DOE Quadrennial Energy Review

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Edison Electric Institute

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Quadrennial Energy Review

Infrastructure Resilience and Vulnerabilities - Cyber, Physical, Climate, Interdependencies

Comments of the Edison Electric Institute

Executive Summary

The Edison Electric Institute (EEI), on behalf of its member companies, hereby respectfully submits these initial comments, and accompanying materials, in response to the Department of Energy's (DOE) Quadrennial Energy Review (QER). As stated by DOE, the QER is intended to provide a multiyear roadmap that outlines Federal energy policy objectives, legislative proposals to Congress, Executive Branch actions, an agenda for research, development and demonstration (RD&D) programs and funding, and financing and incentive programs.

The first phase of the QER will focus on transmission, storage and distribution infrastructure (TS&D), the network that links energy supplies to intermediate and end users. To date, DOE has held its initial public meetings, covering energy infrastructure resiliency and addressing vulnerabilities on April 11th, 2014, New England regional infrastructure needs on April 21, 2014, and petroleum products transmission and distribution on May 27, 2014.[1] DOE has announced additional public meetings.

EEI appreciates the opportunity to participate in the QER, and supports efforts to examine the Nations' energy infrastructure, identify vulnerabilities, and develop policy

[1] Notices of these public meetings were issued by the DOE posted in the *Federal Register* on March 28, 2014, April 10, 2014, and May 9, 2014.

recommendations to address these matters. EEI acknowledges that the significant investments in TS&D infrastructure may influence supply and end use patterns, policies, investments and practices over the course of decades. The U.S. electric system, *i.e.*, "the Grid," is made up of many components, including generation, transmission and distribution lines, transformers, substations, measurement and communications equipment, and control centers, all of which serve end use customers. For purposes of these comments, given the QER's initial focus on TS&D, the use of the "the Grid" tends to address the non-supply portions of the Grid, principally the infrastructure impacting the safe, reliable, secure, and economical delivery of electric service.

The U.S. electric grid is unrivaled in the world, cited by the National Academy of Engineering as the most important engineering achievement of the 20th Century.[2] The Grid is a critical part of our Nation's infrastructure, vital to national security, and to the safety and well-being of all Americans. A modern, resilient infrastructure that continues to provide reliable, efficient, and cost-effective electric service is essential to power our economy and maintain our high standard of living. EEI believes that the traditional flow of power from centralized generation resources through bulk transmission and distribution infrastructure to load will continue to be a predominate supply for our nation's electricity needs, providing the foundation to both access diverse generation resources and transition to new technologies.

[2] National Academy of Engineering. (2014). *Greatest Engineering Achievements of the 20th Century*. Retrieved from http://www.greatachievements.org/

Grid improvements continue to be made to address our country's needs: modernizing infrastructure to include technology innovations, improving resiliency, implementing public policy requirements, addressing environmental concerns, responding to emerging physical and cyber threats, and meeting changing customer expectations. EEI members are proactively engaged in these efforts. EEI emphasizes that the QER process must:

- Recognize the value of the Grid, a national security asset, which: provides a platform for an "all of the above" energy strategy; enables our high standard of living; provides access to a diverse, reliable, and economic electric supply portfolio; facilitates efficient wholesale electricity markets and low electricity prices; accommodates a changing generation mix, including low-carbon, carbon-free and renewable resources; and reliably supports distributed energy resources, including the accompanying value proposition of selling electricity back to the grid.

- Recognize that the safety and security of the Grid to maintain reliability is best addressed through coordinated industry actions, industry-government partnerships, and recognition of federal and state authorities. There are opportunities for EEI member partnerships with federal, state, and local governments and law enforcement to anticipate and effectively respond to events and continuously protect electric infrastructure. New regulations or mandates in this area may not afford necessary flexibility and may be counterproductive.

- Preserve policies that encourage investment, mitigate risk, and provide regulatory certainty. Such policies are paramount to enabling the continued evolution and security of the Grid and assist developers in attracting capital.

- Recognize jurisdictional boundaries and the role that utilities are legally obligated to perform in the states. For example, interstate transmission and wholesale electric sales are under federal jurisdiction, while most distribution facilities and retail sales are under state jurisdictions.[3]

- Recognize that fair regulations and policies are required to advance transmission and distribution system developments necessary for reliable, cost-effective integration of

[3] *See* Federal Power Act, Section 201. In addition, there are numerous state statutes governing utility franchises and operations.

distributed resources and microgrids. Importantly, all beneficiaries of the Grid should pay their fair share, and policies should avoid unreasonable cost shifts among customers.

EEI specifically recommends that:

- The industry should be allowed to develop innovative alternative utility rate design models (both federal and state) to ensure that the Grid is accurately valued and utilities fairly compensated. This will ensure that the Grid can maintain resources necessary for reliability, given the expected growth of distributed generation, and appropriately allocate costs to all electric system users – whether they are traditional buyers of electricity, or are more actively engaged non-traditional buyers and sellers of electricity and demand response. Rate design methods should encourage: forward looking capital attraction for infrastructure investments, reliability and resilience, and innovation.

- Federal officials should seek to enhance tax provisions and other federal programs to ensure consistent funding for long-term plans, particularly for extreme (or extreme weather) events. Such reforms should seek to promote utility efforts to build stronger and resilient systems following extreme events. Federal rules and programs should be inclusive of all entities responsible for developing and maintaining resilient energy infrastructure.

    - The Federal government should assure the continued ability of Community Development Block Grant (CDBG) recipients to utilize funding, including disaster recovery funding, for the repair and restoration of privately-owned electric utility infrastructure in the wake of extreme events.

- Federal and state governments, utilities and other Grid operators should explore new and/or improved opportunities to increase bi-directional, confidential information sharing regarding potential cyber and physical security threats. Solutions should seek to reduce liabilities associated with information sharing.

- Continue to embrace competitive wholesale electricity markets that promote reliability and fuel diversity.

- Regulatory certainty be promoted to assure needed grid investments are made and emerging technologies are reliably integrated into the Grid.

Introduction

EEI is the association of U.S. shareholder-owned electric companies. Our members serve nearly 99 percent of the ultimate customers in the shareholder-owned segment of the industry, and they represent approximately 70 percent of the U.S. electric power industry. EEI's members own more than 60 percent of the nation's circuit miles of transmission, and are owners, operators and users of the bulk power system. EEI membership includes vertically integrated and stand-alone utility business models. EEI's diverse membership includes utilities operating in all regions and in all types of markets, including bilateral. U.S. investor-owned electric utilities (IOUs) spent $90.3 billion on capital expenditures in 2013. This investment created approximately 50,000 permanent jobs and 225,000 construction and other non-permanent jobs.[4] Overall, the electric industry accounts for more than 2 percent of the nation's GDP and employs more than 500,000 workers.[5] As a result, EEI's members can provide a broad-based perspective to the QER and its resulting recommendations.

For the many reasons laid out in these comments, the QER process should recognize the collaborative nature and interdependencies of electric service. The Grid is comprised of many components, including generation, transmission and distribution lines, transformers, substations, measurement and communications equipment, and control centers. The complicated and intertwined nature of these components makes it somewhat difficult to

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[4] Edison Electric Institute, May 1, 2014.

[5] Edison Electric Institute. (2014). *2013 Financial Review: Annual Report of the Investor Owned Electric Utility Industry.* Retrieved from: http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Pages/default.aspx

separate out specific functions, such as TS&D. For example, TS&D infrastructure cannot be reliable without adequate generation to provide critical reliability services in addition to energy and capacity to serve load. While this installment of the QER is focused on TS&D, EEI believes it is important to address the critical services provided by generation necessary for reliable electric transmission and distribution, such as demand and resource balancing and voltage and frequency support. EEI looks forward to participating in future installments of the QER focused on energy supply, including electric generation.

EEI views the Grid as a conduit for commerce and fulfilling our electric needs, as the industry has a long history of collaboration and system planning among generation sources, load centers, and TS&D. EEI notes that the Grid is flexible and not necessarily deterministic of supply and end use. Consider for example, that when generation is sited based on proximity to fuel, such as significant renewable wind resources in the Midwest and West, TS&D facilitates energy solutions.

I. The Grid Will Continue to Provide the Platform for a Comprehensive Energy Strategy to Assure Reliable, Cost-Effective Electric Service

The Grid provides numerous benefits, supporting a diverse portfolio of reliable, economic power sources, and is a major driver for our national and local economies. The Grid provides, and will continue to provide, reliability (e.g., voltage support, and startup power), a platform for energy and capacity transactions in bilateral and organized markets, and opportunities for increased efficiencies. Moreover, the Grid provides a platform for an “all of the above" energy strategy, allowing electricity markets to determine technologies, business models, and fuel sources.

As our dependence on electricity increases, it is important to remember the value proposition the Grid provides in terms of end-use prices paid by customers.

> Electricity is the engine that drives our economy and our modern lifestyle. It is the power behind the "smart" in our smart phones, smart appliances, and smart homes and businesses. With a flip of the switch our lights turn on, with a push of a button our dishwashers come to life, and with a touch of our tablet's screen we can access the Internet and connect to the online world.
>
> While American homes use more electricity today than ever, electricity prices remain an excellent value and have increased at a lower rate than the prices of other consumer goods. In fact, according to the U.S. Department of Commerce, just 1.47 percent of consumer expenditures in 2013 went to electric bills, which means that for every dollar Americans spent on goods and services, less than a penny and a half was spent on electric bills.[6]

As noted, the Grid provides some of the lowest cost electricity in the world, providing an advantage to the U.S. economy. While ensuring the best electric reliability in the world by making significant investments in the Grid, the price of electricity in the U.S. has remained relatively steady over the years (See Figure 1, below).[7]

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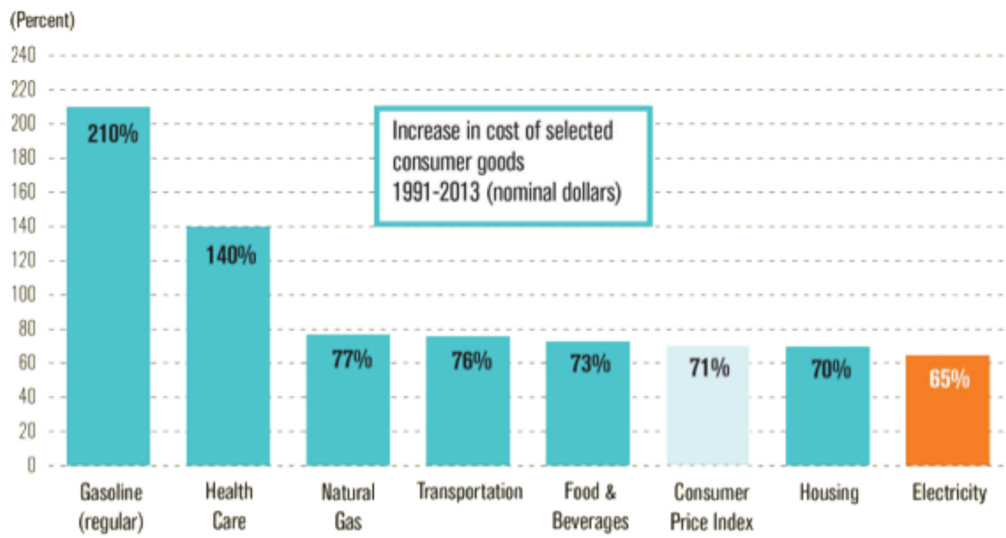
[6] Kuhn, R., Thomas. (2014). *2013 Financial Review: President's Letter*. Retrieved from: http://www.eei.org/resourcesandmedia/industrydataanalysis/industryfinancialanalysis/finreview/Pages/default.aspx

[7] See, for example: Edison Electric Institute. (2014, March). *Transmission Projects: At A Glance.* Retrieved from: http://www.eei.org/issuesandpolicy/transmission/Pages/transmissionprojectsat.aspx.
See also: Edison Electric Institute. (2014, May). [Graphic illustration]. *Actual and Planned Transmission Investment By Investor-Owned Utilities (2007-2016)*. Retrieved from: http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf

Figure 1 – Changes in Electricity Prices Compared to Other Consumer Products



Source: U.S. Department of Labor Statistics (BLS), and U.S. Department of Energy, Energy Information Administration (EIA).

The Grid, particularly transmission and distribution systems, provide unique value by ensuring access to diverse and economic supply sources, facilitating energy transactions, and supporting critical services necessary for reliability. Regardless of the future U.S. generation resource mix, investments in these assets remains necessary and, facilitated by effective and fair transmission and distribution policies, will ensure: (i) that the full benefits of the transitioning Grid are experienced by customers, (ii) the Administration's "all of the above" energy strategy, which includes the integration of Variable Energy Resources (VER), is realized, and (iii) state Renewable Portfolio Standards (RPS) are met.[8,9]

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[8] This strategy includes natural gas, clean coal, nuclear, and variable energy resources. A Variable Energy Resource (VER) is a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. *Integration of Variable Energy Resources,* Order No. 764, 139 FERC ¶ 61,246 (2005).

[9] Twenty Nine States and the District of Columbia have renewable standards.

Initially, utility power systems were isolated and each served its own service area. As service areas expanded, utilities began to interconnect. These interconnections developed for good reasons, including increased resilience based on portfolio diversity and reduced costs (e.g., smaller reserve margins thereby reducing infrastructure build).[10] These interconnections expanded over many years, further reducing costs for customers.

EEI believes that given available technologies, economies of scale inherent in the centralized Grid will continue to provide unmatched efficiencies and cost savings for customers, and will continue to do so for many years to come. Economies of scale also apply to emerging generation sources, including renewables.[11] For example, larger-scale renewable generation is currently a more cost-effective way to promote renewable energy than the implementation of DER.[12] Less centralized electric systems generally exhibit higher costs because of diseconomies

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U.S. Department of Energy. (2013, March). *Database of State Incentives for Renewables & Efficiency.* [Graphic illustration]. Retrieved from: http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf
Note that actions in Ohio to delay implementation of its renewable portfolio standards are pending. Available at: http://www.legislature.state.oh.us/bills.cfm?ID=130_SB_310

[10] Reserve margin is (capacity minus demand)/demand, where "capacity" is the expected maximum available supply and "demand" is expected peak demand. It is calculated for electric systems or regions made up of a number of electric systems. For instance, a reserve margin of 15% means that an electric system has excess capacity in the amount of 15% of expected peak demand. Reserve Margins are set by NERC regional entities. The Energy Information Agency. (2012, June 1). *Reserve Electric Generation Capacity Helps Keep the Lights On.* Retrieved from: http://www.eia.gov/todayinenergy/detail.cfm?id=6510

[11] A recent study concluded that increased use of VER "will require building more transmission than if fossil-fueled or nuclear generating plants built relatively close to load centers were driving system expansion." Massachusetts Institute of Technology. (2011). *The Future of the Electric Grid, An Interdisciplinary MIT Study*. Retrieved from: http://web.mit.edu/mitei/research/studies/the-electric-grid-2011.shtml

[12] Based on current prices, DER are associated with higher capital and installation costs on a per-kilowatt KW basis than larger centralized resources. For example, according to a recent study by GTM Research and the Solar Energy Industries Association, in the first quarter of 2014, the average installed system price of solar PV was: $3.73/watt for residential rooftop, $2.53/watt for commercial rooftop, and $1.77/watt for utility scale. Solar Energy Industries Association. (2014). *U.S. Solar Market Insight Report, Q1 2014, Executive Summary*. Retrieved from: http://www.seia.org/research-resources/us-solar-market-insight

of scale (e.g., relatively higher maintenance costs, more generators to maintain), and higher reserve margins.[13]

> "The very fact that distributed generation programs need additional support within an RPS (renewable portfolio standard) framework suggest that central generation of renewables is likely cheaper than renewable DG- and further evidence for this can be found in the fact that many of the programs intended to support DG come with pre-set limits on the amount of generation to be supported....[14]

Supportive energy and regulatory policies should be continued and, when necessary, crafted to recognize the value of the grid and maximize its value for customers, continue the provision of reliable service at fair and reasonable rates, accommodate geographic, political, and regulatory differences; and contribute to the resilience and flexibility of the Grid.

Specifically, policies should reflect the value of the Grid by:

- Appropriately valuing reliability and its necessary services (*e.g.*, frequency response, voltage control, balancing, etc.), including back-up power; capacity-

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[13] Demonstrating the economies of scale the Grid provides, EPRI estimates that the cost of providing grid services for customers with distributed energy systems is about $51/month on average in the typical current configuration of the grid in the United States; EPRI concludes that in residential PV systems, providing that same service completely independent of the grid would be four to eight times more expensive. The EPRI report found that a residential PV system, completely disconnected from the grid, amortized over 20 years, will have costs above those of an original array of $275- $430 per month; this additional cost may be reduced to $165 - $262 per month within a decade if the costs of batteries and PV module technology are reduced. Electric Power Research Institute. (2014). *The Integrated Grid: Realizing the Full Value of Central and Distributed Resources*. Retrieved from: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=3002002733&Mode=download

[14] Ashley Brown, Executive Director, Harvard Electricity Power Group, Harvard University; and Louisa Lund, Program Director, Consortium for Energy Policy Research, Harvard University. (2013 April). Distributed Generation: How Green? How Efficient? How Well-Priced?. *The Electricity Journal*. Retrieved from: http://ac.els-cdn.com/S1040619013000523/1-s2.0-S1040619013000523-main.pdf?_tid=c8a136aa-f0a2-11e3-804b-00000aab0f27&acdnat=1402406949_3d200b2ce5860f02c0df4eceef8a257b

related costs must be recovered through fair rates and appropriate market mechanisms to ensure equitable allocation of costs and benefits.

- Fostering proper integration, not just interconnection, of emerging technologies with the Grid.
- Appropriately valuing fuel and technology diversity.
- Appropriately valuing the platform for two-way electricity sales.
- Allowing for geographic, political, and regulatory differences.

A. The Grid provides access to diverse resources and technologies

The Grid is vital to national security and a robust economy. As dependence on electricity from all resources increases, so will the importance of the networked nature of the grid, which provides operational flexibility and robustness. The Grid's ability to connect customers to a diverse supply portfolio provides the economy low-cost electricity, while protecting it from fuel supply shocks,[15] generation outages, and potentially disruptive catastrophes. Continued efforts under state and federal planning guidelines to enhance the Grid, *e.g.*, needed transmission to support renewable resource integration and facilitate supply diversity, will help ensure a robust economy.

For many reasons, the Grid is evolving to meet public policy requirements, technology innovations, emerging physical and cyber threats, and changing customer expectations. EEI

[15] Some utilities have experienced degradation in rail service for coal deliveries due to competition from other commodities. As available capacity for coal transportation decreases, some coal facilities are carrying smaller fuel stock piles than average, causing concerns about meeting demand at critical times. Rail infrastructure needs to be adequate to meet a variety of needs; recent experience by some utilities suggests that infrastructure investment in rail is needed.

believes that the value of the Grid can be maximized if emerging technologies (*e.g.*, distributed energy resources (DER) [16] and microgrids[17]) are properly integrated into the current system.

B. The Grid provides a platform for transition

The Grid's value is exhibited in its ability to transition and adapt in order to accommodate the replacement of aging plants, electricity markets, current and projected demand, reliability improvements, strengthened security, environmental objectives such as state mandated RPS and regulations promulgated by the Environmental Protection Agency (EPA), and customer's increasing expectations. EEI notes many of these changes have been supported by public policy initiatives, such as tax credits, net metering policies for the benefit of DER growth, and other measures.[18] EEI believes that as the popularity of these resources increases, the value and necessity of the Grid will expand, not diminish. Presently, the Grid is adapting, utilizing smart technologies to accommodate a cleaner and more fuel efficient generating fleet that helps meet the challenges of changing customer expectations and

[16] DER are resources such as: distributed generation (DG), small natural gas–fueled generators, combined heat and power plants, electricity storage, demand response and solar photovoltaics (PV) on rooftops and in larger arrays.

[17] Microgrids are under evaluation during this transition. While, currently, there is no universal agreement on the definition or size of a microgrid, there is one common theme: a microgrid has the capability to isolate from the macrogrid and independently manage generation assets and balance the critical electric loads within the microgrid. The key components that enable a microgrid to function independently of the macrogrid are: the switch gear that isolates the microgrid at the point of common coupling (PCC), the microgrid controls that maintain stability (equilibrium between supply and use), DERs, and controllable loads; importantly, a microgrid requires the integration of all components. KEMA & Massachusetts Clean Energy Center. (2014 February 3). *Microgrids: Benefits, Models, Barriers and Suggested Policy Initiatives for the Commonwealth of Massachusetts.* Retrieved from: http://images.masscec.com/uploads/attachments/2014/03/Microgrids%20-%20Benefits,%20Models,%20Barriers%20and%20Suggested%20Policy%20Initiatives%20for%20the%20Commonwealth%20of%20Massachusetts.pdf

[18] Presentation: *Business & Operational Implications of the Convergence of Bulk Power & Distributed Energy*, Paul De Martini, March 4, 2014

consumption patterns. A wide scope of new electric power supply resources, including DER, is playing a significant role in this transition.

In addition to adapting to a changing generation fleet, the Grid is transitioning to meet evolving customer expectations and consumption patterns, driven by technology and new applications for electricity use, while facing the highest reliability expectations ever. All businesses are facing the challenge of responding to the "Expectation Economy," fed by nearly unlimited, quick moving, and increasingly transparent information on the internet.[19] For the electric industry, these include increased expectations regarding reliability of service, lower cost and eco-friendly supply sources, including "making-it-yourself" options. Moreover, decisions on a range of DER and related technology and services by commercial customers "have become an integral aspect of managing key financial, energy security, brand, regulatory and competitive risks," according to a recent Ernst & Young survey of 100 global corporations.[20]

The electric industry has significantly increased its deployment of renewable energy in recent years, particularly wind and solar energy, driven in part by state RPS requirements. Renewables continue to grow rapidly, and renewable capacity is expected to more than double by 2035. Nearly 40% of all new capacity built in 2013 was from renewable resources**.**[21]

The industry has also significantly increased the utilization of natural gas for generating electricity. Low natural gas prices have affected all generation sources, and have spurred a

[19] http://trendwatching.com
[20] *Cleantech Matters, Global competitiveness Global Cleantech Insights Cleantech Insights and Trends*, Ernst & Young, 2012
[21] Ventyx Inc., The Velocity Suite

number of natural gas-electric coordination issues that the industry, in conjunction with natural gas producers, pipeline operators, and state and federal regulators, is proactively working to address.

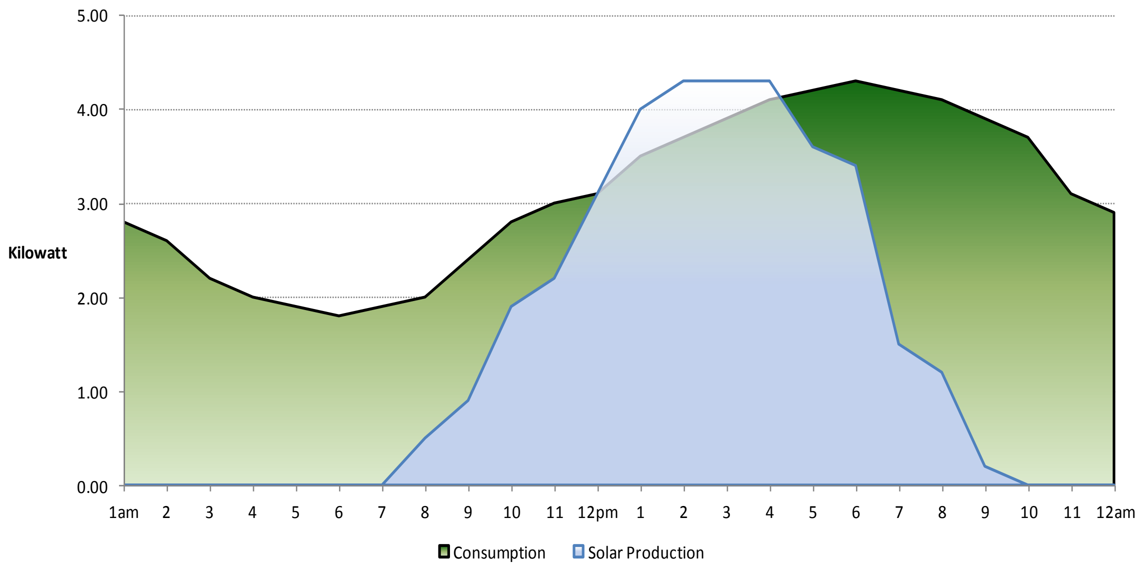
Nearly seventy gigawatts of coal plant retirements or retrofits, almost 20% of the coal fleet, have been publicly announced and are scheduled to take place between 2010 and 2022.[22] Upgrades to the transmission system are likely in many instances to ensure reliability is maintained despite the changing resource mix.

C. The Grid Provides Reliability

While the Grid and emerging technologies, such as DER, can be complementary, the centralized electrical system is still necessary to reliably meet customer needs. The Grid currently provides critical services such as access to generation capacity for back-up and replacement power for when the sun does not shine, the wind does not blow, or there is simply not enough DER to meet demand (current DER penetration is not large enough to meet demand), and provide grid stability. As illustrated by the graph in Figure 2 below, customers with DG systems still use the power system to support its resources and sell excess power, since electricity presently cannot be economically stored on a broad scale for later use.

[22] Edison Electric Institute

Figure 2. Typical Energy Production and Consumption for a Small Customer with Solar PV



Source: *Value of the Grid to DG Customers, IEE Issue Brief September 2013, Updated October 2013*, IEE, an Institute of The Edison Foundation. Available at: http://www.edisonfoundation.net/iei/Documents/IEE_ValueofGridtoDGCustomers_Sept2013.pdf

As the integration of wind and solar resources (both large and small-scale) continues in some regions of the country, the electric industry must maintain high levels of electric system reliability. System operators constantly make generation scheduling decisions in the face of uncertainty, since forecasts are never perfect and unforeseen generation equipment failures and other contingencies may occur. Operating Reserves are held to meet these operational fluctuations.[23] VER may exacerbate the uncertainty; for example, fast moving cloud cover could impact solar resources, and wind may not blow as forecast. Higher penetrations of variability, a

[23] Operating Reserves Include: Frequency Response, Regulating Reserves, Ramping Reserve, Load-following Reserves, and Supplemental Reserves. These different services can meet different types of events, and are categorized based on their ability to respond to events.

recent MIT study explains, will increase operating reserve requirements, which have been cited as one of the largest sources of cost increases associated with integration of VER.[24]

A joint report from the DOE and Duke Energy, acknowledged the utility industry's concerns about "significant penetration" of solar photovoltaic installations. Challenges around operating reliability, integration costs and the allocation of those costs across utilities' customer base "might become limiting factors for PV energy, especially growing distributed generation installed at customer sites."[25]

Growth in VER, including DG, is increasing challenges for system operators to address power quality issues. For example, The California Independent System Operator (CAISO) has analyzed the unique challenges presented by incorporating VER and DG, in California.[26] The Duck curve below graphically displays these challenges and illustrates the need for Grid capabilities and support services. The challenges include: the need for short, steep ramping capabilities in which generation resources can be brought online or shut down quickly; over-generation risks, in which more electricity is supplied than is needed; and decreased availability of units capable of providing frequency response.

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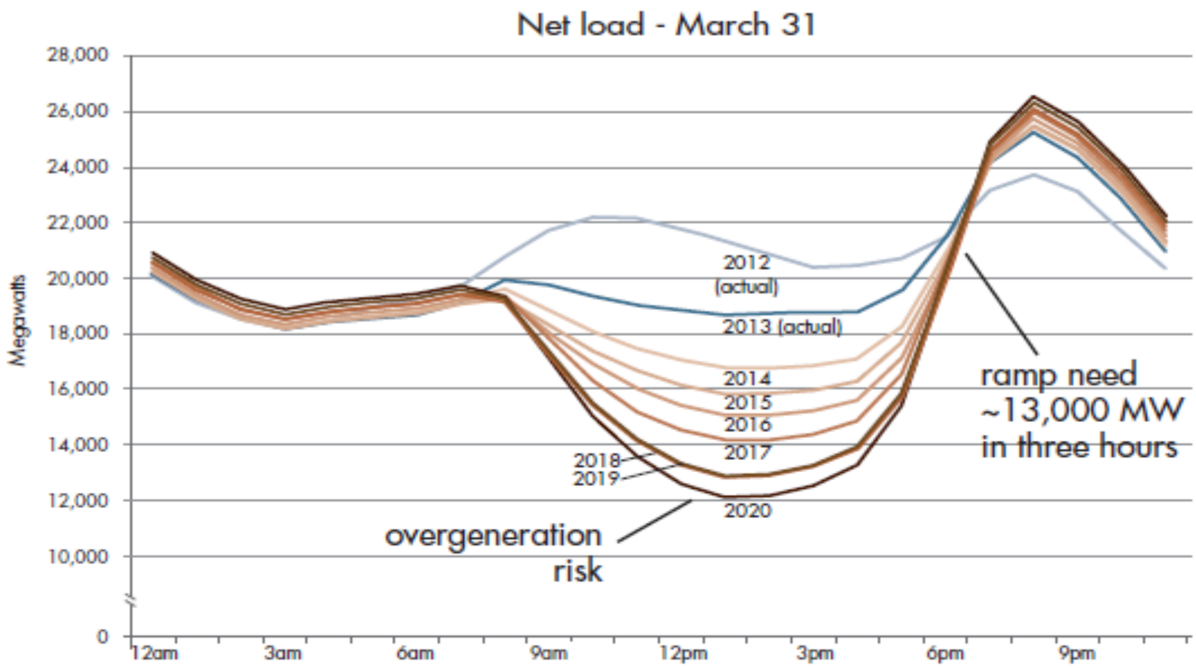
[24] Massachusetts Institute of Technology. (2011). *The Future of the Electric Grid, An Interdisciplinary MIT Study*. Retrieved from: http://web.mit.edu/mitei/research/studies/the-electric-grid-2011.shtml

[25] Pacific Northwest National Laboratory. (2014 March). *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas*. Retrieved from: http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23226.pdf

[26] Fast Facts: What the Duck Curve Tells Us About Managing a Green Grid, California ISO. Retrieved from: http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf. Additionally, Independent System Operators grew out of FERC Orders Nos. 888/889. In FERC Order No. 2000, the Commission encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada). For more information, see: http://www.ferc.gov/industries/electric/indus-act/rto.asp

Figure 3. The Duck Curve Shows Steep Ramping Needs and Overgeneration Risk



Source: *Fast Facts: What the Duck Curve Tells Us About Managing a Green Grid*, California ISO. Available at: http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

System planning and operations experts, the DOE labs, and other entities are working now on solutions to ensure adequate levels of generation reserves, and to address the steep ramping needs and potential over generation supply issues created by VER, maintain necessary levels of frequency and voltage support, and ensure the fidelity of planning, modeling, and operational tools, including Supervisory Control and Data Acquisition (SCADA) equipment and Energy Management Systems (EMS). Current solutions and infrastructure investments include advanced monitoring and control systems, circuit design changes, new and/or updated grid components, operational processes, advanced distribution planning capabilities, and platforms for data exchange.[27] Importantly, system operators will be better equipped to address these variability issues when they have access to a diverse generation portfolio or are part of a sharing group with regional variability.

II. Reliability is the Electric Industry's Mission Number One; Securing and Protecting Our Nation's Electric Grid is Critical to Our Mission

The industry, supported by a highly dedicated workforce, maintains the Grid's physical and cyber security, reliability, and robustness on a continual, minute-to-minute basis. As such, EEI's members are partnering closely with each other and with senior officials from relevant federal and state agencies, as well as law enforcement, to protect the Grid's most critical assets from natural (i.e., natural disasters or environmental catastrophes), cyber, and physical threats.

For many years, the industry developed and operated under voluntary programs to assure reliability.[28] Since enactment of Section 215 of the Federal Power Act in 2005, the electric industry has successfully transitioned to a comprehensive set of mandatory, enforceable reliability standards for the bulk power system. Companies now may be assessed penalties of up to $1 million per day per violation under this system. Since enactment, FERC

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[27] Electric Power Research Institute. (2014). *The Integrated Grid: Realizing the Full Value of Central and Distributed Resources*. Retrieved from: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=3002002733&Mode=download
Paul De Martini. (2014 March 4). *Business & Operational Implications of the Convergence of Bulk Power & Distributed Energy*.

[28] Federal Power Commission. (December 6, 1965). *Report to the President by the Federal Power Commission on the Power Failure in the Northeastern United States and the Province of Ontario on November 9~10, 1965*. Retrieved from http://blackout.gmu.edu/archive/pdf/fpc_65.pdf

approvals and oversight of the mandatory standards have addressed the broad range of challenges identified in the 2003 U.S. – Canada Blackout Report, including for example vegetation management on transmission rights-of-way, emergency planning and operations, system protection, and system operator communications.[29]

A. Vulnerabilities Are Being Addressed Through Measures to Protect, Harden, and Provide Resiliency for America's Electric Infrastructure

One principal focus of the QER, as stated in DOE's public memorandum, is to identify and address infrastructure vulnerabilities that may compromise the operation of the grid.[30] It references Presidential Policy Directive 21 addressing national policy to work with owners, operators, state and local governments to manage risks to critical infrastructure.

National attention on the security and resilience of the Nation's electrical grid has grown along with the recent increase in damaging storms, cyber security threats and physical attacks. Government agencies, industry experts, and the public have called for mechanisms to protect our vital infrastructure. The electric power industry employs threat mitigation, known as "defense-in-depth," that focuses on various layers of protection, including preparation, prevention, response and recovery. Although security cannot be one-hundred percent assured at all times, the industry's commitment is to manage risk appropriately by utilizing such an approach.

[29] U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. Available at: https://www.ferc.gov/industries/electric/indus-act/reliability/blackout/ch1-3.pdf
[30] DOE memorandum to Member of the Public dated April 2, 2014.

As the attention on resilience has escalated, the Nation's utilities have for many years been working to strengthen and protect the grid while forging partnerships to better respond to widespread outages and other emergency situations. As noted by Joseph Rigby in his prepared statement at the April 11, 2014, QER public meeting:

> . . . the utility sector has experience operating an electric utility system; the government must depend on this private sector engineering and operational expertise that keeps the grid running reliably in the face of all hazards.[31]

EEI firmly believes that utility sector expertise and experience must continue to be utilized to ensure reliable, low-cost electric service continues to be provided to customers.

The QER provides an opportunity to encourage consistent funding for long-term plans, particularly for extreme (or extreme weather) events. For example, many state regulators evaluate capital investments holistically, taking into account anticipated challenges and dynamics facing the transmission and distribution system; these efforts should be continued. To this end, prioritization of policies will assist utilities as they seek to prioritize investments in resilient systems, while maintaining their focus on needed capital infrastructure investments, reliability and technology enhancements.

The QER should also consider all applicable tools, including federal tax provisions and disaster funding to incentivize utilities to build stronger and more resilient systems following, and in preparation for, extreme events. Specifically, the Federal government should assure the

[31] Statement for the Record of Joseph Rigby Chairman, President and CEO Pepco Holdings, Inc., "Enhancing Resilience in Energy Infrastructure and Addressing Vulnerabilities" Before the Quadrennial Energy Review Task Force. (April 11, 2014)

continued ability of CDBG recipients to utilize funding, including disaster recovery funding, for the repair and restoration of privately-owned electric utility infrastructure in the wake of extreme events.[32]

B. Public and Private Partnerships for Restoration and Recovery

Establishment of electric power industry/government partnerships designed to enhance recovery and restoration efforts following significant outage events is critical to effective preparation and response. EEI strongly supports these coordinated efforts to minimize the duration of outages. Recommendations resulting from the QER should recognize coordinated efforts and clearly defined roles among industry, federal, and state governments for outage response.

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[32] Under existing law (the Housing and Community Development Act of 1974, 42 U.S.C. §5305 (a)(17)(C)), CDBG funding can be used to provide assistance to "private, for-profit entities, when the assistance . . .meets urgent needs." Under existing Department of Housing and Urban Development (HUD) regulations (24 C.F.R. § 570.201(l)), CDBG funds may be used "to acquire, construct, reconstruct, rehabilitate, or install the distribution lines and facilities of privately owned utilities, including the placing underground of new or existing distribution facilities and lines." However, in connection with the allocation of CDBG disaster recovery funds in 2013 as part of the response to Hurricane Sandy, HUD limited assistance to for-profit entities to only those entities that met the definition of a "small business." This action effectively prevented the use of CDBG funds for the repair or restoration of facilities of privately owned utilities that were badly damaged by Hurricane Sandy.

In prior cases of exceptional damage to the electric grid (9/11, Hurricane Katrina), funds were made available through CDBG program to repair or rebuild privately-owned utility infrastructure. The determination on whether to provide assistance to private entities was made by the state or local jurisdiction receiving the CDBG funding. The cost of repairing or replacing damaged or destroyed utility infrastructure is paid by for by all utility customers through their state-regulated rates. If a state or local government deems it particularly important to avoid added cost burdens on low- and moderate-income electricity customers from high storm/disaster recovery costs, the CDBG program has offered a means to reduce the economic impact of the costs of utility infrastructure repair to local residential and business customers.

The limitation imposed in connection with Hurricane Sandy CDBG Disaster Relief funds should not become a precedent for the future. HUD's action denied CDBG recipients the flexibility to use funds as they deemed necessary to meet the greatest unmet needs. Federal policy should preserve the ability of CDBG recipients to use funds to restore electric infrastructure owned by privately owned utilities.

EEI believes that continued facilitation and participation in emergency response drills will strengthen public/private partnerships and help all parties better coordinate and allocate resources such as equipment (e.g. hardware, materials, human resources, and expertise). Drills and collaborative planning could alleviate certain issues before they become conflicts (e.g., prioritization of recovery, and distribution of limited resources). In the event that conflicts arise, partnerships should provide effective conflict resolution. Recommendations resulting from the QER should encourage further industry-government emergency drill opportunities and logistical coordination; specifically, the Federal Government should be encouraged to examine partnerships to facilitate the movements of transmission transformers by rail, barge, air, or other modes of transportation to locations where equipment is critically needed.

The response to Superstorm Sandy demonstrated that coordination among electric utilities and federal, regional, state and local authorities is vital to restoration efforts. These partnerships have worked to improve communication and coordination in restoration efforts. Utilities, including their trade associations, and government leaders held daily conference calls to ensure that restoration needs were being met and that restoration crews had the necessary resources they required. In addition, an industry senior executive was embedded within the Federal Emergency Management Agency's National Response Coordination Center to ensure that restoration logistics were handled properly and that communication channels were kept open.

Another goal of the enhanced electric industry/government partnership is to streamline transportation logistics during restoration and recovery. Collaboration and information sharing among the U.S. Department of Transportation, state transportation and emergency management agencies, the Department of Homeland Security, the Canadian Border Services Agency and utilities are aimed at expediting the movement of electric utility resources in support of mutual assistance by issuing needed transportation permits and addressing delays through tolls and weigh stations for traveling support crews during restoration efforts. The electric industry/government partnership also seeks to enhance logistical support, security and road access for crews traveling large distances to assist in restoration. Again, during Superstorm Sandy, the U.S. Department of Defense (DOD) assisted the industry by creating restoration staging areas at federal air facilities and providing airlifts for crews and equipment from as far away as California to storm-torn areas in New York and New Jersey.

1. Electricity Subsector Coordinating Council (ESCC)

The Electricity Subsector Coordinating Council (ESCC) serves as the principal liaison between the federal government and the electric power sector, with the mission of coordinating efforts to prepare for, and respond to, national-level disasters or threats to critical infrastructure. The ESCC includes utility Chief Executive Officers (CEOs) and trade association leaders representing all segments of the industry. Its government counterparts include senior Administration officials from the White House, relevant Cabinet agencies, federal law enforcement, and national security organizations. Industry and government leaders have agreed to focus on providing tangible progress in three main areas:

- Tools & Technology: Deploying proprietary government technologies on utility systems that enable machine-to-machine information sharing and improved situational awareness of threats to the grid;

- Information Flow: Making sure actionable intelligence and threat indicators are communicated between the government and industry in a time-sensitive manner; and
- Incident Response: Planning and exercising coordinated responses to an attack.

To support the mission of the ESCC, a Senior Executive Working Group (SEWG) of Chief Operating Officers, Chief Information Officers, and other senior executives who have relevant expertise in the electric power sector has been convened. The SEWG meets by phone on a monthly basis and creates ad hoc "sub-teams" to accomplish the goals identified by the CEOs and Deputy Secretaries. In parallel to this effort, the government also is organizing around these goals with a commitment to align government and industry efforts.

2. National Response Event (NRE) framework

The IOU mutual assistance program provides for sharing of resources between IOUs during storm response. Partnerships in the mutual assistance program are based upon voluntary agreements among electric utilities within the same region. Most of these agreements are managed by seven Regional Mutual Assistance Groups (RMAGs) throughout the country. While RMAGs have handled numerous outages events over several decades and continue to work today, recent events such as the June, 2012 Derecho and Superstorm Sandy illustrated the need for a higher degree of national coordination. The IOUs have developed the NRE Framework to provide that national coordination in the event of another of these very serious events with wide spread power outages. Municipal utilities and electric cooperatives also have their own mutual aid programs that provide restoration support to their participating utilities.

By definition, an NRE is a natural or man-made event that is forecasted to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple RMAGs. The response and restoration plan for a designated NRE includes a new standing and rotating National Response Executive Committee, consisting of senior-level member company executives representing all regions of the United States. It also establishes an inter-RMAG framework for a national allocation of member company mutual assistance resources (utility restoration workers, contractors, and spare materials). When an NRE is declared, all available member emergency restoration resources (including contractors) will be pooled and allocated to participating utilities in a safe, efficient, transparent, and equitable manner.

3. Spare Transformer Equipment Program (STEP)

Utilities plan for all types of contingencies and have spare equipment available as part of their business continuity planning. Just as companies share crews as part of the industry's voluntary mutual assistance program, they also share transformers and other equipment regularly. The electric power industry created the Spare Transformer Equipment Program (STEP) in 2006. This program is designed to support the transmission system by making certain that the electric power industry has a cost-effective process in place to increase reliability by having sufficient spare transformer capacity available. STEP provides a ready mechanism for participating utilities to share assets in the event of catastrophic destruction. More than 50 electric power companies geographically dispersed across the country and engaged in bulk power transmission services are members of STEP. This number continues to grow as additional companies participate in an effort to ensure greater resilience and reliability. Each participating member enters into a STEP contract that provides legally enforceable rights to access hard-to-replace transformers, which have been committed to STEP. To support this program, the electric power industry has identified "worst-case-scenario" requirements to ensure equipment is readily available for various voltage classes of equipment—such as those supporting large substations. This "sufficiency test" is conducted annually to ensure all voltage classes have an adequate number of spares or to determine if new acquisitions need to be made. Coordination involving the transfer of spare equipment has already been reviewed and approved by the Federal Energy Regulatory Commission (FERC) and state utility regulators, thereby requiring no additional regulatory approvals to access this spare capacity during a declared emergency.

4. *SpareConnect*

To complement the existing STEP program, the electric industry is targeting the launch, in the second quarter of 2014, of the *SpareConnect* program, which provides a mechanism for utility asset owners and operators to network with other *SpareConnect* members concerning sharing of transmission and generation step-up transformers and related equipment, including bushings, fans, and auxiliary components. *SpareConnect* establishes a formal program—which already exists on an informal basis—to communicate equipment needs, in the event of an emergency or other non-routine failure, and to connect interested utilities in a more efficient and effective way. As with STEP—where spare transformers are located, operated, and maintained on a decentralized basis thereby protecting the integrity of the overall system—

SpareConnect provides decentralized access to points of contact with similar equipment. Participation in *SpareConnect* is open to all current STEP members as well as other utilities in the U.S., Canada and Mexico and participants are able to request the availability of transformers and related equipment from other participants in the event of an emergency or other non-routine failure. Those participants who are interested in providing transformers or related equipment would work directly and privately with each other on specific terms and conditions around the voluntary provision or sale of equipment.

C. Cyber and Physical Security

The Grid is a complex, interconnected network of generation, transmission, distribution, control, and communication technologies. Due to the interconnected nature of the Nation's grid and a move towards digitization, the electric industry has seen an increasing number of threats to the grid either through cyber or physical attacks. In 2013, Industrial Control System's Cyber Emergency Response Team (ICS_CERT) responded successfully to 256 incidents, 59 percent of which occurred in the energy sector, reported either directly by asset owners or through other trusted partners. ICS_CERT notes that the trusted relationship between ICS_CERT and industry, as well as an increase in awareness and reporting in the energy sector, is responsible for the increase in reported incidents.

The electric power industry is forging ahead with a series of initiatives to safeguard the electric grid from threats and is partnering with federal agencies to improve sector-wide resilience to cyber and physical threats. The industry also collaborates with the National Institute of Standards and Technology, the North American Electric Reliability Corporation

(NERC), and federal intelligence and law enforcement agencies to strengthen its capabilities. As threats to the grid grow and become more sophisticated, the industry remains committed to continuing to strengthen its defenses.

1. NERC's GridEx II

NERC's GridEx II exercise on November 13-14, 2013 simulated a severe, coordinated cyber and physical attack on the electric industry, allowing electric utilities across the nation to exercise their response and recovery plans. Over 2000 individuals participated in this exercise including EEI, member electric utilities, and federal and state agencies. GridEx II concluded with an executive table top discussion that brought together utility CEOs and government executives to discuss some of the most challenging issues that require coordination between industry and government. Utility and federal participants are incorporating the lessons learned from this exercise to improve their individual and coordinated security and resiliency efforts. The ESCC has prioritized the recommendations from the executive table top discussions and the National Infrastructure Advisory Council and is working with government to solve these challenges.

2. CIP Version 5 implementation

NERC and the industry continue to implement a comprehensive set of reliability standards to protect the grid's critical infrastructure. Version 5 of the Critical Infrastructure Protection (CIP) standards represents both a significant expansion of the systems covered as well as required actions over the current version of the CIP standards. Version 5 categorizes bulk electric system (BES) Cyber Systems using a new methodology based on whether a BES

Cyber System has a Low, Medium or High Impact on the reliable operation of the bulk electric system cyber assets will be under protection. Compliance with provisions for High and Medium Impact cyber systems must be met by April 2016 with compliance for Low Impact systems due April 2017.

3. Physical Security Standards

The FERC has directed NERC to develop two sets of mandatory reliability standards aimed at protecting physical assets. In March 2014, FERC directed NERC to develop reliability standards, by June 5, 2014, requiring owners and operators of the Bulk-Power System to address physical security risks to critical substations and control centers via risk assessments, evaluation of potential threats and vulnerabilities of critical facilities, and development, independent review of and implementation of a security plan. NERC, working through an industry-led standard drafting team, completed work on the standard in April and it was approved by a significant majority of industry in early May. The proposed standard, CIP-014-1, was filed with FERC on May 23, 2014.

In a second FERC order, FERC proposed to adopt a new reliability standard to mitigate the impacts of Geomagnetic Disturbances (GMDs) that can have potentially severe, widespread effects on reliable operation of the Bulk-Power System. The NERC standard drafting team developed the proposed standard meeting FERC's requirements that was approved by industry and NERC; it is pending approval by FERC. The second set of standards is due January 2015.

III. Reliability and Resilience Requires Needed Investment in Transmission and Distribution and Proper Integration of the Power Supply Portfolio Into the Grid.

Continued significant investment in the Grid will be paramount to our country's success in reaching our environmental and economic goals and maximizing value to customers, as the Grid facilitates the realization of this Administration's "all of the above" energy strategy. EEI believes that the Grid and emerging technologies (e.g., DER and microgrids) can be complementary, but only if proper integration and planning occurs. To support the proper integration of emerging technologies into the Grid, EEI believes that recommendations resulting from the QER should encourage transmission and distribution investment, encourage integrated planning, ensure reasonable costs for all users, minimize unreasonable cost-shifting.[33]

Given the importance of a robust and resilient grid and the many challenges in developing, siting, constructing and upgrading infrastructure, it is imperative that coordinated planning is supported and investment is encouraged by state and federal policymakers. Regulatory policies should be dependable and applied consistently to provide investors with returns commensurate with the risks associated with developing transmission and distribution in order to ensure sufficient capital is available to finance needed infrastructure. In addition, EEI

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[33] Some net metering policies were designed such that net-metered customers (e.g., solar or other DG systems) are credited for the power they sell to electric companies, usually at the full retail electricity rate which includes all costs associated with the Grid. However through this credit, net-metered customers are effectively avoiding paying the costs of the Grid, which they still use (e.g., poles, wires, meters, advanced technologies, and other infrastructure). As a result, these costs are shifted to those customers without solar or other DG systems. Edison Electric Institute. (2013). *A Policy Framework for Designing Distributed Generation Tariffs*. Retrieved from: http://www.eei.org/about/meetings/Meeting_Documents/Policy%20Framework%20for%20DG%20August%2029%20FINAL.pdf

supports voluntary coordination among state and federal agencies on infrastructure siting, permitting and approval processes, taking regional considerations into account when appropriate.

A. Transmission and Distribution Investment

Integrated transmission and distribution planning is currently carried out by utilities to facilitate investments supporting the Grid, enabling access to a diverse and low cost generation fleet, reliable delivery of electricity, and a platform for transition. Current investments are ongoing, incorporating advanced monitoring systems and other new technologies; these provide the ability in places to automatically isolate and re-route around outages. Moreover, infrastructure build-out employs stronger construction standards than ever before.

Investment risk in the Grid, particularly for transmission infrastructure, can be significant. For example, transmission projects typically require long lead times for planning, siting, and permitting, stakeholder processes, and construction challenges. Public policy requirements have also recently found an increased role in transmission planning, also contributing to risks.[34] Therefore, uncertainty and inherent risks remain for the development of any type of transmission project, requiring regulatory certainty and appropriate rates of return.

Because of the inherent risks and challenges of developing transmission infrastructure, EEI's members have a long history of working with policymakers and regulators to support

[34] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011), order on reh'g, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), order on reh'g, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

effective policies, such as appropriate returns on equity, to address the substantial risks of developing, constructing, operating and maintaining grid infrastructure, as well as the challenges of raising needed capital to fund transmission and distribution development.[35] Supportive policies have encouraged needed investment in our infrastructure, and will be necessary going forward.

Pursuant to state and federal requirements, IOUs and stand-alone transmission companies invested a record $34.9 billion in transmission and distribution infrastructure in 2012. Capital expenditures on transmission totaled $14.8 billion in 2012—a 23.9% increase over the $11.9 billion (nominal $) that the industry invested in 2011. Investment in electric distribution infrastructure totaled $20.1 billion (nominal $) in 2012— a 4.7% increase over the $19.2 billion (nominal $) invested in 2011. These expenditures included measures to improve storm hardening and resiliency, and reliability by incorporating smart grid technologies, advanced metering infrastructure, advanced monitoring technology, storage, and various methods for avoiding peaking plant investments.[36]

B. Planning and Siting

Both federal and state policies play a critical role in the planning, siting, development and cost recovery of transmission infrastructure, while distribution assets fall more distinctly

[35] *See* Transmission Investment – Adequate Returns and Regulatory Certainty Are Key at page 11, published by Edison Electric Institute June 2013.
[36] Edison Electric Institute. (2013). *EEI Survey Shows Electric Power Industry Made Record Levels of Investment in Transmission and Distribution*. [Press Release]. Retrieved from: http://www.eei.org/resourcesandmedia/newsroom/Pages/Press%20Releases/EEI%20Survey%20Shows%20Electric%20Power%20Industry%20Made%20Record%20Levels%20of%20Investment%20in%20Transmission%20and%20Distribution.aspx

under the jurisdiction of states. With respect to transmission siting, states have jurisdictional authority over transmission siting (including interstate facilities), while the Federal government has jurisdictional authority over transmission siting in instances where facilities cross federal lands or international borders. With respect to distribution siting, states and local authorities have jurisdictional authority.

Many states have jurisdictional authority over resource adequacy and utilities' integrated resource and capital plans, to ensure the needs of each states' electric customers are met. Many states holistically evaluate capital investment plans, taking into account new challenges and dynamics facing the distribution system. States will continue to play a critical role in identifying public policies and developing requirements, which are then considered by the relevant planning authority to select transmission projects.

Interregional planning efforts have occurred. FERC has prescribed planning requirements, providing a model for regional and interregional evaluation of transmission infrastructure.

Interconnection-wide system planning efforts have occurred. The DOE funded interconnection-wide planning studies, such as the Eastern Interconnection Planning Collaborative (EIPC), in conjunction with the Eastern Interconnection States' Planning Council (the EIPC is comprised of 40 states and DC in the Eastern Interconnection), and parallel efforts by WECC state regulators and other governmental agencies, provide long-term strategic guidance to planners and stakeholders. These efforts provide potential information sources for the QER.[37]

The Administration has already directed federal agencies to coordinate transmission siting and permitting on federal lands in an attempt to bolster infrastructure development. Building on the previous Rapid Response Team for Transmission, the Administration has established a steering committee to identify best-management practices and process improvements for reducing transmission project review times.[38] Simultaneously, the Administration has required federal agencies to study electric transmission corridors and develop an interagency pre-application process for significant onshore electric transmission projects requiring federal approval.[39] EEI strongly supports these actions to streamline federal permitting and siting processes for transmission development on federal lands; they should continue.

C. The Power Supply Portfolio Must be Properly Integrated into the Grid

The interrelated nature of the Grid, and the growth in the number of smaller-scale resources connected to the Grid, requires proper integration.[40] Proper integration

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[37] The EIPC is currently conducting a Gas-Electric Interface Study, addressing coordination needs between the industries. See http://www.eipconline.com/Gas-Electric_Activities.html

[38] Presidential Memorandum – Modernization Federal Infrastructure Review and Permitting Regulation, Policies, and Procedures (May 17, 2013).

[39] Presidential Memorandum – Transforming our Nation's Electric Grid Through Improved Siting, Permitting, and Review (June 7, 2013).

[40] Continued deployment of DER on utility systems, without proper integration, may not be sustainable. Electric Power Research Institute. (2014). *The Integrated Grid: Realizing the Full Value of Central and Distributed Resources*. Retrieved from: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=3002002733&Mode=download

encompasses coordinated transmission and distribution planning, operations, Grid expansion, and recognizing jurisdictional authorities.

The growth in DER, and its variability, requires appropriate capacities of the existing electric power grid: distribution systems must be capable of absorbing the output of DER; transmission systems must assure that balancing services and supplemental power are available to support DER; and adequate generation must be available to supply replacement power and backup services. Distribution systems were not originally designed to accommodate a high penetration of DER and two-way electricity flows while sustaining high levels of electric quality and reliability.[41]

To some extent, the bulk transmission system is already facilitating bi-directional power flows so that customers can engage in both purchases and sales of energy. If emerging technologies are properly integrated, bi-directional flows over the transmission and distribution systems could be reliably and safely realized at relatively higher penetration rates than observed today. Currently, critical reliability services such as load balancing and voltage support provided by centralized, dispatchable, "large rotating machines."[42] Proper integration of emerging technologies may in the future allow them to also provide critical services to the Grid; until then traditional centralized resources are needed.

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[41] Jurisdictional issues may arise due to increased two-way flows on the distribution system as a result of DER integration.

[42] Testimony of Gerry Cauley, President and Chief Executive Officer North American Electric Reliability Corporation Before the Quadrennial Energy Review Task Force, Public Meeting on "Enhancing Resilience in Energy Infrastructure and Addressing Vulnerabilities" (April 11, 2014).

As the nation considers changes to the electricity system to support emerging technologies such as DER and microgrids, policy makers must work to create policies that do not undermine reliability of the grid that is already in place, unfairly shift costs, or levy experimental and long-lived rate increases onto customers. EEI emphasizes that policy makers should be made fully aware of the complexities associated in ensuring the safe and reliable(e.g., power quality issues that arise with isolated low inertia electric grids), fair, and efficient operation of the Grid as the penetration of emerging technologies grows, and should enable effective mechanisms to assign, ensure, and enforce the reliability and safety of integrated systems. Policy makers should consider:

- reasonable, equitable development and enforcement of reliability and safety standards,
- technical and regulatory barriers for proper integration,
- the costs, benefits, and limitations of portfolio integration,
- how to ensure reasonable costs for customers, and
- how to minimize unreasonable cost-shifting among customers.

As noted by EPRI, an integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require collaboration in the following four key areas:[43]

1) Interconnection Rules and Communications Technologies and Standards
   - *Interconnection rules* that preserve voltage support and grid management

[43] Electric Power Research Institute. (2014). *The Integrated Grid: Realizing the Full Value of Central and Distributed Resources*. Retrieved from: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=3002002733&Mode=download

- *Situational awareness* in operations and long-term planning, including rules of the road for installing and operating distributed generation and storage devices
- Robust *information and communication technologies*, including high-speed data processing, to allow for seamless interconnection while assuring high levels of cyber security
- A *standard language and a common information model* to enable interoperability among DER of different types, from different manufacturers, and with different energy management systems

2) Assessment and Deployment of Advanced Distribution and Reliability Technologies
   - *Smart inverters* that enable DER to provide voltage and frequency support and to communicate with energy management systems to maintain power quality within the grid
   - *Distribution management systems and ubiquitous sensors* through which operators can reliably integrate distributed generation, storage, and end-use devices while also interconnecting those systems with transmission resources in real time
   - *Distributed energy storage and demand response*, integrated with the energy management system
3) Strategies for Integrating DER with Grid Planning and Operation *Distribution planning and operational processes* that incorporate DER
   - *Frameworks for data exchange and coordination* among DER owners, distribution system operators (DSOs), and organizations responsible for transmission planning and operations
   - Flexibility to *redefine roles and responsibilities* of DSOs and independent system operators (ISOs)
4) Enabling Policy and Regulation *Capacity-related costs* must become a distinct element of the cost of grid-supplied electricity to ensure long-term system reliability
   - *Power market rules* that ensure long-term adequacy of both energy and capacity
   - *Policy and regulatory framework* to ensure that costs incurred to transform to an integrated grid are allocated and recovered responsibly, efficiently, and equitably
   - *New market frameworks* using economics and engineering to equip investors and other stakeholders in assessing potential contributions of distributed resources to system capacity and energy costs[44]

[44] Based on EEI's interpretation, this term refers to the need of policy makers to evaluate how to appropriately recover fixed and variable costs from end-use customers as DER deploys more widely.

Similarly, reliable integration of microgrids into the Grid presents challenges that must be addressed. As noted above, microgrids must be able to independently manage generation assets to instantaneously balance with load. Some decentralized capabilities may be desirable in some applications; proper controls and communication systems with the macrogrid will be required to assure parallel operations and respond to emergencies.

As noted by Joseph Rigby, new control and information technologies are enabling possible further sectionalizing and networking of the grid into microgrids that may allow operation independently of the main grid during system emergencies.[45] Industry and policy makers must thoughtfully balance costs and benefits as technologies and their associated economics evolve.[46]

Speaking to the optimality of coordinated integration with the Grid, studies conducted by the DOD on the efficacy of DER and microgrid deployment conclude that most cost-effective solutions will be those that take into account the needs of the local commercial electric grid and implement DER and microgrids so that they can earn value by helping to meet the needs of

[45] Statement for the Record of Joseph Rigby Chairman, President and CEO Pepco Holdings, Inc., "Enhancing Resilience in Energy Infrastructure and Addressing Vulnerabilities" Before the Quadrennial Energy Review Task Force. (April 11, 2014)

[46] As a cautionary note that policies related to integration of DERs, EEI references the German experience. Presently, Germany is targeting producing 50% of its electricity from renewable resources by 2030 and 80% by 2050, with costs to do so now estimated at $1.35 trillion over the next 25 years. Attaining these goals will further increasing high German electric rates, already twice the U.S. average and the highest in Europe. Part of problem is a steep renewables surcharge that is added to every bill, which is set to jump another 20%. *Germany's Energy Poverty: How Electricity Became a Luxury Good*, by Spiegel Staff, Der Spiegel, August 26, 2013. Available at: http://www.spiegel.de/international/germany/high-costs-and-errors-of-german-transition-to-renewable-energy-a-920288.html

the local commercial electric grid.[47] For example, several installations including NSF Dahlgren and Ft. Detrick have determined that operating on-site assets in parallel to the local commercial electric company is "worthwhile" for either increased reliability or to gain financial benefit through Utility rate structures (e.g., demand response programs).[48] EEI believes such findings bolster the concept that integration, not just interconnection, will provide the greatest value to customers and there will continue to be a need for electric utilities to do what they do best: reliably operating and maintaining the grid, while working collaboratively with other stakeholders to develop tailored solutions.

IV. Adherence to Critical Policy Principles Will Ensure the Reliability, Resiliency, and Security of the Grid.

The Grid facilitates our high standard of living and drives our economy by providing access to reliable, cost-effective electricity, and provides the platform for the Administration's "all of the above" energy strategy. Policies should appropriately reflect the value of the Grid and recognize jurisdictional boundaries by:

- Appropriately valuing reliability and its necessary services (e.g., frequency response, voltage control, balancing, etc.), including back-up power; capacity-related costs must be recovered through fair rates and appropriate market mechanisms to ensure equitable allocation of costs and benefits.

- Recognizing utility obligations in the states.

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[47] Van Broekhoven, S.B., et al.: Microgrid Study: Energy Security for DoD Installations, Technical Report 1164, prepared for the Office of the Secretary of Defense by the Lincoln Laboratory, Massachusetts Institute of Technology, June 18, 2012

[48] Van Broekhoven, S.B., et al.: Microgrid Study: Energy Security for DoD Installations, Technical Report 1164, prepared for the Office of the Secretary of Defense by the Lincoln Laboratory, Massachusetts Institute of Technology, June 18, 2012

- Fostering proper integration, not just interconnection, of emerging technologies with the Grid.
- Appropriately valuing fuel and technology diversity.
- Appropriately valuing the platform for two-way electricity sales.
- Allow for geographic, political, and regulatory differences.

There are great benefits to be gained from public/private partnerships to address critical outages and advance grid security. However, EEI does not advocate new mandates in this area, as they may not afford necessary flexibility; we urge our federal partners to continue and build upon the dialogue and information sharing we have accomplished. Recommendations from the QER should:

- Encourage further industry-government partnership emergency drill opportunities to continue improving coordination and allocation of resources, and identification of expertise.
- Encourage Federal and state governments, utilities, and other Grid operators to continue exploring new and/or improved opportunities to increase bi-directional, confidential information sharing regarding potential cyber and physical security threats.
- Support legislation to address liability for information sharing with respect to cyber security.
- Federal officials should seek to enhance tax provisions and other federal programs to ensure a consistent funding for long-term plans, particularly for extreme (or extreme weather) events. Such reforms should seek to promote utility efforts to rebuild stronger and more resilient systems following extreme events. Federal rules and programs should be inclusive of all entities responsible for developing and maintaining resilient energy infrastructure.

  - The Federal government should assure the continued ability of Community Development Block Grant (CDBG) recipients to utilize funding, including disaster recovery funding, for the repair and restoration of privately-owned electric utility infrastructure in the wake of extreme events.

- Industry/Government partnerships should continue to improve logistical coordination and staging during emergency and restoration events, including methods for moving transmission transformers by rail, barge, air, or other modes of transportation.

Regulatory certainty and the consistent application of supportive policies are paramount to encouraging necessary needed investment in the Grid, particularly transmission and distribution infrastructure. Recommendations resulting from the QER should:

- Encourage additional investments by highlighting and encouraging existing federal and state policies and programs that support transmission and distribution investment.
- Recognize the inherent risks and challenges of developing transmission projects and ensure that investors earn predictable, sustainable, and reasonable returns on infrastructure investments, to ensure that the industry continues to attract needed investment.
- Ensure that all who benefit from the Grid, pay for the Grid and minimize unreasonable cost-shifts among customers.
- Promote utilities' efforts to innovate rate designs, allow for flexibility to ensure that the Grid is accurately valued and fairly compensated.
- Recognize policy goals that influence the electric industry's ability to make the necessary investments to meet emerging challenges and opportunities.
- Streamline transmission siting processes on federal lands requiring approval by more than one federal agency.

- Build on DOE's ongoing evaluation of best practices for an Integrated, Interagency Pre-Application Process in an effort to facilitate a more streamlined and efficient transmission project review process.[49]

V. Conclusion

EEI appreciates the opportunity for stakeholder participation in the QER process, and supports this effort to examine the Nations' energy infrastructure, identify vulnerabilities, and develop policy recommendations to address these matters. To that end, we submit these comments for the public record and look forward to participating in the dialogue for this and future installments of the QER.

[49] *See*, Department of Energy – Improving Performance of Federal Permitting and Review of Infrastructure Projects, Request for Information, 78 Fed. Reg. 53436 (Aug. 29, 2013).

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VI. Appendix A. List of Acronyms

Acronym	Definition of Acronym
BES	Bulk Electric Systems
CDBG	Community Development Block Grant
CHP	Combined Heat and Power
CIP	Critical Infrastructure Protection
DER	Distributed Energy Resources
DG	Distributed Generation
DOD	Department of Defense
DOE	Department of Energy
DSO	Distributed System Operators
EEI	Edison Electric Institute
EIPC	Eastern Interconnection Planning Collaborative
EMS	Energy Management System
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESCC	Electricity Subsector Coordinating Council
FERC	Federal Energy Regulatory Commission
ICS-CERT	Industrial Control System’s Cyber Emergency Response Team
IOU	Investor –owned Electric Utilities
ISO	Independent System Operator
KW	Kilowatt

Acronym	**Definition of Acronym**
NERC	North American Electric Reliability Corporation
PV	Photovoltaic
QER	Quadrennial Energy Review
RMAG	Regional Mutual Assistance Group
RPS	Renewable Portfolio Standard
RD&D	Research, Development and Demonstration
SCADA	Supervisory Control and Data Acquisition
SEWG	Senior Executive Working Group
STEP	Spare Transformer Equipment Program
TS&D	Transmission, Storage and Distribution
VER	Variable Energy Resources

Edison Electric Institute

Power by Association℠

Before And After The Storm

A compilation of recent studies, programs, and policies related to storm hardening and resiliency

UPDATE March 2014

Before and After the Storm - Update

A compilation of recent studies, programs, and policies related to storm hardening and resiliency

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INTRODUCTION AND PURPOSE

The United States has experienced a number of large storms within the last ten years ranging from ice and snow, hurricanes, storm surges and strong winds. After each storm, there is an increased focus on investor-owned utility response to widespread customer outages and the infrastructure's ability to withstand devastating weather events. Inevitably, state officials and public utility commissions call for investigations into utility practice and standards, often requiring testimony, appearances before the commission, filings and written reports.

Edison Electric Institute ("EEI") has been asked by its members to update its January 2013 report to incorporate newly released studies on recommendations and best practices with regard to hardening the distribution infrastructure and creating a more resilient system, especially since the impact of Superstorm Sandy in the Fall of 2012. As part of EEI's review, we have also looked at available cost recovery mechanisms and a representative cross-section of state regulatory and legislative actions initiated to address storm resiliency. The updated report also describes the efforts of the industry to enhance and formalize the mutual assistance program, which is a voluntary partnership of electric utilities from across the country, to respond to events that require a national, industry-wide response such as experienced in Superstorm Sandy.

The purpose of this compilation is to provide members with a centralized source of recent studies, reports, and other information regarding options for system hardening and resiliency measures in response to storm related outages of electric distribution facilities. The compilation provides a menu of infrastructure hardening and resiliency options, the relative cost impact of such measures, information on the various cost recovery mechanisms utilized, and a representative overview of various state programs addressing system hardening, resiliency and cost recovery. The compilation is aimed to serve as a reference tool to assist members in addressing state commissions and legislatures as they investigate possible regulatory reforms with respect to how electric utilities combat and respond to storm related outages.

The report does not attempt to make any recommendations regarding the viability or effectiveness of the reported measures and regulatory frameworks. There is no one solution to hardening the infrastructure or creating a more resilient system. Rather, utilities and their regulators must look at the full menu of options and decide the most cost-effective measures to strengthening the grid and responding to storm damages and outages. This report will hopefully serve as a starting point to that conversation.

CHAPTER 1: SYSTEM HARDENING AND RESILIENCY MEASURES

The recent increase in storm activity and extreme weather events has highlighted the need for reinforcing and upgrading the electric distribution infrastructure. EEI has focused its review on potential solutions for combating and mitigating storm damage and outages – system hardening and resiliency measures. **System hardening**, for purposes of this report, is defined as physical changes to the utility's infrastructure to make it less susceptible to storm damage, such as high winds, flooding, or flying debris. Hardening improves the durability and stability of transmission and distribution infrastructure allowing the system to withstand the impacts of severe weather events with minimal damage. **Resiliency** refers to the ability of utilities to recover quickly from damage to any of its facilities' components or to any of the external systems on which they depend. Resiliency measures do not prevent damage; rather they enable electric facilities to continue operating despite damage and/or promote a rapid return to normal operations when damages and outages do occur.[1]

1.1 Hardening Measures

1.1.1 Undergrounding

The undergrounding of transmission and distribution lines has been one of the most often cited measures for mitigating storm damage in recent years as evidenced by the number of reports published over the past seven to eight years. With images of trees and ice bringing down power lines on a 24 hour news cycle after each storm, the common reaction among consumers and regulators is to eliminate poles and bury distribution lines underground shielding them from the effects of extreme weather. Coupled with the aesthetic benefits of having a major portion of the distribution system out of sight, undergrounding has been a major focus of attention after major weather events. However, the costs associated with converting overhead systems underground have made widespread use of such measures cost prohibitive. Of the studies EEI reviewed, there was not a single study that recommended a complete conversion of overhead distribution infrastructure to underground facilities. In fact, none of the studies could identify a single state requiring complete conversion of its distribution system as the costs, estimated to be in the billions of dollars, were not economically feasible and would severely impact customer rates. And although undergrounding distribution and transmission can reduce the frequency of outages, the studies often showed that restoration times actually increased due to the complicated nature of the systems and the inability of restoration crews to visually pinpoint the cause of the disruption. Images of flooded substations and damaged underground facilities after Superstorm Sandy also highlighted the vulnerabilities of undergrounding. However, despite multiple studies citing the prohibitive cost of widespread undergrounding, lawmakers and regulators continue to examine undergrounding opportunities and are closely examining the metrics and data used for developing cost estimates.

The common conclusion among the reviewed studies was that undergrounding could be a viable solution to hardening the infrastructure through targeted or selective undergrounding rather than a total conversion. This

[1] *Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons* (August 2010) prepared by Infrastructure Security and Energy Restoration, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, p. v.

might include placing the worst performing feeders, or feeder portions, underground or placing substation feeders that affected numerous customers underground. Targeted undergrounding was also recommended for those feeders supplying areas that were vital to the community such as police and fire departments, gas stations, hospitals, pharmacies and stores. Coupling such installations with other major excavation projects (such as roadwork, fiber optic cable installation and other construction) could also reduce the costs and disruptive impacts of undergrounding. Reiterating that converting overhead systems to underground systems are anywhere from five to ten times as costly as overhead equipment (estimated to cost between $80,000 and $3 million per mile), the studies recommend targeting the areas where undergrounding would provide the most benefit. The majority of the studies emphasized that undergrounding was not impervious to weather events and that environmental factors must be taken into account when considering underground systems. In coastal areas prone to storm surge, as demonstrated by Superstorm Sandy, underground systems are much more susceptible to damage from flooding and even risk further damage during clean-up efforts. Therefore, it is recommended that any utility or state looking into the possibilities of undergrounding take into account relative costs, environmental factors and actual causes of outages to ensure that undergrounding provides the most cost effective benefit to its electric consumers.

Reports Referencing Undergrounding:

Moreland Commission on Utility Storm Preparation and Response - Final Report (June 22, 2013) delivered to New York Governor Andrew Cuomo.
http://www.governor.ny.gov/assets/documents/MACfinalreportjune22.pdf

Post Sandy Enhancement Plan (June 20, 2013) prepared by Consolidated Edison Co. of New York and Orange and Rockland Utilities. http://www.coned.com/publicissues/PDF/post_sandy_enhancement_plan.pdf

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http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026889

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http://www.governor.maryland.gov/documents/GridResiliencyTaskForceReport.pdf

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http://psc.wi.gov/thelibrary/publications/electric/electric11.pdf

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District of Columbia Order No. 15568 (September 2010).
http://www.pepco.com/_res/documents/DCComprehensiveReliabilityPlan.pdf

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http://www.dcpsc.org/pdf_files/hottopics/Study_Feasibility_Reliability_Undergrounding_Electric_Distribution_Lines.pdf

The Power to Change The Face of America: Converting Overhead Utilities to Underground (2009) prepared by Underground 2020. http://www.governor.maryland.gov/documents/eOverheadToUnderground.pdf

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas.
http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf

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Oklahoma Corporation Commission's Inquiry into Undergrounding Electric Facilities in the State of Oklahoma (June 30, 2008) prepared and submitted by Oklahoma Corporation Commission Public Utility Division Staff. http://www.occeweb.com/pu/PUD%20Reports%20Page/Underground%20Report.pdf

Undergrounding Assessment Phase 3 Final Report: Ex Ante Cost and Benefit Modeling (May 5, 2008) prepared by Quanta Technology for Florida Public Utilities. http://www.quanta-technology.com/sites/default/files/doc-files/PURCPhase3FinalReport.pdf

Undergrounding Assessment Phase 2 Final Report: Undergrounding Case Studies (August 6, 2007) prepared by Quanta Technology for Florida Electric Utilities. http://www.quanta-technology.com/sites/default/files/doc-files/QuantaPhase2FinalReport.pdf

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2007) prepared by the Florida Public Service Commission and submitted to the Governor and Legislature to fulfill the requirements of Chapter 2006-230, Sections 19(2) and (3), at 2615, Laws of Florida, enacted by the 2006 Florida Legislature (Senate Bill 888).
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Evaluation of Underground Electric Transmission Lines in Virginia (November 2006) report of the Joint Legislative Audit and Review Commission to the Governor and The General Assembly of Virginia.
http://jlarc.virginia.gov/reports/Rpt343.pdf

Preliminary Analysis of Placing Investor-Owned Electric Utility Transmission and Distribution Facilities Underground in Florida (March 2005) prepared by the Florida Public Service Commission. http://www.psc.state.fl.us/publications/pdf/electricgas/Underground_Wiring.pdf

A Review of Electric Utility Undergrounding Policies and Practices (March 8, 2005) prepared by Navigant Consulting, Inc. for the Long Island Power Authority. http://www.lipower.org/pdfs/company/papers/underground_030805.pdf

Placement of Utility Distribution Lines Underground, (January 2005) report of the State Corporation Commission to the Governor and The General Assembly of Virginia. http://www.scc.virginia.gov/comm/reports/report_hjr153.pdf

The Feasibility of Placing Electric Distribution Facilities Underground (November 2003) report of the Public Staff to the North Carolina Natural Disaster Preparedness Task Force. http://www.ncuc.commerce.state.nc.us/reports/undergroundreport.pdf

1.1.2. Vegetation Management

Vegetation management is most likely already incorporated into the operations and maintenance activities and budgets of most utilities. However, the various studies reviewed by EEI have explained that the emphasis being placed solely on maintaining specific clearances may not be as effective for every situation. The majority of the reports have had two overarching recommendations: (1) find the true cause of outages and employ necessary vegetation management and (2) coordinate with property owners and local officials to plant and replace downed vegetation that is most conducive to system reliability. Employing targeted vegetation trimming and removal versus strict vegetation clearance cycles was echoed in several of the reports. The prior practice seemed to focus unnecessarily on ensuring specific branch clearances from power lines instead of "danger" trees and branches. As a majority of outages cited were caused by trees or heavy branches falling on lines and bringing down poles rather than tree branches brushing up against power lines, maintaining clearances alone did not address all possible measures to improve reliability. Local officials can assist in mitigation of "danger" tree effects by establishing and enforcing ordinances that require the removal of dead or dying trees from private property near power lines. A second emerging theme in the studies that were reviewed was the usefulness of a concerted effort to plant vegetation near distribution systems that would pose the least reliability issues. In the past, property owners, businesses and local municipalities planted vegetation with little consideration as to the impacts on surrounding utility systems. Again, it is suggested that local officials assist by requiring trees to be labeled as appropriate for planting under power lines or requiring informational brochures at the point of sale. The studies recommended looking at vegetation with shorter heights and longer lifecycles but were careful to reiterate that utilities must staff trained arborists and work closely with customers to ensure a workable outcome for all parties. In fact, the studies showed that direct communication and coordination with regard to vegetation management resulted in higher customer satisfaction rates when it came to utility relationships.

