Sustainable Industry Classification System™ (SICS™) #IF0101
Research Briefing Prepared by the Sustainability Accounting Standards Board®
March 2016
ELECTRIC UTILITIES

Research Brief

SASB’s Industry Brief provides evidence for the disclosure topics in the Electric Utilities industry. The brief opens with a summary of the industry, including relevant legislative and regulatory trends and sustainability risks and opportunities. Following this, evidence for each disclosure topic (in the categories of Environment, Social Capital, Human Capital, Business Model and Innovation, and Leadership and Governance) is presented. SASB’s Industry Brief can be used to understand the data underlying SASB Sustainability Accounting Standards. For accounting metrics and disclosure guidance, please see SASB’s Sustainability Accounting Standards. For information about the legal basis for SASB and SASB’s standards development process, please see the Conceptual Framework.

SASB identifies the minimum set of disclosure topics likely to constitute material information for companies within a given industry. However, the final determination of materiality is the onus of the company.

Related Documents

- Infrastructure Sustainability Accounting Standards
- Industry Working Group Participants
- SASB Conceptual Framework

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INTRODUCTION

The Electric Utilities industry is the backbone of the modern economy. We all depend on its regular maintenance of transmission and distribution lines, as well as the constant production of electricity from a myriad of sources. Society grants many companies in this space a monopoly, a license to operate contingent on providing near continuous service at reasonable rates to all the customers in an allotted service area.

We are currently in the early stages of a new era for utilities, where an international focus on transitioning to a low-carbon economy is catalyzing novel regulatory schemes. These new structures, alongside the proliferation of renewable energy and distributed generation, will make the electric utilities of the next decade significantly different from those prior.

While the industry’s end product, electricity, is universal, the means to produce it varies widely in source and process efficiency. The power-generating portion of this industry faces significant challenges. It must continue to support a growing demand for electricity while keeping costs down for consumers and minimizing environmental and social impacts and externalities. This is a problem with global consequences, greatly impacting climate change, water scarcity, and human health.

Given the significant regional variation in resource availability (which plays a crucial role in the potential energy mix) and regulations, each utility operates under a unique set of conditions and must choose how to best serve its customers.

Management (or mismanagement) of certain sustainability issues, therefore, has the potential to affect company valuation through impacts on profits, assets, liabilities, and cost of capital.

Investors would obtain a more holistic and comparable view of performance with electric utilities companies reporting metrics on the material sustainability risks and opportunities that could affect value in the near and long term in their regulatory filings. This includes both positive and negative externalities, and the non-financial forms of capital that the industry relies on for value creation.

Specifically, performance on the following sustainability issues will drive competitiveness in the Electric Utilities industry:

- Limiting greenhouse gas (GHG) emissions;

SUSTAINABILITY DISCLOSURE TOPICS

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• Limiting other hazardous air emissions;
• Ensuring continued access to the water supplies needed for energy generation;
• Controlling waste streams from energy generation, particularly coal ash;
• Working with stakeholders to address community concerns and thereby ensure access to land needed for transmission and/or distribution (T&D) line expansion and power plants;
• Ensuring company practices and culture promote workforce safety;
• Promoting energy efficiency among customers to decrease consumer costs as well as lower GHG output, while positioning business models to benefit from increases in efficiency;
• Working with regulators to shape the future of utilities, given the increasing focus on a transition to a low-carbon economy and the rise of distributed generation, as well as ensuring the integrity of these regulatory relations;
• Ensuring cost-effective but strong safety measures for nuclear power plant operations;
• Investing in grid resiliency to protect from both storms and cyber-attacks; and
• Working with regulators to ensure both fair compensation for utilities and fair pricing for customers.

**INDUSTRY SUMMARY**

The Electric Utilities industry is made up of companies that generate electricity; build, own, and operate T&D lines; and sell electricity.¹

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¹ Industry composition is based on the mapping of the Sustainable Industry Classification System (SICS™) to the Bloomberg Industry Classification System (BICS). A list of representative companies appears in Appendix I.

**Market structure**

Companies may operate as integrated utilities, meaning they generally operate all elements of the value chain as regulated utilities, including generation, transmission, and distribution. Alternatively, various elements of the value chain can be deregulated. In deregulated markets, company structures are more disparate and may be more complex, but in general, generation at least is split from T&D, which gives customers a choice between electricity providers. In some markets, transmission is also deregulated, leaving traditional utilities to operate only distribution. This deregulation is meant to introduce market competition to keep prices low for consumers.¹ Currently 16 states plus the District of Columbia (D.C.) are deregulated to some degree. Seven previously deregulated states have since suspended these regulations.²

Transmission lines are high-voltage lines meant to carry electricity efficiently over long distances, while distribution lines carry electricity to the end user after the electricity passes through a substation and its voltage is lowered. Electricity can be generated from fossil fuels, nuclear fuel, hydroelectric sources, wind energy, and solar energy, as well as other sources.

While U.S.-listed companies include a few large companies based outside the U.S., such as Korea Electric Power Corporation, the majority are U.S.-based and operate mainly in U.S. markets.³ Therefore the analysis in this brief is based on the U.S. and its regulatory environment.⁴

There are roughly 3,300 electric utilities in the U.S. However, only 189 of these are investor-
owned utilities (IOUs), this subset of IOUs provides energy to nearly 70 percent of all electricity customers.

Broadly speaking, a utility is something that has been determined both to provide a vital public good and to be a service that would be inefficient for society to fully leave up to a free market. The logic of this is evident in the Community Impacts of Project Siting issue, discussed later in this brief, in the case of distribution lines: It would waste resources to have multiple companies operating distribution lines in the same community; this would be akin to allowing multiple owners of private roadway systems to develop competing road networks through communities.

In general, companies focus on local and regional operations, as the regulatory environment makes operations across state lines difficult. Furthermore, segments such as distribution are guaranteed monopolies within their granted service area. There has been a recent trend toward consolidation within regional markets, but no single firm has a significantly large national position. Companies in the power-production segments are slightly more concentrated than those in the transmission segment, but on a national level, the industry is still highly dispersed.

Regulated IOUs accept regulatory oversight of their pricing mechanisms, among many other things, in exchange for society’s continuing to grant their license to operate as a monopoly. Electric utilities are also required to provide universally accessible and highly reliable service while balancing the protection of human life and the environment. This tension will be examined throughout the brief.

Each state has its own utilities commission, often called a public utilities commission (PUC) or a public service commission (PSC), which regulates portions of the state’s electricity market (among other goods and/or services). While state utilities commissions are similar on a macro level, their environments, specific objectives, and strategies to achieve such objectives can be quite different. Broadly speaking, utilities commissions are in charge of approving the rate that electric utilities can charge for their services, deciding what types and amounts of costs can be passed on to ratepayers, and in what rate structures, and determining the “reasonable rate of return” that should be allotted for capital providers.

**Capital expenditures and cost recovery**

Regulated electric utilities must anticipate and articulate their current and future infrastructure needs to utilities commissions so that the costs can be passed on to ratepayers. Depending on the operation and the type of project, this approval may occur before the utility begins a new project.

Traditionally, however, such capital-project approval does not come until after the project is completed, giving rise to regulatory risks associated with project approval, as well as

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Note on Industry Structure

This brief does not address natural gas utilities. Separate SASB standards are available for gas utilities (#IF0102) and should be used to the extent that electric utilities also operate gas utilities.
regulatory lag. As a result, utilities may naturally gravitate toward capital expenditures and capital raises associated with projects that they have a high level of confidence in being approved by their regulators. These regulatory risks and obstacles can limit how proactively electric utilities respond to certain infrastructure issues, as it depends on the sentiment of their regulators.

However, because the returns that regulated utilities earn are generally calculated on the rate base (generally, the level of approved capital investment), they have a conflicting incentive to invest heavily, so long as there is a high likelihood of such projects being approved. Indeed, for a myriad of reasons discussed throughout this brief, including a historic pattern of infrastructure underinvestment, IOU capital expenditures have increased, from $41 billion in 2004 to $103 billion in 2014.\(^8\)

Companies also need to run projects efficiently, as their shareholders are often liable for projects that go over the budget allowed by utilities commissions. Electrical utilities may be able to recover from ratepayers those costs from unforeseen events or accidents, unless they are found to be negligent, in which case the resulting fines and/or loss of revenue will be borne by the shareholders.\(^9\)

All segments of this industry by nature have high barriers to entry. They are highly capital intensive, and there are significant regulatory barriers and compliance costs. Additionally, the entire industry relies on a shrinking pool of highly skilled labor, as an aging workforce is starting to retire, and not enough young workers are entering the industry. This is leading to high salary demands by the workforce.\(^{10}\)

### Revenue drivers

Historically, a utility’s revenue was directly proportional to the amount of electricity it sold (i.e., volumetric ratemaking). However, in recent years, utilities and their regulators in more than a dozen states have put in place varying “decoupling” strategies. Under decoupling, a utility’s revenue is no longer directly tied to the volume of electricity sold, thereby removing a theoretical disincentive for utilities to promote energy efficiency (this concept is discussed in greater detail in the End-use Efficiency & Demand disclosure topic).\(^{11}\)

Weather is a major determinant of company revenue for utilities operating without decoupled rate structures, as electricity is often used for heating.\(^{12}\) Indeed, it is common practice for companies in this industry to list average temperatures in their Form 10-Ks and other Securities and Exchange Commission filings, as it can help explain a significant portion of revenue volatility for utilities that are not decoupled.\(^{13}\) Such weather-related risks may be mitigated if rate structures use a variety of risk-reducing strategies, such as the assortment of specific rate mechanisms falling under the general umbrella of decoupling.

As of January 27, 2016, global annual revenues of electric utility companies totaled roughly $2.63 trillion for the fiscal years reported.\(^{14}\) Roughly $328 billion of this comes from companies domiciled in the U.S.\(^{15}\) The largest segment of revenues globally, based on reported segment data, were related to power generation (41.8 percent), followed by electricity networks (38.8 percent, which includes both transmission and distribution), then fully integrated utility operations (12.6 percent) and energy trading and marketing (5.7 percent). Less than one percent of revenue came from district heating and cooling.
and power storage, based on reported segment revenues.\textsuperscript{16} The five companies that are publicly traded on U.S. exchanges that most represent this diverse industry are, in order of revenue: Exelon Corporation, Duke Energy, Southern Company, American Electric Power, and NRG Energy.\textsuperscript{17}

According to the U.S. Energy Information Administration (EIA), the U.S. generated 4.1 trillion kilowatt-hours (kWh) of electricity in 2014. The chart below breaks this out by energy source.\textsuperscript{18}

<table>
<thead>
<tr>
<th>Energy Source</th>
<th>Percent of Total Electricity (%)</th>
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<tbody>
<tr>
<td>Coal</td>
<td>39</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>27</td>
</tr>
<tr>
<td>Nuclear Energy</td>
<td>19</td>
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<tr>
<td>Hydropower</td>
<td>7</td>
</tr>
<tr>
<td>Wind</td>
<td>4.4</td>
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<tr>
<td>Biomass</td>
<td>1.7</td>
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<tr>
<td>Petroleum</td>
<td>1</td>
</tr>
<tr>
<td>Solar</td>
<td>0.4</td>
</tr>
<tr>
<td>Geothermal</td>
<td>0.4</td>
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<tr>
<td>Various other gases</td>
<td>&gt;1</td>
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Average retail electricity prices can vary widely by geography. For example, in 2013 averages prices were $0.34/kWh in Hawaii and $0.07/kWh in Louisiana.\textsuperscript{19} Major factors in these differences include the proximity of energy-generating resources and the specifics of their regulatory environment. Electricity is often priced in tranches based on levels of energy use. In some cases, this is meant to encourage conservation as well as to mirror the utilities’ cost structure, in which their marginal energy costs rise significantly during periods of high demand (a concept discussed in more detail in the End-Use Efficiency & Demand disclosure topic).

In 2014, residential consumers were the largest consumers of electricity in the U.S., buying 1.4 trillion kWh of electricity. They were closely followed by commercial customers, which purchased 1.3 trillion kWh; and industrial users, which purchased 950 billion kWh in the same year.\textsuperscript{20}

**Challenges to profitability**

U.S. electricity demand was flat between 2007 and 2015, while it had a compound annual growth rate of 2.4 percent between 1990 and 2000.\textsuperscript{21} Slow population growth, coupled with an increased focus on energy efficiency nationwide, accounts for this significant shift (these factors have reduced utility revenue in those markets without a form of decoupling).\textsuperscript{22} The increased focus on energy management manifests in governmental and utility outreach efforts (the latter in decoupled markets or markets that provide incentives to utilities for energy-efficiency-related objectives, which is further addressed in the End-Use Efficiency & Demand disclosure topics) to make customers more efficient in their energy use and to increase the demand for energy-efficient products (e.g., ENERGY STAR\textsuperscript{®}).\textsuperscript{23}

Furthermore, the growth of smart metering technology, a general term, allows for more specific monitoring of energy use. Smart metering has many functions, including enabling some utilities to deploy “demand response” pricing if allowed by regulators; this means utilities offer incentives for customers to not use electricity at times when it is more expensive to produce. This technology also allows for greater and more efficient management of the electric grid, including responding to malfunctions and repairing damaged parts of the grid.\textsuperscript{24}

Utilities in regions rich in solar resources are feeling increasing pressure from the significant
rise of distributed generation; U.S. solar installations increased by 478 percent between 2008 and 2013. Residential and commercial customers with rooftop solar panels installed through third parties can not only generate some or all of their own electricity, which may erode utilities’ revenues, but also sell energy back to the grid because of “net metering” policies. In some markets, such customer sales back to the grid may occur at the retail electricity rate, not the wholesale rate utilities usually pay for electricity. Many utilities are attempting to combat this rising issue by seeking alternative rate structures, such as a base charge for use of the grid (this is discussed in greater detail in the Management of Legal and Regulatory Environment issue).25

In 2014, companies in this industry had a median net income margin of 8.79 percent, a roughly 20 percent increase from the 2012 median net income margin of 7.03 percent.26

Levelized cost of energy (LCOE), a commonly used metric to compare the viability of building utility-scale energy projects from different sources of energy, is the per-kWh total cost of building and operating a generating plant over its expected lifetime. This measure captures everything from cost of materials to capital costs to tax breaks and is used by companies to aid in their choice of what technology or energy resource to invest in.27

While the expansion of solar and other forms of renewable energy can threaten utility profitability, utilities themselves may be able to benefit from investing in these energy sources in some scenarios. For example, the chart below shows LCOE scenarios from the Bloomberg terminal.28

The wide range in LCOEs for different energy sources is based on a myriad of regional factors, including relative input costs (e.g., coal or natural gas deposits in the region) and the regulatory environment.

The rise of hydraulic fracturing in the U.S. has significantly driven down domestic prices of natural gas. The average cost in the U.S. between 2005 and 2010 was 47 percent higher than the average cost between January 2011 and December 2015.29

This has made investment in building natural gas power plants more appealing to utilities companies, relative to investments in other energy-generation sources. New U.S. Environmental Protection Agency (EPA) regulations (discussed further in the Legislative and Regulatory Trends section) around GHG reduction will likely also make natural gas generation more economical, leading to both the construction of new natural gas plants and the retrofitting of many coal-fired plants into natural gas plants. These regulations will also likely cause an expansion in wind and solar energy generation, as these technologies have very low emissions during operations.30

**Company valuation**

Traditionally, investors have viewed electric utilities as low-risk investments. They are also prized for their steady dividend yields. This means that investment in this industry is often inversely related to the current interest rate, as investors seek out predictable, low-risk returns. To value a company in this industry, analysts will typically examine a company’s five-year plan for capital

<table>
<thead>
<tr>
<th>Energy Source</th>
<th>Low-LCOE Scenario (per MWh)</th>
<th>High-LCOE Scenario (per MWh)</th>
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<tbody>
<tr>
<td>Coal</td>
<td>$28.74</td>
<td>$156.71</td>
</tr>
<tr>
<td>Nuclear</td>
<td>$94.10</td>
<td>$156.78</td>
</tr>
<tr>
<td>Thin-film Solar</td>
<td>$85.94</td>
<td>$227.10</td>
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expenditures, its cost of debt (as reflected in its corporate bond rate), and the equity ratio and return on equity that is allowed by regulation in the company’s service area, as well as the overall rate structures used. The current and potential new-customer growth rate is also a key valuation factor.

Investors also examine the local regulatory environment, as this can vary substantially on the state level. It is directly impacted by state-level politics, as the state governor generally nominates the public utility commissioners, who usually serve staggered six-year terms, giving the political party in power indirect influence over the policies of the state utilities commission.

