billion through 2020 and $33 billion through 2040. It is notable that these estimated impacts are significantly lower than the impacts estimated from studies conducted in the 1990s and 2000s.

These costs incurred by failing to close the investment gap are higher than the investment itself. This means that it is economically inefficient for households and businesses to allow this higher cost scenario to occur. Even if sufficient investment is made to close the investment gap, the result will not be a perfect network for electricity generation and delivery, but rather one that has dramatically reduced, though not eliminated, power quality and availability interruptions.

A projected investment gap will be some combination of aging equipment and capacity bottlenecks that lead to the same general outcome—a greater incidence of electricity interruptions.

Table 4 breaks down the estimated impact by region. These costs are not felt equally across the United States. Cumulative cost increases in the Southeast will be 30% of the total and costs in the West will be 22% of the total.

Future Impact on Economy

If future investment needs are not addressed to upgrade our nation's electric generation, transmission, and distribution systems, the economy will suffer. Costs may occur in the form of higher costs for electric power, or costs incurred because of power unreliability, or costs associated with adopting more expensive industrial processes. Ultimately, these costs all lead to the same economic impact: diversion of household income from other uses and a reduction in the competitiveness of U.S. businesses in world economic markets.

As costs to households and businesses associated with service interruptions rise, GDP will fall by a total of $496 billion by 2020. The U.S. economy will end up with an average of 529,000 fewer jobs than it would otherwise have by 2020. As shown in Table 5, even with economic adjustments occurring later on, with catch-up investments, the result would still be 366,000 fewer jobs in 2040. In addition, personal income in the U.S. will fall by a total of $656 billion from expected levels by 2020.

Conclusion

The cumulative need, based on anticipated investment levels and the estimated investment gap, will be $673 billion by 2020, an average of about $75 billion per year. Based on investment over the past decade, closing the gap is within reach: the average annual need projected from 2012 through 2020 falls within the range of annual investment totals in the last decade, and there is not a single year through 2020 that is projected to be outside that range.

Reliable electricity is essential for the functioning of many aspects of household and economic activity today. As the nation moves towards increasingly sophisticated use of information technology, computerized controls and sensitive electronics, the need for electricity reliability becomes even greater. 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 decentralized distribution networks must be kept in good repair to ensure reliable final delivery. Deficiencies or shortfalls in any one of these three elements of electricity infrastructure can affect our nation's future economic growth and standard of living.

1 INTRODUCTION

Our nation's system of electricity generation, transmission and distribution facilities was built over the course of a century. Centralized electric generating plants with local distribution networks were first built in the 1880s, and the grid of interconnected transmission lines began to be built in the 1920s. Today, we have a complex network of regional and local power plants, power lines and transformers that have widely varying ages, conditions and capacities.

The analysis presented in this report illustrates the continuing importance of electric power generation, transmission and distribution systems to the national economy. This infrastructure is needed in good working order to assure that supply of electricity can meet demand, and that the electricity can be delivered reliably to households and businesses. Both deficiencies in the performance of aging equipment and insufficiencies in electric system capacity can lead to difficulty meeting projected demand and reliability standards, which can impose costs on households and businesses. This report highlights the nature of the potential investment gap, and the ways that it can affect the productivity and competitiveness of industries along with the prosperity of households.

This report's economic analysis is based on documentation of electricity system conditions from 2011, data on recent investment trends in electricity infrastructure, and projections of the probable implications of emerging trends extending out to 2040. The needs to maintain and update existing electric energy infrastructure, to adopt new technologies, and to meet the demands of a growing population and evolving economy in the next 30 years will impose significant requirements for new energy infrastructure investment. During the past decade, electric energy infrastructure has been improved through an upturn in investment, and the negative economic impacts noted in studies of 10 and 20 years ago have been partially mitigated. More investment is needed, however, to further reduce the incidence of service disruptions borne by households and businesses.

The extent of the effort that is made to respond to these needs and enhance investment in this infrastructure can have major consequences for industries' competitiveness and performance, along with impacts on the standard of living for American households.

The analysis presented in this report illustrates how deficiencies in electric generation, transmission, and distribution affect the U.S. economy and will continue to do so in the future without a change in investment patterns. The report thus seeks to highlight how deficient electric energy delivery systems impose costs on households and businesses, and how these costs affect the productivity and competitiveness of industries, along with the well-being of households. This report includes the following topics:

- ★ An overview of electricity infrastructure,
- ★ Electricity demand by region and the segmentation of consumers,
- ★ The current and projected shortfall (gap) in electric energy infrastructure investment,
- ★ The national and regional implications of this shortfall,
- ★ An overview of the methodology employed to assess economic performance, and
- ★ Implications of the shortfall in infrastructure investment for national economic performance.

The final sections include a discussion of long-term uncertainties, conclusions, the sources and methodology used, and acknowledgments.

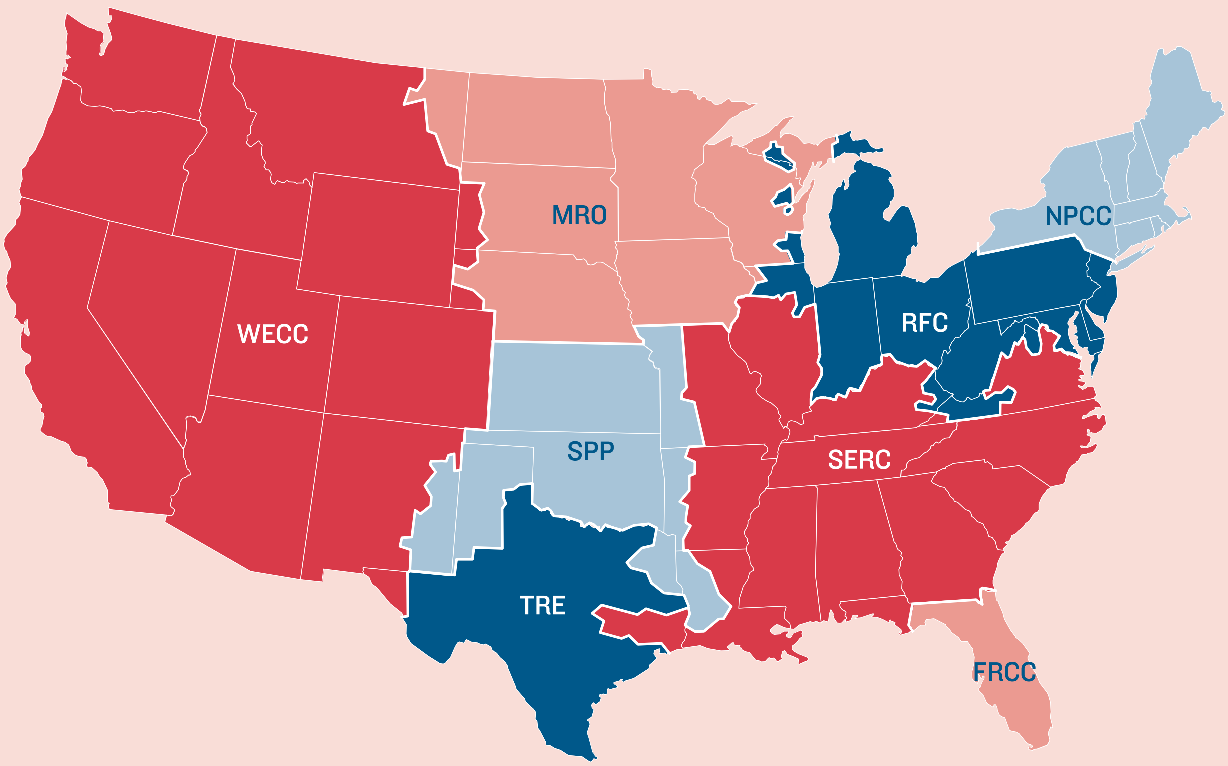
The primary basis for the economic analysis is documentation provided by the U.S. Department of Energy, the North American Electric Reliability Corporation, the Edison Electric Institute, and the Electric Power Research Institute. Each year the U.S. Energy Information Administration (EIA) releases an *Annual Energy Outlook* that projects long-term energy supply, demand and prices based on results from EIA's National Energy Modeling System (NEMS). *Annual Energy Outlook 2011*, published in April 2011, presents actual and projected total electric sales broken down by generation technology for 2008–2035. For this study we presume the EIA projections represent "trends extended" or "business as usual" to 2040.

Regional Approach

Electricity data are reported by various regional structures. This report uses the North American Electric Reliability Corporation (NERC) regions, which divides the contiguous United States into eight regions for reliability planning (Figure 3). Note that the NERC regions covering the West, Midwest and Northeast include Canada. Data in this report has been filtered to include only the United States, except for generation plants and transmission lines that originate in Canada to serve U.S. markets.

The U.S. Energy Information Administration (EIA) sometimes reports data broken down into 22 Electricity Market Module (EMM) regions. In cases where data were reported using other regional structures, such as in EMM regions, estimates were developed to place these data in consistent NERC regions.

FIGURE 3 ★ NERC Regional Entities



FRCC (Florida)	Florida Reliability Coordinating Council
MRO (Midwest)	Midwest Coordinating Organization
NPCC (Northeast)	Northeast Power Coordinating Council
RFC (Mid-Atlantic)	Reliability First Corporation
SERC (Southeast)	Southeast Reliability Corporation
SPP (Southwest)	Southwest Power Pool Regional Entity
TRE (Texas)	Texas Reliability Approach
WECC (West)	Western Electricity Coordinating Council

SOURCE www.nerc.com

The capital gap is the difference between the level of dollars invested in infrastructure under the trend scenario (extending current investment trends) and the level of investment required to replace, expand, or improve infrastructure as demand grows and existing equipment ages.

Objectives and Limitations of This Study

The purpose of this study is to survey the economic effects of current investment trends in America's energy infrastructure. This report does not address the availability or shortages or changing prices of energy resources, the desirability or costs of exploration and extraction, and it is not intended to propose or imply prescriptive policy changes. In addition, the report does not address which fuels, or combination of fuels, are best for the nation's energy future, or 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.

It is difficult to predict future levels of capital spending because a wide range of factors will exert an influence during the coming decades. The analysis focuses on a *trend scenario* that presumes that the mix of electricity generation technologies (electricity generation from oil, natural gas, coal, nuclear, hydro, wind, solar, etc.) continues to evolve as reflected in EIA data, with a continued long-term evolution toward smart grid technologies.[1] Future investment in electric energy infrastructure will likely vary from year to year, reflecting variation over time in the average age and consequent need for replacement of various elements of equipment, facilities, and power lines. In addition, capital spending will tend to rise to meet the requirements of new laws and regulations, the pace of conversion to renewable energy sources, the costs of connecting new energy sources to the existing energy grid, and conversion to more reliable smart grid technologies.

The capital gap is the difference between the level of dollars invested in infrastructure under the trend scenario (extending current investment trends) and the level of investment required to replace, expand, or improve infrastructure as demand grows and existing equipment ages. Regardless of the reason, failure to carry out needed investments can result in shortages—not necessarily in resources, but in the ability to deliver reliable electricity to customers due to inefficient or insufficient generation, transmission, and distribution infrastructure systems that ultimately compromise the ability of customers to receive reliable electricity. Any such shortages will result in the price of electricity being raised so that the supply can meet the demand. (This is in addition to the costs of the fuels themselves.) Thus, the unmet costs of meeting energy infrastructure requirements can be seen as adding future costs for households and for business operations in the U.S.

As part of the *Failure to Act* series, this report focuses on the economic consequences of not making needed investments in electricity infrastructure, because these investments fundamentally affect the productivity and global competitiveness of the U.S. economy and hence long-term job and income growth. This analysis does not consider the short-term impacts of money flows associated with spending on construction, installation and operation of additional infrastructure.