Recognizing that vegetation management represented the highest recurring maintenance cost, the studies were careful to point out that deferral of vegetation management tended to be more costly in the long run. Although specific vegetation costs were not a focal point of the studies, there was a general consensus that vegetation management was one of the more cost effective hardening mechanisms, especially when compared to the relative high costs of undergrounding.

Reports Referencing Vegetation Management:

Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities by the Steering Committee (July 2, 2013) MA DPU 12-76. http://magrid.raabassociates.org/Articles/MA%20Grid%20Mod%20Working%20Group%20Report%2007-02-2013.pdf

Post Sandy Enhancement Plan (June 20, 2013) prepared by Consolidated Edison Co. of New York and Orange and Rockland Utilities. http://www.coned.com/publicissues/PDF/post_sandy_enhancement_plan.pdf

Enhancing Distribution Resiliency – Opportunities for Applying Innovative Technologies (January 2013) prepared by the Electric Power Research Institute (EPRI). http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026889

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State Vegetation Management Task Force Final Report (August 28, 2012) issued to the Connecticut Department of Energy & Environmental Protection. http://www.ct.gov/dep/lib/dep/forestry/vmtf/final_report/svmtf_final_report.pdf

Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf

Report of the Two Storm Panel (January 2012) presented to Connecticut Governor Dannel P. Malloy. http://www.ct.gov/dep/lib/dep/forestry/vmtf/two_storm_panel_final_report.pdf

Report on Transmission Facility Outages During the Northeast Snowstorm of October 29-30, 2011: Causes and Recommendations (May 31, 2012) prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. http://www.ferc.gov/legal/staff-reports/05-31-2012-ne-outage-report.pdf

Best Practices in Vegetation Management for Enhancing Electric Service in Texas (November 11, 2011) submitted by Texas Engineering Experiment Station to the Public Utility Commission of Texas. http://www.puc.texas.gov/industry/projects/electric/38257/Russell_Report.pdf

Potomac Electric Power Company Comprehensive Reliability Plan for District of Columbia including Distribution System Overview, Reliability Initiatives and Response to Public Service Commission of the District of Columbia Order No. 15568 (September 2010). http://www.pepco.com/_res/documents/DCComprehensiveReliabilityPlan.pdf

Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia (July 1, 2010) prepared by Shaw Consultants International, Inc. submitted to the Public Service Commission of the District of Columbia pursuant to Formal Case No. 1026. http://www.dcpsc.org/pdf_files/hottopics/Study_Feasibility_Reliability_Undergrounding_Electric_Distribution_Lines.pdf

New Hampshire Public Utilities Commission After Action Review – December '08 Ice Storm (December 3, 2009). http://www.puc.nh.gov/2008IceStorm/Final%20Reports/PUC%20IceStorm%20After%20Action%20Report%2012-03-09.pdf

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2008) submitted by the Florida Public Service Commission to the Governor and Legislature. http://www.floridapsc.com/utilities/electricgas/eiproject/docs/AddendumSHLegislature.pdf

Reliability Based Vegetation Management Through Intelligent System Monitoring (September 2007) prepared by Power Systems Engineering Research Center. https://www.google.com/url?q=http://www.pserc.wisc.edu/documents/publications/reports/2007_reports/russell_2007_pserc_report_vegetation_management_report_t-27.pdf&sa=U&ei=Q4-3UPXvA4WUiQf2uIG4BQ&ved=0CAcQFjAA&client=internal-uds-cse&usg=AFQjCNGuPbjs4cFbOdcoGaWm9yIjEDiQxQ

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2007) prepared by the Florida Public Service Commission and submitted to the Governor and Legislature to fulfill the requirements of Chapter 2006-230, Sections 19(2) and (3), at 2615, Laws of Florida, enacted by the 2006 Florida Legislature (Senate Bill 888). http://www.floridapsc.com/publications/pdf/electricgas/stormhardening2007.pdf

Report on the Workshop for Best Practices in Vegetation Management (April 17, 2007) sponsored by the Florida Electric Utilities. http://www.floridapsc.com/utilities/electricgas/EIProject/docs/VegetationManagementWorkshopReport.pdf

The Neglected Option for Avoiding Electric System Storm Damage & Restoration Costs – Managing Tree Exposure (2005) prepared by Siegfied Guggenmoos of Ecological Solutions, Inc. http://www.ecosync.com/Avoided%20Storm%20Costs.pdf

Utility Vegetation Management Final Report (March 2004) prepared by CN Utility Consulting, LLC for the Federal Energy Regulatory Commission to support the federal investigation of the August 14, 2003 Northeast Blackout. http://www.ferc.gov/industries/electric/indus-act/reliability/blackout/uvm-final-report.pdf

1.1.3. Higher Design and Construction Standards

As with undergrounding and vegetation management, the key to finding the right design and construction standards should be based on the local conditions of the facilities. The studies reviewed provide a myriad of hardening measures for pole designs to withstand high winds as well as suggestions for how to mitigate widespread outages due to tear-down situations from vegetation. Other reports, especially those in coastal areas, emphasized the importance of elevating substations and other vulnerable facilities that are susceptible to flooding. Submersible equipment, isolation switches, waterproof sealants, moats and flood walls are also recommended in recent studies especially given the damage from floodwaters experienced in New York and New Jersey during Superstorm Sandy. Placement of facilities is another critical component of design and must be updated periodically to account for changing geography, such as flood level potentials and vegetation growth. Several reports also noted that it is imperative when replacing grid components to consider stronger hardening measures rather than replacing the same units in kind or at minimum code requirements.

As to the relative costs of the various hardening choices, prices vary significantly depending on the specific hardening measure, the materials being used, soil and other environmental conditions and the skill needed to implement the hardening mechanism. The studies generally recommended, as with undergrounding, that widespread system hardening is cost-prohibitive and that the most effective use of hardening tools is through a targeted approach. The recommendations are to identify the most critical elements, the worst performing components, those units that have aged and weakened or those elements most in danger of failure and work to replace them with improved system designs such as composites, guying, stronger pole classes or relocation to name a few. Of course, the key to identifying and mitigating potential structural problems lies with robust inspection and maintenance plans. The reports highlight that infrastructure hardening should not come only as a result of storm damage and tear-downs, but as part of a regular maintenance schedule. As newer designs come to market and older designs and equipment are retired, the distribution grid will naturally become more resilient and require fewer replacements and rebuilds in the future.

Reports Referencing Higher Design and Construction Standards:

Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities by the Steering Committee (July 2, 2013) MA DPU 12-76. http://magrid.raabassociates.org/Articles/MA%20Grid%20Mod%20Working%20Group%20Report%2007-02-2013.pdf

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Post Sandy Enhancement Plan (June 20, 2013) prepared by Consolidated Edison Co. of New York and Orange and Rockland Utilities. http://www.coned.com/publicissues/PDF/post_sandy_enhancement_plan.pdf

Florida Power & Light Company 2013 – 2015 Electric Infrastructure Hardening Plan (May 1, 2013) filed with the Florida Public Service Commission in Docket No. 130132-EI. http://www.psc.state.fl.us/library/FILINGS/13/02408-13/02408-13.pdf

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Storm Reconstruction: Rebuild Smart – Reduce Outages, Save Lives, Protect Property (2013) prepared by the National Electrical Manufacturers Association (NEMA). https://www.nema.org/Storm-Disaster-Recovery/Documents/Storm-Reconstruction-Rebuild-Smart-Book.pdf

Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf
Structural Hardening for the Northeast Utilities – CL&P Distribution System (August 22, 2012) prepared by Quanta Technology for Northeast Utilities – CL&P.
http://www.dpuc.state.ct.us/DOCKCURR.NSF/e59368b7c12f537e852573ee005bff7f/2784a7687318599a85257a640067f367/$FILE/Q-EN-006%20Quanta%20storm%20hardening%20%20report%20%208_22_12%20final.pdf

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http://www.ct.gov/dep/lib/dep/forestry/vmtf/two_storm_panel_final_report.pdf

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http://www.pepco.com/_res/documents/DCComprehensiveReliabilityPlan.pdf

Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons (August 2010) prepared by Infrastructure Security and Energy Restoration, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy. http://www.oe.netl.doe.gov/docs/HR-Report-final-081710.pdf

New Hampshire December 2008 Ice Storm Assessment Report (October 28, 2009) prepared by NEI Electric Power Engineering. http://www.puc.nh.gov/2008IceStorm/Final%20Reports/2009-10-30%20Final%20NEI%20Report%20With%20Utility%20Comments/Final%20Report%20with%20Utility%20Comments-complete%20103009.pdf

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas.
http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf

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The Hardening of Utility Lines – Implications for Utility Pole Design and Use (2007) North American Wood Pole Council, Technical Bulletin VII prepared by Martin Rollins, P.E. http://products.construction.com/swts_content_files/1475/593089.pdf

1.1.4. Smart Grid

As smart grid technologies are still being developed and have yet to experience a long history of widespread deployment, there is only anecdotal literature on how smart grid has effectively hardened the distribution system against outages. At least one utility has reported that mapping smart meter outages allowed it to expedite recovery and response after a tornado by precisely identifying the path of the storm damage.[2] Although, smart grid is becoming a featured part of the discussion regarding storm restoration and resiliency and has been cited in many of the studies referenced in this document, the benefits have yet to be tested in a widespread storm scenario. In the context of infrastructure hardening, the most cited benefits are the ability of the system to detect outages and remotely reroute electricity to undamaged (unfaulted) circuits and feeders. Through automated distribution technologies utilizing reclosers and automated feeder switches, faults can be isolated for greater system reliability and fewer customers affected. A key element of successfully utilizing these technologies is designing the distribution system as a looping system that provides for the rerouting of power rather than a radial linear system. However, as some studies have pointed out, smart grid relies on portions of the distribution system remaining intact. In cases of large tear-downs with many poles and wires out of service, there may be simply nowhere to reroute the power to. Therefore, in order for smart grid technologies to work adequately, it may need to be paired with other system hardening mechanisms.

As federal assistance has been made available for smart grid development and the technologies continue to develop, there has been little discussion regarding the relative costs of integrating smart grid technologies into the distribution system.

<u>Reports Referencing Smart Grid</u>:

Economic Benefits of Increasing Electric Grid Resilience to Weather Outages (August 2013) prepared by the President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology. http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

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Powering New York State's Future Electricity Delivery System: Grid Modernization (January 2013) prepared by the New York State Smart Grid Consortium. http://nyssmartgrid.com/wp-content/uploads/2013/01/NYSSGC_2013_WhitePaper_013013.pdf

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[2] *See Improving the Reliability and Resiliency of the US Electric Grid* (2012) from Metering International Issue – 1 authored by Debbie Haught and Joseph Paladino of the U.S. Department of Energy, p. 2.

Storm Reconstruction: Rebuild Smart – Reduce Outages, Save Lives, Protect Property (2013) prepared by the National Electrical Manufacturers Association (NEMA). https://www.nema.org/Storm-Disaster-Recovery/Documents/Storm-Reconstruction-Rebuild-Smart-Book.pdf

Improving the Reliability and Resiliency of the US Electric Grid (2012) from Metering International Issue – 1 authored by Debbie Haught and Joseph Paladino of the U.S. Department of Energy. http://energy.gov/sites/prod/files/Improving%20the%20Reliability%20and%20Resiliency%20of%20the%20US%20Electric%20Grid%20-%20SGIG%20Article%20in%20Metering%20International%20Issue%201%202012.pdf

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Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf

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Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons (August 2010) prepared by Infrastructure Security and Energy Restoration, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy. http://www.oe.netl.doe.gov/docs/HR-Report-final-081710.pdf

New Hampshire December 2008 Ice Storm Assessment Report (October 28, 2009) prepared by NEI Electric Power Engineering. http://www.puc.nh.gov/2008IceStorm/Final%20Reports/2009-10-30%20Final%20NEI%20Report%20With%20Utility%20Comments/Final%20Report%20with%20Utility%20Comments-complete%20103009.pdf

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf

The Value of Distribution Automation (March 2009) prepared by Navigant Consulting for the California Energy Commission – Public Interest Energy Research Program. http://www.ilgridplan.org/Shared%20Documents/CEC%20PIER%20Report%20-%20The%20Value%20of%20Distribution%20Automation.pdf

Oklahoma Corporation Commission's Inquiry into Undergrounding Electric Facilities in the State of Oklahoma (June 30, 2008) prepared and submitted by Oklahoma Corporation Commission Public Utility Division Staff. http://www.occeweb.com/pu/PUD%20Reports%20Page/Underground%20Report.pdf

Value of Distribution Automation Applications (April 2007) prepared by Energy and Environmental Economics, Inc. and EPRI Solutions, Inc. for the California Energy Commission – Public Interest Energy Research Program. http://www.energy.ca.gov/2007publications/CEC-500-2007-028/CEC-500-2007-028.PDF

1.1.5. Microgrids

The concept of "microgrids" is still in the study phase and like smart grid has yet to see widespread deployment or demonstrated its resiliency capabilities during a major storm; however, recommendations highlighting microgrids increased dramatically after Superstorm Sandy. The concept of the microgrid is that it functions as an isolatable distribution network, usually connected to one or more distributed generation sources, that can seamlessly connect and disconnect from the main grid (referred to as "island-mode") in times of widespread outages. Similar to smart grid applications, if major portions of the main grid or the microgrid are torn-down or destroyed in a major weather event, the microgrid capabilities are rendered less effective. There are limited studies of micogrid capabilities, especially as a hardening option. New York, Connecticut and California as well as the U.S. Department of Energy have begun to look into microgrid capabilities and some of the current regulatory frameworks hindering widespread deployment. Although microgrid applications are generally end-user driven and funded, the studies do address areas where utilities can and should be involved, especially with ensuring systems are optimized for interoperability and security. Utilities would also act as an active partner with customers and generators to facilitate and manage the aggregation of loads and the deployment of generation on the microgrid.

As previously mentioned, most microgrid deployment would be funded by the end-users rather than the utility (with estimated returns on investment over 15 years), however, microgrids can provide some cost benefits. By precisely controlling interconnected loads and managing customer voltage profiles, utilities can reduce the cost of providing reactive power and voltage control at microgrid participants' locations. As microgrids remove some of the load that would otherwise be served by the utility on the main grid, microgrids can reduce peak demand or area load growth and similarly help utilities avoid or defer new power delivery capacity investments. As one study points out "[s]uch deferrals can produce financial value to both utilities (e.g., reduced capital budget, lower debt obligations, a lower cost of capital) and ratepayers (i.e., lower rates)."[3] However, it should be noted that in situations where microgrids fail or are damaged and thus rely on the utility as a back-up, stranded investments and hurdles for cost recovery can become problematic for the utility.

Reports Referencing Microgrids:

Economic Benefits of Increasing Electric Grid Resilience to Weather Outages (August 2013) prepared by the President's Council of Economic Advisers and the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology. http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities by the Steering Committee (July 2, 2013) MA DPU 12-76. http://magrid.raabassociates.org/Articles/MA%20Grid%20Mod%20Working%20Group%20Report%2007-02-2013.pdf

U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather (July 2013) prepared by the U.S. Department of Energy. http://energy.gov/sites/prod/files/2013/07/f2/20130716-Energy%20Sector%20Vulnerabilities%20Report.pdf

[3] *Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State* (September 2010) prepared for the New York State Energy Research and Development Authority, p. S-5.

A Stronger, More Resilient New York (June 11, 2013) from the City of New York Mayor Michael R. Bloomberg. http://nytelecom.vo.llnwd.net/o15/agencies/sirr/SIRR_spreads_Lo_Res.pdf
Improving Electric Grid Reliability and Resilience: Lessons Learned from Superstorm Sandy and Other Extreme Events (June 2013) prepared by the GridWise Alliance.
http://www.gridwise.org/documents/ImprovingElectricGridReliabilityandResilience_6_6_13webFINAL.pdf

Storm Reconstruction: Rebuild Smart – Reduce Outages, Save Lives, Protect Property (2013) prepared by the National Electrical Manufacturers Association (NEMA). https://www.nema.org/Storm-Disaster-Recovery/Documents/Storm-Reconstruction-Rebuild-Smart-Book.pdf

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http://www.governor.maryland.gov/documents/GridResiliencyTaskForceReport.pdf

Microgrids (September 12, 2012) prepared by Lee R. Hansen, Legislative Analyst for the Connecticut General Assembly, Office of Legislative Research. http://www.cga.ct.gov/2012/rpt/2012-R-0417.htm

Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf

The Business Case for Microgrids (2011) white paper on the new fact of energy modernization prepared by Robert Liam Dohn of Siemens AG. http://www.energy.siemens.com/us/pool/us/energy/energy-topics/smart-grid/downloads/The%20business%20case%20for%20microgrids_Siemens%20white%20paper.pdf

DOE Microgrid Workshop Report (August 30 – 31, 2011) prepared by the Office of Electricity Delivery and Energy Reliability, Smart Grid R&D Program.
http://energy.gov/sites/prod/files/Microgrid%20Workshop%20Report%20August%202011.pdf

Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State (September 2010) prepared for the New York State Energy Research and Development Authority.
http://www.google.com/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&ved=0CD4QFjAA&url=http%3A%2F%2Fwww.nyserda.ny.gov%2F~%2Fmedia%2FFiles%2FPublications%2FResearch%2FElectic%2520Power%2520Delivery%2F10-35-microgrids.ashx%3Fsc_database%3Dweb&ei=0tC8UN2ZH4rh0QGg4oC4CA&usg=AFQjCNEMLDVWvr-RMvdfopz1FSAbn6bK3w&sig2=dUz2rZfgMcCr4AWDzm6rGQ

The Value of Distribution Automation (March 2009) prepared by Navigant Consulting for the California Energy Commission – Public Interest Energy Research Program.
http://www.ilgridplan.org/Shared%20Documents/CEC%20PIER%20Report%20-%20The%20Value%20of%20Distribution%20Automation.pdf

Value of Distribution Automation Applications (April 2007) prepared by Energy and Environmental Economics, Inc. and EPRI Solutions, Inc. for the California Energy Commission – Public Interest Energy Research Program. http://www.energy.ca.gov/2007publications/CEC-500-2007-028/CEC-500-2007-028.PDF

Microgrid: A Conceptual Solution (June 2004) prepared by Robert H. Lasseter and Paolo Piagi of the University of Wisconsin-Madison. http://energy.lbl.gov/ea/certs/pdf/mg-pesc04.pdf

1.1.6. Advanced Technologies

Many of the advanced technologies currently being studied and rolled out are closely related to smart grid applications in the areas of communication and circuit auto-reconfiguring. Other technologies being used to bolster utilities information gathering and control are various mapping technologies such as Geographic Information Systems ("GIS") and Automated Mapping and Facilities Management ("AM/FM"). There is very limited literature on other technologies outside of smart grid applications; however, there has been some investigation into hydrophobic, nano-particle coatings on distribution lines and other facilities to enhance waterproofing, prevent ice formation on power lines, and combat corrosion and shorting caused from saltwater. Installation of self-healing cables reduces damage to wires by incorporating sealant between insulation layers that flow into any insulation breaks and seals them permanently to prevent further exposure. Of the studies reviewed, the relative cost of these advanced technologies was not included.

Reports Referencing Advanced Technologies:

Enhancing Distribution Resiliency – Opportunities for Applying Innovative Technologies (January 2013) prepared by the Electric Power Research Institute (EPRI). http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026889

Storm Reconstruction: Rebuild Smart – Reduce Outages, Save Lives, Protect Property (2013) prepared by the National Electrical Manufacturers Association (NEMA). https://www.nema.org/Storm-Disaster-Recovery/Documents/Storm-Reconstruction-Rebuild-Smart-Book.pdf

America's Next Top Energy Innovator Challenge – SH Coating, LP, Oak Ridge National Laboratory. http://energy.gov/americas-next-top-energy-innovator/sh-coatings-lp

Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons (August 2010) prepared by Infrastructure Security and Energy Restoration, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy. http://www.oe.netl.doe.gov/docs/HR-Report-final-081710.pdf

Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas. http://www.puc.texas.gov/industry/electric/reports/infra/Utlity_Infrastructure_Upgrades_rpt.pdf

1.2 Resiliency Measures

In the body of research that we reviewed, most of the resiliency measures were considered together in the recommendations and best practices and therefore we only include one "Sources" section that encompasses the storm response and restoration efforts utilized by utilities. Many of the sources cited have also been referenced in the "Hardening" section above as well.

Although the industry as a whole responded well to the massive restoration effort following Superstorm Sandy, utilities quickly agreed that the mutual assistance program should be enhanced and formalized. As described more fully in Appendix C, the electric industry has instituted a formal process for responding to major outage events involving multiple regions that addresses many of the resiliency recommendations in this section.

1.2.1. Increased Labor Force

Sufficient restoration crews are essential to storm response and restoration. Of the studies reviewed by EEI, the major element of securing enough crew members in preparation for major storms is advanced planning. This includes adequate weather prediction paired with advanced reservation of additional crews whether through mutual assistance or outside contractors. All impacted stakeholders should bear in mind that widespread storms encompassing large areas and multiple service territories will lead to increased competition for resources and thus adequate planning is essential. Part of the planning includes securing shelter, food, first aid, shower and toilet facilities, parking and other essentials for crews working around the clock for days on end.

When securing crews, these additional costs should also be taken into consideration. Several studies warned that it is not always cost-effective, and increasingly subject to scrutiny by state officials, to cut full-time staff in favor of attempting to secure additional crews during emergency situations only. Utilities must measure the costs of having available crews compared with the costs of extended outages due to insufficient numbers of prepared crews.

1.2.2. Standby Equipment

Another key consideration in proper storm restoration and recovery, as documented in several studies, is to consider necessary arrangements for response equipment to be on standby (for example strategic alliances or material consignment). Extra trucks, supplied with necessary materials including maps, flashlights, mapping software, communication devices, to name a few, could be readily available to utilities without needing to secure such equipment from outside locations thus slowing response activities. In addition to equipped trucks, crews should be armed with GPS devices as many will be unfamiliar with local roads and service territories. As demonstrated during Hurricane Katrina and Superstorm Sandy, fuel can become scarce after extreme weather events and thus utilities must secure enough fuel for its service trucks, either through on-hand reserves or emergency fuel contracts with suppliers. Other standby equipment to be considered are mobile transformers, mobile substations and large generators that can enable temporary restoration of grid service, circumventing damaged infrastructure, to enable repair of grid components without extended interruptions to customers.

1.2.3. Restoration Materials

As part of storm response and restoration, multiple studies suggested that utilities must have adequate back-up restoration supplies such as poles, wires, transformers and other system components that are on location in storage or are easily obtained through contracts with suppliers. As with securing adequate labor and equipment, large storms with widespread outages may result in competition for materials. The State of New York launched a review of a potential equipment-sharing, inventory and stockpile programs and determined that such programs could facilitate improvement to individual utility practices and help coordinate utilities' response to major events. It was recommended that New York State utilities leverage existing stockpiles at utility and vendor locations statewide and develop a sharing agreement among utilities for deployment of restoration materials during major outage events. In November 2013, the State of New York Public Service Commission directed utilities to finalize the protocols, procedures and plans for sustaining a shared equipment and supplies stockpile.[4]

[4] Order Instituting a Process for the Sharing of Critical Equipment, State of New York Public Service Commission Docket No. 13-M-0047 (November 19, 2013).

As with other recommendations, costs of such back-up restoration materials need to be compared with the costs of extended outages and lost restoration time while waiting for supplies to become available.

1.2.4. Enhanced Communication, Planning and Coordination

Several of the studies reviewed highlighted the many complications and logistical challenges associated with moving multiple crews to large areas all the while keeping customers, regulators and news agencies up-to-date with the latest restoration information. As stressed in one study, utility response must be scalable so that restoration efforts run smoothly whether there are 5,000, 50,000 or 500,000 customer outages.[5] A crucial element in utility plans for major storm events is pre-staging. Having crews, equipment and resources safely positioned before the storm allows for a quicker response and avoids waiting for crews to arrive from outside the affected areas. However, for those crews that do arrive from out of town, standby equipment and restoration materials are already gathered and organized for immediate response. Certain utilities have commissioned new mobile command centers to accommodate response teams. These mobile command centers typically have state-of-the-art technology, including satellite and cellular communications, dispatcher workstations, video monitors with video switcher, SMART boards, and telescoping masts with cameras. These mobile command centers provide utilities with extended capability to manage restoration on location and closer to the customers experiencing outages. Recognizing the importance of pre-staging, some utilities are looking into hiring outside vendors to evaluate and map out staging areas to maximize resource flow and use of space. Part of this pre-staging effort entails coordinating with federal and state agencies to quickly obtain emergency permits and waivers for traveling crews and heavy equipment to bypass tolls and access normally restricted bridges and roadways. Procedures must be in place prior to large outage situations in order to avoid delays in getting mutual assistance crews to assist with restoration.

As several studies pointed out, response times are unnecessarily delayed as outage coordinators are unsure where their crews have been dispatched, what outages remain and where to dispatch crews that have completed a restoration project to ensure the least amount of driving or "windshield" time. Thus, coordination and constant communication is vitally important. As one study suggested, relying on satellite communications is a beneficial option for crew coordination as they are less reliant on terrestrial structures which may have been damaged during the storm or weather event.[6]

In addition, utility communications with its customers is vital. A key frustration, cited in the reports, was out-of-date information and inaccurate restoration estimates. Utilities are taking new and innovative steps to keep the communities and customers informed at all times. These include designating a central contact person or working team to serve as the "one voice" communicator with crews, state and federal government officials, news agencies and customers to ensure the continuity of communication and information for the most accurate assessments and response estimates. Some utilities have implemented storm communication guidelines to ensure consistent communication across all customer channels during the various phases of a storm. These guidelines provide for tailoring communication outreach by taking into account the magnitude of the storm and subsequent customer sentiment. The guidelines include monitoring of customer feedback and scripting for customer service representatives, interactive voice response, text messaging, mobile application notifications, utility websites, Twitter, Facebook, Flickr and YouTube. A number of new technologies have been developed such as text messaging programs and fully functional mobile applications that allow customers to report an outage, view outage information, and receive proactive push notifications with outage status updates.

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[5] *See Report of the Two Storm Panel* (January 2012) presented to Connecticut Governor Dannel P. Malloy, p. 12.
[6] *See Cost-Benefit Analysis of the Deployment of Utility Infrastructure Upgrades and Storm Hardening Programs* (March 4, 2009) prepared by Quanta Technology for the Public Utility Commission of Texas, p. 74.

Though the studies did not explore specific costs attached to communication and coordination efforts, again the general consensus is that utilities must weigh these various costs against the costs of slower restoration and extended outages.

1.2.5. Advanced Technologies

Much of the conversation regarding advanced technologies, in the context of storm response, has centered on smart grid/smart meters. The two-way communication capabilities of smart meters allows utilities to monitor service continuity, identify outages and “ping” customer meters to ensure service has been restored. In the wake of Superstorm Sandy, advanced technologies involving outage management systems and developing better weather and damage forecast models has gained prominence in the discussion surrounding large outage events. An effective outage management system linking load and outage data with GIS allows restoration crews to isolate the areas where outages have occurred and focus their efforts solely on restoration rather than on truck roll-bys to identify damage and customer outages. Some software allows utilities to track restoration crews, equipment and fuel consumption to better manage logistics and allocate resources. Outage Management Systems are being used to detect and report reliability issues in addition to crews using infrared scanning equipment for surface and airborne damage assessment. Infrared scanning detects temperature variances which can indicate damaged or failed equipment. Airborne damage assessment allows technicians to survey damage where traditional vehicles are blocked due to downed trees, flooded roads and other obstacles thereby reducing response time by hours. Automated storm damage information can be instantaneously shared with restoration crews to speed up response and repairs, limiting the need for extra scouting crews. Utilities are recognizing the importance of integrating such data with data from local municipalities, police and fire departments to better coordinate restoration to critical areas.

A cost assessment for smart meters and other automated technologies is contained within the broader context of smart grid programs and differs by region and level of federal assistance. Although costs for many of the recommended advanced technologies may be costly, it is important to remember that those costs should be measured against the costs of delayed restoration when advanced capabilities are not being utilized. As one utility reported during Superstorm Sandy, use of advanced technologies reduced the number of truck rolls during Superstorm Sandy by over 6,000 resulting in a savings of least one million dollars in restoration costs.[7]

Reports Referencing Resiliency Measures:

Economic Benefits of Increasing Electric Grid Resilience to Weather Outages (August 2013) prepared by the President’s Council of Economic Advisers and the U.S. Department of Energy’s Office of Electricity Delivery and Energy Reliability, with assistance from the White House Office of Science and Technology. http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf

Hurricane Sandy Rebuilding Strategy: Stronger Communities, A Resilient Region (August 2013) prepared by the Hurricane Sandy Rebuilding Task for and presented to the President of the United States. http://portal.hud.gov/hudportal/documents/huddoc?id=HSRebuildingStrategy.pdf

[7] See Improving Electric Grid Reliability and Resilience: Lessons Learned from Superstorm Sandy and Other Extreme Events (June 2013) prepared by the GridWise Alliance, p. 12.

Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities by the Steering Committee (July 2, 2013) MA DPU 12-76. http://magrid.raabassociates.org/Articles/MA%20Grid%20Mod%20Working%20Group%20Report%2007-02-2013.pdf

Moreland Commission on Utility Storm Preparation and Response - Final Report (June 22, 2013) delivered to New York Governor Andrew Cuomo. http://www.governor.ny.gov/assets/documents/MACfinalreportjune22.pdf

Post Sandy Enhancement Plan (June 20, 2013) prepared by Consolidated Edison Co. of New York and Orange and Rockland Utilities. http://www.coned.com/publicissues/PDF/post_sandy_enhancement_plan.pdf

A Stronger, More Resilient New York (June 11, 2013) from the City of New York Mayor Michael R. Bloomberg. http://nytelecom.vo.llnwd.net/o15/agencies/sirr/SIRR_spreads_Lo_Res.pdf

Improving Electric Grid Reliability and Resilience: Lessons Learned from Superstorm Sandy and Other Extreme Events (June 2013) prepared by the GridWise Alliance. http://www.gridwise.org/documents/ImprovingElectricGridReliabilityandResilience_6_6_13webFINAL.pdf

Enhancing Distribution Resiliency – Opportunities for Applying Innovative Technologies (January 2013) prepared by the Electric Power Research Institute (EPRI). http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001026889

Powering New York State's Future Electricity Delivery System: Grid Modernization (January 2013) prepared by the New York State Smart Grid Consortium. http://nyssmartgrid.com/wp-content/uploads/2013/01/NYSSGC_2013_WhitePaper_013013.pdf

Storm Reconstruction: Rebuild Smart – Reduce Outages, Save Lives, Protect Property (2013) prepared by the National Electrical Manufacturers Association (NEMA). https://www.nema.org/Storm-Disaster-Recovery/Documents/Storm-Reconstruction-Rebuild-Smart-Book.pdf

The October 2011 Snowstorm: New Hampshire's Regulated Utilities' Preparation and Response (November 20, 2012) prepared by the New Hampshire Public Utilities Commission. http://www.puc.state.nh.us/2011OctSnowstorm/October%202011%20Snowstorm%20(11-20-12)%20final.pdf

Weathering the Storm: Report of the Grid Resiliency Task Force (September 24, 2012) delivered to the Office of Maryland Governor Martin O'Malley pursuant to Executive Order 01.01.2012.15. http://www.governor.maryland.gov/documents/GridResiliencyTaskForceReport.pdf

Weather-Related Power Outages and Electric System Resiliency (August 28, 2012) by Richard J. Campbell, Congressional Research Service. http://www.fas.org/sgp/crs/misc/R42696.pdf

Performance Review of EDCs in 2011 Major Storms (August 9, 2012) prepared by Emergency Preparedness Partnerships for the New Jersey Board of Public Utilities. http://www.nj.gov/bpu/pdf/announcements/2012/stormreport2011.pdf

January 2012 Pacific Northwest Snowstorm – After Action Review (June 19, 2012) prepared by KEMA for Puget Sound Energy. http://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=120231

Report on Transmission Facility Outages During the Northeast Snowstorm of October 29-30, 2011: Causes and Recommendations (May 31, 2012) prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation. http://www.ferc.gov/legal/staff-reports/05-31-2012-ne-outage-report.pdf

State of Rhode Island Division of Public Utilities and Carriers Review of National Grid Storm Preparedness, Response, and Restoration Efforts (February 2012) prepared by Power Services. http://www.ripuc.org/eventsactions/docket/D_11_94_Booth.pdf

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New Hampshire Public Utilities Commission After Action Review – December '08 Ice Storm (December 3, 2009). http://www.puc.nh.gov/2008IceStorm/Final%20Reports/PUC%20IceStorm%20After%20Action%20Report%2012-03-09.pdf

New Hampshire December 2008 Ice Storm Assessment Report (October 28, 2009) prepared by NEI Electric Power Engineering. http://www.puc.nh.gov/2008IceStorm/Final%20Reports/2009-10-30%20Final%20NEI%20Report%20With%20Utility%20Comments/Final%20Report%20with%20Utility%20Comments-complete%20103009.pdf

Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather (July 2008) submitted by the Florida Public Service Commission to the Governor and Legislature. http://www.floridapsc.com/utilities/electricgas/eiproject/docs/AddendumSHLegislature.pdf

CHAPTER 2: COST RECOVERY MECHANISMS

2.1 Types of Costs

Utility costs incurred to respond to storms before, during and after the event—collectively referred to as storm hardening and resiliency—are of two types: Operational and maintenance expenses, which are typically the costs of labor and consumable materials used in the process, and capital costs, which include replacement power poles, wires, transformers, and trucks driven by repair crews.

Traditionally, operational expenses are recovered in base rates after they are reviewed by state regulatory authorities. Capital expenses are usually included in a utility's rate base and depreciated over time. When included in rate base, utilities are allowed to earn a return on these investments and the depreciation expense is included in rates.

Rate base additions and operational expenses traditionally have been considered in the context of general rate cases. However, for a variety of reasons, including the increasing costs involved and unpredictability, utilities and regulators are increasingly turning to other means to deal with cost recovery for storm response, as discussed in this section.

2.2 General Rate Case Recovery

The normal practice by which most investor-owned electric utilities recover costs is through a general rate case, where the utility seeks to change its rates based on either new plant additions or changes in expenses or both. The utility typically presents its costs in a defined "test year." The test year often is an historical test year that ends before the rate case is filed. However, many states are using or moving toward use of current or future test years or hybrids.[8] After reviewing the costs, the state regulatory commission approves or disallows costs and sets an authorized rate of return for the utility's assets. Storm response expenses can be considered in the context of a general rate case, but there may be significant problems with this path for storm cost recovery.

First, if any of the storm costs were incurred outside the utility's test year, they would not be eligible for recovery even if they were prudently incurred and legitimate expenses, except in some cases when post-test year additions are allowed under specified circumstances. Second, many states have prohibitions against single-issue ratemaking, meaning that all costs incurred by the utility must be considered together in a general rate case. A utility that does not have a general rate case scheduled in the near future would have no recourse to recover its costs, perhaps for years.

Moreover, rate cases can be very contentious and take years to resolve, depending on state rules, and they often result in at least some costs being disallowed as a compromise to reach a conclusion. All of this regulatory delay and uncertainty can add to the business risk of the utility and may harm its financial health, exposing it to potential credit downgrades by rating agencies and thus increasing its cost of capital, which in turn can lead to higher rates for customers.

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[8] *Innovative Regulation: A Survey of Remedies for Regulatory Lag* (April 2011) prepared by Pacific Economics Group Research LLC for Edison Electric Institute

The length of time for rate cases to resolve in many states also means that a utility may incur additional storm damage before the costs of previous storms are recovered, resulting in a pancaking effect.

Utilities may not have the capability to finance recovery of costs resulting from multiple storms, especially if storms are large and costly. General rate case recovery may be reasonable for storms with minor damage but can create problems when storms are large or frequent in nature. Many utilities have classifications for major versus minor storms and handle minor storms under regular accounting and cost recovery procedures.[9] In addition, many utilities already collect revenue in base rates for "normal" storm damage based on test year data, which may be based on an historic average.

General rate case recovery may be a more viable method of cost recovery for known, approved capital expenses, such as pre-storm hardening of facilities or undergrounding. In these cases, it is appropriate that costs be capitalized and added to a utility's rate base. Certain operational and maintenance costs are also appropriate for consideration in general rate cases. Routine vegetation management costs are an example of a normal, predictable expense that would typically be included and recovered in base rates.

General rate cases that employ mechanisms other than a historical test year or that use methodologies resulting in a higher rate base valuation than would occur under a traditional averaging method provide additional ways in which storm cost recovery can be achieved in a timely manner. An example is use of a future test year that allows projected capital expenditures (capex) to be included in base rates, thus reducing problems due to regulatory lag or the need for multiple rate cases.

Another example is application of end-of-test-year or "terminal" values to rate base, where rate base is set based on values at the end of the normal test period rather than on averaging values over the period. Use of terminal rate base can better reflect the level of investment during the period rates will be in effect, especially during times of high investment levels. For example, a utility that is in the midst of a large capex spending program for reliability improvement, system hardening, or storm damage resiliency measures might propose a future test year or terminal rate base valuation to ensure that the increased capital spending over historical averages is properly reflected in base rates. States that have allowed use of terminal test year include **Illinois**, **Maryland** and **Texas**.

2.3 Cost Deferral

Because immediate recovery of storm response costs—whether investments to harden systems to prevent storm damage or the costs of recovering from storm damage—may be too much of a burden to place on customers at the time such costs are incurred, often some or all of the costs are deferred. The accounting process for deferrals involves treatment of the costs as a regulatory asset (under-recovery) or regulatory liability (over-recovery). The state regulatory authority essentially allows the utility to place the costs on its balance sheet as an asset or liability, so it does not have to appear on the company's balance sheet and be charged against current revenues (or credited against current costs). The utility maintains the asset or liability on its balance sheet until the costs are recovered from or refunded to customers. The value of the asset or liability does not have to be considered either as income or an expense for tax purposes until there is actually some activity with the asset.

Once the regulatory asset or liability is established, the ultimate cost recovery decision can be deferred until the next general rate case, where an asset can be recovered through base rates or through a multi-year rate

9 *After the Disaster: Utility Restoration Cost Recovery* (February 2005) prepared by Bradley W. for Edison Electric Institute, p. 9.

plan that negates the need for the utility to continually seek new rate cases. Or, as described below, costs associated with the regulatory asset can be recovered through a rate adjustment mechanism outside of a general rate case.

An issue that often arises with respect to cost deferral is whether utilities can charge the carrying costs associated with the asset to customers. This is important because there is an opportunity cost to the utility from delaying cost recovery, and investors are harmed if the opportunity cost is not reflected. The issue of cost deferral and carrying costs has been dealt with in many different ways.

States that have authorized individual utilities to defer storm-related costs include **Arkansas**, **Kentucky**, **Maryland**, **Massachusetts**, **New Jersey**, **New York**, **Ohio** and **Texas**. (See Appendix A.)

2.4 Rate Adjustment Mechanisms

Rate adjustment mechanisms refer to trackers, riders, adders, cost recovery factors and similar terms (that are usually used interchangeably) for a customer surcharge that recovers the costs of one or more specific cost items or categories outside of base rates. These surcharges may be permanent or temporary charges that are approved by regulatory commissions to recover costs that were unforeseen in previous general rate cases, costs that are imposed on the utility and not within its control, costs that are particularly volatile and difficult to predict, costs that are substantial and non-recurring, and/or costs for which the regulatory authority wants to establish a separate line item on customer bills apart from base rates. The most common form of rate adjustment mechanism is a fuel adjustment clause, which allows utilities to collect their most volatile and significant cost as fuel costs change.

Rate adjustment mechanisms have become more prevalent in recent years because they allow utilities and regulators to target specific costs without the need for frequent rate cases, allow customers some transparency as to the components of the rates they pay when the charge appears on the bill as a separate line item, and are favored by the financial community as a means to ensure that utilities are not financially harmed due to slow cost recovery, as can occur when general rate cases are not filed at frequent intervals.

The level of a rate adjustment mechanism may be fixed in advance (usually with scheduled true-ups to reflect actual costs within certain defined periods) or may vary as costs change (usually subject to periodic reviews to ensure the costs were prudently incurred). In any event, there are almost always regulatory proceedings to ensure that the level of the surcharge is equal to actual, prudently incurred costs expended (or saved).

Rate adjustment mechanisms can be designed to end when the specific amount of cost recovery is satisfied and thus are particularly useful for storm response. Rate adjustment mechanisms are also typically used when a charge applies only to a certain set of customers or only for certain periods of the year, such as seasonal adjustments. Many times these mechanisms are used to collect costs imposed by other governmental agencies, such as tax collection riders, environmental riders, and economic development riders. They also may be used to implement special programs such as smart meter and smart grid programs or grid hardening projects.

Rate adjustment mechanisms may or may not include a return to the utility on the assets for which costs are being recovered. While there are exceptions, it is common for capital investments recovered in this way to include a return component while operations and maintenance expenses usually do not include a return.

These mechanisms also may be used to track and recover costs from (or return savings to) ratepayers that commissions have previously allowed to be deferred as regulatory assets (or liabilities). Agreement by regulators to allow costs to be deferred for possible future recovery that would not have been reflected in a test year provides additional confidence to investors that costs will be recovered. Such use of rate adjustment mechanisms allows utilities flexibility, especially where storm costs are substantial and immediate recovery would severely harm utility customers. By obtaining regulatory approval to defer such costs as a regulatory asset (or liability), utilities also can avoid having to write off those expenses in the current period, which would cause harm to investors and increase the risk profile of the utility.

The operational details of rate adjustment mechanisms for deferred costs vary by state jurisdiction. In some cases, the utility is assured estimated cost recovery in a future period at the time the account is approved, subject to prudence review and true-up(s). In other cases, the commission may approve only the rate adjustment mechanism and require the utility to seek approval later of actual costs. Some jurisdictions may limit further additions to the account, while others will allow expenses pertinent to the mechanism's purpose to continue to be accumulated but impose limitations such as a cap to prevent excess earnings.

States that have authorized use of rate adjustment mechanisms include **Florida**, **Mississippi**, **Missouri**, **New Hampshire**, **Ohio**, **Oklahoma**, **Pennsylvania** and **Texas**. (See Appendix A.)

2.5 Lost Revenue and Purchased Power Adjustments

Another potential storm-related cost for which rate adjustment mechanisms may be relevant is an adjustment for lost revenues. Utilities set their rates based on a revenue requirement established by the state regulatory authority and forecasted (or recent historical) sales. If a utility loses customers for extended periods following a storm, its revenues from customers will fall short, and the utility may be unable to pay its fixed costs that are unavoidable with or without customer sales. State regulatory authorities have in some cases approved a lost revenue adjustment clause to allow utilities to recover some or all of these costs.

- While there do not appear to be any lost revenue adjustment mechanisms that are directly targeted at recovering revenues lost because of storms, there are several utilities around the country that have similar mechanisms that automatically adjust rates to reflect changing weather conditions. For example, in September 2009, the **District of Columbia** Public Service Commission approved the implementation of a bill stabilization adjustment (BSA) for Pepco. The BSA is a "decoupling" mechanism applied monthly in order to mitigate the volatility of revenues and customer bills caused both by abnormal weather and customer participation in energy efficiency programs. A similar BSA mechanism in **Maryland** was ended by the regulator as it applied to major storms in October 2012 following a June 2012 "derecho" storm in response to complaints from citizens and elected officials.[10]

Along similar lines, if a utility's generating facilities become unavailable due to storm damage, it may have to purchase power from other sources at rates higher than expected in its cost forecast. Purchased power adjustment clauses are sometimes approved to recover some or all of these additional costs. Purchased power transactions also may be approved to address other storm-related circumstances.

- **Florida** approved a fuel and purchased power cost recovery clause (FPPCRC) that provides for the recovery of both prudently incurred fuel and purchased power costs. Costs of power purchased during storm recovery would be recoverable under this clause if found to be prudent by the Florida Public Service Commission. Florida also has a capacity cost recovery clause (CCRC) in place. The capacity component of purchase power agreements and post-2001 power plant security costs are

[10] Maryland PSC, Case No. 9257 (October 26, 2012).

flowed through this clause.

- The **Texas** Public Utility Commission allowed Entergy Gulf States (EGS) to recover costs, via its fuel adjustment clause, of purchasing both surplus capacity and energy from affiliate Entergy New Orleans (ENO), which lost significant load as a result of Hurricane Katrina. The commission waived a rule restricting such recovery to energy-only costs. The transaction was intended to ease ENO's financial burden resulting from the hurricane, help facilitate restoration by the Entergy system, and save fuel costs for EGS customers. (See Appendix A.)

2.6 Formula Rates

Formula rates are another way of allowing utilities to recover unforeseen costs between general rate cases. Formula rates simply allow utilities to adjust rates between general rate cases because of changes in costs so that they may continue to earn their authorized returns. Some formula rate plans only allow changes if rates fall outside a specific band (either above or below) the rate set in the general rate case.

In almost all cases, utilities still need to present their cost changes and receive regulatory approval before changing their rates. To the extent that a general rate case includes storm-related expenses, and the formula rate allows those costs to change to reflect additional costs, formula rates can be a way to get more immediate recovery of storm damage costs than would be available through the general rate case process.

States that have approved formula rates for individual utilities include **Illinois** and **Louisiana.**

2.7 Storm Reserve Accounts

Storm reserve accounts are a form of self-insurance used by many utilities to "collect in advance" for costs incurred to recover from storms. A storm reserve is an accounting technique that allows utilities to smooth out the earnings impact of storms.[11] Traditionally, a utility would credit a fixed amount from its earnings to a storm reserve account. Storm recovery costs, typically when they are incurred, are charged against the balance in the storm reserve account, subject to review by commissions. In this case, the storm reserve account does not provide any cash to pay the storm costs but rather lessens the earnings impact due to the cost impact of the storm. This only works if there have been sufficient accruals to the storm reserve account to pay the incurred costs.

There are exceptions where storm reserves are funded with cash rather than by accrual. In these cases, cash is withdrawn from the storm reserve account to pay for storm damage as it is needed. Florida Power & Light, for example, has funded storm reserves with cash.

The impacts of recent major storms often have far exceeded amounts available in storm reserves. In some cases, state regulatory authorities allowed utilities to account for the excess as a negative balance in the storm reserve account as a temporary solution. But regulators in many cases have begun allowing utilities to charge customers either to establish or replenish storm reserve accounts in advance of incurring storm recovery costs. In some cases, such customer-funded storm reserve accounts have been permitted by state legislation.

States that have authorized use of storm reserve accounts include **Arkansas**, **Florida**, **Louisiana**, **Massachusetts**, **Mississippi**, **New Hampshire**, **New Jersey**, **New York** and **Texas**. In response to severe

[11] Johnson. op. cit., p. 11.

storms over the past few years, states such as **New York** have approved increases in annual funding of storm reserves. (See Appendix A.)

2.8 Securitization

Securitization is a financial tool that essentially packages bonds backed by secure revenue streams (usually supported by state legislation) and then sells the bonds on the market. By ensuring that the money being invested from the proceeds of these bonds has a high probability of being paid back—usually because a state legislature has mandated that the costs associated with repayment will be placed on customer bills as a surcharge—the bonds can be rated highly and thus get much lower interest rates than the utility would obtain by financing the investments itself. These lower interest costs then translate into lower costs for customers when they pay the servicing costs of the bonds through surcharges.

The first uses of this mechanism in the investor-owned electric utility segment were for so-called “stranded cost” bonds, where utilities—authorized by state legislatures—would set up a stranded cost securitization account, replenished by a surcharge on customer rates to pay whatever amount of stranded costs were allowed by the state. The state or utility would issue securitization bonds and the proceeds would be used by the utility to accelerate the depreciation on portions of their stranded plants to their market levels, with the bonds repaid from the customer surcharges.

The first use of securitization for recovering costs of damages to utility systems occurred after the terrorist acts of September 2001. Consolidated Edison Company of New York used securitized bonds to recover costs of damage to its systems. Since that time, and particularly following Hurricane Katrina, securitization has become an increasingly common method of recovering costs for major storms, especially in hurricane-prone states.

Securitization is not always a preferred mechanism for dealing with storm cost recovery. First it requires the legislature to act in most cases, followed by a favorable ruling from the regulator and then the underwriters. And the administrative costs can be significant. In most cases of securitization, the utility cannot earn on whatever investment results from the proceeds. For example, if a utility is using securitization to finance the reconstruction of a large part of its system, it might not be able to earn on that investment in the future and thus could face a reduced rate base.

While securitization has not been used to date to pay for hardening of facilities to prevent storm damage, it has been suggested as a possible tool for that purpose. For example, a recent report by the State of Maryland suggests securitization as an option for paying for the costs of undergrounding utility systems in the state.[12] Moreover, there may be some precedent for this type of use on the environmental side. For example, in **West Virginia**, securitization was authorized by the commission per a state statute to finance a flue gas desulfurization system at a utility generating plant. In this case, the bonds were backed by a nonbypassable environmental control charge.[13]

States that have authorized securitization of storm-related costs include **Arkansas**, **Florida**, **Louisiana**, **Mississippi**, **Ohio** and **Texas**.

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[12] *Weathering the Storm: Report of the Grid Resiliency Task Force* (September 24, 2012) delivered to the Office of Maryland Governor Martin O’Malley pursuant to Executive Order 01.01.2012.15, pp. 67-68.
[13] West Virginia PSC, Case No. 05-0402-E-CB, et al. (April 7, 2006), decided pursuant to WV Code § 24-2-4e.

2.9 Customer or Developer Funding/Matching Contributions

Where customers, groups of customers, or developers are interested in gaining protection against storm damage, they are often interested in the undergrounding or hardening of transmission and/or distribution lines. The costs of such hardening can be substantial as discussed elsewhere in this report. Some states such as Florida have begun to establish programs whereby utilities harden their systems and recover costs over time through base rates. In some cases, utilities will cover the costs of undergrounding for new residential developments where lines can be put in as excavation is done for other utilities. However, in other cases, the undergrounding of lines must be paid for in full or in part by the customer.

Almost every utility has a slightly different rule as to determining the costs of undergrounding for which the customer is responsible. The most common is that the customer pays for the difference in cost between overhead and underground lines for new installations, and the cost of undergrounding plus the cost of removing overhead lines, less any salvage value for the overhead equipment. In some cases—particularly for new installations—the utility will do a revenue analysis for the customer and reduce the cost of undergrounding if projected revenues are sufficient to cover some of the additional costs. Utilities in some circumstances might also match customer contributions.

With respect to transmission undergrounding, because transmission costs are seldom associated with a particular set of customers, utilities will need to seek regulatory approval for including the costs in rate base. Because of the substantial costs of undergrounding transmission, it is usually only done when circumstances dictate, such as in areas that are particularly environmentally or aesthetically sensitive, or where the terrain requires it.

There are situations where utilities can share costs with other utility providers that are undergrounding (such as gas pipelines or distribution lines or water mains), or take advantage of situations where roads or tunnels are being built and the incremental cost of undergrounding is much less than normal.

Where customers or other entities such as another utility provider pay for or contribute to the costs of undergrounding or other hardening measures, the payment by the contributor is referred to accounting-wise as a contribution in aid of construction (CIAC). Such contributions are generally not allowed to be recovered in a utility's rate base and may be considered as taxable income to the utility. In such cases, the amount to be collected from contributors is grossed up to collect any state or federal taxes that will be paid by the utility.

Florida is an example of a state that has authorized use of CIAC for storm-related investment.

2.10 Federal Funding

The Robert T. Stafford Disaster Relief and Emergency Assistance Act (the Stafford Act) authorizes the Federal Emergency Management Agency (FEMA) to provide federal aid to individuals and families, certain nonprofit agencies, and public agencies upon declaration of a state of emergency by the President.[14] Stafford Act funding is thus available to municipal, state, and rural electric cooperatives but not to investor-owned utilities. Over the past decade, there have been several unsuccessful attempts to amend the Stafford Act to include investor-owned utilities.

Federal funding has been made available, however, in very limited circumstances to investor-owned utilities under the Community Development Block Grant (CDBG) program of the U.S. Department of Housing and

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[14] Federal Stafford Act Disaster Assistance: Presidential Declarations, Eligible Activities, and Funding" (June 7, 2011) prepared by the Congressional Research Service.

Urban Development (HUD). CDBG funds are actually provided to the states, and the utilities wishing to utilize the funds for disaster recovery must do so through agreements with the state government. States must satisfy one or more of three grant objectives:

1. Principally benefit low and moderate income persons
2. Aid in eliminating or preventing slums or blight
3. Meet urgent community development needs because existing conditions pose a serious or immediate threat to the public[15]

It is the third of these requirements that is usually satisfied by storm recovery needs.

CDBG funds can only be used for activities not covered by FEMA or the Small Business Administration, which qualifies investor-owned utilities because they cannot take advantage of these other sources. CDBG funds can be used for short-term relief, mitigation activities to lessen the impact of future disasters, and long-term recovery activities. While there are multiple rules covering the use of CDBG funds, the HUD secretary has fairly broad discretion to waive requirements in emergencies. The CDBG program generally requires matching funds from the state, but those requirements can also lessened or waived in emergencies.

Mississippi is an example of a state that certified storm restoration costs as eligible to receive CDBG funds.

2.11 Insurance

Up until the early 1990s, most utilities carried commercial insurance policies that covered storm damage up to the limits of the policy and after a deductible was met. But new commercial insurance policies to cover storm damage became difficult if not impossible to obtain following the destruction caused by Hurricane Andrew in 1992. Nonetheless, many utilities do carry legacy policies—usually small in amount and with high deductibles. For example, Connecticut Light and Power had a $15 million policy (with a $10 million deductible) in effect at the time of Tropical Storm Irene in 2011.[16] Most utilities also have insurance that covers generating station damage and damage to the facilities immediately surrounding those stations.

Storm reserve accounts (discussed above) represent a form of self-insurance by electric utilities. Funds are collected in advance through customer surcharges and held in reserve by the utility for future storms. Utilities still must obtain approval to apply actual costs against the reserve.

Another form of insurance that has been discussed off and on for years by utilities—particularly those in storm-prone areas—is the idea of a mutually funded insurance reserve that would receive premiums from member companies and pay for damages to members' systems when needed according to pre-determined formulas. The proposed insurance fund would work similarly to NEIL (Nuclear Electric Insurance Limited), which provides insurance coverage to domestic and international nuclear utilities. To date, efforts to establish such an insurance fund have not come to fruition but it remains a possibility for the future.

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[15] Ibid., p. 1.

[16] http://www.ctnewsjunkie.com/ctnj.php/archives/entry/assessment_of_storm_response_can_wait

CHAPTER 3: CROSS-SECTION OF STATE REGULATION

As the frequency and intensity of major storm events have increased in recent years in many areas, so too has state regulatory activity, including post-storm reviews of electric utility preparation and response. Many of these reviews have resulted in legislation, new rules or increased regulatory activity under existing authority to strengthen utility storm readiness and response capability, mitigate risk, and enhance reliability and resiliency of electric systems.

This chapter provides a brief overview of state regulation and a cross-section of key state regulatory activities involving utility storm hardening and resiliency. Recent policy and regulatory activities of 16 states are highlighted below. Regulatory actions in 28 states are described in more detail in a matrix in Appendix A, EEI Cross-Section of State Regulatory Decisions on Storm Hardening and Resiliency. The matrix is not comprehensive but rather provides a snapshot of recent regulatory actions.

3.1 Regulatory Focus on Hardening and Resiliency

The review of states shows that regulatory attention to storm hardening and resiliency to help prevent and mitigate outages has strengthened since Superstorm Sandy. However, regulatory approaches to storm hardening and resiliency – and related cost recovery – continue to vary from state to state and depend on the particular circumstances of the state and utility.

The effects of Sandy have prompted regulators in states such as **New Jersey**, **New York** and **Pennsylvania** to look more comprehensively and strategically at reliability and storm hardening and resilience. Other states have taken more incremental approaches post-Sandy such as **West Virginia**, which directed utilities to focus on expanded vegetation management programs in light of extensive forest growth in the rural state.

Many of these and other states such as **Florida** already had begun to consider or implement changes before Sandy as a result of previous severe weather events and/or out of recognition of electric service reliability issues arising from aging distribution and other infrastructure.

An example of a different approach to cost recovery can be found in **Maryland**, where regulators in several rate cases departed from their longstanding practice of using a historic test year and conditionally allowed test year adjustments to reflect actual and certain forecasted reliability investment. (See Appendix A.) The actions came in recognition of increased reliability spending by utilities – with regulatory encouragement – and of the public need for such investment to reduce the risk of outages and mitigate their impacts.

Even with encouragement of increased utility spending to meet public need, cost recovery from ratepayers is not a given for system hardening and resiliency initiatives, which often mean higher costs for ratepayers. Utilities must, as they have always done, demonstrate the prudence of investments and provide assurance that spending is proportionate to the benefits delivered.

In some cases utilities must meet higher standards for performance that are aligned with higher customer expectations of reliability, as well as perform detailed recordkeeping to aid in assessments of the need for, and costs and benefits of, reliability and resilience investments. For example, the **Maryland** approvals of test year adjustments came with the condition that utilities must meet enhanced reliability performance metrics.

3.2 Changing Regulatory Frameworks

Some states have broadened their regulatory frameworks to enable regulators to give utilities more incentive and flexibility to address storm events and reliability infrastructure needs. The potential for financial and other penalties also is increasing in some states.

Examples of regulatory framework changes, which are more fully detailed in state highlights below and Appendix A and B, include:

- A **Connecticut** law requiring state regulators to review a utility's performance in responding to storms, set new performance standards, and identify the most cost-effective levels of tree trimming and system hardening needed to achieve maximum system reliability and minimize outages. Financial penalties may be imposed for non-compliance with the performance standards.
- A **District of Columbia** law authorizes financing via issuance of revenue bonds to back a public-private partnership between the District and Pepco. The partnership is planning to implement a program to strategically underground feeders that are particularly susceptible to storms.
- An **Illinois** law authorizing use of performance-based formula rates and requiring participating utilities to invest large specified amounts in transmission and distribution systems, with cost recovery addressed in annual formula rate plan proceedings. Utilities file grid modernization plans with performance metrics that carry penalties for non-compliance.
- A **Massachusetts** law that expands the authority of the Department of Public Utilities to oversee utility storm restoration and set performance standards for emergency preparation and restoration of utility service. Financial penalties may be imposed for non-compliance with the performance standards.
- Development by **New York** regulators of a process to change the regulatory model for achieving policy objectives that include assurance of system reliability and resiliency. The regulatory model will include performance and outcome-based incentives.
- **Indiana**, **Pennsylvania** and **Texas** laws authorizing the use of innovative rate adjustment mechanisms to allow more timely cost recovery for eligible distribution investments between general rate cases.

Even in the absence of authority to levy financial penalties, state commissions have authority to determine whether and to what extent utilities may recover storm-related costs from ratepayers, determine the value of rate base, and set an allowed return on capital investments in storm hardening, reliability improvements, and other infrastructure projects. Some commissions have considered utility preparedness and performance in major storms in making such determinations. In determining cost recovery, regulators look to whether costs were prudently incurred and are reasonable in accord with the statutory and regulatory frameworks of each state.

3.3 After Action Reviews: Mixed Results

State public utility commission oversight will continue to be a critical part of initiatives on storm hardening and resiliency. As part of this oversight, regulators conduct post-storm audits—on their own motion or in response to complaints—that often result in new requirements for utilities.

Several investigations that reviewed utility response to Sandy, including proceedings in Connecticut, New York and Pennsylvania, had mixed results. (More details can be found in the state sections below and Appendix A.)

- **Connecticut:** The Public Utilities Regulatory Authority found utilities performed in a "generally acceptable manner" in response to Sandy but also ordered certain improvements, e.g., in training and communications.
- **New York:** A report by the governor-appointed Moreland Commission found utilities unprepared to manage the perceived growing threat from major storms and recommended many changes to state and utility policies.
- **Pennsylvania:** The Public Utility Commission issued a report that was positive about utility response to Sandy and made recommendations for further improvements, e.g., in communications.

3.4 Distribution Reliability Improvements

Many states have taken steps to improve general distribution reliability to prevent or mitigate outages regardless of cause. Distribution reliability measures can include infrastructure inspection and maintenance, vegetation management, and other programs as discussed in Chapter 1 of this report. While the Federal Energy Regulatory Commission (FERC) regulates transmission power lines, including reliability standards that apply to transmission, it is up to state regulators to set vegetation management and other reliability standards for distribution facilities in their states.

Many regulators believe vegetation management and infrastructure inspection are key to improved reliability based on evidence that trees constitute the main cause of storm-related outages in most states. The **Missouri** Public Service Commission pointed to improved reliability as a result of new rules for enhanced vegetation management. In addition to Missouri, states that have directed improvements and/or authorized increased funding for vegetation management include **California**, **Connecticut**, **Maryland**, **Massachusetts**, **New Hampshire, North Carolina**, **Oklahoma** and **West Virginia**. (See Appendix A.)

Other programs encompassing distribution reliability improvement such as infrastructure upgrades have been approved in states such as **California**, **New Hampshire** and **North Dakota**. (See Appendix A.)

3.5 The Roles of Distributed Energy Resources and Smart Grid

The roles of smart grid technologies and distributed generation (DG) in grid resiliency and their interdependence with measures to protect critical infrastructure are the focus of heightened policy and regulatory discussion.

For example, Massachusetts is acting on a stakeholder grid modernization report urging regulators to provide guidelines to utilities to invest in grid modernization to improve system reliability and resiliency. The report linked distributed generation, grid modernization and grid resiliency, including recommendations for measures that improve a utility's ability to reduce the impact of outages. Measures including hardening, distributed generation and storage, aging infrastructure replacement and vegetation management.[17]

Connecticut, New York and **New Jersey** are examples of other states embracing development of microgrids, expanding distributed generation, and/or stepping up grid modernization with smart grid technologies. (See state highlights below and Appendix A).

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[17] Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee (July 2, 2013), Final Report; Massachusetts DPU Case No. 12-76-A (December 23, 2013), order presenting straw proposal for grid modernization.

3.6 Rate Impact Mitigation

Even as many state regulatory commissions are taking a more proactive stance to address storm hardening and resiliency and/or general distribution reliability, they are recognizing that customers have become increasingly resistant to rate increases. State regulators generally are expected to continue seeking to avert or mitigate the impact of rate increases as many utility customers continue to struggle financially in the current economic climate. Pressure to keep rates from increasing comes despite the wide recognition that infrastructure is aging and must be replaced, and that new infrastructure may be needed to better respond to increasingly severe and unpredictable weather events.

Although potential rate impacts are uppermost in the minds of many regulators and policymakers, rate case filings have significantly increased in recent years to reflect needed infrastructure investment and other reliability measures undertaken by utilities on their own initiative to maintain and improve electric service or in response to mandates such as storm hardening requirements in **Florida** and **Texas**. In addition, storms feature prominently in many recent rate case filings.[18] This trend has continued post-Sandy.

3.7 State Highlights: AR, CA, CT, DC, FL, IL, IN, LA, MD, MA, MS, NJ, NY, NC, OH, PA

Arkansas

<u>Securitization of Storm Costs</u>: In March 2009, the Arkansas legislature passed Act 729, the Electric Utility Storm Securitization Recovery Act of 2009,[19] in response to a January 2009 ice storm which caused hundreds of millions of dollars of damage to Arkansas utilities. Unlike some other states, under Act 729 utilities would issue storm bonds themselves, but could not be considered by the Arkansas Public Service Commission (PSC) to be debt of the utility other than for tax purposes. By the same token, revenues collected to repay the bonds could not be considered utility revenue. Act 729 included a requirement that in Financing Orders to be issued by the PSC under the statute, provisions would be made for costs to be recovered using a formula-based mechanism for making expeditious periodic adjustments in the storm recovery charges that customers are required to pay and for making any adjustments that are necessary to correct for any projected over-collection or under-collection of the charges. In its request to recover costs from the January 2009 ice storm, Entergy Arkansas availed itself of the securitization provisions of Act 729 and received approval from the PSC to recover the costs of securitized bonds through a non-bypassable rider on utility bills. The PSC also allowed the company to recover carrying costs during the time between when the costs were incurred and when the bonds securitized.

<u>Storm Reserve Accounting</u>: In a rate case that was filed in 2006, Entergy Arkansas attempted to establish a storm reserve account and to increase rates to begin building up that account. The company noted that the commission had previously approved reserve accounting for storm damage. However, in a decision in June 2007, the PSC rejected the company's request to establish a storm reserve account, stating that it amounted to retroactive and single issue ratemaking, contrary to PSC rules.[20] Following the January 2009 ice storm, concerned about the financial impact on the company of not being able to defer $80-$100 million in new costs, Entergy Arkansas sought the PSC's permission to defer the expense portion of the storm restoration costs pursuant to accounting standards, thereby removing the expense from the income statement and avoiding the reporting of a financial loss in the first quarter earnings report. The commission approved Entergy's request.[21]

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[18] Rate Case Summary, Q4 2011 Financial Update, prepared by Edison Electric Institute
[19] Arkansas Code Annotated 5 23-18-901.
[20] Arkansas PSC Docket No. 06-101-U, Order No. 10 (June 15, 2007).
[21] Arkansas PSC Docket No. 09-018-U (March 6, 2009).

Meanwhile, in 2009 the Arkansas legislature passed a bill specifically allowing Arkansas utilities to use storm reserve accounting.[22] Entergy Arkansas made another filing after this bill was enacted to establish a storm reserve account, which was approved by the PSC in April 2010.[23]

California

Storm Investigations: In December 2011 a windstorm in Southern California caused widespread outages and sparked criticism by local governments regarding pre-emergency planning and coordination. The California Public Utilities Commission (PUC) launched an investigation that resulted in a preliminary report that cited pole failure and flaws in emergency planning among other findings.[24] The windstorm also gave rise to legislation (AB 1650) that was signed into law in September 2012. The law requires the PUC to establish standards for disaster and emergency preparedness plans within an existing proceeding. The law also requires electric utilities to develop, adopt, and update an emergency and disaster preparedness plan every two years. Cities and counties must participate in the development such plans.[25]

Distribution Reliability: The PUC in June 2010 adopted with modifications Pacific Gas and Electric's proposed Cornerstone program aimed at improving distribution system resiliency and reliability to provide customer benefits such as reduced frequency and duration of outages. Cornerstone capital costs and expenses are being recovered through a balancing account outside of general rate cases and are trued-up annually to reconcile actual with forecasted costs.[26]

System Hardening and Cost Recovery Related to Wildfires: Effects of wildfires increasingly are being treated at local, state and national levels in a manner similar to treatment of disasters such as hurricanes and tornadoes, including funding assistance. The CPUC in 2009 undertook a broad review of fire hazards following a series of destructive wildfires in 2007 that the commission thought linked to electric and communications facilities. The commission concluded three phases of the proceeding with decisions that first focused on preparations for the autumn 2009 fire season, then revised rules to improve vegetation management practices, avoid pole failure and improve fire planning, and finally revised rules to incorporate use of modern materials and technologies such as smart grid as well as design and construction practices.[27] New tools were provided, such as giving utilities the ability to address situations where property owners seek to block access to their sites for tree trimming. Under the rules, utilities have authority to turn off power to such properties, subject to specified conditions.

Recovery of costs related to utility wildfire response that exceed insurance proceeds has been a controversial issue in the state. The PUC in late 2012 issued a final decision denying utility applications for recovery of uninsured expenses related to a series of 2007 wildfires through a separate, dedicated balancing account outside of a rate case.[28] The commission was concerned that the applications by an electric utility and a gas utility did not adequately address the possibility that limitless potential for ratepayers to fund third-party claims, including fire suppression and environmental damage, could invite a host of claims by others such as

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[22] Act 434 of 2009, "An Act to Require the Arkansas Public Service Commission to Permit Storm Cost Reserve Accounting for Electric Public Utilities When Requested; and for Other Purposes."
[23] Arkansas PSC Docket No. 09-031-U (April 16, 2010).
[24] *Investigation of Southern California Edison Company's Outages of November 30 and December 1, 2011*, Preliminary Report (February 1, 2012) prepared by California PUC Consumer Protection and Safety Division.
[25] AB 1650, enacted September 23, 2012, http://www.leginfo.ca.gov/pub/11-12/bill/asm/ab_1601-1650/ab_1650_bill_20120923_chaptered.pdf
[26] California PUC Application 08-05-023 (June 24, 2010).
[27] California PUC Rulemaking 08-11-005 (August 20, 2009; January 12, 2012; February 5, 2014).
[28] California PUC Proceeding for Application 09-08-020, *Decision Denying Application* (December 20, 2012).

government entities. The commission also cited concern about the need to ensure that utilities are incentivized to defend against third-party claims and manage risk appropriately.

Grid Modernization: California also has been in the forefront of grid modernization efforts with approvals in recent years of smart grid-related programs for all three major investor-owned utilities in the state. Pacific Gas and Electric in its required annual update to the PUC detailed continued progress toward enhancing the reliability of its transmission and distribution systems. Activities include widespread deployment of smart meters, which have enabled implementation of an outage management integration project to better detect outage areas and "ping" individual meters to determine whether service has been restored. The result has been quicker and more accurate service restoration, the utility reported. San Diego Gas & Electric and Southern California Edison in their 2013 annual reports in the same proceeding highlighted similar developments.[29] In its 2013 annual report to the governor and legislature, the CPUC cited improved system resiliency and other benefits from smart grid investments.[30]

Connecticut

Distribution reliability: In the wake of Tropical Storm Irene and an October 2011 snowstorm that caused widespread outages, Connecticut in June 2012 enacted SB 23, An Act Enhancing Emergency Preparedness and Response.[31] The law requires the Public Utilities Regulatory Authority (PURA) to review the performance of utilities when more than 10 percent of its customers are without service for more than 48 consecutive hours. Utilities must file an emergency plan every two years. The law also established a pilot program to provide up to $15 million in grants and loans for the development of microgrid infrastructure that supports 65 MW of onsite generation at critical facilities. The law also required PURA to establish emergency performance standards and to allow utilities to recover reasonable costs incurred for maintaining or improving infrastructure resiliency pursuant to their approved emergency plans. The PURA implemented performance standards in November 2012.[32] In other related action, the PURA conditioned its approval in April 2012 of a merger of Northeast Utilities and NSTAR with requirements related to distribution reliability, including a directive to spend an incremental $300 million on system resiliency and to develop microgrid infrastructure in collaboration with the state.[33]

Distributed Energy Resources: The Act directed establishment of a first-of-its-kind statewide pilot program for the development of microgrid infrastructure to help protect critical facilities and increase the safety and quality of life of citizens during outages. A first round of the program, which is administered by the Department of Energy and Environmental Protection, awarded a total $18 million to nine projects, which are expected to become operational within 18 months of the July 2013 announcement. A second round was announced a few months later by the governor in which $15 million will be awarded. Selection is expected to be announced in September 2014.

Refrigerated Spoilage Loss: Another investigation directed by the Act resulted in a PURA report to the legislature describing a potential program to compensate customers for spoilage of refrigerated food and medications due to a verified outage. Ratepayers would fund the program through the existing systems benefit charge. The program would reflect a departure from traditional utility liability rules and an extra ratepayer expense, PURA found. Such a program would require legislation and "create a risk of some

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[29] California PUC Rulemaking 08-12-009: annual reports filed by Pacific Gas and Electric, San Diego Gas & Electric and Southern California Edison (October 1, 2013).
[30] *Report to the Governor and the Legislature: California Smart Grid – 2012,* California PUC (May 2013).
[31] Public Act 12-148.
[32] Connecticut PURA Docket No. 12-06-09 (November 1, 2012).
[33] Connecticut PURA Docket No. 12-01-07 (April 2, 2012).

unknown magnitude that reimbursement payments will change the role of the [electric distribution companies] to customers. That change will create a precedent that will affect future regulatory and public policy decisions," PURA said in its decision.[34] Citing a National Regulatory Research Institute report, PURA said only five other states have similar reimbursement programs: **California**, **Illinois**, **Michigan**, **Minnesota** and **New York**.[35]

Storm Investigations: A panel convened by the governor to evaluate the state's response to Tropical Storm Irene and the October 2011 snowstorm issued its report ("Two Storm Report") in January 2012.[36] The report included 82 recommendations, many of which addressed areas affecting electric utilities, including tree trimming, storm hardening and communication issues. The PURA later investigated the performance of utilities in preparing and responding to Sandy, finding that utilities performed "in a generally acceptable manner." The PURA also recommended areas for additional improvement, including communications and estimated restoration times.[37]

Vegetation Management: The Two Storm Report found that Connecticut has one of the densest tree canopies in the country and that fallen trees and limbs caused most of the downed wires during Irene. A PURA investigation of tree trimming practices is currently under way in response to the governor's directives. In a draft decision, PURA said utilities already are implementing most recommendations and requirements to make their infrastructure more resilient to storm damage and to promote shorter restoration time following outages from major storms.[38] Electric utilities have approved vegetation management plans with significantly increased budgets over the next five to eight years. The current PURA investigation is aimed at reviewing and clarifying the practices, procedures and requirements for utility vegetation management to comply with the Governor's directives and legislative mandates. The PURA was set to hold a technical meeting and hear public comments in March 2014 before rendering a final decision.

District of Columbia

Reliability Regulations: In July 2012, the District of Columbia Public Service Commission (PSC) formally adopted comprehensive reliability standards related to major outages.[39] The regulations include requiring electric utilities to develop and implement plans to improve the performance of low performing feeders, and to develop a Major Service Outage Restoration Plan detailing internal and external communication policies concerning outage notifications; utility early storm detection and tracking efforts; staffing, materials and logistical information; and lists of restoration priorities.

Undergrounding: In the District of Columbia, the undergrounding of electric distribution lines has been a hot topic due to the reliability concerns related to major storm outages. In 2009, the PSC engaged a consulting firm, Shaw Consultants International, Inc., to conduct an independent study of the economic and technical feasibility and reliability implications of undergrounding electric distribution lines in the District of Columbia. The firm released its study in July 2010 making several recommendations to the PSC including the continued use of undergrounding when new residential developments are introduced; not undergrounding all existing circuits and selective undergrounding in specific situations where undergrounding can be

[34] Connecticut PURA Docket No.12-06-12 (January 8, 2013).
[35] *Should Public Utilities Compensate Customers for Service Interruptions?* Ken Costello, Principal Researcher, National Regulatory Research Institute, Report No. 12-08 (July 2012).
[36] *Report of the Two Storm Panel* (January 9, 2012) presented to Governor Dannel P. Malloy.
[37] Connecticut PURA Docket No. 12-11-07 (November 16, 2012).
[38] Connecticut PURA Docket No. 12-01-10, draft decision (November 19, 2013).
[39] *D.C. Mun. Regs.*, Title 15, § 3603 (2012).

bundled with infrastructure investments, such as road expansion efforts, and large scale water and sewer replacement.[40]

A public-private partnership between D.C. and Pepco was subsequently announced in May 2013. The partnership plans to implement a $1 billion program to strategically underground feeders that are particularly susceptible to storms. Enabling legislation was needed for the financing, and in February 2014 the D.C. Council passed a bill authorizing the district to issue revenue bonds to finance part of the project.[41] The remainder would be financed through a surcharge mechanism also authorized by the bill.