Analysis of a regulated utility’s financial performance and its future risks and opportunities should be conducted in conjunction with an understanding of a utility’s rate structure. While rate structures and ratemaking are extremely complex topics that vary widely by state and utility, investors who deepen their understandings of a utility’s views and objectives on ratemaking—including past rate cases and expected future rate cases—as well as company performance relative to specific rate structures, will provide further context to assessing the risk-return profile of utilities in an environment where increasing resource efficiency and GHG mitigation is paramount.

It is important to note that a company’s exposure to the risks and opportunities discussed in the following sections is highly contingent on its energy mix, as the issues do not affect each electricity-generation method equally.

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**LEGISLATIVE AND REGULATORY TRENDS IN THE ELECTRIC UTILITIES INDUSTRY**

Regulations in the U.S. and abroad represent the formal boundaries of companies’ operations and are often designed to address the social and environmental externalities that businesses can create. Beyond formal regulation, industry practices and self-regulatory efforts act as quasi-regulation and also form part of the social contract between business and society. In this section, SASB provides a brief summary of key regulations and legislative efforts related to this industry, focusing on social and environmental factors. SASB also describes self-regulatory efforts on the part of the industry, which could serve to pre-empt further regulation.

The potential environmental and safety hazards that accompany electricity generation and distribution result in significant legislation at both the state and the federal levels in order to protect the public. In addition, the natural monopoly that characterizes parts of this industry is accompanied by heavy direct regulation.

**Traditional utility regulation**

The prices and services of regulated utilities are highly regulated by state utilities commissions. Companies typically submit a rate case to their state utilities commission for approval. The rate case stipulates the rates that customers are charged for electricity services and the structure of such rates. Utilities are allowed to directly pass on many costs, such as fluctuations in energy costs, to customers. This means that short- and medium-term input-price fluctuations may not directly affect a utility’s profits, although they highlight some ways in which regulatory trends are impacting the industry.

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*This section does not purport to contain a comprehensive review of all regulations related to this industry, but is intended to*
could affect revenues—if, for example, input prices of non-decoupled utilities spike enough to alter customer behavior. However, electricity is typically relatively price inelastic.

Utilities commissions also stipulate an “allowed return on investment” for utilities in their states; this is generally calculated as a percentage of the rate base. It is important to note that this return is not guaranteed, as the utility still needs to ensure that it keeps its costs within its estimates and that it avoids fines. Customer pricing is structured so that utilities have a reasonable opportunity to earn up to the agreed-upon rate of return. If unexpected events occur that create costs that are seen as unavoidable for the companies, they can often make a case to their regulators to pass those costs through to customers. 32

As noted, more than a dozen states have utilities that use a form of decoupling. 33 Decoupled rate structures attempt to remove the linear relationship between the amount of electricity a utility sells and the company’s revenues. Typically, decoupling mechanisms tie company margins to the number of customers it has and/or set up a system of revenue recovery to counterbalance variables—such as weather and efficiency fluctuations—that can have a significant effect on customer electricity demand. 34

Utilities are often in favor of decoupling because it may reduce the volatility of revenues and returns. In many places decoupling also has strong political and public support, as it addresses the disincentive for energy conservation in traditional pricing systems. 35 Some states also provide performance incentives for companies that achieve consumption-reduction targets among their customers. 36

Environmental protection

This industry faces significant federal environmental oversight from the EPA, whose laws apply mainly to energy generation, although some also affect downstream T&D line placement and operations. The Federal Energy Regulatory Commission (FERC) is in charge of interstate electricity transmission, setting wholesale pricing regulations and preventing market abuse. The distribution of electricity, as well as retail (non-wholesale) pricing, is generally regulated at the state level. 37

The industry is currently facing heavy regulation related to airborne emissions. One of the most recent of these laws is the EPA’s Mercury and Air Toxics Standard (MATS), which places strict power-plant-emission limits on mercury and similar heavy metals. The regulation was introduced in December 2011 and gave companies four years to fully comply, although some companies have been able to get one- or two-year extensions. This law has faced numerous court challenges alleging that the EPA didn’t adequately consider the cost of compliance. In June 2015, the Supreme Court ruled that the EPA had to consider compliance costs and come up with a response plan; the EPA proposal is expected spring 2016. 38 However, many companies have already made significant investments, and therefore a complete rejection of this rule would not have a major effect industry-wide. 39

In mid-2014, the EPA issued the Clean Power Plan guidelines, which govern existing fossil-fuel-fired power plants. This plan falls under the larger carbon pollution standards set by the EPA under the Clean Air Act (CAA). Under this plan, the EPA set a goal for a 30 percent reduction in carbon dioxide emissions by 2030, using 2005 emissions as the baseline. 40 These guidelines stipulate state-
level emissions-reduction targets, giving states the freedom to devise the best mix of strategies to meet these targets. States have until June 2016 to put their plans into place, with the possibility for a two-year extension. If states do not formulate their plans in their allotted time, the EPA will step in and issue its own plan for them.

However, in February 2016, the U.S. Supreme Court issued a stay on the ruling, effectively blocking its implementation—if it is to occur at all—until at least 2017.41 The long-term viability of this law is highly dependent on who wins the 2016 presidential election.42 There is significant pushback from industry members, who argue that the rapid decommissioning of many coal-fired plants that will result from the legislation will threaten grid reliability.43 However, as of February 2016, 20 states are continuing on the path toward compliance, regardless of the stay ruling.44

It is worth noting that these emissions-reduction targets are part of a larger federal commitment by the U.S. State Department, made in March 2015 in preparation for the 21st session of the United Nations Conference of the Parties (COP21), to pursue economy-wide emissions cuts of 26 to 28 percent below 2005 levels by 2025.45

Some types of energy generation face more stringent and specific regulations than others. In December 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities rule, which provides strict guidelines for how coal ash must be disposed of to avoid air or groundwater contamination. The rule also introduced new public reporting requirements for disposal facilities.46 This rule serves as a federal minimum, allowing states to introduce stricter disposal standards, and is likely to significantly increase regulatory compliance costs for operators of coal plants.47

Roughly 100 nuclear reactors operate in the U.S., each of which produces, on average, 20 metric tons of spent uranium fuel annually. The Price-Anderson Act requires utilities to have insurance to cover their potential liabilities related to nuclear accidents, and caps their liability at $255 million.48 The Nuclear Regulatory Committee (NRC) is a governmental regulatory body created in 1974 to license, inspect, and enforce the use of radioactive material.49

The NRC and the U.S. Department of Energy (DOE) are responsible for regulating the disposal of spent nuclear fuel. The DOE was examining the potential for Yucca Mountain in Nevada to be a possible site for a national radioactive-waste depository, but effectively discontinued this project in 2010. Currently, the agency plans to have a pilot interim-storage program running by 2021 and a permanent facility active by 2048. The Nuclear Waste Policy Act of 1982 mandated that the DOE take responsibility for spent nuclear fuel by 1998, and the DOE has since been successfully sued for $4.5 billion, with $22.6 billion in future liabilities projected, by utilities that have had to construct their own storage facilities in the interim.50 This lack of a national repository places more of the containment risk on the companies themselves.

Most types of power plants use significant amounts of water and must comply with the EPA’s Clean Water Act.51 In 2014, the EPA issued a ruling to reduce the amount of aquatic organisms that are sucked into power plants’ cooling water. The rule applies to those plants that withdraw more than two million gallons of cooling water daily and is expected to lead to significant compliance costs.52
Renewable energy and the changing utility landscape

The Public Utilities Regulatory Policy Act was passed in 1978 in the face of rising national energy prices and paved the way for state-level deregulation. This was the first step toward allowing power generation by non-utility entities. It also made it a legal requirement for utilities to buy power from these independent power generators if their price was cheaper than the utilities’ own price. FERC Order Nos. 888 and 889 were introduced in the mid-1990s to ensure that all generators got equal and fair access to transmission lines. This lowered barriers to entry for power generators operating in deregulated states. Some states have begun to use long-term integrated-resource plans and rate strategies. This type of planning encourages companies to examine both supply-side and demand-side (e.g., through encouraging and facilitating greater end-user efficiency) means of reducing costs.

Twenty-nine U.S. states and D.C. have renewable portfolio standards (RPS) requiring all sellers of electricity in a state to source a specified percentage of that energy from renewables. Thresholds vary by state. For example, New York has a quota of 30 percent by 2015, while California requires 33 percent by 2020 and 50 percent by 2030. This obviously affects demand for power generation, bolstering generation companies that have invested in renewable energy to the detriment of companies heavily invested in coal.

The U.S. federal government has also introduced purchasing requirements around renewable energy. The Energy Policy Act of 2005 required federal agencies to purchase at least 7.5 percent of their energy from renewables by 2013. This act was amended in 2013 to raise the requirement to 10 percent in fiscal year (FY) 2015, 15 percent in FYs 2016 and 2017, 17.5 percent in FYs 2018 and 2019, and 20 percent in FY2020 and subsequent years. With $5.8 billion in annual energy costs, the federal government is the largest utilities customer in the U.S., making these requirements a significant driver of national demand for renewable energy.

Forty-four states and D.C. have some variation of net metering laws, which allow commercial and residential customers who generate their own electricity (e.g., through having solar panels on their roofs) to sell excess capacity back to the grid. The specifications of these laws vary widely between states, but in general, they determine how many excess kilowatts of power (and at what price) each state will allow to be sold back to the grid.

These laws are opposed by some companies in the industry and are being challenged in some jurisdictions. Many utilities companies see net metering as a threat to their revenue streams and fear that it encourages “free ridership” on the T&D lines they maintain. To the extent that utilities must pay generators retail prices rather than wholesale rates for the electricity they produce, which is often the case, many see net metering as a temporary subsidy meant to bolster renewable energy sources that are no longer in their infancy. To combat the potential free-ridership problem, some utilities have suggested a mandatory base rate for all utility customers so that all consumers would have to pay for the grid’s maintenance.

Some electric utilities argue that there will be a “death spiral” without this legislation: As more customers leave the grid, electricity prices will have to rise to cover maintenance. These prices will increase the incentive to leave the grid for those with the financial means to do so, until eventually only the poorest are left on the grid.
The severity and timeline for the scenario are hotly debated, however; for example, an American Council for an Energy-Efficient Economy study found only a small sales decrease in the short to medium term as a result of a rise in distributed generation. Some states and utilities are taking long-term views on clean and resilient grids and setting related policy goals, like New York State’s Reforming the Energy Vision plan. The successful completion of this plan will make the utilities of the future more akin to a platform provider and set them up to be compensated accordingly.

SUSTAINABILITY-RELATED RISKS AND OPPORTUNITIES

Industry drivers and recent regulations suggest that traditional value drivers will continue to impact financial performance. However, intangible assets such as social, human, and environmental capitals, company leadership and governance, and the company’s ability to innovate to address these issues are likely to increasingly contribute to financial and business value.

Broad industry trends and characteristics are driving the importance of sustainability performance in the Electric Utilities industry:

- **Increasing support for environmental regulations**: This industry’s operations create significant environmental externalities; it is a major emitter of carbon dioxide and other air pollution. All electric utilities, especially power generators, will be affected by an increasing regulatory emphasis, as shown by the strong commitments made at COP21, on mitigating climate change and protecting human health. There is potential for stranded assets if changing environmental regulation makes certain power-generation sources no longer financially viable.

- **Distributed generation**: The economic viability of distributed generation presents both a challenge and an opportunity to the industry, and companies will need to figure out how to manage this issue properly without inadvertently incentivizing customers to leave the grid.

- **Grid resiliency**: The electricity grid is increasingly threatened by extreme weather patterns (which will likely increase given the effects of climate change) and cyber-attacks. The industry stands to gain from the increased investment needed to handle these issues, but it is at risk for major systems failures. These failures would have far-reaching negative effects on the worldwide economy, as reliable access to electricity is necessary for the U.S. economy to function.

- **License to operate as a monopoly**: Many segments of this industry are allowed to continue their current business model because they are a natural monopoly and they, in exchange for certain financial protections, are required to provide reliable access to an essential public good. Any failure to provide this reliable, and reasonably affordable, access could result in a loss of this social license. This societal contract places increased scrutiny on the actions of regulated electric utilities to help ensure that their policies align with the public’s best interest.

As described above, the regulatory and legislative environment surrounding the Electric Utilities industry emphasizes the importance of
sustainability management and performance. Specifically, recent trends suggest a regulatory emphasis on environmental and consumer protection, which will serve to align the interests of society with those of investors.

The following section provides a brief description of each sustainability issue that is likely to have material financial implications for companies in the Electric Utilities industry. This includes an explanation of how the issue could impact valuation and evidence of actual financial impact. Further information on the nature of the value impact, based on SASB’s research and analysis, is provided in Appendix IIA and IIB.

Appendix IIA also provides a summary of the evidence of investor interest in the issues. This is based on a systematic analysis of companies’ 10-K and 20-F filings, shareholder resolutions, and other public documents, which highlights the frequency with which each topic is discussed in these documents. The evidence of interest is also based on the results of consultation with experts participating in an industry working group (IWG) convened by SASB. The IWG results represent the perspective of a balanced group of stakeholders, including corporations, investors or market participants, and public interest intermediaries.

The industry-specific sustainability disclosure topics and metrics identified in this brief are the result of a year-long standards development process, which takes into account the aforementioned evidence of interest, evidence of financial impact discussed in detail in this brief, inputs from a 90-day public comment period, and additional inputs from conversations with industry or issue experts.

A summary of the recommended disclosure framework and accounting metrics appears in Appendix III. The complete SASB standards for the industry, including technical protocols, can be downloaded from www.sasb.org. Finally, Appendix IV provides an analysis of the quality of current disclosure on these issues in SEC filings by the leading companies in the industry.

ENVIRONMENT

The environmental dimension of sustainability includes corporate impacts on the environment. This could be through the use of natural resources as inputs to the factors of production (e.g., water, minerals, ecosystems, and biodiversity) or environmental externalities and harmful releases into the environment, such as air and water pollution, waste disposal, and GHG emissions.

The Electric Utilities industry depends heavily on environmental capital for inputs to production, which account for a significant share of operating costs. At the same time, its operations and the generation of electricity can create wide-ranging environmental impacts that affect land, air, and water resources as well as human health. As resources are becoming limited or exhibiting price volatility, and legislation seeks to address externalities, utilities need to manage these risks and innovate to reduce the environmental impacts of their operations to ensure operational efficiency and retain their license to operate.


Electric utilities represent the largest source of GHG emissions in the U.S. economy. These emissions are the byproduct of fossil fuels combustion. Electric utilities therefore tend to be the focus of GHG mitigation policies, such as the recent Clean Power Plan in the U.S.
Electric utility companies may face significant operating and capital expenditures for mitigating GHG emissions. While many of these costs can be passed on to a utility’s customers, power generators in the 17 deregulated markets may not be able to recoup these costs.

Most of the emissions are created during generation in the form of carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O). Companies can lower these emissions through different technologies, but the largest factor in utilities’ absolute emissions total is the energy mix. Generally, the higher the percentage of energy a utility generates from renewable or non-fossil-fuel sources—such as hydro, wind, and nuclear power—and the lower the percentage it generates from coal, the lower its overall emissions will be. The T&D segments are responsible for a small amount of emissions—estimated at less than 1 percent. These mainly come from the escape of sulfur hexafluoride, a chemical used for power-line insulation.

Companies that cost-effectively reduce GHG emissions from electricity generation through their choice of energy mix (which depends on whether a company’s place of operation is affected by RPS requirements), as well as through their utilization of industry-leading technologies and processes, can create a competitive advantage and mitigate regulatory compliance costs. Proactive management of this issue could reduce uncertainty around impacts from regulations and unplanned expenditures or plant retirements, as the economy transitions to low-carbon electricity generation over the long term.

Company performance in this area can be analyzed in a cost-beneficial way through the following direct or indirect performance metrics (see Appendix III for metrics with their full detail):

- (1) Gross global Scope 1 emissions, (2) percentage covered under emissions-limiting regulations, and (3) percentage covered under emissions-reporting regulation;
- Description of long-term and short-term strategy or plans to manage Scope 1 emissions, emission-reduction targets, and an analysis of performance against those targets; and
- (1) Number of customers served in markets subject to renewable portfolio standards (RPS), and (2) percentage fulfillment of RPS target by market.