2 OVERVIEW OF THE ELECTRICITY INFRASTRUCTURE

America's electricity energy infrastructure is composed of three distinct elements:

1. **Electricity generation facilities—including approximately 5,800 major power plants and numerous other smaller generation facilities;[2]**
2. **High-voltage transmission lines—a network of over 450,000 miles that connects generation facilities with major population centers;[3] and**
3. **Local distribution systems that bring electric power into homes and businesses via overhead lines or underground cables. The first two elements are usually referred to as the bulk power system. The interconnectivity of electricity infrastructure elements is illustrated by Figure 1.**

Common Elements of Infrastructure

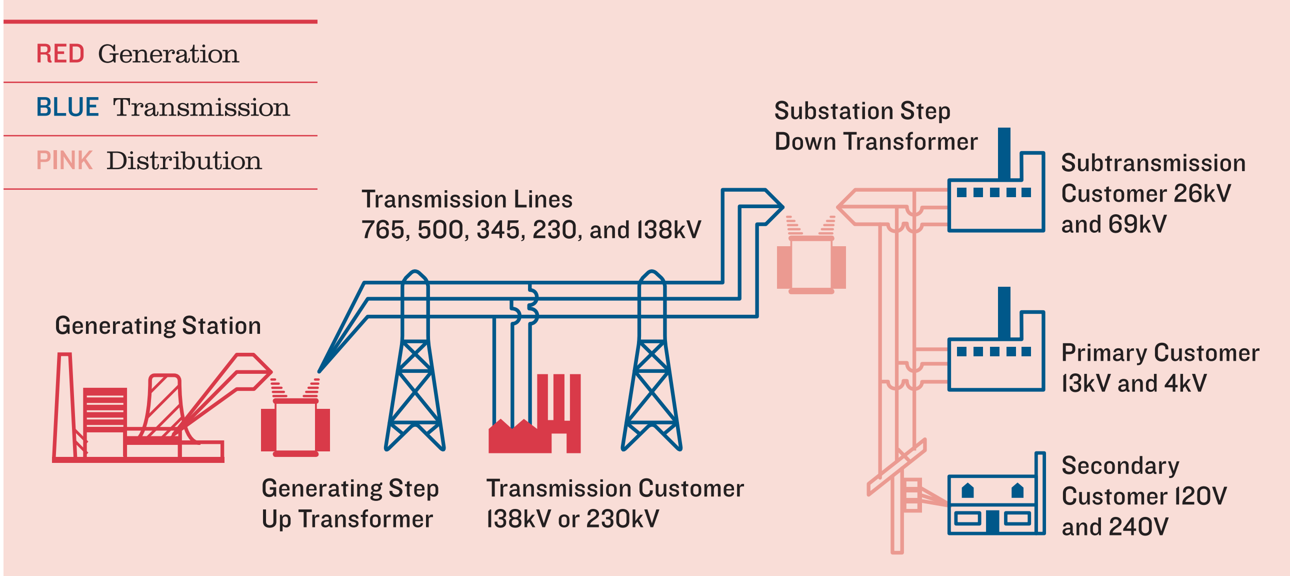
All forms of infrastructure have features in common. In general, infrastructure involves built facilities located across the country that are used by households and businesses, or are used by service providers for households and business. Infrastructure is also a "public good," meaning that much of the population and economy either directly or indirectly benefit from its existence. The electricity infrastructure is similar to surface transportation infrastructure in that both involve a *network* of cross-border and interstate connections, as well as state or regional transmission networks and local distribution systems. Energy infrastructure is also similar to water infrastructure in that both commonly utilize *centralized facilities* to generate or process a product that is distributed to homes and business locations, though in both cases, a small subset of households and businesses instead provide for themselves.

Key Differences from Other Infrastructure Types

It is important to note that the electric energy infrastructure is different from transportation and water and wastewater infrastructure, which were analyzed in previous *Failure to Act* reports, in four ways:

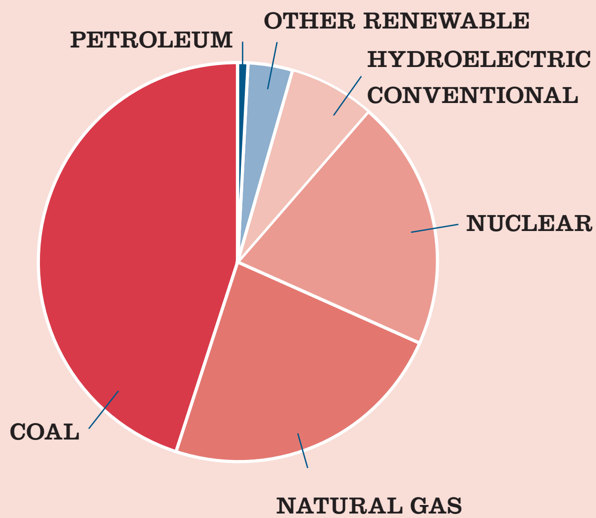
1. *Private ownership.* One distinguishing feature of the electric energy infrastructure (including both bulk power and local distribution) is that most of it is privately owned. A portion of the infrastructure is owned by federal agencies, municipal governments, and rural cooperatives. But the vast majority is owned by for-profit, investor-owned utilities. There are also privately owned "independent power producers." Yet even with private ownership and operation, the rates that local utilities charge is generally regulated by state agencies, and there is also federal and state regulatory oversight of the operation of generating facilities and transmission systems.
2. *The breadth of technologies for electricity generation.* A second distinguishing feature of America's electric energy infrastructure is the wide variation in technologies being employed. The wide range of technologies is most evident for generating facilities, which can employ nuclear power, the combustion of carbon-based "fossil fuels" (including coal, oil, diesel, and natural gas), or renewable power (including hydro, wind, solar, geothermal, or biomass) as shown in Figure 4. Central power plants may employ any of these technologies, and the mix varies across regions of the U.S. In addition, some large businesses operate distributed generation facilities, which are either "cogeneration" power plants that employ steam, heat, or biomass refuse generated from industrial processes, or "self-generation" facilities using combustion, wind, or solar power for either primary or backup power.

FIGURE 1 ★ Elements of Generation, Transmission, and Distribution Systems



SOURCE Federal Energy Regulatory Commission, 2006.

FIGURE 4 ★ **Fuel Source of U.S. Electricity Generation, 2009**

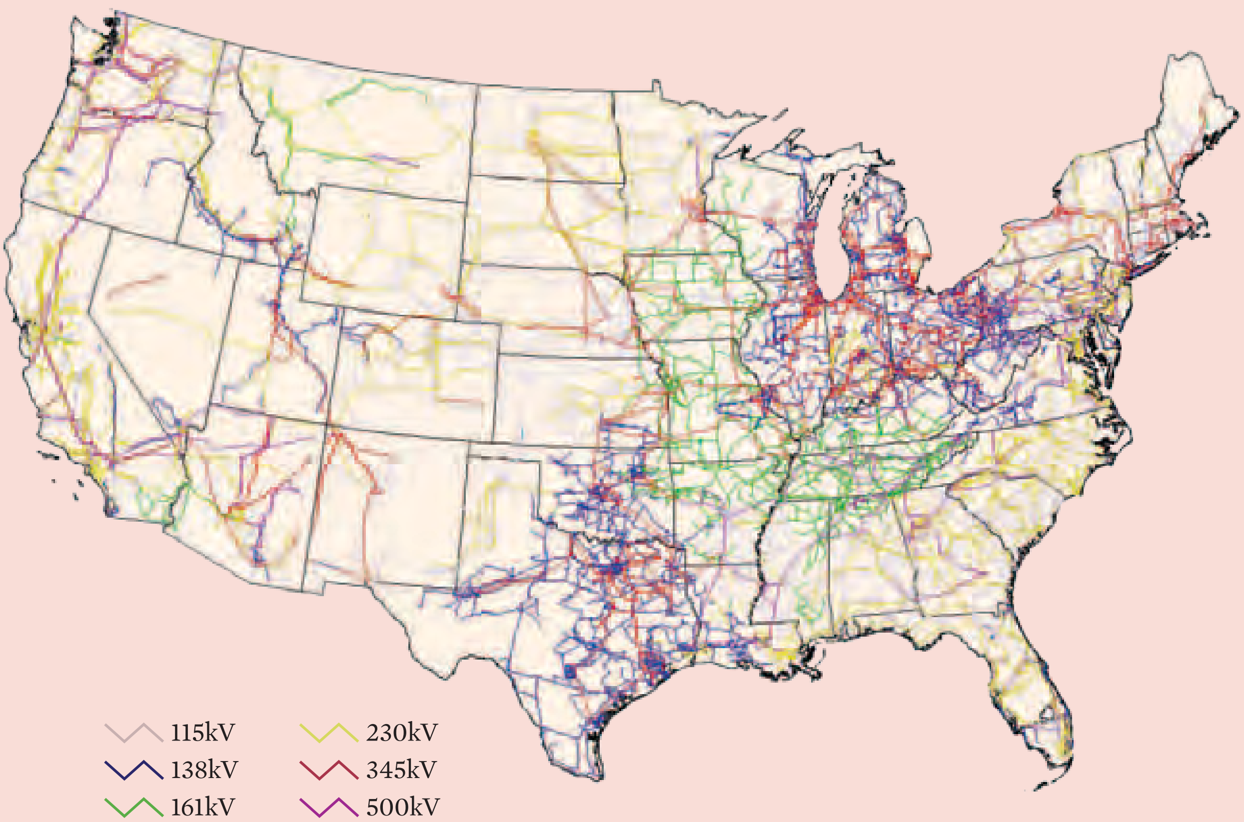


Petroleum	1%
Other Renewables	4%
Hydroelectric Conventional	7%
Nuclear	20%
Natural Gas	23%
Coal	45%

SOURCE U.S. Energy Information Administration, 2009.

3. *The rate of change.* A third distinguishing aspect of electric energy infrastructure is the complex combination of ownership arrangements and operating systems that are constantly evolving, in addition to the variation of technologies described above. This has important implications. On one hand, the diversification of fuel and technology reliance provides a degree of protection against unforeseen future issues with any one type of generation. On the other hand, uncertainty about future prices of fossil fuels, regulations controlling greenhouse gas emissions, and rate of adoption for more renewable power portfolios options can all make it more difficult to forecast the future technology mix and its cost implications. Anticipated future changes regarding the feasibility and implementation of distributed generation and smart grid technologies also add uncertainty about what future infrastructure system will look like.[4]
4. *Deregulation of system elements.* A fourth distinguishing aspect of electric energy infrastructure is deregulation, which has resulted in the three elements (generation, transmission, and distribution) being operated by different parties, facilitating the growth of independent power production and distributed generation.[5] Today, households and businesses typically receive itemized electric bills that charge separately for each of the three elements. However, a small but growing number of businesses and households now have their own generation equipment that minimizes or eliminates their reliance on central power generation and transmission systems at least part of the time, and some of them also sell power back to utilities.[6]

FIGURE 5 ★ The U.S. Electricity Transmission Grid



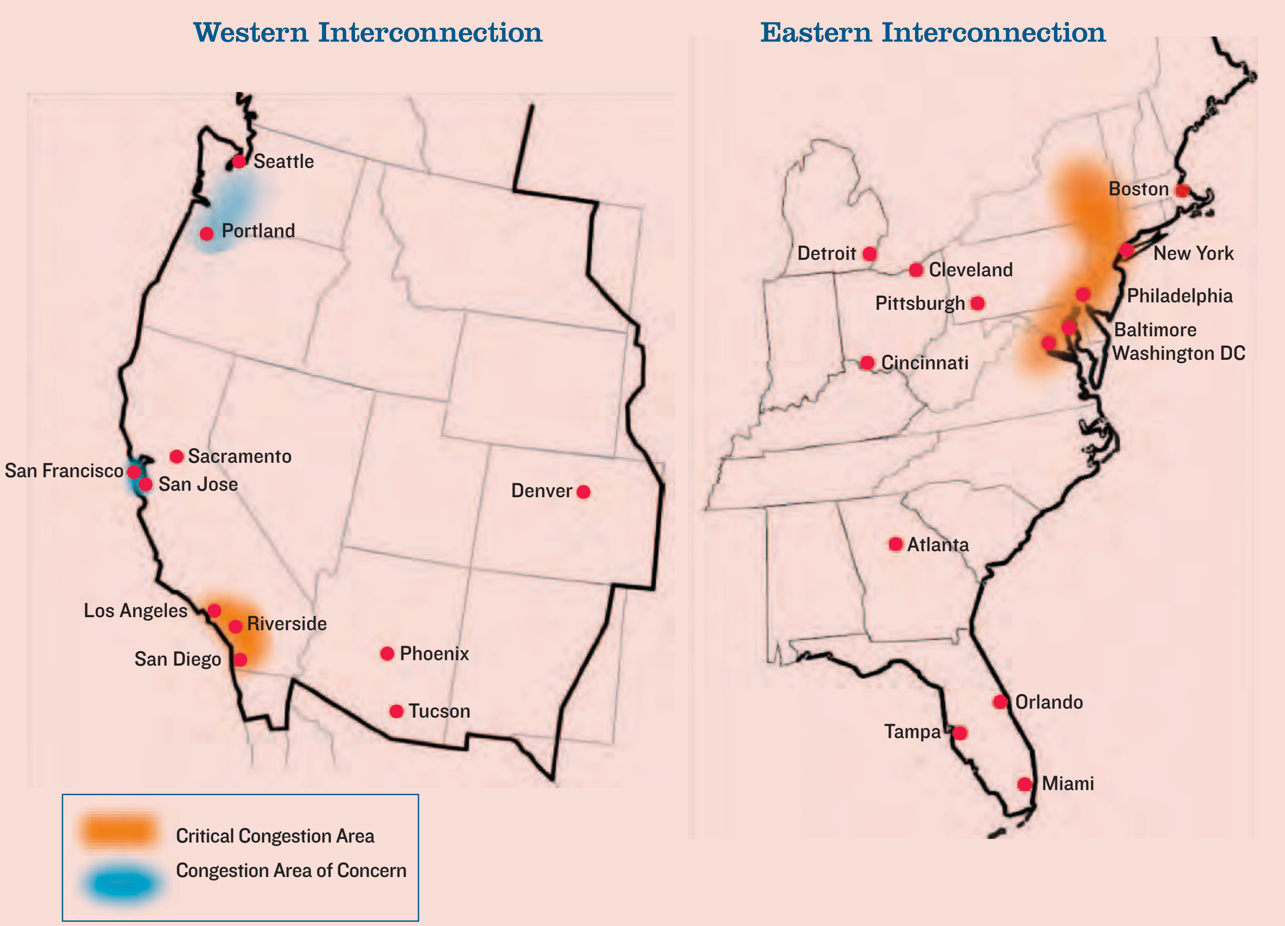
SOURCE U.S. Federal Emergency Management Agency.