Florida

Storm Hardening and Resiliency: Florida is probably unique in that it has adopted the most comprehensive program to date for hardening existing (and future) infrastructure to reduce damage from future storms. Florida has utilized a multifaceted approach that includes the development of new rules and regulations regarding vegetation management and other hardening activities, the development of overhead and underground construction standards, requirements for the filing of utility plans—including cost estimates—for hardening options, and required investments by utilities with predetermined cost recovery, subject to a prudence review. The Florida Public Service Commission (PSC) has also encouraged the filing of tariffs that reduce the costs of undergrounding to customers. The Florida effort also has included the initiation of several research programs at Florida universities to look at new methods to reduce storm damage costs and methods to assess the costs and benefits of various measures.

The Florida initiatives began in early 2006, when the legislature enacted a statute[42] that among other provisions, required the PSC to determine what should be done to increase the reliability of the state's transmission and distribution systems during extreme weather events. The state's legislative action came in response to a series of devastating hurricanes (Dennis, Katrina, Wilma and Rita) in 2005 and 2004 (Charley, Frances, Ivan and Jeanne). The legislature requested recommendations from the PSC in the following areas:

- Encouraging underground electric distribution for new utility service or construction
- Encouraging the conversion of existing overhead distribution facilities to underground facilities, including any incentives for local-government-sponsored conversions
- Utility participation in local-government-sponsored conversion costs as an investment in grid reliability, with such investment recognized as a new plant in service for regulatory purposes
- Encouraging the use of road rights-of-way for the location of underground facilities in any local-government-sponsored conversion project, provided the customers of the public utility do not incur increased liability and future relocation costs.

The PSC initiated its efforts in January 2006 with a workshop on lessons learned from the hurricane seasons of 2004 and 2005. The commission then decided on its multifaceted, multiyear approach to investigate actions needed to harden systems and reduce the amount of future storm damage, including:

- Annual hurricane preparedness briefings by Florida utilities
- A formal electric utility pole inspection program

[40] *Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia* (July 1, 2010) prepared by Shaw Consultants International, Inc. submitted to the District of Columbia PSC pursuant to Formal Case No. 1026.
[41] The Electric Company Infrastructure Improvement Financing Act of 2013, Bill No. 20-0387.
[42] Chapter 2006-230, Sections 19(2) and (3), Laws of Florida.

- An annual assessment of comprehensive reliability reports by the electric utilities
- Ten storm-hardening initiatives that include Florida specific research
- University research on the measurement and effects of storm wind speeds on infrastructure
- University research on best practices for vegetation management
- Development of rules governing utility storm restoration costs
- A rulemaking regarding overhead and underground storm hardening construction standards
- A rulemaking to expand the calculation of contribution-in-aid-of-construction (CIAC) for new underground facilities and conversion of existing overhead facilities to underground to reflect the cost impacts of storm hardening and storm restoration
- Tariffs promoting underground electric distribution facilities
- University research to develop cost benefit methodologies to identify areas and circumstances to facilitate the conversion of overhead distribution facilities to underground facilities

The first related PSC rulemaking dealt with an inspection program for wood poles, requiring an eight-year mandatory wooden pole inspection program, including reporting, for all investor-owned electric utilities and local exchange telephone companies.[43] The commission next adopted a set of rules strengthening reporting requirements.[44] Prior reporting requirements allowed for the exclusion of reliability data that is typically related to power outages that were viewed as being outside the utility's control. Thus, absent the rule change, the reports provided no insight into storm-related impacts on reliable electric service in Florida. The rule changes also specifically require the utilities to retain records and data supporting annual reports.

In another proceeding the commission required utilities to file storm hardening plans and estimated implementation costs by June 1, 2006.[45] The following components were to be considered:

- Three-year vegetation management cycle for distribution circuits
- Audit of joint-use attachment agreements
- Six-year transmission structure inspection program
- Hardening of existing transmission structures
- Transmission and distribution geographic information system
- Post-storm data collection and forensic analysis
- Collection of detailed outage data differentiating between the reliability performance of overhead and underground systems
- Increased utility coordination with local governments
- Collaborative research on effects of hurricane winds and storm surge
- Natural disaster preparedness and recovery program

The commission approved most aspects of the utility storm preparedness initiative plans but required revisions in some areas.[46] The commission also required the companies to file updates to their storm

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[43] Florida PSC Docket No. 060078-EI (February 27, 2006).
[44] Florida PSC Docket No. 060243-EI (July 31, 2006).
[45] Florida PSC Docket No. 060198-EI (April 4, 2006).

hardening plans by March 1, 2007. The commission did not address cost recovery for the approved initiatives, leaving those issues for the utility rate cases or other actions.

The overall effort by the commission also initiated several research programs by Florida universities on issues such as how to measure the costs and benefits of storm hardening activities, measuring the effects of storms on infrastructure, and best practices for vegetation management. In reviewing the utility storm hardening plans, the commission noted that the utilities were not, but needed to be, involved with these research programs. The effort to date has resulted in the publication of several research studies that have been made available on the PSC's web site.[47]

In a final rulemaking initiated in 2006, the commission issued a series of rules and requirements for storm hardening[48]. First, utilities were to file within 90 days a detailed storm hardening plan (different from the "storm response initiatives plan" requirements discussed above), containing a detailed description of the construction standards, policies, practices, and procedures employed to enhance the reliability of overhead and underground electrical transmission and distribution facilities. Such standards, practices and policies were to be in conformance with the provisions of the rule. Each utility storm hardening plan needed to explain the systematic approach the utility will follow to achieve the desired objectives of enhancing reliability and reducing restoration costs and outage times associated with extreme weather events. The hardening plan was also to include pole attachment standards. The PSC held public workshops on the plans filed by utilities in October 2007, and ultimately approved those plans.

The PSC summarized all these activities pursuant to the Florida statute in a required report to the legislature and governor submitted July 2, 2007.[49] In February 2008 an addendum to that report was issued[50] and in July 2008, an update to the 2007 report was provided to the legislature and the governor.[51] These reports reflect the comprehensive and detailed nature of the commission's and the Florida utilities' efforts to improve the ability of the state's transmission and distribution infrastructure to withstand the large number of severe storms faced by the state.

The commission has continued to approve utility storm updates filed every year, finding that they are largely continuations of previously approved plans. The PSC also has noted the unavailability of data to evaluate the effects of the plans because of the dearth of named storms that have affected the state in more recent years.

Securitization of Storm Costs: Following the tremendous damage caused by the 2004 hurricanes, the Florida legislature in early 2005 enacted a statute giving utilities the ability to recover their storm damage costs and replenish storm reserve accounts by selling securitized bonds.[52] Before bonds were issued to cover the 2004 costs, the utilities suffered additional damage from the 2005 hurricanes. With respect to Florida Power &

[46] Florida PSC Docket No. 060198-EI (September 19, 2006).
[47] http://www.psc.state.fl.us/utilities/electricgas/eiproject/index.aspx
[48] Florida PSC Docket Nos. 060172-EU and 060173-EU (January 17, 2007).
[49] *Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather* (July 2007) prepared by the Florida Public Service Commission and submitted to the Governor and Legislature to fulfill the requirements of Chapter 2006-230, Sections 19(2) and (3), at 2615, Laws of Florida, enacted by the 2006 Florida Legislature (Senate Bill 888).
[50] *Addendum to the July 2007 Report to the Legislature On Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather*; Summary of Commission Actions; May 1, 2007 - December 15, 2007 (http://www.psc.state.fl.us/utilities/electricgas/eiproject/docs/SHaddendum.pdf)
[51] *Report to the Legislature on Enhancing the Reliability of Florida's Distribution and Transmission Grids During Extreme Weather* (July 2008) submitted by the Florida Public Service Commission to the governor and legislature.
[52] Title XXVII, Section 366.8260, Florida Statutes.

Light in particular, the PSC approved issuance of up to $708 million in storm-recovery bonds, provided the initial average retail cents per kWh for the storm recovery charge would not exceed the average retail cents per kWh for the 2004 storm surcharge that was currently in effect.[53]

Storm Reserve Accounting: In 2007, the PSC issued an Order allowing utilities to establish storm reserve accounts and capitalize the costs of storm recovery to that account.[54] It is the utility's option whether to expense storm recovery costs or credit them to a storm reserve account. A utility may petition the commission for the recovery of a debit balance in reserve account plus an amount to replenish the storm reserve through a surcharge, securitization, or other cost recovery mechanism. If a utility seeks a change to either the target accumulated balance or the annual accrual amount for the storm reserve, it must file a study with the commission.

Following approval of its storm hardening plan, Progress Energy Florida requested that it be allowed to recover approved storm hardening costs through its storm reserve account. The PSC denied the request,[55] saying it did not meet the purposes specified for storm damage reserve accounts under Florida's rules. In a separate proceeding, the PSC established a uniform procedure by which investor-owned electric utilities were to calculate amounts due as CIAC from customers who request new facilities or upgraded facilities in order to receive electric service.[56]

Illinois

Infrastructure Investment: Illinois in 2012 enacted the Energy Infrastructure Modernization Act (EIMA), a law authorizing and incentivizing investment in upgrades and modernization of the electric grid to provide consumer benefits such as reduced duration of frequency of service outages, improved overall service reliability, and improved power restoration following storms.[57] Under the law, participating utilities may use performance-based formula rates and in return are required to make investments in transmission and distribution systems, including smart grid systems, over 10 years as follows: Commonwealth Edison must invest $2.6 billion and Ameren Illinois must invest $625 million. Electric system upgrades include storm hardening, underground residential distribution cable injection and replacement, and wood pole inspection and replacement. Smart grid investment includes distribution automation, substation microprocessor relay upgrades, and smart meters and related data communications network.

The law sets reliability, customer benefit and vendor diversity metrics. Utilities must file annual work plans and undergo annual rate reviews. The law specifies a formula for calculating ROE in the annual rate reviews and requires adjustments if earned ROE falls outside a 100-basis-point deadband around the authorized ROE. The program terminates in 2014 if the total residential bill increases by more than 2.5 percent per year. The program also may terminate in 2017 if additional spending cannot be justified, and it automatically sunsets in 2022. A "trailer bill," HB 3036, also was enacted that refines the EIMA program, including redirecting of $200 million toward targeted infrastructure investments including undergrounding, storm hardening and other measures.[58]

In 2013, S.B. 9 was enacted to further clarify EIMA provisions by specifying that in rate reconciliations in formula rate plan proceedings, the ICC must use terminal, or year-end, rate base values, year-end capital

[53] Florida PSC Docket No. 060038-EI (May 30, 2006).
[54] Florida PSC Docket No. 070011-EI (May 23, 2007).
[55] Florida PSC Docket No. 090145-EI (July 6, 2009).
[56] Florida PSC Docket Nos. 060172-EU and 060173-EU (January 17, 2007).
[57] SB 1652 (Public Act 97-0616), Energy Infrastructure Modernization Act, enacted October 31, 2011
[58] HB 3036 (Public Act 97-0646), enacted December 30, 2011

structures, and weighted average cost of capital.[59] Enactment occurred via legislative override of a veto by Governor Pat Quinn, who viewed the measure as a circumvention of longstanding regulatory precedent.

Formula Rate Plans: The Illinois Commerce Commission's (ICC) application of EIMA in decisions on initial formula rate plans prior to passage of S.B. 9 left both filing utilities, Commonwealth Edison and Ameren Illinois, with lower revenue prospects than anticipated. [60] This result led to a scaling back of the utilities' investment plans under EIMA. The cases highlighted the importance of methodologies for calculating rate base, capital structure, and interest for purposes of reconciliation adjustments in formula rate plans. The treatment specified by S.B. 9 is intended to better reflect the value of infrastructure investments than the treatment previously used by the ICC, which applied average rate base value, average capital structure, and inclusion only of debt return for reconciliation adjustments.

Following enactment of S.B. 9, the ICC issued a decision in Commonwealth Edison's general distribution rate case in late 2013 that approved use of year-end rate base treatment and capital structure and weighted average cost of capital as interest for purposes of reconciliation adjustments.[61] The provisions of S.B. apply not only to future rate reconciliations under formula rate plans but also to past reconciliation proceedings. The ICC accordingly adjusted, in June 2013, a previous decision for Commonwealth Edison that resulted in a lower revenue requirement. Ameren had not yet gone through a reconciliation by the time of passage.

Refrigerated Spoilage Loss: For the first time under a 15-year-old statute,[62] the ICC found that a utility, Commonwealth Edison, may be liable for damages such as food spoilage and other economic losses experienced by customers in relation to one of a series of storms in summer 2011. In other similar cases, the ICC has consistently waived utility liability for such damage, typically on the basis of findings that damage was unpreventable due to severity of weather. After being denied rehearing, Commonwealth Edison filed a compliance report with confidential information on customers or areas that could be entitled to compensation.

Indiana

Infrastructure Investment: In April 2013, Indiana joined the ranks of states such as **Pennsylvania** and **Texas** that allow distribution infrastructure investment riders for cost recovery for such projects outside of general rate cases. S.B. 560 was enacted to encourage transmission, distribution and energy storage infrastructure investment by utilities, including projects to improve safety and reliability and modernize the grid.[63] The law allows utilities to implement a transmission, distribution, and storage system improvement rider (TDSIC), conditioned on approval by the Indiana Utility Regulatory Commission (URC) of an accompanying seven-year project plan, which is subject to hearings and public comment. The TDSIC can be used to recover no more than 80 percent of capital expenditures related to the plan; 20 percent must be deferred until the next rate case. Utilities with approved TDSIC riders must file a base rate case every seven years. The URC approved the first electric utility TDSIC mechanism for Northern Indiana Public Service in February 2014.[64]

The law also established shorter timeline (300 days) for general rate cases and included other provisions to reduce regulatory lag. The law allows utilities to use a historic test year, forward test year, or hybrid test year

[59] Public Act 098-0015
[60] ICC, Commonwealth Edison Docket No. 11-0721 (May 29, 2012, rehearing, October 3, 2012); Ameren Docket No. 12-0001(September 19, 2012).
[61] ICC, Commonwealth Edison Docket No. 13-0318 (December 18, 2013).
[62] Public Utilities Act, Section 16-125(e).
[63] Public Law 133
[64] URC Docket Nos. 44370 and 44371 (February 17, 2014).

in general rate cases. Under specified circumstances, utilities also may implement interim rate increases to facilitate cost recovery before a final decision is rendered in a rate case.

Storm Reserve Accounting: The URC approved a major storm damage restoration reserve for Indiana Michigan Power. While it reduced the base amount, it allowed IMP to use a tracking mechanism to record variations in O&M expenses from the base amount as a regulatory asset or liability, to be recovered from or refunded to ratepayers in a future rate case. In its decision, the URC said that in the past it has allowed a utility to seek recovery of extraordinary storm restoration costs through a separate proceeding, but only when the related storm was a worst-case scenario. The commission found, however, that these stand-alone cases are often heavily litigated and highly contentions. The approved tracking mechanism will serve to "smooth out the impacts of major storms, thereby mitigating the financial consequences of a major storm," the commission said.

Louisiana

Securitization of Storm Costs: There have been two bills passed by the Louisiana legislature that deal with securitization of utility storm damage costs, both of which resulted from the unprecedented damage caused to the Gulf Coast by Hurricanes Katrina and Rita. A 2006 Louisiana statute authorizing securitization of storm recovery costs, referred to as Act 64, required the companies to establish "special purpose entities" to sell securitization bonds. The Act simply stated that the Louisiana PSC must judge proposed bond issuances on the basis of whether it would result in lower overall costs or would mitigate the impact of storm recovery costs on customers. Rather than institute a separate surcharge for storm recovery, the statute provides that the utility recover its costs of the bonds in general rates. This statute also made clear that the bonds were not backed by the state of Louisiana.

Entergy Louisiana and Entergy Gulf States Louisiana applied for a financing order shortly after passage of the new statute to securitize its costs from Hurricanes Katrina and Rita. (The companies had already received permission to recover the unreimbursed costs in rates.) They received Commission approval,[65] but after over two years were unable to securitize storm costs at what the PSC considered to be favorable rates terms and conditions. Among the possible reasons cited were lack of transparency and the fact that Act 64 did not rely on a separate surcharge or rider for cost recovery, and the state of the securities markets at the time.[66] In 2007, the legislature passed a new law, Act 55, which established the Louisiana Utilities Restoration Corporation to serve as a co-applicant with the utility companies in requesting the sale of bonds for storm recovery by the Louisiana Public Facilities Authority. By establishing the Louisiana Utilities Restoration Corporation, and having the bonds issued by a state authority, the companies were able to successfully sell securitized bonds for storm cost recovery, and at a lower cost to consumers than was possible under Act 64. Act 55 was used again in 2010 to recover damage costs from Hurricanes Ike and Gustav through the sale of securitized bonds. In this case, the PSC established a rider for the collection of funds from customers to repay the bonds.[67]

Storm Cost Recovery by Formula Rate: In 2009, Entergy New Orleans, which is regulated by the City Council of New Orleans Utilities Committee, requested and received approval to implement formula rates which included the recovery of costs due to storm damage, for a three-year period beginning in 2010.[68] The

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[65] Louisiana PSC Docket Nos. U-29203- B, - C and –D (August 15, 2007).

[66] *February 2008 Cumulative Update – Critical Electric Power Infrastructure and Reconstruction: New Policy Initiatives in Four Gulf Coast States After 2005's Catastrophic Hurricanes*, prepared by George Mason University School of Law, Critical Infrastructure Protection Program, p. 27.

[67] Louisiana PSC Docket Nos. U-30981 and U-309812 –A, -B and –C (April 21, 2010).

[68] New Orleans City Council Resolution R-09-136 (April 2, 2009).

formula rates include a rider that collects both for the costs of storm damage and replenishes the company's storm reserve fund.

Storm Investigations: Following Hurricanes Katrina and Rita, the PSC initiated an investigation into the appropriate level of cost recovery for Entergy Louisiana and Entergy Gulf States. Recognizing the catastrophic nature of the storm and the financial position that storm recovery expenditures was placing the companies in, the commission approved interim cost recovery in March 2006 and allowed the company to recover additional forecasted expenses through September of that year.[69] Recovery amounts were to be recovered as an extraordinary cost surcharge which would end when the full amount was collected. The PSC also ordered that after an investigation of the companies' full costs, it would develop a revenue requirement, to be added to rates, for permanent storm recovery.

In an order issued in August 2007, the PSC approved the level of permanent cost recovery for storm damage from Rita and Katrina at $187 million for Entergy Gulf States and $545 million for Entergy Louisiana.[70] Both companies were ordered to establish storm reserve accounts to cover costs of future storms. The PSC requested that the companies seek financing orders to securitize unreimbursed costs from storm damage.

Maryland

Storm Investigations: Maryland has been active in investigating and regulating the actions of investor-owned electric utilities in preparing for and responding to major storms. For example, in February 2011, the Maryland PSC initiated a proceeding to investigate whether the decoupling mechanisms approved for Maryland investor-owned-utilities inadvertently eliminated the incentive for the companies to quickly restore lost service to customers by authorizing the recovery of revenues foregone during extended outages, and if so, whether the decoupling mechanisms should be modified to prevent that outcome. In response to this investigation, the commission issued an order finding that the decoupling mechanisms as currently designed do not appropriately align company financial incentives with reliability goals, and therefore, the commission will require the modification of the decoupling mechanism to prevent collection of decoupling revenue if service is not restored to pre-major storm levels within 24 hours of the commencement of a Major Storm.[71] In October 2012, the commission reaffirmed the January 2012 order and extended the prohibition on collecting decoupling revenue during the first 24 hours of a major outage.[72]

The PSC more recently investigated utility response to the derecho storm of June 29, 2012 and found that the grid is not resilient enough to withstand unscathed a storm the magnitude of the derecho. The commission also found a "disconnect" between the public's expectations for distribution system reliability and the ability of the system to meet those expectations, and it directed utilities to take various steps, including development of shorter term as well as long-term plans to improve reliability. The PSC did not, however, find cause for civil penalties or further action.[73]

The PSC directive built on other work that arose out of an Executive Order[74] issued by Maryland Governor Martin O'Malley initiating a task force to solicit recommendations on how to improve the resiliency and reliability of the Maryland electric distribution system. This task force issued 11 recommendations

[69] Louisiana PSC Docket No. U-29203–A (March 3, 2006).
[70] Louisiana PSC Docket Nos. U-29203- B, - C and –D (August 15, 2007).
[71] Maryland PSC Case No. 9257, *et al.* (January 25, 2012).
[72] Maryland PSC Case No. 9257, *et al*. (October 26, 2012).
[73] Maryland PSC Case No. 9298 (July 26, 2012).
[74] Executive Order 01.01.2012.15 (July 25, 2012).

concerning how specific technology, infrastructure, regulatory, and process improvements can improve the resiliency of Maryland's distribution grid, including allowing a tracker cost recovery mechanism for accelerated and incremental investments.[75]

Reliability Regulations: In 2011, the Maryland Electricity Service Quality and Reliability Act was signed into law requiring the PSC to adopt regulations imposing service quality and reliability standards on electric utility companies, and raising the maximum penalty for failure to comply with the regulations from $500 to $25,000 per violation. Then, in April 2012, the PSC adopted the regulations implementing the service quality and reliability standards in Rule Making 43 (RM43). RM43 set minimum reliability metrics for each utility based on past performance, established a mandatory annual performance reporting system, set up a customer communication survey, and mandated vegetation management and periodic inspections. Also, under RM43, utilities are required to submit a major outage event report within three weeks of a major outage, as well as a restoration plan detailing the utilities' response to a major event. Finally, RM43 provides the PSC the authority to enact civil penalties and disallow costs based on non-compliance with the regulations.

Cost Recovery: In recent rate proceedings the PSC has departed from precedent by allowing application of end-of-test year values to reliability capital investments and post-test year reliability spending adjustments of up to three months in rate cases. The commission also has conditionally approved a reliability spending surcharge for three utilities, known as a grid resiliency charge, which the governor's task force said may be appropriate and that is linked to specific projects such as expansion of poorest performing feeders.[76] Use of these tools, which better reflect for ratemaking purposes the level of investment during the rate period, was approved in recognition of the need to make and accelerate incremental infrastructure investments for safety and reliability. However, the commission has continued to reject longer-term post-test year adjustments, including proposals related to RM43 compliance. The commission cited concern about the estimated nature of such adjustments, including the limited experience with implementation of RM43 so far.[77]

Undergrounding: Maryland has required undergrounding of distribution lines in new commercial and industrial buildings and residential structures since August 1969.[78] In addition, the governor's grid resiliency task force held a session focusing on undergrounding Maryland's electricity distribution system. The discussion touched broadly on the economic feasibility of undergrounding, whether undergrounding truly increases reliability, and the effect of undergrounding on grid resiliency. While the task force issued no specific recommendations concerning undergrounding or other, the consensus among the roundtable participants was that while undergrounding can significantly reduce outages caused by falling vegetation and high winds, due to costs considerations, selective undergrounding is preferable to complete undergrounding of the electric distribution system. The PSC remains cautious about undergrounding, approving half of a utility-requested selective undergrounding project and requiring more detailed information for the approved components.[79]

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[75] *Weathering the Storm: Report of the Grid Resiliency Task Force* (September 24, 2012), delivered to the Office of Maryland Governor Martin O'Malley pursuant to Executive Order 01.01.2012.15, pp. 67-68.
[76] *See, Delmarva Power and Light*, Case No. 9317 (September 3, 2013); *Potomac Electric Power Company*, Case No. 9311 (July 12, 2013); and *Baltimore Gas and Electric*, Case No. 9326 (December 13, 2013).
[77] *Baltimore Gas and Electric*, Case No. 9299
[78] COMAR 20.85.01, and COMAR 20.85.03.
[79] *Baltimore Gas and Electric*, Case No. 9326 (December 13, 2013).

Massachusetts

Storm Response: Massachusetts in November 2009 enacted H 4329, a law that expands the authority of the Department of Public Utilities (DPU) to oversee utility storm restoration.[80] The DPU in April 2010 adopted regulations to implement the law. Under the law, the DPU set performance standards for emergency preparation and restoration of utility service and established financial penalties to be applied for failure to meet the standards. Penalties for failing to meet emergency response plans required of each utility range up to $250,000 per day per incident, with the maximum penalty for a series of violations capped at $20 million. Penalties may not be recovered from ratepayers and instead must be credited to ratepayers of the affected utility in a single billing period, although utilities may petition for a longer period if the credit exceeds $10 million.

The law also authorizes the DPU to issue extraordinary temporary orders for utilities to expend funds and redeploy service to restore service, and it gives the state attorney general the power to appoint a temporary receiver for small utilities (fewer than 100,000 customers) based on a determination that the utility has materially violated DPU standards or on evidence that compliance will not be possible without a receivership. The law was enacted following an investigation by the DPU of a utility's performance in a 2008 ice storm that resulted in findings of shortcomings. Enactment came during a DPU investigation of the response of several utilities to Tropical Storm Irene and an October snowstorm in 2009. The results of the investigation of Irene and the 2009 storm were announced in December 2012 and included financial penalties.[81]

Another law, S 2143, was enacted in August 2012 to establish a Storm Trust Fund, funded by a charge assessed utilities by the DPU that is not recoverable from ratepayers. The funds are used by the DPU to conduct investigations of utility storm response.

Storm Reserve Accounting: Through rate settlements, the DPU has adopted storm funds for various electric distribution companies.[82]

Distribution Reliability: The DPU in late 2012 began reviewing utility service quality (SQ) and SQ guidelines. The department recognized that the attorney general was developing recommendations, which were submitted into the docket. The AG cited concerns that included recent storms and outages, and infrastructure investments and related rate increases. The DPU has solicited input on metrics, benchmarks, offsets and penalty levels.

Distributed Energy Resources: As part of the SQ proceeding above, which is still underway, the DPU has sought input on the possibility of creating a clean energy performance metric. In another initiative, Governor Deval Patrick on January 14, 2014, announced a climate change preparedness plan that includes a $40 million municipal resiliency grant program to be funded by utilities via alternative compliance payments under the state renewables standard. The governor said DPU will work with utilities to accelerate storm hardening and deploy microgrids and resiliency projects for transmission and distribution.

Grid Modernization: The DPU in October 2012 opened an investigation of policies relating to grid modernization, a topic the DPU said has received increased attention in recent years as a result of customer outages following several severe storms. In support of the inquiry, the DPU cited the storm response law

[80] St. 2009, c. 133; 220 CMR § 19
[81] Massachusetts DPU Docket No. DPU 11-119 (December 11, 2012).
[82] Massachusetts DPU, Western Massachusetts Electric Docket No. DPU 06-55 (2006); Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric/NSTAR Gas Docket No. DTE 05-85 (2005).

discussed above and another recently enacted law, S. 2395, An Act Relative to Competitively Priced Electricity in the Commonwealth.[83] The DPU in December 2013 presented a straw proposal for grid modernization following a publication earlier in the year of a working group report.[84] The DPU directed utilities to submit within six months 10-year strategic grid modernization plans that contain infrastructure and performance metrics toward meeting four broad objectives, including reduction of outage effects.[85]

Mississippi

Rate Adjustment Mechanism: In 2007, the Mississippi PSC approved Rider Schedule SRC for Entergy Mississippi as a mechanism to recover securitized and other funds authorized by the PSC.[86] The rider was designed to be applied as a nonbypassable surcharge to all customers. It includes a formula-based mechanism to allow expeditious adjustments intended to correct over- or under-recovery of costs. A similar order was issued for Mississippi Power Company. In 2011, the PSC approved changes in the storm damage rider to reflect an increase in frequency and severity of storms.[87] Rider collections were increased to allow companies to recover their deficit in storm damage reserves that occurred due to Hurricanes Gustav and Ike in 2010, and additional storms of April 2008. The cap on the storm reserve fund was also increased.

Securitization of Storm Costs: In June 2006, the Mississippi PSC issued financing orders permitting both Mississippi Power and Entergy Mississippi to issue securitized storm bonds to recover the costs of Hurricane Katrina that were not otherwise reimbursed by Community Development Block Grants or other payments.[88] The order was issued pursuant to the Hurricane Katrina Electric Utility Customer Relief and Electric Utility System Restoration Act of 2006 passed by the state legislature. By issuing the order, the State Bond Commission (also established by the 2006 legislation) was authorized to issue the bonds to finance recovery costs. Bond debt service is repaid via a system restoration surcharge on customer bills, to be reset by the companies annually to recover 110% of required annual debt service.

Storm Investigations: In approving the issuance of bonds to recover damage costs associated with Katrina, the PSC also determined that certain actions should be taken to reduce future storm damage, and in particular the jurisdictional Mississippi companies were ordered to harden their locations to withstand hurricane force winds approximately 10 miles inland from potential flooding. In addition, Mississippi Power was authorized to use proceeds of its bond sale to build a new storm operations center further from shore.

New Jersey

Storm Hardening and Resiliency: Following Sandy, the New Jersey Board of Public Utilities (BPU) opened various generic proceedings. In one proceeding, the BPU is investigating possible avenues to support utility infrastructure in withstanding major storms and it has asked for utility proposals for infrastructure upgrades.[89] In another proceeding the BPU is investigating the prudence of costs related to 2011 and 2012 major storms for which utilities are seeking rate recovery. Among the responses to the first investigation was Public Service Electric and Gas' proposed Energy Strong program, which is awaiting BPU action. The

[83] St. 2012, c. 209 (August 3, 2012).
[84] *Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee*, Final Report (July 2, 2013).
[85] DPU Docket No. 12-76-A (December 23, 2013).
[86] Mississippi PSC Docket No. 2006-UA-350 (May 22, 2007).
[87] Mississippi PSC Docket No. 2010-UN-436, et al. (October 7, 2011).
[88] Mississippi PSC Docket No. 2006-UA-82 (June 28, 2006).
[89] New Jersey BPU Docket No. AX13030197 (March 20, 2013).

proposal is for a 10-year, $3.9 billion investment program that includes deployment of smart grid technologies, strengthening of distribution infrastructure, and undergrounding in certain areas.

Storm Investigations: The BPU released a report that investigated the restoration efforts by New Jersey's electric distribution companies (EDCs) prior to, during and after Hurricane Irene and the October 29, 2011 snowstorm.[90] The recommendations to the BPU included more detailed development of a vegetation management program; development of an Incident Command System; use of company websites and social media to provide more granular outage details and estimated time of restoration; conducting annual training and exercise drills; and use of benchmarking and external analysis of each company's restoration experiences. This report served as a follow-up to a preliminary report issued by the NJ BPU on December 14, 2011 concerning major storm event planning and emergency response by New Jersey's four EDCs.[91] As a result of another investigation, the BPU imposed new requirements relating to communication among utilities, municipal officials, customers and the Board.[92]

The Board also asked staff to work with Rutgers' Center for Energy, Economic and Environmental Policy (CEEEP) to analyze specific areas that raise concerns and affect restoration efforts in the wake of Sandy. The areas include infrastructure investment such as selective undergrounding and substation protection, expansion of distributed generation, evaluation of smart grid technologies, and identification of best practices for vegetation management.

Distributed Energy Resources and Grid Modernization: New Jersey is focusing more attention on the roles that distributed generation, microgrids, and smart grid technologies may play in grid resiliency. The U.S. Department of Energy and the state last year announced a partnership to develop an advanced microgrid for the New Jersey transit system.[93] See also the discussion above for additional focus on distributed generation and smart grid via a CEEEP study.

Vegetation Management: The state of New Jersey has comprehensive vegetation management regulations for its EDCs.[94] The regulations provide for penalties up to a $100 per day for each violation.[95] See discussion above for additional focus on vegetation management via a CEEEP study.

Undergrounding: In New Jersey, undergrounding of distribution lines is governed under Section 14:3-8.4 of the New Jersey Administrative Code.[96] Under the regulations, distribution lines are required to be constructed underground for new residential developments and streets that are constructed after August 2005.[97] See discussion above for additional focus on selective undergrounding via a CEEEP study.

New York

Storm Hardening and Resiliency: The New York Public Service Commission (PSC) in February 2014 approved multiyear rate plans for Consolidated Edison Co. of New York (Con Edison) that provide for major capital investment in storm hardening and resiliency, including strategic undergrounding and flood

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[90] *Performance Review of EDCs in 2011 Major Storms* (August 9, 2012).
[91] New Jersey BPU Docket No. EO11090543 (December 14, 2011).
[92] New Jersey BPU Docket No. EO12111050 (May 29, 2012).
[93] Department of Energy press release (August 26, 2013).
[94] *Electric Utility Line Vegetation Management*, N.J.A.C. § 14:5-9.2 and 9.6
[95] N.J.A.C. § 14:5-9.10.
[96] *Regulation for Residential Electric Underground*, N.J.A.C. § 14:3-8.4.
[97] *Id*. at § 14:3-8.4(d).

protection projects to protect against coastal storm surge.[98] Concurrent with the rate proceeding was a collaborative track addressing storm hardening and resiliency issues. The PSC in the rate order adopted many of the collaborative's recommendations, which were included in the docket, and approved Phase 2 work, including a voluntary Con Edison climate change vulnerability study in 2014 and review of 2015-16 storm hardening initiatives.

Storm Investigations: New York Governor Andrew Cuomo in late 2012 issued an Executive Order establishing a commission under the Moreland Act to investigate the response, preparation, and management of New York's power utility companies with major storms hitting the state over the previous two years, including Hurricanes Sandy and Irene, and Tropical Storm Lee.[99] The Moreland Commission issued its final report on June 22, 2013, recommending a series of changes to state and utility policies. Recommendations included using public benefit funds and redirecting energy efficiency funds to use for better protecting the electric grid, as well as levying penalties and other measures. The report identified perceived deficiencies in utility storm preparation and restoration as well as best practices by some utilities that the commission said should be adopted statewide. The commission also made recommendations to reform the overlapping responsibilities and missions of the New York Power Authority, the Long Island Power Authority, the New York State Energy and Research Development Authority and the PSC.[100] In response to a request by Governor Cuomo, the PSC in late 2013 adopted a scorecard to serve as guidance to utilities as to what the PSC expects of them and for assessing utility performance related to major storm events.

Distributed Energy Resources: The Moreland Commission's recommendations included using public benefit funds and redirecting energy efficiency funds to use for better protecting the electric grid. In response, the PSC in late 2013 issued an order making changes to the state energy efficiency portfolio standard.[101] The order also started a process for making significant regulatory changes that would address deployment and use of customer-based resources in a more comprehensive policy context. Among the core policy outcomes articulated by the PSC was assurance of system reliability and resiliency. As part of its order approving Con Edison's capital investment program, as discussed above, the PSC directed the utility to pursue development of a plan for a microgrid project as well as a plan to address significant load growth in a section of Brooklyn by offering distributed generation as an alternative to traditional infrastructure. In addition, Phase 2 of the Con Edison resiliency collaborative discussed above will include identification of potential alternative resilience strategies such as additional microgrid and distributed generation projects.

Smart Grid: In New York, while investor-owned electric utilities are making investments designed to modernize the electric power grid, no utility has undertaken mass deployment of smart meters. However, the PSC issued a Smart Grid Policy Statement[102] where the commission recognized that smart meters could "[f]urnish utilities with additional outage management tools."[103]

Vegetation Management: Under 16 NYCRR Part 84 of the New York PSC's Rules of Procedure and an order from Case 04-E-0822, each utility must develop and implement a long-range vegetation management plan for the utilities' right-of-ways. The PSC requires that a utility's long-range plans provide for vegetation management planning in right-of-way corridors for transmission facilities consisting of 34 kV and above, except where located entirely on public streets or roads in right-of-way corridors.

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[98] New York PSC, Case No. 13-E-0030 (February 21, 2013).
[99] Executive Order No. 73 (November 13, 2012).
[100] *Final Report*, Moreland Commission on Utility Storm Preparation and Response (June 22, 2013).
[101] New York PSC, Case No. 07-M-0548 (December 26, 2013).
[102] New York PSC Case Number 10–E–0285 (August 19, 2011).
[103] *Id*. at 32.

Undergrounding: In New York, undergrounding is governed under both 16 NYCRR Part 98 and Part 101. New York was a very early adopter of distribution line undergrounding and since 1969, has required that extensions of electric distribution lines to most new residential subdivisions be placed underground with initial costs up to be borne by the utility up to 60 ft. per customer, with remaining costs to be borne by developers.[104]

North Carolina

Storm Investigations: As a result of a 2002 ice storm that caused significant damage and disruptions, the North Carolina Utilities Commission (UC) initiated an investigation into the response of electric utilities that resulted in a report to the North Carolina Disaster Preparedness Task Force.[105] The UC found that the ice storm was unprecedented in North Carolina history in terms of customer outages for Duke Energy and almost unprecedented for Progress Energy. The report also found that while some government officials faulted companies for their communications during the storm, improvements have since been made. The report further found that utilities have adopted proper procedures for advance planning and getting aid from other utilities, but that the circumstances of this particular storm made things more difficult. The report recommended that utilities examine their tree trimming practices to determine whether improvements were possible.

Undergrounding: In a study conducted in conjunction with the investigation into the December 2002 ice storm noted above, the Public Staff of the UC conducted an examination regarding the feasibility of undergrounding electric distribution facilities.[106] Staff concluded that replacing overhead lines with underground would be prohibitively expensive (about six times the current value of the companies' current distribution assets) and result in higher operations and maintenance costs. The Public Staff did, however, recommend that companies identify the overhead facilities in each region they serve that repeatedly experience reliability problems, determine whether conversion to underground is a cost-effective option for those facilities, and, if so, develop a plan for undergrounding those facilities. In the interim, Public Staff recommended that the companies continue their current practices of: 1) placing new facilities underground when the additional revenues cover the costs or the cost differential is recovered through a contribution in aid of construction, 2) replacing existing overhead facilities with underground facilities when the requesting party pays the conversion costs, and 3) replacing overhead facilities with underground facilities in urban areas where factors such as load density and physical congestion make overhead service impractical.

Vegetation Management: As part of a settlement agreement in a general rate case, Duke Energy Carolinas agreed to review its vegetation management policies and procedures and develop a clear, comprehensive, consistent and publicly available policy description, and file it for review by the UC within 90 days.[107] The settlement agreement provision was based on Public Staff testimony regarding public complaints on the company's vegetation management practices. These complaints generally concerned removal of trees that customers did not want removed, the failure to remove trees that are interfering with power lines, and tree cutting debris being left on customer premises. Public staff believed that the company's practices and procedures were not well-defined or publicly available and therefore had recommended they be filed for commission review. The UC reviewed both Duke's policy description and detailed response to customer

[104] *In the Matter of Sleepy Hollow Lake, et al. v. Public Service Commission of the State of New York*, 352 NY Supp 2d 274, 43 A.D. 2d 439 (1974).

[105] *Response of Electric Utilities to the December 2002 Ice Storm* (September 2003) report of the North Carolina Public Utilities Commission and the Public Staff to the North Carolina Disaster Preparedness Task Force.

[106] *The Feasibility of Placing Electric Distribution Facilities Underground* (November 2003) report of the Public Staff to the North Carolina Natural Disaster Preparedness Task Force.

[107] North Carolina UC Docket No. E-7, Sub 989 (January 27, 2012).

concerns and found that the company implemented its vegetation management policies in a reasonable manner. However, the commission imposed additional reporting requirements.[108]

Ohio

Distribution Reliability: The Public Utilities Commission (PUC) of Ohio requires investor-owned electric utilities in the state to file an annual report of their distribution reliability performance based on specified measures and criteria. Each utility also must file performance standards for approval. The approved standards are minimum performance levels, and missing a standard for two consecutive years constitutes a rule violation.[109] Performance standards can be revised under specified procedures. The PUC has encouraged electric utilities in the state to proactively replace aging distribution infrastructure to improve the reliability of electric service to customers. In deciding a case in 2012, the commission said: "We believe that it is detrimental to the state's economy to require the utility to be reactionary or allow the performance standards to take a negative turn before we encourage the electric utility to proactively and efficiently replace and modernize infrastructure and, therefore find it reasonable to permit the recovery of prudently incurred distribution infrastructure investment costs."[110]
Vegetation Management: Enhanced vegetation management is seen by the PUC as a critical factor in distribution reliability. Utility vegetation management budgets have increased in the years following the Northeast blackout of August 2003, which implicated vegetation management practices as one of the root causes.[111] Reliability rules provide for the inspection, maintenance, repair and replacement of utility transmission and distribution system facilities (circuits and equipment), including vegetation management along rights of way.[112]
Rate adjustment mechanisms: The commission has approved numerous rate adjustment mechanisms that enable timely recovery of investment costs between rate cases to facilitate improved service reliability and to better align utility and customer expectations. Among the riders approved by the PUC in recent years are distribution reliability-related riders for AEP, Duke Energy and First Energy; a vegetation management rider for AEP; and a grid modernization rider for AEP's gridSMART program.

Deferrals: The PUC has allowed several utilities to defer costs related to specific storms for possible future recovery via base rates or storm riders. However, the commission has not always allowed full recovery of deferred costs.

Securitization of Storm Costs: Ohio in December 2011 enacted H.B. 364, which provides electric distribution companies with a mechanism to securitize, through the issuance of phase-in-recovery (PIR) bonds, certain debt previously approved by the PUC.[113] An intended benefit of securitization is customer savings and rate impact mitigation because of lower interest rates on PIR bonds as compared to authorized carrying charges on deferred assets. Deferred assets may include costs related to storm restoration, infrastructure, fuel, environmental cleanup and other areas. In one of the first cases decided under the law, the PUC allowed American Electric Power-Ohio Power to securitize approximately $298 million in previously approved deferred costs, including storm restoration costs related to a Hurricane Ike windstorm in September 2008.[114] The bonds will be backed with a phase-in-rider, which will replace an existing deferred

[108] North Carolina UC Docket No. E-7, Sub 1014 (June 3, 2013).
[109] Rule 4901:1-10-10 (Rule 10) O.A.C.
[110] Ohio PUC Case No. 11-346-EL-SSO, *et al*. (August 8, 2012).
[111] *Final Report on the August 14, 2003 Blackout in the U.S. and Canada: Causes and Recommendations* (April 2004) U.S.-Canada Power System Outage Task Force.
[112] Rule 4901:1-10-27 O.A.C.
[113] Establishes Sections 4928.23-4928.2318 of the Revised Code (December 21, 2011).
[114] Ohio PUC Case No. 12-1969-EL-ATS (March 20, 2013).

asset recovery rider (DARR). The DARR was approved previously to collect costs related to the storm and other approved regulatory assets.

Undergrounding: Cost allocation for undergrounding distribution lines has been an issue in the state. A PUC decision in 2011, which was upheld by the state Supreme Court in 2012,[115] found that AEP appropriately applied a tariff under which it charged a city for costs of relocating overhead distribution lines underground because the city had required such relocation. The city challenged the decision, saying a local ordinance supersedes the tariff. The state high court found that the ordinance was an exercise of police power to promote the health, safety and welfare of the public and did not overcome the "general law" of the state that is attached to the tariff.

Pennsylvania

Rate adjustment mechanism: The state in February 2012 enacted HB 1294 (Act 11) to reduce regulatory lag and provide more ratemaking flexibility for recovery of prudently incurred distribution and other infrastructure costs.[116] The measure is aimed at improving utility access to capital at lower rates and to accelerate improvement and replacement of aging, unreliable infrastructure. The Pennsylvania Public Utility Commission (PUC) in August 2012 issued a final order implementing the new law, which allows electric and other utilities to petition for a voluntary distribution system improvement charge (DSIC) to recover fixed costs related to specific infrastructure projects between general rate cases.[117] The DSIC is capped at 5 percent of distribution rate revenue and is subject to audit. As a pre-requisite, a utility must submit a five- to 10-year long-term infrastructure improvement plan that the PUC must review at least once every five years. The law also allows utilities to use a fully projected test year in rate cases. In May 2013, the PUC approved the first DSIC for an electric utility, PPL Electric, after first approving its long term infrastructure plan to which the DSIC is linked.[118]

Cost deferral: The PUC has approved deferral by utilities of extraordinary storm-related costs for regulatory accounting and reporting purposes, including a recent case where it made clear that future cost recovery of deferred amounts is not guaranteed and that approving a deferral does not constitute a ruling on the reasonableness of costs.[119]

Storm Investigations: The PUC in May 2013 released its report on utility response to Hurricane Sandy, finding that utilities applied lessons learned from 2011 storms with a positive result, especially in communicating with customers and officials and liaising with county 911 and emergency operations centers. The PUC recommended action steps for utilities to continue improvements in these and other areas, such as management of estimated restoration times. In addition, the PUC recommended that its staff continue ongoing work with utilities to reduce the duration and number of outages on worst performing circuits.

In separate action, the PUC issued a proposed policy statement that would revise existing response, recovery and public notification guidelines based on experience gained in recent significant storm-related service outages.[120] The PUC in issuing the proposal also established and sought comment on a Critical Infrastructure Interdependency Working Group in recognition of the need for different types of utilities and other entities to

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[115] Ohio Supreme Court, *In re Complaint of Reynoldsburg*, Docket No. 2011-1274 (November 15, 2012).
[116] Public Utility Code (66 Pa.C.S.).
[117] Pennsylvania PUC Docket No. M-2012-2293611 (August 2, 2012).
[118] Pennsylvania PUC Docket No. P-2012-2325034 (May 23, 2013).
[119] Pennsylvania PUC Docket No. P-2011-2270396 (December 15, 2011).
[120] Pennsylvania PUC Docket No. M-2013-2382943 (September 26, 2013).

coordinate restoration of critical infrastructure. The working group will meet at least once a year to identify mission critical facilities and discuss interdependencies and best practices.

CHAPTER 4: CROSS-SECTION OF STATE LEGISLATION

As with state regulatory activity, inevitably after each major storm or outage event, there is increased executive and legislative activity by governors and other state policymakers. Action in this area tends to focus on reliability standards, emergency preparedness and response plans, infrastructure hardening, and cost recovery issues. As of this report, Connecticut and Massachusetts have passed legislation that allows certain penalties to be assessed to utilities should certain reliability standards and storm response measures not be met.

This section provides a brief overview of recently proposed or enacted state legislation involving utility storm resiliency and response. A more detailed description is included in a matrix in Appendix B, EEI Cross-Section of State Legislative Proposals on Storm Hardening and Resiliency. The matrix will be expanded and updated as additional information is obtained or as developments occur. The matrix is not comprehensive but rather provides a snapshot of recent legislative activity which usually serves as the basis for new regulatory proposals.

4.1 State Highlights: CA, CT, IL, MA, MD, MS, NJ, NY, VT, WI

California

Following the extreme windstorm that occurred in December 2011 in Southern California, the state legislature passed two bills in September 2012 addressing deficiencies in utility outage response. The new legislation requires the California Public Service Commission to establish standards for disaster and emergency preparedness plans for utilities and requires public utilities to preserve all records and evidence collected after any unplanned outages.

Connecticut

The combined effects of Hurricane Irene in August 2011 followed by the October 2011 snowstorm caused significant damage to utility infrastructure in the Northeast with the majority of electrical outages caused by weakened and fallen trees. In June 2012, the Governor signed Senate Bill 23, Public Act No. 12-148, requiring the Connecticut Public Utilities Regulatory Authority to investigate utility practices and establish reliability and emergency response standards for electric utilities as well as identify the most cost-effective means for system reliability. The newly enacted legislation allows for the Public Utilities Regulatory Authority to grant cost recovery in a future proceeding for utility investment in improved resiliency.

District of Columbia

After a series of severe weather events in 2012 that caused widespread outages and left extensive wind damage across the region, Washington D.C. Mayor Gray established the Mayor's Power Line Undergrounding Task Force to study the feasibility of undergrounding major portions of Washington's distribution network. In March 2014, Mayor Gray signed into law the recommendations of the Task Force which authorizes the issuance of revenue Bonds to finance the undergrounding of the 60 most vulnerable overhead distribution power lines and their ancillary facilities.

Illinois

After several major storms and widespread outages in the Chicago area in 2011, several bills were proposed in the Fall of 2011 regarding utility emergency preparedness, communication protocols and vegetation management. In December 2011, the Governor signed into law certain requirements for utility upgrade investments pursuant to an infrastructure investment program and provided for utilities to recover the reasonable costs incurred to maintain or improve the resiliency of its infrastructure necessary to meet established standards.

Massachusetts

Several bills were introduced during the 2013 session proposing hardening measures including vegetation management, infrastructure upgrades and undergrounding. In August 2012, the Governor signed a law establishing the Department of Public Utilities Storm Trust Fund to be used by the department of public utilities to fund investigations into the preparation for and responses to storm and other emergency events by electric companies doing business in the commonwealth. The funds will come from annual assessments made by the department proportional to each electric utility's annual revenues. Any penalties levied against the utilities for any violations of storm response and emergency preparedness will be credited back to utility customers. The law also required electric utilities to file an annual emergency response plan.

Maryland

In August 2012, proposed emergency legislation prohibiting the Public Service Commission from authorizing an adjustment to an electric company's rates to recover profits lost during a disruption in electrical service was introduced to the state Senate; however, there has been no movement on this proposal since its introduction.

Mississippi

Following the devastation of Hurricane Katrina in 2005, the state enacted the Hurricane Katrina Electric Utility Customer Relief and Electric Utility System Restoration Act which provides that the state may issue system restoration bonds with proceeds to be used to securitize the system restoration costs and storm damage reserve levels of those electric utilities affected by Hurricane Katrina, thereby providing electric utility customers relief from traditional methods of recovering system restoration costs.

New Jersey

In the wake of Superstorm Sandy, the legislature has introduced numerous bills in 2013 and 2014 mostly calling for the New Jersey Board of Public Utilities (BPU) to establish performance standards in emergency situations and require utilities to file emergency preparedness plans with the BPU. Other bills have been introduced that require inspections and hardening of the existing infrastructure looking towards the necessity for certain facility construction standards. Prior to Superstorm Sandy, bill A.B. 2760 was introduced giving authority to the BPU to authorize the recovery of all reasonable and prudent costs incurred by an electric utility in repairing, improving, and replacing its equipment and property reasonably associated with the improvement of utility service reliability. This measure was reintroduced in the 2014 session.

New York

Also widely affected by Superstorm Sandy, the New York state legislature introduced several bills aimed at requiring new standards for utility emergency preparedness and response. The proposed "Natural Disaster

Preparedness and Mitigation Act" (S.B. 3761) establishes a disaster preparedness commission consisting of commissioners from each of the New York public sectors, including the chair of the public service commission, to oversee and coordinate state emergency preparedness and response activities. The proposal also calls for the disaster preparedness commission to "utilize, in rate setting proceedings, to recover the reasonable costs incurred to maintain and improve the resiliency of the utility's infrastructure necessary to comply with [established standards]."

Vermont

Citing the devastating effects of Hurricane Irene, Governor Peter Shumlin signed Executive Order 04-13 in April 2013 establishing the Governor's Emergency Preparedness Advisory Council which will review the state emergency preparedness system. Governor Shumlin ordered that the Council must take into consideration the interdependencies between federal, state and local government as well as public service sectors serving the community and provide recommendations on ways to bolster such relationships in emergency preparedness policies and communications.

Wisconsin

In December 2013, Governor Scott Walker signed into law an act creating a State and Province Emergency Management Assistance Compact providing for several states and Canadian provinces to participate in mutual assistance operations such as the sharing of emergency operations plans, resources and communications in responding to an emergency affecting several participating jurisdictions.

APPENDIX A

EEI Cross-Section of State Regulatory Decisions on Storm Hardening and Resiliency

March 2014

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
AR (Public Service Commission)	Generic	• Decided 1/30/09 • Case 09-12-U • Order No. 1	• To facilitate/encourage restoration efforts during Jan 2009 ice storm, grants temporary waiver of certain general service rules, e.g., those governing daily meter reading and customer billing, until utilities are able to resume full compliance	• Invites all public utilities to file in this docket specific proposals for recovery of extraordinary storm restoration expenses related to recent ice storms (see entries below)	
AR	Entergy Arkansas	• Decided 12/30/13 • Case 13-028-U • Order		• Approves $5.8m increase in annual storm reserve • Approves $20.1m related to 2013 winter storm • Approves co.-requested $2m increase in test-year vegetation management expense based on 3-yr. average of known & measureable costs • Rejects co. proposal for $2.3m to shorten vegetation management cycle time, saying costs are not yet known & measureable	
AR	Entergy Arkansas	• Decided 5/25/10 • Case 10-008-U • Order No. 5		• Approves co. request to securitize costs related to damage from Jan 2009 ice storm • Authorizes cost recovery to back bonds, including carrying charges & upfront financing costs, via new Storm Recovery Charges Rider (Rider SRC) • Rider SRC rates to be calculated using demand (kW) for Large General Service customers & energy (kWh) for all other customer classes • Reduces requested $121.9m increase by $293K to	Financing order issued pursuant to Arkansas Electric Utility Storm Securitization Recovery Act of 2009 (AR Code Annotated 5 23-18-901) (Act 729**)**

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				avoid potential double-recovery regarding plant that was damaged by ice storm and retired rather than replaced • Costs to be recovered from all existing and future customers receiving transmission or distribution service from co. • Regarding carrying cost recovery, notes significant time lag between incurrence of storm recovery costs and filing to recover those costs - Finds delay not unreasonable considering the law authorizing securitization was neither adopted nor in effect till months after storm • Caps interest rate on securitized bonds @4.4% • Requires co. to reduce amt. to be securitized by any credit balance in storm reserve account	
AR	Entergy Arkansas	• Decided 4/16/10 • Case 09-031-U • Order No. 3		• Approves request to establish storm reserve account, w/initial amount of $14.449 to be accrued monthly as of Jan 2009 per new Act 434 • Authorizes co. to charge reserve account for O&M storm restoration costs that are reasonable/prudent and not otherwise recovered • Requires quarterly reports • Staff to audit/adjust all storm restoration costs to ensure only reasonable/prudent storm restoration costs are included in reserve account consistent w/statutory provisions	Filing made under provisions of Act 434 of 2009, An Act to Require the Arkansas Public Service Commission to Permit Storm Cost Reserve Accounting for Electric Public Utilities When Requested; and for Other Purposes
AR	Entergy Arkansas	• Decided 3/6/09 • Case 09-018-U • Order		• Allows co. to defer $80m-$100m in storm recovery O&M expenses resulting from Jan 2009 ice storm • Allows co. to defer expense portion of storm restoration costs per accounting standards, thereby removing expense from income statement and avoiding the reporting of financial loss in 1Q earnings report	• Co. stated that w/o accounting order authorizing deferral of storm recovery costs, "there will be a significant negative impact on earnings"
AR	Entergy Arkansas	• Decided 6/15/07 • 06-101-U • Order No. 10		• Rejects co.-proposed use of reserve accounting for rate purposes for both storm damage reserve & storm damage expense, saying co. proposal would constitute retroactive ratemaking by crediting almost $50m of storm costs incurred in	• Co. had proposed that storm-related O&M costs are appropriately booked using reserve accounting; it argued that "(t)he use of reserve

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				prior periods to rate base or CAOL (Current Accrued & Other Liabilities) account and amortizing prior period costs as current expense; says co. method also would constitute single issue ratemaking by isolating one component of revenue requirement for proposed ratemaking treatment w/o taking other components into account - Accepts staff recommendation for inclusion of normal expected annual level of storm damage costs of $14.5m based on historical average; requires co. to reduce amount in storm reserve account to zero	accounting for storm costs is appropriate because of the nature of storm costs ... (given that) ... (t)he severity and number of storms are clearly out of the Company's control." Co. also asserted that normalization vs. use of reserve method "would improperly provide no recovery of previously incurred storm costs above the current level of accrual."
CA (Public Utilities Commis sion)	Generic	• Decided 2/5/14 • Case R08-11-005 • Decision Adopting Regulations to Reduce the Fire Hazards Associated with Overhead Electric Utility Facilities and Aerial Communications Facilities	• Revises General Order 95 to incorporate new and modified rules, including: - Communications facilities in proximity to lines must be built w/higher safety standards - Overhead facilities must be able to support higher vertical loads to reflect increased weight of workers & their equipment - Incorporation of use of modern design & construction materials /standards • Approves consensus plan for utilities to report fire incidents to CPUC enforcement staff for identification of systemic fire safety risks and development of measures to mitigate risk	• Authorizes utilities to track related costs for future recovery in general rate cases	• This decision concludes Phase 3 of docket. Phase 2 concluded with 1/12/12 decision (below). Phase 1 concluded with 8/20/09 decision (below.)
CA	Generic	• Decided 1/16/14 • Case R08-11-005 • Decision Approving the Work Plan for the Development of Fire Map 1	• Approves work plan for design, development & adoption of statewide fire-threat map depicting physical & environmental conditions associated with an elevated risk of power-line fires. PG&E, SDG&E and SCE to jointly provide up to $250K for state to obtain consultants.	• Establishes rebuttable presumption that utility payments (per previous column) are reasonable and may be recovered in rates.	•
CA	Generic	• Decided 1/12/12 • Case R08-11-005 • Decision Adopting Regulations to Reduce Fire Hazards Associated with	• Revises General Orders 95, 165 & 166 as follows: - Requires utilities to remove vegetation strain on conductors energized @ ≤ 750 volts, authorizes increases to time-of-trim vegetation clearances around bare-line	•	• Rules were adopted following series of 2007 wildfires • Resolution E-4576 was issued 5/23/13 approving advice letters (ALs) filed by utilities including PG&E, SDG&E and

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		Overhead Power Lines and Communication Facilities On reconsideration: In 6/27/13 decision, eases definition of "year" for purposes of inspection intervals for overhead lines. Says revision will enhance ability to perform inspection, enhance public safety in certain situations, and may reduce cost.	conducts per specified circumstances - Conditionally authorizes utilities to turn off power supply to property owners who block vegetation mgt. activities around overhead power lines - Requires utilities in Southern CA to prepare fire prevention plans based on specified tasks & criteria; utilities in Northern CA must conduct risk determination and prepare similar plan if need shown - Requires utilities to calculate weight loads on poles when new attachments are made • Institutes additional phase of proceeding to consider materials & practices including use of smart technologies to protect public safety & critical infrastructure, standards regarding wood structures, fire threat mapping, reporting requirements & other matters. This phase was concluded w/2/5/14 decision in this docket (entry above).		SCE. The ALs comply w/the provision to file FPPs. The FPPs, whose specific content was not approved, will be incorporated in annually submitted emergency action plans/reports of the utilities per General Order 166.
CA	Generic	• Decided 8/20/09 • Case R08-11-005 • Decision in Phase 1 – Measures to Reduce Fire Hazards in California Before the 2009 Fall Fire Season	• Directs implementation of numerous measures for electric transmission & distribution lines and related communications facilities prior to autumn 2009 fire season. - This is first phase of broad commission review of fire hazards following destructive wildfires that commission says may be linked to electric and communications lines. The orders seeks to strengthen and clarify existing rules for such facilities.	•	•
CA	Pacific Gas and Electric	• Decided 6/27/13 • Case A11-09-014 • Decision Authorizing Pacific Gas and Electric Company to Recover Costs Recorded in the Catastrophic Event Memorandum	•	• Approves settlement providing for recovery of $26.537m of incremental disaster-related costs recorded in CEMA and incurred responding to 7 events (several wildfires, an earthquake and 2 winter storms). The approved level is closer to ratepayer advocate-recommended disallowances than PG&E's initial request of $32.4m. - Ratepayer advocate had raised concerns about accounting & recovery methods, reasonableness & justification, existence of	•

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		Account [CEMA] Related to Certain Disasters		official disaster declarations, and other items.	
CA	Pacific Gas and Electric	• Decided 6/24/10 • Case A08-05-023 • Decision on Pacific Gas and Electric Company Request to Implement a Program to Improve Electric Distribution System Reliability	• Approves co.-proposed Cornerstone program to increase distribution system resiliency & reliability but at lower than requested funding levels; says need not shown for all proposed projects but that co. may re-propose them later; next co. rate case is in 2014 • Authorizes $357.4m in capital & $9.2m in expense for 2010-2013 for projects that: 1) address identified problems related to worst-performing circuits & substation transformer emergency capacity, and 2) implement feeder interconnectivity and rural reliability projects that are cost-effective	• Adopts ratemaking treatment under which rates to be set initially to recover forecast project costs, w/true-up to actual costs achieved via new balancing account; after 2013 program termination, project costs to be recovered via GRC • Co. has flexibility in how it spends authorized funds but must provide annual reports on work performed & forecasted work • Revenue requirements & rates covering program to be revised annually w/true-up • Underspending to result in customer refunds; overspending not authorized	
CA	• Pacific Gas and Electric • San Diego Gas & Electric • Southern California Edison • 3 other IOUs	• Decided 9/13/12 • Case E-4493 • Resolution	• Adopts contested co.-filed tariff changes under which power may be conditionally shut off to customers who do not allow access to their property for vegetation mgt. activities for fire hazard prevention		• Filings were made per 1/12/12 decision adopting regulations to reduce fire hazards associated w/overhead power lines (Case R08-11-005; see entry above)
CA	• Pacific Gas and Electric • San Diego Gas & Electric • Southern California Edison • Southern	• Decided 7/29/10 • Case E-4311 • Resolution		• Approves establishment of wildfire expense memorandum accounts (WEMAs) as interim mechanisms for recording uninsured wildfire-related costs, except for certain financing costs, incurred while PUC considers establishment of wildfire expense balancing accounts (WEBAs) in Case A09-08-020 (see entry above) - If WEBAs are approved in Case A09-08-020, WEMA balances would be transferred to WEBAs for potential base rate recovery - Categories of allowed costs for recording: 1)	

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	California Gas			payments to satisfy wildfire claims including co-insurance & deductibles expense, 2) outside legal expenses, 3) increases/decreases in wildfire insurance premiums from amounts authorized in GRCs	
CA	• San Diego Gas & Electric	• Decided 5/9/13 • Case A10-12-005 • Decision on General Rate Cases of San Diego Gas & Electric Company and Southern California Gas Company	• Requires SDG&E to implement performance incentives previously developed for co. in D08-07-046, which SDG&E had declined as then authorized. Notes that while uncertainties exist, the record shows clear link between incentives and reliability performance. Co. must include at minimum SAIDI, SAIDET & SAIFI indices, and track/record outage causes. Data to be included in next GRC filing. Fire prevention improvements cited by co. as key contributor to reliability.	• Denies co. request for treating tree/pole brushing costs in 2-way balancing account, leaves door open to revisit in next GRC. Says 1-way account encourages tree performance while containing costs, and pole brushing costs are fairly stable. • Approves funding of various smart grid capital projects but at lower than requested levels, citing financial impact on ratepayers as among the factors. Projects include SCADA controls that PUC says will reduce time it takes to locate and repair problems, to be funded at \$2.25m vs. requested \$4.699m. • Approves \$25.5m for O&M costs related to tree-trimming (400,000 potentially encroaching trees) vs. co.-requested \$27.419m and lower intervenor requests. Says activities likely to increase due to more inspections/clearances as required elsewhere and upward cost pressures from tree growth/mortality/diseases and weather. • Approves slight pole brushing increase to \$4m based on data review vs. co.-requested \$5.354m and lower intervenor requests.	
CA	• San Diego Gas & Electric • Southern California Gas	• Decided 12/20/12 • Case A09-08-020 • Decision Denying Application		• Denies recovery of uninsured expenses related to 2007 wildfires via wildfire expense balancing account (WEBA), saying companies had not met burden of showing all legal and factual issues were addressed, including whether limitless potential for ratepayers to fund 3rd party claims would open door to claims by others such as government entities, and for utility incentives to defend against 3rd-party claims and manage risk • Allows existing wildfire expense memorandum accounts, in which utilities began recording costs in July 2010, to continue. These tracking accounts	

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				were authorized in Case E-4311 (below)	
CA	• Southern California Edison	• Decided 9/19/13 • Case I09-01-018 • Decision Conditionally Approving the Southern California Edison Company Settlement Agreement Regarding the Malibu Canyon Fire	• Approves settlement between co. and CPUC enforcement division involving fire caused by 3 utility poles that fell during a Santa Ana windstorm. Under the settlement, SCE: - Made certain admissions - Agreed to pay $20m to state General Fund - Agreed to provide $17m for assessment & remediation program for approx. 1,453 poles in the Malibu area • Imposes conditions, including: - Pole program to be completed w/in 18 mos. - Bi-monthly reports & comprehensive report	• Total $37m settlement amount to be funded by shareholders	
CA	• Southern California Edison	• Decided 7/11/2013 • Case A07-06-031 • Decision Granting the city of Chino Hills' Petition for Modification of Decision 09-12-044 and Requiring Undergrounding of Segment 8A of the Tehachapi Renewable Transmission Project	• Finds 10/28/11 decision effectively ignored "community values" and placed an unfair, unreasonable burden on Chino Hills residents by requiring abovegrounding Segment 8A w/massive new transmission towers set in narrow right of way. • Approves undergrounding this 3.5-mile segment, capped @$224m, saying it can be built on timely basis and at reasonable cost.		• Two commissioners dissented, saying reconsidering 4-year-old decision creates uncertainty for developers; costs more than 50x the $4m abovegrounding, which poses burden for ratepayers, esp. large energy users; and appears to send message that communities that can afford to pay attorneys will succeed in changing PUC mind.
CA	• Southern California Edison	• Decided 11/29/12 • Case A10-11-015 • Decision on Test Year 2012 General Rate Case for Southern California Edison Company	• Authorizes enhanced equipment inspections & new technology to better track condition/service record of co. assets, esp. poles and wires. Capital program includes infrastructure replacement, distribution construction & maintenance, and development of smart grid/other technologies • Orders independent assessment of system utility poles to determine whether current loads meet legal standards • Requires progress report on various initiatives to improve emergency communications & responses following Dec 2011 windstorms	• Makes numerous adjustments to rate base and forecasted expenses but overall is supportive of major infrastructure program, including significant distribution infrastructure monitoring, replacement & expansion	

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			• Requires independent audit of reliability investment incentive mechanisms (RIIM), which provides incentive to spend funds authorized for reliability vs. diverting them; results must be submitted w/analysis of short-term reliability stats (SAIDI, SAIFI) tracked w/RIIM expenditures since 2003		
CT (Public Utilities Regulatory Authority)	Generic	• Decided 1/28/14 • Case 12-01-10 • Decision	• Reopens record to address motion by UI for technical hearing prior to final decision in tree trimming investigation • Will take public comment in March 2014		• Draft decision issued 11/19/13 reviews/clarifies practices, procedures and requirements for utility vegetation mgt. to comply w/governor's directives and legislative mandates
CT	Generic	• Decided 8/21/13 • Case 12-11-07 • Decision	• Makes findings from investigation into the performance of electric distribution and gas companies in restoring service following Storm Sandy. (See item below.) Finds companies performed in "a generally acceptable manner in preparing for and responding to the storm." Finds areas that can be improved. For example: - For CL&P and UI: Found significant progress in many areas such as communications since previous storms. Required further improvements in estimated time of restoration (ETR) and inclusion of analysis of ETR accuracy in future After Action Reports. Required further collaborative work with governmental agencies to identify and prioritize critical facilities. • In response to consumer advocate concerns, including effect on customers of backup generator failure, requires CL&P and UI to report on feasibility of emergency generator operational readiness management program.		
CT	Generic	• Decided 1/8/13 • Cases 12-06-12 • Decision	• Describes potential refrigerated spoilage program. Legislation would be required. Key features include:	• Potential refrigerated spoilage program would be funded by ratepayers via existing systems benefit charge	• Decision is PURA report to legislature in response to directive in S.B. 23 (see below,

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			- Residential-only - Communications package - $150 bill credit for food spoilage - Up to $200 credit for medication spoilage - Outage verification by utility - Application process w/utility		Case 12-06-09, Notes column)
CT	Generic	• Opened 11/16/12 • Case 12-11-07 • PURA Investigation into the Performance of Connecticut's Electric Distribution Companies and Gas Companies in Restoring Service Following Storm Sandy	• Performance to be reviewed against standards set per Act 12-148 (see entry below) • Says it may order remedies, compliance filings or issue other orders and determine whether sanctions are warranted		• PURA also is investigating cost-effective ways for CL&P to harden its system in Case 12-07-06 and ways to improve cost-effectiveness of CL&P and UI vegetation mgt. programs in Case 12-01-10
CT	Generic	• Decided 11/1/12 • Case 12-06-09 • Decision-PURA Establishment of Performance Standards for Electric and Gas Companies	• Requires electric and gas distribution companies to incorporate performance standards in Emergency Response Plans addressing: - Emergency planning, including storm preparation and communications plans - Restoration & recovery • Sets reporting requirements • Noncompliance can result in civil penalties • CL&P to initiate pilot to determine feasibility/cost-effectiveness of option-like arrangement to procure contract resources for storm response	• Determines that costs incurred to comply w/performance standards are generally recoverable in rates in future proceeding, including carrying costs calculated at co. avg. cost of capital, subject to review	• Case was opened per requirement of S.B. 23, enacted in 2012 as Public Act 12-148, An Act Enhancing Emergency Preparedness and Response, following TS Irene & Oct 2011 snowstorm. Act requires PURA to review performance of utility when more than 10% of its customers are w/o service for more than 48 consecutive hours.
CT	Connecticut Light and Power, United Illuminating	• Decided 8/1/12 • Case 11-09-09 • Decision-PURA Investigation of Public Service Companies' Response to 2011 Storms	• Establishes rebuttable presumption that CL&P ROE will be reduced in next rate case as penalty for poor mgt. performance in response to storms; CL&P will have opportunity to rebut • Both companies to track/implement recommendations from all reviews of 2011 storms (or explain why not implementing)		

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
			• Both companies to implement 4-year tree trimming cycles vs. previous 5- to 7-year cycles • CL&P to file report in Case 12-06-09 (see entry above) on effectiveness of enhanced tree trimming on circuit reliability • CL&P to develop plan to establish heightened readiness for storms, including line worker resources • Both companies to discuss ways to improve mutual assistance process w/EEI & mutual assistance groups • CL&P to develop plan for real-time damage assessment & outage restoration data		
CT	• Northeast Utilities-Connecticut Light and Power	• Decided 3/12/14 • Case 13-03-23 • Decision	•	• Approves $365m storm cost reserve recovery, to be amortized over 6 yrs. w/carrying charges as of 12/1/14 when existing rate freeze expires - Amount is net of $8.3m storm reserve fund balance and $40m of costs written down per settlement agreement approved 4/2/12 in Case 12-01-07 (below) - Amounts relate to costs incurred for 5 storms in 2011-12 including Sandy - Finds most costs related to line crews and other utilities/contractors needed to repair system • Disallows $49m including amounts transferred to capital, reimbursements subsequent to filing, and those found to be already included in base rates - Recovery of capitalized amounts to be determined in next rate case	
CT	• Northeast Utilities-Connecticut Light and Power	• Decided 1/16/13 • Case 12-07-06 • Decision	• Approves co. 5-year system resiliency plan per April 2012 decision in this docket (below). Plan calls for: - Spending $300m: $258m capital, $42m expense - Short-term plan w/two phases: 1) 2013-14 increased vegetation mgt. efforts; 2) 2015-17, increased vegetation mgt. as well as structural/electrical hardening	• Approves co. proposal to recover costs through existing nonbypassable federal mandated congestion charge, subject to semi-annual reconciliation, until co.'s next rate case, at which time costs to be factored into revenue requirements	

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			- Long-term plan after 2017 to be developed based on learnings from short-term plan • Requires detailed regular status report on implementation • Prohibits commingling of storm resiliency spending w/other program spending		
CT	• Northeast Utilities-Connecticut Light and Power • NSTAR	• Decided 4/2/12 • Case 12-01-07 • Decision-Application for Approval of Holding Company Transaction Involving Northeast Utilities and NSTAR	• Approves settlement providing for CL&P to: - Spend $300m on additional distribution system resiliency - Develop microgrid infrastructure in collaboration w/CT Dept. of Energy & Environmental Protection - Enhance Center for Storm and Power System Resiliency at U of Conn.	• CL&P distribution rates frozen until 12/1/14; other retail rate components not affected by freeze • CL&P to file for base rate cost recovery related to TS Irene & Oct 2011 snowstorm net of insurance proceeds & storm fund but must write off $40m of such costs; approved costs may be recovered at end of rate freeze over 6 years • CL&P to submit multiyear plan & cost recovery mechanism w/in 90 days for $300m system resiliency program (see Notes column); recovery to occur via system benefits charge, federally mandated congestion charge or similar mechanism; CL&P to spend up to $100m during rate freeze period, w/revenue requirement capped @$25m, recoverable during freeze period beginning 1/1/13	• CL&P on 7/9/12 submitted an application for approval of a multiyear system resiliency plan (Case 12-07-06)
CT	United Illuminating	• Decided 8/14/13 • Case 13-01-19 • Decision <u>Rehearing</u> • Decided 12/16/13	• Approves $100m ETT program but requires 8-yr. implementation ($12.5m/yr.) vs. requested 4 yrs.; requires more detailed plan before 2014 work can begin	• Offsets entire $53.3m regulatory asset that co. requested to amortize over 6 yrs. through disallowances – reducing amount to $46.1m for 2009-12 – and by offsetting remaining balance via accrued earnings sharing mechanism and other accrued regulatory liabilities. Approved regulatory asset consisted of extraordinary storm expenses related to Irene, Sandy, and 2011 Nor'easter and 4 other major storm events. - Sets definition of "major storm" as having $1m expense threshold before deferral allowed • Approves reinstatement of storm reserve, funded annually @ $2m for major storm costs. (Once reserve funding is exhausted, co. may use deferred accounting.) • Allows co. to capitalize ETT (see previous column);	• On rehearing, approves $1.3m increase in storm regulatory asset and additional $5.5m in costs related to previously disallowed storms; acknowledges "mixed signals," e.g., new storm definition differed from that previously used for determining which storm costs could be recorded as regulatory asset. • <u>Note</u>: Co. had used storm reserve accounting until 2006, at which time PURA approved regulatory asset treatment of major storm costs out of

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				approves 5-yr. amortization of each year's costs; allows carrying charges @approved cost of capital • Approves infrastructure replacement costs of $45m/yr. for 2013-18 vs. requested $57.3m/yr., saying additional levels will be considered in future subject to co. providing long-term plan • Reduces rate recognition of T&D operational excellence initiative (TDOEI) consisting of products/tools for restoration work related to major storms, from requested $98.3m to $56.4m (total) for 2013-16; says additional funding may be considered subject to co. providing more detailed plan w/cost-benefit analysis	concern over potential overfunding of reserve.
DC (Public Service Commis sion)	Generic	• Released 7/1/10 • Case FC-1026 • Study of the Feasibility and Reliability of Undergrounding Electric Distribution Lines in the District of Columbia	• Consultant hired by PSC made recommendations concerning undergrounding including for: o Continued use of undergrounding when new residential developments are introduced o Selective undergrounding in specific situations where undergrounding can be bundled with infrastructure investments, such as road expansion efforts, and large scale water and sewer replacement • Does not recommend undergrounding for all existing circuits		Generic
DC	Potomac Electric Power	• Decided 10/26/12 • Case FC-1087 • Order	• N/A	• Rejects proposal to amortize over 3 years $2.1m related to Hurricane Irene, saying Irene should not be treated differently than other storms; instead orders factoring of expenses into 3-year average storm costs • Approves increase of $500K related to new Enhanced Integrated Vegetation Management (EIVM) program o Requires co. to file annual plan for EIVM w/quarterly targeted Milestones & quarterly reports detailing EIVM effort	• EIVM is a comprehensive program designed to address tree-related outages and increase reliability by removing hazardous trees, and trimming and removing vegetation above utility lines to prevent damage from falling limbs

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FL (Public Service Commis sion)	Generic	• Decided 5/23/07 • Case 070011-EI • Order PSC-07-0444-FOF-EI • Notice of Adoption of Rule		• Amends FL Administrative Code re use of storm reserve accounts • Establishes sub-account to cover property leased from others • In determining costs to be charged to cover storm-related damages, utility to use an Incremental Cost and Capitalization Approach methodology (ICCA) - Under ICCA, costs charged to cover storm-related damages exclude costs that normally would be charged to non-cost recovery clause operating expenses in absence of a storm • Specifies types of storm-related costs allowed to be charged to reserve under ICCA methodology • Utility may choose to expense storm recovery costs vs. crediting them to storm reserve account • Utility may petition for recovery of a debit balance in reserve account + an amount to replenish storm reserve via surcharge, securitization or other cost recovery mechanism • If utility seeks to change either target accumulated balance or annual accrual amount for storm reserve, it must file study w/PSC	• Rule 25-6.0143, F.A.C.
FL	Generic	• Decided 1/17/07 • Cases 060172-EU, 060173-EU, et al. • Order PSC-07-0043-FOF-EU • Notice of Adoption of Rules	• Amends FL Administrative Code re standards of construction, location of facilities, storm hardening & CIAC • Utilities to file by May 2007 and every three years thereafter, a detailed storm hardening plan that must: - Contain detailed description of construction standards, policies, practices & procedures used to enhance reliability of overhead & underground electrical T&D facilities in conformance w/rule provisions - Explain systematic approach utility will follow to enhance reliability & reduce restoration costs/outage times related to extreme weather events	• Establishes uniform procedure by which IOUs calculate amounts due as CIAC from customers who request new facilities or upgraded facilities in order to receive electric service • Incremental costs associated with hardening/resiliency to be recovered through base rates	

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			- Include pole attachment standards		
FL	Generic-utility storm hardening plans	• Decided 4/25/06 • Case 060198-EI • Order Requiring Storm Implementation Plans	• Requires all investor-owned utilities to file plans & estimated implementation costs for 10 storm preparedness initiatives that will be ongoing: - 3-y.r vegetation management cycle for distribution circuits - Audit of joint-use attachment agreements - 6-yr. transmission structure inspection program - Hardening existing transmission structures - Transmission & distribution GIS - Post-storm data collection/forensic analysis - Collection of detailed outage data differentiating reliability performance of overhead & underground systems - Increased utility coordination w/local governments - Collaborative research on effects of hurricane winds & storm surge - Natural disaster preparedness/recovery program		• The PSC on 5/19/08 approved FPUC's plan as part of its general rate case (Case 070300-EI); and on 12/28/07, approved plans filed by TECO (Case 070297-EI), PEF (070298), Gulf (070299) and FPL (070301). • The PSC on 10/26/10 approved plan updates filed by PEF (Case 100262-EI), TECO (100263), FPUC (100264), and Gulf (100265); and on 1/31/11 approved FPL's update (100266). Says the updates largely are continuations of the previously approved plans and notes unavailability of data to evaluate effects of plans due to lack of named storms affecting FL. • The PSC on 12/3/13 approved 2013-15 plan updates filed by Duke (Case 130129-EI), FPL (Case 130132-EI), FPUC (130131), Gulf (130139) and TECO (130138). Says the updates largely are continuations of the previously approved plans; notes unavailability of data to evaluate effects of plans due to lack of storms. Finds utilities are taking proactive steps to withstand severe weather events and reduce restoration and outage times.
FL	Generic	• Decided 2/27/06	• Requires investor-owned utilities to begin		

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
		• Case 060078-EI • Order Requiring Each Investor-owned Utility to Implement Eight-year Pole Inspection Cycle and Requiring Reports	implementing 8-yr. inspection cycle of transmission & distribution wooden poles based on National Electrical Safety Code compliance • Requires annual reporting of prior year inspection results		
FL	Florida Power & Light	• Decided 1/14/13 • Case 120015-EI • Order Approving Revised Stipulation and Settlement		• Approves settlement providing for co. to implement monthly storm cost recovery surcharge, which co. proposed in lieu of seeking annual accrual to storm reserve - 60 days following a request for storm cost recovery, co. would implement on interim basis surcharge ≤ $4/1,000 kWh on residential bills based on 12-mo. recovery period - Any storm costs exceeding that level are to be recovered later as determined by PSC • If co.'s costs related to named storms exceed $800m in any one year, co. may also request increase of $4/1,000 kWh rate accordingly	
FL	Florida Power & Light	• Filed 8/15/12 • Case 120015-EI • Order pending • Joint petition to Suspend Procedural Schedule		• Co. requests approval of settlement allowing it to implement monthly storm cost recovery surcharge - 60 days following a request for storm cost recovery, co. would implement on interim basis surcharge ≤ $4/1,000 kWh on residential bills based on 12-mo. recovery period - Any storm costs exceeding that level to be recovered later as determined by PSC • If co.'s costs related to named storms exceed $800m in any one year, co. may also request increase of $4/1,000 kWh rate accordingly • Surcharge mechanism proposed in lieu of co. seeking annual accrual to storm reserve	• Settlement, including this provision, was approved by the FPSC on 12/13/12
FL	Florida Power & Light	• Decided 5/30/06 • Case 060038-EI • Order PSC-06-0464-FOF-EI		• Approves issuance of up to $708m, 12-year storm-recovery bonds backed by customer surcharge, provided initial avg. retail cents per kWh surcharge will not exceed avg. retail cents	• Similar financing orders were issued for other FL utilities • PSC on 7/2/2007 submitted report to Governor and

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		• Financing Order		per kWh for separate 2004 storm surcharge currently in effect Background: • As result of hurricanes Charley, Frances & Jeanne in 2004, FPL incurred storm-related costs of ~$890m and deficit of ~$536m in its storm reserve as of end of 2004 • PSC on 9/21/05 (Case 041291-EI) approved recovery of $442m of estimated deficit via mo. customer surcharge over 36 months • 2005 FL Legislature passed law giving utilities ability to securitize storm recovery costs - Co. subsequently filed to suspend payments to reserve account and make a new filing to recover costs in an alternative way • FPL's service territory was impacted by four storms in 2005: Dennis, Katrina, Rita & Wilma, two of which inflicted the most damage subsequent to execution of settlement on storm cost amounts, leaving FPL w/even larger reserve deficit estimated @ ~$880m net of insurance proceeds for all four storms • FPL requested financing order in this case (No. 060038) authorizing issuance of storm recovery bonds of up to $1.5b to: 1) recover remaining unrecovered balance of 2004 storm costs, 2) recover prudently incurred 2005 storm costs, less capital costs & insurance proceeds, 3) replenish storm reserve & 4) recover bond issuance costs	Legislature analyzing additional actions necessary to enhance reliability of FL utilities during extreme weather. See: http://www.psc.state.fl.us/publications/pdf/electricgas/stormhardening2007.pdf • Pursuant to Financing Order - $652 million of storm recovery bonds issued May 2007. Previously approved 2004 Storm surcharge suspended and replaced by Storm Bond recovery charge.
FL	Florida Power & Light	• Decided 9/14/05 • Case 050045-E1, et al. • Order PSC-05-0902-S-EI • Order Approving Stipulation and Settlement		• Per settlement, co. agreed to suspend current accrual (~$20m) to storm reserve as of 1/1/06 • Target level for storm reserve to be set in separate proceeding • Replenishment of storm reserve to target level to be accomplished via securitization per §366.8260, FL Statutes, or via separate surcharge that is independent of & incremental to retail base rates, as approved by PSC	
FL	Progress	• Decided 6/18/10		• Allows co. to implement on interim basis, 60 days	

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	Energy Florida	• Case 090145-EI, et al. • Order PSC-10-0398-S-EI • Order Approving Stipulation and Settlement		following a request for storm damage cost recovery, a mo. storm cost recovery surcharge of up to $4.00/1,000 kWh on residential customer bills over 12 mos. - If storm costs exceed that level, any additional costs to be recovered in subsequent year(s) as determined by PSC • Co. may also use surcharge to replenish storm damage reserve to level as of settlement implementation date	
FL	Progress Energy Florida	• Decided 7/6/09 • Case 090145-EI • Order PSC-09-0484-PAA-EI • Notice of Proposed Agency Action Order Denying Rule Waiver		• Denies co. request for waiver of rules to allow recovery via storm reserve account of projected $33m of storm hardening distribution & transmission O&M expenses and depreciation expense vs. normal operating expenses - Waiver required because rules allow only storm damage expense to be recovered via storm reserves • Finds co. had not sufficiently established that a substantial technological, economic, legal, or other type of hardship would result from its compliance w/rule	
GA (Public Service Commission)	Georgia Power	• Decided 12/17/13 • Case 36989 • Order Adopting Settlement Agreement		• Approves extension of amortization period, from 3 to 6 yrs., for recovery of previously incurred storm costs (Storm Damage Regulatory Asset), resulting in $6.9m adjustment. Says adjustment does not adversely affect ability to recover prudently incurred storm expenses but rather is a timing step that reduces impact of overall rate increase on ratepayers.	
IL (Commerce Commission)	Ameren Illinois	• Decided 9/19/12 • Case 12-0001		• Requires 5.6% distribution rate reduction In decision on initial formula rate plan filed under Energy Infrastructure Modernization Act (see entry below) vs. co.-proposed $19.9 million reduction, as revised	• Co. has annual formula rate update pending that will result in rate adjustment in January 2013 (Case 12-0293)
IL	Commonwealth Edison	• Decided 12/18/13 • Case 13-0318 • Order	• In 3rd formula rate plan (FRP) proceeding under 2011 legislation (SB 1652, below), approves delivery rates that reflect further statutory changes per SB 9 (2013). (See Cost	• Approves year-end (terminal) rate base, year-end capital structures for FRP rate reconciliations, and weighted cost of capital as interest rate on reconciliation amount, as required by SB 9.	