**Evidence**

The international pledges made at COP21, with the involvement of the U.S., portend the acceleration of a global, and nearly inevitable, shift toward a low-carbon economy that will have a significant impact on this industry. The electricity generation segment was responsible for 31 percent of total U.S. GHG emissions in 2013. Increased electricity demand caused GHG emissions from electricity generation to increase by 11 percent between 1990 and 2012, prompting an increased regulatory focus. This increase in absolute emissions is unsurprising given the continued relative dominance of fossil-fuel based generation and the population increases during this period. Many companies, including Southern Company, Pacific Gas and Electric (PG&E), and Duke Energy, already report their emissions in SEC documents, although currently these emissions are not reported in a standardized way.

There is wide variation in emissions intensity—as measured in kilograms of carbon dioxide equivalent produced per megawatt-hour (kg CO₂e/MWh)—for different energy sources, as demonstrated in the chart below.
These large variations in carbon intensity highlight the importance of the energy mix in a company’s regulatory and financial exposure related to climate change.

Coal-fired power plants play an outsize role in the generation of GHG emissions by electric utilities, accounting for 75 percent of CO₂ emissions while generating only 39 percent of the electricity. Furthermore, according to an Oxford University study, 73 percent of the U.S. coal plant fleet was subcritical, less efficient than new plants and generally decades old; the average subcritical coal plant emits 75 percent more carbon emissions than a new state-of-the-art power plant.

Depending on the future political climate, it may soon be most cost effective to close older coal plants that to have a low ratio of energy produced to GHGs emitted. As mentioned previously, 20 states are continuing forward with the Clean Power Plan, despite the stay order by the Supreme Court. With the recent drop in natural gas pricing, utilities are considering converting these coal plants to natural gas power plants, as much of the necessary infrastructure, such as transmission lines, can be cost effectively converted.

As mentioned in the Legislative and Regulatory Trends section, 29 states and D.C. have RPS requirements. This is a significant driver for creating demand for renewable energy, and conversely, decreasing demand for the least efficient sources of energy. According to a 2016 joint study by the National Renewable Energy Laboratory (NREL) and the Lawrence Berkeley National Laboratory, more than 5,600 megawatts of renewable energy generation was built per year between 2013 and 2014 to meet RPS requirements.

Between the EPA’s Clean Power Plan and the MATS rule (discussed further in the Air Quality issue, below), the EIA estimates that 90 gigawatts (GW) of coal-fired plants will be retired by 2040—50 GW more than it estimates would be retired without these rules—as they will no longer be economical to maintain. The EPA estimates that the annual cost of the Clean Power Plan by 2030, when more of the effects would be felt, would be between $7.3 billion and $8.8 billion.

Companies are facing significant investor scrutiny in this area, resulting in 10 shareholder resolutions related to GHG reduction being filed with electric power companies as of the first quarter of 2015 alone. For example, the New York State Common Retirement Fund filed a resolution with Alliant Energy, asking the company to publish its strategy to reduce its GHG emissions to reach national goals. This resolution was withdrawn when the company agreed to address the concerns. CMS Energy Corporation and FirstEnergy Corporation both received similar resolutions, which were also withdrawn when the companies agreed to address them.

Some companies are currently tracking and aggressively pursuing reductions in their GHG emissions. For example, Consolidated Edison achieved a 47 percent decrease in CO₂e between

<table>
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<tr>
<th>Energy Generation Type</th>
<th>Lower Bound (kg CO₂e/MWh)</th>
<th>Upper Bound (kg CO₂e/MWh)</th>
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</thead>
<tbody>
<tr>
<td>Black Coal</td>
<td>757</td>
<td>1085</td>
</tr>
<tr>
<td>Black Coal (Carbon-capture System)</td>
<td>247</td>
<td>n/a</td>
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<tr>
<td>Natural Gas</td>
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<td>15</td>
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<td>Solar PV</td>
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<td>103</td>
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2007 and 2014, from 6 million metric tons to 3.2 million metric tons. This was achieved through equipment repair projects and increasing natural gas while decreasing coal in the company’s energy mix.\(^8^1\)

AES Corporation mentioned in its FY2014 Form 10-K that financial analysts are already looking at GHG emissions as a source of regulatory risk when assessing a company’s risk profile, which may affect the cost of capital: “Certain financial institutions have expressed concern about providing financing for facilities which would emit GHGs, which can affect our ability to obtain capital, or if we can obtain capital, to receive it on commercially viable terms. Further, rating agencies may decide to downgrade our credit ratings based on the emissions of the businesses operated by our subsidiaries or increased compliance costs which could make financing unattractive.”\(^8^2\)

Companies that are not seen as actively addressing environmental concerns, especially in regard to climate change, can risk losing their license to operate. In 2014, Boulder, Colorado successfully municipalized a previously investor-owned utility because the city claimed that the company was not doing enough to mitigate its climate-change impact.\(^8^3\) Other cities, such as Minneapolis and Santa Fe, have discussed similar measures. These are, of course, specific one-time examples, but because utilities are seen as providing an essential service, the potential of losing the license to operate is a serious risk for companies that do not adequately address their climate impact.\(^8^4\)

In some regulated markets, if new regulation causes the early retirement of an existing plant, investors may be able to recoup losses of the unrealized revenue from customers, as regulation requires investors to be compensated for previously approved projects that are not allowed to reach the end of their useful life. Investors in deregulated markets lack such protections.

Furthermore, many older generating facilities are fully depreciated and do not provide investors with a return on equity, because rates are based on the depreciation cost for the large investments required to build the power plants. Similarly, since regulated utilities earn a return on equity through the consumer rate base, the new investment required by the regulation will drive profit growth.\(^8^5\)

It is also important to note that, in regulated markets, company planning relating to this issue is ultimately beholden to the regulator approving the budget for proposed projects. However, companies that adopt long-term strategies in this area and that are able to effectively communicate these needs to their utilities commission will be in a superior long-term position to lower related risks for their shareholders.\(^8^6\)

As discussed in the regulatory section, above, companies are also taking into account the role energy efficiency measures can play in GHG reductions with integrated resource planning. End-user energy efficiency measures are discussed in greater detail in the End-Use Efficiency & Demand issue, but it should be noted that GHG reductions from demand-side efficiency can often be overall cheaper than GHG reductions on the supply side.\(^8^7\)

**Value Impact**

GHG emissions caps or other regulatory restrictions on emissions could pose a long-term threat and also create new opportunities for the industry. If companies are required to modify their facilities, such regulations could result in increased and potentially unanticipated capital and operating expenditures and permitting costs,
affecting cash flows. Delays in permitting can disrupt production or force companies to curb production, which would lower revenues. Furthermore, companies could also face fines if GHG emissions rules are violated, affecting one-time costs. They could also face impacts to their tangible assets if regulation makes some power plants uneconomical to continue running. This has the potential to affect unregulated power generators the most, as they will not be able to recoup any costs from their customers if their generation plant is not compliant with regulations or for the R&D expenditures needed to implement carbon-capture technology.

RPS mandates and regulations that favor low-GHG energy generation will bring increased market size and revenues for companies with a larger share of renewable energy generation in their portfolio.

Companies with high GHG emissions face potential credit ratings downgrades as well as an increased risk profile from current and future climate change regulations. Power generators providing energy inefficiently (related to GHG emissions) will likely see decreased demand and market share as customers move toward more emissions efficient options. These factors, coupled with a possible increase in long-term investors divesting from this industry or from carbon-intensive companies, will likely raise these companies’ cost of capital.

The global trend toward a low-carbon economy is bringing with it increasingly stringent GHG regulations in different regions to address climate change targets. The probability and magnitude of these impacts are, therefore, likely to increase in the future.

Disclosure of Scope 1 GHG emissions enables financial analysis of the current and future effects of GHG mitigation policies and pressures on profitability and cash flow. The metric also allows for comparative analysis of competitor performance and their respective exposure to GHG risks, allowing for investment preference and, ultimately, capital allocation. The percentage of emissions covered under regulatory programs can indicate what companies are at risk of significant financial impacts due to GHG emissions. Being able to analyze and compare a company’s progress toward RPS standards and the RPS-related regulations that a company operates in gives an analyst further insight into its strategy and performance on this issue.

Furthermore, discussion of a company’s strategy to manage Scope 1 emissions gives analysts a view into the company’s ability to address the operational and financial impacts associated with GHG emissions and could provide insight into a company’s strategy to improve its relative and absolute performance on the issue through specific strategic initiatives and investments.

**Air Quality**

In addition to GHGs, which have global climate impacts, fuel combustion in electricity-generation operations generates hazardous air pollutants (HAPs), criteria air pollutants (CAPs), and volatile organic compounds (VOCs). HAPs, CAPs, and VOCs have more localized, but nonetheless significant, human health and environmental impacts compared with those of GHGs.

These pollutants are regulated by the EPA under the CAA, as well as by state and local agencies, creating significant regulatory risks for electricity generators, mostly related to increased capital expenditures (which in some cases can be prohibitive to the continuation of a facility). Some of these regulations that affect company operations are the Cross-state Air Pollution Rule.
VOCs are a precursor to particulate matter (PM) that is 10 micrometers or less in diameter and ozone formation. PM$_{10}$ is associated with health effects such as premature mortality for adults and infants, heart attacks, and asthma attacks. PM$_{2.5}$ includes fine particles, which can cause even more chronic health conditions as their size allows them to lodge deeply within the lungs. In addition, ozone is associated with impacts on vegetation and the climate.

The EPA sets permissible levels for CAPs, such as sulfur dioxide (SO$_2$) and nitrogen oxides (NO$_x$), based on human health and/or environmental criteria. Human health impacts of air emissions and financial consequences for electric utility companies are likely to be exacerbated when facilities are located close to a community.

Active management of facility emissions through implementing industry best practices across operations can lower regulatory risks. A company’s power-generation mix will also have a substantial impact on its regulatory risk related to air emissions, as a higher use of renewable energy sources, such as wind or solar, will lower the company’s overall toxicity and regulatory exposure. Conversely, coal-fired plants generate relatively high levels of toxic emissions.

To reduce emissions of SO$_2$, coal plants generally have three options: using “clean coal,” or coal that is washed to remove some of the SO$_2$ before it is burned; “scrubbing” emissions before they are released into the atmosphere; or retiring older plants that have little to no scrubbing capability. Scrubbers (formally flue gas desulfurization scrubbers) trap the SO$_2$ particles before they are emitted. In 2011, 60 percent of U.S. coal power plants had scrubbers.

Companies can manage air quality concerns through both internal actions to reduce emissions and effectively working with regulators to establish priorities and comprehensively incorporate risks into short- and long-term capital planning. Company performance in this area can be analyzed in a cost-beneficial way through the following direct or indirect performance metrics (see Appendix III for metrics with their full detail):

- Air emissions of the following pollutants: NO$_x$ (excluding N$_2$O), SO$_2$, particulate matter (PM10), Pb, and Hg; percentage of each in or near areas of dense population.

Evidence

The Electric Utilities industry is a significant source of certain harmful air pollutants; as a result, it faces substantial regulatory risks. Air pollution data for all industrial processes from the EPA’s National Emissions Inventory show that in 2011 (the most recent data available), fuel combustion related to electric utilities released 12.6 percent of NO$_x$, 67.5 percent of SO$_2$, and 1.3 percent of PM.

Companies that actively manage this issue are likely to be viewed with less risk and more upside opportunity by investors. An Oxford University study found that, in 2015, non-GHG-emissions-based regulation forced the closing of roughly 16 percent of U.S. subcritical coal plant capacity.

Air emissions from coal plants have serious health risks, which regulations attempt to properly price. A 2011 study by the American Lung Association found that particle pollution from coal plants caused an estimated 13,000 deaths per year in the U.S. A 2011 study by the Harvard Center for Health and the Global Environment found that the health cost of coal emissions was $187.5 billion. Some industry participants estimate that EPA’s MATS ruling, an attempt to price these
externalities that limits mercury and other air emissions, will cost the industry $9.6 billion per year. Furthermore the EPA estimates that these rules would avoid 4,200 to 11,000 premature deaths, as well as other benefits that roll up to an estimated $90 billion public health benefit.

In its FY2014 Form 10-K, AES Corporation estimated the cost related to complying with the MATS rule at $511 million through 2016.97

DTE Energy’s two coal-fired plants in Wayne County, Michigan, are estimated to emit at least 85 percent of the SO₂ measured in the air in the area. Citizens and environmental groups have been arguing that the region’s abnormally high level of SO₂ is responsible for the high number of pediatric asthma cases (the highest in Michigan) and the high rate of asthma hospitalization (three to six times higher than the state average).98 Wayne Country, which includes Detroit, has a population of roughly 1.7 million.99

In 2013, the EPA found Wisconsin Power and Light, a subsidiary of Alliant Energy, to have violated segments of the CAA that regulate emissions of SO₂, NOₓ, and PM. To comply with the settlement, the company will have to reduce these emissions by roughly 54,000 tons per year from 2011 levels. The EPA estimates that this will cost Wisconsin Power and Light more than $1 billion.100

In its FY2014 Form 10-K, Alliant disclosed this about an ongoing case: “If we are unsuccessful defending or settling such litigation . . we could be subject to restrictions or prohibitions on operating our generation facilities, costly upgrades to our generating facilities, payment of damages or fines, requirements to complete other beneficial environmental projects, and litigation costs, all of which could be material. An adverse result in such legal actions could have a material adverse impact on our financial condition and results of operations. In addition, we may also be subject to third party environmental claims relating to property damage or personal injury that arise from our operations.”101

**Value Impact**

How companies manage air quality is likely to affect their cost structure. Harmful air emissions from operations may result in higher ongoing regulatory compliance costs, or one-off impacts on cash flows. These could come from regulatory penalties affecting extraordinary expenses, or from new capital expenditures to install best-in-class control technology. For a regulated utility, the last option could be a potential benefit for investors, as it would increase the amount of investment on which they could receive a return.

Companies may also face legal challenges from local populations or other businesses, resulting in one-time costs and increased contingent liabilities.

Denial of permits or delays in permit approval can have a significant impact on costs and profitability if these delays drive up projects costs and the utilities commission doesn’t allow the costs to be passed through.

As concerns about the health effects of air emissions grow and regulations become increasingly stringent, the probability and magnitude of impacts from this issue are likely to increase in the future.

Being able to compare companies’ emissions of NOₓ, SO₂, particulate matter, lead, and mercury indicates their relative exposure to related regulation. Furthermore, being able to compare the percentage near areas of dense populations, a driver of future regulation, gives insight into the potential for greater community and regulatory scrutiny.
Water Management

Many types of electricity generation require enormous amounts of water, mainly for cooling purposes. This industry is facing increasing water-related supply and regulatory risks. There is serious potential for stranded assets, meaning a risk that a subset of power plants won’t be able to operate at their full capacity, or at all, because of water constraints.

While water has typically been a freely available and abundant commodity in many parts of the world, it is becoming a scarce resource because of increasing consumption from population growth and rapid urbanization, as well as reduced supplies as a result of climate change. Furthermore, water pollution makes available water supplies unusable or expensive to treat. Based on recent trends, it is estimated that by 2025, important river basins in the U.S. will face severe water problems as demand overtakes renewable supplies. Many important river basins can already be considered “stressed.”

As national water supplies tighten and electricity generation, agriculture, and municipal use increasingly compete for those supplies in the coming decade, the availability of water is a key factor to consider when calculating the future value of a utility’s assets and evaluating existing proposals for new generation sources.

Thermoelectric plants have three main types of cooling systems. Once-through systems take in water, push the water through pipes to absorb heat, and then return to the higher-temperature water to its source. Closed-loop systems, as their name suggests, reuse the water taken in by cooling it through air exposure; this does cause some water loss through evaporation. Dry-cooling systems don’t use water, but instead use air, which can reduce the water consumption of a plant by over 90 percent; however, this system is more energy intensive. As of 2008, 43 percent of thermoelectric generation used once-through systems, 56 percent used closed systems, and only roughly 1 percent used dry-cooling systems, according to the Union of Concerned Scientists.

Large water withdrawals not only contribute to water stress but also can have biodiversity impacts. Fish, as well as fish eggs and larvae, are sucked up during the power-generation process; this is known as impingement. Aquatic life is also killed by the increased water heat and pressure of the discharged water, as well as by chemicals added to treat the water; this is called entrainment. A recent strengthening of the Clean Water Act Section 316(b) related to plants that withdraw more than 2 million gallons of water per day imposes stringent fish mortality standards and reporting requirements. The amendment can require considerable capital investment and raise costs significantly for the 544 plants affected.

Companies can invest in more efficient water-usage systems for existing plants and place strategic priority on assessing long-term water availability, as well as biodiversity risks when siting new power plants. Company performance in this area can be analyzed in a cost-beneficial way through the following direct or indirect performance metrics (see Appendix III for metrics with their full detail):

- (1) Total water withdrawn, and (2) total water consumed, percentage of each in regions with high or extremely high baseline water stress;
- Number of incidents of non-compliance with water quality and/or quantity permits, standards, and regulations; and
• Discussion of water management risks and description of strategies and practices to mitigate those risks.