Key Issues

Power plants use a variety of different technologies with widely different fuel needs and operating costs that lead them to serve base load, peak load, or backup functions. These fuel mixes vary widely across regions of the U.S. The transmission lines have a variety of different voltage (power) and capacity (electricity) characteristics that lead them to serve different functions in the movement of electricity from generation plants to local load (distribution) centers. Moreover, local utility customers are served by a wide variety of different transformer types, of different ages and capacities, which progressively step down power from higher to lower voltages to serve local utility customers.

Altogether, our nation's electric energy infrastructure is a patchwork system that has evolved over a long period of time, with equipment of widely differing ages and capacities. For example, about 51% of the generating capacity of the U.S. is in plants that were at least 30 years old at the end of 2010. Most gas-fired capacity is less than 10 years old, while

FIGURE 6 ★ Map of Congested Paths in Electric Transmission Systems



SOURCE U.S. Department of Energy, *National Electric Transmission Congestion Study*, December 2009.

NOTE These maps are available because Congress directed the U.S. Department of Energy to conduct a study every three years on electric transmission congestion and constraints within the Eastern and Western Interconnections in the Energy Policy Act of 2005.

73% of all coal-fired capacity is 30 years or older.[7] Moreover, nationally, 70% of transmission lines and power transformers are 25 years or older, while 60% of circuit breakers are more than 30 years old.[8]

The aging of equipment explains some of the equipment failures that lead to intermittent failures in power quality and availability. The limited capacity of older equipment also explains why there are congestion points in the grid that can also lead to brownouts and occasional blackouts. These concerns make it critical to understand the nature of the current and projected future shortfall, or gap, between system supply and demand. The spatial pattern of congestion is shown through Figure 5 that illustrates the U.S. transmission grid, and Figure 6, which shows critically congested areas on the electric grid of the Eastern Interconnection and the Western Interconnection.

3 SUPPLY AND DEMAND

Electricity Demand

Demand for electricity generation has two key metrics: "peak demand," representing the kilowatts (kW) of capacity needed on the system to meet the greatest hour of demand, and "load," representing the total kilowatt-hours (kWh) of electric energy demanded.

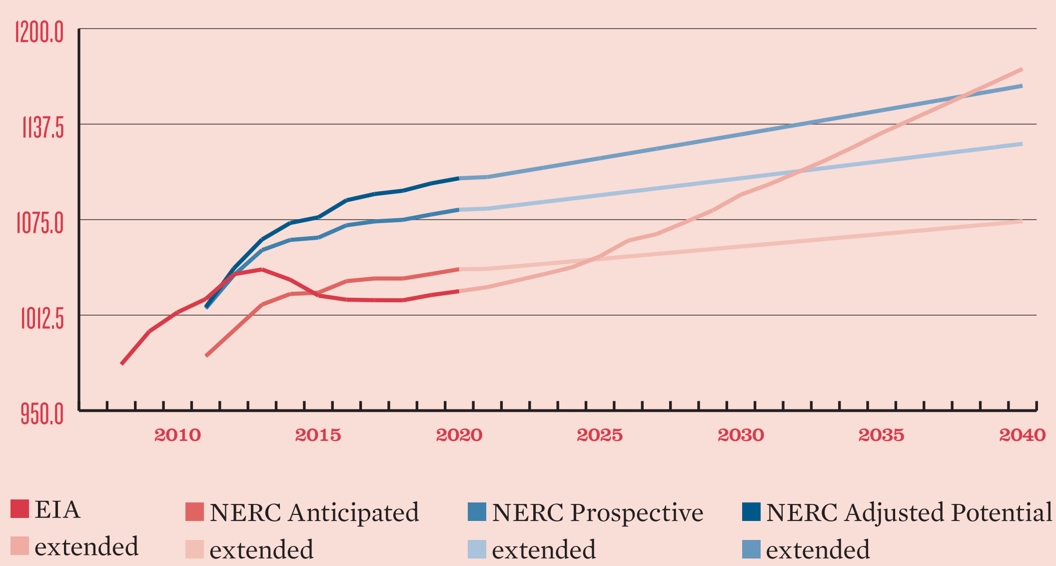
On the basis of projections made by the U.S. Energy Information Agency (EIA), electricity use is expected to increase nationally by 26% from 2011 to 2040 (see Table 6).[9] Over the long term, significant regional differences are expected as use increases by 39% in Florida, 34% in the Western states, and 20% in the Mid-Atlantic area. It is important to note that, over the short term, from 2011 through 2020, national growth of electricity demand is expected to be 8% and the increased demand in all regions is expected to average 8% or 9%. Divergence across different geographical areas in the United States is not expected until the 2021–40 period.

TABLE 6 ★ U.S. Demand for Electric Energy is Expected to Increase 8% between 2011 and 2020

DEMAND	2011	2020	2040
U.S. demand In terawatt-hours	3,692	3,976	4,658
Percent residential	37%	35%	36%
Percent nonresidential	63%	65%	64%
OVERALL PERCENT GROWTH			
2011–20	8%		
2021–40	17%		
2011–40	26%		

SOURCES EIA, *Annual Energy Outlook 2011* (for 2008–35); calculations by La Capra Associates to extend the analysis to 2040.

FIGURE 7 ★ Comparison of Complete NERC and EIA Projections for U.S. Summer Capacity, extended through 2040 *(gigawatts)*



SOURCE *NERC, 2011 Long-Term Reliability Report.*

NOTE "Anticipated" refers to the most conservative supply estimate from NERC, based on existing resources plus future planned capacity resources.

Over the recent ten year period, estimated investment in electric generation facilities varied from $18 billion to $72 billion, while transmission and distribution investments varied from $6 to $10 billion and $17 billion to $22 billion.

The bulk power system is designed and planned to meet seasonal peak demand in addition to a certain reserve margin. Annual peaks tend to occur in the summer in most parts of the U.S., due to cooling loads, and the electric system needs to be sized to meet these loads. However, in some locations, peak demand occurs in the winter.[10] NERC has an alternative and higher forecast of growth in peak demand, which indicates a rise of 13% from 2011 to 2020, compared with the EIA's projection of 8% for the same years.[11]

Electricity Supply

The primary sources for data on existing and projected power generation, also called supply capacity, are EIA and NERC. Both provide estimates of existing and projected power generation during the next 25 and 10 years, respectively. Their estimates of U.S. total summer capacity are compared in Figure 7. Note that faded lines indicate the trends extended to the year 2040.

Recent Investment Trends

From 2001 through 2010, annual capital investment in transmission and distribution infrastructure averaged $62.9 billion, including $35.4 billion in generation, $7.7 billion in transmission, and $19.8 billion in local distribution (in 2010 dollars).

As seen in Table 7, investment for transmission has been growing annually since 2001 at nearly a 7% annual growth rate. For generation, investment levels have varied widely from year to year, with the lowest levels in the 2004–06 time period. For local distribution, however, national-level investment peaked in 2006 and has since declined to less than the level observed in 1991.

The average rates of these investments are used in the next chapter as a basis for calculating the gap between investment rates and expected future increases in investment needs. However, it is important to note the widely varying annual investment levels from 2001 to 2010, as shown in Table 1, which ranged from $44 billion to $101 billion. Spending for generation showed the widest range, while distribution was the most narrow in range. Over the recent ten year period, estimated investment in electric generation facilities varied from $18 billion to $72 billion, while transmission and distribution investments varied from $6 billion to $10 billion and $17 billion to $22 billion, respectively (all dollars adjusted to 2010 value).

TABLE 7 ★ Construction Expenditures for Generation, Transmission, and Distribution: 2001–10 *(in billions of 2010 dollars)*

EXPENDITURES	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001
Generation	28.9	38.9	71.6	49.5	18.1	24.4	17.7	25.0	37.0	43.0
Transmission	10.2	9.9	9.0	8.5	8.2	7.5	6.3	6.2	5.7	5.6
Distribution	16.9	17.7	20.3	20.8	22.3	21.1	20.2	19.3	19.9	19.7
Total	**56.0**	**66.4**	**101.0**	**78.8**	**48.6**	**53.0**	**44.2**	**50.5**	**62.6**	**68.2**

SOURCES *Electric Power Annual 2011*, U.S. Energy Information Administration; and *2012 Statistical Yearbook of the Electric Power Industry*, Edison Electric Institute.

NOTE Numbers may not add due to rounding.

TABLE 1 ★ Annual Average Construction Expenditures for Generation, Transmission, and Distribution: 2001–10 *(in billions of 2010 dollars)*

TYPE OF EXPENDITURES	AVERAGE ANNUAL	LOW ANNUAL	HIGH ANNUAL
Generation	35.4	17.7	71.6
Transmission	7.7	5.6	10.2
Distribution	19.8	16.9	22.3
Average TOTAL	**62.9**	**44.2**	**101.0**

NOTE Low and high annual "total" expenditures represent the average total spending from 2001 to 2010, and are not sums of the annual average expenditures of the three components of the electric infrastructure system. Numbers may not add due to rounding.

SOURCES Transmission and distribution numbers from Edison Electric Institute, *2012 Report*, table 9–1; generation investment was estimated from reporting forms of the EIA and Federal Energy Regulatory Commission, with averages applied for investment cost per kWh for applicable generating technologies.

4 THE POTENTIAL INVESTMENT GAP

This chapter summarizes the data, assumptions, and methodology underlying the difference between the investment levels expected annually through 2040 and the investment levels that will be needed to assure the reliable delivery of electricity to businesses, households, and other users. The analysis of this potential investment gap that follows considers recent investment trends, projected future investment rates, and the extent of the shortfall between expected investment rates and forecasted future investment requirements. It is conducted separately for each of the three elements of generation, transmission, and distribution systems. The tables present the results for a *trend scenario* that is based on EIA projections and assumes a continuing shift in the mix of generation technologies, and further implementation of smart grid technologies.

From 2011 through 2040, the averages of 2001–10 investments are assumed and the gap represents annual expenditures above the averages for generation, transmission, and distribution (see Table 1). It is important to note that in any given year, the total need may be within the ranges of 2001–10 investments but exceed the average annual expenditures. For example, needed generation investments from 2011 to 2040 will range from $35 billion to $61 billion. For every year, the total is within the 2001–10 range of generation expenditures, although $61 billion is about $25 billion above the average seen during the last decade.

Overview of Key Findings

Nationally, extending current trends leads to funding gaps in electric generation, transmission, and distribution that are projected to grow over time to a level of $107 billion by 2020 and almost $732 billion by 2040, as shown in Table 2. These are totals above the averages for past expenditures. In 2020,

TABLE 2 ★ National Electricity Infrastructure Gap: Estimated at $107 Billion by 2020 *(in billions of 2010 dollars)*

TYPE OF INFRASTRUCTURE	CUMULATIVE GAP 2020	2040
Generation	12.3	401.1
Transmission	37.3	111.8
Distribution	57.4	219.0
U.S. TOTAL	**107.0**	**731.8**

SOURCES EIA, NERC, Eastern Interconnection Planning Collaborative, Phase I Report, December 2011, Renewable Energy Transmission Initiative Electric Power Research Institute and Federal Energy Regulatory Commission. Calculations by La Capra Associates and EDR Group.

NOTE Numbers may not add due to rounding.

distribution and transmission infrastructure are expected to account for more than 88% of the investment gap, while generation infrastructure will represent roughly 11.5%. By 2040, however, generation infrastructure is seen as potentially the most costly element of the gap, accounting for 55% of the total, with transmission accounting for 15%, and distribution accounting for 30%. This is a reversal from 2020, when generation is expected to be the best-funded element of electricity infrastructure. By itself, this funding does not necessarily mean that there will be a future shortage of electricity available. Rather, it indicates that future investment needs will be greater.