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			Recovery.)	- The changes resulted in approval of a general rate increase ($324.6m) that exceeded the original filed amount ($292m), but was lower than ComEd's revised filing submitted following S.B. 9 enactment ($336.7m.) - Revenue requirement reflects 2012 reconciliation adjustment & 2014 initial rate year revenue requirement (including projected 2013 plant additions)	
IL	Commonwealth Edison	• Decided 6/5/13 • Case 11-0662 • Order	• Grants co. waiver of liability for service interruptions that occurred 2/1/11 during major winter storm. Finds damage to distribution system was unpreventable due to severity of weather. • Declines AG request to open investigation into ComEd infrastructure and storm hardening investments, saying it found no basis.		
IL	Commonwealth Edison	• Decided 6/5/13 • Case 11-0588 • Order	• Waives liability for damages experienced by customers due to service interruptions for 5 of 6 storms in summer 2011 but for first time under 15-year-old Public Utilities Act (Section 16-125(e), said co. may be responsible for such damages related to 1 of the storms. Orders co. to notify 34,559 customers that they are eligible to file a claim for reimbursement for outages. • Rejects AG request to open investigation of ComEd system, saying it did not find any systematic failure by co.		
IL	Commonwealth Edison	• Decided 11/8/12 • Case 11-0692 • Order	• Approves undergrounding as least cost option ($121m) for 4.3-mile, 345 kV Burnham/Taylor transmission line in Chicago • Accepts co. finding that overhead options not viable because of: - insufficient space for poles - inability to secure easements on IL DOT property due to IL DOT regs - inability to cross Metra (commuter rail) ROW & meet safety standards due to		

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			obstructions - ComEd does not own or have rights to most of property needed for overhead route		
IL	Commonwealth Edison	• Decided 5/29/12 • Case 11-0721 • Reheard 10/3/12 • Order		• Approves 3-year, performance-based formula rate tariff under new law (see Notes column) - Results in rate reduction larger than co. expected • As part of formula rate plan, approves 5-year amortization of $2.2m as unusual operating expense related to Jun 2010 storm and rate-basing of unamortized storm costs of $8.9m w/deferred tax impact • On rehearing, affirms use of average rate base for calculating revenue requirement in annual FRP reconciliations vs. co. request to use year-end rate base, saying year-end method does not take into account certain depreciation or give proper weight to what actually happens in rate base prior to 12/31 of each year; that there is room for legislative interpretation; and that impact on customers should be weighed - Largely upholds approved methodology for calculating interest on reconciliation adjustments that relies on short-term debt rate vs. co.-proposed weighted avg. cost of capital - Following rehearing, co. announced it would slow pace of investment under new law	• This is first formula rate plan (FRP) proceeding under new ratemaking framework set by SB 1652, Energy Infrastructure Modernization Act, enacted 19/31/12(Public Act 97-0616). The law: - Provides for performance-based formula rate plans (FRPs) under which storm & other specified unusual operating expenses to be amortized over 5 years; any unamortized balance to be rate-based - Requires participating electric utilities to invest in T&D systems, w/cost recovery addressed in annual FRP proceedings, subject to CC review & approval - ComEd must invest $2.6b & Ameren IL $625m over 10 years - HB 3036, trailer bill enacted separately, re-directs $200m toward targeted undergrounding, tree-resistant overhead conductors & other storm hardening measures, in addition to inspection & replacement of residential underground & mainline cable programs per SB 1652 - ComEd filed investment plan

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					on 1/6/12 & Ameren filed plan on 3/3/12 for informational purposes (undocketed) - CC retains
IN (Utility Regulatory Commission)	Northern Indiana Public Service	• Decided 2/17/14 • Case 44370 • Order of the Commission	• Approves co.-proposed projects in 7-yr. plan that accompanied TDSIC proposal (below, Case 44371) - Some project approvals are subject to further definition and more specifics in plan update proceedings - Plan largely consists of replacement projects for T&D infrastructure for purposes of safety, reliability, system modernization & economic development -		• SB 560, enacted 4/30/13, authorizes URC to approve a TDSIC rider to facilitate recovery, outside of a general rate case, of costs related to infrastructure investments. A utility seeking approval of a TDSIC rider must file a 7-yr. project plan. A utility with such a tracker must file a base rate case every 7 yrs.
IN		• Decided 2/17/14 • Case 44371 • Order of the Commission		• Approves transmission, distribution, and storage system improvement charge (TDSIC) • Total projected revenue requirement related to 7-yr. plan (above, Case 44370) is approx. $262m, w/additional $139m (deferred balance over life of plan) to be recovered via base rates; rate case to be filed before end of 7-yr. plan • TDSIC: - To recover 80% of eligible/approved capital expenditures & TDSIC costs (e.g., depreciation, property taxes); remaining 20% to be deferred - Adjusted semiannually - Any related rate increase to be capped at 2% in 12-mo. period; incremental amts. to be deferred - Overall return used in rate adjustments must be calculated using regulatory capital structure that includes zero-cost capital, e.g., deferred income tax • 10.2% ROE (as approved in last rate case)	

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IN	Indiana Michigan Power	• Decided 2/13/13 • Case 44075 • Order of the Commission		• Approves $4.2m major storm damage restoration reserve based on 5-yr. average, reduced from co.-requested $6.2m based on 3-yr. average • Approves tracker for recovery of incremental variations from reserve ($4.2m) in storm O&M costs; costs to be recorded monthly as regulatory asset or liability for recovery/refund in future rate case; says this will "smooth out the impacts of major storms, thereby mitigating the financial consequences of a major storm."	
KY (Public Service Commission)	Generic	• Decided 5/30/13 • Case 2011-00450 • Order	• Requires each utility to collect/maintain all records necessary to evaluate system reliability performance in accord w/most recent IEEE Std. No. 1366 and to file reports annually w/specified information, e.g., SAIDI and SAIFI systemwide and for each circuit - Order based on finding that outage reporting requirements are not sufficient to judge adequacy of service		• Utilities filed rehearing petitions arguing that additional costs are imposed w/o guaranteeing reliability improvements. The PSC in a 7/9/13 order agreed to rehear the decision.
KY	Louisville Gas & Electric	• Decided 12/27/11 • Case 2011-00380 • Order		• Approves establishment of $8.1m regulatory asset to track O&M costs related to Aug 2011 thunderstorm w/high winds - Amt. is excess of $4.8m in storm damage expense currently embedded in base rates per 10/21/10 order (Case 2009-00549) - As total costs become known, LG&E to adjust downward if total < $8.1m & expense any actual costs exceeding $8.1m • Says in light of increasing requests for regulatory assets for severe weather events in recent years and results of previous post-storm audits, it will conduct more detailed reasonableness review than in previous cases when co. seeks recovery of deferred amounts in future rate case	• Notes similar regulatory assets were approved for LG&E and Kentucky Utilities for storm-related costs: - LG&E Case 2008-00456, et al. for storm damage from Hurricane Ike & Jan 2009 ice storm - KU Case 2008-00457, et al. for same events above - KU Case 2003-00434 for portion of 2003 ice storm expenses - LG&E Case 6220 for costs related to 1974 tornado
LA (Public Service Commission)	• Entergy Gulf States (LA)	• Decided 1/7/14 • Case U-32707-A • Order		• Approves settlement providing for withdrawal of co. request to increase storm reserve accruals in base rates. Co.'s formula rate plan (FRP) to be extended 3 yrs. - To extent Hurricane Isaac-related escrow amts.	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				are not funded to at least $87m, inclusive of current $21.5m balance, co. may re-request accrual increase during FRP extension period	
LA	• Entergy LA	• Decided 1/7/14 • Case U-32708-A • Order		• Approves settlement providing for withdrawal of co. request to increase storm reserve accruals in base rates. Co.'s formula rate plan (FRP) to be extended 3 yrs. - To extent Hurricane Isaac-related escrow amts. are not funded to at least $187m, co. may re-request increase during FRP extension period	
LA	• Entergy LA • Entergy Gulf States (LA)	• Decided 4/21/10 • Cases U-30981, U-30981-A, -B, -C • Order		• Approves "black box" settlement providing for recovery of $11.64m less than requested; approved amounts = $394m for EL & $233.9m for EGSL (including amounts already recovered via existing storm fund = $134m for EL, $85.5m for EGSL) • Approves mechanisms for companies & LA Utilities Restoration Corp. to finance – via Act 55 bond issuance – system restoration costs & replenishment of storm damage reserves up to $200m for EL & up to $90m for EGSL - Bonds to be backed by all ratepayers via mo. nonbypassable surcharge (Rider FSC II) - Separate order (Case U-30981-C) addresses calculation of offsets to FSC II Rider based on insurance proceeds, sharing of tax benefits from securitization, and other offsets - Reaffirms previous decisions that all customers/loads taking service from companies must share in cost to repair & restore service as well as cost to fund storm damage reserve, including customers taking service at transmission levels • Cost allocation was negotiated separately & included in settlement - For Entergy LA, 86.28% of costs to be classified as distribution related, 13.72% as transmission & generation related. Retail customers taking service at transmission voltages to be assigned	• Act 64 enacted in 2006 authorizes electric utilities to file for PSC approval to issue taxable bonds to securitize hurricane restoration costs • Act 55 enacted in 2007 established LA Utilities Restoration Corp., which may issue state tax-exempt bonds to finance hurricane restoration costs

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				base revenue share of 33% of costs deemed to be distribution related and 12 coincident peak share of costs deemed to be transmission & generation related - Percentages slightly differ for EGS - All approved system restoration & storm reserve costs not assigned to transmission-level retail customers to be assigned to other retail rate schedules based on each schedule's share of base revenue	
LA	• Entergy LA • Entergy Gulf States (LA)	• Decided 4/16/08 • Cases U-29203-E, -F, -G • Order		• Approves settlement resolving remaining issues for recovery of storm damage costs • Accompanying financing orders authorize securitization of costs per 2007 Act 55 • Provides for additional benefits to customers over those that would have been available under previous orders (pursuant to 2006 Act 64-see entry above-Notes column) - Estimates customers will save additional $40m due to tax benefits achievable under new law that companies agreed to share w/customers, as well as other savings - Requires that any credits for insurance, government grants & certain tax benefits be credited back to customers 100%, w/o offset due to any ratemaking mechanisms - Because of potential tax savings, companies agreed to, and PSC approved, hold-harmless clause under which customers guaranteed to be at least as well off under new financing as they would have been under previously approved financing (see entry below)	• For various reasons including state of securities markets, companies were unable to issue bonds to recover costs of hurricanes Katrina & Rita per previous financing orders in this docket on terms acceptable to PSC • This case was initiated based on Act 55 enacted in 2007 allowing companies to securitize bonds at lower costs & w/additional tax benefits (see also entry above)
LA	• Entergy LA • Entergy Gulf States (LA)	• Decided 8/15/07 • Cases U-29203-B, -C, -D • Order		• Approves overall level of permanent storm damage recovery for hurricanes Rita & Katrina @$187m for EGSL & $545m for EL • Accompanying financing orders authorize securitization of costs per 2006 Act 64 (see entry above-Notes column) • Requires both companies to establish storm	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				reserve accounts to cover costs of future storms • Requires funding of both recovery costs & establishment of storm reserve accounts via bond issuance per Act 64 • Bonds to be backed by revenue from nonbypassable customer surcharge (Securitized Storm Cost Offset Rider) - Customers cannot bypass storm charges via self-generation or co-generation; charge to be collected from all existing/future customers using transmission or distribution - Total costs to be allocated to customer classes based on their contribution to base revenues • Securitization to be performed via establishment of "Special Purpose Entities," which would be subsidiaries of companies • PSC may review proposed bond issuances	
LA	• Entergy LA • Entergy Gulf States (LA)	• Decided 3/3/06 • Case U-29203-A • Order		• Grants co.-requested interim rate relief due to recovery from hurricanes Rita & Katrina • Allows EGSL to recover ≤ $6m and EL ≤ $14m for costs incurred between Mar-Sep 2006 • Recovery amounts to be recovered as extraordinary cost surcharge, to end when full amount collected • Says it will develop revenue requirement after investigation of full costs for permanent storm recovery • Requires companies to develop securitization proposal • Hires outside consultant to audit co. expenses	
LA	Entergy New Orleans	• Decided 4/2/09 • City Council Resolution R-09-136 • Resolution and Order Approving Agreement in Principal		• Approves settlement in GRC providing for formula rates for 3 years as of 1/1/10 • Formula rate plan includes recovery of non-capital storm damage costs & re-funding of storm reserves via storm reserve rider • City's auditors to review final costs of co. response to hurricanes Rita & Katrina for inclusion in rider • Capital costs to be addressed in 2010 formula rate	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				plan review	
MA (Department of Public Utilities)	Generic	• Decided 12/23/13 • Case 12-76-A • Order	• Presents straw proposal for grid modernization (GM) following Working Group report (Notes column). Plan has 2 parts: 1. Directive to each electric distribution co. to submit, w/in 6 mos. of final order, a 10-year strategic grid modernization plan (GMPs) as part of planning process. Plan must have infrastructure & performance metrics toward meeting 4 objectives including reduction of outage effects. First GMP must include comprehensive advanced metering plan. GMPs required at least every 5 years. 2. Address in separate proceedings GM topics including time-varying rates; cybersecurity, privacy and access to meter data; and electric vehicles • Notes co. methods of reducing outage effects is under review in service quality proceeding; GMPs are expected to help achieve any new reliability metrics or standards set in that proceeding (Case 12-120, below) • Seeks comment, plans hearings	• Says it will examine advanced metering functionality under targeted regulatory framework including: 1) review/preauthorization by DPU; 2) benefit-cost analysis w/in a business case; benefits must exceed costs; and 3) if justified, targeted cost recovery mechanism. If an investment is preauthorized, prudence would be evaluated in later cost recovery proceeding. - Finds capital expenditure tracking mechanism is appropriate for targeted cost recovery • Declines to adopt future test year for cost recovery model, saying it would be based on projections involving speculation and uncertainty, exposing ratepayers to unwarranted risk	• Stakeholder Working Group on 7/2/13 submitted to DPU a report containing information, principles, recommendations on wide array of GM issues
MA	Generic	• Opened 7/31/13 • Case 13-09 • Order Instituting Rulemaking	• Opens docket for purpose of implementing requirement of 2012 law, An Act Relative to Emergency Service Response of Public Utility Companies, requiring notification by transmission companies of vegetation management activities. The DPU and others must be notified at least 30 days ahead.		
MA	Generic	• Opened 12/11/12 • Docket No. 12-120 • Vote to Open Investigation	• Undertakes review of utility service quality (SQ) metrics in SQ standards to determine whether changes are needed. DPU is developing a straw proposal in a process involving discovery and hearing. • Topics include: penalties; offsets; existing and potential new metrics for reliability, safety, customer satisfaction; potential new penalty for downed wire response; potential clean		

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			energy metrics; benchmarking for metrics; potential new or deleted metrics.		
MA	Generic	• Opened 10/2/12 • Case 12-76 • Vote and Order Opening Investigation	• Opens investigation into electric grid modernization (GM) • Says GM technologies & policies are vital for maintaining/improving electric system reliability & offer opportunity to reduce frequency/duration of outages via automated remote-controlled grid devices & real-time communication to distribution companies of outages & infrastructure failures • Seeks to develop roadmap to GM over short, medium & long term; potential policies include: - Planning procedures to allow stakeholder input on GM initiatives - Requirements for EDCs to achieve specific GM goals - Performance standards for GM practices - Cost recovery treatment of GM investments - Investigation policies for consumer protection • GM Stakeholder Working Group (WG) established with series of meetings scheduled - Initial WG report is due Jun 2013		
MA	National Grid	• Decided 5/3/13 • Case 13-59 • Order	•	• Allows co. to replenish storm fund outside base rate case band before prudence review by $40m annually over next 3 yrs. for total $120m - Says replenishment will save ratepayers $41m in interest as compared to alternative deferral scenario - Says co. not entitled to replenishment until prudence review completed in separate proceeding for costs incurred related to 14 extraordinary storms in previous 3 yrs; any overcollection to be returned to ratepayers w/interest	
MA	National Grid	• Decided 8/3/12 • Case 11-129	• Approves 2-year voluntary smart grid pilot, citing among potential benefits reduced	• Approves 5-year depreciation for all smart grid technology related to pilot	

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		• Order	customer outage time & increased operational efficiency of grid - Pilot includes testing of remote power outage sensors that enable crews to be dispatched directly to source of problem & restore power more quickly. It also will include systems to help identify affected customers during storms, thereby improving restoration times.	• Allows use of co. tax-adjusted weighted avg. cost of capital as carrying charge for all pilot investments • Approves allocation of grid-facing costs to distribution customers and allocation of customer-facing costs to basic service customers; approves co.-proposed method for allocating shared capital expenses to both components • Co. to file request for cost recovery in year after costs incurred	
MA	National Grid	• Decided 9/22/11 • Case 11-03 • Order on Amended Settlement	• Approves settlement providing for: - Voluntary $1.2m penalty - Implementation of automated system to identify affected life support customers, make required notifications & related actions - Improved wires down dispatch & related service quality metric for response times - Co.-funded study at MA university on correlation between wind speed, direction, geography, weather conditions & outages, @$50K to $100K cost. - Co. contribution of $50K for firefighting training at MA academy & additional $50K each to United Way of MA and American Red Cross		
MA	National Grid	• Decided 11/30/09 • Case 09-39 • Order	• N/A • N/A	• Permits continued operation of storm fund after 12/31/09 expiration set in previously approved settlement (Case 99-47 (1999)); cites levelizing effect on rates - Allows annual collection of ~$4m in base rates for fund - Allows fund to be used to recover non-capital storm costs in excess of $1.25m - Fund balance accrues interest @co. weighted avg. cost of capital - Fund capped @$20m (symmetrical); any excess returned to ratepayers via reconcilable surcharge w/interest; for deficits co. may	

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				propose recovery method • Allows recovery of ~$30m storm fund deficit balance resulting from 2008 winter storm via 5-year surcharge + interest, subject to prudence review; cites "excellent preparedness" by co.	
MA	• Northeast Utilities-Western Massachusetts Electric • NSTAR	• Decided 4/4/12 • Case 10-170-B • Order		• Approves NU-NSTAR merger settlement providing that storm costs incurred by NSTAR for TS Irene & Oct 2011 snowstorm will be excluded from storm fund calculation & deferred, w/carrying costs calculated @prime rate, to be recovered via surcharge outside of base rates over 5 years, subject to prudence review • WMECO recovery of Oct 2011 storm costs to be deferred until final decision in Case 11-119-C • Says settlement does not shield merging companies from penalties if ongoing storm investigations find violations of regulatory standards set in CMR §19.03	
MA	NSTAR	• Decided 12/30/13 • Case 13-52 • Order		• Disallows $3.5m of requested $38m in costs related to T.S. Irene & Oct 2011 snowstorm; finds remaining costs were incremental, storm-related, and reasonably & prudently incurred - Finds co. imprudent in not seeking reimbursement from Verizon for vegetation mgt. of jointly owned poles; disallows 50% of requested $6.2m + carrying charges - Disallows some incremental telephone & fuel costs, citing lack of record support • Requires utilities in future storm cost recovery filings to provide "complete, reviewable, and cohesive documentation," including specified work order information; cites difficulty in reviewing storm-related costs in this proceeding	
MA	Western Massachusetts Electric	• Decided 1/31/11 • Case 10-70 • Order		• Permits continued operation of storm fund previously set per 2006 settlement (Case 06-55) - Increases annual revenue to existing storm fund from $300K to $575K to better reflect incremental expenses - Caps storm fund @$3m (symmetrical)	

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				- Allows fund to be used to recover storm costs in excess of $300K • Allows ~$15m in non-capital costs from 2008 ice storm to be recovered outside of base rates & outside of storm fund via reconcilable storm surcharge over 5 years, w/carrying costs calculated @customer deposit rate • Allows co. to propose cost recovery mechanism if storm fund deficit exceeds $3m • Will conduct separate prudence inquiry on actual costs to be applied against fund	
MD (Public Service Commission)	Generic	• Decided 9/3/13 • Rulemaking (RM) 43 • Order	• Accepts 1st annual reports by utilities under RM43 (below) for partial year 2012 as well as corrective action plans where warranted, and w/certain modifications • Finds utilities substantially complied w/systemwide reliability standards		
MD	Generic	• Decided 2/27/13 • Case 9298 • Order	• Following investigation of utility response to 2012 derecho, finds no cause for civil penalties or further action • Finds "disconnect" between public expectations for distribution reliability and ability of systems to meet those expectations • Directs utilities to file shorter-term (5 yr.) plans to improve reliability • For longer term, directs utilities to submit studies on infrastructure or operational investments needed to reduce outages • Directs staff to draft proposed changes to reliability regs to include major outage event data and strengthen poorest performing feeder standard • Directs staff to study performance-based ratemaking to better align rates w/reliability, including provision for penalties • Directs other utility steps, including reports on staffing and communications, and participation in work group w/staff		
	Generic	• Decided 10/26/12	• N/A	• Affirms & expands 1/25/12 order in this docket	

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		• Cases 9257, 9258, 9260 • Order		(see entry below) to prevent imposition on customers of decoupling surcharge for revenue losses even during first 24 hours of the onset of a major storm	
MD	Generic	• Executive Order .01.01.2012.15 • Issued 9/24/12	• In late July 2012, following 6/29 Derecho, Gov. O'Malley issued Executive Order creating task force to issue report about options for improving resiliency of electric distribution system in MD as well as options for financing and cost recovery of such options • Task Force made 11 recommendations: - Improve RM 43's reliability and reporting requirements (see below for RM 43 details) - Accelerate RM 43's march toward reliability - Allow tracker cost recovery mechanism for accelerated and incremental investments - Implement a ratemaking structure that aligns customer and utility incentives by rewarding reliability that exceeds metrics and penalizes reliability that doesn't - Perform joint exercises between state and utilities - Facilitate information sharing among utilities, state agencies and emergency management agencies - Increase citizen participation in "special needs" customer lists and share information with emergency management agencies - Evaluate state-wide vegetation management regulations and practices - Determine cost-effective levels of investment in resiliency - Study staffing pressures due to graying of workforce - Task Energy Future Coalition with developing a pilot proposal	• See task force recommendations	
MD	Generic	• Effective 5/28/2012 • Rulemaking (RM) 43	• Rulemaking to address reliability and service quality standards initiated as result of legislation passed by MD General Assembly	• Legislation increased potential penalties for non-compliance with regulations	

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			• Requires utilities to achieve standards of reliability performance and report certain data re service quality (SQ) and reliability • Among other things, the regulations: - Establish specific SAIFI and SAIDI metrics for each utility from 2012 to 2015 - Require that remediation action be taken for poorest performing 3% of feeders and protective devices activities 5 times or more during a 12 month period - Require at least 92% of sustained outages during normal events be restored w/in 8 hrs. - Require at least 95% of sustained outages during "Major Events" of < 400,000 or 40% of customers be restored w/in 50 hrs. - Require response to a government emergency responder-guarded downed wire w/in 4 hrs. after notification by a fire or police department, or 911 emergency dispatcher at least 90% of the time - Set min. vegetation management standards		
MD	Generic	• Decided 1/25/12 • Case 9257, et al. • Order		• Finds decoupling mechanisms for utilities as currently designed do not appropriately align company financial incentives w/reliability goals • Prevents imposition on customers of decoupling surcharge for revenue losses beginning 24 hours after commencement of a major storm and continuing until all major storm-related sustained interruptions are restored	• PSC established these non-consolidated dockets to investigate whether decoupling mechanisms previously approved for MD electric utilities inadvertently eliminated incentive for utilities to quickly restore lost service to customers by authorizing the recovery of revenues foregone during extended outages, and if so, whether the decoupling mechanisms should be modified to prevent that outcome
MD	Baltimore Gas and Electric	• Decided 12/13/13 • Case 9326	• Conditionally approves 5-yr., $72.6m Electric Reliability Investment (ERI) program consisting	• Approves recovery of costs related to 5 approved ERI programs via annually trued up surcharge,	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
		• Order	of 5 of 8 co.-proposed programs: 1) Expansion of poorest performing feeders, 2 & 3) expanded recloser deployment (13 kV distribution feeders & 34 kV lines), 4) diverse routing of 34 kV supply circuits, and 5) half of selective undergrounding initiative. Revenue requirement increases from $2.3m in 2014 to $9.5m in 2018; cites cost in approving only half of this program. - Conditions including enhanced reporting requirements. - Approval criteria: cost-effectiveness; provision of accelerated & incremental benefits to increase reliability & resiliency; appropriateness for surcharge cost recovery. - Prudence of actual expenditures to be reviewed later. • Reasons for rejecting 3 of 8 proposed ERI programs: 1) expansion of vegetation mgt.; says fuller understanding of impact needed; 2) CIADI improvement; cites uncertainty over cost-effectiveness; and 3) substation reliability performance improvement; cites minimal estimated benefits to ratepayers.	called grid resiliency charge, to sunset in 5 years. • Rejects consumer advocate proposed basis point reduction in overall ROE as result of surcharge, saying this can be addressed later in rate case • As in other cases (e.g., Case 9299 below), accepts 2 rate base adjustments: - Terminal test year treatment of non-revenue producing investments to improve safety & reliability; increases electric rate base by $58.4m - Actual post-test year safety & reliability investments thru Oct 2013; increases electric rate base by $20.4m • As in Case 9299 (below), rejects post-test year projected investment because "not known and measureable" • Rejects co. proposal to recover storm restoration expense over 3 yrs. vs. existing 5 yrs., citing lack of "demonstrable scientific evidence" that extreme weather would continue to occur on any predictable basis and that 5 yrs. is insufficient. • Approves annualized vegetation management expense, saying RM43 compliance will marginally increase such expenses & require time before they normalize	
MD	Baltimore Gas and Electric	• Decided 9/9/13 • Case 9291-Phase 1 • Order	• Based on staff investigation of 14 feeders, finds BGE did not violate state law or regulation but also finds some feeders in Howard Co. have significant reliability issues • Directs co. to continue work on its Reliability Enhancement Work Plan and report on results • Directs co. to annually survey customers on these feeders on satisfaction w/work plan		• Proceeding was initiated by apparently first of its kind petition whereby a PSC investigation is triggered when at least 100 customers join to file a complaint • Phase 2 will involve staff investigation of 33 additional feeders in Howard Co. identified by complaint
MD	Baltimore Gas and Electric	• Decided 2/22/13 • Case 9299 • Order		• Approves adjustments to historical test year treatment as follows: - Terminal test year treatment of non-revenue producing investments to improve safety &	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				reliability and comply w/RM43 (generic item above 5/28/12); says this increases electric rate base by approx. $41.5m total (w/ corresponding operating income adjustments). Says approval based on co. demonstration of commitment to safety & reliability - Actual post-test year safety & reliability and RM43 investments for Oct-Nov 2012 • Rejects inclusion of planned post-test year safety & reliability and RM43 investments for Dec 2012-Dec 2013, finding the adjustment fails to meet "known and measurable" standard because it is based on estimate that is based on limited experience to date	
MD	Baltimore Gas and Electric	• Decided 3/9/11 • Case 9230 • Order		• Approves creation of regulatory asset allowing deferral of non-capital storm restoration costs for Dec 2009 & Feb 2010 snowstorms, which were not "major storms" per PSC) • Continued historical practice of 5 year normalization of major storm costs • Declines co. proposal to utilize terminal test year rate base instead of 13-month avg. test year rate base for reliability investments, saying co. did not show that its proposed adjustments were required to address existing or ongoing reliability shortfalls	
MD	Delmarva Power and Light	• Decided 9/3/13 • Case 9317 • Public Utility Law Judge Division-Letter to Parties Finalizing the Proposed Order		• Adopts settlement providing for 3-yr., reconcilable grid resiliency charge (GRC) w/2014 revenue requirement of $0.1m; future amounts to be decided in annual true-up proceedings - GRC to recognize investments in accelerated feeder-line replacement - Same conditions apply as those included in Pepco GRC (Case 9311 below)	
	Delmarva Power and Light	• Decided 7/20/12 • Case 9285 • Order		• Allows use of terminal test year basis for reliability investments (instead of avg. test year basis) and inclusion of post-test year reliability investments (that don't produce add'l revenue) in rate base • Approves amortization over 5 years of capital	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				costs incurred during Hurricane Irene • Negatively adjusts recoverable amount of Irene capital costs by 7.66%, citing inadequate tree trimming practices that it says resulted in excessive expenses in restoration efforts • Denies cost recovery related to Service Quality and Reliability Standards (RM43) that defined reliability & service quality performance standards for distribution systems on grounds that costs are not known or measurable as the regulations had just recently become effective • Rejects proposal for Reliability Investment Recovery Mechanism (RIM) to remain consistent in denying all such requests for infrastructure surcharges and saying reliability surcharge will not enhance reliability	
MD	Delmarva Power and Light	• Decide 12/30/09 • Case 9192 • Order		• Allows in rate base post-test year reliability investments that will not generate additional revenue	
MD	Potomac Electric Power	• Decided 7/12/13 • Case 9311 • Order	• Disallows $23.4m related to AMI meters, saying co. has not yet demonstrated cost-effectiveness; declines to follow previous order (No. 85028 in Case 9286) where rate recovery was allowed for AMI meters on basis of being "used and useful."	• Conditionally approves 3-yr. reconcilable grid resiliency charge (GRC), including return on investment, for 1 co.-proposed project: $24m accelerated priority feeder replacement project - Co. must meet new reporting requirements including detailed project description, performance objectives, incremental milestones and projected costs - Declines to adopt related co.-proposed performance-based incentive mechanism, citing limited scope of GRC • Rejects GRC for 2 other co.-proposed projects: 1) accelerated vegetation mgt.; says one-time benefit does not justify GRC treatment; and 2) selective undergrounding; says approval premature and directs further study. • Approves terminal test year treatment of reliability projects completed through 2012 test year, increasing rate base by $12.5m • Approves post-test year additions of reliability	• Commissioner Williams filed partial dissent on GRC, saying he would have preferred a deferred 2-yr. regulatory asset • Commissioner Brenner issued concurrence, citing concerns over GRC and saying he would have preferred a deferred regulatory asset

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				projects completed in 1Q 2013, increasing rate base by $45m • Rejects post-test year projected investment beyond 1Q 2013 because "not known and measureable"; reflects $123.5m of investment not included • Approves 5-year amortizations of O&M costs related to 2012 Derecho and Sandy and inclusion of unamortized balances in rate base, finding co. testimony "credible but unverified"; requires audit on which to base any future adjustments to these items • Approves expenses for compliance w/RM 43 (below) reliability regulations.	
MD	Potomac Electric Power	• Decided 7/20/12 • Case 9286 • Order		• Allows use of terminal test year basis for reliability investments (instead of average test year basis) and inclusion of post test year reliability investments (that don't produce add'l revenue) in rate base • Approves amortization over 5 years of capital costs incurred during Jan 2011 snowstorm & Hurricane Irene • Negatively adjusts recoverable amount of Hurricane Irene costs by 1.5% and Jan 2011 storm by 6.2%, citing inadequate tree trimming practices that it says resulted in excessive expenses in storm restoration efforts • Denies cost recovery related to Service Quality and Reliability Standards (RM43) that defined reliability & service quality performance standards for distribution systems on grounds that costs are not known or measurable as the regulations had just recently become effective • Disallows recovery for vegetation mgt. program, citing significant amount of under-spending in past years and saying the non-industry standard 2-year trim cycle maintained by co. has resulted in continued catch-up spending due to imprudence • Rejects co. proposal for Reliability Investment	• Co. filed for recovery of costs related to annual vegetation mgt. costs @$23.5m, including $15m for forecasted tree trimming • Dissenting opinion would allow immediate full recovery of storm costs due to their 'minor storm' status

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				Recovery Mechanism (RIM) to remain consistent in denying all such requests for infrastructure surcharges and saying reliability surcharge will not enhance reliability	
MD	Potomac Electric Power	• Decided 8/6/10 • Case 9217 • Order	• Approves establishment of new Enhanced Integrated Vegetation Management (EIVM) initiative that includes: hazard tree removal; removal of over-hanging limbs; removal of undergrowth and aggressive clearance pruning	• Approves 10-year amortization of ~$7.5m in non-capital costs related to Feb 2010 snowstorm • Approves increase in net annual O&M expenses related to new EIVM initiative • Defers decision to approve $1.6m of AMI expenses because it had not yet approved co.'s AMI program in a separate preceding • Rejected co. proposal to use terminal test year basis for reliability investments (instead of average test year basis) and to include post test year reliability investments in rate base	
MI (Public Service Commis sion)	Generic	• Opened 1/8/14 • Case U-17542 • Order Commencing Investigation	• Opens investigation related to ice storm that hit Lower Peninsula 2/21-22/13. Issues: - Impact on utility distribution systems - Utility response before/during storm - Whether changes needed to reduce outage potential - Whether utilities failed to properly maintain distribution systems - Customer reporting of outages - Safety concerns related to downed lines • Sets timetable for reports and comments • Remedial action possible		
MO (Public Service Commis sion)	Generic	• Opened 3/20/13 • Case EW-2013-0425 • Order Opening an Investigation to Address Legislative Concerns Regarding Proposals to Modify Ratemaking Procedures for Electric Utilities and Establishing a Procedural Schedule		• Opens docket to gather comments in response to request by legislator on pending bills, HB 398 and SB 207. Bills would authorize utility implementation of infrastructure system replacement surcharge (ISRS) and expense tracker for tracking/recovery, outside of general rate cases, of costs related to reliability and other infrastructure investments. Gas utilities in the state use ISRS mechanisms.	• Comments were gathered by the PSC. However, the bills failed.

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MO	Generic	• Effective 6/1/08 • Rule 4 240-23.020- Electrical Corporation Infrastructure Standards • Rule 4 CSR 240-23.030- Electrical Corporation Vegetation Management Standards and Reporting Requirements	• Establishes standards requiring electric utilities to inspect/replace old & damaged T&D infrastructure • Requires utilities to more aggressively trim trees/other vegetation: 4-year cycle for urban infrastructure & 6-year cycle for rural	• Both rules include provisions allowing utility to seek recovery of extra costs incurred to comply.	• Rules were implemented following extensive storm-related outages in 2006
MO	Ameren-Union Electric	• Decided 7/13/11 • Case ER-2011-0028 • Report and Order	• Finds co. reliability has improved since two new rules took effect on 6/30/08: Rule 4 CSR 240-23.020) & (Rule 4 CSR 240-23.030 (see entry above) • Encourages co. to continue spending money to improve reliability • Requires co. to spend ~$1.3m/year on heavy underground apprentice program under which staff to be trained on industrial type routing of underground electric lines in urban areas; adds ~$1.3m to revenue requirement	• Approves continuation of vegetation mgt. & infrastructure inspection tracker (see entry below) • Sets tracker base levels @$52.2m for vegetation mgt.; $7.7m for infrastructure • Accepts contested 47-mo. normalization for calculating avg. annual non-labor storm costs; allows recovery via base rates of co.-requested $7.1m test year storm costs	• Says storm costs vary greatly from year to year, citing as examples: - Co. incurred $6m in non-labor storm restoration costs in 9 mos. ending 12/31/07 - $4.8m in 2008 - $9m in 2009 - $38K in 2010 - $8.1m in Feb 2011
MO	Ameren-Union Electric	• Decided 5/28/10 • Case ER-2010-0036 • Report and Order		• Approves continuation of vegetation mgt. & infrastructure inspection tracker (see entry below) • Sets tracker base levels @$50.4m for vegetation mgt.; $7.6m for infrastructure, based on spending in 12 mos. thru 1/31/10 • Orders refund to customers of $3.4m overcollection, amortized over 3 years • Denies co.-requested tracker for storm restoration costs, citing unwillingness to expand use of trackers; finds existing accounting authority order (AAO) approach adequate under which co. allowed to accumulate/defer extraordinary storm non-labor O&M costs, to be considered for recovery – typically over 5 years – in next GRC.	

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				• Allows base rate recovery of $6.4m in test year storm costs; remaining $4m in extraordinary storm expense to be amortized/recovered over 5 years	
MO	Ameren-Union Electric	• Decided 1/27/09 • Case ER-2008-0318 • Report and Order		• Citing uncertainty re cost of complying w/2 new rules (per entry above), establishes two-way tracker under which co. to track actual expenditures around base levels. Co. to create regulatory asset/liability for possible future recovery/refund. • Spending above base level capped @$10%. Co. may request accounting order for amounts exceeding cap. Assets & liabilities to be netted against each other & considered in next GRC • Sets tracker base levels @$54.1m for vegetation mgt.; $10.7m for infrastructure inspection	
MO	Empire District Electric	• Decided 2/27/13 • Case ER-2012-0345 • Order Approving Stipulation and Agreement		• Approves settlement providing for continuation of vegetation mgt. tracker mechanism, w/expense base level of $12m • In 10/31/12 decision in this docket, denied co.-requested interim increase, citing order in Case EU-2011-0387 (below) and other factors that it says make co. adequately protected until final rate decision	• Generate rate increase request had as key drivers restoration costs related to May 2011 tornado and loss of customers related to tornado
MO	Empire District Electric	• Decided 11/30/11 • Case EU-2011-0387 • Order Approving and Incorporating Unanimous Stipulation and Agreement		• Allows co. to defer & capitalize expenses related to May 2011 tornado for possible future recovery in next GRC - Co. to defer actual incremental O&M costs related to restoration following tornado as well as depreciation & carrying charges = ongoing AFUDC rates related to tornado capex	
MO	Empire District Electric	• Decided 7/30/08 • Case ER-2008-0093 • Report and Order		• Allows co. to implement 2-way tracker to track costs related to vegetation mgt. & infrastructure inspection around base level and defer for future recovery/refund • Sets tracker base level @total $8.6m	• Tracker is similar to one approved for AmerenUE; see entry above for further detail • PSC on2/27/13 approved settlement providing for continuation of vegetation mgt. tracker & $12m base level (Case ER-2012-0345)

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MS (Public Service Commission)	Entergy MS	• Decided 10/7/11 • Case 2010-UN-436, et al. • Order Adopting Joint Stipulation		• Approves change in existing storm damage rider to reflect increase in frequency/severity of storms - Increases rider collections to allow co. to recover deficit in storm damage reserves that occurred due to hurricanes Gustav & Ike in 2010, and additional storms of 4/4/08 • Increases cap of storm reserve fund from $15m to $25m	
MS	Entergy MS	• Decided 5/22/07 • Case 2006-UA-350 • System Restoration Charge Order		• Approves Rider Schedule SRC as mechanism to recover securitized & other funds authorized by PSC - Rider is to be applied as non-bypassable surcharge to all customers - Includes formula-based mechanism to allow expeditious adjustments intended to correct over-/under-recovery of costs - Estimated to initially increase customer bills by 1.5%	
MS	Entergy MS MS Power	• Decided 6/28/06 • Case 2006-UA-82 • Order • Decided 6/28/06 • Case 2005-UA-0555 • Order	• Orders both companies to harden their locations to withstand hurricane force winds ~10 miles inland from potential flooding • Grants MS Power funds for new storm operations center & facility annex	• Approves recovery of $89.2m for Entergy and $303.4m for MS Power for recovery of costs from Hurricane Katrina • Requires companies to mitigate customer impacts by securitizing these costs pursuant to "Hurricane Katrina Electric Utility Customer Relief and Electric Utility System Restoration Act of 2006" • Authorizes State Bond Commission (established by legislation) to issue bonds to finance recovery costs • Bond debt service is repaid via system restoration charges reset by companies annually to recover 110% of required annual debt service • System restoration charge is a bill surcharge paid by all customers	• Approved recovery to be reduced by any funds received via Community Development Block Grants or other sources • ~$350m of CDBG funds were ultimately made available to MS utility customers
NC (Utilities Commission)	Generic	• Issued 11/21/03 • Undocketed • Report of the Public Staff to the North Carolina Natural Disaster	• Reflects results of feasibility investigation conducted in conjunction w/investigation of utility response to Dec 2002 ice storm (see entry below) • Staff focuses on undergrounding distribution, saying most damage sustained in severe		

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		Preparedness Task Force. "The Feasibility of Placing Electric Distribution Facilities Underground," Nov 2003	weather events usually involves distribution vs. transmission lines • Staff concludes that replacing overhead lines w/underground would be prohibitively expensive (~ 6X current value of utility distribution assets) and would also result in higher O&M costs • Staff recommends that companies identify overhead facilities that repeatedly experience reliability problems, determine whether conversion to underground is cost-effective option and, if so, develop plan for undergrounding those facilities • In interim, Staff recommends companies continue current practices of: 1) placing new facilities underground when additional revenues cover costs or cost differential is recovered via CIAC, 2) replacing existing overhead facilities w/underground when requesting party pays conversion costs, and 3) replacing overhead facilities w/underground in urban areas where factors such as load density & physical congestion make overhead service impractical		
NC	Generic	• Issued 8/29/03 • Undocketed • Report of the North Carolina Public Utilities Commission and the Public Staff to the North Carolina Disaster Preparedness Task Force. "Response of Electric Utilities to the December 2002 ice Storm," Sep 2003	• Finds ice storm was unprecedented in NC history in terms of customer outages for Duke Energy and almost unprecedented for Progress Energy • Finds some government officials faulted companies for communications during storm and improvements have since been made • Finds utilities have in place proper procedures for advance planning & obtaining aid from other utilities that were disrupted to some extent by circumstances of this storm • Finds that all utilities should examine tree trimming practices to determine whether improvements are possible	• Notes costs of storm are being recovered in current rates, making rate increase unnecessary	
NC	Duke	• Decided 3/5/14	• Asserts exclusive jurisdiction over utility		• The case arose out of

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	Energy Carolinas	• Case E-7, Sub 1038 • Order on Jurisdiction and Dismissal of Complaint	implementation of vegetation management practices, dismisses city complaint - Determines that 4 proposed areas of utility regulation by the City of Greensboro via a Utility Vegetation Management Ordinance are preempted by state law - The 4 areas are: 1) trimming standards, 2) trimming cycle, 3) appeals process, 4) large debris removal		Greensboro resident complaints over tree trimming activities by Duke pursuant to its vegetation management plan and policies (VMPP) filed with the commission in May 2012 in Case E-7, Sub 1014 (below)
NC	Duke Energy Carolinas	• Decided 6/3/13 • Case E-7, Sub 1014 • Order Accepting Compliance Filings and Requiring Filing of Reliability Data	• Reviews co. filing of vegetation management policy & practices as required in Case E-7, Sub 989 (below) as well as co. response to customer concerns. • Finds co. implemented policies in reasonable manner but imposed additional reporting requirements		
NC	Duke Energy Carolinas	• 1/27/12 • Case E-7, Sub 989 • Order Granting General Increase in the Matter of Application of Duke Energy Carolinas , LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	• Approves GRC settlement providing for co. to review vegetation mgt. policies/ procedures & develop clear, comprehensive, consistent & publicly available policy description, to be filed for review in separate docket w/in 90 days - Provision arose out of Public Staff testimony re public complaints on vegetation mgt. practices - Complaints generally concerned removal of trees that customers did not want removed, failure to remove tress that are interfering w/power lines & tree cutting debris being left on customer premises • Staff said co. practices/procedures were not well-defined or publicly available		• Similar recent finding made for Progress Energy Carolinas • Following several extensions, co. filed vegetation mgt. policies/procedures on 5/21/12 (Case E-7, Sub 1014; Status = open)
ND (Public Service Commis sion)	Xcel-Northern States Power	• Decided 2/29/12 • Case PU-10-657, et al. • Order on Settlement	• Approves settlement providing for co. to file PBR plan w/metrics to measure/evaluate system reliability, including rate of return incentives & penalties - Plan to include focus on localized reliability performance • Approves increased funding for reliability improvements including additional engineer		

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			• Sets additional reporting requirements • Approves new funding for additional veg. mgt. crew ($212,000 in 2012) • Approves recovery of capital investments related to Minot flood restoration effort		
NH (Public Utilities Commission)	Public Service Co. of New Hampshire	• Decided 6/27/13 • Case DE 13-127 • Order Following Hearing		• Approves co. request to increase annual revenue amt. to be deposited in major storm reserve fund from $7m to $12m, citing frequency/severity of recent storms & related repair/restoration costs • Approves co. request to recover pre-staging costs for qualifying storms; PUC encouraged pre-staging as part of review of Dec 2008 & Oct 2011 storms • Affirms co. capital cost treatment of hazard tree removal that was formerly O&M expense, saying there is no evidence that capitalization is inconsistent w/FERC chart of accounts, and it is subject to audit	
NH	Public Service Co. of New Hampshire	• Decided 6/28/10 • Case DE 09-035 • Order Approving Settlement Agreement on Permanent Rates	• Approves continuation of, and base rate increases for, reliability enhancement program (REP) (previously approved 5/25/07, Case DE 06-028): - Co. to continue spending $8.2m/year for O&M for existing - Co. to invest $12.8m/year in capital projects for expanded program (REP II) - Co. to spend additional $2.4m in O&M thru 6/30/12, followed by additional increases for O&M, for REP II - Co. to file annual reports • Approves high level design for geographic information system including GIS-based outage mgt. system	• Approves $3.5m/year base rate funding for existing major storm cost reserve (Note: This amount was doubled to $7m/year in order issued 6/27/12, Case DE-12-110, approving step increase per settlement) • Approves amortization of ~$44m of costs related to 2008 ice storm on straight-line basis over 7 years; any unamortized balance to accrue interest @4.5%/year	
NH	Unitil Energy Systems	• Decided 4/26/11 • Case DE 10-055 • Order Approving Settlement Agreement	• Approves expanded reliability enhancement program (REP) & vegetation mgt. program (VMP): - Co. to spend $1.75m/year in REP capex during 5-year settlement term & increase annual REP O&M expense by $300K as of 5/1/12. Additional amts. to be included in	• Approves storm cost reserve w/annual $0.4m funding to enable cost recovery for major storms as of 7/1/10 thru 5-year settlement term • Allows levelized recovery of previously deferred $7.7m + interest related to 2008 ice storm & 2010 wind storm via reconcilable storm recovery adjustment factor surcharge; any unamortized	• This action came with approval of 5-year rate plan w/4 step adjustments; specific amounts for future increases are not yet approved • PUC on 6/29/10 approved interim base rate increase

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			future step increases - VMP to incorporate 5-year trim cycle on multi-/single- phase distribution systems; augmented spending includes $1.25m step increase as of 5/1/11 & additional amt. in future step increase, subject to review • Co. to file annual reports for REP, VMP & complete fuse and re-closer studies	balance to accrue interest • Funding for REP, VMP capital and O&M expenses to be included in base rate step increases as follows: - REP revenue requirements to be based on actual capex, capped @$2m in 2012, 2013 & 2014 - VMP increases in step adjustments are ~$1.3m in 2011 & ~$1m in 2012	including recovery of $0.5m of costs related to Dec 2008 ice storm and $0.5m of incremental costs related to vegetation mgt.
NJ (Board of Public Utilities)	Generic	• Decided 5/29/13 • Case EO12111050 • Order Requiring Electric Utilities to Implement Recommendations	• Imposes new requirements aimed at improving communications among utilities, municipal officials, customers and the Board during extreme weather events/outages		
NJ	Generic	• Decided 3/20/13 • Case AX13030196, EO13020155, et al. • Establishment of a Generic Proceeding	• Opens investigation of the prudence of costs related to 2011 & 2012 major storms for which electric distribution companies (EDCs) are seeking rate recovery. - For each pending or future base rate case, EDCs must file detailed report by 7/1/13		• See 3/19/14 entry below for JCP&L
NJ	Generic	• Decided 3/20/13 • Case AX13030197, EO13020155, et al. • Establishment of a Proceeding	• Opens generic docket, "Storm Mitigation Proceeding," to investigate ways to support/protect utility infrastructure in relation to major storms – for all regulated utilities, not only electric distribution companies (investor owned). • Invites all regulated utilities to submit detailed proposals for infrastructure upgrades, per parameters set by 1/23/13 order (below) • Directs staff to evaluate PSEG's proposed Energy Strong measures		
NJ	Generic	• Decided 2/20/13 • Case EO12070650 • Order	• Imposes new reporting requirements on power outages, circuit performance, hazard trees in the aftermath of Sandy - The information will be used to identify areas or equipment that may warrant further investigation		
NJ	Generic	• Decided 1/23/13	• Accepts consultant report released 8/9/12		• Hurricane Sandy is not

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		• Case EO11090543 • Order Accepting Consultant's Report and Additional Staff Recommendations and Requiring Electric Utilities to Implement Recommendations	(below) and requires actions by utilities in specified timeframes in 5 categories of potential improvements: - Preparedness: Conduct 1st annual training exercise simulating response to outage affecting 75% of customers - Communications: Provide pre-/post-event information thru various methods to assist customers, govt. & emergency mgt. officials, and mutual aid crews in preparing for & dealing w/aftermath of major events - Restoration & response: Establish better process for obtaining mutual assistance, esp. when large-scale events affecting multiple utilities occurs, and better track/support crews - Post event: Track and use "lessons learned" from each major event to make improvements and seek stakeholder input - Underlying infrastructure issues: Provide cost-benefit analyses related to various upgrades; examine infrastructure and use available data to determine how to better protect substations from flooding, how vegetation mgt. is impacting electric systems, and how distribution automation can be incorporated to improve reliability		addressed in order and is the subject of a separate investigation.
NJ	Generic	• Report released 8/9/2012 • Performance Review of EDCs in 2011 Major Storms	• Recommendations for EDCs include: - more detailed development of vegetation management program - development of Incident Command System - using company websites & social media to provide more granular outage details & estimated time of restoration - conducting annual training/exercise drills - require practice of benchmarking & external analysis of each company's restoration experiences		• Report prepared for BPU by Emergency Preparedness Partnership in response to 12/14/11 Order (Case EO11090543)
NJ	Generic	• Decided 12/14/11 • Case EO11090543	• BPU orders EDCs to take several actions including:		• In addition to preliminary order, BPU ordered the hiring

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		• Investigation of New Jersey's Utilities' Response to Hurricane Irene	- Improved coordination of resources/staff w/government officials - Improved outage websites & use of social media for restoration updates - Development of process for more accurate, timely & more geographically targeted estimated time of restoration - Review/revision of customer call back scripts to better convey messaging - Reevaluate provision of restoration information to specific customer classes including special needs customers & well-water dependent customers - Coordinate more closely w/state & local crews working to clear roads and remove storm debris • For one EDC, directs full implementation of its Preliminary Communications Plan for any subsequent severe weather events		of a consultant to further investigate the Storms of 2011 in more detail with emphasis on substations, vegetation management, and customer communications
NJ	Atlantic City Electric	• Decided 6/21/13 • Case ER12121071 • Order Approving Stipulations		• Approves settlement adopting co. proposal to fully recover $70m of incremental storm restoration costs related to 2012 derecho wind storm and Sandy. Of the total, $44.2m in capital costs will be included in rate base and $25.8m in O&M costs will be recovered in base rates via 3-yr. amortization, with no rate base treatment of unamortized balance. ACE agreed not to seek further rate increases associated w/the 2 storms.	• The storm-related settlement amount was based on a finding of prudence in a generic proceeding (Case AX13030196, above).
NJ	Jersey Central Power & Light	• Decided 3/19/14 (written order pending) • Case AX13030196		• Approves settlement providing for recovery of $736m of requested $744m of costs related to 2011-12 storms including Sandy - Of total, $163m of costs related to Irene and an Oct 2011 snowstorm will be reflected in a separate, pending distribution rate case (Case ER-12111052); recovery mechanism for remainder of settlement costs is uncertain	• The decision for JCP&L came in a generic investigation of the prudence of utility storm costs (above)
NJ	Public Service Electric and	• Decided 6/21/13 • Case EO13020155, et al.	• Directs PSEG to implement staff recommendations to: - Begin work on Energy Strong Station Flood		

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	Gas	• Order – Request for Specific Action and Additional Information	and Storm Surge Mitigation subprogram w/investigations & planning - Provide detailed cost estimates		
NM (Public Regulation Commission	Generic	• Decided 11/27/12 • Case 12-00089-UT • Final Order and Final Amended Rules	• Promulgates final rules based on 12/21/11 staff report, "Severe Weather Event of February, 2011 and its Cascading Impact on NM Utility Service." Rules require electric & gas utilities to: - Explicitly consider fuel diversity, alternative or redundant fuel delivery systems, and backup fuel capability in planning processes - Recognize electricity- and gas-dependent facilities that serve retail load as critical load - Modify/standardize outage reporting - Implement emergency plans including specified components		
NV (Public Utilities Commission)	Generic	• Decided 10/4/05 • Case 05-5014 • Order		• Requires utilities to develop analysis of incremental undergrounding costs in cases where localities mandate such undergrounding and to maintain in records until cost recovery determined in general rate proceeding - Points to New Mexico Public Service undergrounding special services tariff as reasonable starting point for such analysis	
NV	Sierra Pacific Power	• Decided 12/23/10 • Case 10-06001, et al. • Order	• Approves ~$25m related to Phase II Tracy-Silver Lake transmission line w/some undergrounding; incremental ~$15m undergrounding costs estimated generally @4x cost of overhead option; co. to file actual costs in compliance filing • Approves ~$1.7m for Fairview 900 AM distribution feeder facilities including ~$1.5m for undergrounding costs, of which $961,624 was incremental (higher than would have been paid for aboveground option) • Approves ~$1.9m for Radio Channel Project to upgrade radio communications as result of lessons learned in 2005 fire in Carson City	• Allocates incremental T&D undergrounding costs to ratepayers of two localities that mandated underground portions as conditions of permits; cites cost causation principles; direct costs + interest to be amortized over 3 years or until paid, to be recovered via surcharge @levelized per kWh rate • Radio channel upgrade costs to be recovered via base rates	• Phase 1 approvals given in 2007 GRC, Case 07-12001

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NV	Sierra Pacific Power	• Decided 6/27/08 • Case 07-12001 • Order	• Approves ~$10m related to 16-mi., 120 kV Tracy to Sugarloaf transmission line, including $5.9m for undergrounding 3.36 mi.	• Assigns incremental undergrounding costs to ratepayers of locality that mandated undergrounding as condition of permits; cites cost causation principles; direct costs + interest to be amortized over 3 years and recovered via surcharge; costs treated as non-standard installation where customers provide CIAC	
NY (Public Service Commis sion)	Generic	• Decided 12/26/13 • Case 07-M-0548 • Order Approving EEPS [Energy Efficiency Portfolio Standard] Program Changes	• Directs staff to recommend in 1Q 2014 a process for decisions to change regulatory model, including performance- and outcome-based incentives, that will be required to achieve policy objectives. - Policy outcomes include assurance of system reliability & resiliency. Says customer-based resources should be deployed and used to support economically efficient system resiliency • Directs staff, NYSERDA and utility program administrators (EEPS) to convene "E^2 working group" to develop action plan • Makes specified changes to EEPS for 2014-15		• The order was issued in keeping with the Moreland Commission Final Report issued 6/22/13), which recommended, among other things, redirecting public benefit and energy efficiency funds to use to better protect the grid
NY	Generic	• Decided 12/23/13 • Case 13-E-0140 • Order Approving the Scorecard for Use by the Commission as a Guidance Document to Assess Electric Utility Response to Significant Outages	• Adopts quantitative tool, or "scorecard," for use by utilities and PSC to assess utility storm restoration performance; says it is intended as guide in assessing utility performance and in setting utility expectations of what PSC wants. - Assigns metrics & points into 3 categories: Preparation (150 pts.), operational response (550 pts.) and communications (300 pts.) - Utilities must submit specified data on per-event basis w/in 30 days of restoration for use by staff to score each outage for each utility		
NY	Generic	• Decided 11/19/13 • Case 13-M-0047 • Order Instituting a Process for the Sharing of Critical Equipment	• Directs utilities to finalize protocols, procedures & plans for sustaining shared equipment & supplies stockpile, to be filed by 12/16/13 - Program to build on existing utility equipment storage & delivery system		• Proceeding was initiated by 2/13/13 order to address recommendations by Gov. Cuomo to establish inventory of long-term capital assets and critical equipment for mutual

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
			• Urges utilities to work toward standardizing their most common materials • Urges uniform accounting practices for sale of utility shared critical equipment & supplies • Grants pre-approval of equipment transfers, subject to conditions, e.g., annual reporting • For security purposes, urges utilities to request trade secret protection for storeroom location and inventory information • Directs utilities to form Material Sharing Group to formulate detailed procedures and protocols for sharing equipment & supplies		use of utilities during emergency events
NY	Consolidated Edison Co. of New York	• Decided 2/21/14 • Case 13-E-0030, et al. • Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal	• Approves settlement providing for minimum $1b investment over 4 years in capital projects & programs to address reliability, storm hardening & resiliency, and related areas • Provides for ConEd to develop plan to address load growth in section of Brooklyn that offers DG as alternative to traditional infrastructure, facilitates DG installation, and other measures • Approves development of implementation plan for microgrid project • Approves changes to reliability performance and customer service metrics to provide incentives for higher performance levels • Approves expanded business incentive rate program to help small businesses recovering from Superstorm Sandy • Approves second phase of Resiliency Collab orative, which will focus on completion of co.'s voluntary 2014 climate change vulnerability study, review of 2015-16 storm hardening initiatives, ID of potential alternative resilience strategies such as microgrids and DG, and other areas (See Notes column)	• Approves recovery of $247m of Sandy costs and $78m in costs related to other storms, to be amortized over 3 yrs. subject to refund following staff review - Finds $124m in incremental storm costs reflected in above amounts (relative to current rates) to be appropriate in light of increased frequency of storms w/higher restoration costs • Approves increase in storm reserve fund from $5.6m/yr. to $21.4m/yr. - Approves new rules relating to costs charged to reserve to avoid potential double recovery and ensure efficient use of resources -	• The ALJ for the proceeding led a collaborative track of the proceeding regarding storm hardening & resiliency issues. The collaborative resulted in a stipulation on flood maps and a report filed by ConEd on 12/5/13. The collaborative parties agreed on an interim design standard to protect critical utility infrastructure from flooding in the future. Four working groups address: 1) storm hardening design standards, 2) alternative resiliency strategies, 3) natural gas system resiliency , and 4) risk assessment/cost benefit analysis.
NY	Consolidated Edison Co. of New	• Decided 3/26/10 • Case 09-E-0428 • Order	• Reaffirms outage notification system & incentive mechanism detailed in Case 00-M-0095 (decided 4/23/02) whereby failure to	• Co. agrees as part of settlement to defer costs in excess of storm reserves of $16.8m for future recovery	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
	York		meet applicable performance thresholds will result in revenue adjustment		
NY	National Grid-Niagara Mohawk Power	• Decided 3/15/13 • Case 12-E-0201, et al. • Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal	• Adopts 3-yr. rate plan as outlined by major parties in Joint Proposal (JP), which allows for new PSC storm preparedness initiatives during rate period • Reliability performance incentives are linked to SAIFI and CAIDI but do not apply to major storms; however, JP specifies that staff makes/submits findings after major storms • JP provides for system hardening activities, e.g., equipment inspections, periodic tree-trimming, targeted feeder work, flood mitigation and new transformer banks	• Per JP, approves $29m for major storm recovery, reflecting 10-yr. avg. and $6m increase from last rate case (10-E-0050) - Amount is reconcilable; costs exceeding $29m to be deferred via simplified mechanism • NiMo can change capital projects (previous column), accommodated w/in overall capital funding levels; if cost of change exceeds $8.8m annual threshold, co. can defer added costs	
NY	National Grid-Niagara Mohawk Power	• Decided 9/23/11 • Case 10-E-0050 • Order Approving Emergency Economic Development Programs with Modifications	• Approves w/changes co.-proposed 4 emergency economic development programs for qualifying non-residential customers affected by Hurricane Irene and TS Lee. - Co. to provide grants up of to $100K per community to customers and communities for activities such as capital investment. - Imposes reporting requirements - Requires outreach/communication plan	• Approves deferral of up to $6m for potential future recovery	• Approves on 7/19/13 similar program for nonresidential customers affected by flooding from rains in Jun 2013; capped @$2m total. Deferral not allowed but co. may petition later. Case 12-E-0201, et al. This emergency rule was made permanent in order issued 10/15/13.
NY	National Grid-Niagara Mohawk Power	• Decided 1/24/11 • Case 10-E-0050 • Order		• Approves $23m base rate allowance for major storm expenses • Denies co. proposal to establish $30m storm reserve account, citing inability to accurately estimate storm costs • Approves establishment of deferral account for major storms w/ $2.205m per storm deductible for use in severe weather events where costs exceed annual budgeted amount	
NY	Orange & Rockland Utilities	• Decided 6/14/12 • Case 11-E-0408 • Order		• Approves continued use of storm reserves for major storm events • Approves amortization of costs of Hurricane Irene & Oct 2011 snowstorm = $2.08m annual rate expense; recovery to begin in Rate Year 2 of multiyear rate plan	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
NY	Orange & Rockland Utilities	• Decided 6/16/11 • Case 10-E-0362 • Order		• Approves continued use of storm reserve accounting for storm restoration • Adopts 5-year amortization schedule for deficit between actual expenditures & storm reserves	
OH (Public Utilities Commission)	AEP-Ohio Power	• Decided 3/20/13 • Case 12-1969-EL-ATS • Financing Order		• Approves securitization of approx. $298m of previously approved deferred costs, including storm costs related to Hurricane Ike windstorm in Sep 2008 - Storm cost deferral was approved 12/19/08 in Case 08-1301-EL-AAM - Deferred asset recovery rider (DARR) was approved 12/4/11 to collect costs related to storm cost deferral and other approved regulatory assets. DARR to be withdrawn under securitization order. • Bonds to be backed by new phase-in rider, to be trued up annually • Bond proceeds to be used to redeem, retire or repay portion of existing debt, resulting in estimated savings to customers of $22m (nominal) or $28.8m (net present value). Savings result from lower effective interest rate as compared to currently authorized carrying charge on deferred assets	• Approval is made under recent law, H.B. 364, enacted 12/21/11. Law allows electric distribution companies to securitize previously deferred assets via issuance of phase-in-recovery (PIR) bonds. Deferred assets may consist of fuel costs, infrastructure costs, environmental cleanup and other costs. This case represents one of first times PUC has issued a decision under the law.
OH	AEP-Ohio Power	• Decided 8/8/12 • Case 11-346-EL-SSO, et al. • Opinion and Order		• Approves distribution investment rider (DIR) to accelerate recovery of prudently incurred capital costs, including carrying costs, for incremental infrastructure to maintain/improve reliability - Finds DIR will facilitate better service reliability & align co./customer expectations - DIR includes 10.2% ROE - DIR to be capped @$86m in 2012, $104m in 2013, $124m in 2014 & $51.7m after that thru 5/31/15, when electric security plan (ESP) expires, for total $365.7m. Overages/under-recoveries to be applied to increase or decrease next-year cap - DIR to be adjusted quarterly to reflect in-service net capital additions; to be reviewed annually	• Actions are part of case involving continued transition to competitive market via electric security plan, which has as major goal improvement of service reliability • Enhanced vegetation mgt. program was first approved 3/18/09; co. is moving from performance-based to 4-year, cycle-based program (Case 08-917-EL-SSO)

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				- DIR to be collected as % of base distribution revenues; co. agrees not to seek base rate change before 6/1/15 - Directs co. to work w/staff to develop distribution maintenance/replacement plan • Approves deferral of incremental storm costs above or below $5m/year for possible future recovery, pending outcomes of prudence reviews; if costs are incurred due to unexpected large storms, co. to file separate application each year throughout 3-year term of ESP • Approves continuation of enhanced vegetation mgt. program via previously approved Enhanced Service Reliability Rider (ESRR) - Approves merger of ESRR zonal rates into 1 rate - Directs co. to file revised vegetation mgt. program by 12/31/12 • Approves continuation of previously approved gridSMART rider, subject to annual true-up/reconciliation, w/certain changes; gridSMART investment not included in DIR rider (see above)	
OH	AEP-Columbus Southern Power	• Decided 4/5/11 • Case 08-846-EL-CSS • Opinion and Order	• Denies allegation by city of Reynoldsburg that co. Tariff 17 providing that munis must pay for cost of undergrounding to extent cost exceeds that of standard overhead lines is unjust, unreasonable or unlawful • Finds it does not have authority to resolve questions whether local ordinance supersedes tariff or whether tariff violates state Constitution; says those are matters for court to resolve - Reynoldsburg ordinance authorizes city to require a utility to relocate its facilities underground at its own cost - City sought to recover $1.2m it spent in relocation costs • Finds AEP appropriately applied tariff and charged city for relocation costs		• OH Supreme Court found tariff supersedes ordinance, saying ordinance was exercise of police power to promote public health/safety and did not overcome "general law" of the state attached to the tariff (Slip Opinion 2012-Ohio-5720; Case 2011-1274, decided 11/15/12) • Tariff 17, "Temporary and Special Service," was approved 5/12/92 (Case 91-418-EL-AIR) • Reynoldsburg Ordinance (City Code Chapter 907) was passed 5/9/05
OH	Dayton	• Decided 12/19/12		• Allows deferral of incremental O&M expenses	• DP&L is seeking to recover

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
	Power and Light	• Case 12-2281-EL-AAM • Finding and Order		related to June 2012 wind storm but reduces requested amt. by 3-yr. avg. of O&M expenses related to major storms - Carrying cost is most recent approved cost of long-term debt = 5.86%	O&M expenses related to major storms in 2011 & 2012 and certain 2008 expenses, and requested approval of a storm cost recovery rider for expenses going forward, in Case 12-3062-EL-RDR
OH	Duke Energy Ohio	• Decided 5/1/13 • Case 12-1682-EL-AIR, et al. • Opinion and Order		• Adopts settlement providing for: - $11 increase for vegetation mgt. to maintain 4-yr. trim cycle - Withdrawal of co. request for storm deferral/tracking mechanism and incremental recovery of 2012 storm costs	
OH	Duke Energy Ohio	• Decided 1/11/11 • Case 09-1946-EL-RDR • Opinion and Order		• Approves recovery of ~ $14m of incremental O&M costs related to 2008 Hurricane Ike wind storm, lowering by about half co.'s $28.5m request • Says co. did not meet burden of proof in showing disallowed costs were prudently incurred, e.g., discretionary supplemental expenses for salaried employees and certain contractor costs billed to OH rather than IN & KY • Costs to be recovered via previously approved Distribution Reliability Rider (DR-IKE) over 3 years; carrying charges included @most recently approved long-term debt rate of 6.45% • Costs to be allocated to distribution customers; demand-billed customers to be charged on per-kW basis & all other classes to be billed class-specific mo. customer charge	• OH Supreme Court on 4/5/12 upheld PUC decision against Duke challenge (Slip Opinion 2012-Ohio-1509, Case 2011-0767, Decided 4/5/12) • Related PUC actions: - Approved on 7/8/09 Duke's Distribution Reliability Rider, set at zero, for 2008 Ike storm costs as part of GRC settlement; authorized co. to file for initial rider level later (Case 08-709-EL-AIR) - Approved on 1/14/08 Duke deferral of $31mof incremental O&M expenses related to 2008 Ike storm w/carrying costs for possible future recovery (Case 08-709-EL-AIR) - Approved on 1/14/08 similar deferra7 for Dayton Power & Light @unspecified amount (Case 08-1332-EL-AAM)
OK	Oklahoma	• Decided 7/9/12	• Approves funding for increased vegetation	• Adjusts smart grid rider	Cites to: Order No. 558445 in

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
(Corporation Commission)	Gas and Electric	• Case PUD 201100087 • Final Order Approving Joint Stipulation and Settlement Agreement	mgt. • Report required on results of smart grid deployment	• Extends storm cost recovery rider • Modifies system hardening program rider	Cause Nos. PUD 200800215 and PUD 200700447; Cause PUD 200800398; Arkansas Docket 10-109-U, Order No. 8)
OK	Public Service Co. of Oklahoma	• Decided 1/5/11 • Case PUD 201000050 • Final Order Approving Joint Stipulation and Settlement Agreement			
OK	Public Service Co. of Oklahoma	• Decided 12/18/09 • Case PUD 200900181 • Final Order Approving Joint Stipulation and Settlement Agreement		• Approves capital investment rider under which co. to annually recover ~$30m, reflecting return of/on costs related to certain incremental generation and T&D investments (including vegetation mgt.) not yet reflected in existing rates • Rider amts. subject to refund pending review in next GRC	
PA (Public Utility Commission)	• Generic	• Decided 3/6/14 • Case M-2013-2382943 • Policy Statement	• Finalizes proposed policy statement that revises existing response, recovery & public notification guidelines - Adds storm preparation and response best practices developed following hurricanes Irene & Sandy - Focus is on coordination, communications, event forecasting, and holding exercises to better respond to major storms • Establishes Critical Infrastructure Interdependency Working Group, which will identify mission critical facilities and discuss interdependencies & best practices of different types of utilities and other entities involved in restoration of critical infrastructure		

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
PA	• Generic	• Issued 5/7/13 • Undocketed • Summary Report of Outage Information Submitted by Electric Distribution Companies Affected by Hurricane Sandy October 29-31, 2012	• Releases report on Hurricane Sandy prepared by PUC Bureau of Technical Utility Services • Report finds utility response reflected many lessons learned from 2011 storms, especially regarding communicating w/customers, elected officials & local emergency mgt. • Recommendations to utilities include: - Continued use/enhancement of social media & other communication methods - Collaboration on best practices for managing estimated restoration times - Continued work on messaging - Continued cooperation/communication w/local emergency mgt. - Continued work on peak call volume issues - Continued offering of regional concalls before a storm and during restoration • Report provides that staff will continue to work w/utilities to reduce duration/number of outages due to worst performing 5% of circuits and to ensure circuits help are not on 5% list for more than 4 consecutive quarters		
PA	• Generic	• Decided 8/2/12 • Case M-2012-2293611 • Final Implementation Order	• As precondition for DSIC approval, a utility must submit 5- to 10-year long-term infrastructure improvement plan (LTIIP) & asset optimization (AAO) plan (see Cost Recovery column) • LTIIPs must reflect/maintain acceleration of infrastructure replacement over historic levels • AAO Plans must describe eligible property repaired/replaced/improved in previous 12 mos. and those to be improved in upcoming 12 mos. • PUC must review plans at least once every five years • Will initiate separate rulemaking proceeding regarding periodic review of LTIIPs	• Authorizes electric/other utilities to apply for cost recovery between GRCs for distribution infrastructure repair, replacement & improvement via distribution system improvement charge (DSIC), a voluntary project-specific mechanism formerly available only to water utilities - DSIC subject to audit - Cost of equity = ROE approved in utility's most recent fully litigated base rate case, including ROE set via settlement, w/in previous 2 years - If last GRC was > 2 years ago, ROE set by other means; will form working group to address related issues - Caps DSIC-related rate increases between GRCs @5% of distribution rates billed; PUC says waivers are allowed but it is not likely to waive	• HB 1294 (Act 11) enacted on 2/14/12, amending Title 66 of PA Consolidated Statutes, to reduce regulatory lag & provide more ratemaking flexibility for time recovery of prudently incurred infrastructure costs so as to improve access to capital at lower rates and accelerate infrastructure improvement & replacement • PUC Commissioner Gardner dissented on the final rule's acceptance of use of a stipulated ROE for the DSIC vs. fully litigated, non-settled ROE

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				cap absent experience w/actual operation of DSIC - DSIC is rest to zero if new base rates are set or if showing is made that utility will earn ROR used to calculate fixed costs beyond authorized level • Sets procedures for use of fully projected test year in base rate cases; will initiate separate rulemaking to further address related issues	
PA	PPL Electric	• Decided 10/31/13 • Case M-2013-2275471 • Opinion and Order	• Approves settlement providing for co. to add provision to storm restoration procedures instructing personnel not to deviate from co. guidelines when assigning restoration crews • Per settlement, co. to pay $60K civil penalty • Finds underlying incident, which involved alleged reassignment of crew from higher priority to lower priority job related to Oct 2011 snowstorm, appears to be of a singular, non-recurring nature		
PA	PPL Electric	• Decided 5/23/13 • Case P-2012-2325034 • Opinion and Order		• Approves distribution system improvement charge (DSIC) mechanism for projected included I previously approved long-term infrastructure improvement plan (LTIIP). Projects include repairs, replacement or upgrade of poles & towers, overhead/underground conductors, transformers & distribution substation equipment, and other capital projects. Features include: - 5% cap on total revenue collected - Annual reconciliations - PUC audits - Customer notification of changes in DSIC - Reset to zero when eligible plant is included in rate base - Reset to zero when PPL is determined to have overearned • Directs some issues to ALJ for hearing and recommended decision, e.g., whether revenues associated with other riders are properly included as distribution revenue	• PPL's DSIC is first such mechanism approved for electric utility under Act 11 (See entry above for Case M-2012-2293611.)