Evidence

Electricity production is a highly water-intensive process. Out of 130 GICS\textsuperscript{v} sub-industries, independent power producers are ranked first and electric utilities are ranked 15th for water intensity per dollar of output.\textsuperscript{106}

Separately, MSCI research found that electric utilities are 11 times more water intensive than all other industries combined.\textsuperscript{107} Thermoelectric power production is the most water-intensive form of electricity generation, accounting for 41 percent of annual U.S. water withdrawals, although much of this water is returned, indicating that actual water consumption is a drastically lower percentage—thermoelectric power production accounts for roughly 3 percent of total water consumption.\textsuperscript{108}

Forty U.S. state water departments are predicting water shortages in their state in the next decade, which they attribute to the impacts of climate change and extreme weather events and, specifically, the effect of the energy sector on U.S. water usage patterns.\textsuperscript{109} Demand for water in the U.S. is expected to increase by 40 percent over the next 20 years.\textsuperscript{110} This may place electric utilities in conflict with other major users of water, mainly agricultural companies, and could strain water supplies needed for operations.

One out of four U.S. utilities has operations in water-stressed regions.\textsuperscript{111} These regions have $21 billion in electricity sales that are being put at risk. For regional utilities in drought-prone regions of the U.S., sales at risk could reach as high as 57 percent.\textsuperscript{112}

Besides thermoelectric power generation, nuclear power also relies heavily on water for cooling purposes; the Browns Ferry Nuclear Plant on the Tennessee River in Alabama was forced to reduce its generating capacity by between 40 and 60 percent for 45 days when a heat wave lowered the amount of usable water.\textsuperscript{113} This shows that even though much of the water used in this industry can be recycled and reused, the availability of such vast quantities of water can still be a significant operational barrier for companies.

To produce one MWh of electricity, nuclear plants need 3,100 liters of water. Coal- and natural-gas-powered plants also have high cooling-water requirements, at 2,800 and 2,300 liters of water, respectively, per MWh of electricity.\textsuperscript{114} In general, it is preferable to site coal, nuclear, natural gas, and oil power plants near water sources, which is becoming more difficult as a result of water shortages and subsequent competition for the remaining resources.\textsuperscript{115}

Shareholders are taking notice. Ameren shareholders submitted a resolution for the company to set goals to reduce water risks in 2014, which was withdrawn when the company agreed to address it.\textsuperscript{116}

American Electric Power, in its FY2014 Form 10-K, disclosed: “A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs
related to mitigating these physical and financial risks.”

Exelon, whose 619 MW Oyster Creek nuclear plant has used 1.4 billion gallons of water a day, stuck a deal with the state of New Jersey to shut down the plant 10 years before its operating license was set to expire rather than invest in the cooling towers required by regulation, stating the cost of the towers was greater than the plant’s value. This represents a significant loss of a baseload plant, likely driving up costs as energy sources with potentially higher marginal-use costs are used to replace the supply.

The impacts of power plants on aquatic life are quite significant. For example, the New Jersey Salem Nuclear Plant alone kills more than four times the amount of fish that fishermen kill each year, an estimated 1.1 million weakfish and 842 million bay anchovies.

The EPA has estimated the cost of compliance with the new power plant requirement under Section 316(b) of the Clean Water Act to be $384 million industry-wide. As costs will be operation-specific, it will take careful measurement by individual companies to estimate their compliance cost. FirstEnergy acknowledged this uncertainty and the resulting potential for significant capital expenditures in its FY2014 Form 10-K: “FirstEnergy is studying various control options and their costs and effectiveness, including pilot testing of reverse louvers in a portion of the Bay Shore power plant’s cooling water intake channel to divert fish away from the plant’s cooling water intake system depending on the results of such studies and any final action taken by the states based on those studies, the future costs of compliance with these standards may require material capital expenditures.”

Regulated utilities may be able to pass all or some of this cost increase on to their customers, depending on their PUC, but for deregulated power generators, this ruling will likely be costly.

**Value Impact**

Managing water consumption and discharge can influence operational risks faced by companies, with potentially acute impacts on value from disruptions to production. Water supply constraints—physical and/or regulatory—could force companies to curb or cease electricity generation, which would put revenues at risk. Lower usage of baseload plants, like nuclear plants, can increase company costs if they have to rely more on higher-marginal-cost peaking plants to make up for the lost energy. Generation assets could face write-downs because of water stress affecting the ability to operate. Higher water prices due to supply constraints can also directly affect operating costs of electric utilities companies, as well as potentially require increased capital expenditures to gain alternative water supplies. The possibility of frequent plant shutdowns or reduced capacity can raise a company’s risk profile.

Water discharges that are noncompliant with regulations and/or that cause significant biodiversity impacts can create risks of extraordinary expenditures, and the potential for increased capital expenditures to prevent future occurrences in the face of regulatory action or a negative public response.

The probability and magnitude of the impact of water management on financial results in this industry are likely to increase in the near term. This is a result of increasing water stress over time due to the impacts of climate change, among other factors, and the possibility of regulatory restrictions on water use or water-sourcing cost increases.
To understand the relative operational risks companies face, investors can compare data on the percentage of water consumed in water-stressed regions. Companies that strategically invest to lower their water usage and ensure proper investment for treatment of wastewater are less exposed to the related risks than companies that do not address these issues, particularly for operations in water stressed regions. A previous pattern of a relatively high number of incidents of non-compliance with water quality and/or quantity permits, standards, and regulations can indicate a higher risk of future regulatory scrutiny and related cost increases, in the absence of strong, long-lasting, corrective measures.

Coal Ash Management

Electricity generators must contend with the safe disposal of the hazardous byproducts of their operations. The source of waste that is likely to have the most significant effect on company value in the power generation segment is coal ash. It is worth noting that this issue will affect companies differently depending on the extent to which they generate electricity from coal.

According to the EPA, coal ash is one of the largest industrial waste streams in the U.S. It contains heavy metal contaminants that have been associated with a myriad of cancers and other serious diseases, especially when they leach into groundwater.\textsuperscript{122}

The Disposal of Coal Combustion Residuals from Electric Utilities Act requires liners for the ash ponds where utilities often store this waste, as well as monitoring of the nearby groundwater and geographical restrictions (e.g., no landfills can be built in earthquake zones).\textsuperscript{123}

Coal ash can also have beneficial uses when recycled or in some way reused. It is often used in the creation of fly ash concrete or wallboard. Forty percent of coal ash is currently used this way, and companies that can find markets for this waste can benefit from higher revenue.\textsuperscript{124}

Safe handling of coal ash, location of coal ash impoundments in areas where their potential to cause harm to human life or the environment is limited, strong monitoring and containment of coal ash, and sale for beneficial uses of coal ash are important strategies to reduce regulatory compliance costs as well as penalties for non-compliance. There can be significant litigation and/or remediation costs if the coal ash leaches into the surrounding environment.

Company performance in this area can be analyzed in a cost-beneficial way through the following direct or indirect performance metrics (see Appendix III for metrics with their full detail):

- Amount of coal combustion residuals (CCR) generated, percentage recycled; and
- Total number of coal combustion residual (CCR) impoundments and number by EPA hazard potential classification, broken down by EPA structural integrity assessment.

Evidence

In 2012, 110 million tons of coal ash were generated in 47 states and Puerto Rico.\textsuperscript{125} A 2009 EPA survey of coal ash impoundments found that roughly 7 percent were “High Hazard Potential Units,” which the EPA defines as “those where failure or mis-operation will probably cause loss of human life.”\textsuperscript{126} This is not to say that these were specifically unsafe themselves, just that their failure had the potential for significant damage.\textsuperscript{127}

In a separate 2014 study of all U.S. coal ash impoundments, EPA engineers found 152 of the
559 sites they surveyed to have a hazard-potential rating of “poor.” No site received the potential worst possible rating of “unsatisfactory” (other possible ratings were “fair” and “good”), and the EPA does note that a poor rating can also be due to a lack of information. However, the fact that 27 percent of all coal ash impoundments were rated in this low safety bracket indicates a potential for significant negative outcomes. Indeed, the improper disposal of this massive waste stream can have a significant impact on company profits. Duke Energy was fined $25.1 million by the State Department of Environment and Natural Resources of North Carolina because of findings that coal ash from its Sutton Plant in Wilmington had seeped into local groundwater. The company was not allowed to pass this cost on to its consumers, as it was found to be negligent. This example demonstrates how regulated utilities can generally recoup costs for unavoidable accidents involving hazardous waste, but not if they are found to have violated laws or to have been negligent. The resulting federal grand jury investigation resulted in a further $102 million fine, or about 14 cents a share, because a leaky storm pipe spilled an estimated 39,000 tons of coal ash into the Dan River in North Carolina. This represents $68.2 million in fines and restitution, and $34 million for community service and mitigation projects.

In addition to these civic cases, Duke Energy reported that the initial plugging of the leaking storm pipe cost $24 million. It estimates that it may take three decades and cost up to $10 billion before the cleanup is finished. Duke Energy has been the target of two shareholder lawsuits as a result of its handling of this incident. Related concerns caused the North Carolina legislature to look further into Duke Energy’s coal ash disposal strategies, and the investigation found 32 ash ponds in the state at risk of leaching contaminants into the groundwater.

In a similar incident in 2008, a Kingston, Tennessee facility owned by the Tennessee Valley Authority (TVA) had a failure that resulted in the spill of 5.4 million cubic yards of coal ash, which covered 300 acres of land. The resulting cleanup cost more than $1 billion. Furthermore, there was a related class-action lawsuit that was settled in 2014 for $27.8 million. The TVA is a federally owned utility, but this again highlights the potentially significant economic impact to improper coal ash management.

In response to these leaks, the Improving Coal Combustion Residuals Regulation Act of 2015 was finalized by the EPA to provide a federal requirement for the disposal of coal ash. Major industry associations, like the Edison Electric Institute, are generally supporters of the regulation of coal ash, but disagree with the ruling’s lack of enforcement from the EPA, which then sets the stage for self-enforcement and citizen suits. This new rule will cause nearly all coal ash containment efforts to have to retrofit or close. It sets up containment guidelines as well as strict reporting requirements to prevent leakage and significant failures from occurring. As mentioned before, these public records open up utilities to litigation risks from the public or from shareholders.

American Electric Power, in its 2014 annual report, reported a financial benefit from proper coal ash management: “Currently, approximately 40 percent of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses.”
Value Impact

Management of coal ash can create operational efficiencies for companies, with a potential to reduce costs on an ongoing basis. A company’s performance on this issue can have a chronic impact on value, given the ongoing operating expenditures related to handling waste and hazardous materials. Companies’ capital expenditures could increase as they strengthen their waste management infrastructure.

Improper hazardous waste disposal or loss of containment could also affect companies through one-time regulatory fines or lawsuits, leading to extraordinary expenses and contingent liabilities. Remediation efforts could result in significant operating and capital expenditures. Companies may be unable to recoup these expenditures through electricity price increases if they are found to be negligent. Poor performance on this issue could also cause significant reputational damage resulting in a decrease in intangible assets.

The effective sale of spent coal ash can also increase company revenues.

The amount, by weight, of coal ash produced and the number of impoundments (broken down by EPA structural integrity assessment) are a rough proxy for the risk companies face for a coal ash-related accident and therefore the risk of acute, high-magnitude impacts on value. The percent recycled shows the degree to which companies are entering this market to gain extra revenue from their coal ash.

SOCIAL CAPITAL

Social capital relates to the perceived role of business in society, or the expectation of business contribution to society in return for its license to operate. It addresses the management of relationships with key outside stakeholders, such as customers, local communities, the public, and the government.

The Electric Utility industry’s activities have significant impacts on local communities, and it is important for companies to manage the concerns of these stakeholders. Companies that perform poorly on addressing community concerns could be impacted by an erosion or a revoking of their social license to operate. This could take the form of denied or delayed regulatory permits.

Community Impacts of Project Siting

New transmission lines, new power generation plants, and the expansion of existing power plants all can have significant land requirements. Furthermore, while electricity is an essential service that people support in the abstract, many people do not want large-scale power generation happening close to their home or place of work, nor do they want transmission lines running through their land, which makes stakeholder engagement key to the land permitting process. Utilities must balance the interests of a wide array of stakeholders with the long-term needs of all their customers. It is worth noting again here that electric utilities have a social license to operate in regulated markets, maintaining their monopoly through efficiently providing a necessary public service. This means activities that reportedly negatively impact their customers can face high levels of scrutiny.

For example, people may be worried about the effect of air pollution on their health, fears of a nuclear accident may make them wary of living near a nuclear plant, wind turbines might cause noise pollution or block their view, or they may
find a transmission line through their yard aesthetically displeasing or worry that it could lower their property values. Furthermore, there are environmental concerns since utility projects can disrupt local wildlife habitats. RPS mandates and mandates to lower the cost per kWh and GHG emissions are creating incentives expected to drive the expansion of renewable energy resources, such as solar and wind energy. The expansion of these energy sources will require not only large tracts of land for power generation but also significant upgrades and expansions to the nation’s grid, especially its transmission lines, which need to be built to reach power plants that are sometimes in remote locations far from load centers. Solar and particularly wind resources are often abundant in remote places, requiring hundreds of miles of additional transmission lines (this creates an incentive for retrofitting coal plants to be natural gas plants; generally they can use the same transmission lines). This could be mitigated by an emphasis on and company support for distributed generation, which sites electricity generation at locations already connected to the grid.

Furthermore, power generators’ placement decisions and effective engagement with stakeholders in the surrounding area when building new plants or significantly retrofitting or expanding existing ones can have a significant impact on the amount of time required to bring a project to fruition. The better a company’s stakeholder engagement team can present the benefits of the project and address potential community concerns, the faster ground can be broken and the company can start earning revenue and prevent the cost overruns that delays can accrue.144

It is important to note that many renewable energy technologies emit negligible air pollutants, which can make communities more amenable to having them close to their homes than fossil-fuel-powered plants.145

Transmission siting is generally regulated at the state level, although FERC also has limited regulatory control. It can require the use of eminent domain, which allows utilities to take private property for public use. This can significantly speed up the land-acquisition process, as it removes the ability of landowners to prolong negotiations and forces them to sell their land. This obviously can cause some criticism if people feel that the process is being abused. The siting of transmission lines has generally been legally protected as a fair definition of a public use, which requires a state level “Certificate of Need” to prove its necessity. Utilities are then required to justly compensate landowners for the fair market value of their land.146

Both generation and transmission projects generally require an environmental impact survey for the project to be approved.147 Companies that anticipate potential issues and actively engage with stakeholders can expedite their approval process. Company performance in this area can be analyzed in a cost-beneficial way through the following direct or indirect performance metrics (see Appendix III for metrics with their full detail):

- Number of projects requiring environmental or social modification, percentage of modifications resulting from formal public interventions or protests; and
- Discussion of community engagement processes to identify and mitigate concerns regarding project environmental and community impacts.
Evidence

Different generation technologies have varying land-use requirements. Estimates of land use for some energy-generation types, measured in square meters per gigawatt-hour per year, are outlined in the chart below.148

<table>
<thead>
<tr>
<th>Energy Generation Type</th>
<th>Land Usage (in square meters per gigawatt-hour per year [m²/GWh/yr])</th>
</tr>
</thead>
<tbody>
<tr>
<td>Onshore Wind (assuming only the turbine footprint plus the needed access roads)</td>
<td>1,100</td>
</tr>
<tr>
<td>Nuclear</td>
<td>1,200</td>
</tr>
<tr>
<td>Coal (including strip mining sites)</td>
<td>5,700</td>
</tr>
<tr>
<td>Solar PV</td>
<td>7,500</td>
</tr>
<tr>
<td>Hydro (accounting for land for the reservoir)</td>
<td>200,000</td>
</tr>
</tbody>
</table>

The length of the approval process for large-scale energy generation and transmission projects can be difficult to predict, which increases the riskiness of investments in new projects. For example, for public land for utility-scale solar, the land-permit-approval process alone can take three to five years. This process requires public forums, a detailed proposal from the company that explains its entire construction plan and strategies to lower its environmental impact, and a full independent environmental impact statement (EIS). Approval can be expedited if the project is on previously disturbed land or brownfields (land that contains hazardous waste or pollutants).149

Massive amounts of new transmission line will need to be built to reach renewable energy generation plants. A 2011 NREL study estimates that between 17,000 and 22,000 miles of new transmission lines will be needed for just the eastern half of the U.S. to generate 20 percent of electricity from wind by 2030.150

Costs associated with acquiring land and assembling it into corridors can amount to 10 percent of transmission development costs—up to $400,000 per pole-mile.151 While these costs can, of course, often be recouped by regulated utilities, if companies go over their projected costs in this (or other) areas, their profits can be reduced.