The gap is calculated as total estimated needs per year minus the 2001–10 average annual investment levels and summed to aggregate levels in 2020 and 2040. Table 8 illustrates the calculations for five specified years.

Generation

Generation Technologies

Table 9 shows the reliance of each NERC region on various power-producing technologies as of 2011. Note the prominence of coal in every region, especially in the Midwest. The Texas, Florida, and Northeast regions use the highest proportion of natural gas, while the Midwest uses the least. Nuclear power is spread out among all regions, and it is relied on most in the Northeast and least in the Southwest. Note also that renewable sources are most prominent in the Western states and are also employed in the Northeast and Midwest, though they are insignificant in other regions. Conversely, oil generation is minimal as a proportion of current power usage.

Table 10 shows the increase in each region of the plant additions that are expected through 2040. As displayed, most regions are anticipated to build significant capacity in gas plants (and limited coal plants). Note the prominence of gas in every region, but especially Florida, the Northeast, and the Mid-Atlantic region. Conversely, new renewable sources are prominent in four regions and minimal in the other four, and nuclear power is prominent in the Southeast.

Investment Need

Electricity infrastructure at the wholesale level is regulated by the Federal Energy Regulatory Commission (FERC) and NERC. FERC regulates markets and incentives for infrastructure investment, while NERC (as authorized by FERC) monitors reliability levels. Systems are maintained to a “1 day in 10 years” loss-of-load expectation. The history or origin of this standard is not well documented, but is believed to have originated with academic papers written in the 1940s.[12] As utilities began to study the use of this standard and find it acceptable, more and more utilities began to incorporate it into their planning departments. It was eventually accepted by NERC as the standard that should be followed throughout the country.

Utilities and independent system operators plan to have resources available to meet this expectation. As such, reliability at the level of the bulk power system is usually good (and better than at the level of the distribution system), so major outages at the levels of the generation and transmission system are now relatively rare. For this analysis, a simplified reliability analysis based on planning reserve margins was used, which represents the percentage of additional resources beyond peak demand levels that are needed to meet the loss-of-load expectation.

TABLE 8 ★ Projected Needs and Gap by Year Compared with 2001–10 Average Investment Levels *(in billions of 2010 dollars)*

ASPECT OF NEEDS	2012	2015	2020	2030	2040
Projected national needs					
Generation	35.4	38.3	37.8	54.1	61.0
Transmission	11.4	11.4	11.4	11.4	11.4
Distribution	24.6	25.4	26.8	30.2	28.9
TOTAL	**71.5**	**75.1**	**76.0**	**95.8**	**101.3**
Baseline 2001–10 averages					
Generation	35.4	35.4	35.4	35.4	35.4
Transmission	7.7	7.7	7.7	7.7	7.7
Distribution	19.8	19.8	19.8	19.8	19.8
TOTAL	**62.9**	**62.9**	**62.9**	**62.9**	**62.9**
Calculated gap by year*					
Generation	0	2.9	2.3	18.7	25.6
Transmission	3.7	3.7	3.7	3.7	3.7
Distribution	4.8	5.6	7.0	10.4	9.1
TOTAL	**8.5**	**12.2**	**13.1**	**32.8**	**38.4**

*Calculated as the difference between projected national needs and baseline 2001-10 averages.

NOTE The generation portion of "projected national needs" is based on each region generating 115% of expected electricity demand (see Figures 8 & 9). The 15% reserve margin is included to ensure reliability. Numbers may not add due to rounding.

SOURCE EIA Annual Energy Outlook 2011 (years 2008-2035) and NERC 2011 Long-term Reliability Report, Eastern Interconnection Planning Collaborative, Phase I Report, December 2011, Renewable Energy Transmission Initiative Electric Power Research Institute and Federal Energy Regulatory Commission. Calculations by La Capra Associates and EDR Group

TABLE 9 ★ Proportion of Reliance on Electricity Generation Technologies by Region *(percent)*

TECHNOLOGY	REGION							
	TEXAS	FLORIDA	MIDWEST	NORTH-EAST	MID-ATLANTIC	SOUTH-EAST	SOUTH-WEST	WEST
Coal	37	31	70	10	59	52	57	29
Petroleum	0	6	0	2	1	0	0	0
Natural Gas	42	44	3	41	12	16	32	26
Nuclear	12	16	13	31	27	27	5	11
Pumped Storage/Other	0	1	0	1	0	0	0	0
Renewables	8	1	14	14	2	5	6	34
Distributed Generation	0	0	0	0	0	0	0	0
Total by Region	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

SOURCE EIA, *Annual Energy Outlook*, 2011.

TABLE 10 ★ Additions of New Capacity Expected by Region for Electricity Generation Technologies *(percent)*

TECHNOLOGY	REGION							
	TEXAS	FLORIDA	MIDWEST	NORTH-EAST	MID-ATLANTIC	SOUTH-EAST	SOUTH-WEST	WEST
Coal	14	0	16	0	0	8	0	2
Oil and natural gas steam	0	0	0	0	0	14	0	0
Combined-cycle gas	32	99	19	60	70	18	28	35
Combustion turbine/diesel	44	0	40	9	23	52	25	15
Nuclear power	0	0	0	0	0	16	0	0
Renewable sources	5	0	21	31	4	6	46	44
Distributed generation	5	0	3	0	3	15	0	4
Total new capacity by region	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

NOTE Projections by the EIA are through 2035 and are assumed for 2040. Additions are in terms of megawatts expected to be added.

SOURCE EIA, *Annual Energy Outlook*, 2011.

Nevertheless, there are outages at the distribution level, which usually are not built to meet varying state and local standards.

Forecasts of future electric demand are provided by the EIA. Its forecasts, shown in Table 11, portray future demand for electric power given expected changes in population, economic activity, and energy-efficient technologies. The data shows that the EIA expects continued modest growth in future demand for electricity (an 8% increase by 2040). During the 2011–40 period, demand in all regions is expected to grow at 1.0% or less per year and only 0.7% per year for the U.S. as a whole. Much of this low demand growth is expected to be due to energy efficiency and an overall decline in energy intensity per dollar of gross domestic product. Though it is useful to analyze energy demand, electric systems are planned to meet peak loads. However, it is noteworthy that the electric energy demanded by businesses and institutions is expected to increase compared with sales to households. In 2010, 61% of electric energy purchases were made by nonresidential customers, and in 2020 and 2040, this proportion is expected to grow to 65% and then fall slightly to 64%.

Table 12 shows two concepts of peak demand. The top rows of the table show EIA's supply forecast, which essentially represents a forecast of generation investment need, because the EIA assumes that NERC planning standards are met. The bottom rows of the table give a forecast from NERC. The first important point is the difference between the two national totals. The top set of data is based on historical, existing generation and how demand levels and other market or policy factors affect generation build-out, and includes any generation capacity that is used to meet the reserve margins.

The bottom set of data represents actual internal regional peak demand forecasts (by NERC) without reserve margins. One drawback of the NERC forecast is that data are only available through 2021, compared with 2035 for EIA data. Moreover, the NERC forecast of demand is much higher than the EIA's demand forecast (which is based on generation supply). For data consistency purposes and to account for the current generation oversupply that is reflected in the EIA forecasts, the 2016–21 NERC growth rates were used rather than the growth rate for the entire 2010–21 period to project demand to 2040. This results in a lower forecasted "need" figure, but one that is likely more plausible than the value for the entire 2010–21 period.

Forecasted Supply

For electricity generation, the supply forecast was developed by examining recent trends in supply and continuing these trends into the future by applying the NERC supply forecast to the NERC demand forecast of internal peak loads. Three supply forecasts categorize the likelihood of supply into "anticipated," "prospective," and "conceptual," with "anticipated" providing the lowest, most conservative outlook. This analysis uses the more conservative estimate of "anticipated" supply stream, though the other forecasts can also be used. To maintain consistency with projected demand trends, the averaged 2016–21 growth rate was applied to determine the supply forecast to 2040.

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. Although it can vary by locality, NERC's reference margin level is 15%, meaning that generation of 115% of expected peak demand is needed to ensure reliability of supply. Due to capacity surpluses, most regions and the country as a whole are currently projected to exceed the 115% margin through 2020, with the exception of Texas.[13]

TABLE 11 ★ Projected Changes in U.S. Electric Energy Demand, 2010, 2020, and 2040

MARKET SEGMENT	ANNUAL TOTALS/PROJECTIONS (TERAWATT-HOURS) 2010	2020	2040	COMPOUND ANNUAL GROWTH (%) 2010–20	2020–40	2010–40
Total electricity sales	3,749	3,976	4,658	0.6	0.8	0.7
Electricity sales, residential	1,455	1,394	1,692	-0.4	1.0	0.5
Electricity sales, nonresidential	2,293	2,583	2,966	1.2	0.7	0.9
Percent demand, nonresidential	61	65	64			

NOTE 1 terawatt-hour = 1 billion kilowatt-hours. Estimates for 2035–40 assume an annual growth rate equal to the average 2030–35 annual growth rate.

SOURCE EIA, *Annual Energy Outlook 2011* (for 2008–35).

TABLE 12 ★ Peak Demand Projections, 2010, 2011, 2020, and 2040

DEMAND PROJECTION	ANNUAL TOTALS (GIGAWATTS)				COMPOUND ANNUAL GROWTH RATE (%)		
Electric generating capacity, EIA, *Annual Energy Outlook 2011* projection	**2010**	**2011**	**2020**	**2040**	**2010–20**	**2020–40**	**2010–40**
	1,014	1,023	1,028	1,174	0.1	0.7	0.5
From NERC, *2011 Long-Term Reliability Report*		**2011**	**2020**	**2040**	**2011–20**	**2021–40**	**2011–40**
		1,551	1,759	2,256	1.4	1.3	1.3

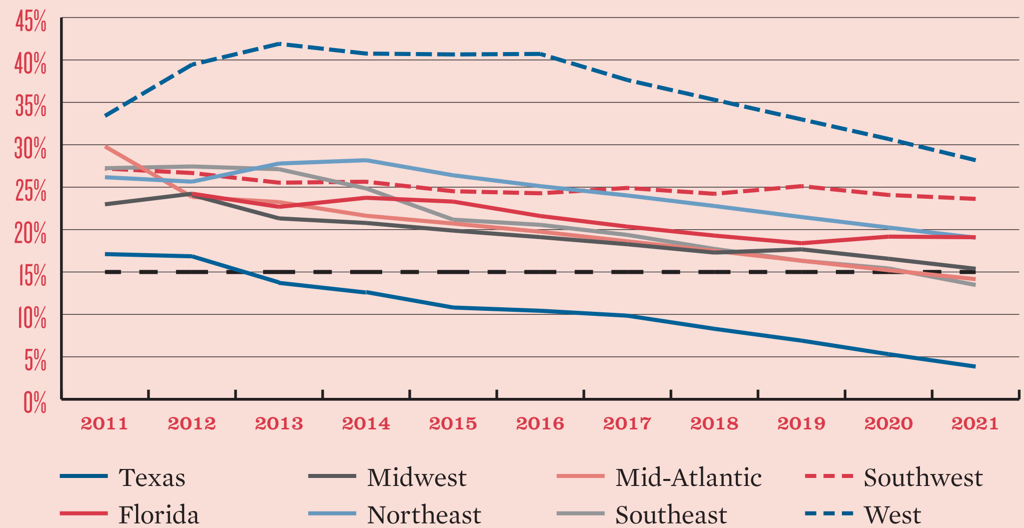
NOTE Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load exclusive of auxiliary power), as demonstrated by tests during summer peak demand. Includes electric utilities, small power producers, and exempt wholesale generators.