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				- DSIC rates are subject to refund pending final resolution of ALJ issues	
PA	PPL Electric	• Decided 12/15/11 • Case P-2011-2270396		• Allows deferral of unanticipated O&M expenses, possibly $15m to $20m but unknown at this time, related to Hurricane Irene in Aug 2011 for potential recovery in future rate case - Says it is not ruling on reasonableness of costs and future recovery is not guaranteed - Does not specify amortization schedule but says PPL should expense deferred amounts on "reasonable" schedule	• Notes approved deferral is similar to deferrals approved in the past for accounting purposes
TX (Public Utility Commis sion)	Generic	• Decided 9/22/11 • Case 39465 • Order Adopting New §25.243 as Approved at the September 25, 2011 Open Meeting		• Approves distribution cost recovery factor (DCRF) mechanism similar to existing interim transmission cost recovery mechanism • Enables utilities to more efficiently/timely recovery & earn return on distribution-related investment including storm hardening & smart grid investment if included in eligible FERC accounts as follows: • Distribution plant-FERC 352, 353, 360-374, 391 • Distribution-related intangible plant-FERC 303 • Distribution-related communication & networks-FERC 397 • Prudence review/reconciliation occurs in next general base rate case • DCRF may be considered in setting rate of return in GRC	• No utility DCRF application had been made as of 11/19/12 • Rule implements SB 1693, enacted 5/28/11; provides for streamlined proceedings to authorize recovery of/on new distribution investment + related taxes; does not provide for recovery of expenses; applies to both restructured & vertically integrated utilities; allows annual rate updates, capped @four increases between full rate cases; new DCRF rates should reflect increases in base rate revenue resulting from load growth; requires PUC rule under which utilities to file earnings reports; law sunsets 8/31/17
TX	Generic	• Decided 6/24/10 • Case 37475 • Order Adopting New §25.95 as Approved at the June 11, 2010 Open Meeting	• Adopts rule requiring utilities to develop infrastructure storm hardening plan providing for cost-effective strategies to increase ability of T&D facilities to withstand extreme weather conditions • Requires each utility to submit forward-		

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
			looking plans over 5-year period as of 1/1/11, updated every 5 years		
TX	Generic	• Decided 12/14/09 • Case 37472 • Order Adopting New §25.94 as Approved at the December 2, 2009 Open Meeting	• Requires each utility to submit annual report describing efforts to identify areas w/in service territory that are esp. susceptible to damage during severe weather and to harden T&D facilities in those areas		• Rule implements HB 1831 enacted in 2009 - Makes various changes to existing law regarding disaster preparedness, emergency management and vehicles used in emergencies - Emphasizes importance of T&D infrastructure risk mgt. & maintenance
TX	CenterPoint Energy Houston Electric	• Decided 8/26/09 • Case 3720 • Financing Order		• Approves securitization, authorizes issuance of 13-year transition bonds backed by nonbypassable system restoration surcharge imposed on retail electric providers to finance $662.8m of system restoration costs related to hurricanes Ike & Gustav + carrying costs - Amount reached via settlement approved 4/17/09 (Case 36918) - Says transaction will save ratepayers $417m (nominal) over bond term & $326m on present-value basis	
TX	Entergy Gulf States	• Decided 1/17/06 • Case 31710 • Order		• Grants waiver to allow recovery via existing fuel adjustment clause (FAC) of surplus capacity/energy costs of purchasing surplus power from affiliate Entergy New Orleans (ENO), which lost significant for unknown period as result of Hurricane Katrina - Only energy cost recovery allowed in absence of waiver - Cites special circumstances and co. position that low-priced, short-term arrangement helps mitigate ENO financial burden resulting from hurricane, allows time for Entergy system restoration efforts, and saves fuel costs for EGS customers - Limits recovery to actual all-in contract or cost	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
				that would have been incurred/recovered via FAC but for those purchases, the latter based on reported prices for on-/off-peak energy	
TX	Entergy TX	• Decided 9/14/12 • Case 39896 • Order		• Reduces regulatory asset balance for deferred Hurricane Rita costs from $22.2m to $15.2m, saying calculation begins w/co.-claimed amt. in previous rate case (Case 37744-black box settlement of Rita costs approved), less amortization accruals (over 5 years) to end of test year in present case, less additional insurance proceeds received since previous rate case - Says accrual of carrying charges on asset should have ceased when Case 37744 concluded because the asset would have then begun earning return as part of rate base • Says co. should continue recording annual storm reserve accrual until modified by PUC order. - Finds appropriate total annual self-insurance storm reserve expense is ~$8.3m, consisting of annual $4.4m accrual for avg. annual expected storm losses + annual $3.9m accrual for 20 years to restore reserve from current deficit - Says target self-insurance reserve is ~$17.6m	
TX	Entergy TX	• Decided 9/11/09 • Case 37247 • Financing Order		• Approves securitization, authorizes issuance of 14-year transition bonds backed by nonbypassable customer transition surcharge to finance $539.8m of system restoration costs related to Hurricane Ike + estimated upfront qualified costs & carrying costs - Amount reached via settlement approved 8/18/09 (Case 36931) - Says transaction will save ratepayers $322m (nominal) over bond term & $240m on present-value basis	• SB 769 enacted in 2009 authorizes securitization to obtain timely recovery of system restoration costs
TX	Xcel Energy-Southwestern Public Service	• Decided 6/19/13 • Case 40824 • Order		• Approves settlement under which SPS agrees to refrain for filing for distribution cost recovery factor in 2013	

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
VA (State Corporation Commission)	Dominion Virginia Power	• Decided 7/15/05 • Case PUE-2004-00062	• Approves construction of $13.1m, 8-mile, 500 kV transmission line on company-preferred route in Fauquier Co. to meet reliability needs - Rejects intervenor-proposed underground alternative, saying co. showed higher cost, reliability risk (e.g., effects on power flows per co. testimony) outweigh ratepayer benefits		• Co. testimony cited other cases (e.g., PUE-2002-00702, Decided 10/8/04) where SCC has declined to require or commented unfavorably on undergrounding when feasible overhead options exist
WV (Public Service Commission)	Generic	• Decided 1/23/13 • Case 12-0993-E-T-W-GI • Commission Order	• Following investigation of effects of derecho and Hurricane Sandy in 2012, finds increased right of way (ROW) maintenance will lessen future storm impacts. Requires utilities to: - File petitions for approval of comprehensive, time cycle-based ROW vegetation mgt. programs w/spot trimming as necessary - File status reports on progress toward planned improvements to storm response procedures as stated in derecho storm reports filed in this proceeding	• Required petitions for ROW programs (previous column) must propose cost recovery mechanism for any rate increase - Proposals for surcharges or other adjustment mechanisms must contain specified information, e.g., calculation methodology and true-up procedure	• Says it might be appropriate for utilities to seek legislation authorizing trimming outside of existing ROWs if trees pose significant risk to utility service
WV	Generic	• Decided 11/7/12 • Case 12-0014-E-PC, et al. • Commission Order	• Adopts settlements under which utilities agree to meet reliability targets recommended by staff. The SAIDI, CAIDI and SAIFI targets will be effective 2014-18.		• Following a severe snowstorm and outages in 2009-10, the commission adopted reliability rules in July 2011. Rules for the Government of Electric Utilities, 150 C.S.R. 3. The rules required utilities to file reliability targets, which they did in this proceeding, resulting in the approved settlements.
WV	AEP-Appalachian Power, Wheeling Power	• Decided 3/18/14 • Case 13-0557-E-P • Commission Order	• Approves co.-proposed 4-yr., end-to-end, cycle-based vegetation management program (VMP), which is significant expansion of existing program. - Finds it is in the public interest to institute an "aggressive" program in light of increasingly severe storms since 2009. "The enhanced VMP will cost money, but doing	• States that it will develop a cost recovery mechanism in co.'s upcoming base rate case - VMP costs incurred before end of rate case to be deferred @4% interest - Mechanism will recover actual & projected costs, w/periodic review - Mechanism may include surcharge, base rate increment, or combination	• AEP filed in response to 1/23/13 order requiring utilities to make filings for expanded vegetation management plans (See case entry above)

State	Company	Date/Docket/ Title	Infrastructure Hardening & Storm Resiliency Measures	Cost Recovery	Notes
			nothing, in our opinion, costs even more.”		

Note: Public utility commission cases are listed first by any generic orders, then alphabetically by company and chronologically for each company, starting with the most recent
Sources: Published material from state utility commissions, state legislatures, courts and companies; SNL Financial Inc.
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Acronyms & Abbreviations

AAO – accounting authority order
AFUDC – allowance for funds used during construction
AMI – advanced metering infrastructure
BPU – Board of Public Utilities
CAIDI – customer average interruption frequency index
CC – Commerce Commission or Corporation Commission
CIAC – contributions in aid of construction
CIS – customer information system
DCRF – distribution cost recovery factor
DOT – department of transportation
DPU – Department of Public Utilities
DSIC – distribution system improvement charge
EDC – electric distribution company
EIVM – enhanced integrated vegetation management
Generic – applies to more than one utility
GM – grid modernization
GRC – general rate case
IOUs – investor-owned utilities
MOU – memorandum of understanding
N/A – not applicable or not addressed
O&M – operation and maintenance
PBR – performance-based regulation
PSC – Public Service Commission
PUC – Public Utility Commission or Public Utilities Commission
PURA – Public Utilities Regulatory Authority
ROE – return on equity
ROW – right of way
SAIDI – system average interruption frequency index
SB – Senate bill
SG – smart grid
T&D – transmission and distribution
TBD – to be determined
TS – tropical storm
UC – Utilities Commission

Edison Electric Institute
Power by Association

APPENDIX B

EEI Cross-Section of State Legislative Proposals on Storm Hardening & Resiliency

March 2014

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
CA	• Approved 9/23/12 • A.B. 1650 • Portantino. Public utilities: emergency and disaster preparedness	• Requires the commission to establish standards for disaster and emergency preparedness plans within an existing proceeding, as specified. Requires an electrical corporation to develop, adopt, and update an emergency and disaster preparedness plan, as specified. Authorizes every city, county, or city and county within the electrical corporation's service area to designate a point of contact for the electrical corporation to consult with on emergency and disaster preparedness plans.	• N/A	Enacted 9/23/12 Adds Section 768.6 to the Public Utilities Code
	• Approved 9/7/12 • A.B. 2584 • Bradford. Electrical corporations: investigations.	• Requires every electrical corporation and gas corporation that has an unplanned service outage resulting from an accident, natural event, or caused by the unplanned act of a utility employee, to preserve and not dispose of any materials that evidence the cause of the unplanned outage for 5 business days following the unplanned outage.	• N/A	Signed by the Governor 9/7/12 Adds Section 316 to the Public Utilities Code

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
CT	• Approved 6/15/12 • S.B. 23 • An Act Enhancing Emergency Preparedness and Response – Public Act No. 12-148	• The Public Utilities Regulatory Authority shall initiate a docket to establish industry specific standards for acceptable performance by each utility in an emergency to protect public health and safety, to ensure the reliability of such utility's services to prevent and minimize the number of service outages or disruptions and to reduce the duration of such outages and disruptions, to facilitate restoration of such services after such outages or disruptions, and to identify the most cost-effective level of tree trimming and system hardening, including undergrounding, necessary to achieve the maximum reliability of the system and to minimize service outages.	• The authority shall allow, in a future rate proceeding, each utility to recover the reasonable costs incurred by such utility to maintain or improve the resiliency of such utility's infrastructure necessary to meet the standards established pursuant to this section pursuant to a plan first approved by the authority.	Signed by the Governor 6/15/12 Replaces subsection (b) of section 28-5 of the 2012 supplement to the general statutes
	• Introduced 3/21/12 • H.B. 5551 • An Act Concerning the Protection of Power and Telephone Lines	• To (1) allow companies that provide electric or telephone services to acquire by eminent domain a tree or shrub that is on or adjacent to an existing right-of-way or easement held by the company if the company determines that such tree or shrub would cause an interruption in the delivery of such service due to the condition of the tree or in the event of a storm accompanied by winds of hurricane force, snow or ice, and (2) make technical changes.	• N/A	Introduced by the Judiciary Committee 3/21/12 Public hearing 3/29/12

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
CT	• Introduced 3/12/12 • H.B. 5544 • An Act Concerning Storm Preparation and Emergency Response	• To review the emergency response and service restoration efforts of certain public service companies and to establish emergency response and service restoration performance standards for such companies; to require back-up generators for telecommunications towers; to encourage the placement of certain utility infrastructure underground; to enable increased tree trimming; and to establish a micro-grid grant and loan pilot program.	• N/A	Introduced by the Energy and Technology Committee 3/12/12 Public hearing 3/20/12
	• Introduced 3/2/12 • H.B. 5407 • An Act Concerning Performance Standards for Public Utilities	• Requires the Commissioner of Energy and Environmental Protection to recommend performance standards for utility companies with the objective of enhancing communication during emergencies.	• N/A	Introduced by the Planning and Development Committee on 3/2/12 Public hearing 3/9/12
DC	• Approved 3/3/14 • B. 20-387 • Electric Company Infrastructure Improvement Financing Act of 2013	• Provides for the filing of a triennial Underground Infrastructure Improvement Projects Plan to identify problem feeders and recommendations for undergrounding the worst performing overhead feeders	• Authorizes and provides for the issuance of revenue Bonds in an aggregate principal amount not to exceed $375 M to finance the construction by the District Department of Transportation of underground facilities to be used by the Potomac Electric Power Company in connection with the undergrounding of certain electric power lines and their ancillary facilities.	Signed by Mayor Vincent Gray 3/3/14
HI	• Introduced 1/22/14 • H.B. 2384 • Relating to Natural Disasters	• Establishes the natural disaster working group to develop procedures for expediting recovery from natural disasters that are not declared "state disasters" by the governor.	• N/A	Introduced by Representative Cindy Evans (D) Referred to House Committee on Public Safety 1/27/14 Referred to House Committee on Finance 1/27/14

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
IL	• Approved 12/30/11 • H.B. 3036 • Public Utilities – Net Metering – Upgrade Investments – Public Act No. 97-0646	• provides for an infrastructure investment program for improvements designed to reduce outages due to storms	• A participating utility shall recover the expenditures made under the infrastructure investment program through the ratemaking process, including, but not limited to, the performance-based formula rate process	Signed by the Governor 12/30/11 Adds 16-108.5 (b)
	• Introduced 11/21/11 • H.B. 3884 • Overhead Utility Facilities Damage Prevention Act	• Provides that it shall be unlawful for any person to plant restricted vegetation within 20 feet of an electric utility pole or overhead electrical conductor located within the State. Provides that any restricted vegetation planted, whether by a person or by natural means, within 20 feet of an electric utility pole or overhead electrical conductor located within the State shall be subject to removal.	• N/A	Introduced by Representative Jack Franks (D) 11/21/11 House Session Sine Die 1/8/13
	• Introduced 10/24/11 • S.B. 2507 • Electric Utility Outages	• Amends the Public Utilities Act. Creates a new Article concerning electrical outages and emergency preparedness for electric utilities. Defines "area outage emergency". Provides that an electric utility must establish an Emergency Operations Center capable of receiving communications from municipalities and counties regarding down power lines or other damage during an area outage emergency.	• N/A	Introduced by Senator Sue Garrett 10/24/11 Senate Session Sine Die 1/8/13
MA	• Introduced 7/3/13 • H.D. 3750 • An Act relative to public utility company vegetation management.	• **[Bill text not yet available]**	• N/A	Introduced by Representative Josh Cutler (D)

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
MA	• Introduced 1/15/13 • H.B. 2929 • An Act promoting storm resistant utility infrastructure upgrades	• Modifies existing law related to emergency response plans to require the identification of necessary upgrades to transmission and distribution infrastructure to ensure reliable service to customers, including, but not limited to, the replacement of damaged wires, transformers, conduits or substations with storm-resistant, modernized technologies and other upgrades to prevent service disruption during emergencies. Establishes that each investor-owned electric distribution, transmission or natural gas distribution company, when implementing an emergency response plan, shall replace damaged or destroyed distribution or transmission infrastructure with upgraded, storm-resistant or other modernized infrastructure to prevent future service disruptions, as determined in advance by the department. The department shall consider and approve of such necessary upgrades annually in each emergency response plan.	• N/A	Introduced by Representative Stephen DiNatale (D) Referred to Joint Committee on Telecommunications, Utilities and Energy 1/22/2013 Hearing scheduled 9/10/13

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
MA	• Introduced 1/17/13 • H.B. 2989 • An Act relative to underground infrastructure	• Directs the Department of Public Utilities to promulgate rules and regulations relating to the construction of utility infrastructure designed to shield the utility infrastructure from damage sue to storms, vandalism, security issues, maintenance issues and overload issues. Directs the Department of Public Utilities to prioritize and incentivize the creation of underground utilities wherever feasible.	• N/A	Introduced by Representative Chris Walsh (D) Referred to Joint Committee on Telecommunications, Utilities and Energy 1/22/2013 Hearing held 9/10/2013 – a vote was not taken on the measure
	• Approved 8/6/12 • S.B. 2143 • An Act relative to the emergency service response of public utility companies	• Provides for filing of emergency preparedness plans, sharing of information and designation of emergency staff	• Establishes Department of Public Utilities Storm Trust Fund to reimburse department of public utilities for investigations into the preparation for and responses to storm and other emergency events by the electric companies • funding is provided through an assessment against each electric company based upon the intrastate operating revenues derived from sales within the commonwealth of electric service • specifies that any penalty levied by the department against an investor-owned electric distribution, transmission or natural gas distribution company for any violation of the department's standards of acceptable performance for emergency preparation and restoration shall be credited by the company to the affected customers of the penalized company	Signed by the Governor on 8/6/12 Adds sections to General Law Chapters 25 and 164

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
MD	• Introduced 8/9/12 • S.B. 9 • Electric Companies - Rate Adjustment to Recover Profits Lost During Service Disruption - Prohibition	• N/A	• Prohibits the Public Service Commission from authorizing an electric company to adjust the electric company's rates to recover profits lost during a disruption in electrical service; and making the Act an emergency measure.	Introduced by Senator Frosh 8/9/12 First reading in Senate Rules
MS	• Approved 3/6/06 • H.B. 1498 • The Hurricane Katrina Electric Utility Customer Relief and Electric Utility System Restoration Act	• N/A	• Authorizes state general obligation bonds to be issued to pay for damage to electric utilities caused by Hurricane Katrina	Signed by the Governor 3/6/06
NJ	• Introduced 1/14/14 • A.B. 248	• Directs Board of Public Utilities (BPU) to adopt best practices and standards concerning electric, gas and water public utility infrastructure design and response to service interruptions resulting from a major catastrophic event which is defined to mean a natural or humanly caused occurrence arising from conditions beyond the control of the public utility, including, but not limited to, a thunderstorm, tornado, hurricane, flood, heat wave, snowstorm, ice storm or an earthquake, which results in a sustained interruption of utility service to at least 10% of the customers in an operating area or 10% of the customers of a municipality or county located in an operating area or the declaration of a state of emergency or disaster by the State or by the federal government.	• N/A	Introduced by Assembly member Sean Kean (R) and Assembly member David Rible (R) Referred to Assembly Telecommunications and Utilities Committee Identical bills from last session: A.B. 3532, S.B. 2439

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NJ	• Introduced 1/14/14 • A.B. 274	• Requires public utilities to meet with county emergency management coordinators on a daily basis for the duration a major catastrophic event. Provides that, no later than 24 hours following a major catastrophic event, a public utility representative is required to be available to meet with the county emergency management coordinator at a location in the county experiencing the major catastrophic event.	• N/A	Introduced by Assembly member Donna Simon (R) Referred to Assembly Homeland and Security and State Preparedness Committee
	• Introduced 1/14/14 • A.B. 1014	• Requires certain electric public utilities to file emergency response plan with BPU.	• N/A	Introduced by Assembly member Daniel Benson (D) Referred to Assembly Telecommunications and Utilities Committee
	• Introduced 1/14/14 • A.B. 1032 • The Reliability, Preparedness, and Storm Response Act	• Requires public utilities to file certain information concerning emergency preparedness with BPU and increases penalties.	• N/A	Introduced by Assembly member Daniel Benson (D) Referred to Assembly Telecommunications and Utilities Committee

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NJ	• Introduced 1/14/14 • A.B. 1412 • An Act establishing uniform Statewide reliability standards for electric and gas public utilities	• Requires the BPU to establish uniform statewide standards of acceptable performance for service reliability and restoration of service after a service interruption that every investor-owned electric and gas public utility in the State must follow and requires electric public utilities to submit to the board a review of strategies to mitigate flooding of substations within flood zones. • Requires all electric and gas public utilities to file a service reliability plan and an emergency communications strategic plan for review and approval by the board; Allows the board to impose civil penalties if it finds that the length of the service interruptions were materially longer than they would have been but for the utility's failure.	• amendment authorizes BPU to authorize the recovery of all reasonable and prudent costs incurred by an electric or gas public utility in repairing, improving, and replacing its equipment and property reasonably associated with the improvement of utility service reliability consistent with the provisions of the bill. For the purpose of determining rates, such costs may include placing them in the respective public utility's rate base through an annual adjustment or recovering the costs through another ratemaking methodology approved by the board. All costs associated with repairing, improving, and replacing utility equipment and property reasonably associated with the improvement of utility service reliability may be eligible for rate treatment that is approved by the board, including a full return on the public utility's invested capital.	Introduced by Assembly member Upendra Chivukula (D) Referred to Assembly Telecommunications and Utilities Committee Hearing held; amended; passed 2/6/14 Identical bill from previous session: A.B. 2760
	• Introduced 1/14/14 • S.B. 166 • The Reliability, Preparedness, and Storm Response Act	• Requires public utilities to file certain information concerning emergency preparedness with BPU and increases certain penalties	• N/A	Introduced by Senator Jim Whelan (D) and Senator Shirley Turner (D) Referred to Senate Economic Growth Committee Identical bills from previous session: S.B. 26, A.B. 3671

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NJ	• Introduced 1/8/13 • S.B. 2429 • Public Utility Reliability Investment Act	• Requires public utilities to file infrastructure improvement plans to increase service reliability with the Board of Public Utilities	• N/A	Introduced by Senator Raymond Lesniak (D) 1/8/13 Identical bill: A.B. 3816 Introduced 2/11/13 Referred to Assembly Telecommunications and Utilities Committee
	• Introduced 12/17/12 • S.B. 2414	• Directs the BPU to study, prepare and submit, within six months of the effective date of the bill, to the Governor and to the Legislature, a written report which shall make findings which shall include the BPU's determination of whether the state's electric distribution system is maintained and operated by the electric public utilities in a manner that meets BPU standard and an assessment of the reliability of the state's electric distribution system through an application of other applicable standards. Directs the BPU to provide recommendations to improve reliability. •	• N/A	Introduced by Senator James Holzaphel (R) 12/17/12 Referred to Senate Economic Growth Committee Identical bill: A.B. 3616 Referred to Assembly Telecommunications and Utilities Committee
	• Introduced 12/13/12 • A.B. 3621	• Establishes requirements for newly installed and replacement electric utility poles and transmission towers. •	• N/A	Introduced by Assembly member John McKeon (D) 12/13/12 Referred to Assembly Telecommunications and Utilities Committee
	• Introduced 12/13/12 • A.B. 3622	• Directs the BPU to study the feasibility of adopting certain requirements for the installation of new and replacement electric distribution utility poles and transmission towers. •	• N/A	Introduced by Assembly member John McKeon (D) 12/13/12 Referred to Assembly Telecommunications and Utilities Committee

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NJ	• Introduced 12/6/12 • A.B. 3589	• Requires new electric distribution lines to be located underground wherever practicable	• N/A	Introduced by Assembly member Michael Carroll (R) Referred to Assembly Telecommunications and Utilities Committee 12/10/12
	• Introduced 12/3/12 • A.B. 3535	• Establishes Energy Infrastructure Study Commission. • Tasks the commission with making recommendations for improving the State's electric utility infrastructure	• N/A	Introduced by Assembly member Wayne DeAngelo (D) Passed by Assembly 5/20/13 Referred to Senate Economic Growth Committee 5/20/13
	• Introduced 11/19/12 • A.B. 3488	• Requires the BPU to adopt standards providing that, in operating areas that have been affected by a major catastrophic event, every electric distribution line of an electric public utility installed after the effective date of the bill, or installed, reinstalled, or repaired in response to damage resulting from a major catastrophic event, shall be located underground, wherever feasible, as determined by the BPU	• N/A	Introduced by Senator James Holzaphel (R) Referred to Telecommunications and Utilities Committee 12/3/2012 Identical bill: S.B. 2358 Referred to Senate Economic Growth Committee
	• Introduced 11/19/12 • A.B. 3482	• Requires the State's electric public utilities having ownership or control of utility plant infrastructure located in a flood hazard area to establish a plan to move the utility plant infrastructure out of the flood hazard area or to submit information showing that any plan to move utility plant infrastructure would not be feasible	• N/A	Introduced by Assembly member Jack Ciattarelli (R) Referred to Telecommunications and Utilities Committee 12/3/2012

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NJ	• Introduced 11/19/12 • A.B. 3483	• Establishes in the Department of Community Affairs, the "New Jersey Task Force on Underground Utility Lines" (task force). Specifies that the purpose of the task force is to study and evaluate the extent to which underground utility lines have been installed in the state, and to develop recommendations relating to the feasibility of expanding the number of underground utility line installations, the various options for the financing of such expansion, and the consequences of expanding installation of underground utility lines in this State	• N/A	Introduced by Assembly member Amy Handlin (R) Referred to Telecommunications and Utilities Committee 12/3/2012
	• Introduced 9/27/12 • A.B. 3255 • The Reliability, Preparedness, and Storm Response Act of 2012	• Requires the BPU to develop and enforce performance benchmarks for service reliability and communications for electric public utilities and requires electric public utilities to submit to the BPU a review of strategies to mitigate flooding of substations within flood zones. In addition, the bill requires all public utilities conducting business in the State to file a service reliability plan and an emergency communications strategic plan for review and approval by the BPU. After review of a public utility's service reliability plan and communications plan, in either or both, the BPU may order the public utility to make such modifications as it deems reasonably necessary to remedy any deficiency • Gives BPU authority to increase certain penalties	• N/A	Introduced by Assembly member Gregory McGuckin (R) 9/27/12 Referred to Assembly Homeland Security and State Preparedness Committee Identical bill: S.B. 2206 Referred to Senate Economic Growth Committee

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NY	• Introduced 1/9/14 • A.B. 8387	• Requires every city in the state, who has a population of 95,000 or more, to conduct a study of preparedness and readiness in the case of a disaster, natural or man-made, that would affect the state's power grid in such city. Requires each city to study their ability to maintain vital services, backup generating systems, law enforcement, hospitals, the integrity of computer systems operated by institutions within the city, first responders for immediate deployment and any further analyses that the Commissioner of Homeland Security and Emergency Services or Director of the Office of Emergency Management deems necessary. States that the purpose of these studies is for the cities to identify those areas of concern.	• N/A	Introduced by Assembly member Felix Ortiz (D) Referred to Assembly Committee on Cities
	• Introduced 4/4/13 • A.B. 6502 • Utility Preparedness Act of 2014	• Creates a utility preparedness program, which will impose new standards for preparedness and power restoration to address forthcoming major utility outages, like that experienced during Hurricane Sandy. • States that the public service commission adopt and enforce rules, performance incentives and standards for each transmission and distribution company during power outages in which more than ten percent of a transmission and distribution company's customers are without power for more than forty eight-consecutive hours.	• N/A	Introduced by Assembly member Shelley Mayer (D) Referred to Assembly Corporations Authorities Commissions Committee Amended 1/28/14 Identical bill: S.B. 4502 Referred to Senate Energy and Telecommunications Committee Re-referred to Senate Energy and Telecommunications Committee 1/8/14 Amended 1/24/14

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NY	• Introduced 2/14/13 • S.B. 3761 • Natural Disaster Preparedness and Mitigation Act	• Enacts the "natural disaster preparedness and mitigation act" providing for enhanced disaster preparedness and recovery from disasters.	• The disaster preparedness Commission shall utilize, in rate setting proceedings, to recover the reasonable costs incurred to maintain or improve the resiliency of the utility's infrastructure necessary to comply with the established standards	Introduced by Senator Malcolm Smith (D) Referred to Senate Veterans, Homeland Security & Military Affairs Committee Re-referred to Senate Veterans, Homeland Security & Military Affairs Committee 1/8/14 Amended 1/28/14
	• Introduced 1/29/13 • A.B. 3822	• Requires electric corporations to submit electric utility emergency plans to the public service commission for review and approval; provides such plans shall set forth training and planning for power outages, procedures to determine the extent of outages, procedures to determine the length of time the outages will continue, load relief policies, decision making plans, and any other information such commission requires; annually requires electric corporations file emergency plans and verification of the ability to implement such plan; requires electric corporations to report to the public service commission within 60 days of an outage which lasts more than 48 hours.	• N/A	Introduced by Assembly member Francisco Moya (D) Referred to Assembly Energy Committee 1/29/13 Re-referred to Assembly Environmental Energy 1/8/14 Identical bill: S.B. 2773 Referred to Senate Energy and Telecommunications Committee 1/23/13 Re-referred to Senate Energy and Telecommunications Committee 1/8/14
	• Introduced 1/14/13 • A.B. 2300	• Regulates the cutting, topping and removal of trees upon rights of way by providers of electric service. Requires the planting of replacement trees in certain cases.	• N/A	Introduced by Assembly member Thomas Abinanti (D) Referred to Assembly Energy Committee 1/14/13 Re-referred to Assembly Environmental Energy 1/8/14

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
NY	• Introduced 1/9/13 • S.B. 710	• Requires the public service commission to establish standards of acceptable performance for electric corporations.	• N/A.	Introduced by Senator Kevin Parker (D) Referred to Energy and Telecommunications Re-referred to Energy and Telecommunications 1/8/14
	• Introduced 1/9/13 • S.B. 1345	• Requires that the Public Service Commission ensure equitable treatment of all retail customers of electric corporations and municipal electric utilities by requiring investor owned utilities include them in any filed storm preparation and response plans.	• N/A	Introduced by Senator George Maziarz (R) Referred to Energy and Telecommunications Re-referred to Energy and Telecommunications 1/8/14 Recommit, enacting clause stricken 1/22/14
	• Introduced 1/4/12 • S.B. 6094	• Amend the public service law, in relation to requiring the PSC to establish standards of acceptable performance for electric corporations in the event of a power outage and subsequent power restoration	• N/A	Introduced by Senator Kevin Parker (D) 1/4/12 Referred to Energy and Telecommunications
	• Introduced 1/27/11 • S.B. 1777 • Safety and Reliability Inspection	• Requires a safety and reliability inspection of all utility poles used by electric corporations providing electric service to over 300,000 customers and the replacement or removal of deficient poles	• N/A	Introduced by Senator Bill Perkins (D) 1/27/11 Referred to Codes 6/14/11 Referred to Ways and Means 6/17/11 Enacting Clause stricken 7/11/11 Identical bill A.B. 6181; Amended 6/8/11 Referred to Energy and Telecommunications 1/4/12 Amended and recommitted to Energy and Telecommunications 6/8/11 Referred to Energy and Telecommunications 1/4/12

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
PA	• Introduced 2/6/13 • S.B. 35	• Authorizes and provides for the coordination of activities relating to disaster preparedness and emergency management activities by agencies and officers of the Commonwealth, and similar Federal-State and State-Local activities in which the Commonwealth, and its political subdivisions, intergovernmental cooperative entities, regional task forces, councils of governments, school districts and other appropriate public and private entities participate.	• N/A	Introduced by Senator Lisa Baker (R) Referred to Veterans Affairs and Emergency Preparedness Committee
TX	• Approved 6/17/11 • S.B. 937	• Requires the Public Utility Commission of Texas by rule to require an electric utility, municipally owned utility, electric cooperative, qualifying facility, power generation company, exempt wholesale generator, or power marketer to give to a nursing facility, an assisted living facility, and a facility that provides hospice services the same priority that it gives to a hospital in its emergency operations plan for restoring power after an extended power outage.	• N/A	Signed by the Governor 6/17/11 Subchapter D, Chapter 38, Utilities Code, is amended by adding Section 38.072
	• Approved 4/16/09 • S.B. 769	• N/A	• Provides for securitization methods for the recovery of system restoration costs incurred by electric utilities following hurricanes, tropical storms, ice or snow storms, floods, and other weather-related events and natural disasters.	Signed by the Governor 4/16/09 Amends Chapter 36, Utilities Code, by adding Subchapter I

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
VT	• Approved 4/4/13 • Executive Order 04-13 • Governor's Emergency Preparedness Advisory Council	• The order states that the mission of the Governor's Emergency Preparedness Advisory Council shall be to assess the state's overall homeland security preparedness, policies, communications and to advise on strategies to improve the system already in effect. • The order also states that the Council shall carefully consider the interdependencies between federal, state, local governments, Vermont National Guard, first responders, law enforcement, emergency managers, public health officials and private community organizations. The Council is also urged to take into consideration the available financial resources.	• N/A	Signed by Governor Peter Shumlin (D) 4/4/13 Expires 7/15/19

State	Date/Bill/Title	Infrastructure Hardening & Resiliency Measures	Cost Recovery	Status
WI	• Approved 12/13/13 • S.B. 119	• Ratifies a compact between several states and provinces of Canada that would provide for the possibility of mutual assistance in managing an emergency or disaster. • Allows for the temporary suspension, to the extent authorized by law, of statutes or ordinances that impede the response to an emergency or disaster. Requires members to agree to respond to the request for assistance as soon as possible, but the compact allows a member to withhold or withdraw resources to protect its own jurisdiction. • Provides that the states currently considering ratifying the compact as Illinois, Indiana, Ohio, Michigan, Minnesota, Montana, North Dakota, Pennsylvania, New York and Wisconsin and the Canadian provinces of Alberta, Manitoba, Ontario and Saskatchewan. Allows other states and provinces to ratify the compact.	• N/A	Approved by Governor Scott Walker (R) 12/13/13 2013 Wisconsin Act 97 Identical bill: A.B. 136

APPENDIX C
National Response Event

In 2013, EEI and its members ratified a new mutual assistance framework for events that require a national, industry-wide response. Going forward, when an event requires a national response, the industry will declare a "national response event" (NRE). An NRE is a natural or man-made event that is forecast to cause or that causes widespread power outages impacting a significant population or several regions across the U.S. and requires resources from multiple Regional Mutual Assistance Groups (RMAGs). When an NRE is declared, the industry's mutual assistance efforts will be scaled to the national level and coordinated so industry restoration resources are allocated in a singular and seamless fashion. All available emergency restoration resources (including contractors) will be pooled and allocated to participating utilities in a safe, efficient, transparent, and equitable manner. The NRE framework is designed to help increase public safety, accelerate the industry's response during national events, and minimize economic consequences for consumers and the nation.

- In the case of an industry-wide NRE, the industry's mutual assistance process will be coordinated at the national level in order to ensure industry resources are seamlessly allocated in the most efficient manner possible. For regional or local outages, mutual assistance resources will continue to be managed through the RMAG process.
- A new National Response Executive Committee (NREC), comprised of senior-level utility executives from all regions of the country, will govern the NRE allocation process. Upon request of an affected utility CEO, the NREC will declare an NRE and will activate the National Mutual Assistance Resource Team (NMART).
- The NMART evaluates mutual assistance requests and assigns available resources to affected utilities in coordination with the RMAGs. When an NRE is declared, all available industry emergency restoration resources (including contractors) will be pooled and allocated to participating utilities to best meet restoration needs in a catastrophic event.
- During an NRE, mutual assistance is provided in a coordinated, transparent, and equitable manner to restore power as efficiently and safely as possible for all customers and communities.
- An NRE designation is reserved for only the most significant events, such as a major hurricane, earthquake, an act of war, or other occurrence that results in widespread power outages.

The electric power industry is prepared for significant outage events and continues to improve its coordination and response and recovery efforts. Customers have increasing expectations and electricity dependence, and the industry is committed to making the mutual assistance process efficient, transparent, and equitable regardless of the size and scope of the event.

Electric Power Industry-Government Partnerships

Improving Communication and Coordination

In order to facilitate and improve information sharing, communication, and coordination during major outages, senior electric power industry officials will be embedded with government response teams at the U.S. Department of Energy and will coordinate with the Federal Emergency Management Agency. This allows a direct, two-way flow of information between industry responders and government emergency managers.

Streamlining Transportation

The industry is partnering with the U.S. Department of Transportation and state transportation agencies to expedite the movement of electric utility resources in support of mutual assistance and power restoration. EEI, with the support of federal and state governments, is developing information resources and tools to address the specific needs of utilities to move fleets and resources across state lines during a significant outage event.

The industry also has negotiated a new procedure for U.S. and Canadian border crossings with the Department of Homeland Security and the Canadian Border Services Agency to minimize delays and to ensure timely movement of mutual assistance crews across the international border.

Enhancing Logistical Support, Security, and Road Access

During Sandy, the U.S. Department of Defense (DOD) assisted the industry by providing airlift for crews and equipment. The industry is currently engaged in an ongoing dialogue with the DOD to build upon the unique capabilities that the military can provide during an emergency.

This effort includes working to expand logistical support, such as access to DOD property and facilities for pre-staging areas, exploring ways to enhance security and road access with the National Guard, and securing access to critical supplies and equipment from the Army Corps of Engineers.

The result of these partnerships is a higher level of collaboration between the electric power industry and government to ensure we are all better prepared for the next major outage event.

For more information on the National Response Event framework, please see http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/RestorationResources/Pages/default.aspx

The **Edison Electric Institute** (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers.

With more than $85 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Reliable, affordable, and sustainable electricity powers the economy and enhances the lives of all Americans.

EEI has 70 international electric companies as Affiliate Members, and 250 industry suppliers and related organizations as Associate Members.

Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

For more information, visit our Web site at www.eei.org.

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In place since 2006, the Spare Transformer Equipment Program ("STEP") has provided a binding, contractual arrangement for sharing assets between utilities in the event of a "Triggering Event"—a terrorist attack resulting in the destruction or long-term disabling of transmission transformers.

With 51 utilities participating in STEP, a trusted network has formed, with members providing information and assistance to each other in the event of equipment damage or failure, even when the situation does not constitute a STEP "Triggering Event." Beyond this, on numerous occasions STEP members have demonstrated a willingness and unique capability to provide assistance concerning equipment availability and technical resources to utilities inside and outside of STEP.

SpareConnect—A voluntary, collaborative, and "value-added" program

To complement the existing STEP program, *SpareConnect* will provide a mechanism for utility asset owners and operators to network with other *SpareConnect* members concerning sharing of transmission and generation step-up (GSU) transformers and related equipment, including bushings, fans, and auxiliary components. *SpareConnect* would establish a formal program—which already exists on an informal basis—to communicate equipment needs, in the event of an emergency or other non-routine failures and to connect interested utilities in a more efficient and effective way. *SpareConnect* would not be used in place of a utility's existing sparing program.

As with STEP—where spare transformers are located, operated, and maintained on a decentralized basis thereby protecting the integrity of the overall system—*SpareConnect* would provide decentralized access to points of contact with similar equipment. It would **not** create or manage a central database of spare equipment. It would **not** create a binding obligation on any participant to provide any information or to make any particular piece of equipment available.

Participation in *SpareConnect* would be open to all current STEP members as well as other utilities in the U.S., Canada and Mexico. Terms of Service will include standard confidentiality provisions. *SpareConnect* participants would be able to request the availability of transformers and related equipment from other participants in the event of an emergency or other non-routine failure. Those participants who are interested in providing transformers or related equipment would work directly and privately with each other on specific terms and conditions around the voluntary provision or sale of equipment.

RAISING OUR GAME

Distributed energy resources present opportunities—and challenges—for the electric utility industry. By Theodore F. Craver, Jr.

Anyone flying into the airports of Southern California can catch a bird's-eye glimpse of the future of the electric power system. This vast region is dotted with the reflections from shiny solar panels on the rooftops of homes, schools, and businesses. Photovoltaic (PV) solar systems also can be found on some parking lots and warehouses.

Ted Craver

California is one of several states where customer-owned or leased solar is becoming a fast-growing part of the electric system. The cost of installing PV solar systems has fallen dramatically in recent years. Further cost efficiencies are expected.

PV solar is the most visible segment of a major, ongoing transformation of our electric system, known as distributed generation, or more broadly, distributed energy resources (DERs). These resources include power generators, typically smaller than one megawatt,

Sungreen Systems, Inc.

Edison International

Grid-scale battery storage research and development at SCE's Advanced Technology Center in Westminster, CA.

located at or near customer sites—PV solar as well as internal combustion engines, natural gas-fired micro turbines, combined heat and power systems, small wind turbines, and fuel cells. They also include localized energy storage, such as batteries, along with energy efficiency and demand response programs.

Although some of these technologies are further along than others, distributed energy is becoming more widespread. In 2011, there were about 1,600 megawatts of distributed generation installed in the United States, according to the Energy Information Administration, which projects that PV solar will grow about 44 percent annually until 2015. Based on recent trends, PV likely will be the largest component of DERs by 2015.

Here in California, which has more than one quarter of the nation's distributed generation, our customers are being actively recruited by companies offering to install rooftop solar systems. The distributed energy phenomenon creates an exciting and challenging time for us in the electric power business. DERs are an example of a catch phrase I often use: In the electric power business, we expect to see more change in the next 10 years than we saw in the last 100.

Distributed energy has the potential to offer customers cleaner power, more choices, and more control over their energy bills.

Some people see all this change as a threat to the utility business. DERs certainly present some challenges that must be addressed. However, on balance, I see them as an opportunity to make our nation's power grid more flexible and ultimately to better serve our customers.

Distributed energy has the potential to offer customers cleaner power, more choices, and more control over their energy bills. DERs also can provide a number of benefits to utilities, including increased customer engagement in how their energy is sourced, delivered, and used. DERs likewise can complement "electricity-as-fuel" technologies such as plug-in electric vehicles, which themselves can become distributed resources via the energy stored in their batteries. In addition, when DERs are strategically located, they can defer, and sometimes substitute for, installation of new utility infrastructure such as power plants, transmission lines, and certain distribution upgrades.

The primary challenge we face is how to get from here to there while ensuring that electric service remains safe, reliable, and affordable for all customers. Achieving this will require continuing technological development, innovative financing, substantial infrastructure investment, changes in regulatory schemes, and adjustments in how we do business.

In this article, I want to explore some

Ted Craver is chairman, president, and CEO of Edison International and vice chairman of Edison Electric Institute.

of these issues and offer a roadmap for a cleaner, distributed energy grid of the future that integrates with our existing electric system and potential upgrades.

At Edison International, our Southern California Edison (SCE) utility has long been at the forefront of developing new technologies and cleaner energy. For example, SCE was a pioneer in developing air pollution control systems in the 1950s, and energy efficiency programs starting in the 1970s.

Today at our Advanced Technology Centers in Pomona and Westminster, CA, we research and develop plug-in electric vehicle technology, battery storage, and smart grid applications. And in the last few years we have installed approximately 90 megawatts of rooftop solar generation on warehouses as a way to encourage growth of the emerging PV solar industry.

California takes pride in being at the forefront of renewable energy and environmental policy. Part of that is due to our history of combatting air pollution, and part is due to the influence of Silicon Valley and the state's enthusiasm for attacking problems with technology.

The rapid growth of DERs suggests they can become a significant part of the electric system in just a few years.

Some of those policies are driving the rapid growth of DERs in California. The state's renewables portfolio standard requires that 33 percent of delivered power come from renewable sources such as solar, wind, and geothermal by the year 2020. California's global warming law calls for a reduction in carbon dioxide emissions to 1990 levels by 2020. The California Solar Initiative offers incentives for customers to install their own solar generators. And the California Public Utilities Commission (CPUC) has proposed that the state's three investor-owned utilities procure 1,300 megawatts of energy storage by the end of the decade.

California utilities have the central role of making all of this work. We work with the governor, legislature, and state regulators to help bring about this energy future without undermining our core mission of delivering safe, reliable, and affordable power.

Utilities in other states are grappling with many of these same issues. Although DERs account for only about 1 percent of the nation's total electric capacity, their rapid growth suggests they can become a significant part of the electric system in just a few years. That is why members of EEI view distributed energy as perhaps the most important development currently facing our industry.

SCE has installed approximately 90 MW of rooftop solar generation on warehouses to encourage growth of the PV solar industry.


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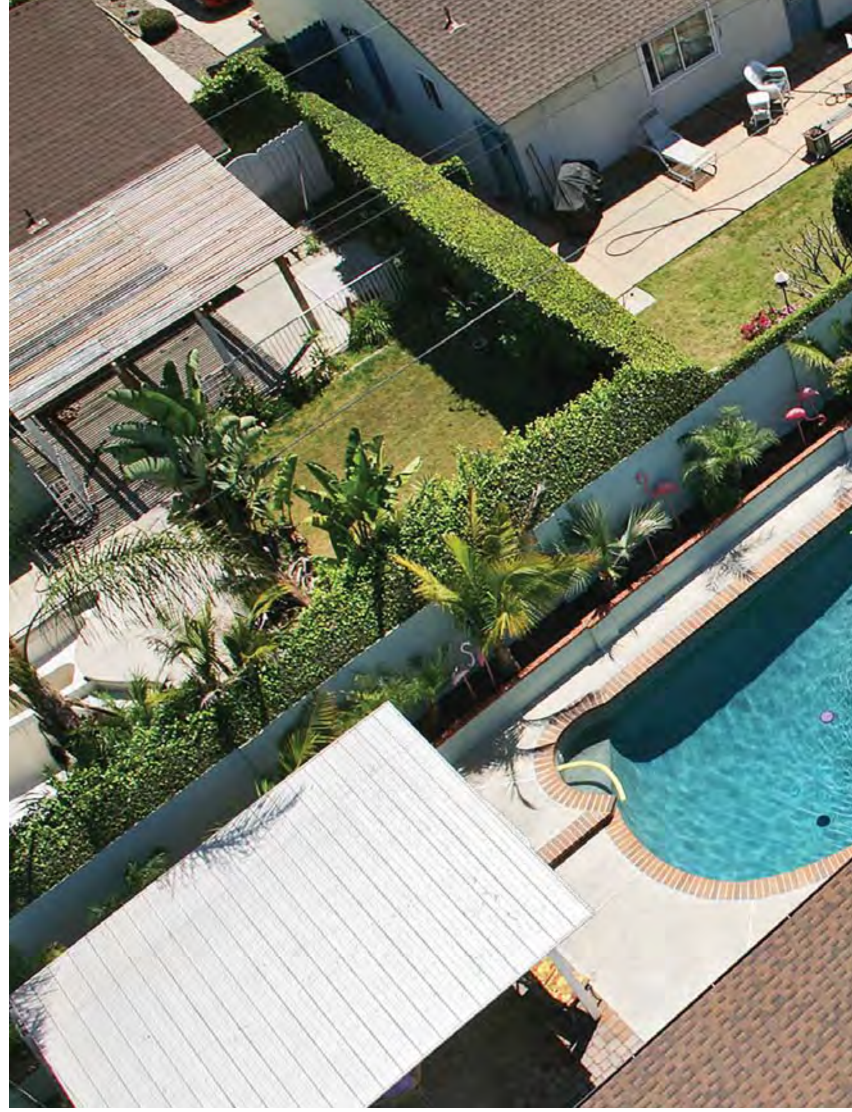

Shared fixed costs are required to safely and reliably operate and maintain the grid for everyone's benefit.

We want to see DERs integrated into the power grid to achieve the benefits they promise to our customers. Doing so requires us to objectively identify and resolve several important issues affecting electric system safety, reliability, and affordability.

Safety and Reliability

Distributed generation can pose potential safety risks for utility workers, first responders, and the public if, for example, the generation fails to de-energize when there is a downed power line. This situation, known as "islanding," occurs when a circuit loses power but inverters from customer solar systems continue to feed power into the now isolated circuit. This causes circuits or circuit segments to remain energized when service crews think they are off. SCE is working with other western utilities to recommend "smart inverter" standards to address this challenge.

The distribution grid that we operate was designed for one-way flow of electricity from power plant to customer. However, DERs require two-way flows when, for example, a customer's solar generator feeds power back into the system. That can cause fluctuations in voltage and frequency, creating reliability problems if the distribution grid has not been modified to handle such flows. The variable nature of most renewable resources, especially rooftop solar, creates a challenge for our grid operators who must continuously and instantaneously manage supply and demand.

The variable nature of most renewable resources, especially rooftop solar, creates a challenge for our grid operators.

Locating DERs in an optimal way, such as on more robust urban circuits, is important for grid reliability. Some DERs actually enhance grid stability by providing additional flexibility and resiliency. Other DERs have strained existing distribution networks, especially our rural circuits, creating the need for system upgrades. Random deployment of additional DERs without regard to location will worsen this situation.

Affordability—Fairness and Social Justice

Beyond the safety and reliability issues, rooftop solar and other distributed resources present important fairness questions about who pays for the shared system costs.

This point deserves some elaboration. The total costs of generating electricity, distributing it, and managing the complex electric system are allocated among residential customers almost entirely based on their individual kilowatt-hour (KWH) usage. We refer to this as a volumetric charge. The more KWH used, the higher the bill; the fewer KWH used, the lower the bill. But there are fixed costs that

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are not driven by usage. These fixed costs are required to safely and reliably operate and maintain the grid for everyone's benefit. They represent about one-third of SCE's total costs.

In this type of rate design, the large fixed costs of the grid are allocated among all residential customers based on their usage. This method of determining regulated rates is prevalent across the country, and it works well enough when all customers buy all of their electricity from their utility. However, it does not work well when some customers self-generate a meaningful portion of their electricity but still rely on the utility for the rest.

Here's why: When customers use their rooftop solar array to self-generate a portion of their total electricity needs, they receive less from the grid. However, they must remain connected to the grid to supply part of their electricity when the sun isn't shining or their system isn't generating enough to meet their needs, and as back-up for when their self-generation system is unexpectedly down. These residential customers are shifting a portion of their share of the fixed cost of the system to all the other customers who don't have solar panels. Their cost avoidance places a burden on everyone else in the form of higher rates.

Tied to the issue I just described is another rate-design policy employed in California and more than 40 other states called net-energy metering (NEM). This system allows customers with solar arrays to get paid by the utility, usually at full retail rates, for the amount of power they feed back into the grid. Their meter actually spins backwards when they are generating more power than they are consuming, and the negative charge is deducted from their monthly bill. This distorts the true cost of service for both NEM and non-NEM customers, and results in shifting costs from one customer group to another. At SCE, net metering policies shifted approximately $90 million in costs to our non-NEM customers in 2012.

Customers with distributed energy resources rely upon a reliable and modernized electric power grid as much, if not more than, existing customers.

There also is a social justice issue here, which is beginning to attract the attention of policy makers. Rooftop solar customers tend to be more affluent because the installations cost several thousand dollars, even after tax subsidies. Even if systems are leased instead of purchased, customers must have a strong credit rating to qualify. That means people who can't afford solar are picking up a disproportionate share of the overall cost of the electric system.

At Edison International, as well as across the industry and at EEI, we have been working on a set of proposals designed to enable a distributed energy future for all customers. These ideas involve technology and infrastructure investment, regulatory and rate reforms, and new business models.

Technology and Infrastructure

Customers with DERs rely upon a reliable and modernized electric power grid as much, if not more than, existing customers. They require a grid that is flexible, resilient, and capable of managing two-way flows of electricity. The bulk power system, with its central generation plants and high-voltage transmission, is already largely designed this way. However, by definition, DERs reside on the distribution system and are not directly associated with the bulk power system. Distribution systems vary in design and functionality across the country and within individual utilities.

SCE's system is a good example. Our utility has been in existence for 127 years and grew rapidly through acquisitions of varied systems. Some of our system is very rural and largely "radial" in design—meaning one-way flows of electricity from central plant to customer. Many of our suburban circuits are the same design. But we also have some urban communities, such as Long Beach, that have a true networked design, capable of

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Leviton

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The distribution system of the future will integrate smart technologies such as home energy management, smart appliances, and plug-in electric vehicles.

two-way flows of electricity. We even have a functioning microgrid serving the town of Bishop, which is self-sufficient and capable of separating from the rest of the grid and our system.

At SCE, as well as at other utilities, certain components throughout our system are feeling their age and need to be replaced. This must be done systematically, before they fail, and with an eye to creating the distribution system of the future.

Such a system must be capable of supporting and enabling DERs and the evolving customer requirements for more flexibility and choice. It must be able to handle the two-way flow of electrons while remaining stable. It must be made "smarter" to integrate smart technologies such as digital meters, smart appliances, smart inverters, and plug-in electric vehicles. It must be hardened to guard against cyber-attacks. This means it is vital that utilities continue their major investments in maintaining and upgrading the grid.

At SCE, we are conducting two pilot studies intended to help us develop the electric system of the future. An energy storage project will demonstrate how large-scale battery arrays can store up to 32 megawatt-hours of energy from wind farms. Our Irvine Smart Grid Demonstration Project will put DERS and microgrid elements to work in the "real-world" neighborhood of Irvine.

Regulatory and Rate Reform

As I outlined above, the current system of subsidies for distributed energy has distorted the true costs of these technologies and created inequities between customer groups. It is important that we work with state regulators to fix these problems imbedded in our current rate design. Our philosophy is that electric rates should as much as possible reflect the true costs of providing electric service.

We in the utility business seek a level playing field with the new entrants in our markets.

In California, stakeholders have been engaged in an effort to address residential rate design to enable DERs, reduce cost shifting between customer groups, and create fair and transparent rates. In fact, the California Legislature recently passed a law known as AB 327 that is a significant step toward restoring fairness in electric rates for all customers. The legislation will allow the CPUC to improve the current outdated electricity rate structure with one in which electric rates more accurately reflect the actual costs of electric service.

Among other things, AB 327 permits the CPUC to:

- establish a monthly customer charge that begins to recognize the fixed-cost components of providing a reliable electric system; and
- reduce the number and rates of retail tiers, while continuing protections for low-income customers.

In addition, we believe that NEM customers should not be paid the full retail rate for excess electricity they generate and feed back into the grid. Instead, they should be credited a rate that reflects the wholesale cost of producing alternative power. Important in this regard is that AB 327 calls upon the CPUC to develop new guidelines applicable to the NEM program beginning in 2017, which must consider the costs and benefits to all customers and to the grid.

New Business Models

Investing in technology and infrastructure and reforming rates are necessary but probably not sufficient to survive, much less thrive, in this new world of distributed energy.

We must raise our game. I believe that means being more competitive, more entrepreneurial, and even more customer-focused. This includes looking for new ways to promote innovative and efficient uses of electricity, such as electric transportation. It also means operating with excellence—emphasizing efficiency and cost controls to help keep our rates competitive while still investing in the grid.

In addition, we in the utility business seek a level playing field with the new entrants in our markets. We are not afraid of competition. We have decades of experience in delivering electricity and are eager for the chance to develop new and better ways to serve customers.

Current regulations limit how we can participate in these new technologies. We believe regulators should allow utility companies—either directly through their regulated utilities or affiliated competitive companies—to participate in DER markets through direct ownership, partnerships, or other means. Let customers have a choice whether to be served by utilities, their affiliates, or third-party providers.

At Edison International, we are interested in exploring new business opportunities, even beyond our 50,000-square-mile utility service territory. We are in the early stages of building a platform of businesses under the Edison International umbrella that are focused on DERs and power management services aimed at serving the needs of commercial and industrial customers. Also, we continue to explore ways to expand and participate in the electrification of transportation.

We don't know exactly what the electric power business is going to look like in 10 or 20 years. But it seems clear that the way power is generated, distributed, and used is likely to change a great deal. We have to look for opportunities to find new and better ways to serve our customers—starting now.

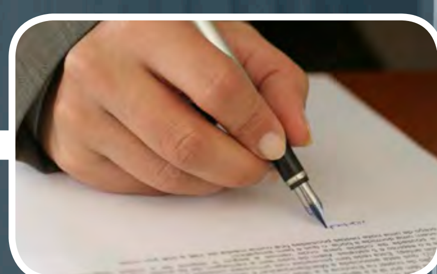
This brings to mind one of my favorite quotes from Charles Darwin that I have used several times with our employees: "It is not the strongest of the species that survives, nor the most intelligent that survives. It is the one that is the most adaptable to change."

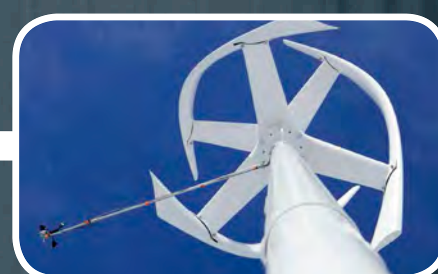
I think that says it all. ◆

CCIF

Critical Consumer Issues Forum

Policy Considerations Related to Distributed Energy Resources





July 2013

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CCIF 2012 Kickoff Forum

NASUCA President & Maryland People's Counsel Paula Carmody welcomes the approximately 200-member audience to Baltimore.

The "Public Policy Goals & Practices Concerning DER" panel included Ron Litzinger, President, Southern California Edison; Bill Levis, Consumer Counsel, Colorado Office of Consumer Counsel; Jeff Goltz Commissioner, Washington Utilities & Transportation Commission; and David K. Owens, Executive Vice President of Business Operations, Edison Electric Institute (Moderator).

The "Benefits & Challenges of DER panel included Joseph L. Fiordaliso, Commissioner, New Jersey Board of Public Utilities; Joe Como, Director, California Division of Ratepayer Advocates; and Gregory Bollom, Assistant Vice President – Energy Planning, Madison Gas & Electric Company.

Landis+Gyr's Ward Camp, Hawaii Public Utilities Commission Chair Hermina Morita, and Oregon Public Utility Commission Chair Susan Ackerman continue discussion of DER policy issues.

I. Introduction

About CCIF

Formed in 2010, the Critical Consumer Issues Forum (CCIF) brings state commissioners, consumer advocates, and electric utility representatives together to tackle consumer-focused energy issues through interactive discourse and debate, to find consensus when possible, and at a minimum, to achieve a clearer understanding of—and appreciation for—each other's perspectives and positions.

To provide leadership, CCIF first organized Executive and Advisory Committees, each with balanced representation from the three core communities (see Appendices A & B). These committees guide each initiative from topic selection to issuance of the final report. Specifically, CCIF's signature 3-step process entails:

1. A large open kickoff forum, typically collocated with the NARUC & NASUCA Annual Meetings, to introduce a topic and initiate discussion among CCIF's three core communities and other stakeholders;
2. A series of smaller, invitation-only spring summits in which the three communities engage in facilitated dialogue; and
3. A report issued in the summer to share key takeaways with the broader stakeholder community.

Importance of CCIF

Consumer issues are at the forefront of the energy policy debate. State commissioners, consumer advocates, and electric utilities are uniquely positioned to understand those issues and how to best mitigate any potential negative impacts on consumers. These three groups play an important role in influencing the policies and decisions with respect to energy at the state level, and these state policies and decisions are often drivers of broader energy policy. Therefore, it stands to reason that they take the lead on addressing key energy issues so that our policies benefit from their experience, expertise, and insights on consumer preferences and concerns. CCIF provides these three core groups a unique opportunity to take that lead—by providing a non-adversarial, collaborative environment in which they can candidly discuss and proactively address a variety of energy issues with potentially broad impacts on electric consumers.

CCIF Track Record

The CCIF formula has proven successful and its reports have contributed to the energy policy debate. Through this collaborative effort, CCIF has previously addressed topics including grid modernization and the regulatory process. In 2011, CCIF released its first report, which contained 30 consensus principles on grid modernization. CCIF's 2012 report explored whether and how transparency, communication, prioritization, and collaboration may be used to improve the regulatory process. Both reports are available at www.CCIForum.com.

CCIF Initiative on Distributed Energy Resources

In late 2012, CCIF leadership identified the challenging topic of distributed energy resources (DER) as ripe for discussion among the three core groups. Without question, state commissioners, consumer advocates, and electric utilities have both individual and collective perspectives that should be considered as policies are formed in this area. Therefore, CCIF kicked off its latest initiative on DER in November 2012 with a program that examined our distributed future, the benefits and challenges of DER, and relevant public policy initiatives and regulatory actions. The forum provided a solid foundation for the series of facilitated two-day dialogues that followed as well as the framework that ultimately was developed by the approximately 100 summit participants *(state commissioners, consumer advocates, and electric utility representatives featured on page 7-8).*

This report is a compilation of their collective perspective on some of the critical issues pertaining to DER. In addition, it demonstrates that these groups are clearly able and ready to help lead the state and national debates on challenging and complex energy issues—those pertaining to DER and countless others. The following is an overview of the framework on DER that constitutes the body of this report.

Focus & Objective

While recognizing that DER typically includes energy efficiency and demand response, participants from the three core communities chose to narrow CCIF's focus to distributed generation. In addition, they identified CCIF's objective with respect to this new topic. Specifically, they wanted to develop a framework to assist policymakers and other stakeholders in evaluating issues related to the potentials and challenges of DER in providing safe, reliable, affordable, cost-effective, and environmentally sound energy supply.

Potential Benefits & Challenge

Participants thoughtfully identified balanced lists of potential benefits and challenges of DER. As reflected in the framework, when paired with appropriate public policies, DER has the potential to provide direct and indirect benefits to consumers, both individually and collectively. Likewise, the challenges associated with DER merit consideration as well.

Principles

Finally, CCIF identified 21 principles in the following four areas: Financial & Regulatory Issues; Market Development & Deployment Issues; Consumer Issues; and Safety, Reliability & System Planning Issues. These principles memorialize the hard work of a significant number of state commissioners, consumer advocates, and electric utility representatives who participated in the CCIF process to collectively address a number of DER issues. CCIF trusts that the valuable perspectives reflected within these principles will be instrumental as we continue to build upon these ideas through further constructive dialogue with the broader stakeholder community.

II. CCIF Framework on DER

Focus & Objective of CCIF Initiative on DER

What is DER? Distributed Energy Resources (DER) include distributed generation, which are non-centralized sources of electricity generation generally interconnected to the distribution system and located at or near customers' homes or businesses. While DER can include energy efficiency and demand response, this collaborative process focuses on distributed generation. Examples of DER addressed by this collaborative include solar panels, energy storage devices, fuel cells, microturbines, reciprocating engines, small wind, backup generation, CHP systems, etc.

What is CCIF's Objective? The role of DER is growing and may require new approaches for providing and regulating electricity services. We recognize the need for a better understanding of costs and benefits of DER. Our goal is to develop a framework to assist policymakers and other stakeholders in evaluating issues related to the potentials and challenges of DER in providing safe, reliable, affordable, cost-effective, and environmentally sound energy supply. In developing this framework, we recognize the differing regulatory and market structures (e.g., vertically integrated, wires-only utilities, etc.) of the states, as well as the potential significance of regional and federal requirements.

Potential Benefits & Challenges of DE

When paired with appropriate public policies, DER has the potential to provide direct and indirect **benefits** to consumers, both individually and collectively. Depending on the type of DER, benefits that may be realized include:

1. Cost and risk reduction benefits;
2. Security and reliability;
3. Environmental benefits;
4. Innovation, expanded research and development, and other economic benefits; and
5. Expanded customer choice and control.

Likewise, the **challenges** associated with DER should be considered. Depending on type of DER, such challenges may include:

1. Financial impacts on utilities and customers, including increased costs, revenue losses, and cost-shifting;
2. Safety, security, operational control, reliability, and planning;
3. Siting, permitting, and other environmental issues;
4. Maintaining consumer protection standards; and
5. Jurisdictional and regulatory issues.

Principles on DER

Financial & Regulatory Issues

1. Generally, DER costs imposed on utilities should be borne by those who cause the costs. For example, backup or standby utility costs (particularly regarding intermittent DER technologies) should be borne by the operator of the DER.

2. Any required allocation of costs to others should be rational, transparent, based on benefits received, and not unduly burdensome.

3. DER incentives[1] should be based on clear policy objectives and periodically reevaluated based on market conditions. Once the underlying policy objectives are met or as the technologies become cost-competitive or cost-prohibitive, such incentives should be modified or discontinued.

4. Any incentives, through ratemaking practices, taxes, or otherwise, should be fair, transparent, and appropriate.

5. Utility investments required to accomplish DER deployment should be consistent with state policies and recovered in a manner consistent with state laws and regulatory policies.

6. To the extent that state commissions evaluate new regulatory policies and procedures in light of increased emphasis on DER, they should take into account the interests and concerns of all stakeholders.

Market Development & Deployment Issues

7. Utility and regulatory processes and requirements should allow for customer deployment of DER technologies subject to reasonable rules and regulations.

8. Utility participation in DER markets should be fair, reasonable, non-discriminatory, and overseen and approved by the appropriate regulatory authority.

9. Policies related to DER interconnection or deployment should be fair, reasonable, not unduly discriminatory, and overseen and approved by the appropriate regulatory authorities.

10. DER should be permitted on either the customer side or the utility side of the meter in accordance with interconnection rules and other applicable regulations.

11. While policies and their application may vary by state, DER programs, grants, or subsidies should be periodically evaluated for cost-effectiveness and adjusted by the appropriate regulatory authority as market conditions and policy objectives or requirements change.

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[1] For purposes of this discussion, participants considered "incentives" as benefits received by or cost reductions to a DER project, such as tax subsidies, rebates, subsidized financing, any net metering arrangement that provides benefits exceeding the underlying value of the energy received from that DER, etc.

12. Utilities and DER providers should work toward appropriate and reasonable data sharing that facilitates capturing system benefits and identifying costs of DER.

Consumer Issues

13. As DER technologies are deployed, consumer protection policies should be periodically reviewed and revised as appropriate. In any event, consumers should be given a clear avenue to resolve complaints.

14. Utilities and DER providers, with the participation of state regulatory bodies and consumer advocates, should develop standards for data protection, access, and disclosure consistent with state requirements.

15. States, consumer advocates, and utilities should coordinate education and customer engagement programs and make available objective information associated with DER technologies.

16. In developing DER policies, particular attention should be given to the cost impacts on all utility customers, including those not participating and those least able to afford such costs.

Safety, Reliability & System Planning Issues

17. Utilities should be aware that changes to utility system planning and operations may be required because of greater integration of DER technologies.

18. DER interconnection standards, procedures, and practices must ensure the safety of the public, first responders, and electric utility workers. These standards, procedures, and practices must also protect utility and customer assets.

19. DER deployment must be accomplished in a manner that does not compromise the continued reliability of utility infrastructure and operating systems.

20. DER deployment should not diminish infrastructure security or cybersecurity.

21. Transmission and distribution planning entities should consider and incorporate as appropriate state DER requirements into their planning processes.

III. Conclusion

Objective Met

Recognizing that this framework and the principles therein do not address all issues with respect to the expansive topic of DER, the consensus achieved by participating state commissioners, consumer advocates, and utility representatives is significant nonetheless. Consistent with the participants' stated objective, the framework provides a solid foundation upon which to build future constructive discussion and good policy.

Disclaimer

Please note that these principles are not intended to override any individual or collective policies or positions developed by state commissioners, consumer advocates, electric utility representatives, or by the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Utility Consumer Advocates (NASUCA), Edison Electric Institute (EEI), or any other organizations referenced herein. Instead, CCIF work products are meant only to complement such policies or positions and provide a framework for additional discussion and policy development.

Acknowledgments

The CCIF Executive and Advisory Committees would like to acknowledge the valuable contributions of the following individuals and organizations:

- NARUC, NASUCA, and EEI, particularly the guidance of their respective leaders and the valuable input and hard work of their respective teams.
- All state commissioners, consumer advocates, and electric utility participants who worked tirelessly to draft and revise the CCIF Framework on DER both during and after the Spring Summits in San Mateo, Atlanta, and Newark *(see page 7)*.
- All speakers, panelists, and attendees who participated in the November 2012 Kickoff Forum in Baltimore, where many of the issues addressed within this report were first introduced *(see page 13)*.