In some instances, building new transmission lines requires the filing of at least one eminent domain claim, which is where utilities are, under certain circumstances, allowed to take property (compensating the owner) needed for public use.152 For example, American Electric Power said that of the 3,200 easements required for the 903 miles of transmission line that the company built in the spring of 2014, 41 of them required the use of eminent domain.153 Landowners often fight these cases, as the presence of power lines can lower property values.154 These legal battles can slow down projects, potentially cause lines to be rerouted, and generate significant legal fees.

In Mansfield, Georgia, for example, Georgia Transmission Corporation claims that community resistance to its new transmission line will cost the company $600,000 to temporarily reroute the power line and an additional $300,000 in financing costs for the delay.155 Failure to engage with communities either to find compromises or to gain knowledge of potential community resistance can result in significant unanticipated costs for companies.

An Eversource transmission project called the Northern Pass, which was proposed in 2010, has faced significant delays because of environmental concerns and potential effects on property values. In its 2015 third-quarter conference call, it stated:
“The DOE is currently preparing a supplement to the Draft EIS to reflect the changes we announced on August 18, and has indicated that it will complete that supplement this month . . . As we announced in mid-October, we expect the project to cost approximately $1.6 billion, somewhat higher than our $1.4 billion price tag we noted previously. This is due largely to the additional excavation cost associated with the incremental undergrounding.”

This undergrounding is largely in response to critics who believe that the utility towers needed for aboveground transmission lines would reduce property values and impact the natural beauty of the area.

The 2005 Supreme Court case of Kelo vs. The City of New London allowed the city to grant eminent domain for the purpose of economic development (a wider definition of public good than, say, expanding a road), which has worried some communities. This mistrust and fear among stakeholders can make it politically popular to ban the use of eminent domain by private companies. For example, in March 2012 the governor of New Hampshire signed a law banning private power-line companies from using eminent domain for projects, as was planned for the previously mentioned Northern Pass project, which certainly aided in slowing the project.

Value Impact

Land use and community relations issues can be a source of both value and risk for Electric Utilities. Failure to adequately engage with communities can result in permitting delays that can cause unexpected increases in capital expenditures and/or increases in project-related operating expenses. Project delays also negatively affect the timing of when revenue generation can begin. Uncertainty about the approval of land-use or environmental permits can raise the risk profile of a project. A thorough stakeholder engagement process with landowners and local communities is necessary to ensure projects are completed at or under cost. Furthermore, significant negative community response can cause reputational damage for companies, lowering the value of their intangible assets.

Depending on the regulatory environment, cost overruns from permitting-related delays may not be recoverable from the rate base. Loss of eminent domain rights or uncertainty about the approval of land-use permits can raise the risk profile of a company and, subsequently, its capital costs.

If an analyst sees that a company is having to modify a significant number of its projects, especially due to formal public interventions or protests, they may adjust projections that take into account the estimated cost of projects looking forward. Furthermore, a greater understanding of a company’s specific stakeholder engagement strategy to ensure and communicate a favorable benefit-cost ratio moving forward can help analysts adjust their valuations of future projects, including assumptions about costs and about timing of revenue generation.

HUMAN CAPITAL

Human capital addresses the management of a company’s human resources (employees and individual contractors), as a key asset to delivering long-term value. It includes factors that affect the productivity of employees, such as employee engagement, diversity, and incentives and compensation, as well as the attraction and retention of employees in highly competitive or constrained markets for specific talent, skills, or education. It also addresses the management of labor relations in industries that rely on economies
of scale and compete on the price of products and services. Lastly, it includes the management of the health and safety of employees and the ability to create a safety culture within companies that operate in dangerous working environments.

Routine electric utility operations can expose workers to health and safety risks, and result in financial impacts for companies. Maintaining a healthy and productive workforce can improve labor productivity. It can also lower direct medical expenses or regulatory penalties. A company’s ability to protect employee health and safety, and to create a culture of safety at all levels of the organization, can therefore directly influence the results of its operations.

Workforce Health & Safety

Employees of electric utilities face numerous hazards in the construction and maintenance of electric distribution and transmission lines, as well as with the various means of electricity generation. Many of these employees work for extended periods at great heights and face electrocution risks.

In recent years the industry as a whole has had relatively few injuries and deaths, compared with the national average, despite its aforementioned dangers. Companies need to maintain a culture of safety to ensure good working conditions for their employees, ensure strong operational productivity, and manage potential risks of regulatory penalties.

Company performance in this area can be analyzed in a cost-beneficial way through the following direct or indirect performance metrics (see Appendix III for metrics with their full detail):

- (1) Total recordable injury rate (TRIR), (2) fatality rate, and (3) near-miss frequency rate (NMFR).

Evidence

The nature of the electric utilities industry, as both a societally granted monopoly and a necessary part of modern life, means that its actions receive significant public and regulatory scrutiny. Line workers, of which there were nearly a quarter million in 2014, is one of the top 10 most dangerous professions in the U.S., given the risks of falls and electrical burns.

Companies in this industry have made tremendous strides in worker health and safety over the past few decades; an Electrical Safety Foundation International study found that between 1992 and 2010, fatal injuries have declined by more than 50 percent and nonfatal injuries declined by more than 60 percent. Both these rates are higher than the economy-wide average over this same time period, where fatal injuries declined by 28 percent and nonfatal injuries declined by 57.3 percent. In 2014, the Electric Utilities industry had a nonfatal industry rate of 2.1 per 100 equivalent full time workers; the average for employees across all industries was 3.2 in the same year. However, none of this lessens the importance of maintaining a culture of safety for the industry.

The broader financial implications of safety performance are well established. According to the National Safety Council, each lost-time injury or illness costs a company an average of $37,000, while each fatality costs $1.4 million. Furthermore, in a survey of CFOs conducted by Liberty Mutual Insurance, 60 percent of respondents reported that one dollar of investment in injury prevention returned two dollars or more in savings, and more than 40
percent said that productivity is the chief benefit of strong workplace safety programs.52

Companies often prominently discuss safety during shareholder calls, reinforcing its importance to companies and investors. For example, CMS Energy president and CEO John G. Russell stated in the company’s fourth-quarter 2015 earnings call that it was a “record-setting year.” He noted, “I’m most proud of our safety result, the best in our company’s 130-year history . . . Since 2006, the company has achieved breakthrough performance. Safety incidents are down 79 percent. Productivity is up 62%. Outage minutes are down 34 percent, and employee engagement is first quartile. I’m confident this performance will continue to drive the results you have been accustomed to. These areas will continue to improve, and we look to other initiatives to improve service and reduce costs . . . For 2016, we plan to continue our breakthrough performance. Operationally, we will continue to make safety a top priority for our employees, customers and the communities we serve.” 164 CMS clearly draws a relationship between operational safety and operational efficiency.

While the majority of companies in this industry do not publically disclose their safety data, the industry, through the Edison Electric Institute, completes an internal safety survey. Companies often take about their safety performance in relation to these industry averages, aiming frequently for upper-quartile or upper-decile performance. For example, AES Corporation, in its 2014 CSR report, disclosed, “Our target for LTI [lost time injuries] rates was set to be below the U.S. utility industry top 25 percent benchmark LTI rates. Our businesses have been below this benchmark for the last several years. During 2014, AES’ businesses achieved their lowest LTI rates for AES people, operational contractors and construction contractors—our businesses’ aggregate LTI rate went down 21 percent for AES people, 33 percent for operational contractors and 45 percent for construction contractors compared to 2013.” 165

Safety is significant enough to the operations of electric utilities that some companies explicitly tie employee compensation to performance on the issue. For example, in 2015, PG&E tied 50 percent of managers’ performance-based pay to safety performance; this is an increase from 40 percent in 2014.166

Non-compliance with Occupational Safety and Health Administration (OSHA) standards can result in regulatory penalties for companies, as well as additional operating costs to achieve compliance. These are generally not costs that can be passed on to customers and instead directly lower shareholder returns. For example, in 2015, PG&E agreed to pay $5.5 million for a 2012 demolition death in Los Angeles, where the California PUC determined that the utility failed to properly ensure the safety of the site.167 Often, safety fines are an order of magnitude smaller, for example, a Duke Energy employee was electrocuted in 2014, resulting in OSHA finding five safety violations and recommending penalties of $90,000.168 However, repeated violations of this nature could also directly harm a company’s margins and operational performance, as well as increase its compliance costs and over time make retaining and recruiting employees difficult. To avoid these issues, companies need to be vigilant in creating a culture that rewards strictly following safety protocols.

**Value Impact**

A strong safety culture and record is key for workplace productivity and operational efficiency, and directly affects operating costs. Furthermore, injuries or fatalities can result in one-time costs,
including regulatory penalties, and legal costs from personal injury litigation. Companies may face contingent liabilities as a result of lawsuits. A poor safety record can also create significant negative publicity for a company, negatively affecting its intangible assets and making it more difficult to attract employees.

The total recordable injury rate, fatality rate, and near miss frequency rate are all indicative of a company’s safety environment and culture, and the likelihood that it will face costs associated with accidents or fatalities. Past incidents also provide an understanding of the magnitude of possible future incidents, assuming no change in the company’s safety initiatives.

**BUSINESS MODEL AND INNOVATION**

This dimension of sustainability is concerned with the impact of environmental and social factors on innovation and business models. It addresses the integration of environmental and social factors in the value-creation process of companies, including resource efficiency and other innovation in the production process. It also includes product innovation and efficiency and responsibility in the design, use-phase, and disposal of products. It includes management of environmental and social impacts on tangible and financial assets—either a company’s own or those it manages as the fiduciary for others.

The trend of utilities commissions in some regions to prize energy efficiency over new infrastructure builds will benefit companies that are able to work with new technologies, and with their customers, to reduce overall electricity use. These strategies for reduced grid usage can not only provide for new investment opportunities but also lower operational cost.

**End-Use Efficiency & Demand**

Regulators are focusing on two different methods of mitigating GHG emissions: reducing emissions associated with power generation (as discussed in Greenhouse Gas Emissions & Energy Resource Planning disclosure topic) and reducing the energy demand of end-users. This disclosure topic directly relates to the latter category.

Energy efficiency is a low-cost method to reduce GHG emissions, as less electricity needs to be generated to provide the same end-use energy services. Additionally, electric utility customers are often interested in energy efficiency for potential economic savings as well as reducing their environmental impact. The structure in which companies in the Electric Utilities industry are positioned to economically benefit or suffer in an environment with increasing societal needs around GHG emissions mitigation is a critical issue.

Utilities can partake in a wide range of activities to promote energy efficiency among their customers, while potentially financially benefiting themselves. Such activities may include proposing rate structures that incentivize efficient consumption while rewarding companies for increasing end-use efficiency, offering rebates for energy efficient appliances, weatherizing homes, educating consumers on energy-saving methods, and investing in technology that allows customers to track their energy usage, among many other strategies. ¹⁶⁹

As mentioned in the “Legislative and Regulatory Trends” section, some utilities, regulators, and states are pursuing alternative ratemaking that promotes efficiency or at least remove utilities’
potential disincentives to promote efficiency.\textsuperscript{vi} Examples of other alternative rate designs (or components of rate designs) include cost trackers, rate and revenue caps, formula rate plans, and forward test years.\textsuperscript{170} While the specifics of such rate structures and programs vary widely by state and utility, “decoupling” measures generally remove the disincentive for utilities to work with their customers on efficiency efforts, through delinking utility revenues from their customers’ consumption. The resulting rate structure indicates that utilities can proceed with encouraging end-customer efficiency (or at the very least, not discouraging efficiency), without jeopardizing revenues—and potentially even growing revenues from reduced customer consumption through a variety of other related programs such as performance incentives. Overall, such rate structures designed to promote efficiency are generally seen as reducing the risk profile of utilities, while potentially providing financial incentives for effectively promoting end-use efficiency.

Rate structures are further complicated by industry-specific dynamics such as variable energy demand, dynamic pricing, new capital projects, and distributed generation. To the extent that electric utilities can influence a smoother electricity demand curve, operating costs may be able to be mitigated. Electric utilities can significantly decrease their costs if they are able to decrease their reliance on peaking plants. These plants (often natural gas– or petroleum-based) operate at a much higher variable cost than base-load plants (which are generally coal, nuclear, or hydro plants and that run nearly constantly) and are started and stopped to meet spikes in customer demand.\textsuperscript{171} Electric utilities, in general, often prefer to have a steady electricity demand to avoid the use of these more expensive forms of electricity generation. However, this is not possible in the current system, because energy use is correlated to natural factors such as economic activity and weather patterns.

Investment in smart-metering technology, which generally allows for an accurate and relatively continuous reading of individual energy use, gives better data to both companies and consumers. Rate structures and regulatory frameworks that allow for the incorporation of pricing models made possible by smart metering (i.e., dynamic pricing) can aid in the implementation of energy-efficiency programs, such as demand-response programs. These programs generally allow companies to offer incentives to their customers to curb electricity use during times of peak demand, smoothing out some of the natural demand. As a result, such programs and rate mechanisms have been found to increase transmission efficiency, along with reducing energy generation costs.

End-use energy efficiency and rate structures both affect the approval of new capital projects by regulators pursuant to adding such investments to the rate base. Depending on the sentiment of the utilities commission in a company’s region, energy efficiency can be a regulatory priority before new builds are considered.\textsuperscript{172} This incentivizes companies to ask for necessary investments for efficiency efforts and implement these efforts to lower their operating costs as much as possible before asking for larger infrastructure upgrades.

\textsuperscript{vi} Several other substantial drivers of alternative ratemaking exist beyond public policy objectives related to energy efficiency or aggregate energy consumption. Examples include rising costs, regulatory lag, and other capital requirements that may be insufficiently addressed by traditional ratemaking. The Edison Institute provides an overview of such issues and potential remedies in “New Regulatory Frameworks for Electric Infrastructure Investment” and “Alternative Regulation for Evolving Utility Challenges: An Updated Survey.”
As a result, the various impacts of end-use energy efficiency and demand on electric utilities— including voluntary programs, regulatory schemes, and pricing mechanisms—result in a complex issue for companies in the industry. Overall, companies whose strategic plan strives to reduce their downside risks from demand fluctuations, gain adequate and timely returns on needed efficiency investments, and lower costs through these investments and differing manners of customer engagement will be best positioned to earn stronger risk-adjusted returns over the long term.

As mentioned above, distributed generation, such as rooftop solar, is another complex facet related to end-use energy demand and rate structures. Utility policies and rate structures that address the integration of distributed generation into the grid, as well as policies relating to owners of distributed generation receiving some form of compensation or credit for electricity provided to the grid, are complex and potentially polarizing. Net metering, for example, in which distributed generation sent to the grid generally provides the owner with credit at retail electricity rates, has propelled the expansion of GHG-emissions-free solar-energy generation in line with general public policy objectives; yet it may also be viewed as a policy that is not economically fair to grid owners and operators as a result of the reliance on the grid. While utilities, capital providers, regulators, end-users, and other stakeholders actively seek rate structures that are fair and reasonable to all parties, as well as that comply with the fundamental principles of ratemaking objectives, long-term societal needs around energy efficiency and GHG-emissions mitigation will impact utilities and their investors through rate structures.^

Company performance in this area can be analyzed in a cost-beneficial way through the following direct or indirect performance metrics (see Appendix III for metrics with their full detail):

- Percentage of electric load served by smart-grid technology; and
- Customer electricity savings from efficiency measures by market.

**Evidence**

The Electric Utilities industry has invested considerable amounts of effort and resources into energy efficiency. In 2012, 124.6 billion kWh of electricity was saved through the industry’s energy efficiency programs. Such programs can provide economic benefits to utilities through a variety of channels. This is especially true if rate structures or other regulatory programs allow “earnings opportunities to include performance based incentives tied to benefits delivered to their customers by cost-effective initiatives to improve energy efficiency, integrate clean energy generation, and improve grids,” as recommended in a joint statement from the Edison Electric Institute (EEI) and the National Resources Defense Council (NRDC). Additionally, companies in the industry can benefit from energy efficiency by potentially lowering operational costs and expanding the rate base through energy-efficiency-enabling infrastructure investments such as smart-grid technology.