TABLE 13 ★ Generation Supply Forecast—National Aggregations *(in Gigawatts)*

SCENARIO	2011	2020	2040
Anticipated peak capacity resources	986	1,043	1,074
Prospective peak capacity resources	1,017	1,081	1,125
Adjusted potential capacity resources	1,018	1,102	1,163

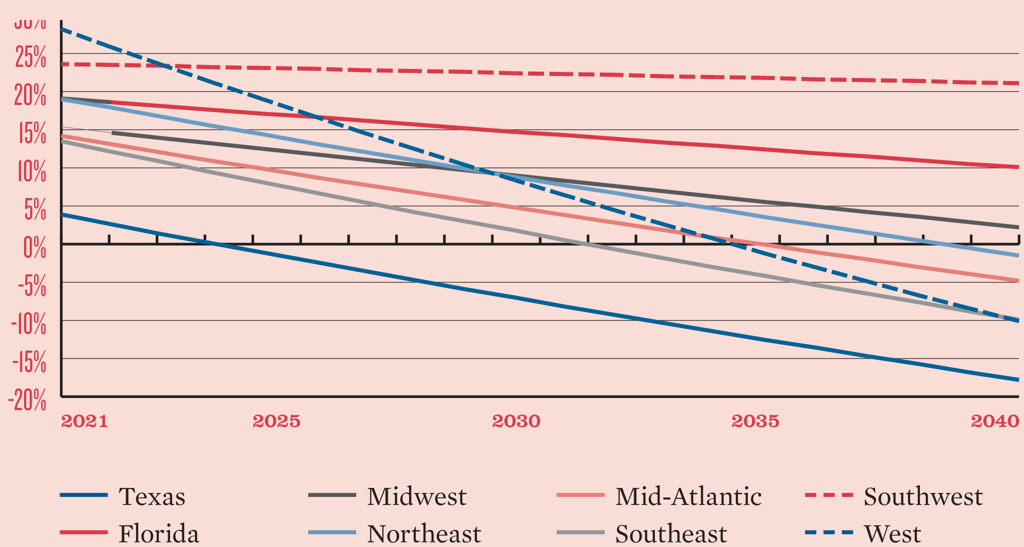
SOURCE NERC, *2011 Long-Term Reliability Report*.

FIGURE 8 ★ NERC Projection of Planning Reserve Margins by Region, 2011–21



SOURCE NERC 2011 Long-term Reliability Assessment to 2021 and trendline calculations by La Capra and EDR Group to 2040.

FIGURE 9 ★ NERC Projection of Planning Reserve Margins by Region, 2021–40



SOURCE NERC 2011 Long-term Reliability Assessment to 2021 and trendline calculations by La Capra and EDR Group to 2040.

In general, the nation is currently facing an oversupply phase of electric generation, and the EIA's *Annual Energy Outlook 2011* forecast data for demand and supply discussed above assumes that this oversupply, coupled with improvements in electric energy efficiency, will not lead to absolute shortages before 2024. The gap predicted for generation in 2020 is because supply in the Texas region is expected to fall below a 15% reserve margin (or 115% of expected demand) before that year (Table 14). Extending current trends indicates that the generation of electricity for five of the NERC regions (Texas, Southeast, Mid-Atlantic, West, and Northeast) will fall below 100% of demand by 2040, with only the Southwest area remaining above the 115% planning reserve margin. These trends are graphically represented in Figures 8 and 9.

Figure 8 shows capacity by region compared with retaining at least 100% capacity and the additional 15% margin from 2011–2021, based on trends extended for demand and electricity generation.

Figure 9 extends this overview, and shows expected generation capacity compared with demand from 2021–40. As previously mentioned, only the Southwest area is expected to maintain generation capacity that is 15% above demand. Two other regions, Florida and the Midwest, are expected to generate electricity to meet demand over the duration of the 20-year time span, but will fall beneath the 15% margin for reliability. Generation of electricity for five other regions is expected to fall below demand by 2040: the Northeast, the Southeast, Texas, the Mid-Atlantic, and Western states.

Generation Gap Analysis

With supply and demand forecasts from a consistent source, the gap is calculated as the amount of additional generation (in gigawatts, GWs) necessary to meet regional demand forecasts plus the necessary reserve margins of 15 percent. The data show that initially all regions are well above the reference reserve margins, with only the Texas region in danger of falling below reference levels over the near term. However, both current investment trends and rates of projected future demand growth differ by region, so long-term needs and the associated gaps will grow at different rates around the country.

To calculate potential future generation need, the projected future demand (plus reserve margin) is forecast in terms of GWs for each region and then compared with the supply forecast to calculate a GW need for each year of the forecast period. Once the gap in GW is calculated, generation needs are translated into dollar streams. It was assumed first that the need would be met according to the costs of technology mixes projected by the *Annual Energy Outlook 2011* that supply electric energy by region to 2035.[14] This value was multiplied by the number of GWs needed in each region to produce the dollar stream of infrastructure investment needs. Note that this stream only consists of capital cost, and no operation and maintenance costs are included.

Overall, this generation gap analysis considers the amount of generation spending that is necessary to meet the reliability criterion (as represented by meeting reserve margin reference levels). Within the *trend scenario,* the gap is expected to grow over time to a level of $401 billion by 2040. A breakdown of this gap by region is shown in Table 14.

The generation gap is based on peak demand forecasts from NERC, and is assumed to grow at the annual rate projected from 2016–21. The gap also is based on NERC reference levels for reserve capacity, meaning that the gap calculations are based on regional attainment of 115% of projected peak capacity. As discussed above, there is a minimal gap shown through 2020 due to a current oversupply of generation capacity.

Transmission

Transmission and generation are considered as two parts of the "bulk power system" and are almost exclusively used for wholesale market transactions. Very few (and very large) customers directly access the transmission system. As a result, transmission systems are regulated at the federal level. The distribution system is where most reliability problems occur; it is regulated by individual states and discussed in a subsequent section.

Investment Need for Meeting Load Growth and Reliability

Transmission investment has increased significantly in the past few years, on both a national and regional basis. As a result, many of the concerns that were expressed in the middle to late 2000s concerning the lack of investment in the transmission system in terms of demand growth have essentially been eliminated. First, incentives provided by FERC and supported by mandates or planning studies by states and regional transmission organizations have led to an uptick in investment planning. Second, aggressive energy efficiency deployment in many regions, coupled with the recent economic downturn, has reduced load requirements.

This change in the level of concern can be seen by comparing language in the reliability assessments that are produced annually by NERC. For example, in the 2007 version of that report, the following statement was highlighted: "A recent NERC survey of industry professionals ranked aging infrastructure and limited new construction as the *number one challenge to reliability*—both in likelihood of occurrence and potential severity."[15] By contrast, note the language in this report's 2011 version: "Transmission growth is responding to increased plans for integrating and delivering new resources (i.e., renewables); constructed transmission is

TABLE 14 ★ **Electric Generation Investment Gap: Estimated at $12 Billion by 2020 and $401 Billion by 2040** *(in billions of 2010 dollars)*

REGION	GENERATION GAP ESTIMATE 2020	2040
Florida	0	3.5
Midwest	0	29.5
Northeast	0	22.1
Mid-Atlantic	0	66.1
Southeast	0	121.2
Southwest	0	0
Texas	12.3	47.3
West	0	111.3
U.S. TOTAL	**12.3**	**401.1**

NOTE The generation gap is defined as the investment that is necessary to ensure that regions achieve a 15% planning reserve margin. Numbers may not add due to rounding.

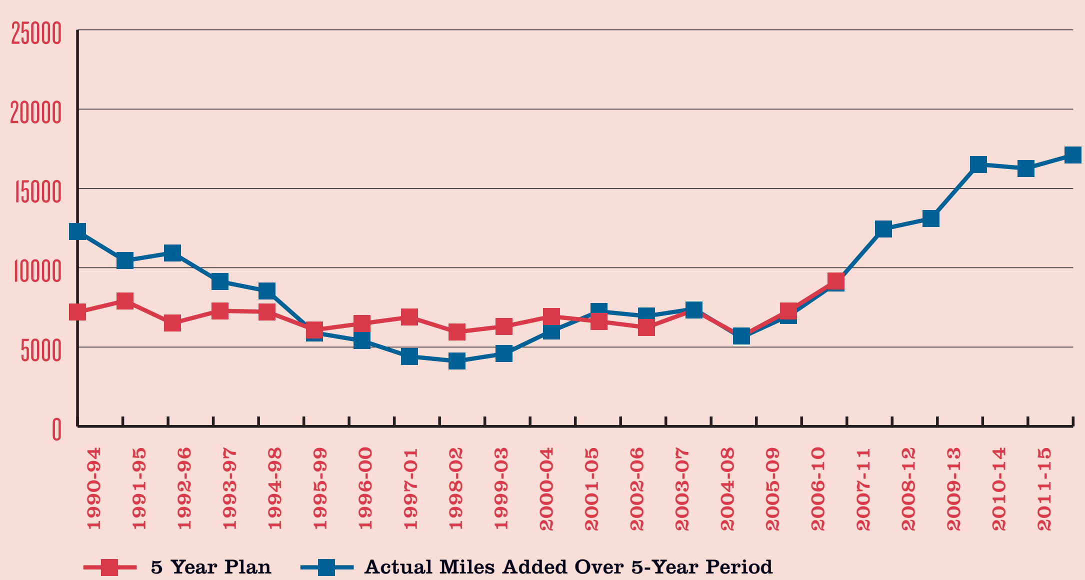
SOURCES NERC; calculations by La Capra and EDR Group.

on pace with projections" and "an analysis of the past 15 years shows that additional transmission (greater than 200 kV) during the next five years would nearly triple the average miles that has historically been constructed during a five-year period."[16]

Figure 10 shows that the planned investment in transmission infrastructure picked up significantly starting in the 2006–10 period. Before this time, investment was more or less constant, in the range of 6,000–8,000 circuit-miles per period. Future investment is expected to reach close to 18,000 circuit-miles, which represents a dramatic increase in infrastructure investment. In addition, it is important to point out that the calculation of the gap is based on trends extended, not only with regards to demand for electricity and in technology trends and regulations, but also that privately-owned utility investments in the coming 30 years will be at the

The planned investment in transmission infrastructure picked up significantly starting in the 2006–10 period. Before this time, investment was more or less constant.

FIGURE 10 ★ **Actual and Planned Transmission Infrastructure, 1990–2015**



SOURCE NERC, *2011 Long-Term Reliability Assessment.*

annual average rates for generation, transmission and distribution that were seen during 2001–10.

This conclusion should not be interpreted as meaning that there is no need or value in additional transmission infrastructure. It only means that the aggregate level of actual spending on transmission infrastructure is now tracking with planned levels of investment. Localized issues can still be present. For example, there can be opportunities for enhancing connections between NERC's regions, which would have beneficial impacts on congestion management, reliability, and greater deliverability of renewables from resource-rich regions, such as the Midwest and Oklahoma/Texas area, to urban centers in the Eastern United States.

Transmission Gap Analysis

The transmission gap analysis is based on projected demand to 2040 and investment trends for each region. Demand is based on peak demand forecasts from NERC and is assumed to grow at annual growth rate found in 2016–21 period. Supply is assumed to grow at historical growth rate based on five-year moving averages of the 1999–2010 period and based on NERC circuit-mile data for each region. The gap is calculated as the difference between the rates of demand and supply for each region, and it assumes a constant $2.375 million (in constant 2010 dollars) cost per circuit-mile, which is spread out evenly during the 2011–40 period.

With this trend scenario, the gap in transmission investment is projected to grow over time to a level of nearly $112 billion by 2040, as shown in Table 15. A number of factors can affect the size of this investment gap, most notably the rates of change in the mix of generating technologies and their corresponding locations relative to power sources and population centers.[17]

Local Distribution

The aging of local distribution networks has received particular attention in many areas, given that intermittent power failures are commonly associated with downed power lines, transformer malfunctions, and underground equipment failures. Although investment in electric distribution infrastructure has recently increased and now exceeds historical load growth, it is also important to assess the adequacy of this investment to meet growing needs for greater reliability and capacity to address the changing nature of electricity use. Investment in or the expansion of electric distribution infrastructure is undertaken by local distribution companies, which can be owned by investors or municipalities. Usually, investor-owned utilities invest to meet locally acceptable standards and then seek to recover their investment costs through rate increases. Some states do allow recovery outside formal rate increase proceedings. These standards are set by each utility according to its capital budgeting process, with regulatory oversight by states, and this process varies widely, with some states actively penalizing utilities for poor reliability or customer service performance and other states having no penalties but maintaining the ability to deny cost recovery for imprudent investments.

Figure 11 shows the annual rate of investment in local electricity distribution networks, expressed as three-year and five-year moving averages. Overall, it shows compounded annual growth rates in the range of 1.5% to 2%, which is up considerably from the rate occurring in the early and middle 1990s.