Future CCIF Initiatives

CCIF offers participants the ability to engage in constructive debate on important energy topics. CCIF provides a forum for state commissioners, consumer advocates, and electric utility representatives to collectively develop sound energy policies that fully consider impacts on consumers and other stakeholders. CCIF is designed to be a continuing, long-term effort to facilitate such leadership by these core groups and to address a variety of important energy issues in a collaborative, proactive manner. Therefore, we urge all interested stakeholders to stay tuned for future CCIF initiatives and events, and we specifically **invite all NARUC and NASUCA Annual Meeting attendees to join us the afternoon of Saturday, November 16, 2013, in Orlando** *(more details at www.CCIForum.com in the coming months).*

Appendix

Acknowledgment of CCIF Participants

Due to the nature of the collaborative process and the extensive degree of participation, specific principles developed within this process should not be attributed to specific individuals or to the organizations that he or she represents. With that understanding, the Critical Consumer Issues Forum (CCIF) would like to acknowledge the following individuals who participated in CCIF events focused on the topic of Distributed Energy Resources (DER):

Hon. Susan Ackerman
Oregon Public Utility Commission

Mr. Charles A. Acquard
NASUCA

Hon. Lorraine H. Akiba
Hawaii Public Utilities Commission

Hon. Bob Anthony
Oklahoma Corporation Commission

Mr. Noel Black
Southern Company

Mr. Gregory Bollom
Madison Gas & Electric Company

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Ms. Delanie Breuer
Public Service Commission of Wisconsin

Ms. Janee Briesemeister
AARP

Hon. Eric Callisto
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Mr. David Crews
East Kentucky Power Cooperative

Hon. Swati A. Dandekar
Iowa Utilities Board

Mr. Laurence C. Daniels
DC Office of the People's Counse

Mr. Evan Dean
Edison Electric Institute

Mr. Philip J. Dion
UNS Energy Corporation

Mr. Tom Donadio
First Energy

Hon. Patrice Douglas
Oklahoma Corporation Commission

Mr. Bruce Edelston
Energy Policy Group, LLC

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California Public Utilities Commission

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Wyoming Office of Consumer Advocat

Hon. Wayne E. Gardner
Pennsylvania Public Utility Commission

Ms. Linda Gervais
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Texas Office of Public Utility Counse

Hon. Jeffrey Goltz
Washington Utilities & Transportation Commission

Mr. Craig Graziano
Iowa Office of the Consumer Advocat

Ms. Janice D. Hager
Duke Energy

Hon. Darrell Hanson
Iowa Utilities Board

Mr. Wayne Harbaugh
Baltimore Gas & Electric Company

Ms. Becky Harsh
Edison Electric Institute

Mr. Charlie Higley
Citizens Utility Board of Wisconsin

Mr. Timothy A. Hoffman
Consumers Energy

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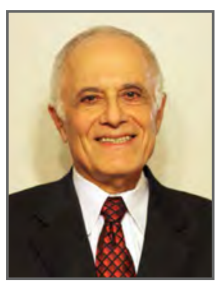

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A former Florida Public Service Commissioner (2006-2009), Katrina McMurrian draws upon extensive regulatory experience to organize and facilitate relevant policy forums and to advise an array of entities on key regulatory and public policy matters. McMurrian currently serves as the Executive Director of the Critical Consumer Issues Forum (CCIF), a unique forum in which state commissioners, consumer advocates, and utility service providers collectively address, via a series of interactive dialogues, real world issues of importance to consumers and policymakers. McMurrian also serves as Executive Director of the Nuclear Waste Strategy Coalition, an ad hoc organization representing the collective interests of state utility regulators, consumer advocates, tribal governments, local governments, nuclear-generating utilities, and other stakeholders on nuclear waste policy matters.

As a commissioner, McMurrian decided numerous multi-million dollar cases, appeared before Congress, worked with other state and federal agencies, and participated on a number of influential national policy boards. She served on several National Association of Regulatory Utility Commissioners (NARUC) committees, including Electricity, Nuclear Issues (Vice Chair), Consumer Affairs, and Education & Research, as well as on collaboratives with FERC, including Demand Response (Co-Chair), Smart Grid, and Competitive Procurement. She also served on the Executive Committee of the Nuclear Waste Strategy Coalition, Advisory Council to the Electric Power Research Institute (EPRI) Board, EPRI Energy Efficiency/Smart Grid Group, Keystone Energy Board, Eastern Interconnect States Planning Council, and the Southeastern Association of Regulatory Utility Commissioners (SEARUC). Additionally, McMurrian Co-Chaired the 2009 NARUC/DOE National Electricity Delivery Forum.

A Northwest Florida native, McMurrian received a Bachelor's degree in finance from Florida State University in 1994 and an MBA from FSU in 1998.

CCIF Events on DER

Fall Kickoff Forum
November 15, 2012
Renaissance St. Louis Grand Hotel
Baltimore, MD
Collocated with the NARUC and
NASUCA Annual Meetings in Baltimore
Approximately 200 participants

Spring Summit 1
March 25-26, 2013
San Mateo Marriott San Francisco Airport Hotel
San Mateo, CA
16 State Commissioners + 2 Staff
9 Consumer Advocates
10 Utility Reps

Spring Summit 2
April 10-11, 2013
Renaissance Concourse Atlanta Airport Hotel
Atlanta, GA
5 State Commissioners + 2 Staff
7 Consumer Advocates
11 Utility Reps

Spring Summit 3
May 6-7, 2013
Newark Liberty International Airport Marriott Hotel
Newark, NJ
8 State Commissioners + 2 Staff
13 Consumer Advocates
18 Utility Reps

DC Public Service Commission Chair Betty Ann Kane listens as the speakers respond to her question at the CCIF 2012 Kickoff Forum in Baltimore.

Illinois Commerce Commissioner Erin O'Connell-Diaz, Michigan Public Service Commissioner Greg White, and Southern Company's Noel Black enjoy spirited debate of DER issues at the CCIF 2012 Kickoff Forum.

Connecticut Consumer Counsel Elin Swanson Katz, Consolidated Edison Company of New York's President Craig S. Ivey, and Washington Utilities & Transportation Commissioner Jeff Goltz open the dialogue at the CCIF 2013 Summit in Newark.

CCIF 2013 Summits

PSEG's Tim Fagan, NASUCA President & Maryland People's Counsel Paula Carmody, and Duke Energy's Hilda Pinnix-Ragland consider proposed consensus language.

Pepco's Robert Revelle (left) and FirstEnergy's Colin Mount (right) listen intently as Wisconsin Public Service Commissioner Eric Callisto shares his perspective with the group.

Consolidated Edison Company of New York's President Craig S. Ivey shares recommendations to best prepare for the growth of DER.

Entergy's Andrew Owens and New Jersey Board of Public Utilities Commissioner Mary-Anna Holden are engaged in the summit dialogue.

AARP's Janee Briesemeister proposes an edit to a principle related to cost impacts on consumers.

CCIF Kickoff Agenda

CCIF
Critical Consumer Issues Forum

Presents the CCIF 3rd Annual Kickoff Forum:

Policy Considerations Related to Distributed Energy Resources

Saturday, November 10, 2012 ♦ 2:00 pm – 5:00 pm

Baltimore Hilton ▯ 401 West Pratt Street ▯ Baltimore, MD 21201

Key Ballroom 5 & 6 (2nd Floor)

AGENDA

2:00 – 2:05 **Welcome to Baltimore**
Paula M. Carmody, NASUCA President & Maryland People's Counsel

2:05 – 2:10 **Introduction & Expectations**
David A. Wright, NARUC President & South Carolina Public Service Commission Chairman

2:10 – 2:30 **Keynote: What are Distributed Energy Resources (DER)?**
To provide an overview of the technologies (including those fueled by more traditional means, such as gas-fired distributed generation and combined heat and power; those designed to reduce load; and those using newer resources like renewables) and policies (such as net metering, RPS, tax incentives, and rebates) that are contributing to the increased use of distributed energy resources.
Jesse Berst, Founder & Chief Analyst, Smart Grid News

2:30 – 3:15 **Benefits & Challenges of DER**
Panelists will discuss the benefits and challenges presented by alternative supply options on consumers, utilities, and regulators. Consumers are increasingly becoming more informed and engaged on choices about how they receive energy and how they manage their usage, but not all consumers choose to or are in positions to invest in these technologies. Utilities can benefit from new technologies but may also see increased costs as these technologies further develop. Regulators face the challenge of facilitating new consumer demands while minimizing any negative impacts to the electric delivery system and consumers.

Moderator: *Erin M. O'Connell-Diaz, Commissioner, Illinois Commerce Commission*

Panelists:

- *Joseph L. Fiordaliso, Commissioner, New Jersey Board of Public Utilities*
- *Joe Como, Director, California Division of Ratepayer Advocates*
- *Gregory Bollom, Assistant Vice President – Energy Planning, Madison Gas & Electric Company*

3:15 – 3:30 **Break**

3:30 – 4:55 **Public Policy Goals & Practices Concerning DER**
This panel will focus on public policy initiatives and regulatory actions concerning DER, such as net metering, rebates, tax incentives, performance-based incentives, and low-cost financing.

Moderator: *David K. Owens, EEI Executive Vice President, Business Operations*

Panelists:

- *Jeff Goltz, Chairman, Washington Utilities & Transportation Commission*
- *Bill Levis, Consumer Counsel, Colorado Office of Consumer Counsel*
- *Ron Litzinger, President, Southern California Edison*

4:55 – 5:00 **Closing & Next Steps**
Paula M. Carmody, NASUCA President & Maryland People's Counsel

CCIF Sample Summit Agenda

CCIF
Critical Consumer Issues Forum

Presents…

Policy Considerations Related to *Distributed Energy Resources (DER)*

May 6-7, 2013

Newark Liberty International Airport Marriott Hotel
Salons E-H

Agenda

The electric industry is facing transformative technological and economic changes whose effects are increasingly converging at the distribution side of the business. Customers are beginning to have a range of alternative supply options, including demand resources, distributed generation, energy storage, electric vehicles, microgrids, virtual power plants, and others. And as with any new transformational technology, distributed energy resources (DER) offer a great many opportunities and challenges. During CCIF's 2013 summit series, state commissioners, consumer advocates, and electric utility representatives will come together to discuss the potential impacts of DER on customers and to ensure that the proper policies are in place so that the integration of DER occurs safely, fairly, and reliably.

Monday, May 6th

9:00 – 10:00 **Continental Breakfast** *(Salons E-H)*
(Please note that meeting begins at 10:00 AM in Salons E-H.)

10:00 – 10:05 **Welcome & Introductions**
Katrina McMurrian, CCIF Executive Director

10:05 – 12:00 **DER: Setting the Stage Panel & Group Discussion**
From their unique perspectives, panelists will set the stage by identifying and discussing the primary issues of importance pertaining to DER, by predicting its impact on the future, and by recommending actions to best prepare for the integration of DER. All participants are encouraged to join in on the dialogue in preparation for the principles development process to follow.
Moderator: Katrina McMurrian, CCIF Executive Director
Panelists:

- ***The Honorable Jeff Goltz, Commissioner, Washington Utilities & Transportation Commission***
- ***Ms. Elin Swanson Katz, Consumers' Counsel, Connecticut Office of Consumer Counsel***
- ***Mr. Craig S. Ivey, President, Consolidated Edison Company of New York, Inc.***

12:00 – 12:30 **Deli Lunch** *(Salons E-H)*

12:30 – 1:00 **Overview over Lunch: CCIF Goals & Principles Process**
Katrina McMurrian, CCIF Executive Director

- CCIF Background (Leadership, Participation, Purpose, Process, Past Initiatives)
- Goals for Summit Series on DER
- Expectations for Post-Summit Report on DER
- Principles Process and Constraints

1:00 – 3:00 **DER Principles Discussion I: Financial Issues**
Facilitated Group Discussion

3:00 – 3:15 **Break**

3:15 – 5:15 **DER Principles Discussion II: Market Development & Deployment Issues**
Facilitated Group Discussion

5:30 – 6:30 **Networking Reception** *(Grand Ballroom Foyer)*

6:30 – 8:30 **Plated Dinner & Continued Issue Discussion** *(Salon D)*

Tuesday, May 7th

7:00 – 8:00 **Hot Breakfast Buffet** *(Salons E-H)*
(Please note that meeting begins at 8:00 AM in Salons E-H.)

8:00 – 10:00 **DER Principles Discussion III: Consumer Issues**
Facilitated Group Discussion

10:00 – 10:15 **Break**

10:15 – 12:15 **DER Principles Discussion IV: Safety, Reliability & System Planning Issues**
Facilitated Group Discussion

12:15 – 12:30 **Boxed Lunch** *(Salons E-H)*

12:30 – 2:00 **Working Lunch: Principles Review & Final Touches; Communications Plan; Next Steps**
Facilitated Group Discussion

2:00 **Meeting Adjourns**

For more information about CCIF or this report:

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VALUE OF THE GRID TO DG CUSTOMERS

IEE Issue Brief
September 2013
Updated October 2013

IEE | INNOVATION ELECTRICITY EFFICIENCY

An Institute of The Edison Foundation

Value of the Grid to DG Customers

IEE Issue Brief

September 2013
Updated October 2013

Prepared by

Lisa Wood
IEE

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Borlick Associates

VALUE OF THE GRID TO DG CUSTOMERS

Some advocates of distributed generation (DG) claim that the DG customer derives no benefit from being connected to the host utility's distribution system.[1] While it is easy to say that a DG customer is "free from the grid," that is simply not true – even for a DG customer (or a micro-grid) that produces the exact amount of energy that it consumes in any given day or other time interval.[2]

This paper describes how a DG customer (or a micro grid) that is connected to the host utility's distribution system 24/7 utilizes grid services on a continuous, ongoing basis. The point is to recognize the value of these grid services and to develop a methodology for the DG customer to pay for using the services. The utility's cost of providing grid services consists of at least four components – the typical fixed costs associated with: (i) transmission, (ii) distribution, (iii) generation capacity, and (iv) the costs of ancillary and balancing services that the grid provides throughout the day for the DG customer.

There is a related question about how much DG customers should be paid, or credited, for the excess electric energy they produce on-site and inject into the grid. This paper does not explicitly address this "value of on-site energy" issue.

THE BENEFITS OF REMAINING CONNECTED TO THE DISTRIBUTION SYSTEM

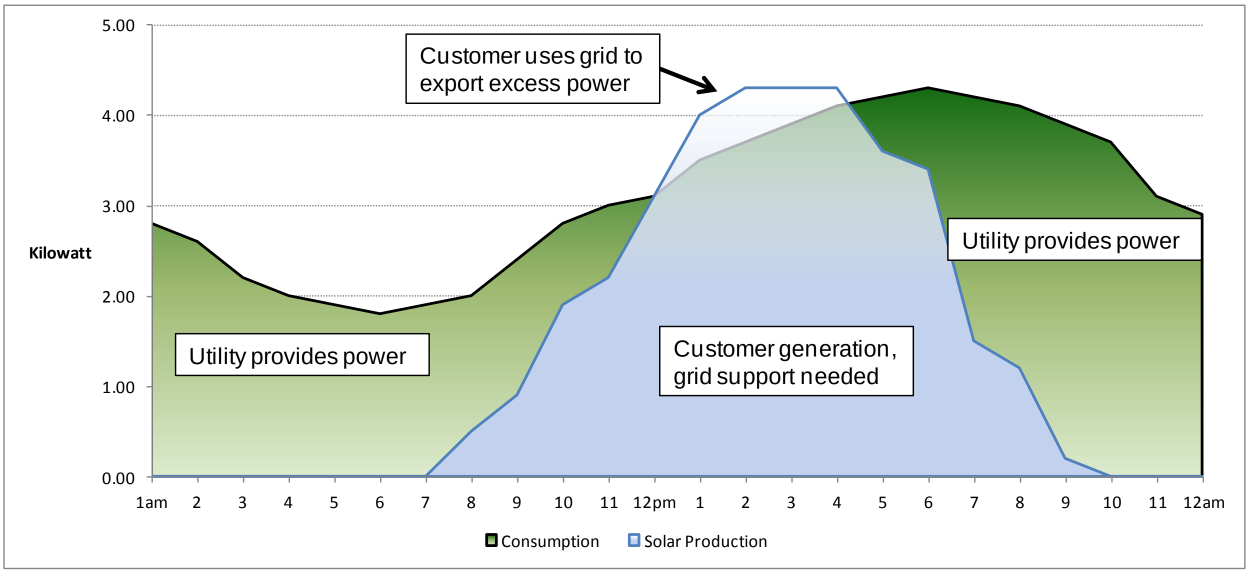
Consider a residential or small commercial customer with solar PV panels on its rooftop. Figure 1 displays a typical hourly pattern of energy production and consumption for such a customer. The green area is the energy delivered by the host utility and consumed by the customer. The area under the blue curve is the energy produced on-site by the solar panels. The area below the blue curve and above the green line is the excess energy injected into the utility's distribution system. The key take-away from this graphic is that the customer's consumption and generation are almost never equal; consequently, most of the time the customer is using the external power system to offset the difference between the customer's consumption of electric energy and its on-

1 A recent Forbes article, "Distributed Generation Grabs Power from Centralized Utilities," August 8, 2013, ignores and fails to mention the grid services that are provided to DG customers continuously by the host utility.

2 The term, DG, refers to small retail customers with on-site generation that are net metered.

site production. In most cases the customer will be taking energy from the grid during many hours of the day. For example, the customer depicted in Figure 1 takes power from the grid in all hours except from noon to about 4:30 pm.

Figure 1: Typical Energy Production and Consumption for a Small Customer with Solar PV



Customers with any type of DG that are connected to the grid will be utilizing external grid services to:

- balance supply and demand in sub-second intervals to maintain a stable frequency *(i.e.*, regulation service);
- resell energy during hours of excess generation and deliver energy during hours of deficit generation;
- provide the energy needed to serve the customer's total load during times when on-site generation is inoperable due to equipment maintenance, unexpected physical failure, or prolonged overcast conditions (*i.e.*, backup service);
- provide voltage and frequency control services and maintain high AC waveform quality.

Clearly, even if the customer's total energy production over some time interval (*e.g.*, a monthly billing cycle) exactly equals its consumption over that same interval, that customer is still utilizing at least some, if not all, of the above grid services during that time interval.

So what value does a customer with solar PV generation derive from remaining connected to the grid? Let's begin by examining the charges that a typical residential customer consuming an average of about 1000 kilowatt-hours (kWh) per month [average consumption based on Energy Information Administration (EIA) data and rounded] will pay for grid services, excluding the charges for the electric energy itself. These charges are designed to allocate to the customer its fair share of the fixed costs associated with the transmission system, the distribution system, balancing and ancillary services, and the utility's (or the retail supplier's) investment in generation capacity.[3] As stated earlier, the electric energy charges designed to recover the cost of the energy (kWh) consumed by the customer (including the associated transmission and distribution losses), are excluded here. Table 1 illustrates these charges for a typical residential customer.[4]

Table 1 – Non-Energy Charges Paid by a Typical Residential Customer on a Retail Tariff

Average Residential Customer: Non-Energy Charges as Percent of Typical Monthly Bill	
Average Monthly Usage (kWh)*	1000
Average Monthly Bill ($)*	$110
Typical Monthly Fixed Charges	
Ancillary/Balancing Services	$1
Transmission Systems	$10
Distribution Services	$30
Generation Capacity ^	$19
Total Fixed Charges for Customer	$60
Fixed Charges as Percent of Monthly Bill	**55%**

*Based on Energy Information Administration (EIA) data, 2011
^The charge for capacity varies depending upon location. This is just an estimate.

In this example, the typical residential customer consumes, on average, about 1000 kWh per month and pays an average monthly bill of about $110 (based on EIA data). About half of that bill (*i.e.,* $60 per month) covers charges related to the non-energy services provided by the grid,

3 In "retail choice" states the retail customer can choose its energy supplier, which may not be the utility. In all other states the utility will be the retail supplier.

4 Other charges, such as sales and franchise taxes and environmental charges could be added to the table; however, the focus of this paper is on the grid services that are provided by the host utility.

including a charge for generation capacity. Because residential retail rates are almost always designed to recover most of the power system's fixed costs through kWh charges, a DG customer will avoid paying some or all of its fair share of the fixed costs of grid services. Ultimately the fixed costs that the DG customer does not pay, which are significant, will be shifted to other retail customers. In this example, each DG customer shifts up to $720 per year in costs (*i.e.,* $60 * 12 months) to other retail non-DG customers. To put this into context, if 50 percent of the residential customers in a given utility service territory had DG, the non-DG residential customers in that service territory could experience bill increases of up to 55 percent – from $110 per month to $170 per month. Clearly this cost shift is substantial and simply not fair.

IEE submits that DG customers should pay their fair share of the cost of the grid because pushing any of this cost onto non-DG customers raises serious economic efficiency and fairness issues. Indeed this is one of the key issues in the current debate over net metering.

To illustrate the value provided by the grid for a solar PV customer, consider what it would cost that customer to self-provide the technical equivalent of these services through some combination of energy storage and/or thermal generation (*e.g.,* a Generac home generator).

Preliminary estimates of the monthly costs that a typical residential customer would have to incur to self-provide the balancing and backup services that the grid currently provides are substantially higher than the $60 charge shown in Table 1.[5] Furthermore, this cost estimate of self-provision excludes the additional cost of maintaining the level of voltage and frequency control and AC waveform quality currently provided by the grid. An off-the-grid DG customer (or micro-grid) simply cannot provide, at reasonable cost, the same quality of service that a large power system provides. So, in fact, most DG customers remain connected to the grid today and utilize grid services.

This straightforward cost comparison to "self providing" grid services reveals three things. First, the balancing and backup services that the grid provides to DG customers are needed and have substantial value. Second, it does not make economic sense for a DG customer to self-provide these services. Third, it is unfair for DG customers to avoid paying for these grid services,

5 The Electric Power Research Institute (EPRI) is developing estimates of the cost of self-providing grid services and expects to release its results in 2014.

thereby shifting the cost burden to non-DG customers. Obviously, DG customers should pay their fair share of the cost of the grid services that the host utility provides.

Economies of Scale Associated with Power Systems

In many ways, the growth of DG and micro grids today goes full circle back to the early days of the electric power industry. Initially power systems were isolated and each served its own service area. As service areas expanded, utilities began to interconnect. PJM was the first entity to interconnect utilities for reliability purposes and to centrally provide balancing services. This evolution was driven by the substantial economies of scale that still exist today as ISO/RTO markets continue to grow and expand.[6]

These interconnection entities developed for good reasons. When a small power system interconnects with a larger one, all members of the resulting combined entity benefit. However, it has been observed that the small system benefits disproportionately more than the incumbent members. For example, the small system's operating reserve margin will decrease substantially. This phenomenon is even more pronounced when a micro-grid interconnects with a power system.

DG Market is Growing, Pricing it Right is Key

Although net metering was a convenient vehicle for kick-starting the DG market, there are now serious questions among state policymakers regarding its continuation and needed reforms. *One main concern, addressed by this paper, is that net-metered customers are avoiding payment of their fair share of the grid services described earlier, thereby causing those lost revenues to be recovered from other customers.* As also demonstrated in this paper, these "grid" costs are quite significant – about 55 percent of the monthly electric bill for a residential customer as demonstrated in Table 1. Although this may not have been a major problem when the DG market was in its infancy, sending the wrong price signals to both customers and to the DG industry is a major problem as the DG market rapidly grows and develops.

6 Entergy's decision to join MISO is a recent example.

REVENUE DECOUPLING WILL NOT RESOLVE THE DG COST-SHIFTING ISSUE

Revenue decoupling is currently being used to promptly restore utility net revenues that would otherwise be lost due to declining electricity sales resulting from utility investments in energy efficiency (EE). Although revenue decoupling makes the utility whole, it does so by explicitly shifting costs from participating EE customers to nonparticipating EE customers using a public or system benefits charge (which is typically visible and transparent to all customers as a charge on their utility bills). Decoupling causes the same cost shifting problem that is created by DG with net metering. However, a fundamental difference is that the magnitude of the "cost shifting" to non DG customers is on a much larger scale than the cost shifting due to energy efficiency. A recent study revealed that decoupling rate adjustments for energy efficiency are quite small – about 2 to 3 percent of the retail rate.[7] In contrast, as described earlier in this paper, a DG customer could shift up to 55 percent of the retail rate onto non-DG customers (and, unlike efficiency charges, which are transparent, the DG cost shifting is essentially invisible to customers).

The amount of cost-beneficial energy efficiency is limited because the more you achieve, the less cost-beneficial the next increment of energy savings becomes. This "diminishing return" aspect means that energy efficiency increases only when it makes economic sense. In contrast, no such economic limit applies to DG. In fact, costs – particularly for rooftop solar PV – are expected to decline over time. *Although regulators have been willing to accept a relatively limited amount of cost shifting to promote utility investments in energy efficiency (about 2-3 percent of rates, on average), they are unlikely to accept the magnitude of cost shifting that will accompany the rapid expansion in net-metered DG unless some reforms to net metering are put into place.*[8]

ALTERNATIVE APPROACHES TO END COST SHIFTING DUE TO NET METERING

Three basic approaches to net metering are under examination across the nation, each of which seeks to ensure that a DG customer using grid services pays its fair share of the costs of those services while still receiving fair compensation for the excess energy that it produces:

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7 "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations." Pamela Morgan, Graceful Systems LLC. February 2013.

8 Distributed generation and net metering were very hot topics at the Summer 2013 NARUC meetings with at least five panel discussions addressing them.

- Redesign retail tariffs such that they are more cost-reflective (including adoption of one or more demand charges);
- Charge the DG customer for its gross consumption under its current retail tariff and separately compensate the customer for its gross (*i.e.,* total on-site) generation; and
- Impose transmission and distribution (T&D) "standby" charges on DG customers.

These three approaches are illustrative and are further described below.

Redesign Retail Tariffs (APS Proposal). To address the fundamental issue that a residential customer with rooftop solar should be compensated at a fair rate for the power it exports (sells) to the grid and also pay a fair price for its use of grid services, APS is proposing two options.[9] The first option requires the customer to take service under an existing demand-based rate schedule. The demand charge would cover a reasonable portion of the cost of grid services.

The second option allows the customer to choose an existing APS rate schedule for its total electric consumption and APS will purchase all of the customer's rooftop solar generation at market-based wholesale rates. This option ensures recovery of grid services and sends more accurate price signals to DG customers. It is also conceptually very close to what Austin Energy has already put in place.

Treat On-site Generation and Consumption Separately (Austin Energy Tariff). Austin Energy has implemented a solar tariff that fully compensates its DG customers for their gross on-site generation while separately charging them for their gross consumption under its existing retail tariff.[10] This approach effectively ensures that the cost of grid services are recovered from DG customers while also compensating DG customers for their generation at the utility's full avoided cost of procuring energy. The Public Utility Regulatory Policies Act (PURPA), under Title II, provides an established precedent for such compensation.[11] This approach requires a separate meter for on-site generation.

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9 APS conversation, July 2013.

10 Rabago, K.R., *The 'Value Of Solar' Rate: Designing An Improved Residential Solar Tariff*, Solar Industry, February, 2013. Available at www.solarindustrymag.com.

11 Although PURPA only applies to generating resources that are Qualified Facilities (QFs), this condition has not been applied if the customer receives a credit on its electric bill, rather than a monetary payment for its generated energy.

Implement T&D Standby Charges for DG Customers (**Dominion Tariff).** Dominion requires a residential net-metered DG customer with a solar installation whose rated output is greater than 10kW and up to 20kW, to pay a monthly transmission standby charge of $1.40 per kW and a monthly distribution standby charge of $2.79 per kW. However, these standby charges are respectively reduced, dollar for dollar, by the customer's transmission and distribution charges that are recovered through kWh charges applied to the customer's monthly electricity consumption up to the point where each standby charge is fully phased out. This became effective on April 1, 2012. Dominion also proposed a placeholder for a future generation standby charge, but it was not approved. The Commission ruled that a generation standby charge should be studied and filed in a future proceeding.

A FINAL THOUGHT

In light of the rapid growth in net-metered DG, it is critical that these customers pay their fair share of the cost of grid services provided to them – and sooner rather than later. Updating net metering policies to put an end to the cost shifting that is occurring today should be done now.

About IEE

IEE is an Institute of The Edison Foundation focused on advancing the adoption of innovative and efficient technologies among electric utilities and their technology partners that will transform the power grid. IEE promotes the sharing of information, ideas, and experiences among regulators, policymakers, technology companies, thought leaders, and the electric power industry. IEE also identifies policies that support the business case for adoption of cost-effective technologies. IEE's members are committed to an affordable, reliable, secure, and clean energy future.

IEE is governed by a Management Committee of electric industry Chief Executive Officers. IEE members are the investor-owned utilities that represent about 70% of the U.S. electric power industry. IEE has a permanent Advisory Committee of leaders from the regulatory community, federal and state government agencies, and other informed stakeholders. IEE has a Strategy Committee of senior electric industry executives and 30 smart grid techology company partners.

Visit us at: **www.edisonfoundation.net/IEE**

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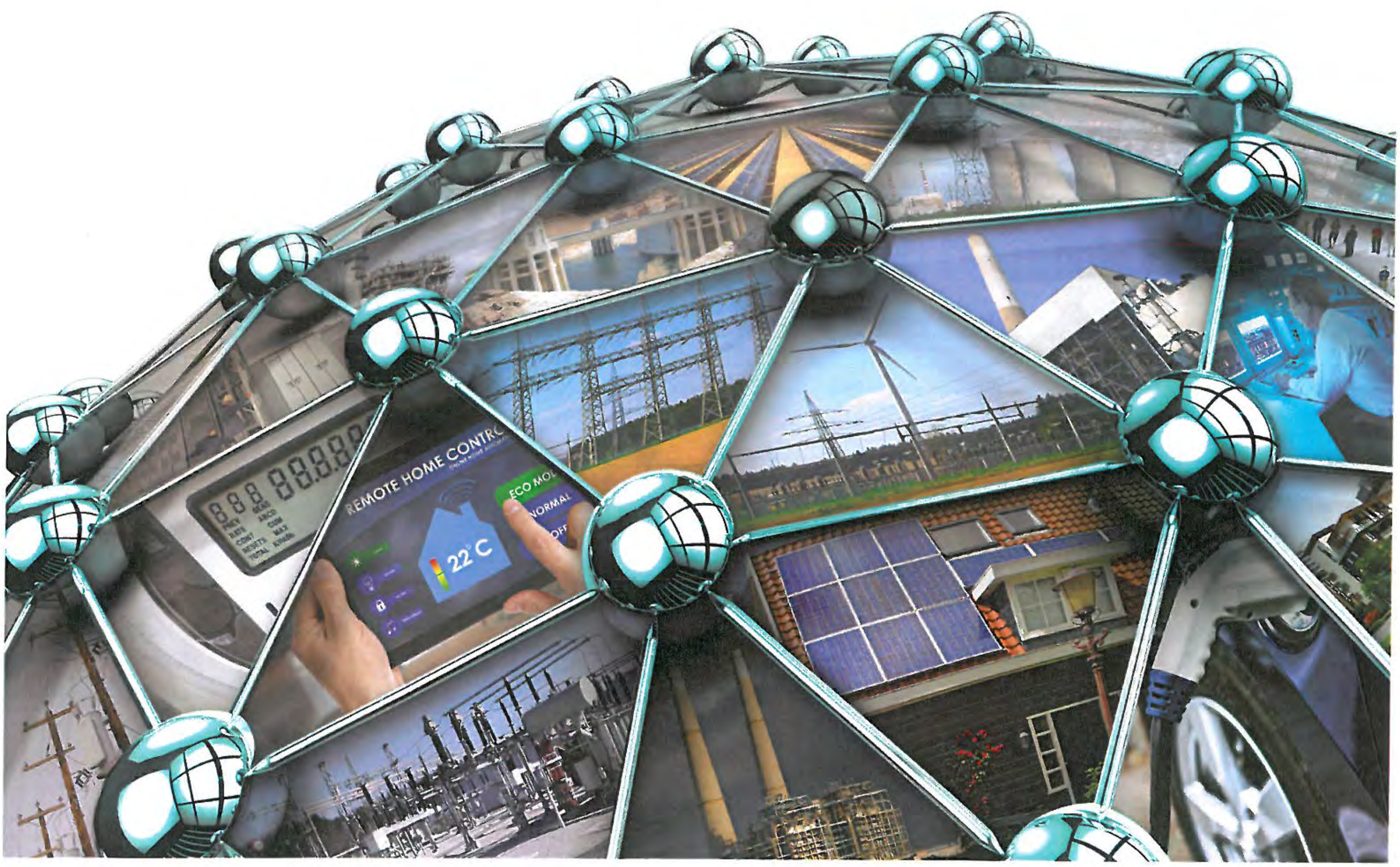
THE INTEGRATED GRID

REALIZING THE FULL VALUE OF CENTRAL AND DISTRIBUTED ENERGY RESOURCES



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Executive Summary

The electric power system has evolved through large, central power plants interconnected via grids of transmission lines and distribution networks that feed power to customers. The system is beginning to change—rapidly in some areas—with the rise of distributed energy resources (DER) such as small natural gas–fueled generators, combined heat and power plants, electricity storage, and solar photovoltaics (PV) on rooftops and in larger arrays connected to the distribution system. In many settings DER already have an impact on the operation of the electric power grid. Through a combination of technological improvements, policy incentives, and consumer choices in technology and service, the role of DER is likely to become more important in the future.

The successful integration of DER depends on the existing electric power grid. That grid, especially its distribution systems, was not designed to accommodate a high penetration of DER while sustaining high levels of electric quality and reliability. The technical characteristics of certain types of DER, such as variability and intermittency, are quite different from central power stations. To realize fully the value of distributed resources and to serve all consumers at established standards of quality and reliability, the need has arisen to integrate DER in the planning and operation of the electricity grid and to expand its scope to include DER operation—what EPRI is calling *the Integrated Grid*.

The grid is expected to change in different, perhaps fundamental ways, requiring careful assessment of the costs and opportunities of different technological and policy pathways. It also requires attention to the reality that the value of the grid may accrue to new stakeholders, including DER suppliers and customers.

This paper is the first phase in a larger Electric Power Research Institute (EPRI) project aimed at charting the transformation to the Integrated Grid. Also under consideration will be new business practices based on technologies, systems, and the potential for customers to become more active participants in the power system. Such information can support prudent, cost-effective investment in grid modernization and the integration of DER to enable energy efficiency, more responsive demand, and the management of variable generation such as wind and solar.[1]

Along with reinforcing and modernizing the grid, it will be essential to update interconnection rules and wholesale market and retail rate structures so that they adequately value both capacity and energy. Secure communications systems will be needed to connect DER and system operators. As distributed resources penetrate the power system more fully, a failure to plan for these needs could lead to higher costs and lower reliability.

Analysis of the Integrated Grid, as outlined here, should not favor any particular energy technology, power system configuration, or power market structure. Instead, it should make it possible for stakeholders to identify optimal architectures and the most promising configurations —recognizing that the best solutions vary with local circumstances, goals, and interconnections.

Because local circumstances differ, this paper illustrates how the issues that are central to the Integrated Grid are playing out in different power systems. For example, Germany's experience illustrates consequences for price, power quality, and reliability when the drive to achieve a high penetration of distributed wind and PV results in outcomes that were not fully anticipated. As a result, German policymakers and utilities now are changing interconnection rules, grid expansion plans, DER connectivity requirements, wind and PV incentives, and operations to integrate distributed resources.

In the United States, Hawaii has experienced a rapid deployment of distributed PV technology that is challenging the power system's reliability. In these and other jurisdictions, policymakers are considering how best to recover the costs of an integrated grid from all consumers that benefit from its value.

[1] *This paper is about DER, but the analysis is mindful of the ways that DER and grid integration could affect energy efficiency and demand response as those could have large effects as well on the affordability, reliability, and environmental cleanliness of the grid.*

Action Plan

The current and projected expansion of DER may significantly change the technical, operational, environmental, and financial character of the electricity sector. An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration in the following four key areas:

1. Interconnection Rules and Communications Technologies and Standards
   - ***Interconnection rules*** that preserve voltage support and grid management
   - ***Situational awareness*** in operations and long-term planning, including rules of the road for installing and operating distributed generation and storage devices
   - Robust ***information and communication technologies***, including high-speed data processing, to allow for seamless interconnection while assuring high levels of cyber security
   - A ***standard language and a common information model*** to enable interoperability among DER of different types, from different manufacturers, and with different energy management systems
2. Assessment and Deployment of Advanced Distribution and Reliability Technologies
   - ***Smart inverters*** that enable DER to provide voltage and frequency support and to communicate with energy management systems [1]
   - ***Distribution management systems and ubiquitous sensors*** through which operators can reliably integrate distributed generation, storage, and end-use devices while also interconnecting those systems with transmission resources in real time [2]
   - ***Distributed energy storage and demand response***, integrated with the energy management system [3]
3. Strategies for Integrating DER with Grid Planning and Operation
   - ***Distribution planning and operational processes*** that incorporate DER
   - ***Frameworks for data exchange and coordination*** among DER owners, distribution system operators (DSOs), and organizations responsible for transmission planning and operations
   - Flexibility to ***redefine roles and responsibilities*** of DSOs and independent system operators (ISOs)
4. Enabling Policy and Regulation
   - ***Capacity-related costs*** must become a distinct element of the cost of grid-supplied electricity to ensure long-term system reliability
   - ***Power market rules*** that ensure long-term adequacy of both energy and capacity
   - ***Policy and regulatory framework*** to ensure that costs incurred to transform to an integrated grid are allocated and recovered responsibly, efficiently, and equitably
   - ***New market frameworks*** using economics and engineering to equip investors and other stakeholders in assessing potential contributions of distributed resources to system capacity and energy costs

Next Steps for EPRI and Industry

EPRI has begun work on a three-phase initiative to provide stakeholders with information and tools that will be integral to the four areas of collaboration outlined above:

- **Phase I** – A concept paper (this document) to align stakeholders on the main issues while outlining real examples to support open fact-based discussion. Input and review were provided by various stakeholders from the energy sector including utilities, regulatory agencies, equipment suppliers, non-governmental organizations (NGOs), and other interested parties.
- **Phase II** – This six-month project will develop a framework for assessing the costs and benefits of the combinations of technology that lead to a more integrated grid. This includes recommended guidelines, analytical tools, and procedures for demonstrating technologies and assessing their unique costs and benefits. Such a framework is required to ensure consistency in the comparison of options and to build a comprehensive set of data and information that will inform the Phase III demonstration program. Phase II output will also support policy and regulatory discussions that may enable integrated grid solutions.
- **Phase III** – Conduct global demonstrations and modeling using the analytics and procedures developed in Phase II to provide comprehensive data and information that stakeholders will need for the system-wide implementation of integrated grid technologies in the most cost-effective manner.

Taken together, Phases II and III will help identify the technology combinations that will lead to cost-effective and prudent investment to modernize the grid while supporting the technical basis for DER interconnection requirements. Additionally, interface requirements that help define the technical basis for the relationship between DER owners, DSOs, and transmission system operators (TSOs) or ISOs will be developed. Finally, the information developed, aggregated, and analyzed in Phases II and III will help identify planning and operational requirements for DER in the power system while supporting the robust evaluation of the capacity and energy contribution from both central and distributed resources.

The development of a consistent framework supported by data from a global technology demonstration and modeling program will support cost-effective, prudent investments to modernize the grid and the effective, large-scale integration of DER into the power system. The development of a large collaborative of stakeholders will help the industry move in a consistent direction to achieve an integrated grid.

Key Points – The Integrated Grid

Several requirements are recognized when defining an integrated grid. It must enhance electrical infrastructure, must be universally applicable, and should remain robust under a range of foreseeable conditions:

- Consumers and investors of all sizes are installing DER with technical and economic attributes that differ radically from the central energy resources that have traditionally dominated the power system.
- So far, rapidly expanding deployments of DER are *connected* to the grid but not *integrated* into grid operations, which is a pattern that is unlikely to be sustainable.
- Electricity consumers and producers, even those that rely heavily on DER, derive significant value from their grid connection. Indeed, in nearly all settings the full value of DER requires grid connection to provide reliability, virtual storage, and access to upstream markets.
- DER and the grid are not competitors but complements, provided that grid technologies and practices develop with the expansion of DER.
- We estimate that the cost of providing grid services for customers with distributed energy systems is about $51/month on average in the typical current configuration of the grid in the United States; in residential PV systems, for example, providing that same service completely independent of the grid would be four to eight times more expensive.
- Increased adoption of distributed resources requires interconnection rules, communications technologies and standards, advanced distribution and reliability technologies, integration with grid planning, and enabling policy and regulation.
- Experience in Germany provides a useful case study regarding the potential consequences of adding extensive amounts of DER without appropriate collaboration, planning, and strategic development.
- While this report focuses on DER, a coherent strategy for building an integrated grid could address other challenges such as managing the intermittent and variable supply of power from utility-scale wind and solar generators.

Today's Power System

Today's power system was designed to connect a relatively small number of large generation plants with a large number of consumers. The U.S. power system, for example, is anchored by ~1,000 gigawatts (GW) of central generation on one end, and on the other end are consumers that generally do not produce or store energy [4] [5]. Interconnecting those is a backbone of high-voltage transmission and a medium- and low-voltage distribution system that reaches each consumer. Electricity flows in one direction, from power plants to substations to consumers, as shown in Figure 1. Even with increasing penetration, U.S. distributed resources account for a small percent of power production and consumption and have not yet fundamentally affected that one-way flow of power.

Energy, measured in kilowatt-hours (kWh), is delivered to consumers to meet the electricity consumption of their lighting, equipment, appliances, and other devices, often called *load*. *Capacity* is the maximum capability to supply and deliver a given level of energy at any point in time. *Supply capacity* comprises networks of generators designed to serve load as it varies from minimum to maximum values over minutes,

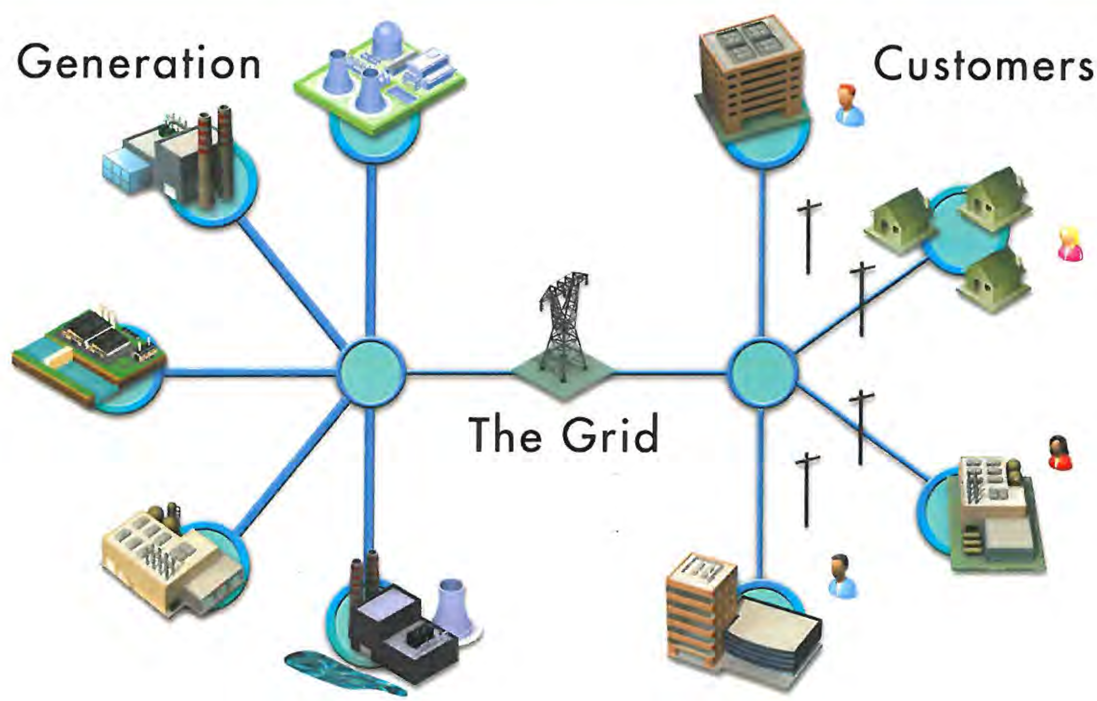

Figure 1: Today's Power System Characterized by Central Generation of Electricity, Transmission, and Distribution to End-Use Consumers.

hours, days, seasons, etc. *Delivery capacity* is determined by the design and operation of the power transmission and distribution systems that deliver the electricity to consumers. The system's supply and delivery capacity plan is designed to serve the expected instantaneous maximum demand over a long-term planning horizon.

Because the whole grid operates as a single system in real time and the lead times for building new resources are long, planning is essential to ensuring the grid's adequacy. Resource adequacy planning determines the installed capacity required to meet expected load with a prescribed reserve margin that considers potential planned and unplanned unavailability of given generators. In addition to providing sufficient megawatts to meet peak demand, the available generation (along with other system resources) must provide specific operating capabilities to ensure that the system operates securely at all times. These ancillary services include frequency regulation, voltage support, and load following/ramping. As a practical matter, the reliability of grid systems is highly sensitive to conditions of peak demand when all of these systems must operate in tandem and when reserve margins are smallest.

Today's power system has served society well, with average annual system reliability of 99.97% in the United States, in terms of electricity availability [6]. The National Academy of Engineering designated electrification enabled by the grid as the top engineering achievement of the twentieth century. Reliable electrification has been the backbone of innovation and growth of modern economies. It has a central role in many technologies considered pivotal for the future, such as the internet and advanced communications.

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The Growth in Deployment of Distributed Energy Resources

The classic vision of electric power grids with one-way flow may now be changing. Consumers, energy suppliers, and developers increasingly are adopting DER to supplement or supplant grid-provided electricity. This is particularly notable with respect to distributed PV power generation—for example, solar panels on homes and stores—which has increased from approximately 4 GW of global installed capacity in 2003 to nearly 128 GW in 2013 [7]. In Germany, the present capacity of solar generation is approximately 36 GW, while the daily system peak demand ranges from about 40 to 80 GW. By the end of 2012, Germany's PV capacity was spread across approximately 1.3 million residences, businesses, and industries and exceeded the capacity of any other single power generation technology in the country [8]. This rapid spread of DER reflects a variety of public and political pressures along with important changes in technology. This paper focuses on system operation impacts as DER reaches large scales.

By the end of 2013, U.S. PV installations had grown to nearly 10 GW. Although parts of the U.S. have higher regional penetration of PV, this 10 GW represents less than 2% of total installed U.S. generation capacity [9], which matches German PV penetration in 2003 (Figure 2). With PV growth projected to increase in scale and pace over the next decade, now is the time to consider lessons from Germany and other areas with high penetration of distributed resources.

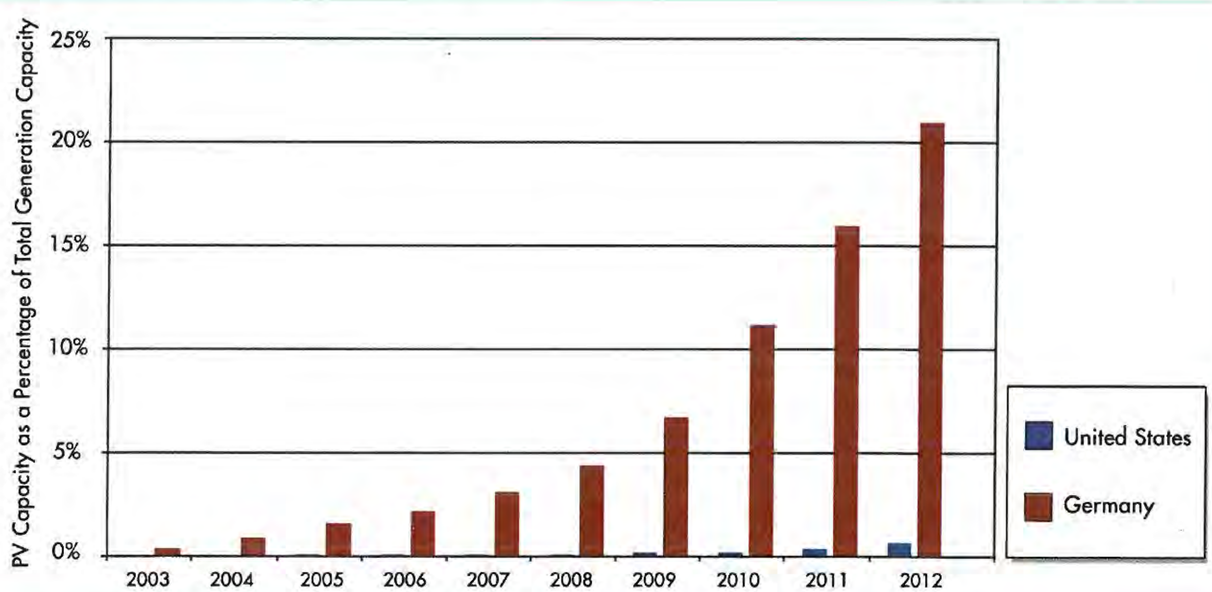

Figure 2: U.S. PV Capacity as a Percentage of Total Capacity Compared with Germany at the Beginning of Its "Energy Transformation."

In addition to Germany, high penetration of distributed PV is evident in California, Arizona, and Hawaii and in countries such as Italy, Spain, Japan, and Australia [7]. Beyond PV, other distributed resources are expanding and include such diverse technologies as batteries for energy storage, gas-fired micro-generators, and combined heat and power (CHP) installations—often referred to as *cogeneration*. In the United States natural gas prices and the cost and efficiency of gas-fired technologies have made these options effectively competitive with retail electricity service in some regions, for some consumers [10]. In jurisdictions where power prices are high, even more costly DER such as solar PV can be competitive with grid-supplied power.

In most cases, grid-connected DER benefit from the electrical support, flexibility, and reliability that the grid provides, but they are not integrated with the grid's operation. Consequently, the full value of DER is not realized with respect to providing support for grid reliability, voltage, frequency, and reactive power.

Distributed PV power generation has increased from approximately 4 GW of global installed capacity in 2003 to nearly 128 GW in 2013.

Germany's Experience: More Distributed but Not Integrated

The circumstances surrounding Germany's extensive deployment of distributed solar PV and wind offers important lessons about the value of planning for integration of DER, both economic and technical. Germany's experience is unique for these reasons:

- Germany represents a large interconnected grid with extensive ties with other grids, which is similar to the U.S. and other countries.
- The penetration of DER over the past decade is substantial (~68 GW of installed capacity of distributed PV and wind generation over 80 GW of peak load). The observed results, in terms of reliability, quality, and affordability of electricity, are not based on a hypothetical case or on modeling and simulations.
- This growth in penetration of DER occurred without considering the integration of these resources with the existing power system.
- Germany has learned from this experience, and the plan for continuing to increase the deployment of solar PV and wind generation hinges on many of the same integrated grid ideas as outlined in this paper.

German deployment was driven by policies for renewable generation that have commanded widespread political support. PV and wind generation are backed by the German Renewable Energy Sources Act (EEG), which stipulates feed-in tariffs[2] (FIT) for solar power installations. This incentive, which began in 2000 at €0.50/kWh ($0.70/kWh) for a period of 20 years, has stimulated major deployment of distributed renewable generation.

In the meantime, electricity rates have increased in Germany, for various reasons, to an average residential rate in 2012 of €0.30/kWh ($0.40/kWh), more than doubling residential rates since 2000 [8]. These higher electricity rates and lower costs for DER, due to technology advancements and production volume, have turned the tables in Germany. Today, the large FIT incentives are no longer needed, or offered, to promote new renewable installations.[3]

Notably, the desire to simultaneously contain rising electricity rates while promoting deployment of renewable energy resources has led to an evolution in German incentive policy for distributed renewable generation. For residential PV the FIT has dropped from ~ €0.50/kWh in 2000 to ~ €0.18/kWh today. An electricity price greater than the FIT has resulted in a trend of self-consumption of local generation. To ensure that all customers are paying for the subsidy for PV, the German cabinet in January 2014 approved a new charge on self-consumed solar power. Those using their own solar-generated electricity will be required to pay a €0.044kWh ($0.060/kWh) charge. Spain is considering similar rate structures to ensure that all customers equitably share the cost. Still to be resolved is how grid operating and infrastructure costs will be recovered from all customers who utilize the grid with increasing customer self-generation.

Technical repercussions have resulted from DER's much larger share of the power system. Loss of flexibility in the

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[2] *Feed-in tariffs are a long-term guaranteed incentive to resource owners based on energy production (in kWh), which is separately metered from the customer's load.*

[3] *PV installations commissioned in July 2013 receive €0.104 to €0.151/kWh ($0.144 to $0.208/kWh) for a period of 20 years.*

generation fleet prompted the operation of coal plants on a "reliability-must-run" basis. Distributed PV was deployed with little time to plan for effective integration. Until the last few years and the advent of grid codes, PV generators were not required to respond to grid operating requirements or to be equipped to provide grid support functions, such as reactive power management or frequency control. Resources were located without attention to the grid's design and power flow limitations. The lack of coordination in planning and deploying DER increases the cost of infrastructure upgrades for all customers and does not provide the full value of DER to power system operation. Rapid deployments have led to several technical challenges:

1. Local over-voltage or loading issues on distribution feeders. Most PV installations in Germany (~80%) are connected to low-voltage circuits, where it is not uncommon for the PV capacity to exceed the peak load by three to four times on feeders not designed to accommodate PV. This can create voltage control problems and potential overloading of circuit components [11].
2. Risk of mass disconnection of anticipated PV generation in the event of a frequency variation stemming from improper interconnection rules.[4] This could result in system instability and load-shedding events [12]. The same risk also exists from both a physical or cyber security attack.
3. Resource variability and uncertainty have disrupted normal system planning, causing a notable increase in generation re-dispatch[5,6] events in 2011 and 2012 [13].
4. Lack of the stabilizing inertia from large rotating machines that are typical of central power stations[7] has raised general concern for maintaining the regulated frequency and voltage expected from consumers, as inverter-based generation does not provide the same inertial qualities [14].

[4] *Distributed PV in Germany initially was installed with inverters that are designed to disconnect the generation from the circuit in the event of frequency variations that exceed 50.2 Hz in their 50 Hz system. Retrofits necessary to mitigate this issue are ongoing and are estimated to cost approximately $300 million [12].*

[5] *German transmission system operator Tennett experienced a significant increase in generation re-dispatch events in 2011 and 2012 relative to previous years. Generation scheduling changes are required to alleviate power flow conditions on the grid or resource issues that arise on short notice rather than in the schedule for the day.*

[6] *While the primary driver to re-dispatch issues has been a reduced utilization of large nuclear generators, the increase in wind generation and PV in Germany is expected to continue changing power flow patterns.*

[7] *Many DER connect to the grid using inverters, rather than the traditional synchronous generators. Increasing the relative amount of distributed and bulk system inverter-based generation that displaces conventional generation will negatively impact system frequency performance, voltage control and dynamic behavior if the new resources do not provide compensation of the system voltage and frequency support.*

Smart inverters capable of responding to local conditions or requests from the system operator can help avoid distribution voltage issues and mass disconnection risk of DER. This type of inverter was not required by previous standards in Germany, although interconnection rules are changing to require deployment of smart inverters. (See the highlight box below for further information.)

The rate impacts and technical repercussions observed in Germany provide a useful case study of the high risks and unintended consequences resulting from driving too quickly to greater DER expansion without the required collaboration, planning, and strategies set forth in the Action Plan. The actions in Phases II and III should be undertaken as soon as it is feasible to ensure that systems in the United States and internationally are not subjected to similar unintended consequences that may negatively impact affordability, environmental sustainability, power quality, reliability, and resiliency in the electric power sector.

Smart Inverters and Controls

With the current design emphasis on distribution feeders supporting one-way power flow, the introduction of two-way power flow from distributed resources could adversely impact the distribution system. One concern is over-voltage, due to electrical characteristics of the grid near a distributed generator. This could limit generation on a distribution circuit, often referred to as *hosting capacity*. Advanced inverters, capable of responding to voltage issues as they arise, can increase hosting capacity with significantly reduced infrastructure costs [15], [16].

German Grid Codes

In Germany, grid support requirements are being updated so that distributed resources can be more effectively integrated with grid operation [17], [18]. These requirements, called *grid codes,* are developed in tandem with European interconnection requirements recommended by the European Network of Transmission System Operators (ENTSO-E) [19], [20]:

1. Frequency control is required of all generators, regardless of size. Instead of disconnecting when the frequency reaches 50.2 Hz, generator controls will be required to gradually reduce the generators' active power output in proportion to the frequency increase (Figure 3). Other important functions, such as low-voltage ride-through, are also required at medium voltage.

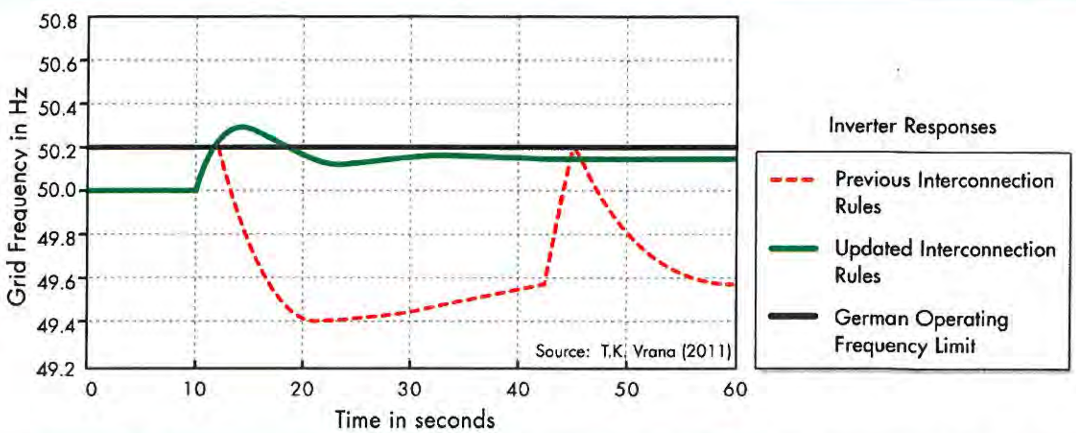

Figure 3: Example of Improved Performance with Inverter Controls That Implement a Droop Function for Over-Frequency Conditions Rather Than Tripping.

2. Voltage control functions are required from inverters, depending on the requirements of the DSO. Control methods include fixed power-factor operation, variable power factor as a function of active power, or reactive power management to provide voltage control.
3. Communication and energy management functions are now required of distributed resources, receiving commands from the system operator for active and reactive power management. As of 2012, this capability is required for all installations greater than 30 kVA. Systems less than 30 kVA without this capability are limited to 70% of rated output.

Germany is requiring that all existing inverters with a capacity greater than 3.68 kVA be retrofitted to include the droop function rather than instantly tripping with over-frequency. The cost of the retrofit associated with this function is estimated to be $300 million.

While necessary, these steps are probably still not enough to allow full integration of DER into the grid. Significant investment in the grid itself will be needed, including development of demand response resources (for example, electric transportation charging stations with time of use tariffs), and various energy storage systems. Also needed are markets and tariffs that value capacity and replacement of fossil-fueled heating plants with electric heating to take advantage of excess PV and wind capacity. German energy agency DENA determined that German distribution grids will require investment of €27.5 billion to €42.5 billion ($38.0 billion to $58.7 billion) by 2030. This includes expanding distribution circuits between 135,000 km and 193,000 km [21]. Extensive research is under way to develop and evaluate technologies to improve grid flexibility and efficiency with even more renewable capacity.

Assessing the Cost and Value of Grid Services

An electric grid connection, in ways different from a telephone line, provides unique and valuable services. Thirty percent of landline telephone consumers have canceled this service, relying solely on cellular service [22]. In contrast, virtually all consumers that install distributed generation remain connected to the grid. The difference is that the cellular telephone network provides functionality approximately equal to landline service, while a consumer with distributed generation will still need the grid to retain the same level of service. Unlike a cell phone user, operating without interconnection to this grid will require significant investment for on-site control, storage, and redundant generation capabilities.

This section characterizes the value of grid service to consumers with DER, along with calculations illustrating costs and benefits of grid connection. Subsequent sections focus on the value that DER can provide to the grid. In the context of value, it is important to distinguish the difference between value and cost. Value reflects the investments that provide services to consumers. It guides planning and investment decisions so that benefits equal or exceed costs. The costs that result are recovered through rates that, in a regulated environment, are set to recover costs, not to capture the full value delivered.

Value of Grid Service: Five Primary Benefits

Often, the full value of a grid connection is not fully understood. Grid-provided energy (kWh) offers clearly recognized value, but grid connectivity serves roles that are important beyond providing energy. Absent redundancy provided by the grid connection, the reliability and capability of the consumer's power system is diminished. Grid capacity provides needed power for overload capacity, may absorb energy during over-generation, and supports stable voltage and frequency. The primary benefits of grid connectivity to consumers with distributed generation are shown in Figure 4 and are described below.

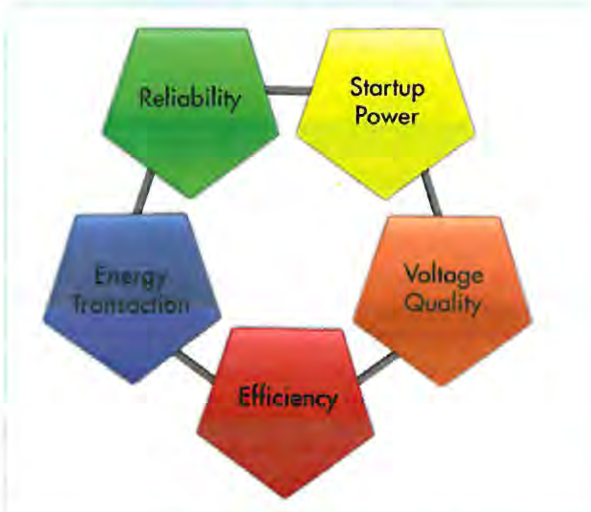

Figure 4: Primary Benefits of Grid Connectivity to Consumers with Distributed Generation.

1. **Reliability** – The grid serves as a reliable source of high-quality power in the event of disruptions to DER. This includes compensating for the variable output of PV and wind generation. In the case of PV, the variability is not only diurnal, but as shown in Figure 5, overcast conditions or fast-moving clouds can cause fluctuation of PV-produced electricity. The grid serves as a crucial balancing resource available for whatever period—from seconds to hours to days and seasons—to offset variable and uncertain output from distributed resources. Through instantaneously balancing supply and demand, the grid provides electricity at a consistent frequency. This balancing extends beyond real power, as the grid also ensures that the amount of reactive power in the system balances load requirements and ensures proper system operation.[8]

The need for reliability is fundamental to all DER, not just variable and intermittent renewable sources. For example, a customer depending solely on a gas-fired generator, which has an estimated reliability of 97%, is projected to experience 260 hours of power outage [23] compared with the 140 minutes of power outage that U.S. grid consumers experience on average (excluding major events such as hurricanes) [6]. Improvements in reliability are generally achieved through redundancy. With the grid, redundant capacity can be pooled among multiple consumers, rather than each customer having to provide its own backup resources. This reduces the overall cost of reliability for each customer [23].

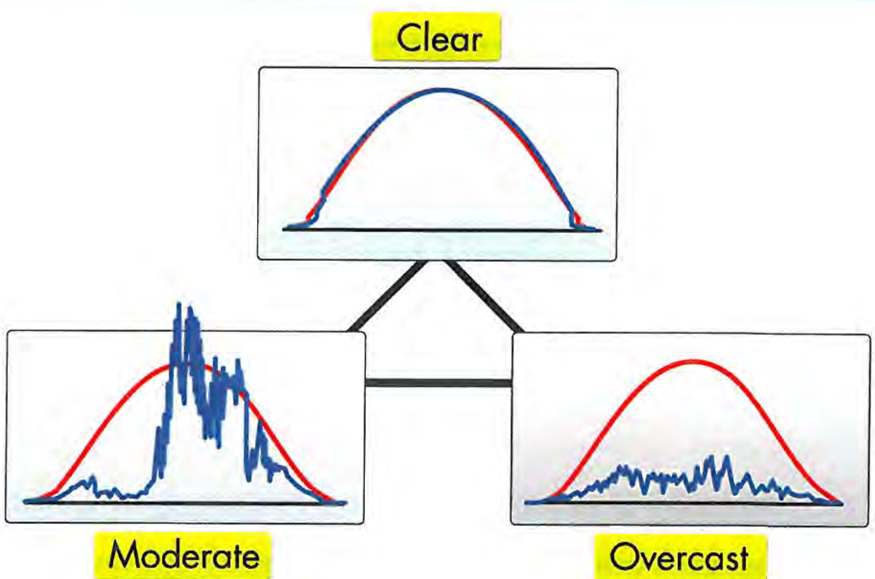

Figure 5: The Output of PV Is Highly Variable and Dependent on Local Weather.

[8] *Consumer loads typically require two different kinds of power, both real and reactive. Real power is a function of the load's energy consumption and is used to accomplish various tasks. Reactive power is transferred to the load during part of the cycle and returned during the other part, doing no work. Balancing both real and reactive power flow is a necessary function of a reliable electric grid.*

2. **Startup Power** – The grid provides instantaneous power for appliances and devices such as compressors, air conditioners, transformers, and welders that require a strong flow of current ("in-rush" current) when starting up. This enables them to start reliably without severe voltage fluctuation. Without grid connectivity or other supporting technologies,[9] a conventional central air conditioning compressor relying only on a PV system may not start at all unless the PV system is oversized to handle the in-rush current. A system's ability to provide this current is directly proportional to the fault contribution level.[10] Even if a reciprocating engine distributed generator is used as support, its fault level is generally five times less than the grid's [23]. The sustained fault current from inverter-based distributed resources is limited to the inverter's maximum current and is an order of magnitude lower than the fault level of the grid.

Figure 6 illustrates the instantaneous power required to start a residential air conditioner. The peak current measured during this interval is six to eight times the standard operating current [24]. While the customer's PV array could satisfy the real power requirements of the heating, ventilating, and air conditioning (HVAC) unit during normal operation, the customer's grid connection supplies the majority of the required starting power.

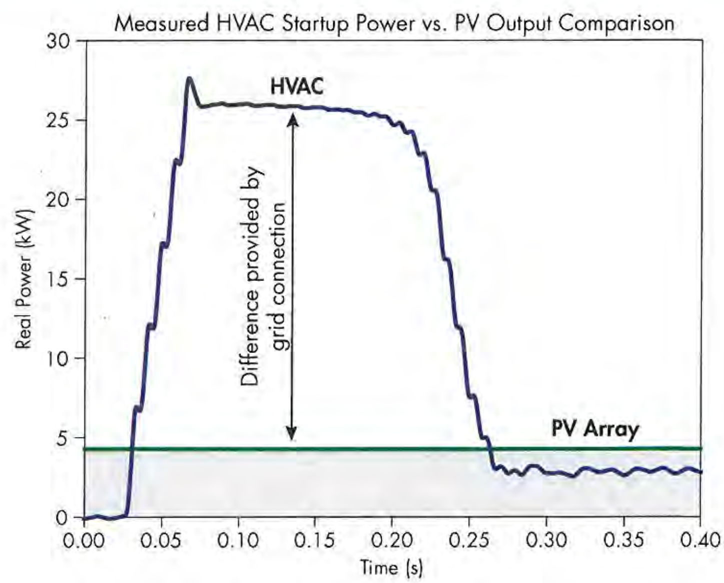

Figure 6: The Grid Provides In-Rush Current Support for Starting Large Motors, Which May Be Difficult to Replicate with a Distributed Generator.

[9] *Supporting technologies include variable-frequency drive (VFD) systems, which are able to start motors without the in-rush current common in "across-the-line" starting [24].*

[10] Fault level *is a measure of the current that would flow at a location in the event of short circuit. Typically used as a measure of electrical strength, locations with a high fault level are typically characterized by improved voltage regulation, in-rush current support, and reduced harmonic impact. Locations with a low fault level are more susceptible to voltage distortion and transients induced by harmonic-producing loads.*

3. **Voltage Quality** – The grid's high fault current level also results in higher quality voltage by limiting harmonic distortion[11] and regulating frequency in a very tight band, which is required for the operation of sensitive equipment. Similarly, the inherent inertia of a large connected system minimizes the impact of disturbances, such as the loss of a large generator or transmission line, on the system frequency. As shown in Figure 7, grid-connected consumers on average will experience voltage that closely approximates a sinusoidal waveform with very little harmonic distortion.

   In contrast, voltage from a distributed system that is not connected to the grid will generally have a higher voltage harmonic distortion, which can result in malfunction of sensitive consumer end-use devices. Harmonics cause heating in many components, affecting dielectric strength and reducing the life of equipment, such as appliances,[12] motors, or air conditioners [25]. Harmonics also contribute to losses that reduce system efficiency. In addition, a disturbance occurring inside the unconnected system will create larger deviations in frequency than if the system maintained its connection to the larger grid.

4. **Efficiency** – Grid connectivity enables rotating-engine-based generators to operate at optimum efficiency. Rotating-engine-based distributed resources, such as micro-turbines or CHP systems are most efficient when operating steadily near full output [26]. This type of efficiency curve is common for any rotating machine, just as automobiles achieve the best gasoline mileage when running at a steady optimal speed. With grid

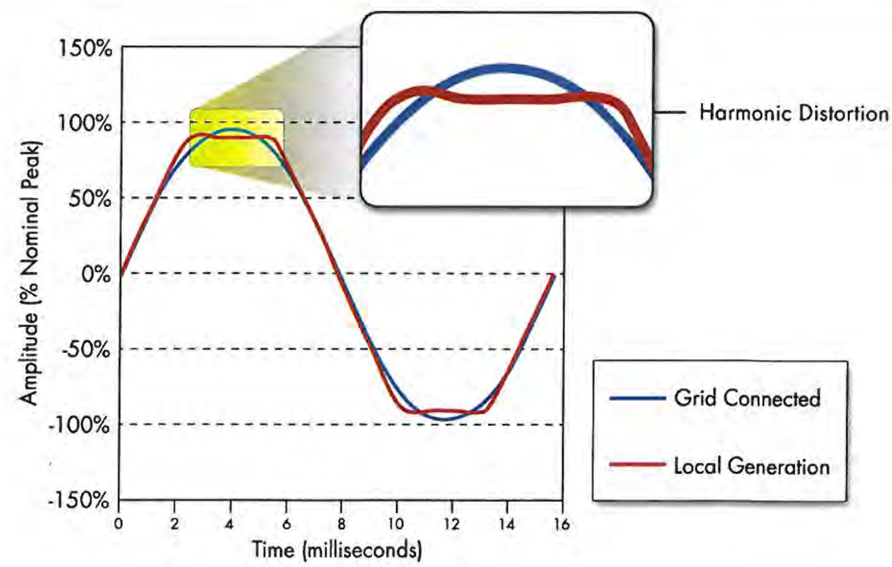

Figure 7: The Grid Delivers High-Quality Power with Minimal Harmonic Distortion.

[11] Harmonics *are voltages or currents that are on the grid, but do not oscillate with the main system frequency (60Hz in the United States). The magnitude of the harmonics, when compared to the magnitude of the 60Hz component, is referred to as the* harmonic distortion.

[12] *Technological improvements are available, such as uninterruptible power supplies (UPS), that reduce the sensitivity of loads to poor power quality, but at an additional cost.*

connectivity, a distributed energy resource can always run at its optimum level without having to adjust its output based on local load variation. Without grid connectivity, the output of a distributed energy resource will have to be designed to match the inherent variation of load demand. This fluctuating output could reduce system efficiency as much as 10%–20% [26].

5. **Energy Transaction** – Perhaps the most important value that grid connectivity provides consumers, especially those with distributed generation, is the ability to install any size DER that can be connected to the grid. A utility connection enables consumers to transact energy with the utility grid, getting energy when the customer needs it and sending energy back to the grid when the customer is producing more than is needed. This benefit, in effect, shifts risks with respect to the size of the energy resource from the individual user to the party responsible for the resources and operation of the grid. Simulated system results for such transactions are provided in Figure 8.

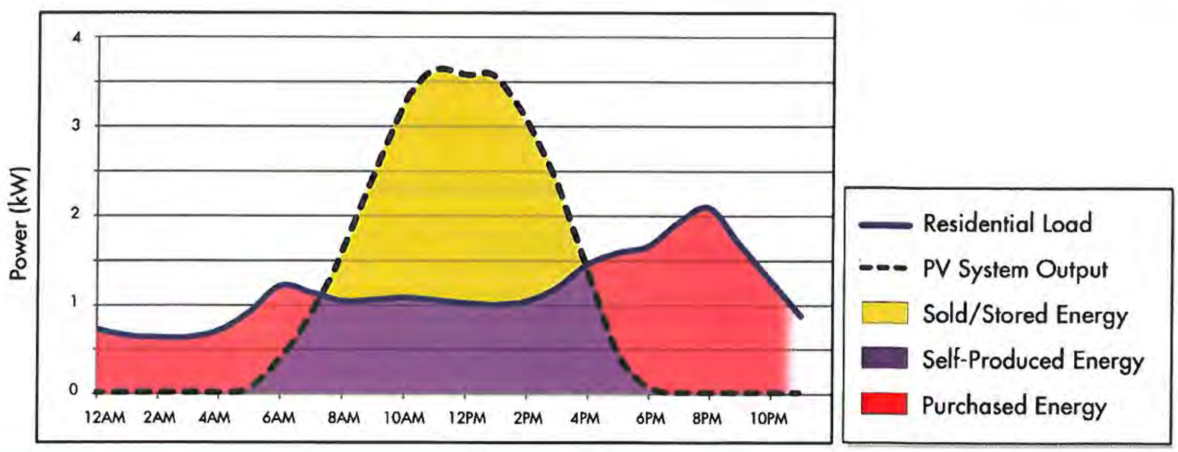

Figure 8: Because Residential Load and PV System Output Do Not Match, Owners of Distributed Generation Need the Grid for Purchasing or Selling Energy Most of the Time.

Cost of Grid Service: Energy and Capacity Costs

For residential customers, the cost for generation, transmission, and distribution components can be broken down as costs related to serve the customer with *energy* (kWh) and costs related to serve the customer with *capacity* that delivers the energy and grid-related services. The five main benefits of grid connectivity discussed in the previous section span both capacity and energy services. Figure 9 shows that, based on the U.S. Department of Energy's *Annual Energy Outlook 2012*, an average customer consumes 982 kWh per month, paying an average bill of $110 per month, with the average cost of $70 for generation of electricity. That leaves $30 for the distribution system and $10 for the transmission system [27]—known together as "T&D". These are average values, and costs vary among and within utilities and across different types of customers. (See *Appendix A* for explanation of calculations in this section.)

The next step in the analysis is to allocate these costs (generation and T&D) into fractions that are relevant for analyzing how the grid works with DER. In this analysis we focus on capacity and grid-related services because they are what enable robust service even for customers with DER. Indeed, consumers with distributed generation may not consume any net energy (kWh) from the grid, yet they benefit from the same grid services as consumers without distributed generation.