Generally, energy efficiency is often the most economical choice for ratepayers as well; research from the American Council for an Energy-Efficient Economy (ACEEE) shows the LCOE of energy efficiency ranges from 2 to 5 cents per kWh (with an average of 2.8 cents per kWh); this is lower

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^VI This issue is discussed in more detail in the issue Management of the Legal and Regulatory Environment.
than the LCOE of building any other type of energy generation by one-third to one-half.175

American Electric Power, in its FY2014 Form 10-K, disclosed that between 2008 and 2014, its energy efficiency programs “have reduced annual consumption by more than 5.2 million MWh and peak demand by more than 1,500 MW. To achieve these levels, AEP operating companies invested approximately $700 million during the same period.”176 It does not provide estimates on cost savings; however, one can infer this resulted in significant cost savings as, for example, peak energy costs for utilities can be an order of magnitude higher than costs for generation under normal demand.177 The company goes on to note that working with its utilities commission to ensure appropriate cost-recovery mechanism are in place is essential to its success and that it plans to work closely with regulators on this issue.178

Conversely, if utilities do not focus on end-use energy efficiency prior to seeking rate base expansions predicated on new power generation or other infrastructure projects, then utilities and their investors may face significant risks related to under-recovery (i.e., regulators failing to add the entirety of a capital project to the rate base when appropriate). In New York, rapid population growth in Brooklyn and Queens (whose combined population rose by 3.2 percent from April 2010 to July 2013 alone) is causing stress on Con Edison’s grid. Regulators indicated that they would likely not accept Con Edison’s initial proposal to build a new $1.1 billion substation to handle the increased electricity demand because it would represent a significant expense for consumers that regulators felt was avoidable. Con Edison now plans to defer the project from its initial 2019 target to 2024, saving customers an estimated $400 million to $500 million. Instead, Con Edison is meeting with customers to help identify methods for them to reduce their energy use.179

If a utility will not be granted its infrastructure upgrade, effective energy-efficiency programs can provide a better return for investors. This incentive alignment allows for customer savings, which are looked on favorably by utilities commissions, as well as higher investor returns from new recoupable investment opportunities and a lower GHG profile for utilities, which, in regulated regions, need to generate less electricity.180

A study by the Electric Power Research Institute found that the addition of smart-grid technology will require an investment of $3.7 billion between 2012 and 2030.181 The practicality and political popularity of this investment will help utilities continue to have a significant capital base approved by their utilities commission, increasing investor returns.182

Furthermore, a U.S. Department of Energy study that ran smart-grid-related strategy pilot programs in a few cities found that significant savings were realized by the related utilities. For example, in the city of Glendale, population 38,000, smart metering, alongside customer education, was able to reduce peak electricity consumption by 4.1 percent, even without offering the affected customers a price incentive to do so.183

Demand-response programs have been found to increase transmission efficiency, as higher current density results in greater electric losses. If, for example, demand-response programs reduce demand in a distribution line enough to reduce the current from 17 amps to 15 amps during peak times, electricity losses could be reduced by more than 20 percent. Furthermore, this reduced usage can extend the lifetime of distribution lines by around 10 percent. While highly dependent on the specifics of a line, demand-response programs
can also reduce operating and maintenance costs and reduce transformer overloads.\textsuperscript{184}

An Advanced Energy Economy study that projected the effects of a peak-demand decrease of 0.25 percent per year over 10 years—the “medium scenario” in Illinois—showed a $2.2 billion reduction in costs due to avoided capacity costs, lower transmission and distribution costs, and lower overall energy costs; the price of the program was only a little more than $800 million, showing, in this projection, a significant long-term benefit to utilities that aggressively pursue related strategies.\textsuperscript{185}

Roughly half the states also have performance incentives for energy efficiency. In addition to decoupling investment (plus the allowed rate of return) from energy efficiency, states have different methods to incentivize results. Analysis by ACEEE shows that these generally fall into three buckets: performance-target incentives (bonuses based on hitting certain targets), shared savings (utilities getting a percentage of the net savings), and rate of return incentives (increased return on equity [ROE]). For an example of the latter, in Nevada, the base ROE is 10.25 percent, but successful energy efficiency programs could warrant a 15.25 percent ROE.\textsuperscript{186} While the amounts vary by regulatory environment, they can be significant; PG&E reported that it was awarded roughly $60 million for its energy efficiency efforts between 2012 and 2014.\textsuperscript{187} Furthermore, eight states have monetary penalties for failing to meet state energy efficiency standards; these vary by state and the size of utility. For example, a large utility in Illinois could be penalized $665,000.\textsuperscript{188}

In their joint statement, the EEI and NRDC further recognized the gains being made in clean energy and energy efficiency as well as “the vital need for regulatory policies that will support fair and adequate cost recovery for maintaining the evolving grid.” The statement encouraged state utility regulators to view electricity rate structures in the context of the utility business “meeting customers’ energy service needs,” as opposed to a “commodity business dependent on growth in electricity use to keep its owners financially whole.”\textsuperscript{189} Overall, the joint statement provides evidence for the critical importance of the form that utility rate structures take in terms of implications for utilities’ financial performance as well as societal objectives around energy efficiency and GHG emissions mitigation.

**Value Impact**

Companies that perform well on end-use efficiency and demand reductions through specific investments and working with regulators to align financial incentives may be better positioned over the long-term to outperform on risk-adjusted returns. Working with regulators in this regard to continue the growth of potentially favorable alternative rate designs, such as decoupling, and other programs designed to promote end-use efficiency and demand reductions, may increase the stability of long-term revenues, provide additional revenue opportunities, and drive down the cost of capital as a result of risk reductions. In some areas companies may also be able to gain a higher return on equity from efficiency investments. Spending on efficiency programs can increase companies’ capital expenditures and as well potentially increase operating expenditures to provide customers to efficiency incentives.

Given the current political climate, it is likely that energy sector regulations will increasingly emphasize energy efficiency, increasing the probability and magnitude of this issue in the future.
Customer electricity savings from efficiency measures shows, by market, a company’s ability to successfully employ efficiency strategies. As discussed above, achieving such savings can affect financial value in different, potentially significant, ways. The magnitude and type of financial impact, both positive and negative, depends directly upon the regulatory environment in the market in which the company operates; therefore, electricity savings by market may differ significantly. Comparing energy savings over time could indicate changes in a company’s efficiency investments, the technical potential to achieve further efficiency, or changes in the regulatory environment that could provide higher or lower incentives for efficiency. The percent of electric load served by smart-grid technology gives (among other benefits) insight into a company’s investment in a technology that allows for greater efficiency and communication with customers, potentially lowering company.

LEADERSHIP AND GOVERNANCE

As applied to sustainability, governance involves the management of issues that are inherent to the business model or common practice in the industry and are in potential conflict with the interest of broader stakeholder groups (government, community, customers, and employees). They therefore create a potential liability, or worse, a limitation or removal of license to operate. This includes regulatory compliance, lobbying, and political contributions. It also includes risk management, safety management, supply chain and resource management, conflict of interest, anti-competitive behavior, and corruption and bribery.

The rise of distributed generation due to developments in renewable energy technologies, as well as the increasing national emphasis on a transition to a low-carbon economy, has the potential to significantly change the traditional utility business model. The ways companies work with their regulators to ensure that they are compensated fairly for work maintaining the grid without pushing their customers to leave the grid altogether will be a careful balancing act vital to their revenue growth. Companies also need to demonstrate that they have appropriate relationships with their utilities commission to assuage investor fears about the potential for corruption.

Furthermore, companies that proactively work to strengthen their grid against physical and cybersecurity threats stand to both lower their risks of related liabilities and provide a way to generate higher returns for their investors through new investment.

Nuclear Safety & Emergency Management

Nuclear power plants are generally owned by investor owned utilities, and sometimes jointly owned by multiple utilities. Nuclear incidents, while exceedingly rare, can have significant human and environmental consequences. Following past nuclear incidents policymakers have typically reacted by strengthening safety regulations and/or curtailing licenses for nuclear plant operations, as well as forcing nuclear plants to be shut down. However, owners of nuclear power plants in the U.S. have operated for decades without a public safety incident. They carry private insurance and would have significantly limited liability from the Price-Anderson Act if an incident were to occur. However, owners of nuclear energy generation still face related risk as, even if the probability is small, the outcome of a nuclear accident would be disastrous. The Three Mile Island accident in
1979 was the most significant nuclear accident in U.S. commercial power plant history. While the relatively minor radioactive release caused little health-related damages, the incident catalyzed a significant strengthening of regulation by the NRC, significantly increased compliance costs, and generally heightened the industry’s emphasis on safety.¹⁹¹

Utilities could face a loss of their license to operate, either entirely or in the operation of nuclear plants, if an incident were to occur. The latter would hurt a company’s competitive position and make it more difficult to meet GHG emission standards; nationally, meeting proposed carbon reduction goals would be difficult without nuclear energy.

The NRC oversees the operations of nuclear facilities. Ongoing vigilance related to nuclear safety and emergency management is enforced by the NRC’s strict safety rules. Failure to comply with NRC rules can be exceedingly expensive to nuclear power operators; in extreme circumstances it can make the continued operation of the plant uneconomical.

As a result of significant financial repercussions from ongoing safety compliance as well as the materialization of tail-risk incidents, utilities that own or operate nuclear plants need to be vigilant in the safety upgrades of their facilities. They also need to maintain robust emergency preparedness training for their staff. The industry has a safety-related self-regulatory body, the Institute of Nuclear Power Operations, which promotes and measures the industry’s best practices.¹⁹² Company performance in this area can be analyzed in a cost-beneficial way through the following direct or indirect performance metrics (see Appendix III for metrics with their full detail):

- Total number of nuclear power units, broken down by NRC Action Matrix Column; and
- Discussion of efforts to manage nuclear safety and emergency preparedness.

Evidence

Compliance with the NRC Reactor Oversight Process (ROP) is integral to the continued operation of nuclear energy facilities. Within the ROP, there is an Action Matrix, where the NRC aggregates information from its inspections to place plants in five categories of compliance, (level one being fully compliant with the law). As of February 16, 2016, all but 10 of the 100 operational nuclear power plants in the U.S. were in the highest performance category, seven plants were level two, meaning they were in need of regulatory response, and three plants were level four, meaning they had multiple violations of the NRC framework.¹⁹³

While it is relatively easy for a nuclear power plant to move from level two back to level one, it can cost more than $100 million to return a reactor from level four to level one.¹⁹⁴ In addition to the cost of returning a reactor to compliance, violations themselves can be extremely expensive; civil penalties are allowed to be up to $140,000 per day per violation.¹⁹⁵ However, this is not as costly as a more serious event could be. For example, the 2011 Fukushima nuclear power plant disaster caused the evacuation of 300,000 people (with many people still unable to return), as well as significant contamination of farmland and water supplies. In just the FY that the Fukushima event occurred, Tokyo Electric Power booked a $15.4 billion loss.¹⁹⁶ Incidents of this magnitude can also have a significant effect industry-wide; Germany, within days of the incident, immediately closed half its nuclear plants.
and then began working on plans to phase out the rest. 197

The decision to close a facility as large as a nuclear plant is the result of a mix of factors, but receiving a level-four safety rating (bringing with it a significant increase in compliance costs) was a key factor in the decision to close the Pilgrim Nuclear Power Station in Massachusetts. The plant is scheduled now to close by 2019, but was meant to be operational until 2032. This represents significant lost future revenue. The Pilgrim plant currently provides around 10 percent of the power in Massachusetts. 198

Southern Company noted the importance of NRC compliance and the potential outcomes if regulations are not followed in its FY2014 10-K: “In the event of non-compliance with NRC licensing and safety-related requirements, the NRC has the authority to impose fines and/or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants.” 199

Value Impact

Continued compliance with the NRC framework is paramount to the continued operations of nuclear power plants. Failure to comply with these standards can result in higher operational costs, an increase in capital expenditures to ensure safety compliance and best practices, and potentially significant impaired assets and loss of future revenue streams if nuclear plants are deemed unusable before the expected end of their life because of safety concerns. Furthermore, a significant safety incident could not only cause significant asset impairment and result in large one-time costs; it could result in the company losing its entire license to operate nuclear power plants.

A company’s nuclear power plant holdings, broken down by their positioning with respect to the NRC action matrix, can indicate adjustments that might need to be made to the risk premium or predicted operating and capital expenditures of the company. Changes in the action matrix placement over time could indicate improved or worsening performance related to nuclear safety. This disclosure, supplemented with a discussion of the company’s efforts to manage nuclear safety and emergency preparedness, can indicate the strength of the company’s safety culture and ability to mitigate financial repercussions related to nuclear safety and tail risk incidents.

Grid Resiliency

Electric Utilities own or operate critical infrastructure that supports modern society. Systemic or economy-wide disruptions may be created if the infrastructure of electric utilities is not prepared to handle major disruptions. Disruptions can be caused by cyber-attacks, extreme weather events, and natural disasters.

The increased use of smart-grid technology—though it has many benefits, as highlighted previously—makes the grid more vulnerable to cyber-attacks, as it provides hackers more entryways into infrastructure systems. Agents in foreign governments are already known to have infiltrated the grid cyber security, causing concern and heightened scrutiny from the highest levels of the U.S. government.

As the frequency and severity of extreme weather events associated with climate change continues to increase, all segments of electric utilities
companies, and especially those with major T&D operations, will face increasing physical threats to grid infrastructure. Furthermore, increasing temperatures decreases the efficiency of many forms of power generation as well as increase the line losses of transmission and distribution lines.201

Hurricane Sandy, a major hurricane that struck the U.S. East Coast in 2012, is estimated to have caused between $27 billion and $52 billion in total economic damage and brought to the forefront the vulnerability of the electric grid.201 This has created increasingly urgent demands from a wide group of stakeholders for “infrastructure hardening,” providing public support for funding such upgrades. The increasing frequency of storms may put companies at significant financial risk. For companies with assets that have fully depreciated, stakeholder interest in this issue could also be a significant opportunity, as it makes the case for new infrastructure investments.

As electric utility companies expand their grid infrastructure and adopt new technologies, they need to ensure the reliability and resilience of such systems to avoid disruption of key services.202 System upgrades include not only sturdier, more storm-resistant infrastructure but also the addition of smart grids, which can help a utility’s repair crews pinpoint the exact location of outages in the aftermath of a storm, cutting down on repair costs and lost revenue from disconnected service.203

These service disruptions have potentially high societal costs, as electricity is critical for the continued function of most elements of modern life, from medicine to finance, creating a high societal expectation of continuous service. Companies can protect shareholder value by implementing internal strategies that minimize the probability and magnitude of systemic impacts from extreme weather events and cyber-attacks and by actively submitting compelling rate cases to improve the reliability, resilience, and quality of their infrastructure and services. Company performance in this area can be analyzed in a cost-beneficial way through the following direct or indirect performance metrics (see Appendix III for metrics with their full detail):

- Number of incidents of non-compliance with North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection standards; and
- (1) System Average Interruption Duration Index (SAIDI), (2) System Average Interruption Frequency Index (SAIFI), and (3) Customer Average Interruption Duration Index (CAIDI), inclusive of major event days.

Evidence

The cybersecurity of electric utilities is known to be vulnerable to access by agents of foreign governments.204 This has been identified as a key risk for the U.S. and it is the focus of a presidential initiative.205 While the total economic fallout from an attack is difficult to calculate, in 2003 a blackout in Ohio that was unrelated to a cyber-attack left 50 million people without power for up to four days and is estimated to have cost $10 billion. Some security experts believe a successful cyber-attack on the grid infrastructure could cause blackouts that could last for months.206 Cyber-attacks are not infrequent—some utilities even report daily attempts to breach their systems.207 The political nature of this threat makes it more likely that rate cases seeking to specifically address infrastructure strengthening will be approved, which can be a potential source for shareholder returns. The first known power outage caused by a cyber-attack occurred in
February 2016, in Ukraine, heightening fears of similar events.  

A recent survey found that cybersecurity was one of the top five concerns for U.S. electric utilities; however, only a third of respondents felt confident that they had the proper internal controls and monitoring systems.  

Southern Company acknowledged this risk in its FY2014 Form 10-K, stating, “Cyber-attacks, both threatened and actual, could impact the ability of the traditional operating companies and Southern Power to operate and could adversely affect financial results and liquidity.”  

A report from the President’s Council of Economic Advisers and the U.S. Department of Energy found that severe weather is the leading cause of power outages in the U.S., with 679 outages between 2003 and 2012. These cost the U.S. economy, on average, between $18 billion and $33 billion per year. Furthermore, the report cites EIA data showing that the instances of these economically destructive storms had increased significantly since 1992. The potential for losses is exacerbated by the fact that 70 percent of transmission lines and power transformers are more than 25 years old and the average power plant is more than 30 years old, making them more susceptible to storm damages. 