The *trend scenario* for investment in local distribution infrastructure is based on the level of construction expenditures by shareholder-owned utilities for the period 1980–2008.[18] Although the actual trend varies from year to year to reflect economic cycles, the average annual growth rate for the most recent five-year period is actually similar to the average rate during the entire 28-year period. Projections for 2009–40 business-as-usual expenditures were based on two factors. One was the most recent five-year average rate of 1.05%, which is slightly lower than the moving average figures discussed above. The other is the incremental cost of gradually implementing smart grid technologies

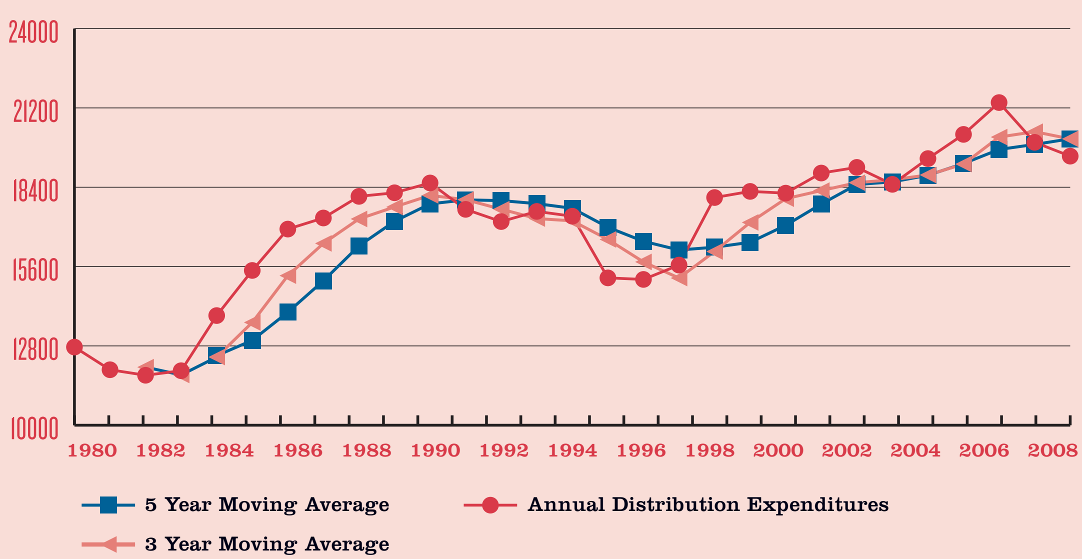
TABLE 15 ★ Electric Transmission Investment Gap: Estimated at $37 Billion by 2020 and $112 Billion by 2040 *(in billions of 2010 dollars)*

REGION	TRANSMISSION GAP ESTIMATE 2020	2040
Florida	1.8	5.5
Midwest	1.4	4.3
Northeast	1.6	4.7
Mid-Atlantic	6.4	19.2
Southeast	10.9	32.7
Southwest	0	0
Texas	0	0
West	15.2	45.5
U.S. TOTAL	**37.3**	**111.8**

SOURCES NERC; Eastern Interconnection Planning Collaborative, "Phase I Report, December 2011"; Renewable Energy Transmission Initiative; calculations by La Capra Associates and EDR Group.

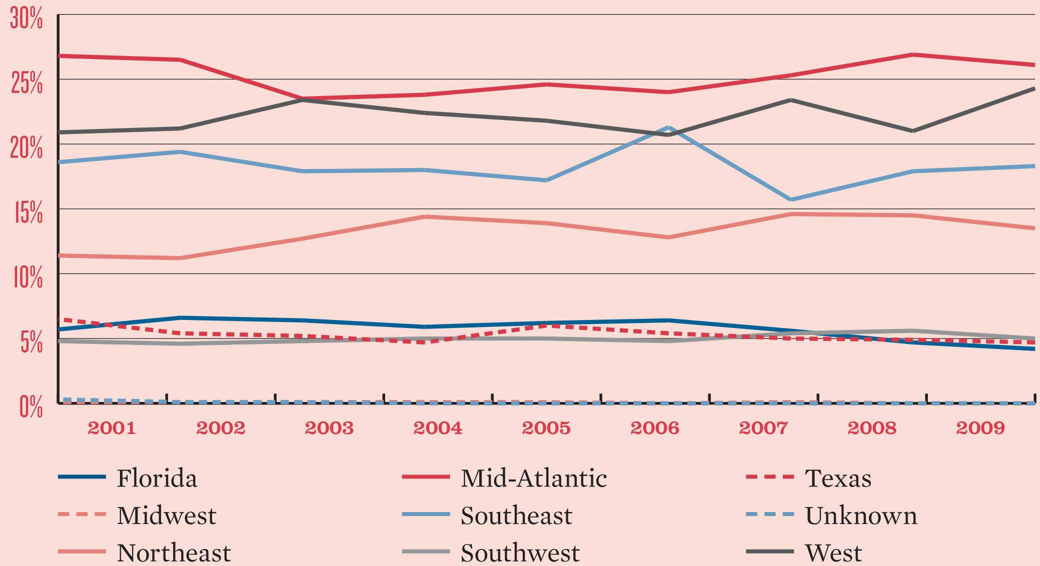
NOTE Numbers may not add due to rounding.

FIGURE 11 ★ Distribution Expenditures from 1980 Show Compound Annual Growth Rates of 1.5% to 2%



SOURCE Edison Electric Institute, *Statistical Yearbook 2009*.

FIGURE 12 ★ Distribution Additions, NERC Regions' Share of the National Total, 2001–9



SOURCE Federal Energy Regulatory Commission (FERC Form 1 Data). Calculations by La Capra associates to fit data into NERC regions.

during the period up to 2040, to maintain and upgrade reliability as required by increasingly sophisticated electronic equipment. The latter was based on estimates from an Electric Power Research Institute study for the incremental costs to implement the smart grid,[19] which provides low and high estimates of total 20-year costs for the transmission, distribution, and customer aspects.[20]

The regional pattern of investment in local distribution infrastructure is estimated based on an allocation that represents historical patterns, as shown in Figure 12.

Distribution Gap Analysis

Under the trend scenario, the investment gap for local distribution infrastructure is projected to grow over time, to a level of $57 billion by 2020 and $219 billion by 2040. A breakdown of these needs by region is presented in Table 16.

This gap can widen if additional investments are required to allow for the accelerated growth of locally distributed power, with accordingly higher requirements for a faster implementation of smart grid technologies to address their intermittent supply characteristics.

Overall Gap: Summary

The cumulative total investment gap adds together the generation, transmission, and distribution infrastructure gaps. Those results are shown by region in Table 17, and indicate that the investment funding gap will be highest in the Southeast, the Western states, and the Mid-Atlantic area, and lowest in the Southwest and Florida. It does not appear to be growth alone driving the gap, but rather a combination of supply, technologies, and demand, as reviewed earlier in this report.

TABLE 16 ★ Electric Distribution Investment Gap: Estimated at $57 Billion by 2020 and $219 billion by 2040 *(in billions of 2010 dollars)*

REGION	DISTRIBUTION GAP ESTIMATE 2020	2040
Florida	2.4	9.2
Midwest	3.0	11.5
Northeast	6.4	24.4
Mid-Atlantic	11.8	45.0
Southeast	18.8	71.7
Southwest	2.4	9.2
Texas	2.3	8.7
West	10.3	39.3
U.S. TOTAL	**57.4**	**219.0**

SOURCES Edison Electric Institute, FERC, Electric Power Research Institute.

NOTE Numbers may not add due to rounding.

TABLE 17 ★ Regional Breakdown of Electric Distribution Investment Gap, 2020 and 2040 *(in billions of 2010 dollars)*

REGION	DISTRIBUTION GAP ESTIMATE 2020	2040
Florida	4.2	18.2
Midwest	4.4	45.3
Northeast	8.0	51.2
Mid-Atlantic	18.2	130.3
Southeast	29.7	225.6
Southwest	2.4	9.2
Texas	14.6	56.0
West	25.5	196.0
U.S. TOTAL	**107.0**	**731.8**

SOURCES Edison Electric Institute, FERC, Electric Power Research Institute.

NOTE Numbers may not add due to rounding.

5 | THE COST INCURRED BY A FAILURE TO INVEST

The Chain of Impacts

Failure to close the investment gap and adequately invest in our nation's electricity infrastructure can occur for many reasons, including disagreements over construction plans for generation facilities or additional transmission lines, or the failure to allow for the electricity rate levels needed to support more efficient energy use, technology adoption, or investment. Whatever the reason, the result of a growing investment gap will be some combination of aging equipment and capacity bottlenecks that leads to the same general outcome: a greater incidence of electricity interruptions.

The interruptions may occur in the form of equipment failures, intermittent voltage surges, and power quality irregularities due to equipment insufficiency, and/or blackouts or brownouts as demand exceeds capacity for particular periods. These periods can be unpredictable in terms of frequency and length. Regardless of these details, the result is a loss of reliability in electricity supply, which imposes direct costs on both households and businesses.

These costs can take several distinct forms, including (1) damage to a growing portion of equipment made with sensitive electronic circuits that can be affected by voltage spikes and surges; (2) spoilage of food and other items that are heated, refrigerated, or kept in controlled conditions; (3) wasted, unproductive time for workers at affected business manufacturing and service facilities when production processes are temporarily idled; and (4) added costs incurred by an increased reliance on (and use of) backup generators, power quality monitoring and conditioning equipment, or rescheduling of production shifts.

Prior Studies of the Costs of Electricity Interruptions

The best way to estimate the magnitude of the costs to be incurred by households and businesses if the investment gap grows in the future is to consider interruptions and the scale of costs already being incurred. Nationally, a 2004 study found that customers are faced with 4.3 momentary outages of less than 5 minutes that cost the U.S. more than $50 billion each year and 1.2 sustained outages of 5 minutes or more that account for an additional $29 billion, totaling $79 billion annually in 2002 dollars. The study also found that the average length of sustained outages were 106 minutes each.[21] A separately conducted 2003 study concluded that on average U.S. electric customers experience 1.5 to 2 outages per year, with average durations lasting two hours.[22]

These costs caused by electricity interruptions occur in the form of idle worker time, product spoilage, equipment damage, and replacement costs. The aforementioned 2004 study found that industrial firms can each lose about $2,000 to $5,000 per power interruption, commercial establishments can lose $700 to $1,300, and households each lose less than $5 per occurrence, as shown in Table 18.[23]

A series of studies completed in the 1990s and first decade of the 2000s estimated the total annual cost of power outages and reliability for our national economy. When normalized to 2010 dollars, estimates of the annual cost to our nation ranged from $39 billion to $201 billion per year, as illustrated in Table 19. The reasons for the variation were differences in methodology and the range of costs being included. However, it should be noted that the condition of electricity infrastructure has improved markedly during the past decade since those studies were conducted. Improvements in quality have been particularly significant in generation and transmission systems due to significant investments made since 2005, and the national investment gap is now smaller than in earlier decades.

Estimation of Future Costs Incurred by Failing to Close the Investment Gap

For this study, the costs associated with maintaining and improving electricity adequacy and reliability were calculated based on (1) estimates of the regional long-term investment needs for generation, transmission, and distribution infrastructure; and (2) estimates of the added costs and forgone benefits incurred if they are not made, drawing on studies by the EIA and Electric Power

TABLE 18 ★ Average Cost of Power Interruptions per Household and per Business *(in constant 2010 dollars)*

DURATION OF INTERRUPTION	RESIDENTIAL	COMMERCIAL	INDUSTRIAL
Momentary	2.64	733	2,294
1 hour	3.27	1,074	3,943
Sustained Interruption*	3.62	1,293	5,124

*The mean time of sustained interruptions is 106 minutes (when data were trimmed of outliers). Costs were reported in 2002 dollars and were inflated to 2010 dollars for this table. The study estimated total annual losses at $79 billion or a range of $22 billion to $135 billion in 2002 dollars.

SOURCE LaCommare and Eto, 2004.

TABLE 19 ★ Comparison of Annual Impacts of Inadequate Electricity Delivery, Selected Study Years

REPORTED DOLLAR AMOUNT	STUDY YEAR	ADJUSTED TO CONSTANT 2010 DOLLARS	COSTS INCLUDED	AUTHOR/SOURCE
$26 billion	1993	$39 billion	Limited to power-quality analysis and manufacturing sector	J. Clemmensen, Electric Power Research Institute, "Estimating the Cost of Power Quality," *IEEE Spectrum*, 1993.
$150 billion	1998	$201 billion	Accounts for U.S. industry, but does not include commercial or household sectors	S. Swaminathan and R. K. Sen, *Review of Power Quality Applications of Energy Storage Systems*, Report SAND98–1513 (Sandia National Laboratories, 1998).
$119 billion	2001	$147 billion	Includes business sectors but not households	Primen, *The Cost of Power Disturbances to Industrial and Digital Economy Companies*, Report TR-1006274 (Electric Power Research Institute, 2001).
$79 billion	2002	$96 billion	Includes households, commercial and Industrial	K. H. LaCommare and J. H. Eto, *Understanding the Cost of Power Interruptions to U.S. Electricity Customers,* Report LBNL-55718 (Lawrence Berkeley National Laboratory, 2004).

Research Institute. It was assumed that small, locally based sources of distributed generation would be required to fill the electricity availability gap, resulting in some associated higher costs.[24]

The finding is that a failure to meet the projected investment gap will result in a cost to businesses and households, starting at $17 billion in 2012 and growing annually to $23 billion by 2020 and $44 billion by 2040. The cumulative costs approach $200 million by 2020 and $1 trillion by 2040. Annual costs to the economy will average $20 billion though 2020 and $33 billion through 2040. These estimated impacts are significantly lower than the impacts estimated from studies conducted in the 1990s and 2000s, presented above in Table 19.