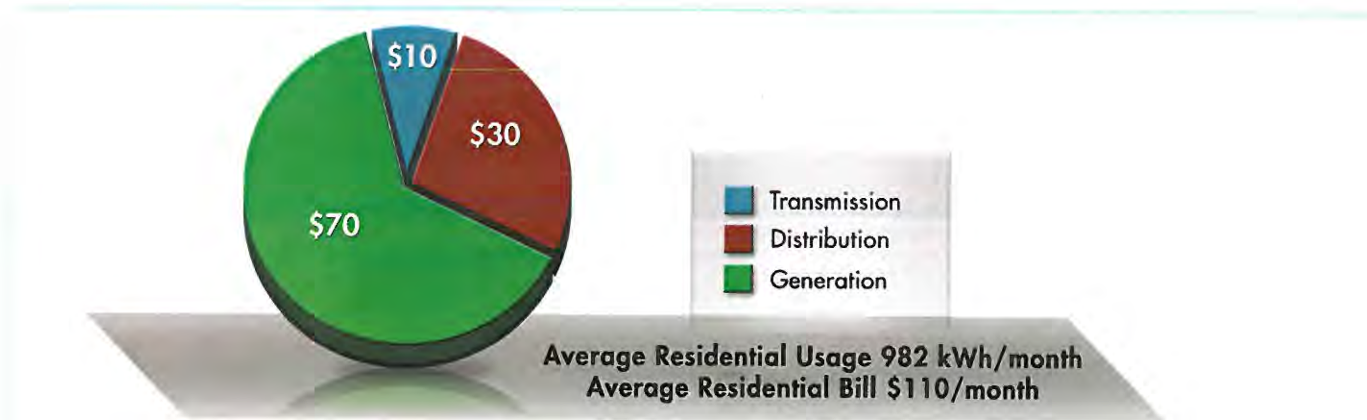

Figure 9: Cost of Service Breakdown for Today's Grid-Connected Residential Customer [27].

Calculating the total cost of capacity follows the analysis summarized in Figure 10. These values are based on the assumption that most costs associated with T&D are related to capacity (except for a small fraction representing system losses—estimated to be $3 per month per customer from recent studies in California) [28]. Working with recent data from PJM [29] regarding the cost of energy, capacity, and ancillary services it is possible to estimate that 80% of the cost of generation is energy related, leaving the rest for capacity and grid services. This 80-20 split will depend on the market and in the case of a vertically integrated utility will depend on the characteristics of the generation assets and load profile, but it is a useful average figure with which some illustrative calculations follow.

As illustrated, the combination of transmission, distribution, and the portion of generation that provides grid support averages $51/month, while energy costs average $59/month. These costs vary widely across the United States and among consumers and also will vary with changes in generation profile and the deployment of new technologies such as energy storage, demand response-supplied capacity, and central generation. The values are shown to illustrate that capacity and energy are both important elements of cost and should be recovered from all customers who use capacity and energy resources. Customers with distributed generation may offset the energy cost by producing their own energy, but as illustrated in previous sections, they still utilize the non-energy services that grid connectivity provides.

Figure 10: In Considering the Value of the Integrated Grid, Costs of Generation, Transmission, and Distribution Can Be Further Determined for Energy and Capacity.

Cost of Service Without Grid Connectivity

Technologies are available that enable consumers to self-generate and disconnect from the grid. To estimate the capacity-related cost for such investments, a simplified analysis examined a residential PV system. The analysis was based on estimating the additional costs of providing the five services that grids offer—as outlined earlier in this section. For illustration, consider a residential PV system that is completely disconnected from the grid, amortized over 20 years, and presented as a monthly cost. Reinforcing the system for an off-grid application required the following upgrades:

- Additional PV modules beyond the requirements for offsetting annual energy consumption in order to survive periods of poor weather
- Multi-day battery storage with a dedicated inverter capable of operating in an off-grid capacity
- Backup generator on the premises designed to operate for 100 hours per year
- Additional operating costs, including inverter replacement and generator maintenance

In simulation, the cost to re-create grid-level service without a grid connection ranges from \$275–\$430 per month *above* that of the original array. Expected decreases in the cost of battery and PV module technology could reduce this to \$165–\$262 within a decade. Further information on this analysis is provided in Appendix A. Costs for systems based on other technologies, or larger deployments such as campus-scale microgrids, could be relatively lower, based on economies of scale. However, even if amortized capital costs are comparable to grid services, such isolated grids will result in deteriorating standards of reliability and quality of electricity service and could require extensive use of backup generators whose emissions negatively impact local air quality.

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Enabling Policy and Regulation

A policy and regulatory framework will be needed to encourage the effective, efficient, and equitable allocation and recovery of costs incurred to transform to an integrated grid. New market frameworks will have to evolve in assessing potential contributions of distributed and central resources to system capacity and energy costs. Such innovations will need to be anchored in principles of equitable cost allocation, cost-effective and socially beneficial investment, and service that provides universal access and avoidance of bypass.

As discussed, the cost of supply and delivery capacity can account for almost 50% of the overall cost of electricity for an average residential customer. Traditionally, residential rate structures are based on metered energy usage. With no separate charge for capacity costs, the energy charge has traditionally been set to recover both costs. This mixing of fixed and variable cost recovery is feasible when electricity is generated from central stations, delivered through a conventional T&D system, and used with an electromechanical meter that measures energy use only by a single entity [30] [31].

Most residential (and some commercial) rate designs follow this philosophy, but the philosophy has not been crisply articulated nor reliably implemented for DER. Consequently, consumers that use distributed resources to reduce their grid-provided energy consumption significantly but remain connected to the grid, may pay significantly less than the costs incurred by the utility to provide capacity and grid connectivity. In effect, the burden of paying for that capacity can potentially shift to consumers without DER [32].

A logical extension of the analysis provided here, as well as many other studies that look at DER under different circumstances, is that as DER deploy more widely, policy makers will need to look closely at clearly separating how customers pay for actual energy and how they pay for capacity and related grid services.

A policy and regulatory framework will be needed to encourage the effective, efficient, and equitable allocation and recovery of costs incurred to transform to an integrated grid.

Realizing the Value of DER Through Integration

The analysis of capacity-related costs (including the cost of ancillary services) in the previous sections is based on today's snapshot of the components that make up the grid and is also based on a minimum contribution from DER to reduce the capacity cost. With increasing penetration of variable generation (distributed and central), it is expected that capacity- and ancillary service-related costs will become an increasing portion of the overall cost of electricity [33].

However, with an integrated grid there is an opportunity for DER to contribute to capacity and ancillary services that will be needed to operate the grid. The following considerations will affect whether and how DER contribute to system capacity needs:

- **Delivery Capacity** – The extent to which DER reduce system delivery capacity depends on the expected output during peak loading of the local distribution feeder, which typically varies from the aggregate system peak. If feeder peak demand occurs after sunset, as is the case with many residential feeders, local PV output can do nothing to reduce feeder capacity requirements. However, when coupled with energy storage resources dedicated to smoothing the intermittent nature of the resources, such resources could significantly reduce capacity need. Similarly, a smart inverter, integrated with a distribution management system, may be able to provide distributed reactive power services to maintain voltage quality.
- **Supply Capacity** – The extent to which DER reduce system supply capacity depends on the output expected during high-risk periods when the margin between available supply from other resources and system demand is relatively small. If local PV production reduces high system loads during summer months but drops significantly in late evening prior to the system peak, it may do little to reduce system capacity requirements. Conversely, even if PV production drops prior to evening system peaks, it may still reduce supply capacity requirements if it contributes significantly during other high-risk periods such as shoulder months when large blocks of conventional generation are unavailable due to maintenance. Determining the contribution of DER to system supply capacity requires detailed analysis of local energy resources relative to system load and conventional generation availability across all periods of the year and all years of the planning horizon.

With an integrated grid there is an opportunity for DER to contribute to capacity and ancillary services.

- **System Flexibility** – As distributed variable generation is connected to the grid, it may also impact the nature of the system supply capacity required. Capacity requirements are defined by the character of the demand they serve. Distributed resources such as PV alter electricity demand, changing the distributed load profile. PV is subject to a predictable diurnal pattern that reduces the net load to be served by the remaining system. At high levels, PV can alter the net load shape, creating additional periods when central generation must "ramp" up and down to serve load. Examples are early in the day when the sun rises and PV production increases and later, as the sun sets, when PV output drops, increasing net load. The net load shape also becomes characterized by abrupt changes during the day, as when cloud conditions change significantly.
- **Integration of DER Deployment in Grid Planning** – Adequacy of delivery and supply capacity are ensured through detailed system planning studies to understand system needs for meeting projected loads. In order for DER to contribute to meeting those capacity needs in the future, DER deployment must be included in the associated planning models. Also, because DER are located in the distribution system, certain aspects of distribution, transmission, and system reliability planning have to be more integrated. (Read more in the section, *Importance of Integrated Transmission and Distribution Planning and Operation for DER*.)
- **DER Availability and Sustainability over the Planning Horizon** – For either delivery or supply capacity, the extent to which DER can be relied upon to provide capacity service and reduce the need for new T&D and central generation infrastructure depends on planners' confidence that the resource will be available when needed across the planning horizon. To the extent that DER may be compensated for providing capacity and be unable or unwilling to perform when called upon, penalties may apply for non-performance.

In addition to altering the system daily load curve, wind and solar generation's unscheduled, variable output will require more flexible generation dispatch. For example, lower cost and generally large and less operationally flexible plants today typically carry load during the day. These resources may have to be augmented by smaller and more flexible assets to manage variability; however, this flexibility to handle fast ramping conditions comes with a cost. [34] [35] The potential for utilizing demand response or storage should not be overlooked, as rapid activation (on the order of seconds or minutes) could provide additional tools for system operators. Improving generator scheduling and consolidating balancing areas could improve access and utilization of ramping resources, preventing the unnecessary addition of less-efficient peaking units [36].

In addition to altering the system daily load curve, wind and solar generation's unscheduled, variable output will require more flexibile generation dispatch.

Figure 11 illustrates the importance of understanding the system to determine the value of DER. The graph shows the German power system's load profile and the substantial impact of PV power generation at higher penetration [37]. In this case, the PV resource's peak production does not coincide with the system peak, and, therefore, does not contribute to an overall reduction in system peak. From the single average plots in Figure 11, it is unclear to what extent PV might contribute to system capacity needs during critical supply hours outside of absolute system peak. During system peak, which for Germany is winter nights, the ~36 GW of installed PV does not contribute to reducing that peak. This is based on the requirements of "reliably available capacity" [38], which is defined as the percentage of installed capacity that is 99% likely to be available.

The ~33 GW of wind is also credited to a minor extent towards meeting the winter peak demand. Hydro power provides the bulk of the 12 GW of renewable resource that is considered as reliable available capacity to meet the 80 GW of winter peak load. However in the United States, where the PV peak coincides more with the system peak (depending on the facility's orientation, shading, and other factors), the results could be different. In general, however, PV without storage to achieve coincidence with system peak will be relatively ineffective in reducing capacity costs due to its variable, intermittent nature.

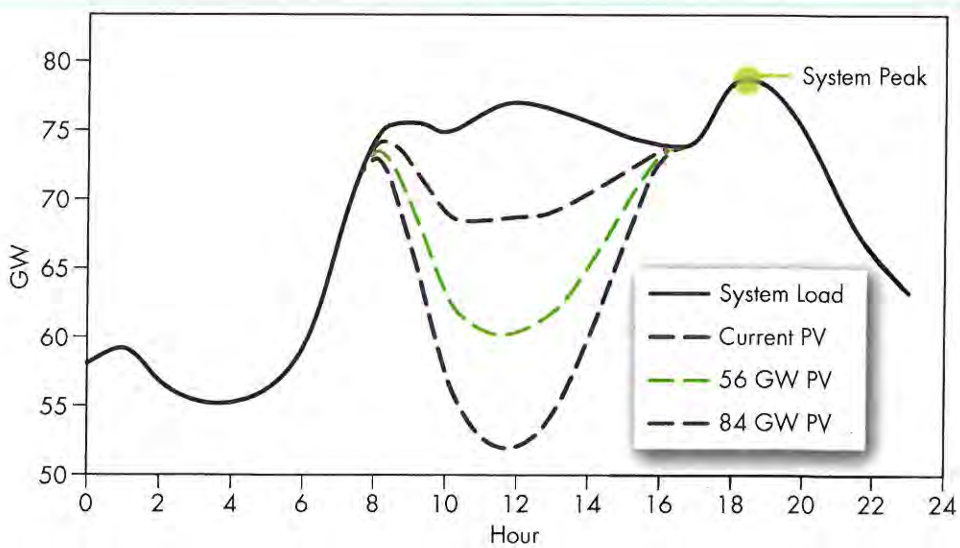

Figure 11: Peak Load Reduction and Ramp Rate Impacts Resulting from High Penetration of PV [39].

Importance of Integrated Transmission and Distribution Planning and Operation for DER

To realize their full value while ensuring power quality and reliability for all customers, DER must be included in distribution planning and operation, just as central generation resources are included in transmission planning and operation. As DER penetration increases and becomes concentrated in specific areas, their impact can extend beyond the distribution feeders to which they are interconnected, potentially affecting the sub-transmission and transmission systems. The aggregated impact of DER must be visible and controllable by transmission operators and must be included in transmission planning to ensure that the transmission system can be operated reliability and efficiently. Additionally, the T&D system operators must coordinate to expose DER owners to reliability needs and associated price signals. This will require significantly expanded coordination among T&D system planners and operators, as well as the development and implementation of new analysis tools, visualization capabilities, and communications and control methods.

Integrated T&D planning methods that include DER are not yet formalized, even in regions with high DER penetration levels such as Germany, Arizona, California, and Hawaii. Without a framework for integration into both T&D system operations, the cost of integration will increase significantly and the potential value of DER will not be fully realized. For example, DER installations in sub-optimal locations, such as the end of long feeders, may require significant feeder upgrades to avoid impacts to voltage quality. When strategically located, however, DER may require little or no upgrade of the feeder while delivering multiple benefits.

Examples of Integration of DER in Distribution Planning and Operations

The Hawaiian Electric Company (HECO) system on the island of Oahu had more than 150 MW of installed distributed PV in mid-2013. At this level of penetration, HECO has found it necessary to develop PV fleet forecasting methods, which it uses to provide operators with geographic information on expected PV output and potential impact on local feeder operations, as well as aggregate impact on system balancing and frequency performance. Additionally, HECO has developed detailed distribution feeder models that incorporate existing and expected future PV deployments for considering PV in planning. Although still in development, HECO is taking these steps to ensure reliability by integrating distributed PV into their operational and planning processes.

To realize their full value while ensuring power quality and reliability for all customers, DER must be included in distribution planning and operation, just as central generation resources are included in transmission planning and operation.

Realizing the importance of planning in DER procurement and operation, regulatory commissions in some cases have decided that distributed resource needs are best served by utility ownership or at least utility procurement of required distributed resources [40], [41]. Competitive procurement often reduces the asset cost while proper planning reduces integration costs and often maximizes the opportunity for capitalizing on multiple potential DER value streams. A recent ruling from the California Public Utilities Commission (CPUC) highlighted this consideration by requiring utilities to procure energy storage, ensuring that these resources are sufficiently planned in the context of the distribution grid [42].

Presently, most DER installations are "invisible" to T&D operators. The lack of coordination among DER owners, distribution operators, and transmission operators makes system operations more difficult, even as system operators remain responsible for the reliability and quality of electric service for all consumers. Likewise, utilities miss an opportunity to use DER, with the proper attributes, to support the grid. The expected services rendered from distributed storage in California are provided in Table 1. However, an integrated grid is required to enable many of these services, making integration beneficial to the entire system, not only to customers who own DER.

Category	Storage "End-Use"
Describes the point of use in the value chain	Describes the use or application of storage
Transmission/Distribution	Peak shaving
	Transmission peak capacity support (upgrade deferral)
	Transmission operation (short-duration performance, inertia, system reliability)
	Transmission congestion relief
	Distribution peak capacity support (upgrade deferral)
	Distribution operation (voltage/VAR support)
Customer	Outage mitigation: micro-grid
	Time-of-use (TOU) energy cost management
	Power quality
	Back-up power

Table 1: Expected T&D and Customer Services from Distributed Storage in California [43].

Realize the Benefits of Distributed Energy Resources

An integrated grid that enables a higher penetration of DER offers benefits to operators, customers, and society. These examples illustrate the diverse nature of these benefits:

- **Provide distribution voltage support and ride-through** – DER can provide distribution grid voltage and system disturbance performance by riding through system voltage and frequency disturbances to ensure reliability of the overall system, provided there are effective interconnection rules, smart inverters, or smart interface systems.
- **Optimize distribution operations** – This can be achieved through the coordinated control of distributed resources and the use of advanced inverters to enhance voltage control and to balance the ratio of real and reactive power needed to reduce losses and improve system stability.
- **Participate in demand response programs** – Combining communication and control expands customer opportunities to alter energy use based on prevailing system conditions and supply costs. Specifically with respect to ancillary services, connectivity and distribution management systems facilitate consumer participation in demand response programs such as dynamic pricing, interruptible tariffs, and direct load control.
- **Improve voltage quality and reduced system losses** – Included in this are improved voltage regulation overall and a flatter voltage profile, while reducing losses.
- **Reduce environmental impact** – Renewable distributed generation can reduce power system emissions, and an integrated approach can avoid additional emissions by reducing the need for emissions-producing backup generation. Also contributing will be the aggregation of low-emissions distributed resources such as energy storage, combined heat and power, and demand response.
- **Defer capacity upgrades** – With proper planning and targeted deployment, the installation of DER may defer the need for capacity upgrades for generation, transmission, and/or distribution systems.
- **Improve power system resiliency** – Within an integrated grid, distributed generation can improve the power system's resiliency, supporting portions of the distribution system during outages or enabling consumers to sustain building services, at least in part. Key to doing this safely and effectively is the seamless integration of the existing grid and DER.

Figure 12 illustrates a concept of an integrated grid with DER in residences, campuses, and commercial buildings networked as a distributed energy network and described in a recent EPRI report [44].

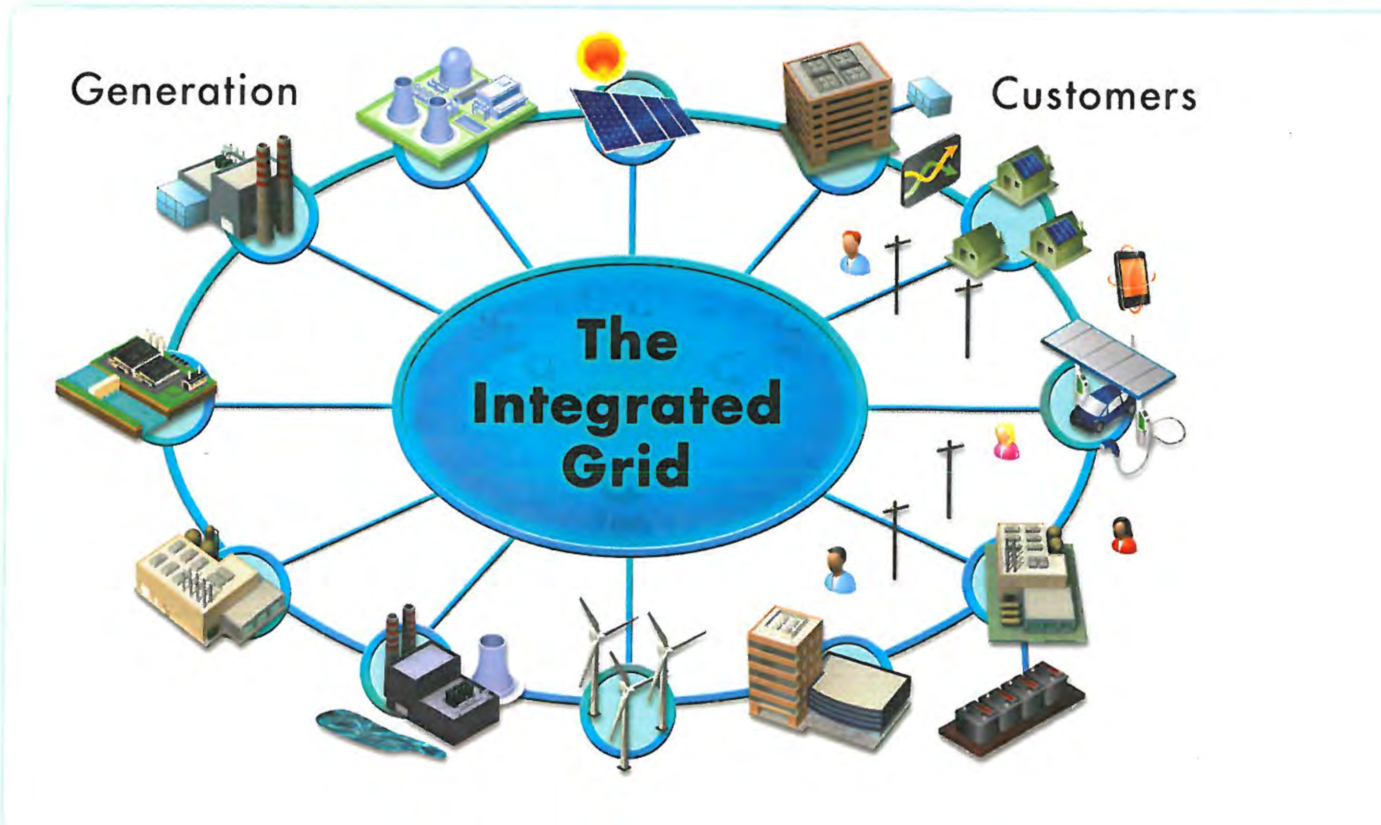

Figure 12: Creating an Architecture with Multi-Level Controller [44].

Grid Modernization: Imperative for the Integrated Grid

Grid modernization of the distribution system will include re-conductoring, and augmenting its infrastructure along with deploying smart technologies such as distribution management systems (DMS), communication, sensors, and energy storage is a key component of moving to the Integrated Grid. It is anticipated that this combination of infrastructure reinforcement and smart technology deployment can yield the lowest-cost solution for a given penetration level of DER in a feeder.

Table 2 shows a menu of technology options for the DSO side, the consumer side, and the integration of the two that will enable a distribution feeder to reliably integrate greater DER penetration [45], [46]. The solutions, which have been outlined and evaluated by others in the industry, are organized as follows:

- System operator solutions are those actions that the DSO could take to bolster the performance and reliability of the system where DER deployment is growing.
- Interactive solutions are those that require close coordination between the system operator and DER owner and generally provide the operator the ability to interact with the DER owner's system to help maintain reliable system operation.
- DER owner solutions are those that could be employed at the customer end of the system through installation of technology or operational response measures.

A comprehensive understanding of each approach is beyond the scope of this paper but is an important element of EPRI's proposed work. Assuming that any grid investment will be paid for by customers, it is important to determine if, and under what situations, such investments may prove cost-effective and in the public interest.

The coordinated demonstration of each option outlined in Table 2 across different types of distribution system feeders can help provide a knowledge repository that stakeholders can use to determine the prudence of the various investments needed to achieve an integrated grid. Such demonstrations also can provide information essential for all stakeholders regarding rules of engagement among DER owners, DSOs, TSOs, and ISOs.

No one entity has the resources to conduct the demonstrations and the associated engineering analysis to document costs, benefits, and performance of all technology options across all types of distribution feeders. EPRI proposes using its collaborative approach globally to develop a comprehensive repository of data and information that can be used to move toward the Integrated Grid.

System Operator Solutions	Interactive Solutions	DER Owner Solutions
Network reinforcement	Price-based demand response	Local storage
Centralized voltage control	Direct load control	Self-consumption
Static VAR compensators	On-demand reactive power	Power factor control
Central storage	On-demand curtailment	Direct voltage control
Network reconfiguration	Wide-area voltage control	Frequency-based curtailment

Table 2: Technology Options [45], [46].

Action Plan

The current and projected expansion of DER may significantly change the technical, operational, environmental, and financial characteristics of the electricity sector. An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration in the following four key areas:

1. Interconnection Rules and Communications Technologies and Standards
   - ***Interconnection rules*** that preserve voltage support and grid management
   - ***Situational awareness*** in operations and long-term planning, including rules of the road for installing and operating distributed generation and storage devices
   - Robust ***information and communication technologies***, including high-speed data processing, to allow for seamless interconnection while assuring high levels of cyber security
   - A ***standard language and a common information model*** to enable interoperability among DER of different types, from different manufacturers, and with different energy management systems

2. Assessment and Deployment of Advanced Distribution and Reliability Technologies
   - ***Smart inverters*** that enable DER to provide voltage and frequency support and to communicate with energy management systems [1]
   - ***Distribution management systems and ubiquitous sensors*** through which operators can reliably integrate distributed generation, storage, and end-use devices while also interconnecting those systems with transmission resources in real time [2]
   - ***Distributed energy storage and demand response***, integrated with the energy management system [3]

3. Strategies for Integrating DER with Grid Planning and Operation
   - ***Distribution planning and operational processes*** that incorporate DER
   - ***Frameworks for data exchange and coordination*** among DER owners, DSOs, and organizations responsible for transmission planning and operations
   - Flexibility to ***redefine roles and responsibilities*** of DSOs and ISOs

4. Enabling Policy and Regulation
   - ***Capacity-related costs*** must become a distinct element of the cost of grid-supplied electricity to ensure long-term system reliability
   - ***Power market rules*** that ensure long term adequacy of both energy and capacity
   - ***Policy and regulatory framework*** to ensure that costs incurred to transform to an integrated grid are allocated and recovered responsibly, efficiently, and equitably
   - ***New market frameworks*** using economics and engineering to equip investors and other stakeholders in assessing potential contributions of distributed resources to system capacity and energy costs

Next Steps for EPRI

In order to provide the knowledge, information, and tools that will inform key stakeholders as they take part in shaping the four key areas supporting transformation of the power system, EPRI has begun work on a three-phase initiative.

Phase I – Develop a Concept Paper

This concept paper was developed to align stakeholders on the main issues while outlining real examples to support open fact-based discussion. Input and review was provided by various stakeholders from the energy sector including utilities, regulatory agencies, equipment suppliers, non-governmental organizations (NGOs), and other interested parties. The publication of this paper will be followed by a series of public presentations and additional topical papers of a more technical nature that will more completely analyze various aspects of the Integrated Grid and lessons learned from regions where DER penetration has increased.

Phase II – Develop an Assessment Framework

In this six-month project, EPRI will develop a framework for assessing the costs and benefits of combinations of technology that lead to an integrated grid. Such a framework is required to ensure consistency in the comparison of options and to build a resource library that will inform the Phase III demonstration program.

In order to organize a comprehensive framework, EPRI will analyze system operator, DER owner, and interactive options listed in Table 2. Since each country, state, region, utility, and feeder may have differing characteristics that lead to different optimized solutions, efforts will be made to ensure that the framework is flexible enough to accommodate these differences.

Additionally, a testing protocol will be developed in support of the Phase III global demonstration program to ensure that a representative sample of systems and solutions will be tested.

Phase III – Conduct a Global Demonstration and Modeling Program

Phase III will focus on conducting global demonstrations and modeling using the analytics and procedures developed in Phase II to provide data and information that stakeholders will need for the system-wide implementation of integrated grid technologies in the most cost-effective manner.

Using the Phase II framework and resource library, participants in Phase III can combine and integrate their various experiments and demonstrations under a consistent protocol. However, it is neither economic nor practical for an individual DSO to apply all the technological approaches across different types of distribution circuits. Therefore, Phase III, planned as a two-year effort, will present the opportunity for utilities globally to collaborate to assess the cost, benefit, performance, and operational requirements of different technological approaches to an integrated grid.

Demonstrations and modeling projects in areas where DER deployment is not expected near term will use the analytics and procedures developed in Phase II to ensure that results can provide data and information that utilities will need for planning investments in the system-wide implementation of integrated grid technologies.

With research organizations and technology providers working with distribution companies on individual demonstration projects, EPRI can work to ensure that findings and lessons learned are shared, and to consolidate the evaluations of the different approaches. The lessons learned from the real life demonstrations will be assembled in a technology evaluation guidebook, information resources, and analysis tools.

New technologies for grid modernization will continue to evolve as the transformation to an integrated grid continues in this decade and beyond. The effort outlined in Phase II and Phase III will not be a one-time event but will set the stage for ongoing technology development and optimization of the integrated grid concept. As new technology evolves, a comprehensive framework for assessment of the technology as outlined in Phases II and III can support prudent investment for grid modernization using solid scientific assessment before system-wide deployment.

An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration.

Outputs from the Three-Phase EPRI Initiative

Taken together, Phases II and III will help identify the technology combinations that will lead cost-effective and prudent investment to modernize the grid while supporting the technical basis for DER interconnection requirements. Also to be developed are interface requirements that help define the technical basis for the relationship between DER owners, DSOs, and TSOs or ISOs. The information developed, aggregated, and analyzed in Phases II and III will help identify planning and operational requirements for DER in the power system and inform policymakers and regulators as they implement enabling policy and regulation. The development of a consistent framework backed up with data from a global technology demonstration and modeling program will support cost-effective and prudent investments to modernize the grid in order to effectively integrate large amounts of DER into the existing power system.

A key deliverable from the Phase II and III efforts will be a comprehensive guidebook, analytical tools, and a resource library for evaluating combinations of technologies in distribution system circuits. In order to maximize the value of these deliverables, EPRI will seek to partner with organizations that are leading integrated grid-style analyses and demonstration projects to ensure that all have access to the full database of inputs and outputs from these important projects even if they were not directly involved in the technical work. Key components of the guidebook, analytical tools, and resource library will include:

- Comprehensive descriptions of technological approaches and how they can be applied in a distribution system
- Modeling tools and approaches required to assess the performance of the technical solutions
- Operational interface that will be required between DER owners and DSOs
- Analytics to assess the hosting capacity of distribution circuits
- Analytics to evaluate technology options and costs to support greater penetration of DER
- Analytics to characterize the value of integrated grid approaches beyond increasing feeder hosting capacity

A collaborative approach will be essential to develop the comprehensive knowledge repository of costs, benefits, performance, and operational requirements of the multitude of technical approaches that can be implemented in a given distribution feeder for a specific level of DER integration. The guidebook, analytical tools, and resource library will build on prior work of EPRI and other research organizations to develop a portfolio of solution options outlined in Table 2. They will also use the DOE/EPRI cost/benefit framework for evaluating smart grid investments as part of smart grid demonstrations around the world [47].

Conclusion

Changes to the electric power system with the rise of DER have had a substantial impact on the operation of the electric power grid in places such as Germany and Hawaii. As consumers continue to exercise their choice in technology and service, as technologies improve in performance and cost, and as federal and regional policy incentives are passed, DER could become even more pervasive.

DER deployment may provide several benefits, including reduced environmental impact, deferred capacity upgrades, optimized distribution operations, demand response capabilities, and improved power system resiliency. The successful integration of DER depends pivotally on the existing electric power grid, especially its distribution systems, which were not designed to accommodate a high penetration of DER while sustaining high levels of electric quality and reliability. Certain types of DER operate with more variability and intermittency than the central power stations on which the existing power system is based. The grid provides support that balances out the variability and intermittency while also providing other services that may be difficult to replicate locally.

An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration in the following four key areas:

1. **Interconnection Rules and Communications Technologies and Standards**
2. **Assessment and Deployment of Advanced Distribution and Reliability Technologies**
3. **Strategies for Integrating DER with Grid Planning and Operation**
4. **Enabling Policy and Regulation**

In order to provide the knowledge, information, and tools that will inform key stakeholders as they take part in shaping the four key areas supporting transformation of the power system, EPRI has begun work on a three-phase initiative:

- Phase I – Align stakeholders with a concept paper (this document).
- Phase II – Develop a framework for assessing the costs and benefits of combinations of technology that lead to an integrated grid.
- Phase III – Initiate a worldwide demonstration program to provide data to those seeking to implement integrated grid solutions.

The initiative will help identify the technology combinations that will lead to cost-effective and prudent investment to modernize the grid while supporting the technical basis for DER interconnection requirements. It will develop interface requirements to help define the technical basis for the relationship between DER owners, DSOs, and TSOs or ISOs. Finally, the information developed, aggregated, and analyzed in Phases II and III will help identify planning and operational requirements for DER in the power system while supporting the robust evaluation of the capacity and energy contribution from both central and distributed resources.

The development of a consistent framework supported by data from a global technology demonstration and modeling program will support cost-effective and prudent investments to modernize the grid and the effective, large-scale integration of DER into the power system. The development of a large collaborative of stakeholders will help the industry move in a consistent direction to achieve an integrated grid.

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Appendix A – Cost Calculations

Generation, Transmission, and Distribution vs. Cost of Energy and Capacity

Generation, transmission, and distribution breakdowns are provided from EIA estimates in ($/kWh), assuming an average customer usage of 982 kWh/month.

Generation is broken into two components (energy and capacity) based on PJM market estimates of the price breakdown: "2010 PJM Market Highlights: A Summary of Trends and Insights." 2011. http://www.pjm.com/~/media/documents/reports/20110513-2010-pjm-market-highlights.ashx

Of which, 80% was estimated as energy related, while the other 20% was attributed to capacity.

Distribution and transmission are estimated based on the following breakdown from SCE (E3 NEM Effectiveness Report): http://www.ethree.com/documents/CSI/CPUC_NEM_Draft_Report_9-26-13.pdf

Among the appendices, Southern California Edison's (SCE's) implied transmission and distribution (T&D) costs were provided. When those costs were scaled back to national average values, the percentages are provided below:

SCE Implied Cost breakdowns (when scaled to $40/month)

Cost Breakdown	$/Month	Fixed %	Variable %	Fixed ($)	Variable ($)
Customer	$14.29	100%	0%	$14.29	$-
Distribution	$15.71	90%	10%	$14.14	$1.57
Sub-transmission	$4.29	60%	40%	$2.57	$1.71
Transmission	$5.71	100%	0%	$5.71	$-
TOTAL	$40.00			$36.71	$3.29

Thus the variable (energy-based) T&D costs were taken at $3/month.

Cost of Off-Grid Residential Solutions

Cost figures reflect the additional cost to take a residence that produces 100% of its energy locally (from PV) and turn it into a self-sufficient entity that can operate without a grid connection.

These costs include the following, which are then amortized across the lifetime of the project (20 years):

- Extra PV panels (beyond the annual kWh requirement)
- Battery storage
- Charge controller
- Backup generator

Software Package: HOMER Energy (Hourly energy profile simulator)
Locations: St. Louis, MO and San Francisco, CA
Analysis includes appropriate incentives Federal ITC and net-energy-metering

Location	St. Louis, MO	San Francisco, CA
Load Profile (OpenEI)	12MWh/yr	7.67MWh/yr
Real Interest Rate	3.5% (5.5% APR – 2% inflation)	
Project Lifetime	20 years (no salvage)	
PV System (Array + Inverter) Installed Cost	\$3-\$4/W installed (after incentive) [2013] \$1.50-\$2/W installed [2020]	
Battery Cost	\$450-\$550/installed kWh [2013] \$200-\$300/installed kWh [2020]	
Generator	\$400/kW	
System Controller	\$600/kW	
System O&M	\$32/kW/yr PV system O&M + \$0.50/hr generator O&M + \$3/battery/yr	

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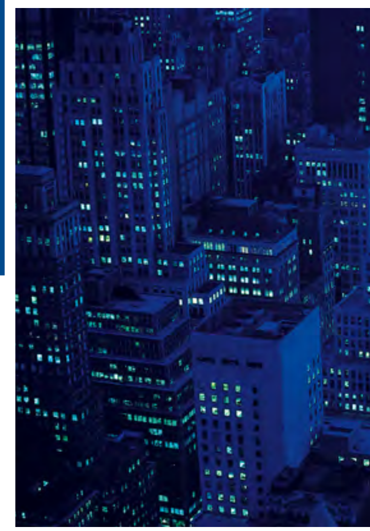

Transmission Investment

Adequate Returns and Regulatory Certainty Are Key

June 2013

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I. Executive Summary

A Robust Transmission System Is Critical to Electric Reliability

The North American electric system is comprised of a complex, interconnected network of generating plants, transmission lines, and distribution facilities. Electric utilities have interconnected their transmission systems to ensure reliability of service and to facilitate energy exchanges and other market transactions. Transmission lines link the generators of electricity to the distributors, transporting electricity to local electric utilities, which in turn deliver it to customers.

The numerous benefits of a robust transmission network are undisputed, and the nation's shareholder-owned electric utilities have a long history of making cost-effective investments in needed and beneficial transmission infrastructure. In fact, these utilities have increased their investment in transmission significantly in recent years, and are projected to spend an additional $54.6 billion on transmission infrastructure through 2015 (real $2011). At the same time, electric utilities have invested in cleaner energy sources, greater efficiency, and more resilient and flexible distribution facilities that use modern, smart technologies.

The Federal Energy Regulatory Commission (FERC or the Commission), Congress, and the Administration have determined that cost-effective, properly planned electric transmission investments are needed, and they all have taken actions in the past decade to promote investment. These investments ensure a reliable and efficient electric power grid that can promote robust competitive wholesale electric markets; reduce congestion; support delivery of renewable and cleaner energy resources; respond to emerging security threats; and safely and securely meet the needs of a 21st-century digital economy that increasingly relies on electricity.

Transmission Investment Requires Significant Capital

The electric power industry is the most capital-intensive industry in the United States, with transmission assets accounting for just one aspect of overall utility investments. In 2012, electric utilities invested $90.5 billion in generation, transmission, and distribution systems.

Compared to other assets, transmission investments are extremely risky and require long lead times for the planning process and stakeholder involvement. They also often face extensive and sometimes successful litigation on siting and related issues; in addition, cost recovery can be challenging. As a result, investors require predictable, sustainable, and reasonable returns, or they will reallocate their capital into one of the many other sectors that offer a more competitive return and less risky investments. There are many attractive investment options at this time.

The nation is in a unique economic situation, as the Federal Reserve and other government policies have reduced the cost of debt to serve important economic goals. While there often has been a consistent spread between the costs of debt and equity in the past, the electric power industry, like other domestic businesses, has seen that spread widen considerably in recent years so that the cost of equity is far higher than the traditional spread compared to the cost of debt.

Key Regulatory Policy Goals Must Be Sustained

In recent years, FERC has relied upon a discounted cash flow (DCF) financial model to determine utility cost of equity for transmission. However, that model has not been adjusted to reflect the fundamental shift between the cost of debt and equity that has occurred during the current slow economic recovery. As a result, application of the traditional DCF model can result in dramatically lower returns on equity (ROEs) for transmission investment. Such an application fails to recognize that:

- The current returns are still within the range of reasonableness;
- There is no link between record low interest rates and investors' expected return on transmission investment;
- Adequate long-term returns are important to the long-term investment in the transmission system and other policy goals.

It also does not demonstrate there is any reduction in the risks of planning, siting, and building transmission. While transmission accounts for about 11 percent of an electric customer's total bill, ROEs need to be predictable and sustainable over the long-term in order for a robust, modernized transmission system to produce savings and to promote many different policy benefits.

The Edison Electric Institute (EEI) supports a reasonable and practical solution to a strict application of these challenges. In the past, FERC, like all regulatory commissions, has adjusted its regulatory methodologies to reflect changes in economic and financial realities to ensure that ROEs remain within the range of reasonableness. It is critical that FERC stay the course and provide regulatory certainty and adequate returns by making a few simple adjustments to its analysis of the current challenges and to the DCF methodology. Otherwise, the nation's electric utilities and their investors could divert needed capital to investments with greater returns, jeopardizing transmission reliability.

II. Introduction

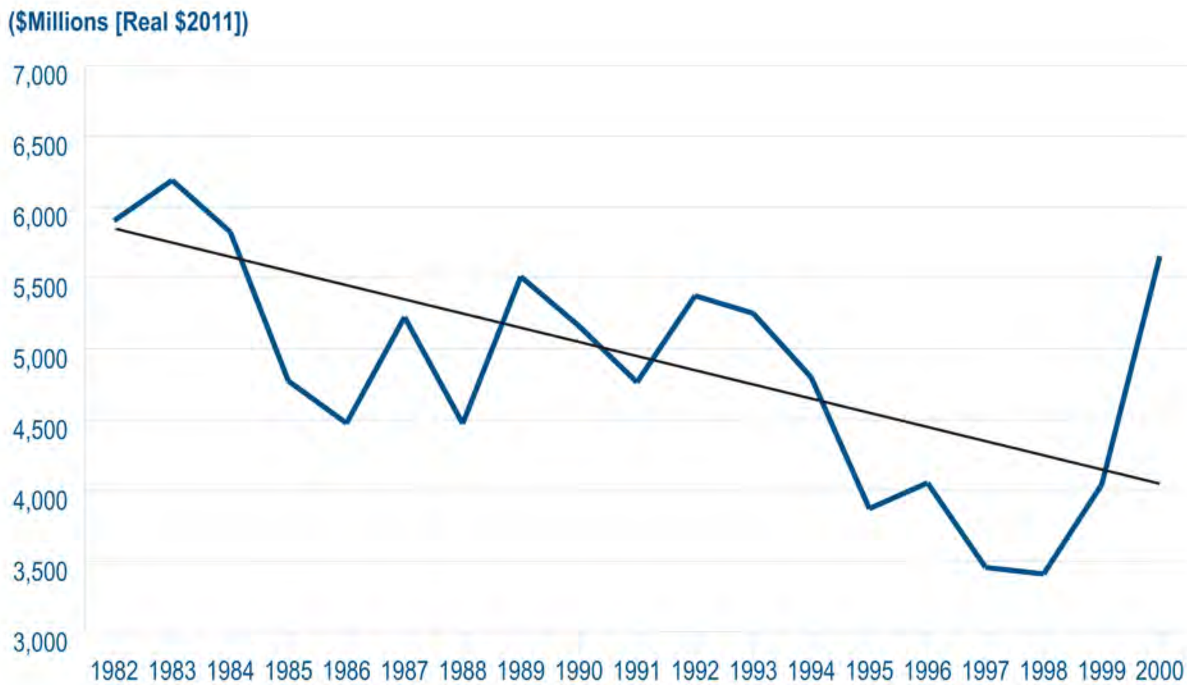
EEI's shareholder-owned electric utility members[1] are making cost-effective transmission investments to ensure that the power grid is reliable and efficient, meets 21st-century electricity needs, and supports competitive wholesale markets. There are numerous benefits of a robust transmission system, which have been recognized by Congress,[2] the Administration,[3] and FERC.[4] Recently, however, several parties have advocated for significant reductions to existing FERC-authorized returns on transmission investments. The parties raising questions rely on a narrow, mechanistic application of FERC's preferred DCF financial model for determining authorized returns during the current period of artificially low record interest rates. This kind of application can produce ROE results that are downward-biased and are insufficient to meet legal and regulatory standards;[5] moreover, such results would compromise established policy goals. These parties fail to: demonstrate that the link between the record low interest rates and investors' expected returns on transmission investment has remained constant; recognize the widespread benefits of a robust transmission network; demonstrate that the risks of developing transmission have diminished; and recognize the premise upon which historical transmission investments were made, *i.e.*, stable returns over the asset lives of the facilities.

EEI urges FERC to consider all of the benefits of transmission, as well as its importance to the Commission's policy goals and regulatory standards, in addressing these challenges by recognizing the limitations of the DCF analysis and assessing the application of the DCF methodology described herein. Over the long term, failure to retain stable and adequate returns for transmission investment that reflect the actual financial conditions influencing that investment likely will prevent the industry from attracting the necessary capital required for a 21st-century transmission grid. Ultimately, this may lead to less efficient and less cost-effective energy solutions for electricity consumers.

III. Robust Transmission Infrastructure Provides Numerous Benefits to Customers

Over the past decade, EEI members have reversed the trend of declining investment in our nation's transmission infrastructure that occurred prior to 2000, as shown in the graph below.

Historical Transmission Investment by Shareholder-Owned Electric Utilities (1982-2000)



Source: SNL Financial and EEI Finance Department

Since 2001, EEI members' year-over-year transmission investment has nearly doubled from $5.8 billion in 2001 to $11.1 billion in 2011 (real $2011).[6] These transmission investments have funded necessary projects, including several projects supported by FERC's Order No. 679,[7] which implemented Congress' directive to incentivize improvement and expansion of our nation's transmission infrastructure.

Customers receive considerable benefits from these transmission investments including:

- An assurance of U.S. electric system reliability;
- Facilitation of robust electric market competition;
- Reduced congestion and line loss costs;
- Integration of new generation resources, including renewables;[8]
- The necessary upkeep of infrastructure; and

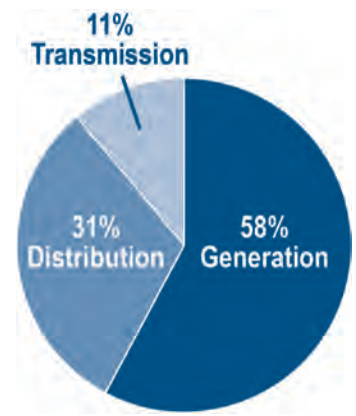
- A more resilient grid in the face of extreme weather events.

All of these benefits are provided by transmission plant, which remains the smallest portion of an electric customer's bill. On average, transmission costs are approximately 11 percent of the price of electricity when compared to generation and distribution.[9]

The benefits of robust transmission infrastructure can be seen around the country:

- Investments made by transmission owners in ISO-New England have resulted in annual savings of approximately $700 million in reduced energy and capacity market costs for electric customers.[10]
- In PJM, the Trans-Allegheny Interstate Line (TrAIL) project that entered service in 2010 resulted in a reduction of congestion costs of 50 percent, saving customers millions of dollars during 2010 and 2011.[11]
- In the MISO region, the Multi-Value Projects (MVPs) portfolio alone is expected to create thousands of jobs and provide additional energy-cost savings. Specifically, MISO estimates that the 2011 portfolio of 11 transmission projects will provide benefits between $15.6 and $49.3 billion, approximately 1.8 to 3.0 times the projected capital costs of $5.2 billion (real $2011).[12]

Major Components of U.S. Average Electricity Price, 2011



Investing in transmission infrastructure also provides grid resiliency, which helps to avoid major electricity blackouts that can result in significant economic losses. For example, due to a transmission issue starting on August 14, 2003, an estimated 50 million people in the Midwest and Northeast United States and Ontario, Canada, experienced an area-wide blackout lasting up to four days in some areas. Total estimates of business and other losses for this event ranged from $4 billion to $10 billion for the outage periods.[13]

The Need for a Robust Transmission Grid Is Undisputed

EEI believes the clear conclusion of governmental and regulatory bodies is that the public policy benefits of transmission investment are without dispute, and the need for greater transmission investments is clear.

FERC continues to articulate public policy reasons for additional investment in transmission infrastructure and recognizes the benefits of a robust transmission system. For example, with the issuance of Order No. 1000, the Commission stated that "[t]he need for additional transmission facilities is being driven, in large part, by changes in generation mix."[14] Also, FERC stated that "additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation;" and "…increased adoption of [renewable portfolio standard measures] has contributed to rapid growth of renewable energy resources that are frequently remote from load centers, and thus [increase the] need for transmission to access remote resources …."[15] This also is consistent with FERC's strategic goals (Fiscal Years 2009-2014), which state, in part, that the Commission will "[p]romote the development of safe, reliable and efficient energy infrastructure that serves the public interest" in order to fulfill its mission to "[a]ssist consumers in obtaining reliable, efficient and sustainable energy services at a reasonable cost through appropriate regulatory and market means."[16] To support this strategic goal, FERC has pursued policies to support electric transmission planning and to encourage new electric transmission facilities that advance efficient transmission system operation.[17]

In January 2011, the five sitting FERC Commissioners endorsed the need for transmission investment in a letter to the editor of *The Wall Street Journal*, disputing an editorial critical of FERC's proposed rule covering transmission planning and cost allocation. The Commissioners stated "investment in transmission promotes efficient and competitive electricity markets, which hold down prices for consumers. Transmission investment also enhances reliability and allows access to new energy resources."[18] Indeed, additional transmission investment is needed as electricity providers continue to address the evolving energy needs of our nation.

Recent extreme weather events also have highlighted the need for reinforcing and upgrading electric infrastructure.[19] In addition, the U.S. Environmental Protection Agency (EPA) is promulgating and implementing evolving regulations that are driving significant generation retirements. Managing these generation retirements will increase the need for new and upgraded transmission assets. For example, PJM recently approved more than $5 billion of transmission enhancements driven by plant retirements, generation projects switching to natural gas, and the growth of wind power projects.[20]

Moreover, transmission development to integrate and support renewable energy resources remains critical, especially those remotely located resources that need access to the market and load centers. For example, the American Wind Energy Association recently released a report highlighting that "transmission is 'extremely important' to the future of the wind industry in the United States, and as noted previously, is the 'industry's number one barrier' to integrating more wind energy."[21]

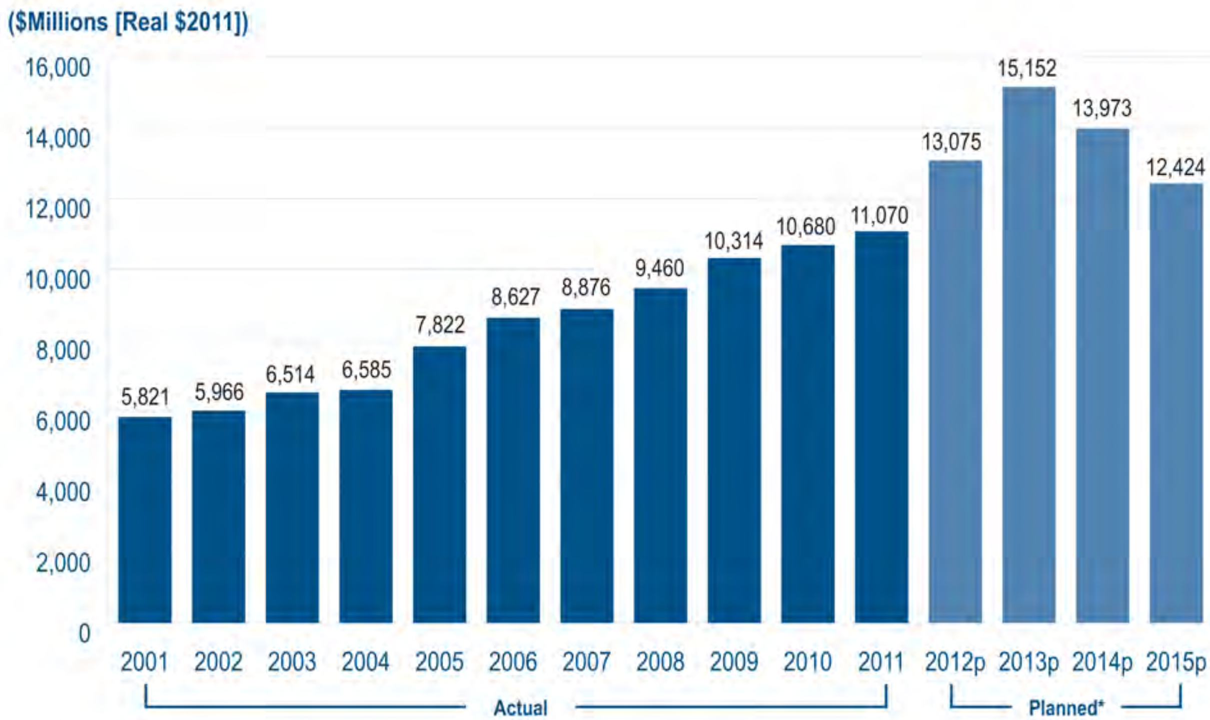
Meanwhile, the North American Electric Reliability Corporation (NERC) and FERC continue to develop and approve a growing list of mandatory standards aimed at ensuring Bulk Power System reliability, requiring incremental capital investments for all utilities that own transmission.[22] In addition, the cyber and physical security needs of the nation's critical infrastructure, including the electric grid, also require increased attention and investment.[23] While there have been increases in distributed energy resources, transmission investments still are needed to support these resources locally and in the wholesale energy markets. And, although demand response and energy efficiency may reduce electricity usage, increased customer participation does not affect the need for transmission materially. Generation resources still are needed to meet electricity demand, and transmission is needed to integrate these resources and reduce system congestion.

As the Nation's Demand for Reliable, Affordable Electricity Grows, EEI Members Remain Committed to Developing the Transmission Needed to Provide Reliable Electricity

EEI members have responded to the growing transmission needs of our nation. The graph below demonstrates EEI members' commitment to meet those needs as demonstrated by the recent increase in transmission investments. These investments have been encouraged by FERC's subsequent policies implementing the Energy Policy Act of 2005 (EPAct 2005).

In response to the sustained need for transmission investments, EEI projects that its members will invest an additional $54.6 billion in transmission through 2015 (real $2011).[24] However, planned transmission investments are affected by economic conditions, capital allocation, financial markets, and public policy objectives. Currently, EEI forecasts a decrease in transmission investment after 2013 (relative to 2013), in part because several major projects recently have been modified, delayed, or cancelled. While transmission investments by EEI members during 2014 and 2015 are anticipated to be significantly higher than in 2011, it is important to note that, given the length of time it takes to plan, permit, and build significant transmission projects (up to 10 years), the ramp up in investment reflects investment decisions made in response to policies enacted by Congress in EPACT 2005 and appropriate ROEs. These planned transmission investments are premised on ROEs that are consistent with currently authorized levels.

Actual and Planned Transmission Investment by Shareholder-Owned Electric Utilities (2001-2015)



p = preliminary
Note: The Handy-Whitman Index of Public Utility Construction Costs used to adjust actual investment for inflation from year to year. Forecasted investment data are adjusted for inflation using the GDP Deflator.
*Planned total industry expenditures are preliminary and estimated from 85% response rate to EEI's Electric Transmission Capital Budget & Forecast Survey. Actual expenditures from EEI's Annual Property & Plant Capital Investment Survey and from the FERC Form 1 reports.
Source: Edison Electric Institute, Business Information Group

Longer-term, EEI's 2013 *Transmission Projects: At A Glance* report highlights more than 150 planned transmission projects, totaling approximately $51.1 billion (nominal $) planned through 2023. These projects do not include investments in transmission upgrades or replacements to existing facilities.[25] Fifty-two percent of these projects are interstate projects, which face significant challenges for siting, permitting, cost allocation, and cost recovery from numerous federal, state, and local entities. Seventy-six percent of these projects support the integration of renewable resources, such as wind and solar.[26] These projects are critical to assisting electricity providers' cost-effective compliance with renewable portfolio standards (RPS) currently in place in 29 states and the District of Columbia.[27] For example, Southern California Edison's Tehachapi Renewable Transmission Project is expected to accommodate 4,500 megawatts (MW) of high-quality renewable resources, meeting approximately one-third of California's 33-percent RPS.[28]

While the proposed investment numbers are significant, The Brattle Group estimates that the *need* for additional transmission investment through 2030 is in the range of $240 billion to $320 billion.[29] With supportive FERC policies in place since EPAct 2005, the industry has been able to devote more capital expenditures to transmission and is moving forward to build transmission. But, much more needs to be done, and the risks and challenges of developing and building transmission have not lessened. Many projects that proposed—and needed to provide—the most significant benefits to customers, are the large regional and inter-regional, backbone projects; these projects also carry the most upfront development time, longer construction schedules, and overall risk.

As previously noted, EEI members are obligated to maintain the reliability of the electric system.[30] While EEI members take such obligations seriously, it will be increasingly challenging to ensure robust reliability if expected returns fall below those for other investments that are more attractive and less risky than transmission. Moreover, the choices of how to meet particular reliability needs are numerous, and electric utilities must make those choices within the confines of capital limitations. If ROEs for transmission are not sufficient, a utility may choose a short-term, more-local project or an alternative resource solution to maintain reliability rather than choose the riskier, more strategic option that could provide additional benefits to customers and be more cost-effective. Given the numerous risks and challenges associated with developing large-scale transmission, it is critical that returns are sufficient to encourage EEI members to focus on evaluating and building the larger, more challenging projects needed for a more robust electric grid that will provide reliability and other benefits to customers in both the short and long term.[31]

Order No. 1000 Effectiveness Relies on Continued Transmission Investments

As previously noted, in Order No. 1000, FERC recognized the benefits of a robust transmission system and the need for additional investment. Order No. 1000 establishes key regional planning and cost-allocation requirements for transmission projects. The goal of Order No. 1000 is to promote more coordinated regional planning and inter-regional planning processes to identify needed, cost-effective, transmission along with the implementation of regional cost allocation for projects that provide regional benefits.[32]

These checks and balances protect customers by ensuring that only needed, cost-effective, and efficient transmission projects that meet local and regional needs ultimately are constructed. Properly structured, these open, transparent and comprehensive processes should identify cost-saving opportunities, support robust wholesale electricity markets, and facilitate the construction of new transmission to meet reliability and public policy requirements. However, without adequate returns to support investment in needed transmission, projects evaluated in these planning processes may not be undertaken because limited capital will be invested elsewhere, likely resulting in delay or absence of projects required to address congestion, to implement public policy objectives, and to bring benefits to customers.

IV. The Risks and Challenges of Developing Transmission Have Not Diminished

Investing in transmission introduces a number of risks and challenges, including significant development risk around ultimately championing a project through the planning process,[33] financing risks, and permitting risks and challenges. Congress recognized the importance of transmission investment and the attendant risks of development when it enacted, as part of EPAct 2005, section 219 of the Federal Power Act (FPA). Congress has not amended or taken other action to diminish the importance of transmission investment since EPAct 2005, nor have project risks and challenges fundamentally changed.

Given these risks, transmission investments are unlike investments in any other utility infrastructure where the projects tend to be smaller in size, shorter in duration, and are located in one area. Due to the long-term nature of transmission projects, regulatory certainty is needed to obtain and maintain financing. With regard to financial challenges, transmission developers are frequently faced with low or negative free cash flows (internally generated cash less capital investments) for an extended period of time when embarking on transmission projects, given their heavy development costs and long lead times. These long lead times include pre-construction activities, such as development and siting approvals. Such financial challenges can put pressure on a utility's financial metrics that are used to determine interest rates and terms for accessing needed capital and may limit the ability to access capital on favorable terms. This potentially can drive up a utility's borrowing costs (if it can get access to capital at all) or limit a utility's overall capital expenditures. Since the cost of accessing capital ultimately is borne by customers, it is clearly in everyone's interest that this outcome be avoided.[34] Regulators should look for opportunities to provide certainty by maintaining and authorizing stable, long-term returns for transmission developers and owners to support timely development of beneficial and necessary transmission investments.

Prior to construction, transmission projects generally are evaluated using a Commission-approved transmission planning process, which rigorously evaluates the costs and benefits of each project, assesses the forecasted changes in regional supply and demand, and considers alternative solutions such as new generation or demand-side energy-efficiency measures.[35] Once projects are selected, they still are subject to additional evaluations as part of federal agency and state commission reviews and siting processes.

In some jurisdictions, projects also are subject to additional reviews in subsequent planning cycles and may be delayed, scaled back, or cancelled. In addition, there is a wide disparity in how different planning processes evaluate the benefits of transmission, with some jurisdictions evaluating a significant number of the benefits while others rely mainly on reliability or narrowly defined analyses. However, these reviews and benefit analyses contribute to the riskiness of developing efficient transmission projects.

Lengthy, complicated, and costly siting and permitting processes continue to be major barriers to installing new transmission lines and upgrading existing lines. Since multiple federal, state, and local government agencies often are involved in right-of-way authorizations and related environmental permitting, the lack of inter-agency coordination forms another obstacle to permitting and siting. The challenge of locating lines across states and across federal lands, coupled with targeted, strong opposition from a variety of public interest groups, make the process even more daunting. Rerouting lines occurs with regularity, which increases construction costs.

Federal agencies have agreed to coordinate permitting efforts on federal lands, and a Department of Energy (DOE)-led Rapid Response Team for Transmission has engaged in an effort to streamline the federal approvals for seven large-scale transmission projects. Yet, these efforts have not been implemented broadly yet to significantly reduce the permitting time and expedite permitting on federal lands.[36] Moreover, depending on the location, there may be demands to place transmission underground, which can increase cost and construction times dramatically.[37] This, when coupled with other things such as political challenges, exacerbates the already long lead times for developing transmission and adds another layer of financial risk.

Southern California Edison's Devers-Colorado River ("DCR") transmission line project illustrates the significant challenges that utilities face in developing transmission. The DCR project includes the construction of new 110-mile and 42-mile 500-kilovolt (kV) transmission lines and a new 500-kV switchyard to facilitate, primarily, the development of renewable generation resources. The project originally was estimated to cost $545.3 million (real $2005); however, this estimate has increased to $701.3 million (real $2005). The single largest drivers behind the cost increase are direct and indirect costs associated with extensive environmental measures, including costs for mitigation, land, and field monitors; the costs of preparing permits; notice-to-proceed requests; requests for variances and determinations of National Environmental Policy Act adequacy; addendums; project refinement reports; requests for temporary extra workspace; and the resources needed to prepare, review and process documents.

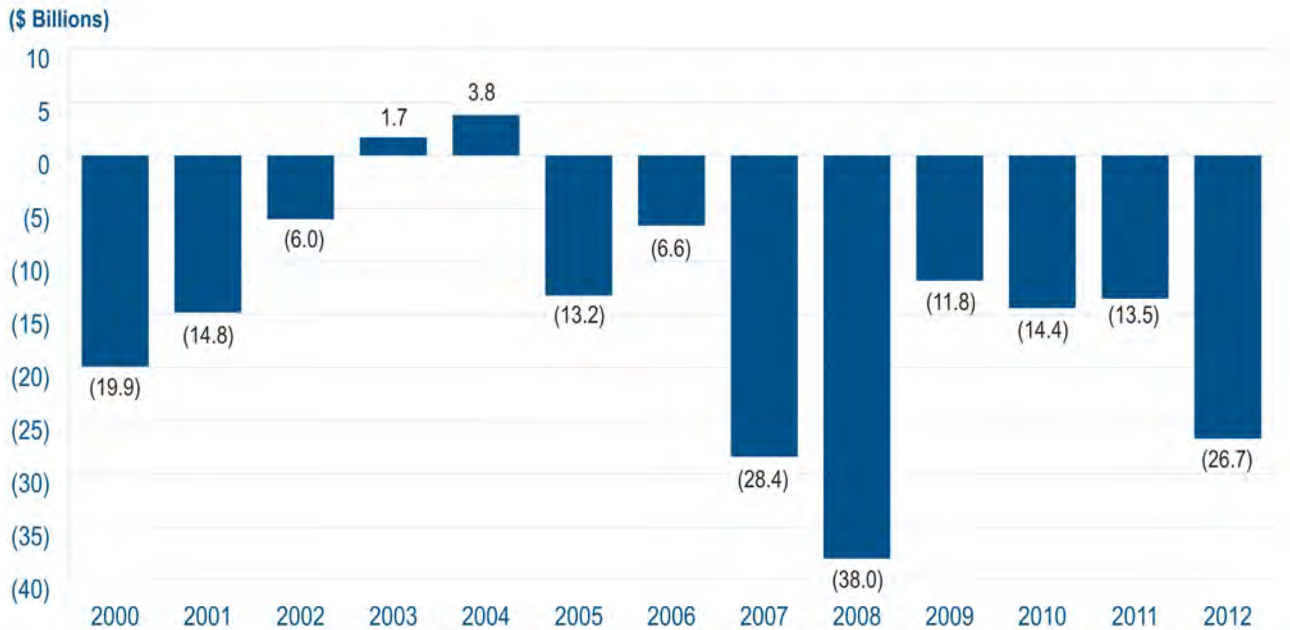
Another example of development challenges is the experience of joint-venture partners to develop the Prairie Wind project.[38] This project is a 110-mile, double-circuit 345-kV line with a projected cost of $225 million. Early in the planning stages, Prairie Wind briefly considered a route through the Red Hills area of Kansas, but rejected it due to concerns expressed by environmental groups, state and federal wildlife agencies, and landowners about a potential adverse impact on sensitive species and substantial additional costs for environmental remediation. Ultimately, the line had to be rerouted to avoid habitats of the lesser prairie chicken and a number of bat species.[39]

American Transmission Company's crossing of the Namekagon River as part of its Arrowhead-Weston 345-kV line tells a similar story. The Arrowhead-Weston Transmission Line Project is a 220-mile, 345-kV line built from Wausau, Wisconsin, to Duluth, Minnesota, to address what was at the time the second-most congested transmission seam in the Eastern Interconnection. The project needed to cross the Namekagon River, a wild and scenic river that is part of the St. Croix National Scenic Riverway, regulated by the National Park Service (NPS). Both a permit and an easement were needed prior to beginning construction. Although the river already was crossed by another utility's 161-kV line and two petroleum pipelines, obtaining the NPS permits took approximately 5.5 years and cost $3.9 million, almost twice the actual $2.0 million construction costs of the river crossing.

V. Transmission Investments Must Compete with Alternative Investment Opportunities

EEI members invested $90.5 billion in generation, transmission, and distribution systems in 2012 and are projected to invest approximately $85 billion annually through 2015 with the expectation of retaining currently existing ROEs.[40] Meanwhile, industry free cash flow, or internally generated cash flows less capital investments before financing, has been negative since 2005.[41] This requires utilities to access the equity and debt markets to fund investments. Moreover, transmission assets generate low levels of cash flows for reinvestment, since a primary source of cash flows from utility assets is depreciation, and many transmission assets are at the end of their depreciable lives. Therefore, access to equity capital in the financial markets to fund needed transmission is all the more critical as utilities work to maintain and/or expand their systems to meet customers' needs reliably and cost-effectively.

Industry Free Cash Flow



($ Billions)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Net Cash Provided by Operating Activities	42.1	55.4	56.3	57.0	58.1	50.2	69.4	61.1	61.3	82.9	77.7	84.4	84.2
Capital Expenditures	(47.4)	(57.2)	(49.0)	(43.0)	(41.1)	(48.4)	(59.9)	(74.1)	(82.8)	(77.6)	(74.2)	(78.6)	(90.5)
Dividends Paid to Common Shareholders	(14.6)	(13.1)	(13.4)	(12.3)	(13.2)	(15.1)	(16.1)	(15.4)	(16.5)	(17.1)	(18.0)	(19.3)	(20.5)
Free Cash Flow	**(19.9)**	**(14.8)**	**(6.0)**	**1.7**	**3.8**	**(13.2)**	**(6.6)**	**(28.4)**	**(38.0)**	**(11.8)**	**(14.4)**	**(13.5)**	**(26.7)**

Note: Totals may not equal sum of components due to rounding. Source: SNL Financial and EEI Finance Department

Utilities Compete Globally and with Other Industries for Capital

The ROE approved by FERC is intended to provide investors a return comparable to returns on similar investments of comparable risk. In order for utilities to attract capital to develop needed transmission, the ROE approved by FERC must be adequate and stable to attract investors and meet regulatory standards affirmed by the courts.[42] Investors only are willing to commit capital to utilities if they expect to earn a predictable return that is commensurate not only with the risks and challenges associated with developing transmission but also with the returns available to investments with comparable risks. It is both the level of return and the stability of that return that attract investment.

To the extent that FERC decisions result in a significant reduction of base ROEs after facilities have been placed into service, investors and financing entities will view future investment in the sector as less desirable, given the potential for unpredictable results as well as the diminished return. The result is that actions to reduce base ROEs have a magnifying effect of increasing investors' required cost of capital, further shrinking the available pool of funds for transmission investment.

Now is not the time to make significant reductions to ROEs on transmission investments. The competition for capital for infrastructure is growing, as illustrated by projected and significant capital needs in other industries. In addition to the electric power industry's capital expenditure needs, the American Petroleum Institute projects oil and natural gas industry investments of $5 trillion through 2035.[43] Also, a 2012 study on drinking water infrastructure needs estimates that the most urgent investments could be spread over 25 years at a cost of approximately $1 trillion.[44] There are other studies that identify infrastructure needs that will require significant amounts of capital.[45]

Apart from other investment opportunities in the energy industry, capital markets offer a wide variety of comparable risk alternatives in other sectors of the economy that compete with transmission investments for investors' scarce capital. As a result, there will be significant competing demands for capital and financing. If returns on electric transmission infrastructure are not sufficient and stable, investors will avoid such investments and instead will seek better and more stable returns elsewhere. For example, review of FERC's historical decisions indicates that, in 2011, FERC's approved ROEs for natural gas pipelines were 264 basis points higher, on average, than those of electric utilities and present alternative investment opportunities. ROEs proposed by complainants and FERC staff in current section 206 filings before the Commission would imply a dramatic and unwarranted increase in this differential.

Transmission Investments Compete with Alternative Utility Investments

As currently applied by the Commission, the DCF methodology results in transmission ROEs that are below currently authorized state ROEs. In some cases, these differences may amount to 200 or more basis points. For example, EEI data shows that the average state-approved ROE in 2012 was 10.15 percent, which—even being at the lowest in decades—is significantly above those under review and pending before FERC.[46]

Rational markets would not produce such significant and abrupt adjustments to existing ROEs; if anything, such anomalous results should signal that the Commission must reexamine its application of the DCF model and recognize that the model is not working in the current environment. As a result, changes to the DCF methodology and its evaluation of the results are needed. Rather than sending unintended investment signals with sharp downward adjustments to utilities' ROEs, the Commission should take the opportunity to consider the practical and necessary adjustments to its DCF methodology, as well as the insight offered by alternative approaches and the competition for capital.

With the needs for utilities not only to invest in ongoing transmission upgrades, but also generation and distribution system upgrades, it will be difficult for utilities to justify continued transmission investment, or to attract capital to such investment, if they cannot offer investors the opportunity to earn a fair, stable return. Transmission continues to be inherently more difficult to develop, construct, and operate than other areas of infrastructure development. As a result, transmission infrastructure development remains a pressing need across the country.

In determining a just and reasonable ROE, the Commission should consider state ROEs in relation to the result produced by the DCF methodology and its own policy goals related to transmission development. Such an approach would help to avoid undermining the progress that has been made in developing transmission by allowing the Commission to consider broader policy needs and the supporting actions necessary to achieve those results.

Capital markets are highly sophisticated and will move to risk-comparable investment opportunities with higher returns where such opportunity exists. FERC should give careful consideration to the competition for capital when determining just and reasonable ROEs for transmission, particularly where rigid application of the current DCF methodology leads to unsupported divergence between transmission ROEs and ROEs of risk-comparable utilities such as natural gas pipelines.

VI. FERC's Ratemaking Should Align with Its Public Policy Priorities

As required by the FPA, FERC must assure just and reasonable rates. In Order No. 1000, FERC adopted reforms, including a requirement that transmission providers consider needs driven by public policy goals in regional and interregional requirements in the planning processes. Public policy goals include cost-effective integration of renewable resources required under state statutes and voluntary guidelines. In particular, as noted, 29 states and the District of Columbia have set statutory deadlines to achieve these goals. In addition to these mandated deadlines, eight states have voluntary guidelines for development and integration of renewable resources.[47]

Compliance with state statutory goals will require additional transmission. Given the long lead times and risks, stable and compensatory ROEs are needed to ensure that the capital necessary to finance these and other projects is available. To ensure that ROEs remain sufficiently robust to support investment in this additional transmission, EEI recommends the Commission adopt the principles described in the following sections.

To Provide a More Stable Regulatory Framework for Investment, Requests to Lower Existing Returns Should Be Required to Demonstrate That These Returns Fall Outside of the Range of Reasonableness

Under section 206 of the FPA, parties requesting revisions to existing utility rates bear the burden of demonstrating that existing rates are not just and reasonable before FERC may consider whether a new rate should be established.[48] Accordingly, complainants must meet this initial burden of proof: specifically, they must show that the existing ROE falls outside of the statutory *range of reasonableness* in determining an ROE using the FERC-preferred DCF methodology. This range of reasonableness is bound by a low-end ROE calculation and a high-end ROE calculation, which result from the DCF financial model. The evaluation of whether an existing rate can be considered to be unjust and unreasonable should continue if, and only if, the complainant demonstrates the existing rate falls outside of this *range of reasonableness*. Without this standard, there is no real measure as to whether an existing rate is just and reasonable and calls into question every previously authorized return, depending on market conditions.

FERC's Analytical Method of Determining ROEs Should Not Be Allowed to Undermine Its Policy Objectives and Hinder Needed Transmission Investment

While FERC has relied solely on the results of a specific application of the DCF model to determine ROEs for electric transmission operations, dependence on a single, mechanical approach heightens the risk that the evidence considered by the Commission will not reflect realities in the capital markets accurately. The DCF methodology is a useful tool in estimating investors' requirements, but there is no "perfect" method to calculate a fair and reasonable ROE. Volatile and anomalous capital market conditions further increase the risks that a single, formulaic DCF application will not produce a just and reasonable ROE, particularly when those capital market conditions are the result of abnormal intervention.

There is considerable evidence that current financial market conditions spurred by the Federal Reserve's monetary policy in response to the 2008 recession seriously have undermined the Commission's ability to rely on its DCF approach as the sole determinant of a just and reasonable ROE. The results of FERC's DCF analysis, as it has evolved, can vary dramatically depending on:

- Whether the key metric of central tendency is the median or the midpoint;
- The makeup of the proxy group; and

- The criteria used to eliminate outliers.

Even when there is general agreement on these parameters, the DCF model can produce results that are not sufficient to support transmission investments and can undermine FERC's policy objectives. Legal precedent and the rule of reason support the Commission's careful consideration of current financial market conditions and the results of alternative methods. FERC should exercise flexibility, within or as an adjunct to, its existing DCF methodology, to account for the extraordinary financial environment now extant (*e.g.*, continuing Federal Reserve actions to stimulate the economy by keeping interest rates low, purchasing bonds,[49] etc.) and ensure that ROEs are sufficient to support needed transmission investment.

The Commission Must Recognize Limitations of the DCF Methodology and Adjust Implementation

Today's economic and financial conditions contribute to anomalous results in DCF analysis, as it currently is applied. Further, DCF proxy group result screens and other implementation aspects of the methodology that have been put into place over time have biased the DCF model to produce lower results in the current interest rate environment, which do not reflect financial market conditions in the future.

For example, Southern California Edison's experience with issuing preferred equity demonstrates that investors continue to expect returns that are well above current yields on Treasury securities. Although interest rates have fallen since 2008 as a result of the Federal Reserve's efforts to stimulate the economy, data on rates for preferred equity issued by Southern California Edison indicates that the cost of equity has not experienced a commensurate decline and remains much higher than the interest rates on Treasury securities. This is illustrated in the following table, which shows that the spreads between preferred equity issues and interest rates on Treasury securities have increased as much as 164 to 208 basis points.[50] In fact, the average rate for preferred equity issues increased by four basis points, notwithstanding significant declines in Treasury rates and FERC DCF estimates.[51]

SCE Preferred Equity Rates and Spreads, Before and After 2008

Issue Date	Preference Stock Issue	Projected/ Actual Preferred Coupon		30-Year Treasury Rate	Spread Over 30-Year Treasury	20-Year Treasury Rate	Spread Over 20-Year Treasury	10-Year Treasury Rate	Spread Over 10-Year Treasury
4/27/05	SCE Series A Preference Stock	5.349%	*	#N/A	#N/A	4.65%	0.70%	4.25%	1.10%
9/21/05	SCE Series B Preference Stock	6.125%		#N/A	#N/A	4.52%	1.61%	4.19%	1.94%
1/24/06	SCE Series C Preference Stock	6.00%		#N/A	#N/A	4.63%	1.37%	4.40%	1.60%
	Average Rate/Spread, Prior to 2008	**5.82%**			**#N/A**		**1.22%**		**1.54%**
3/10/11	SCE Series D Preference Stock	6.50%	**	4.53%	1.97%	4.25%	2.25%	3.37%	3.13%
1/17/12	SCE Series E Preference Stock	6.25%	*/**	2.89%	3.36%	2.57%	3.68%	1.87%	4.38%
5/17/12	SCE Series F Preference Stock	5.625%	**	2.80%	2.83%	2.39%	3.24%	1.70%	3.93%
1/29/13	SCE Series G Preference Stock	5.100%	**	3.18%	1.92%	2.79%	2.31%	2.03%	3.07%
	Average Rate/Spread, After 2008	**5.87%**			**2.52%**		**2.87%**		**3.63%**
	Increase in Rate/Spread	**0.04%**					**1.64%**		**2.08%**
	* - Coupon rate floats after ten years								
	** - Cumulative preference stock								

Simply stated, the current DCF analyses may not produce results conducive to attracting the capital that utilities require to meet the need for increased transmission investment. This will make it considerably more challenging to achieve the goals of increased transmission set by Congress and FERC. Consistency in ROE determinations will help to ensure increased long-term capital flow to transmission infrastructure investment. Considering present dislocations in the capital markets, FERC should maintain flexibility in its analysis and exercise its discretion in determining ROEs to protect customers and to enable utilities to attract the necessary capital investment.