AES Corporation, in its FY2014 Form 10-K, acknowledged the added costs and increased operational risk from extreme weather variations brought on by climate change: “According to the Intergovernmental Panel on Climate Change, physical risks from climate change could include, but are not limited to, increased runoff and earlier spring peak discharge in many glacier and snow-fed rivers, warming of lakes and rivers, an increase in sea level, changes and variability in precipitation and in the intensity and frequency of extreme weather events. Physical impacts may have the potential to significantly affect the Company’s business and operations, and any such potential impact may render it more difficult for our businesses to obtain financing. For example, extreme weather events could result in increased downtime and operation and maintenance costs at the electric power generation facilities and support facilities of the Company’s subsidiaries.”  

Furthermore, Exelon noted in its FY2014 Form 10-K that the company is making large investments in smart-meter technology, and even received approval from its utilities commission to accelerate the investment schedule: “ComEd [an Exelon subsidiary] will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. On June 11, 2014, the ICC [Illinois Commerce Commission] approved ComEd’s request to accelerate the deployment, which allows for the installation of more than four million smart meters throughout ComEd’s service territory by 2018, three years in advance of the originally scheduled 2021 completion date. To date, nearly 550,000 smart meters have been installed in the Chicago area by ComEd.”  

**Value Impact**  

As electrical services are essential for most personal and business activities, disruptions can have a systemic impact that could endanger a company’s license to operate. High-impact disruptions could affect the company’s risk profile and cost of capital. Frequent or high-impact electrical disruptions can lead to reputational damage. This could affect market share and revenue over the long term, as customers seek alternative and more resilient sources of electricity. Company plant, property, and equipment could be damaged due to extreme
weather events or temperature increases, impacting the value of tangible assets. Technology and system upgrades may be necessary to address the causes of disruptions or to repair damaged infrastructure, resulting in capital expenditures. In regulated markets, capital expenditures can bring returns to shareholders. Utilities that face a higher number of system interruptions and/or those that have prolonged interruptions face lost revenues during the disruptions as well as increased system maintenance costs.

Given increasing impacts of climate change and more sophisticated cyber-attacks, the probability and magnitude of value impact on electric utilities are likely to increase in the future.

A higher duration and/or frequency of system outages over time or relative to peers could indicate a higher risk profile for the utility’s operations. In the absence of corrective actions, the utility may face additional disruptions in the future, directly impacting the bottom line. The North American Electric Reliability Corporation (NERC)’s Critical Infrastructure Protection standards are meant to assure the reliability of U.S. electric power systems. Frequent non-compliance with these standards indicates higher exposure to cybersecurity risks and the potential for higher regulatory compliance costs in the future due to more stringent oversight.

Management of the Legal & Regulatory Environment

The business models of regulated electric utilities in the U.S. are evolving, partially related to distributed generation and the changing policy environment around GHG emissions, which incentivizes or puts pressure on utilities to invest in renewable energy generation and energy efficiency. Utilities in each jurisdiction must engage with regulators and policy makers to ensure that regulation rewards actions that are in the long-term best interest of their shareholders. In general, this also tends to align industry and societal interests in the long term. This issue also focuses on the nature of companies’ relationships with their regulators, as well as the strict internal controls and transparency efforts they need to have in place to ensure that these interactions do not violate the law or the public’s trust.

Many electric utilities have been focusing their regulatory and legislative engagement efforts on policies related to distributed generation, including its growth in a manner that is beneficial to shareholders. Regulations around net metering, for example, can have a large effect on companies’ profit margins if they have operations in states where significant rooftop solar feeds back into the grid (see the “Legislative and Regulatory Trends” section, above). If companies fail to promote policies that align company and customer incentives or promote a balance of company versus customer interests, especially by over prioritizing the short term, companies can risk backlash from customers. This can potentially even including defecting from the grid in very extreme circumstances, especially in the coming decade as electricity storage may become more economically viable. Companies, of course, do not have total control over the outcome of legislation and public policy, but they may spend a significant amount of resources to engage with regulators and legislators to help them manage their legal and regulatory environment.

Power generators, especially deregulated power generators, can place themselves in a precarious position by promoting short-term benefits at the expense of the long-term viability of their assets. If a utility builds a plant that it will not be able to fully depreciate and realize all its projected
revenue because a regulatory shift makes the marginal cost of operating the plant too high, this represents a significant stranded asset; for example, the asset may release a high level of GHG emissions, and it could be prohibitively expensive to retrofit the plant to meet certain new regulations that place a cap on these emissions. Investors should examine the larger regulatory landscape to ensure that it is being effectively managed by companies with long-term interests in mind.

Investor determinations regarding effective management of the long-term legal and regulatory environment by companies in the industry are difficult and complex. Policies and financial impacts can vary widely between markets, though maintaining a long-term perspective in the context of macro themes around societal needs for GHG mitigation and resource efficiency, for example, is critical. This may be especially true for many companies in the industry that wish to continue to position themselves to investors as they have historically: as low-risk, income-producing investments.

Companies also need to maintain the highest degree of professional integrity in their relationships with regulators. In exchange for their monopolistic positions, the rates and services utilities provide customers are highly regulated by numerous regulatory authorities serving varying functions at the state, federal, and local levels. At a minimum, such relationships and interactions must be unwavering in their full compliance with applicable legal confines and other requirements, and supported by robust processes and internal controls that ensure compliance. Failure to maintain absolute compliance in working with regulators could result in costly fines and penalties, negative impacts to rate decisions, and eroded levels of stakeholder trust—an outcome that could be extremely costly for a monopolistic business model that is largely dependent on constructive regulatory decisions for long-term financial success.

Regulatory authorities that are generally most applicable to this disclosure topic include the relevant state utility commissions and FERC. Both state utility commissions and FERC often have direct influence or control over highly impactful regulatory decisions, including rates, rate structures, and energy infrastructure (with FERC generally being more applicable in interstate commerce).

Companies in the industry regularly work and communicate with regulators, usually through formal, established processes, such as the submission of rate cases to a utilities commission. Such interactions with regulators are governed by strict and potentially complex requirements and limitations. For example, states and their utility commissions typically have strict rules concerning ex parte communications when a regulatory proceeding is under way.

Defined under the federal Administrative Procedures Act, ex parte communication is “an oral or written communication not on the public record with respect to which reasonable prior notice to all parties is not given, but it shall not include requests for status reports on any matter or proceeding covered by this subchapter.”\(^{215}\) Legal restrictions on ex parte communications between utilities and their regulators are generally in place to “prevent a party from gaining an unfair advantage in a contested matter.”\(^{216}\)

Greater transparency and investor analysis around companies’ long-term public policy and regulatory strategies, as well as strong internal controls, would provide significant benefits to investment analysis and the efficiency of capital markets. Company performance in this area can be
analyzed in a cost-beneficial way through the following direct or indirect performance metrics (see Appendix III for metrics with their full detail):

- Discussion of policies and processes to identify and manage potential ethical violations resulting from interactions with utility commissions;
- Amount of legal and regulatory fines and settlements associated with allegations of violations resulting from interactions with utility commissions; and
- Discussion of positions on the regulatory and political environment related to environmental and social factors and description of efforts to manage risks and opportunities presented.

**Evidence**

Macro trends that put in place incentives for lower-carbon energy generation and the proliferation of distributed generation (and storage) are likely only going to intensify in the coming decades. This is a crucial junction when utilities need to work with regulators and policy makers to ensure that rules and rate structures guaranteeing the long-term success of this industry are established. This industry can make its voice heard on these political issues, and has increasingly done so. One measure of the industry’s involvement is the amount spent on lobbying efforts. These numbers are useful to establish the industry’s ability to present its case in these debates. The 2000s saw significant growth in lobbying efforts by electric utilities, with spending more than doubling from $79 million in 2000 to $192 million in 2010. According to data from the Center for Responsive Politics, the Electric Utilities industry spent the sixth most on lobbying of any industry in 2015, and spent the third most total between the years 1998 and 2016 (slightly over $2 billion), though it has declined in very recent years.

Utilities will have the difficult task in the coming decades of balancing their need to continue to receive funds to maintain the grid with the need to avoid pursuing punitive regulatory efforts that, in the long run, may push more customers toward grid defection. For example, many in the industry will be closely following the outcome of New York State’s Reforming the Energy Vision plan as a potential model for the future of the electric utility. To quote Audrey Zibelman, who chairs the New York Public Services Commission “The existing ratemaking structure falls far short of the pace of technology development that defines many parts of our economy. By fundamentally restructuring the way utilities and energy companies sell electricity, New York can maximize the utilization of resources, and reduce the need for new infrastructure through expanded demand management, energy efficiency, renewable energy, distributed generation, and energy storage programs.” The resulting plan takes a holistic approach to GHG reduction, energy conservation, and the encouragement of new technologies. A key element of this would be an increase in the utilities’ role as a distributed-systems platform; this is meant to have utilities play a larger role in the optimization of integrating distributed generation within the grid. The need for such a plan was echoed and generally supported by a working group that included the major utilities affected: Consolidated Edison, PSEG Long Island, and New York Power Authority. Their continued stakeholder input could speed the implementation process and result in more favorable terms for the utilities.

Electric utilities, with their significant influence, can play a role in shaping major legislation in the industry. For example, Southern Company sued to halt the previously discussed Clean Power Plan, as
one of its executives claimed the new emissions requirements would require the retirement of 4,800 MW of coal generation at one of its subsidiaries, Georgia Power, which represents more than 20 percent of Georgia Power’s total capacity. Southern Company overall generated roughly 44 percent of its electricity from coal in 2015. The majority of other utilities have been working to comply with the ruling. This is not to say that it isn’t a viable short-term strategy to attempt to block the ruling if the utility feels that it will unduly raise costs for its consumers and harm investors, but the absence of a predictable set of long-term regulations could increase the risk profile of coal-heavy companies, as international agreements like COP21 make some form of increasing regulation more likely, whether in the short or long term. This is likely recognized by companies such as Southern Company, which is making serious strides to cut its emissions.

Net metering and related regulations, such as provisions for fixed fees for the use of the grid, are currently being hotly debated. In the third quarter of 2015, 27 states were either evaluating or actively attempting to change their net metering policies. NV Energy, based in Nevada, supported the Nevada PUC’s decision to reduce the credits solar customers received for net excess generation, as well as raise the fixed costs they pay for maintenance of the grid. How this plays out may have significant repercussions for other utilities commissions. NV Energy has presented a range of potential strategies to the PUC regarding the potential time period for phasing in the new strategy (over 8, 12, 16, or 20 years) and the extent to which old policies would be grandfathered in. On the latter issue, in response to public outcry (including a class action lawsuit being filed against the utility), NV Energy announced it would submit a proposal in support of grandfathering in previous customer’s rates.

There is a delicate balance between raising rates to account for needed grid maintenance and not placing rates so high that they encourage grid defection and grid alternatives (i.e., storage) to flourish. Utilities can also position their business model to include investment in distributed generation.

For example, Arizona Public Services (APS) was a staunch opponent of net metering in 2013, launching a negative public campaign that included funding nonprofits that ran negative solar advertisements in the state. It was nervous about the rapid growth of solar: the first quarter of 2015 had a 112 percent increase in rooftop solar applications over the first quarter of 2014 in its service area. APS has recently changed tactics, however, and instead was approved to invest nearly $30 million to place solar panels on customers’ roofs. It will pay customers to host these panels and would have the ability to strategically place them to help smooth out demand (see the issue End-User Efficiency & Demand disclosure topic). This example supports the argument that companies that are able to align their public policy strategies and engagement efforts with long-term customer and societal interests—and communicate this to shareholders—may face less risk and greater long-term opportunities.

While incidents of non-compliance concerning utility-regulator interactions are rare, such incidents have the potential to cause severe impacts on companies in the industry.

In 2014 and 2015, Pacific Gas and Electric Company, a public utility in California owned by PG&E Corporation, notified the California Public Utilities Commission (CPUC) regarding potential violations of ex parte rules. Such potential violations relate to improper discussion of regulatory proceedings, such as a rate case and
the selection of an administrative law judge. In November 2014, the CPUC fined the utility $1 million (to be borne by shareholders, not ratepayers) and denied a revenue increase that was to be collected from ratepayers over a five-month period, which could ultimately deprive the utility of $400 million in revenue.

In a statement from a CPUC commissioner, the significance of this decision was made clear: “Through this decision, we continue to send a signal to PG&E that we expect full compliance and appropriate respect for the CPUC’s processes and its staff, as well as fair treatment to its consumers.” Furthermore, three PG&E executives were dismissed in association with this matter and additional restrictions were placed on the company concerning communication with regulators.

Additionally, PG&E and the CPUC are being investigated by the U.S. Attorney’s Office in San Francisco and the California Attorney General’s Office related to this matter. This incident also caused significant reputational damage for PG&E, increasing the likelihood that, moving forward, the company could face more unfavorable regulation.

In December 2015, Southern California Edison, a utility owned by Edison International, was fined $16.74 million by the CPUC related to ex parte communications that occurred between a senior executive of the utility and the president of the CPUC in 2013. These communications related to ongoing proceedings concerning the San Onofre nuclear plant. The CPUC final decision found that eight communications should have been previously reported and that two violations of a CPUC ethical rule occurred.

This incident serves to illustrate that compliance with ex parte regulations is complex and even violations that largely revolve around the timing of notices can result in substantial fines. Additionally, multiple lawsuits against Edison International and certain executive officers and/or board members that intend to be securities class action lawsuits, as well as a shareholder derivative lawsuit, have been filed in conjunction with this matter. Company disclosures state that the company “cannot predict the outcome of these proceedings.”

Furthermore, substantial critical media coverage followed this event that could serve to erode the public’s trust. If such erosions of stakeholder trust occur in meaningful ways, states may be pressured into evolving the regulatory environment in a manner that could be deemed unfavorable from the perspective of companies in the industry and their investors.

Southern California Edison, in its FY2015 10-K, disclosed risks related to regulatory changes regarding this issue: “The CPUC is considering rulemaking to govern communications between the CPUC officials, staff and the regulated utilities. Changes to the rules and processes around ex parte communications could result in delayed decisions, increased investigations, enforcement actions and penalties. In addition, the CPUC or other parties may initiate investigations of past communications between public utilities, including SCE [Southern California Electric], and CPUC officials and staff that could result in reopening completed proceedings for reconsideration.”

Value Impact

Companies will be able to lower their risk profile, and their cost of capital, by proactively working with regulators to shape the 21st century energy infrastructure that provides clean, affordable, and reliable energy. It is equally important to clearly
articulate this strategy to investors to ensure a lower risk profile. Over time, policy corrections can emerge through public pressure and tangible economic impacts that reverse previous policies that might have favored short-term industry profitability at the expense of societal benefits. This can impact a company’s reputation and lower the value of its intangible assets. It can also result in unanticipated costs and limitations on companies that might be harmful to long term profitability. For example, companies could face chronic impacts on value if regulatory measures are so excessively punitive to distributed generators that they cause them to leave the grid, thus reducing overall industry revenue in the medium-term. As environmental regulation will likely only become increasingly strict and technological and financial innovation contribute to increasing distributed generation, the probability and magnitude of this issue will increase in the medium- and long-term.

It could be useful for an analyst, especially one with a long-term investment horizon, to carefully examine a company’s discussion of its position on the regulatory and political environment related to environmental and social factors as well as related strategies. In this way, the analyst would be better able to assess whether a company is likely to face benefits or negative financial impacts from the macro industry trends discussed in this issue.

Unethical and illegal business practices related to interactions with regulators, such as state utility commissions, can result in an acute impact on value through significant one-time fines and penalties, as well as potential negative impacts on rates and rate cases that could result in lost revenue. Regulatory actions can also result in higher ongoing compliance costs. This issue can also affect a company’s reputation and the likelihood of constructive, long-term, stakeholder-inclusive regulation, which could impact a company’s risk profile and cost of capital, as well as intangible assets.