Table 20 shows the estimated cost impact by economic sector. Table 4 breaks down the estimated impact by region. It is notable that these costs incurred by failing to close the investment gap are actually higher than the avoided investment. This means that it is economically inefficient for households and businesses to allow this higher cost scenario to occur. It should also be made clear that even if sufficient investment is made to avoid the investment gap, the result will not be a perfect network for electricity generation and delivery, but rather one that has dramatically reduced (though not eliminated) power quality and availability interruptions.

Failure to meet the projected investment gap will result in a cost to businesses and households, starting at $17 billion in 2012 and growing annually to $23 billion by 2020 and $44 billion by 2040.

TABLE 20 ★ Cumulative Impacts by Sector, 2012, 2012–20, and 2012–40

(in billions of 2010 dollars)

ECONOMIC SECTOR	2012	CUMULATIVE, 2012–20	CUMULATIVE, 2012–40
Residential	6	71	354
Commercial/other	6	74	402
Industrial	4	52	239
Transportation	0.03	0.38	3.82
TOTAL	**17**	**197**	**998**

SOURCES Calculations by La Capra and EDR Group based on data from EIA and Electric Power Research Institute.

TABLE 4 ★ Cumulative Impacts by Region, 2012, 2012–20, and 2012–40

(in billions of 2010 dollars)

REGION	2012	CUMULATIVE, 2012–20	CUMULATIVE, 2012–40
Florida	0.7	8	32
Midwest	0.8	9	59
Northeast	2.0	17	79
Mid-Atlantic	3.0	36	194
Southeast	5.0	59	297
Southwest	0.5	6	18
Texas	0.5	18	80
West	4.0	44	239
TOTAL	**17**	**197**	**998**

SOURCES Calculations by La Capra and EDR Group based on data from EIA and Electric Power Research Institute.

6 | ECONOMIC IMPACTS

If future investment needs are not addressed to replace and upgrade our nation's electric generation, transmission, and distribution systems, then costs will be borne by both households and businesses. These costs may occur in the form of higher costs for electric power, or costs incurred because of power unreliability, or costs associated with adopting more expensive industrial processes. Ultimately, they all lead to the same economic impact: diversion of household income from other uses and a reduction in the competitiveness of U.S. businesses in world economic markets.

If annual investments in electric energy infrastructure through 2040 continue to average $63 billion, as they did during the past decade, then by 2020 the cumulative deficit (gap) for investment in electricity infrastructure will be $107 billion, and this would increase to $732 billion by 2040. The direct cost to businesses and households would be even greater than the missed investment, rising to $197 billion by 2020 and $998 billion by 2040. Nationally, these costs are passed into the national economy in the form of business expenses, lost production and household spending diverted to satisfying demand for electrical power. These broader impacts on the U.S. economy would represent a cumulative loss of gross domestic product (GDP) amounting to $496 billion by 2020 and $1.95 trillion by 2040.

The loss of competitiveness for businesses that sell to overseas markets, and the higher prices paid for foreign imports, would also lead to a loss of jobs. These estimated job "losses" will occur in the form of a lower rate of national economic growth, and hence a lower rate of job growth. Overall, the U.S. economy will end up with an average of 529,000 fewer jobs than it would otherwise have by 2020. And even with economic adjustments occurring later on, with catch-up investments, the result would still be 366,000 fewer jobs in 2040, as shown in Table 5.

Table 21 illustrates that job losses will fall heavily on the retail and other consumer spending sectors due to the expected diversion of household spending. Personal consumption expenditures[25] are projected to be reduced by a cumulative $400 billion by 2020 and $2.1 trillion by 2040 (in 2010 dollars). Moreover, service disruptions that force businesses to shut down will have a disproportional impact on hourly workers and also on business locations that require direct personal interaction, such as stores and restaurants. Lastly, retail is the nation's largest economic sector in terms of numbers of jobs. Therefore, job impacts will be disproportionately

Even with economic adjustments occurring later on, with catch-up investments, the result would still be 366,000 fewer jobs in 2040.

TABLE 5 ★ Effects on U.S. GDP and Jobs, 2011–40

ANNUAL IMPACTS	2020	2040
GDP	-$70 billion	-$79 billion
Jobs	-529,000	-366,000
Business Sales	-$119 billion	-$159 billion
Disposable Personal Income	-$91 billion	-$86 billion
AVERAGE YEAR	**2012–2020**	**2021–2040**
GDP	-$55 billion	-461,000
Jobs	-461,000	-588,000
Business Sales	-$94 billion	-$180 billion
Disposable Personal Income	-$73 billion	-$115 billion
CUMULATIVE LOSSES	**2012–2020**	**2021–2040**
GDP	-$496 billion	-1.95 trillion
Jobs	NA	NA
Business Sales	-$847 billion	-$3.6 trillion
Disposable Personal Income	-$656 billion	-$2.3 trillion

NOTE Losses in business sales and GDP reflect impacts in a given year against total national business sales and GDP in that year. These measures do not indicate declines from 2010 levels.

SOURCES EDR Group and LIFT model, University of Maryland, INFORUM Group, 2012

TABLE 21 ★ Job Losses by Sector, 2020 and 2040

SECTOR	2020 JOB IMPACTS	PERCENT	2040 JOB IMPACTS	PERCENT
Retail trade/restaurants and bars	213,000	40	136,000	37
Business and professional services	101,000	19	94,000	26
Manufacturing	59,000	11	55,000	15
Construction	52,000	10	38,000	11
Other	105,000	20	42,000	12
TOTAL	**529,000**	**100**	**366,000**	**100**

NOTE Losses in jobs reflect impacts in a given year against total national business sales and GDP in that year. These measures do not indicate declines from 2010 levels.

SOURCES EDR Group and LIFT model, University of Maryland, INFORUM Group, 2012.

assumed in that sector compared to others that might contribute more to GDP or be more energy intensive.

Substantial losses in manufacturing sectors are also anticipated due to less reliable electricity service with a shortfall in electricity infrastructure investment. These losses will signify reduced competitiveness of U.S. industries. Figure 13 indicates which industries will be most harmed.

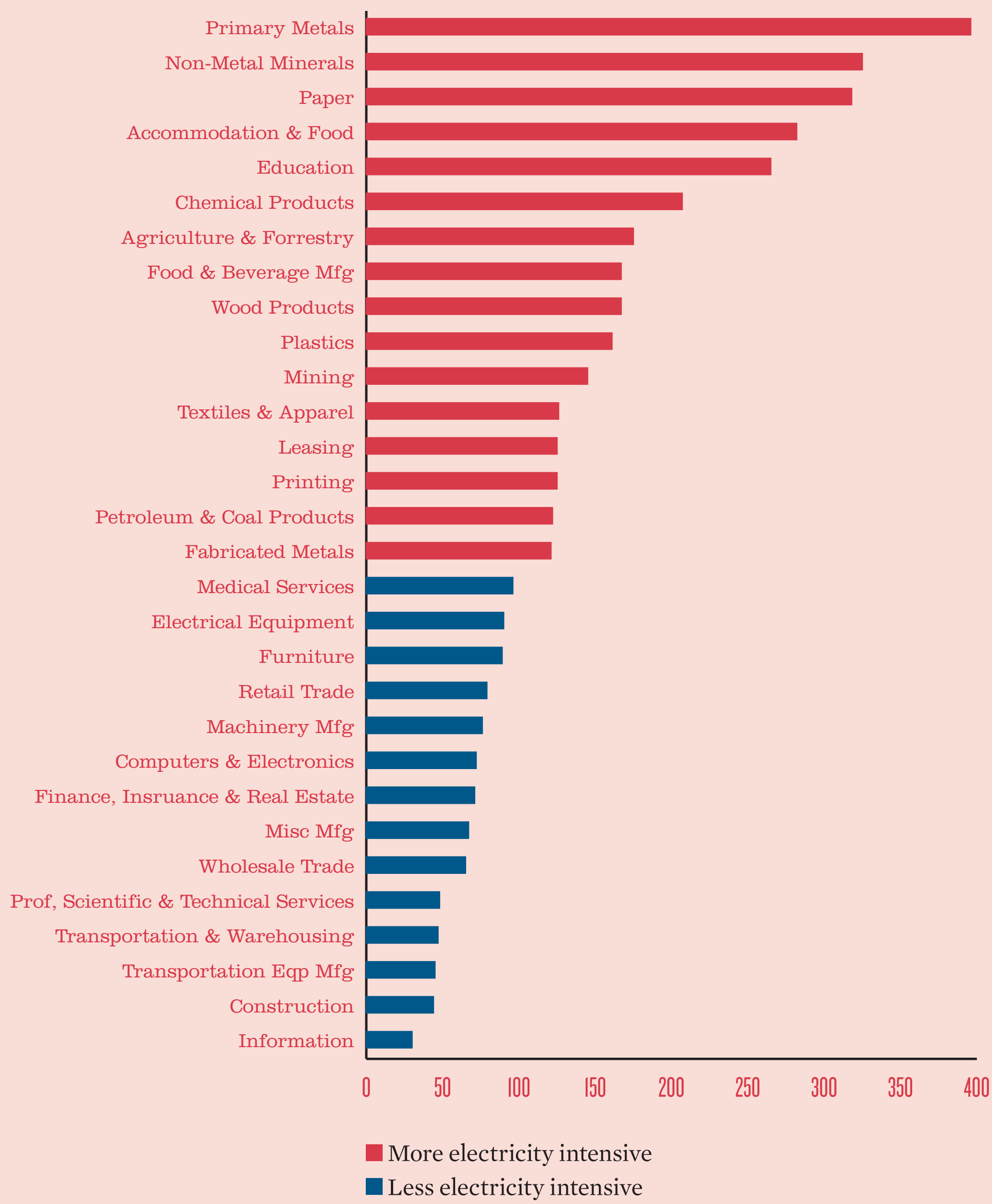
By 2020, the potential investment needs in infrastructure may cause the U.S. to lose $10 billion in exports, which could grow to $40 billion by 2040 (in 2010 dollars). The hardest-hit industrial sectors will be:

- ★ Aerospace,
- ★ Electronic components, and
- ★ Air transportation.

Energy Intensive Industries

Industries vary to the extent that they depend on a reliable supply of electricity. One way to measure the relative energy dependence of U.S. industries is to compare the amount of electricity that each sector purchases. Figure 13 is an index of reflecting the relative reliance on electricity among individual industries, represented as a proportion of the national average electricity purchased by each industry. Nationally, purchases of "electric power generation, transmission, and distribution" average of 6.8% of total industry revenue. In the index presented below, a value of "100" is set to the national average. A value greater than 100 indicates that industries use a higher portion of their revenues for electricity and an index value less than 100 indicates that electric services consume a smaller than average portion of business revenues.

FIGURE 13 ★ Electricity Intensity by Industry



SOURCES Bureau of Economic Analysis, U.S. Department of Commerce, aggregated by Minnesota IMPLAN Group, Inc., 2009. Calculations by EDR Group

7 CONCLUSIONS

Reliable electricity is essential for the functioning of many aspects of household and economic activity today. As the nation moves towards increasingly sophisticated use of information technology, computerized controls and sensitive electronics, the need for electricity reliability becomes even greater. In addition, overall demand for energy is expected to increase as the United States economy and population grows between today and the year 2040.

To obtain the needed electric power, households and businesses depend to a large extent 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 decentralized distribution networks must be kept in good repair to ensure reliable final delivery. Connections among the different elements of this broader system are crucial to meet regional and national energy needs as well as to support emerging changes in the spatial pattern of power sources and population locations. Deficiencies or shortfalls in any one of these three elements of electricity infrastructure can affect our nation's future economic growth and standard of living.

Three key factors affect the sufficiency and reliability of electricity infrastructure: (1) the age of infrastructure, (2) the capacity of infrastructure, and (3) the spatial pattern of infrastructure relative to the locations of electricity generation and consumption. All three affect requirements for future investment in electricity infrastructure. This study examined the magnitude of expected need for future investment in electricity infrastructure and compared it to recent investment trends (assuming a continuing evolution of technologies). Although recent investment trends show a distinct improvement in infrastructure investment over earlier decades, even continuing the rate of average annual investment seen over the past decade is not expected to cover all of the increase in demand for electricity. This report, conducted after significant annual investment increases by privately-owned utilities since 2005 were made, estimates the annual cost to businesses, households, and institutions at about $16 billion in 2012 and averaging $33 billion annually through 2040 under current investment trends.

This analysis showed that if current trends are to continue, then the nation will face a cumulative electricity infrastructure funding gap of $107 billion by 2020, rising to $732 billion by 2040. In turn, an investment shortfall of that magnitude will cost businesses and households a cumulative $197 billion by 2020 and $998 billion by 2040. These costs are passed into the U.S. economy in the form of increased business and household expenses, which will also affect the nation's competitiveness in economic trade. Economic models indicate that this could ultimately result in a $500 billion cumulative loss in GDP by 2020 and about $2.5 trillion by 2040.

Long-Term Uncertainty

It is difficult to predict future levels of capital spending in electricity infrastructure because a wide range of factors will exert an influence over the coming decades occurring in supply and demand factors—such as the relative cost or availability of oil or natural gas, regulatory actions to promote greenhouse gas reduction, other environmental concerns, and new technology changes that increase or decrease the rate of investment required to deliver sufficient services to meet the demand for electricity.

The three aspects of the electricity infrastructure network—generation, transmission, and distribution—are connected and mutually dependent. Changes in one of the three may require investment in the other two to ensure that the supply of electricity effectively reaches customers.

The investments required for generation could increase if it becomes necessary to replace shortfalls in the availability of elements of the existing fuel mix or to meet environmental concerns. If generation technologies change, then it is likely that additional transmission investment will be required to connect the new power sources to the distribution grid. Moreover, if additional investments are required in the generation and transmission networks—for example, to allow for the cost of the accelerated growth of locally distributed solar and wind power, with accordingly higher requirements for smart grid technologies to address their intermittent supply characteristics—then local distribution infrastructure investment needs may also rise.

Since electricity generation, transmission and distribution are all made by private companies operating under public oversight, the funding gap is not a simple matter of increasing public expenditures. Rather, the nature and magnitude of private investment in electricity infrastructure is affected by private capital loan and bond markets, perceived economic risks and uncertainties, and public policies governing regulation, approval of electricity rates, and facility siting processes. Public policies, regulations and processes can play a role affecting the pace, location and nature of electric infrastructure investments.

★ ABOUT THE STUDY

This study illustrates what could happen to the national economy if households and businesses do not have reliable energy service. Economic impacts are based on: (1) forecast demand for electricity; (2) current and projected mix of electricity generation technologies; and (3) observed investment patterns for generation, transmission and distribution infrastructure. Consistent with guidelines from the North American Energy Reliability Corporation (NERC), a 15% buffer is used as a means to incorporate reliability in projected supply and demand calculations. The analysis approach compares two scenarios:

- ★ The implied base case in which sufficient investment is made per region to maintain electricity generation, transmission distribution infrastructure systems to meet anticipated future needs and reliability standards, and

- ★ The *Failure to Act* scenario in which maintaining current investment trends lead to a growing gap between the performance of regional electricity infrastructure and the regions' anticipated needs.

Capital needs and expenditures for all three parts of electricity infrastructure are based on federal government and industry sources. The primary basis for the economic analysis is documentation provided by the U.S. Department of Energy (2011 *Annual Energy Outlook*), the North American Electric Reliability Corporation, the Edison Electric Institute, and the Electric Power Research Institute.

Each year the U.S. Energy Information Administration (EIA) releases an Annual Energy Outlook that projects long-term energy supply, demand and prices based on results from EIA's National Energy Modeling System (NEMS). Annual Energy Outlook 2011, published in April 2011, presents actual and projected total electric sales broken down by generation technology for 2008–2035. For this study we presume the EIA projections represent "trends extended" or "business as usual" to 2040.

After calculating capital needs, several assumptions were made to translate capital needs into economic costs, and are discussed in Section 5. Key sources and assumptions include:

- ★ **Generation.** This analysis was built assuming that decentralized distributive generation would fill in the generation gap that would not be met. Distributed generation capital cost assumptions came from EIA. A California study was used to calculate fuel and O&M costs (Itron, Inc, 2011). The sum of capital, O&M, and fuel were used to calculate costs.

- ★ **Transmission.** For transmission, regions employ different assumptions about what foregone benefit (or opportunity cost) is an acceptable and reasonable basis for use. For example, the Mid-Atlantic utilize a minimum threshold of 1.25/1, while the Midwest specifies ratios varying from 1 to 3 depending on the type of transmission project and how close one is to the in-service date (Fink, S., 2011 and MISO, 2011). This study used the ration of 1.25 as a single measure across regions, although, it is possible that this undervalues the benefits of transmission. For example, a recent Brattle study posited that transmission cost-analyses tend to underestimate benefits because they are hard to quantify, but yet are real, economic benefits.

- ★ **Distribution.** Electric Power Research Institute provided benefit estimates of the smart grid by including different attributes (EPRI, 2011). We removed the "softer" attributes that would tend not to be included in bills to customers and removed some of the attributes that would be already counted in the other gap analysis. The result is a set of benefit to cost ratios that are lower than the study but that is more credible for input to an economic model.

Following calculation of the capital gap and expected costs to customers, the economic analysis process has three steps:

1. The added costs incurred by households and businesses due to increasingly inadequate infrastructure are calculated on a year-by-year based on the difference of the two scenarios.
2. Those added costs are distributed amongst households and various sectors of the economy in accordance with their location and electricity use patterns.
3. An economic model of the U.S. economy is used to calculate how households' income and expenditure patterns, as well as business productivity, is affected and lead to changes in our nation's competitiveness and economic growth. The results are provided in terms of long-term changes in jobs and income in the U.S. This sequence makes use of the LIFT model (Long-term Inter-industry Forecasting Tool), a national policy and impact forecasting system developed by INFORUM—a research center within the Department of Economics at the University of Maryland, College Park.

Economic impacts for purchase and deployment of technologies beyond a trends extended approach, such increased emphasis on renewable energy sources to meet environmental or energy independence goals or intensifying extraction and use of natural gas beyond what is now in place and predicted would change the investment scenarios and results of this study.

ENDNOTES

1. "Smart grid" refers to technologies that modernize the electricity utility grid and improve how electricity is delivered to consumers. It uses "computer-based remote control and automation" with "sensors to gather data (power meters, voltage sensors, fault detectors, etc.), plus two-way digital communication between the device in the field and the utility's network operations center. A key feature of the smart grid is automation technology that lets the utility adjust and control each individual device or millions of devices from a central location." (Source: http://energy.gov/oe/technology-development/smart-grid) It also provides a means to dynamically optimize electricity supply and demand, provides for more widely distributed generation and enables greater system reliability. Source: Title XIII of the Energy Independence and Security Act of 2007 (EISA provided legislative support for DOE's smart grid activities coordinating national grid modernization efforts).

2. Major power plants are defined here as operational power plants that generate at least 1 MW of power. Source: *Electric Power Annual 2010*, table 5.1.

3. There are over 450,000 miles of transmission lines over 100,000 volts, which include over 150,000 miles of transmission lines over 230,000 volts. The latter number is referenced in the 2009 ASCE Report Card on America's Infrastructure and is referenced by the U.S. Government Accountability Office. Source: U.S. Government Accountability Office, www.gao.gov/products/GAO-08-347R.

4. As the cost-effectiveness of small-scale generation equipment increases, there is a potential for more "distributed generation," with "microgrids" that can reduce the need for future investment in large central generation plants and associated transmission lines serving them. As sophisticated "smart grid" computer systems become more available to digitally monitor and instantaneously shift demand or reroute power (to offset equipment failures or other sudden supply and demand changes), there is also a potential for change in future needs for transmission and distribution investments. In theory, the two emerging technologies can be complementary. However, both technologies require added investment in a particular type of equipment that can potentially reduce needs for other types of equipment. And though both can potentially provide greater reliability and flexibility for meeting future needs, the rate of their future implementation will also depend on various regulatory, institutional, and economic factors that have yet to be played out.

5. "Distributed generation" refers to decentralized energy generation that is produced by many small energy sources, often located on business or household premises or in close proximity to them. It is a category that can also encompass on-site generation, cogeneration, dispersed generation, embedded generation and decentralized generation.

6. Distributed generation technologies currently account for under 1% of US generating capacity, but have been growing in use and are projected to accelerate in future years. In 2012, distributed generation is expected to produce 130 million killawatt hours of electricity. By 2040 it is expected to produce 4.63 billion killawatt hours, an average annual increase of nearly 17%. That said, distributed generation is expected to remain a small portion of the energy mix unless households and businesses become anxious about ensuring reliable electricity. Under current conditions, the total share of killawatt hours is expected to increase from 0.003% of the nation's electricity mix in 2012 to 0.1% in 2040. (Source: Energy Information Administration, Form EIA-759, Monthly Power Plant Report. 2008 and 2009.

7. See www.eia.gov/energy_in_brief/age_of_elec_gen.cfm.

8. See www.globalenvironmentfund.com.

9. EIA projections for total sales of electricity extend from 2008 to 2035. To extend the projections to 2040, we assumed that sales for each region and customer class would grow at the average 2030–35 annual growth rate.

10. In most regions in the U.S., "peak periods of electricity demand is in the summer season. However, in certain regions/sub-regions, such as the northwest United States, South Dakota (MIRO-MAPP region) and Florida, peak demand in the winter exceeded peak summer demand when the expected demand of the 2011/2012 winter is compared to the expected demand in the summer of 2012. Source: *NERC 2011 Long Term Reliability Assessment*, tables 8 and 9.

11. NERC, *2011 Long-Term Reliability Assessment Projection*.

12. PJM Resource Adequacy Analysis Subcommittee, "Comparison of PRISM and MARS," February 9, 2011.

13. NERC estimates planning reserve margins over the next 10 years in its *2011 Long-Term Reliability Assessment*. EIA also estimates actual margins for 1999–2010 and projected margins for 2011–15 in its *Electric Power Annual 2010*, released in November 2011. Estimates of generation capacity to demand are based on extending trends from these estimates.

14. These numbers were further projected to 2040 for this analysis as shown in Table 11 on page 29.

15. NERC, *2007 Long-Term Reliability Assessment*, 19.

16. NERC, *2011 Long-Term Reliability Assessment*, 36–37.

17. Essentially, every type of electric generating facility is either located near a fuel or power source (e.g., gas pipeline, river, or wind site) or requires the transportation of fuel (e.g., natural gas or coal) to its site, and also requires transmission lines to carry its generated electricity to markets. As a result, there tend to be location impacts and additional transportation or transmission infrastructure investment requirements associated with all changes in the mix of generating technologies or fuel sources.

18. Data were taken from Edison Electric Institute, *Statistical Yearbook 2011*. The 2011 Statistical Yearbook reports transmission and distribution (T&D) investments through 2009. The Institute released preliminary 2010 investments as this study was underway. A comparison of 2009 and 2010 expenditures showed that overall 2009 T&D investments were 98.4% of 2010 totals (in constant 2010 dollars). This analysis went forward with data from the 2011 Statistical Yearbook (2009 data) because the 2010 and 2009 totals were equivalent and the 2010 data were preliminary.

19. Electric Power Research Institute, *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid*, 2011. This study also provided estimates for transmission system improvements, but given that the future that we used for the Eastern Interconnection Planning Collaborative study also included smart grid improvements, we did not include the Electric Power Research Institute estimates to be conservative.

20. These studies do not provide regional breakdowns of their expenditure estimates. To estimate distribution investment by NERC region, we obtained FERC Form 1 data on distribution additions by individual utilities. The total distribution expenditures from our FERC Form 1 data for 2001–8 were within 10% (and within 5% for many years) of the national estimates in Edison Electric Institute data. By assigning each utility to its NERC region, shares of national spending were allocated to each region. Each region's relative share was fairly stable over the 10-year period. A five- year average national share was used for each region to estimate the regional shares of the business-as-usual and smart grid distribution investments.

21. LaCommare and Eto, 2004.

22. Data from the Electric Power Research Institute.

23. LaCommare and Eto, 2004.

24. As noted earlier, EIA expects that electricity generated by distributed generation will grow by almost 17% per year through 2035. This represents a nearly 36 fold increase from 2012. If that rate of increase continues to 2040, electricity produced by distributed generation would increase 77 times the projected 2012 total. EIA expects the rate of increase of killawatt hours produced by distributed generation to be considerably higher than for any other technology. (Source: Energy Information Administration, Form EIA-759, Monthly Power Plant Report. 2008 and 2009).

25. Personal consumption expenditures (PCS) is a concept from the U.S. Bureau of Economic Analysis and is a measure of goods and services targeted towards individuals and consumed by individuals.

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ASCE
AMERICAN SOCIETY OF CIVIL ENGINEERS

World Headquarters
1801 Alexander Bell Drive
Reston, Virginia 20191

Washington Office
101 Constitution Avenue, NW
Suite 375 East
Washington, DC 20001

202/789-7850
202/789-7859 FAX

reportcard@asce.org
www.asce.org/failuretoact