Furthermore, two other disclosures can provide analysts with information with which to assign risk premiums in valuing utilities – (i) a company’s history of fines and settlements for alleged or actual violations in interacting with utility commissions and (ii) a company’s strategy of internal controls to prevent such incidents.
APPENDIX I

FIVE REPRESENTATIVE ELECTRIC UTILITIES COMPANIES

<table>
<thead>
<tr>
<th>COMPANY NAME (TICKER SYMBOL)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exelon Corporation (EXC)</td>
</tr>
<tr>
<td>Duke Energy (DUK)</td>
</tr>
<tr>
<td>Southern Company (SO)</td>
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<tr>
<td>American Electric Power (AEP)</td>
</tr>
<tr>
<td>NRG Energy (NRG)</td>
</tr>
</tbody>
</table>

\*\* This list includes five companies representative of the Electric Utilities industry and its activities. This includes only companies for which the Electric Utilities industry is the primary industry, companies that are U.S.-listed but are not primarily traded over the counter, and for which at least 20 percent of revenue is generated by activities in this industry, according to the latest information available on Bloomberg Professional Services. Retrieved on January 16, 2016.
## APPENDIX IIA: Evidence for Sustainability Disclosure Topics

<table>
<thead>
<tr>
<th>Sustainability Disclosure Topics</th>
<th>EVIDENCE OF INTEREST</th>
<th>EVIDENCE OF FINANCIAL IMPACT</th>
<th>FORWARD-LOOKING IMPACT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>HM (1-100)</td>
<td>IWGs</td>
<td>EI</td>
</tr>
<tr>
<td>Greenhouse Gas Emissions &amp; Energy Resource Planning</td>
<td>94*</td>
<td>98</td>
<td>1</td>
</tr>
<tr>
<td>Air Quality</td>
<td>94*</td>
<td>91</td>
<td>2</td>
</tr>
<tr>
<td>Water Management</td>
<td>63*</td>
<td>91</td>
<td>3t</td>
</tr>
<tr>
<td>Coal Ash Management</td>
<td>75*</td>
<td>861</td>
<td>51</td>
</tr>
<tr>
<td>Community Impacts of Project Siting</td>
<td>46</td>
<td>77</td>
<td>7</td>
</tr>
<tr>
<td>Workforce Health &amp; Safety</td>
<td>50*</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>End-use Efficiency &amp; Demand</td>
<td>96*</td>
<td>77</td>
<td>6</td>
</tr>
<tr>
<td>Nuclear Safety &amp; Emergency Management</td>
<td>67*</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Grid Resiliency</td>
<td>63*</td>
<td>89</td>
<td>3t</td>
</tr>
<tr>
<td>Management of the Legal &amp; Regulatory Environment</td>
<td>75*</td>
<td>84</td>
<td>4</td>
</tr>
</tbody>
</table>

**HM:** Heat Map, a score out of 100 indicating the relative importance of the topic among SASB’s initial list of 43 generic sustainability issues. Asterisks indicate “top issues.” The score is based on the frequency of relevant keywords in documents (i.e., 10-Ks, 20-Fs, shareholder resolutions, legal news, news articles, and corporate sustainability reports) that are available on the Bloomberg terminal for the industry’s publicly listed companies. Issues for which keyword frequency is in the top quartile are “top issues.”

**IWGs:** SASB Industry Working Groups

**%:** The percentage of IWG participants that found the disclosure topic likely to constitute material information for companies in the industry. (-) denotes that the issue was added after the IWG was convened.

**Priority:** Average ranking of the issue in terms of importance. 1 denotes the most important issue. (-) denotes that the issue was added after the IWG was convened.

**EI:** Evidence of Interest, a subjective assessment based on quantitative and qualitative findings.

**EFI:** Evidence of Financial Impact, a subjective assessment based on quantitative and qualitative findings.

**FLI:** Forward-looking Impact, a subjective assessment of the presence of a material forward-looking impact.

1 During the IWG phase the “Coal Ash Management” disclosure topic was called “Coal Ash & Spent Fuel Management”. At that time, the scope of the issue included an angle on spent nuclear fuel, which was since removed.
### APPENDIX IIB:
Evidence of Financial Impact for Sustainability Disclosure Topics

<table>
<thead>
<tr>
<th>Evidence of Financial Impact</th>
<th>REVENUE &amp; EXPENSES</th>
<th>ASSETS &amp; LIABILITIES</th>
<th>RISK PROFILE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Revenue</td>
<td>Operating Expenses</td>
<td>Non-operating Expenses</td>
</tr>
<tr>
<td>Market Share</td>
<td>New Markets</td>
<td>Pricing Power</td>
<td>Cost of Revenue</td>
</tr>
<tr>
<td>Greenhouse Gas Emissions &amp; Energy Resource Planning</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Air Quality</td>
<td></td>
<td></td>
<td>•</td>
</tr>
<tr>
<td>Water Management</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Coal Ash Management</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Community Impacts of Project Siting</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Workforce Health &amp; Safety</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>End-use Efficiency &amp; Demand</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Nuclear Safety &amp; Emergency Management</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Grid Resiliency</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
<tr>
<td>Management of the Legal &amp; Regulatory Environment</td>
<td>•</td>
<td>•</td>
<td>•</td>
</tr>
</tbody>
</table>

- **MEDIUM IMPACT**
- **HIGH IMPACT**
## APPENDIX III
### SUSTAINABILITY ACCOUNTING METRICS—ELECTRIC UTILITIES

<table>
<thead>
<tr>
<th>TOPIC</th>
<th>ACCOUNTING METRIC</th>
<th>CATEGORY</th>
<th>UNIT OF MEASURE</th>
<th>CODE</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Greenhouse Gas Emissions &amp; Energy Resource Planning</strong></td>
<td>(1) Gross global Scope 1 emissions, (2) percentage covered under emissions-limiting regulations, and (3) percentage covered under emissions-reporting regulations</td>
<td>Quantitative</td>
<td>Metric tons (t), CO₂-e, Percentage (%)</td>
<td>IF0101-01</td>
</tr>
<tr>
<td></td>
<td>Description of long-term and short-term strategy or plan to manage Scope 1 emissions, emission-reduction targets, and an analysis of performance against those targets</td>
<td>Discussion and Analysis</td>
<td>n/a</td>
<td>IF0101-02</td>
</tr>
<tr>
<td></td>
<td>(1) Number of customers served in markets subject to renewable portfolio standards (RPS) and (2) percentage fulfillment of RPS target by market*</td>
<td>Quantitative</td>
<td>Number, Percentage (%)</td>
<td>IF0101-03</td>
</tr>
<tr>
<td><strong>Air Quality</strong></td>
<td>Air emissions of the following pollutants: NOx (excluding N₂O), SOx, particulate matter (PM₁₀), Pb, and Hg; percentage of each in or near areas of dense population</td>
<td>Quantitative</td>
<td>Metric tons (t), Percentage (%)</td>
<td>IF0101-04</td>
</tr>
<tr>
<td><strong>Water Management</strong></td>
<td>(1) Total water withdrawn and (2) total water consumed, percentage of each in regions with High or Extremely High Baseline Water Stress</td>
<td>Quantitative</td>
<td>Cubic Meters (m³), Percentage (%)</td>
<td>IF0101-05</td>
</tr>
<tr>
<td><strong>Coal Ash Management</strong></td>
<td>Number of incidents of non-compliance with water quality and/or quantity permits, standards, and regulations</td>
<td>Quantitative</td>
<td>Number</td>
<td>IF0101-06</td>
</tr>
<tr>
<td></td>
<td>Discussion of water management risks and description of strategies and practices to mitigate those risks</td>
<td>Discussion and Analysis</td>
<td>n/a</td>
<td>IF0101-07</td>
</tr>
<tr>
<td></td>
<td>Amount of coal combustion residuals (CCR) generated, percentage recycled</td>
<td>Quantitative</td>
<td>Metric tons (t), Percentage (%)</td>
<td>IF0101-08</td>
</tr>
<tr>
<td><strong>Community Impacts of Project Siting</strong></td>
<td>Total number of coal combustion residual (CCR) impoundments and number by EPA Hazard Potential Classification, broken down by EPA structural integrity assessment</td>
<td>Quantitative</td>
<td>Number</td>
<td>IF0101-09</td>
</tr>
<tr>
<td></td>
<td>Number of projects requiring environmental or social modification, percentage of modifications resulting from formal public interventions or protests**</td>
<td>Quantitative</td>
<td>Number, Percentage (%)</td>
<td>IF0101-10</td>
</tr>
<tr>
<td></td>
<td>Discussion of community engagement processes to identify and mitigate concerns regarding project environmental and community impacts</td>
<td>Discussion and Analysis</td>
<td>n/a</td>
<td>IF0101-11</td>
</tr>
</tbody>
</table>

* Note to IF0101-03—The registrant shall discuss its operations in markets with RPS regulations or where regulations are emerging, including whether it is meeting its regulatory obligations, whether regulations require future increases to the registrant’s renewable energy portfolio, and strategies to maintain compliance with emerging regulations.

** Note to IF0101-10—The registrant shall discuss modifications that relate to significant projects such as those with large transmission or generation capacity.
## APPENDIX III
### SUSTAINABILITY ACCOUNTING METRICS—ELECTRIC UTILITIES

<table>
<thead>
<tr>
<th>TOPIC</th>
<th>ACCOUNTING METRIC</th>
<th>CATEGORY</th>
<th>UNIT OF MEASURE</th>
<th>CODE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Workforce Health &amp; Safety</td>
<td>(1) Total recordable injury rate (TRIR), (2) fatality rate, and (3) near miss frequency rate (NMFR)</td>
<td>Quantitative</td>
<td>Rate</td>
<td>IF0101-12</td>
</tr>
<tr>
<td>End-Use Efficiency &amp; Demand</td>
<td>Percentage of electric load served by smart grid technology***</td>
<td>Quantitative</td>
<td>Percentage (%) by Megawatt-Hours (MWh)</td>
<td>IF0101-13</td>
</tr>
<tr>
<td></td>
<td>Customer electricity savings from efficiency measures by market****</td>
<td>Quantitative</td>
<td>Megawatt-Hours (MWh)</td>
<td>IF0101-14</td>
</tr>
<tr>
<td>Nuclear Safety &amp; Emergency</td>
<td>Total number of nuclear power units, broken down by Nuclear Regulatory Commission (NRC) Action Matrix Column</td>
<td>Quantitative</td>
<td>Number</td>
<td>IF0101-15</td>
</tr>
<tr>
<td>Management</td>
<td>Discussion of efforts to manage nuclear safety and emergency preparedness</td>
<td>Discussion and Analysis</td>
<td>n/a</td>
<td>IF0101-16</td>
</tr>
<tr>
<td>Grid Resiliency</td>
<td>Number of incidents of non-compliance with North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection standards</td>
<td>Quantitative</td>
<td>Number</td>
<td>IF0101-17</td>
</tr>
<tr>
<td></td>
<td>(1) System Average Interruption Duration Index (SAIDI), (2) System Average Interruption Frequency Index (SAIFI), and (3) Customer Average Interruption Duration Index (CAIDI), inclusive of major event days*****</td>
<td>Quantitative</td>
<td>Minutes, Number</td>
<td>IF0101-18</td>
</tr>
<tr>
<td>Management of the Legal &amp;</td>
<td>Discussion of policies and processes to identify and manage potential ethical violations resulting from utility commissions</td>
<td>Discussion and Analysis</td>
<td>n/a</td>
<td>IF0101-19</td>
</tr>
<tr>
<td>Regulatory Environment</td>
<td>Amount of legal and regulatory fines and settlements associated with allegations of violations resulting from interactions with utility commissions*****</td>
<td>Quantitative</td>
<td>U.S. Dollars ($)</td>
<td>IF0101-20</td>
</tr>
<tr>
<td></td>
<td>Discussion of positions on the regulatory and political environment related to environmental and social factors and description of efforts to manage risks and opportunities presented</td>
<td>Discussion and Analysis</td>
<td>n/a</td>
<td>IF0101-21</td>
</tr>
</tbody>
</table>

*** Note to IF0101-13—The registrant shall discuss the opportunities and challenges associated with the development and operations of a smart grid.

**** Note to IF0101-14—The registrant shall discuss customer efficiency regulations relevant to each market in which it operates.

***** Note to IF0101-18—The registrant shall discuss notable service disruptions such as those that affected a significant number of customers or disruptions of extended duration.

****** Note to IF0101-20—The registrant shall briefly describe the nature, context, and corrective action taken as a result of the fine and/or settlement.
APPENDIX IV: Analysis of SEC Disclosures | Electric Utilities

The following graph demonstrates an aggregate assessment of how representative U.S.-listed Electric Utilities companies are currently reporting on sustainability topics in their SEC annual filings.

<table>
<thead>
<tr>
<th>Electric Utilities</th>
<th>0%</th>
<th>10%</th>
<th>20%</th>
<th>30%</th>
<th>40%</th>
<th>50%</th>
<th>60%</th>
<th>70%</th>
<th>80%</th>
<th>90%</th>
<th>100%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greenhouse Gas Emissions &amp; Energy Resource Planning</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>98%</td>
</tr>
<tr>
<td>Air Quality</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>91%</td>
</tr>
<tr>
<td>Water Management</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>91%</td>
</tr>
<tr>
<td>Coal Ash Management</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>86%</td>
</tr>
<tr>
<td>Community Impacts of Project Siting</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>77%</td>
</tr>
<tr>
<td>Workforce Health &amp; Safety</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>77%</td>
</tr>
<tr>
<td>End-Use Efficiency &amp; Demand</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>77%</td>
</tr>
<tr>
<td>Nuclear Safety &amp; Emergency Management</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>77%</td>
</tr>
<tr>
<td>Grid Resiliency</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>89%</td>
</tr>
<tr>
<td>Management of Legal &amp; Regulatory Environment</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>84%</td>
</tr>
</tbody>
</table>

IWG Feedback*  

*Percentage of IWG participants that agreed topic was likely to constitute material information for companies in the industry.

1 During the IWG phase the “Coal Ash Management” disclosure topic was called “Coal Ash & Spent Fuel Management”. At that time, the scope of the issue included an angle on spent nuclear fuel, which was since removed.

2 The “Workforce Health & Safety” and “Nuclear Safety & Emergency Management” disclosure topics were introduced after SASB convened IWGs and per stakeholder feedback.

3 At the time of analysis, the “Management of Legal & Regulatory Environment” focused on ethical violations in the context of ratemaking and market manipulation. This may not reflect all elements covered by this disclosure topic.
REFERENCES


3 Author’s calculation based on data from Bloomberg Professional service, accessed March 24, 2015 using the ICS <GO> command. The data represents global revenues of companies listed on global exchanges and traded over the counter from the Electric Utilities industry, using Levels 3, 4, and 5 of the Bloomberg Industry Classification System.


6 “Electricity Regulation in the U.S.,” Regulatory Assistance Project.

7 Ibid, p. 5

8 Ibid.


12 AmeriGas Partners, L.P., Q1 2015 Earnings Call, p. 3.


14 Data from Bloomberg Professional service, accessed December 24, 2015 using the ICS <GO> command. The data represents global revenues of companies listed on global exchanges and traded over the counter from the Electric Utilities industry, using Levels 3, 4, and 5 of the Bloomberg Industry Classification System.

15 Author’s calculation based on data from Bloomberg Professional service, accessed January 27, 2016 using the ICS <GO> command. The data represents global revenues of companies listed on global exchanges and traded over-the-counter from the Electric Utilities industry, using Levels 3, 4, and 5 of the Bloomberg Industry Classification System.

16 Author’s calculation based on data from Bloomberg Professional service, accessed March 24, 2015 using the ICS <GO> command. The data represents global revenues of companies listed on global exchanges and traded over the counter from the Electric Utilities industry, using Levels 3, 4, and 5 of the Bloomberg Industry Classification System.

17 Author’s calculation based on data from Bloomberg Professional service, accessed March 24, 2015 using the ICS <GO> command. The data represents global revenues of companies listed on global exchanges and traded over the counter from the Electric Utilities industry, using Levels 3, 4, and 5 of the Bloomberg Industry Classification System.


64 Ibid.
74 Ben Caldecott, Gerard Dericks, and James Mitchell, “Stranded Assets and Subcritical Coal,” Smith School of Enterprise and the Environment, Oxford University, March 2015, p. 8, accessed February 10, 2016,

Maize, “Tricky Business: Taking Down Old Coal Plants.”


156 Eversource, FY2015 Q3 Conference Call, November 3, 2015, p. 5.


158 Wells, “Land Battles Rise as U.S. Eyes 450,000 Miles of New Pipe.”


Naureen Malik and Jonathan Crawford, “Con Edison Seeks to Avoid Building $1 Billion Substation.”


202 Ibid., p. 4.
203 Ibid., p. 10.
216 Ibid.
222 Consolidated Edison, Q3 2015 10-Q for the Period Ending September 30, 2015 (filed November 5, 2015), p. 64.


225 Data from Bloomberg Professional service, accessed March 11, 2016 using the BI EGENN <GO> command.


232 “CPUC Fines PG&E $1.05 Million, Orders Consumer Reparations, and Imposes Ex Parte Restrictions,” November 20, 2014, accessed March 4, 2016, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K250/143250567.PDF.


235 Ibid., p. 97–98.