Such flexibility should reflect the fact that current utility bond yields are anomalous and are expected to increase significantly, primarily driven by Treasury bonds being artificially and historically low, due to federal intervention to restore economic growth. Nevertheless, investors' required equity risk premium above lower-risk bonds has expanded, making it greater than otherwise would be the case at a more "normal" interest rate level. Equity continues to be the riskiest form of security in a corporation, and investors will not purchase equity unless it provides a return that exceeds the yield on bonds by some amount consistent with investors' premium expectations.

Since investors' required equity risk premium has expanded under current economic conditions, EEI recommends enhancements to provide the Commission flexibility to accommodate shifts in capital market conditions, to ensure that its public policy goals are achieved, and to ensure that utilities can continue to make the level of transmission investment needed. EEI, along with several economic and financial experts in individual FERC proceedings, support the following recommendations:

- Consider the results of alternative approaches, such as the risk premium method and the capital asset pricing model. In addition, consider the results of the current DCF analysis performed on a proxy group of companies from other capital-intensive industries or low-risk firms from the competitive sector. The results of these alternative analyses may be used as benchmarks in evaluating a fair ROE from within the range of reasonableness established by the DCF method applied to electric utilities. This will allow FERC to better set base ROEs in the current environment in the upper end of the zone of reasonableness to offset distortion of the DCF analysis. In parallel, allow flexibility to set ROEs in the upper end of the range of reasonableness based on benchmarking results. (For example, if the results show the central tendency is consistently below other benchmarking methods, FERC should set the ROE to be comparable to the outcome of other methods.) Electric utilities do not compete just with other electric utilities for capital; they also compete with companies from other sectors of the economy.
- Increase the screen for low estimates in a proxy group to be higher, such as 200-300 basis points above the prevailing long-term utility bond yield; and/or incorporate *projected* bond yields and then apply the currently applicable 100-basis-point threshold.
- Recognize that low and high DCF values are independent estimates, and the fact that one is considered to be an outlier does not compromise the remaining estimate, as the two methods are independent of each other. FERC should discontinue its policy of removing both results for a company from the proxy group if only one DCF estimate is identified to be excluded.
- There should be a shorter period of time for excluding companies with a recent dividend cut. FERC's practice of a multi-year exclusion of these companies is unreasonable, especially in instances where the cut was related to an external one-time event (e.g., storm restoration). The DCF is a forward-looking model relying on data that is current, using data that is no more than six months old, and forecasted growth rates. Therefore, a dividend cut that occurred six months prior is reflected in the market price and a longer exclusion from the proxy groups is not warranted.

FERC should make these practical adjustments to its ROE methodology immediately to better align it with current market conditions and facilitate reasonable returns. Furthermore, these changes have the benefit of being relatively simple and straightforward and, therefore, should not require a significant overhaul of the DCF methodology.

VII. FERC Should Reaffirm Its Commitment to Transmission Investment by Ensuring Adequate and Stable ROEs Are Retained

Finally, the Commission must consider the long-term implications of compromising its policy of promoting transmission investment. The record shows that utilities responded to the Commission's policy of promoting transmission by increasing their investments in this area significantly to the benefit of wholesale markets, reliability, renewable integration, and customers nationwide. In addition, numerous utilities pursued the development of wholesale energy markets by joining ISOs and RTOs per Commission policy. For the Commission to backtrack now would signal to the utilities and investors that its policies lack stability and durability.

FERC must realize that utility decisions to make long-term investments, and investors' decisions to commit the capital to back such investments, depend on stable and predictable regulatory policies. If the Commission changes course now, the long-term implications will be significant and may be irreversible. Therefore, rather than undermine its stated policies supporting needed transmission investment, FERC should reaffirm its commitment to transmission investment by making necessary adjustments in its approach to setting a just and reasonable ROE for transmission investment.

Endnotes

1 EEI is the association of U.S. shareholder-owned electric utilities and affiliates worldwide. EEI's members own or operate approximately 70 percent of the electric industry assets in this country, including approximately 70 percent of the transmission facilities in our nation. EEI's diverse membership includes utilities operating in all regions, including in regions with Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) and companies supplying electricity at wholesale in all regions.

2 *See, e.g.,* Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, § 1241 (2005) (EPAct 2005).

3 *See, e.g.,* Announcement of the Rapid Response Team – Transmission Pilot Projects, Secretary Ken Salazar, "Transmission is a vital component of our nation's energy portfolio…serves as important links across our country to increase our power grid's capacity and reliability…This is the kind of critical infrastructure we should be working together to advance in order to create jobs and move our nation toward energy independence" (2011); Secretary Steven Chu, "To compete in the global economy, we need a modern electricity grid," "An upgraded electricity grid will give consumers choices while promoting energy savings, increasing energy efficiency, and fostering the growth of renewable energy resources" (2011); Announcement of Load Guarantee for One Nevada Transmission Line, Secretary Steven Chu "This project…is a win for the economy as well as for the environment."

4 *See, e.g.,* Chairman Jon Wellinghoff, Testimony before the House Energy and Commerce Committee Energy and Environment Subcommittee, "A robust electric transmission grid is essential to achieving the vision of an energy future that I believe most of us share." (2010); Commissioner Philip Moeller, Statement on Transmission Planning and Cost Allocation, Docket No. RM10-23-000, "By building needed transmission, our nation's transmission network can be maintained at reliability levels that are the envy of the world, while simultaneously improving consumer access to lower-cost power generation." (2011)

5 Sound regulatory economics and the standards for determining compensatory returns are set forth by the Supreme Court in [*Bluefield* (*Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923)] and *Hope* [*FPC v. Hope Natural Gas Co*., 320 U.S. 591 (1944)], specifically, that a utility's allowed return on common equity should be sufficient to: (1) fairly compensate investors for capital they have invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

6 Actual expenditures are from EEI's Annual Property & Plant Capital Investment Survey and FERC Form 1s.

7 *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2007), *order on reh'g*, 119 FERC ¶61,062 (2007).

8 It is important to note that reliable integration of renewable resources, such as wind and solar, are dependent on a robust transmission grid.

9 While the transmission cost component may vary over time and by region, the Department of Energy recently estimated that transmission comprises 11 percent of a customer's bill. *See, e.g*., Energy Information Administration, http://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices.

10 *See, i.e.,* ISO-NE Order No. 1000 compliance filing, ER193-000, October 25, 2012.

11 *See,* FERC Office of Enforcement, *2011 State of the Markets Report* (Apr. 19, 2012), available at: http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/som-rpt-2011.pdf. In addition, it appears that the TrAIL project entering service in 2011 (along with some other transmission improvements) will reduce

congestion costs by about $1 billion in 2012. *See,* Figure 13.2 of the 2010 PJM RTEP Plan, available at: http://www.pjm.com/~/media/documents/reports/2010-rtep/2010-section13.ashx.

12 *See, e.g.,* MVPs Create Jobs, Benefits for States, available at: https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/MVP%20Benefits%20-%20Total%20Footprint.pdf.

13 *See*, *e.g., The Economic Impacts of the August 2003 Blackout*, Electric Consumer Research Council, February 2, 2004. *See also, Average Cost of a Power Interruption in the U.S.*, source: LaCommare and Eto, 2004, available at: http://www.infrastructurereportcard.org/a/#e/power-interruptions This report includes estimates of average costs of a sustained outage, defined as a sustained interruption of 106 minutes or more.

14 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 45 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (Order No. 1000-A), *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012) (Order No. 1000-B).

15 Order No. 1000 at PP 46, 497.

16 Federal Energy Regulatory Commission, The Strategic Plan - FY 2009-2014 at 3 (revised March 2013) available at http://www.ferc.gov/about/strat-docs/FY-09-14-strat-plan-print.pdf.

17 *See id*. at 22.

18 Letter to the Editor, *The Wall Street Journal*, January 10, 2011.

19 *See, e.g., PSE&G Working to Make NJ "Energy Strong,"* (announcing $3.9 billion, 10-year proposal to reduce power outages, stabilize customer bills, and create 5,800 jobs), available at: http://www.pseg.com/info/media/energy_strong/press_kit/index.jsp; *Washington, DC Mayor Gray Accepts Interim Report and Recommendations from Power Line Undergrounding Task Force* (announcing innovative plan, historic financing is expected to boost electric reliability by 95 percent), available at: http://mayor.dc.gov/release/mayor-gray-accepts-interim-report-and-recommendations-power-line-undergrounding-task-force.

20 *See* PJM Grid Operator Plans Billions In Transmission Improvements to Meet Massive Generator Fuel Shift, available at: http://pjm.com/~/media/about-pjm/newsroom/2013-releases/20130307-rtep_report_published.ashx.

21 AWEA: 2012 was 'best year ever' for wind in the U.S., transmission still a barrier, TransmissionHub (4/11/2013), available at: http://wiresgroup.com/docs/TransHub_AWEA_041213.pdf.

22 *Reliability Standards for the Bulk Electric System of North America* (updated March 12, 2013), available at: http://www.nerc.com/docs/standards/rs/Reliability_Standards_Complete_Set.pdf.

23 *See*, *e.g.,* Executive Order – Improving Critical Infrastructure Cybersecurity, available at: http://www.whitehouse.gov/the-press-office/2013/02/12/executive-order-improving-critical-infrastructure-cybersecurity.

24 Planned total industry expenditures are preliminary and are estimated from an 85-percent response rate to EEI's Electric Transmission Capital Budget & Forecast Survey.

25 A free copy of the report is available as an eBook and PDF on EEI's Web site at: http://www.eei.org/ourissues/ElectricityTransmission/Pages/TransmissionProjectsAt.aspx.

26 *Id*. (Some of these investments are also captured in EEI's total transmission investment projections through 2015.)

[27] http://www.eei.org/ourissues/ElectricityGeneration/FuelDiversity/Documents/EEI_State_RES_Mandate_Table.pdf.

[28] California Independent System Operator Corp., *2011 Annual State of the Grid Report*, at 17 (August 2011), available at: http://www.caiso.com/Documents/2011AnnualStateoftheGrid-20110817web.pdf. *Transmission Projects: At A Glance* (March 2013), at 126.

[29] *See*, *Employment and Economic Benefits of Transmission Investment in the U.S. and Canada*, The Brattle Group, (May 2011), page ii.

[30] Section 215 of EPAct 2005 requires a FERC-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to FERC oversight or FERC can independently enforce Reliability Standards, Energy Policy Act of 2005, Pub. L. No 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005), 16 U.S.C. 824o.

[31] As noted in *Transmission Projects: At A Glance,* most transmission projects in the report are multifaceted, addressing a range of needs and delivering a number of benefits. *See supra* note 26.

[32] Order No. 1000 at p 4.

[33] Order No. 1000 provides that certain transmission projects will be open to competition in the planning process and increases the risk of whether a particular project will be selected in the regional plan.

[34] While there are certain project-specific rate treatments provided by FERC for qualifying projects, such as full rate base treatment for Construction Work in Progress, they do not fully mitigate the risks of the project for the transmission developer. These additional risks must be addressed by the developer in financing the project.

[35] There are also merchant transmission projects that may result from voluntary contracts.

[36] *See* Memorandum of Understanding among the nine federal agencies (October 2009), available at: http://energy.gov/sites/prod/files/Transmission%20Siting%20on%20Federal%20Lands%20MOU%20October%2023%2C%202009.pdf; Council of Environmental Quality, *Interagency Rapid Response Team for Transmission,* available at: http://www.whitehouse.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission.

[37] *See Out of Sight, Out of Mind 2012*: An Updated Study on the Undergrounding of Overhead Power Lines (January 2013) at pp. 30-33, prepared by Kenneth L. Hall, P.E. of Hall Energy Consulting, Inc. for Edison Electric Institute, available at: http://www.eei.org/ourissues/electricitydistribution/Documents/UndergroundReport.pdf.

[38] This project is being jointly developed by Westar Corporation, American Electric Power, and MidAmerican Energy and approved by the Southwest Power Pool pursuant to its regional planning process.

[39] *See* Prairie Wind Transmission, available at: http://www.westarenergy.com/wcm.nsf/resources/2011-6-29/$file/2011-6-29.pdf?openelement.

[40] Fitch Ratings, "Corporate CapEx Study: Growth Stalls in 2013," October 25, 2012.

[41] Free Cash Flow = Net Cash Provided from Operating Activities – Capital Expenditures – Dividends Paid to Common Shareholders. Sources: EEI Financial Department; company reports; SNL Financial.

[42] *See Hope*, *Bluefield* discussed *supra*.

[43] *See* American Petroleum Institute "America's New Energy Future: The Unconventional Oil and Gas Revolution and the U.S. Economy" available at: http://www.ihs.com/info/ecc/a/americas-new-energy-future.aspx.

[44] *See, e.g., 2013 Report Card for America's Infrastructure*, American Society of Civil Engineers (2013), available at: http://www.infrastructurereportcard.org; citing a 2012 American Water Works report.

[45] *See* American Association of Railroads estimates $24.5 billion in freight rail investment in 2013, available at: https://www.aar.org/newsandevents/Press-Releases/Pages/Freight-Railroads-Plan-to-Invest-24-Billion-in-Private-Dollars-in-2013-On-Americas-Rail-Network-So-Taxpayers-Dont-Have-To.aspx

[46] *See* Financial Update, Quarterly Report of the U.S. Shareholder-Owned Electric Utility Industry (Q4 2012), available at: http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Documents/2012_Q4_Rate_Case_Summary.pdf.

[47] *See* U.S. Department of Energy Database of State Incentives for Renewables & Efficiency (DSIRE), Renewable Portfolio Standard Policies (March 2013), available at: http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

[48] *See, e.g., Nantahala Power & Light Co.*, 19 FERC ¶ 61,152, at 61,276 (1982); *Cal. Mun. Utils. Ass'n v. Cal. Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,315 at PP 69-72 (2009); *Cities of Bethany, Bushnell, Cal. v. FERC*, 727 F.2d 1131, 1143 (D.C. Cir. 1984); *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956); *Cal. Indep. Sys. Operator Corp.*, 111 FERC ¶ 61,337, P 27 (2005).

[49] *See* Robert Mitkowski, Value Line, *Weak Jobs Report Gives Fed Cover to Continue Bond-Buying Program, but*… (Apr. 13, 2013) ("the Fed's extra-aggressive monetary policy…is creating extreme environments in segments of the economy. Those include the bond market…").

[50] It is reasonable to expect that common stock ROEs would show a similar increase relative to interest rates.

[51] While FERC's present DCF method does not incorporate Treasury rates directly, it does utilize utility bond yields as a cutoff for low estimates, and that cutoff does not incorporate this change in relative risk.

The **Edison Electric Institute (EEI)** is the association of U.S. shareholder-owned electric companies. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70% of the U.S. electric power industry. We also have as Affiliate members more than 80 International electric companies, and as Associate members more than 200 industry suppliers and related organizations.

Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas.

EEI provides public policy leadership, critical industry data, strategic business intelligence, one-of-a-kind conferences and forums, and top-notch products and services.

For more information on EEI programs and activities, products and services, or membership, visit our Web site at www.eei.org.

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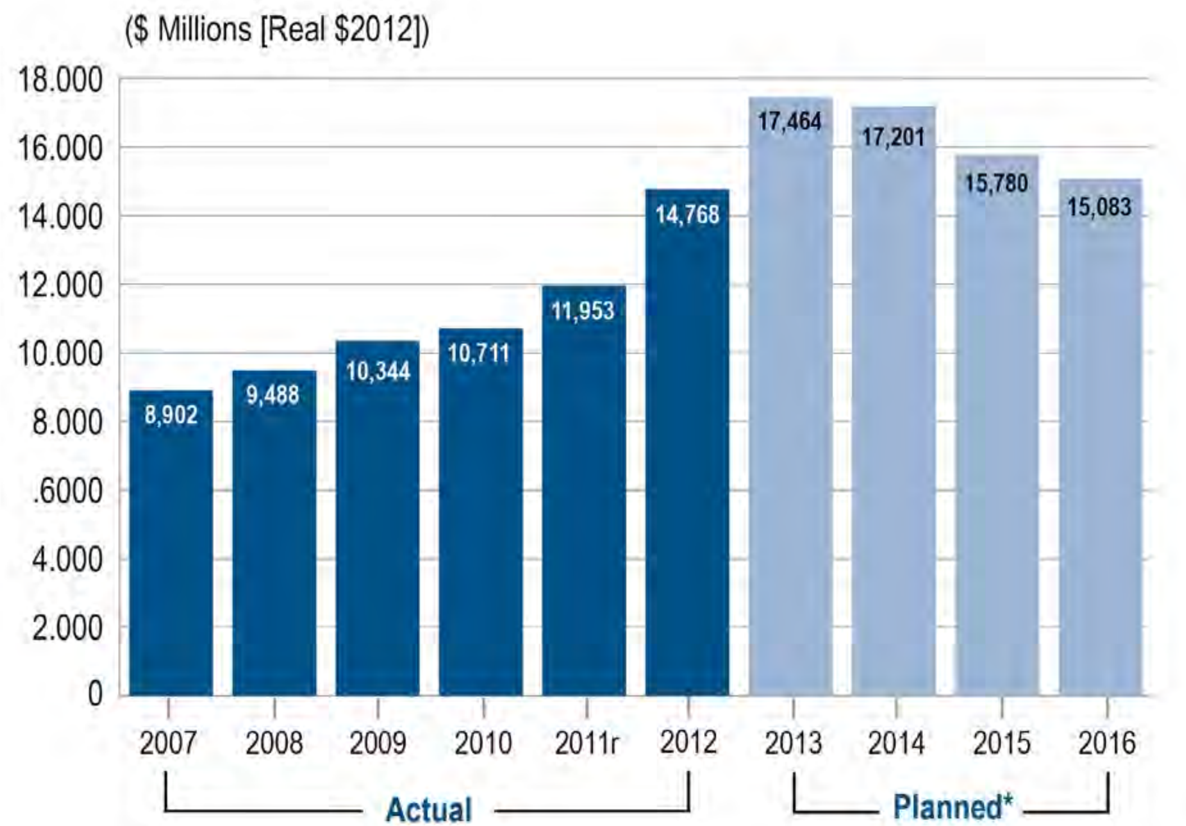
Actual and Planned Transmission Investment By Investor-Owned Utilities (2007-2016)



*Planned total industry expenditures are preliminary and estimated from data obtained from the EEI Transmission Capital Budget & Forecast Survey, supplemented with data obtained from company 10-K reports and investor presentations. Actual expenditures are from EEI's Annual Property & Plant Capital Investment Survey and FERC Form 1 reports.

r = revised

Note: The Handy-Whitman Index of Public Utility Construction Costs used to adjust actual investment for inflation from year to year. Forecasted investment data are adjusted for inflation using the GDP Chain-type Price Index.

Source: Edison Electric Institute, Business Information Group.

Updated as of May 2014.

EDISON ELECTRIC INSTITUTE

March 17, 2005

EEI Principles on Transmission Investment

Effective Wholesale Competition Needs a Robust, Reliable and Cost-Effective Transmission Infrastructure

Greater competition in electricity markets is expanding the use of the nation's electric transmission grid. Built originally to serve existing and future loads, interconnect neighboring utilities, and support reliability, the grid also is now being used to support a larger number of wholesale transactions across regions. EEI's members continue to actively invest in the transmission system in order to meet these needs.

The Federal Energy Regulatory Commission has raised concerns about whether integrated electric utilities are building transmission facilities. Historical and projected data demonstrates that both integrated companies and stand-alone transmission companies are making increasing investments in transmission. Reversing a trend of declining transmission investment, from 1999 to 2003 annual transmission investment by shareholder-owned utilities increased 12 percent annually and totaled $17 billion over the period. From 2004-2008, preliminary data indicates that utilities have invested or are planning to invest $28 billion, more than a 60 percent increase over the earlier period.

Shareholder-owned utilities will continue to build transmission facilities for which they can obtain cost-recovery. However, existing impediments continue to frustrate and delay transmission investment. Federal and state regulatory and legislative policies should be aimed at eliminating these impediments. This will bolster efforts to build more transmission in the future, which in turn, will enhance local, regional and inter-regional wholesale electricity markets. These policies are outlined below:

Eliminating Impediments, Providing Regulatory Certainty and Cost Recovery, and Facilitating Transmission Investment

1. State and federal policy should eliminate regulatory impediments and provide regulatory certainty, particularly with respect to attractive returns, incentives, cost allocation and cost recovery, in order to raise the capital necessary to construct needed, cost-effective transmission facilities.

2. Transmission pricing should (a) allow for cost recovery of fixed and variable costs and a reasonable return on transmission investment, (b) ensure, to the extent practicable, that cost responsibility follows cost causation, (c) minimize the potential for cost shifting, (d) permit the recovery of all prudently incurred transition costs, and (e) promote efficient siting of new transmission and generation facilities.

3. Conflicting federal and state regulatory policies can result in unrecoverable, trapped costs. FERC and the states must ensure that the necessary regulatory mechanisms are in place to allow for the full recovery of all prudently incurred costs and the avoidance of trapped costs.

4. FERC and the states should allow full recovery of all prudently incurred costs to design, study, pre-certify, and permit transmission facilities. FERC should amend its rules to allow full recovery of the prudently-incurred costs of abandoned transmission projects.
5. FERC should allow utilities to include construction work in progress (CWIP) in rate base (in lieu of AFUDC) as this will encourage transmission construction through improved cash flow and greater rate stability.
6. FERC should allow for accelerated depreciation in ratemaking to improve financial flexibility, and promote additional transmission investment.
7. Where states require purchases of renewable resources that lack siting flexibility, FERC should allow alternative transmission pricing and cost recovery approaches to support the building of transmission facilities to help achieve state renewable resource goals.
8. FERC transmission policies should not favor one corporate structure, business model or retail regulatory model over another. Many different structures and business models can coexist in a competitive wholesale marketplace for the construction of transmission, provided there are fair rules in place for all market participants.
9. The Congress should take action to attract the capital necessary to build transmission capacity by repealing the Public Utility Holding Company Act (PUHCA), with appropriate federal and state access to books and records, and by providing the appropriate incentives in the tax code, including accelerated depreciation.

Improving Transmission Planning, Siting and Reliability

1. A regional planning process can identify cost-saving opportunities and facilitate the construction of new transmission to support robust wholesale markets and improved reliability.
2. Regional state committees (RSCs), where in existence, should facilitate the obtaining of necessary state regulatory approvals by parties seeking to build new transmission facilities that cross state boundaries or have multi-state impacts.
3. RSCs should assist in coordinating state siting activities through the use of standardized applications, joint data and studies, coordinated schedules and deadlines, and other mechanisms, where possible.
4. Regardless of whether there is an RSC in their region, states should streamline their transmission line siting processes and take regional considerations into account as appropriate.
5. FERC should have backstop siting authority if states cannot or will not act on applications to build transmission to relieve critical transmission bottlenecks and the Department of Energy (DOE) should act as lead agency to coordinate all authorizations and environmental reviews required under federal law to site transmission facilities on federal lands and to set deadlines for federal reviews.
6. All market participants should be subject to mandatory, enforceable reliability standards that are developed or approved by the North American Electric Reliability Council (NERC), with oversight and enforcement by the Federal Energy Regulatory Commission.

EDISON ELECTRIC INSTITUTE

September 11, 2008

EEI Principles on Transmission Investment For Renewable Resources

Background

There is increasing public and private interest in a diversified, sustainable domestic energy supply for the nation. Federal and state policies are promoting, and in some cases mandating, the use of renewable energy resources, such as wind, solar, tidal energy and biomass, to generate electricity. Over twenty-five states and the District of Columbia have established renewable resource portfolio requirements. Legislation introduced in Congress would grant federal utilities significant advantages over investor-owned utilities to build or upgrade transmission facilities to transmit power from renewable resources. Similarly, recently-enacted legislation promoting certain types of energy projects, such as combined heat and power, may affect transmission access priorities.

Reliably and cost-effectively interconnecting and integrating renewable resources presents unique issues for electric utilities. Renewable resources can be location-constrained and remote from existing transmission facilities. Their output can also be variable, which can raise reliability concerns. Siting and building transmission facilities to support renewable resources often is more difficult and takes significantly longer than the siting and building of the renewable resources themselves. Overcoming these types of challenges often requires significant investment in transmission infrastructure.

In order to integrate renewable resources and other generation, maintain reliability, and support wholesale competition, investor-owned utilities will continue to plan and build transmission facilities for which they can obtain cost recovery. However, regulatory uncertainty and siting impediments often frustrate and delay transmission investment. Federal and state regulatory policies should be aimed at eliminating these impediments, which will allow the timely interconnection and integration of renewable resources and other generation into the bulk power system in an efficient and cost-effective manner.

Transmission Investment for Renewable Resources

1. Transmission Planning, Siting and Permitting

Transmission planning, including planning for facilities to integrate renewable resources, should be open, transparent, and comprehensive, and take into account local, sub-regional, regional and interregional considerations. States should work together to facilitate the expeditious siting and permitting of cost-effective multi-state transmission projects needed to accommodate the development of renewable resources. Elimination of conflicts among federal, regional, and state policies on planning, siting, and permitting should be a priority.

2. Interconnection Queuing

Interconnection queuing policies and procedures should enable the timely and efficient interconnection of all generating resources, including renewables. Current processes coupled with a tremendous number of interconnection requests have resulted in congested and unworkable interconnection queues in some regions. To alleviate this problem, FERC should consider regional variations to queuing rules proposed by transmission providers and other stakeholders that are not unduly discriminatory and consistent with local and regional planning processes.

3. Transmission Open Access

Transmission service for renewable resources should be provided in a manner consistent with federal open access transmission policies, which require open access for all generation sources including those needed to support variable renewable resources, such as wind and solar generation. Network transmission facilities built for renewable resources and other generation should be developed consistent with such open access policies. Limiting network transmission facilities to specific resources, such as renewable resources, is not feasible.

4. Reliability

Renewable resources, like other bulk power system generation, must comply with applicable NERC reliability standards. Variable resources, such as wind and solar generation, require system support capabilities, such as operating reserves, regulation and load following to maintain grid reliability. The costs of these support capabilities must be accounted for in order to determine the total cost of integrating variable resources into a system or region.

5. Government Utilities Building Transmission

Federal policy regarding renewable resources should not favor government transmission investment over private sector transmission investment and should preserve existing rights of utilities to build and upgrade transmission facilities within their systems.

6. Transmission Investment Incentives

Federal regulatory policy should promote construction of new or upgraded transmission facilities that integrate renewable resources by providing transmission investment incentives based on the case-specifics of the transmission project.

7. Cost Allocation

Transmission cost allocation and recovery mechanisms for renewable resources should provide regulatory certainty and allow for full cost recovery and a reasonable return. FERC should allow transmission cost allocation and recovery approaches which support the building of transmission to help achieve renewable resource goals.

Edison Electric Institute

Power by Association[SM]

Transmission Projects: At A Glance

Prepared by: **Edison Electric Institute**

MARCH 2014

Attribution Notice and Disclaimer

Note: The status of the projects listed in this report was current when submitted to EEI but may have since changed between the time information was initially submitted and date this report was published.

Note: Further, information about projects, including their estimated in-service dates, are provided by the respective EEI member developing the project. Inclusion in this report does not indicate that the project has been included in an approved transmission plan or has received any required state or federal approvals.

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EXECUTIVE SUMMARY

Utilities make investments in their system to provide customers with reliable and economic electric service, addressing system needs such as meeting reliability requirements, modernizing and replacing infrastructure as needed, accommodating new and retiring electricity generation sources and meeting public policy requirements. This eighth annual publication of EEI's *Transmission Projects: At A Glance* report showcases a cross-section of major transmission projects that EEI's members completed in 2013 or have planned for the next ten years and highlights EEI members' continuing focus to make needed transmission investments. This report represents a sampling of the wide array of projects currently planned or under construction by EEI's members.

Building a Stronger Grid to Meet Customer Needs

EEI's members remain dedicated to building needed and beneficial transmission, and modernizing the nation's transmission network to meet twenty-first century demands. In 2012, total transmission investment reached $14.8 billion (real $2012). We expect that increases in year-over-year total transmission investment by EEI's members will have peaked in 2013 with estimated investment at approximately $17.5 billion (real $2012). These transmission investments provide an array of benefits which include: providing reliable electricity service to customers, relieving congestion, facilitating wholesale market competition, supporting a diverse and changing generation portfolio and mitigating damage and limiting customer outages in extreme weather. New transmission investments also deploy advanced monitoring systems and other new technologies designed to ensure a more flexible and resilient grid. At the same time, all transmission projects are integrated into local systems in order to maintain the paramount objective of providing reliable electricity service to customers.

Over 170 projects are highlighted in this report, totaling approximately $60.6 billion in transmission investments through 2024.[1] This figure is up from the approximately $51.1 billion highlighted in the 2013 report, due to changing projections of system needs. Consistent with federal and state policies, transmission projects are planned through the use of open and transparent processes that include analysis and consideration on a comparable basis of proposed transmission solutions. This ongoing evaluation and reevaluation of projects protects customers by ensuring that only efficient and cost-effective transmission solutions are ultimately constructed.

Since transmission projects address an array of needs and deliver a number of benefits, most projects in this report are multifaceted. That is, they are not developed solely to meet any one specific purpose. Accordingly, one project may fall into more than one transmission investment category. Of the total $60.6 billion worth of transmission projects highlighted in this report, interstate transmission projects represent $26.2 billion (43 percent); projects supporting the integration of renewable resources represent approximately $46.1 billion (76 percent); projects where EEI member companies are collaborating with other utilities, including non-EEI members, to develop the project represent approximately $29.8 billion (49 percent);

1 This investment is only a portion of the total transmission investment anticipated through 2024 by EEI's members.

and high-voltage projects of 345 kV and above represent approximately $45.7 billion (75 percent) (nominal $).

Policies Supporting Transmission Development

Effective policies for planning and siting, cost allocation and cost recovery are important to achieve the levels of transmission investments needed for reliable and cost-effective service to electricity customers. Continued investment in transmission infrastructure will be required to maintain reliability, support shifts in the nation's generation portfolio, offer greater flexibility with the increase in distributed generation, and meet public policy requirements. However, the risks of building transmission have not diminished since the first *Transmission Projects: At A Glance* report was published in 2007. Recognizing the numerous benefits of a robust transmission system and the inherent risks and challenges of developing transmission are unlike any other utility plant, EEI's members have a long history of working with policymakers and regulators to support effective policies, such as appropriate returns on equity, to address the substantial risks of developing, constructing, operating and maintaining transmission infrastructure, as well as the challenges of raising needed capital to fund transmission development.

The Energy Policy Act of 2005 ("EPAct 2005") set forth several statutory requirements intended to support transmission investment, and the Federal Energy Regulatory Commission ("FERC") reaffirmed its pricing policy providing rate treatments and adequate returns to assist in mitigating the risks associated with developing, constructing, operating, and maintaining transmission infrastructure. In addition, FERC advanced its strategic goal of supporting the development of transmission by enabling identification of projects through appropriate regional and interregional coordination processes and supporting allocation of costs for the selected transmission solutions that meet customer and system needs.

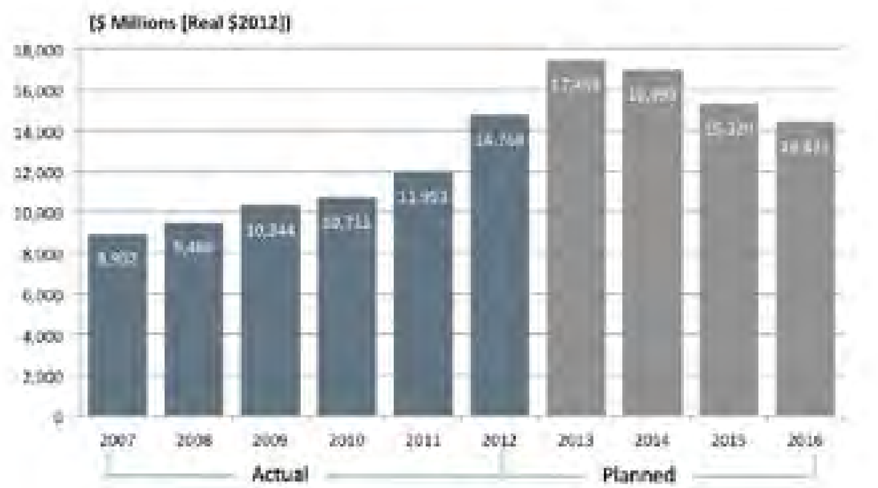
Despite recent disagreements regarding transmission incentives and adequate returns on investment, FERC should continue to foster the construction and upgrade of beneficial transmission by balancing the need to promote investment in long-term infrastructure assets with the short-term, cyclical movements in the capital markets in order to ensure sufficient access to capital to build needed transmission projects that present significant risks to developers.

INTRODUCTION

Building a Stronger Grid to Meet Customer Needs

While the electric industry and general economic climate have changed significantly since the first *Transmission Projects: At A Glance* publication in 2007, EEI members remain firmly dedicated to prudent investment in needed and beneficial transmission. In 2012, EEI members' total transmission investments reached approximately $14.8 billion (real $2012).

As shown in the chart, year-over-year total transmission investment increased through 2013, when EEI estimates a peak at approximately $17.5 billion.[2] Without question, this level of investment in our nation's transmission infrastructure is significant and will provide numerous benefits for electricity customers. Investment in transmission enhances the high level of reliable electricity service that customers expect and reduces congestion and system losses, which result in direct cost savings for customers. Transmission investment also facilitates the integration of new generation sources, including renewable resources, by adding robust support to the existing network, or by directly interconnecting resources, even when located far from load centers. Transmission also provides access to other flexible power resources and support services to compliment the increasing amounts of distributed generation.



In addition, these transmission investments help to ensure the continued reliability of the grid in the face of generator retirements as our nation's mix of electric power resources change in response to new U.S. Environmental Protection Agency ("EPA") rules, state and local environmental requirements, and shifts in the costs of generation and power plant operations. Accordingly, compliance with EPA's evolving clean air and water regulations will require new transmission infrastructure.

Grid Modernization

EEI members remain dedicated to planning and modernizing the nation's transmission network to meet twenty-first century electric energy demands. Recent extreme weather events have highlighted the need for reinforcing and upgrading electric infrastructure. Such investments improve the durability of transmission and distribution infrastructure, allowing the system to withstand the impacts of severe weather events with minimal damage.

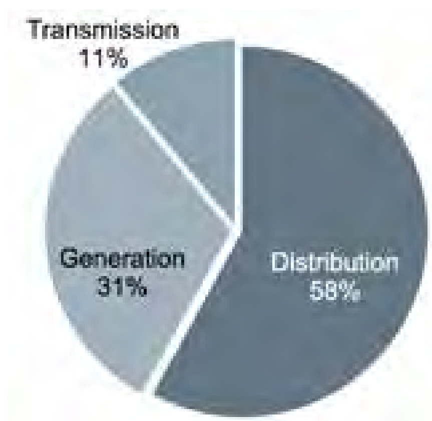
2 Actual expenditures are from EEI's Annual Property & Plant Capital Investment Survey and FERC Form 1s.

With increasing penetration of distributed generation technology (e.g. rooftop solar, combined heat and power) and an overall interest by consumers in clean energy, transmission remains vitally important to maintaining system-wide reliability by providing access to other, flexible power resources in cases when such intermittent power supply is unavailable. At the same time, large concentrations of distributed generation increase the need for the transmission system to detect and react quickly to balance supply and demand when those generation sources go offline or are unable to meet 100 percent of customer demand. To enable flexible networks that allow for more customer control and choice, it is important that regulatory frameworks, adequate returns and equitable cost allocation are in place for utilities to provide services that meet customer needs.

Meanwhile, EEI members continue to introduce innovative technologies in transmission projects to meet system needs when they provide benefits to customers and improve service. Consistent with EPAct 2005 and FERC's transmission incentives rate policy, many of the projects highlighted in this report integrate advanced transmission technologies including fiber optic communication, advanced conductor technology, enhanced power device monitoring and energy storage devices.

Policies Supporting Transmission Development

As demonstrated by the sample of transmission projects in this report, investment in our nation's transmission grid continues as EEI's members address the evolving energy needs of the nation. Since the issuance of EPAct 2005, which set forth several statutory requirements intended to attract additional investment in the transmission grid, the risks associated with planning, siting and constructing needed transmission have not diminished.



To continue to foster the development of necessary transmission, FERC should balance the need to promote investment in long-term infrastructure assets with the short-term, cyclical movements in the capital markets. Returns commensurate with the long-term prevailing risks are necessary to continue to attract sufficient capital to achieve the needed transmission investment levels and promote the implementation of advanced technologies. This is particularly true given the growing competition for capital to invest in our nation's strategic assets and infrastructure. In response to a recent complaint regarding adequate returns on transmission investment, an initial decision, pending further FERC review, recognized that "[i]f transmission investment is substantially limited in the future, it will have a negative impact upon operational needs, reliability, and ultimately ratepayers' future costs."[3] Transmission remains the smallest portion

3 Martha Coakley, et al. v. Bangor Hydro-Electric Co., et al., 144 FERC ¶ 63,012 at P 576 (2013).

of electricity bills, when compared to generation and distribution costs,[4] and while the benefits of transmission projects are realized on the date they are placed into service, utilities recover these investments over the facility's useful life (typically 40 years).

Moreover, in EPAct 2005, Congress required the adoption of transmission incentives for certain qualifying projects in recognition of the benefits of a robust transmission network, the risks of its development, and the challenges of raising adequate capital to invest in transmission given other capital requirements. These transmission incentives were also created to encourage the deployment of advanced transmission technologies.[5] In 2012, FERC released a Policy Statement reaffirming that development of transmission still presents risks and challenges that are not present for investment in any other utility plant.

Recognizing the importance of transmission to the nation's economy, security and quality of life, the Administration recently announced the first "Quadrennial Energy Review"[6] building off of its *Blueprint for a Secure Energy Future*,[7] instructing the heads of twenty-two executive departments and agencies to collaborate on a year-long review of transmission and distribution infrastructure. EEI members look forward to working collaboratively with stakeholders to complete this review and determine if there are further opportunities to modernize, expand, upgrade, or transform energy infrastructure to accommodate changes in energy supply, integrate new information and security technologies, and meet customers' increasing demands.

Meanwhile, the Administration continues to direct federal agencies to coordinate transmission siting and permitting on federal lands to bolster infrastructure development to meet current challenges including environmental impacts, national security, reliability, aging facilities and transformations in energy supply. Building upon the efforts of the interagency Rapid Response Team for Transmission, the Administration has established a steering committee to identify best-management practices and process improvements for reducing transmission project reviews[8] and has required federal agencies to study electric transmission corridors and develop an interagency pre-application process for significant onshore electric transmission projects requiring federal approval.[9] In response, the Department of Energy ("DOE") initiated the development of best practices by seeking public comment on its proposed Integrated, Interagency Pre-Application Process in order to facilitate a more streamlined and efficient

4 While the transmission component may vary over time and by region, the DOE recently estimated that transmission comprises eleven percent of a customer's bill. See, e.g., Energy Information Agency, http://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices.

5 Section 1223 of EPAct 2005 defines an "advanced transmission technology" as a technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility.

6 Presidential Memorandum – Establishing a Quadrennial Energy Review (Jan. 9, 2014).

7 Blueprint for a Secure Energy Future (Mar. 11, 2011), available at http://www.whitehouse.gov/sites/default/files/blueprint_secure_energy_future.pdf.

8 Presidential Memorandum - Modernizing Federal Infrastructure Review and Permitting Regulations, Policies, and Procedures (May 17, 2013).

9 Presidential Memorandum - Transforming our Nation's Electric Grid Through Improved Siting, Permitting, and Review (June 7, 2013).

transmission project review process.[10] The Administration and federal agencies have appropriately recognized the difficulties in permitting and siting transmission facilities on federal lands. The resulting coordination efforts must continue in order to help address a major challenge in the effort to enhance the United States transmission network.

An Evolving Investment Trend

Planned transmission investments are affected by economic conditions and the rate of electricity demand growth. Accordingly, EEI forecasts a slight decrease in transmission investment after 2013, primarily attributable to load growth forecast revisions in response to the current economic environment, as well as lower long-term growth rates due to increases in demand side management and energy efficiency. In recent years, the industry had significant investments and continues to invest in new large-scale, high-voltage facilities. In addition, the industry has focused on upgrades and replacement of existing facilities to further modernize the transmission grid. So, as the planning factors change, transmission planners respond by adjusting their system infrastructure needs to meet customer demands. Nevertheless, EEI expects investment by its members during 2014 and 2015 to be significantly higher than in years prior to 2013.[11]

The aggregate investment figure highlighted in this report provides further evidence of this trend as projected transmission investments increases for 2013. Over 170 projects are highlighted in this report, totaling approximately $60.6 billion in transmission investments through 2024, compared to the 2013 report total through 2023 of approximately $51.1 billion (nominal $).

The projects in this report are also reflective of the need to invest in high-voltage facilities to serve the changing generation mix and emerging needs of customers. Approximately 75 percent of the reported projects are high voltage (345 kV and higher), representing over 13,000 line miles. Several of the projects included in this report are in the proposal stages and are subject to additional review. System planners will review the costs and benefits of transmission facilities and will consider alternatives such as new generation supply, demand response, energy efficiency and increased deployment of distributed generation resources. Moreover, the local and regional transmission planning processes may lead to modification, delay or cancelation of some of these projects or the addition of new projects. The evolution of a project from “concept” to “steel in the ground” is part of the dynamic transmission planning process.

Transmission Planning

Prior to construction, transmission planning processes evaluate the costs and benefits of each project, assess the forecasted changes in regional supply and demand, and consider alternative

10 Department of Energy - Improving Performance of Federal Permitting and Review of Infrastructure Projects, Request for Information, 78 Fed. Reg. 53436 (Aug. 29, 2013).

11 Planned total industry expenditures are preliminary and estimated from an approximately 80 percent response rate to EEI’s Electric Transmission Capital Budget & Forecast Survey.

solutions.[12] In addition, in some regions, transmission projects are identified as part of state integrated resource planning processes. Once transmission projects are selected in a regional process, they are subject to additional evaluations as part of state commission reviews and siting processes. These checks and balances protect consumers by ensuring that only cost-effective and efficient transmission projects that meet local and regional needs are constructed.

In 2011, FERC sought to enhance existing regional and interregional planning procedures with its issuance of Order No. 1000. Starting in 2012 and continuing into 2014, each planning region developed or is developing proposals to reform: i) planning, including procedures to identify transmission needs driven by public policy requirements; ii) cost allocation methodologies; and iii) non-incumbent developer participation. In 2013, the industry submitted to FERC interregional compliance proposals that provide a cost allocation method for new interregional transmission facilities. These reforms are intended to provide further support for transmission development.

At the same time, EEI members continue active participation in initiatives to coordinate transmission planning activities. One such effort is the Eastern Interconnection Planning Collaborative ("EIPC") where planning authorities in the Eastern Interconnection are now studying the interaction and potential interdependency of gas infrastructure with the electric system. Other coordinated transmission expansion efforts are underway in ERCOT through the Long Term System Assessment performed in conjunction with the Electric System Constraints and Needs study. Transmission planners in the Western Interconnection have developed a 10-year plan and are now pursuing a 20-year, regional transmission plan framework. These experiences and analyses will assist in efficiently advancing the evaluation of transmission needs and solutions.

Report Scope

It is against this backdrop that EEI developed this report of member company transmission projects. Contained herein is a broad, though not comprehensive, perspective on the variety of transmission projects being built in the United States to support a number of needs and objectives. While the focus in this report is to present targeted projects within these broad categories, it is important to note that these transmission projects represent only a portion of total planned transmission addressing an array of needs and delivering a number of benefits, regardless of the initial development intention. With that in mind, most projects in this report are multifaceted. That is, they are not developed solely to meet any one specific purpose. Rather, they fall into more than one transmission investment category.

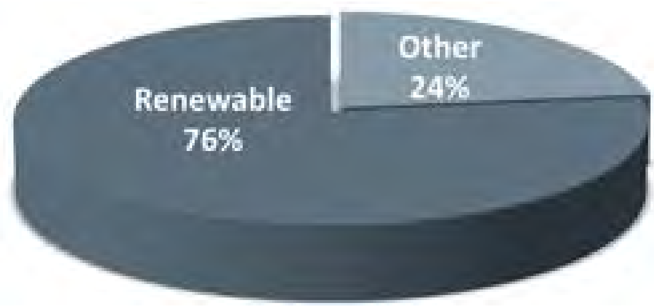
12 There are also merchant transmission projects that may result from voluntary contracts.

Interstate Transmission Projects

These interstate projects span two or more states, and often present additional challenges for siting, permitting, cost allocation and cost recovery. Interstate projects account for approximately 7,700 miles and $26.2 billion (nominal $).

Transmission Supporting the Integration of Renewable Resources

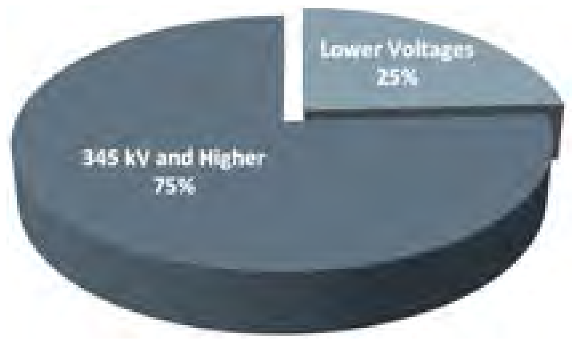
These projects support the integration of renewable resource generation. Renewable energy technologies include: wind power, solar power, hydroelectricity, geothermal, biomass and biofuels. Highlighted projects that facilitate the integration of renewable resources reflect the addition or upgrade of 12,200 miles of transmission with an accompanying investment cost of approximately $46.1 billion (nominal $).



Transmission Projects Developed by Multiple Project Partners

Given the unique risks and challenges of developing transmission, among other things, several EEI member companies are collaborating with other utilities, including non-EEI members, to develop large-scale transmission projects. This collaboration allows entities to spread the investment risks while also leveraging each other's experience in developing needed transmission. Projects where multiple project partners are collaborating account for approximately 10,000 miles, representing a cost of approximately $29.8 billion (nominal $).

High-Voltage Transmission Projects



In addition to focusing on upgrades and replacements to modernize the grid, there is continued investment in large, high-voltage projects to accommodate changing generation sources and customer needs. As more renewable generation, which is typically located far from load, enters the supply mix, high-voltage transmission lines are vital in transporting that generation over long distances. High-voltage projects consisting of 345 kV and higher represent approximately 13,000 miles and an investment cost of over $45 billion (nominal $).

Transmission Project Inclusion Criteria

A minimum project investment threshold of $20 million was applied to the selection of projects contained in this report, for both transmission system improvements, as well as those supporting the integration of renewable resources. Similar to previous years, however, a lower threshold of $10 million was applied to any Smart Grid projects included in this report.

Highlighted Projects Recently Completed (2013)

Project Name	Transmission Planning Region (FERC Order No. 1000)
Benton North to Benton South 115 kV Line	MISO
Church Road to Getwell	MISO
Cleveland Area Synchronous Condensers (Eastlake Unit 5)	PJM
CREZ Projects	ERCOT
Devers – Colorado River and Devers – Valley No. 2 Transmission Project	CAISO
Dyer Road 230/115 kV Substation Project	SERTP
Eldorado – Ivanpah Transmission Project	CAISO
Greater Springfield Reliability Project	ISO-NE
Intercession to Gifford – 230 kV 3000 Amp Ckt 1 Transmission Project	FRCC
Jacksonville 230 kV Static VAR Compensator	SERTP
Kathleen to Zephyrhills N – 2nd 230 kV Line Transmission Project	FRCC
Lower SEMA Transmission Project	ISO-NE
Michigan Thumb Loop Transmission Project (Phase One)	MISO
Mona to Oquirrh (Energy Gateway Second Circuit)	NTTG
NEEWS – Rhode Island Reliability Project	ISO-NE
Northeast Louisiana Improvement Projects (Phase One)	MISO
One Nevada 500 kV Transmission Intertie	WestConnect
Pawnee – Smoky Hill 345 kV Transmission Project	WestConnect
PHASOR Program	CAISO
Pleasant Prairie – Zion Energy Center	MISO
Ray Braswell to Wynndale – New 115 kV Line	MISO
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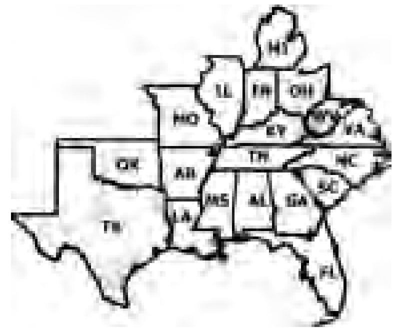
AMERICAN ELECTRIC POWER (AEP)



Company Background:

- AEP is one of the largest electric utilities in the United States, delivering electricity to more than five million customers in 11 states.
- AEP's service territory covers approximately 200,000 square miles in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.
- System-wide there are approximately 40,000 circuit miles of transmission lines, including over 2,100 circuit miles of 765 kV transmission.
- Customer service is provided through AEP's seven regional utilities: AEP Ohio; AEP Texas; Appalachian Power; Indiana Michigan Power; Kentucky Power; Public Service Company of Oklahoma; and Southwestern Electric Power Company.
- AEP is continuing its efforts to develop an extra high-voltage (EHV) interstate transmission superhighway. In furtherance of this effort, AEP is increasing on-system investment through the establishment of service territory focused transmission companies (Transcos). AEP is also maintaining a focus on its current project-based joint ventures with several utilities to build transmission in regions across the country:
    - Electric Transmission Texas, LLC (ETT): A joint venture with a subsidiary of MidAmerican Energy Holdings Company established to invest in transmission within the Electric Reliability Council of Texas (ERCOT);
    - Transource Energy, LLC: A partnership with Great Plains Energy, Inc. to pursue competitive transmission projects under FERC Order 1000;
    - Electric Transmission America, LLC (ETA): A joint venture with a subsidiary of MidAmerican Energy Holdings;
    - ETA has established Prairie Wind Transmission, LLC, a joint venture with Westar Energy to build EHV transmission in the Southwest Power Pool (SPP);
    - Pioneer Transmission, LLC: AEP and Duke Energy formed a joint venture to build a 765 kV transmission line in Indiana.
- Between 2003 and 2012, AEP put $4.3 billion of transmission plant into service.

Prairie Wind Transmission, LLC

Prairie Wind Transmission
A joint venture between Westar Energy and ETA

Description: The Prairie Wind project consists of approximately 108 miles of new double-circuit 345 kV transmission line linking an existing 345 kV substation near Wichita, Kansas to a new 345 kV Thistle substation northeast of Medicine Lodge, Kansas (near the Flat Ridge Wind Farm). The line continues south from the wind farm to the Kansas-Oklahoma border.

Cost: The total project is estimated to cost $170 million. ETA and Westar Energy will each invest $85 million.

Status: The project broke ground on August 1, 2012 and is currently under construction. The project is scheduled to be in-service by December 2014.

Investment Partners: Electric Transmission America, LLC (a 50/50 joint venture between subsidiaries of American Electric Power and MidAmerican Energy Holdings Company) and Westar Energy.

Benefits: The line will increase the reliability of the transmission system and the capacity to move power in the area, providing utilities and their customers with access to lower-cost electricity. Additionally, it will facilitate wind generation development and allow utilities to operate their existing power plants more efficiently.

Pioneer Transmission, LLC

Description: The Pioneer project consists of approximately 286 miles of new 765 kV transmission line linking Duke Energy's Greentown Station (near Kokomo, Indiana) to AEP's Rockport Station (near Evansville, Indiana). Originating at Duke Energy's Greentown Station, the 765 kV line runs west to the existing Reynolds 345 kV substation just north of Lafayette, Indiana before extending southwest to AEP's Sullivan Station and further south to AEP's Rockport Station.

Cost: The total project is estimated to cost $1.1 billion.

Status: The 66 mile segment of the project that runs from Greentown to the existing Reynolds 345 kV substation was included in the 2011 MISO Transmission Expansion Plan as a Multi-Value Project (MVP). The Greentown to Reynolds segment has entered the EPC phase. It will be developed jointly by Pioneer and NIPSCo. The remaining portion of the project will be evaluated by MISO and PJM as part of their next planning review cycles. The anticipated in service date for the Greentown to Reynolds segment is 2018.

Investment Partners: American Electric Power and Duke Energy.

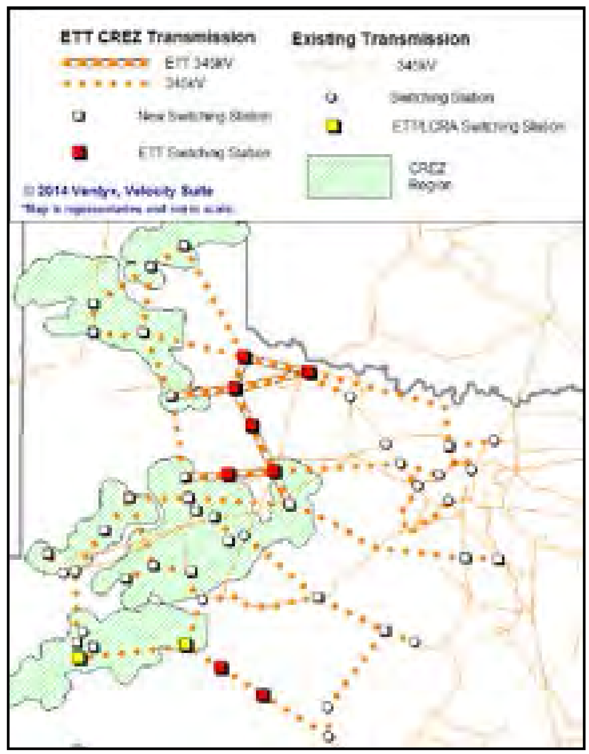
Benefits: The project will enhance the reliability of power delivery by creating a major new route for power. It will better link the region's power plants and create a route for new generation, such as wind energy. Pioneer, along with the other MVP projects approved by MISO, will facilitate the integration of wind generation in Indiana and enhance market efficiency.

Electric Transmission Texas

Company Background:

- Electric Transmission Texas, LLC (ETT) is a regulated transmission-only electric utility that builds, owns, and operates transmission assets within the Electric Reliability Council of Texas (ERCOT) under the regulation of the Public Utility Commission of Texas (PUCT).
- Currently, ETT owns and operates 1,304 circuit miles of transmission and has 530 circuit miles under development through region-wide efforts.

Competitive Renewable Energy Zone Projects



Description: The PUCT assigned $4.93 billion of Competitive Renewable Energy Zone (CREZ) transmission projects to be constructed by seven transmission and distribution utilities. The project will eventually transmit 18,456 megawatts (MW) of wind power from West Texas and the Panhandle to highly populated metropolitan areas of the state. ETT's current CREZ portfolio includes 1,087 circuit miles of 345 kV transmission lines.

Cost: ETT's current estimate of total CREZ investment is approximately $1.5 billion through 2013.

Status: Majority of construction for CREZ was in 2012 and 2013. All of the CREZ projects were in service by the end of 2013.

Investment Partners: ETT is a joint venture between subsidiaries of AEP and MidAmerican Energy Holding Company. Each owns a 50 percent equity ownership in ETT.

Benefits: The CREZ program, including ETT's projects, is expected to provide the capacity to transfer roughly 18,000 megawatts (MW) of wind power from West Texas and the Panhandle to highly populated metropolitan areas of the state. This increased transfer capacity will reduce existing constraints on installed wind plants and provide transmission capacity for future projects.

Valley Import Project and Cross Valley Project

Description: The Valley Import Project and Cross Valley Project are among the most significant planned projects in ERCOT, and include over 200 pole miles of ETT 345 kV transmission into and within the Lower Rio Grande Valley, and two new 345 kV stations.

Cost: The combined estimated capital cost for the Valley Import Project and Cross Valley Project is nearly $800 million. ETT's portion of the projects is estimated to be roughly $500 million.

Status: These projects have a planned in-service date of 2016.

Investment Partners: ETT is a joint venture between subsidiaries of AEP and MidAmerican Energy Holding Company. Each owns a 50 percent equity ownership in ETT.

Benefits: The projects will relieve existing transmission constraints in the area and serve future demand in this rapidly growing area of the U.S.

AEP Transcos

Company Background:

- AEP Transmission Company, LLC serves as a holding company for AEP's seven transmission–only electric utilities that were formed in 2009 to assist AEP's Operating Companies by providing an additional source of capital to meet their increasing transmission capital needs thereby allowing greater financial flexibility to AEP's utility Operating Companies to make appropriate capital investment decisions across their distribution, generation, and transmission functions.
- OH Transco, I&M Transco, OK Transco, KY Transco, and WV Transco are operational and have assets in-service or under construction.
- AP Transco can seek certification of future projects in its own name but the Virginia SCC will determine whether the project will ultimately be owned by AP Transco or APco.
- SW Transco is pending approval in Arkansas and Louisiana, with decisions anticipated in 2014.

I&M Transco: Sorenson 765/345 kV New Station/Lines

Description: The Sorenson project addresses low voltages in the Fort Wayne area and is a PJM mandated project. This project includes 14 miles of new 765 kV line and a 765/345 kV transformer at Sorenson Station, as well as a 345 kV line that will utilize AEP's new Breakthrough Overhead Line Design (BOLD).

Estimated Cost: $250 million.

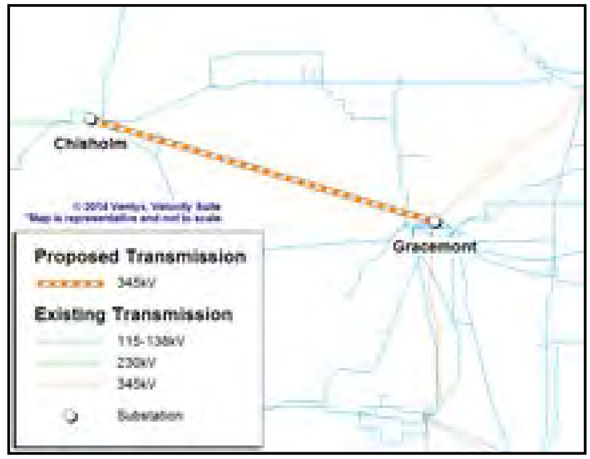
Status: Expected staged in-service dates in 2015-2016.

Investment Partners: None.

Benefits: The Sorenson project will bring an additional EHV source of power closer to Fort Wayne and ensure reliable service in the region.

OK Transco: Chisholm to Gracemont 345 kV

Description: The Chisholm to Gracemont 345 kV line addresses future overloads on the 138 kV network in western Oklahoma. Multiple 138 kV elements are overloaded for the future loss of various lines. This project alleviates the issue by introducing a new EHV 345 kV source at Chisholm in western Oklahoma.



Estimated Cost: $120 million.

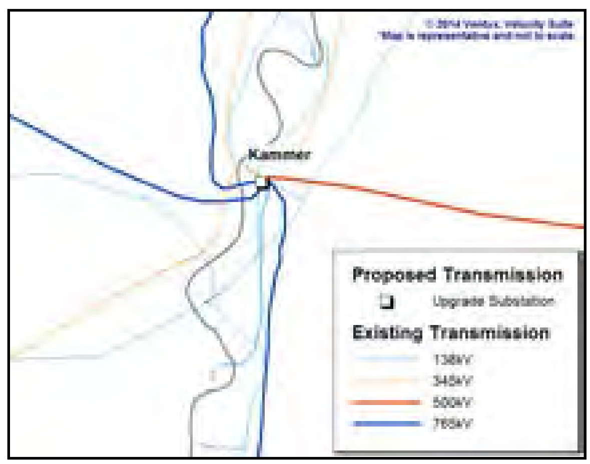
Status: Expected in-service date of March 2018.

Investment Partners: None.

Benefits: The Chisholm to Gracemont EHV 345 kV transmission line ensures reliable service in western Oklahoma by connecting this area to the existing Oklahoma EHV system at Gracemont.

WV Transco: Kammer 345/138 kV Rebuild/Expansion

Description: The Kammer project provides the network upgrades to maintain grid reliability for generation retirements. The project includes new circuit breakers in the 765 kV and 345 kV yards, and a complete rebuild of the 138 kV yard at Kammer Station.



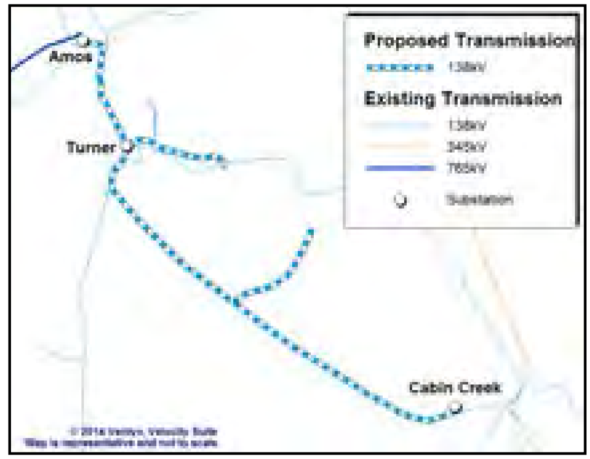
Estimated Cost: $165 million.

Status: Expected in-service date of December 2015.

Investment Partners: None.

Benefits: The Kammer project will ensure continued reliable service to the region after the retirement of 630 MW of generation.

Kanawha Valley Area (KVA) Improvements



Description: The Kanawha Valley Area project provides network upgrades to maintain grid reliability in West Virginia for generation retirements. The project includes rebuilding a 52 mile double-circuit 138 kV line and establishing a connection between the Mountaineer and Sporn Stations via a new 765/345 kV transformer.

Estimated Cost: $252 million.

Status: Expected in-service date of December 2016.

Investment Partners: None.

Benefits: The KVA project will not only meet the immediate needs to maintain grid reliability, but position the region well for future growth.

AMEREN CORPORATION

Company Background:

- Ameren Corporation serves 2.4 million electric customers and 900,000 natural gas customers across 64,000 square miles in Illinois and Missouri. Ameren has three subsidiaries which are transmission-owning members of the MISO. The three companies own and operate approximately 7,500 miles of transmission lines.

- Ameren Transmission Company (ATX) is the transmission development subsidiary. ATX was formed in July 2010 and is dedicated to regional electric transmission infrastructure investment.
- Ameren Illinois Company (AIC) delivers electric and gas service to its customers in Illinois.
- Ameren Missouri is a vertically integrated utility providing electric and gas service in central and eastern Missouri.
- Between 2003 and 2012, Ameren invested approximately $694 million in transmission.

Grand Rivers Projects

Description: The approved Grand Rivers Projects consist of three new transmission projects in Illinois and Missouri consisting of over 500 miles of 345kV transmission lines. These projects are named Illinois Rivers, Mark Twain and Spoon River.

The Illinois Rivers project consists of approximately 375 miles of 345 kV transmission from northeastern Missouri, crossing the Mississippi River and continuing east across Illinois to the Indiana Border.

The Mark Twain project is approximately 90 miles of 345 kV transmission from the Missouri- Iowa border in northeast Missouri connecting to the Missouri terminus of the Illinois River project.

The Spoon River project consists of 70 miles of 345 kV transmission in Northwest Illinois. (A portion of the Spoon River project may be built by another MISO transmission owner in accordance with the MISO Transmission Owners Agreement.) These three projects will primarily be constructed by Ameren Transmission Company of Illinois. Fiber Optic Shield Wire will be used throughout the project to facilitate high speed relaying, with the potential to be used for data pathways for smart grid development. Additionally, at least one advanced technology; low-loss transformer will be installed.

Cost: Over $1.3 billion.

Status: The Grand Rivers Projects were designated as Multi-Value Projects (MVPs) as part of the $6 billion of transmission investment included in the 2011 MISO Transmission Expansion Plan which was approved by the MISO Board of Directors on December 8, 2011. In May 2011, the Illinois Rivers Project received FERC approval for incentive ratemaking treatment, including Construction Work in Progress (CWIP), use of a hypothetical capital structure during construction, and future recovery of abandonment costs. In November 2012, the same incentive ratemaking treatment was also approved by FERC for the Mark Twain and Spoon River projects. After close to 100 public meetings throughout Illinois on the proposed Illinois Rivers route, a filing with the Illinois Commerce Commission was made in November 2012 requesting a Certificate of Public Convenience and Necessity. In August 2013, the Illinois Commerce Commission (ICC) issued an order supporting the need for the project and granting a Certificate of Public Convenience and necessity (CPCN) for the construction of portions of the Illinois Rivers transmission project. In February 2014, the ICC issued a final order approving the remaining substations and routes for the Illinois Rivers project. The first substation is expected to be placed into service in 2015. The first transmission line sections of Illinois Rivers are expected to be in-service in 2016, with all portions of the project expected to be completed by the end of 2019.

The Mark Twain and Spoon River projects are both in the planning and design stage. Both are expected to be placed into service by the end of 2018.

Investment Partners: None.

Benefits: Collectively, with the other MISO-approved MVPs, these projects will enable the integration of wind and other renewable energy resources into the MISO system to meet the MISO member renewable energy standards and goals. They enhance the reliability of the bulk electric system and improve the MISO market efficiency by reducing energy production costs. They also provide the system with flexibility and resiliency as the generators in MISO implement their plans for environmental compliance, including possible generation plant closures.

Fargo – Mapleridge

Description: The project involves the construction of a new substation near Peoria, Illinois (Mapleridge) that will split the existing Duck Creek – Tazewell 345 kV line into two circuits. From Mapleridge, a new 345 kV line will be extended in a northerly direction, approximately 16 miles, to the existing Fargo substation. The project includes a new 345/138 kV transformer at Fargo. Fiber Optic Shield Wire will be installed to facilitate high speed relaying and communication. This project will be constructed by Ameren Illinois.

Cost: $80 million.

Status: The public meeting process was completed in late 2012 and a Certificate of Public Convenience and Necessity (CPCN) filing was made with the Illinois Commerce Commission (ICC) in February 2013. In September 2013, the ICC granted the CPCN for the project. Design and easement acquisition activities for the project are in progress. The planned in-service date of the project is December 2016.

Investment Partners: None.

Benefits: This project will eliminate the risk of low voltages on the north side of Peoria, Illinois.

Bondville – SW Campus

Description: The project involves the construction of nine miles of new 138 kV line near Champaign, Illinois and upgrades to the existing Bondville and Southwest Campus substations, including multi-breaker 138 kV ring busses at each station. This project will be constructed by Ameren Illinois.

Cost: $45 million.

Status: A Certificate of Public Convenience and Necessity was received from the ICC in August 2012. Design and easement acquisition for the project are nearing completion. Construction at the Bondville and SW Campus substations is underway and the transmission line construction is targeted to begin in March 2014. The planned in-service date of the project is June 2015.

Investment Partners: None.

Benefits: This project reduces the risk of potential loss of load and voltage collapse due to multiple outages of transmission lines and transformers in the Champaign area.

Brokaw – South Bloomington

Description: The project involves the construction of approximately six miles of new 345 kV line near Bloomington, Illinois and upgrades to the existing Brokaw and South Bloomington substations. The project includes a new 345/138 kV transformer at South Bloomington. This project will be constructed by Ameren Illinois.

Cost: $30 million.

Status: A Certificate of Public Convenience and Necessity was received from the ICC in September 2012. Design and easement acquisition for the project are underway. The planned in-service date of the project is December 2015.

Investment Partners: None.

Benefits: This project is needed to avoid potential future loss of load due to a common tower outage involving two 138 kV lines.

Latham – Oreana

Description: The project involves the construction of nine miles of new 345 kV line north of Decatur, Illinois from the Oreana substation to a new tap on the existing line from Clinton to Latham. The project also includes the construction of 345 ring busses at Oreana and Latham and other substation upgrades. This project will be constructed by Ameren Illinois.

Cost: $30 million.

Status: A Certificate of Public Convenience and Necessity was received from the ICC in April 2011. The transmission line portion of the project was placed in-service in October 2013 and the Oreana Substation was placed in-service in November 2013. The remaining portion of the project, the Latham substation modifications, is planned to be in service by December 2014.

Lutesville – Heritage

Description: This project involves the construction of a new 14 mile 345 kV transmission line from the existing Lutesville Substation to a new 345/138 kV substation (Heritage) northwest of Cape Girardeau, Missouri. Fiber Optic Shield Wire will be installed to facilitate high speed relaying and communication. This project will be constructed by Ameren Missouri.

Cost: $60 million.

Status: A Certificate of Public Convenience and Necessity was received from the Missouri Public Service Commission in April 2013. The design and easement acquisition activities for this project are currently in progress. The planned in-service date of the project is June 2016.

Investment Partners: None.

Benefits: This project is necessary to avoid the potential loss of more than 300 MW of load in the Southeast Missouri area due to multiple contingencies. The project is also needed to assure adequate post-contingency voltages and maintain facility loadings within ratings.

AMERICAN TRANSMISSION COMPANY (ATC)

AMERICAN TRANSMISSION COMPANY®

Company Background:

- ATC started business on January 1, 2001 as the first multi-state, transmission-only utility in the United States. ATC has a single focus: transmission. ATC's transmission system allows energy producers to transport electric power from where it's generated to where it's needed similar to the interstate highway system with high-voltage electricity traveling on the transmission system wires like vehicles on the highway.
- ATC provides electric transmission service in an area from the Upper Peninsula of Michigan, throughout the eastern half of Wisconsin and into portions of Illinois. The 9,480 circuit miles of high-voltage transmission lines and 529 substations provide communities with access to local and regional energy sources.
- ATC operates their $3.3 billion transmission system as a single entity. As a public utility whose infrastructure serves as the link in transporting electricity to millions of electricity users, ATC has duties and responsibilities to:
    - Operate the transmission system reliably;
    - Assess the ability of the system to adequately meet current and future needs;
    - Plan system upgrades to meet those needs in the most efficient, effective, and economic ways;
    - Construct upgrades in time to meet those needs; and
    - Maintain the transmission equipment and surroundings to minimize opportunity for failures.
- Between 2003 and 2012, ATC invested nearly $3.0 billion in transmission.

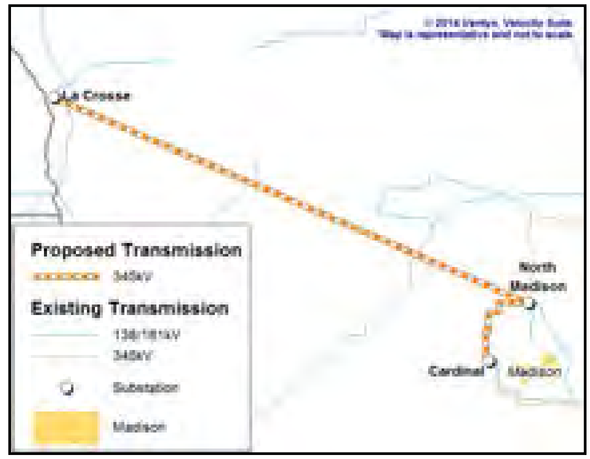
Badger Coulee

Description: The Badger Coulee project consists of 160 to 180 miles of new single-circuit, 345 kV transmission line from Xcel Energy's Briggs Road Substation near La Crosse to ATC's North Madison Substation near Madison, Wisconsin and will continue to ATC's Cardinal 345 kV Substation in the town of Middleton (Dane County, Wisconsin).

Cost: Approximately $514 million to $552 million, depending on ordered route.

Status: Following public input, ATC and Xcel Energy filed an application with the Public Service Commission of Wisconsin (PSCW) in October 2013. If approved by the PSCW, construction of the new line would begin in 2016 to meet an in-service date of late 2018.

Investment Partners: ATC and Xcel Energy are investment partners. Eligible for cost sharing as a MISO Multi-Value Project (MVP).



Benefits: This project is a multiple benefits project providing economic, reliability, and public policy benefits to ATC and Xcel Energy, their customers and the MISO region. Economic benefits were evaluated for a variety of future scenarios; the project demonstrated economic benefits in every future. Reliability benefits include second contingency voltage collapse avoidance, single contingency voltage support and thermal relief, improved generation stability response, and improved import capability. Public policy benefits include allowing more import of higher-capacity wind. All of these benefits have been monetized and the sum of the benefits exceeds the cost of the project in six of six futures studied. MISO regional benefits include providing a regional backbone that can be utilized for allowing additional wind generation resources to be interconnected and delivered to the system.

Cardinal Bluffs

Description: The Cardinal Bluffs project consists of approximately 115 miles of new single-circuit, 345 kV transmission line from Dubuque County, IA area to Dane County, WI. The new line will interconnect a new 345 kV substation on ITC Holdings Corp.'s Salem – Hazelton line in Dubuque County, IA to American Transmission Co.'s Cardinal 345 kV Substation in the Town of Middleton (Dane County, WI). An intermediate substation connection to the existing ATC system also will be included as part of the project.

Cost: Approximately $458 million in nominal dollars.

Status: This project has a projected in-service date of 2018-2020.

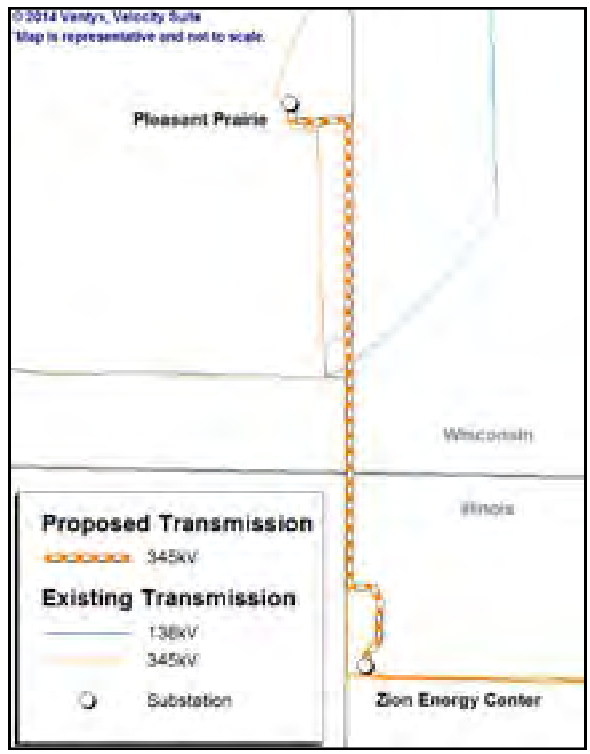
Investment Partners: ATC and ITC are investment partners. This project is eligible for cost sharing as a MISO MVP project.

Benefits: This project is a multiple benefits project providing economic, reliability, and public policy benefits to ATC and ITC, their customers, and the MISO region. Economic benefits were evaluated for a variety of future scenarios; the project demonstrated economic benefits in every future.

Reliability benefits include voltage support, thermal relief, and improved transfer capability. Public policy benefits include allowing more development and import of higher-capacity wind. All of these benefits have been monetized and the sum of the benefits exceeds the cost of the project in six of six futures studied. MISO regional benefits include providing a regional backbone that can be utilized for allowing additional wind generation resources to be interconnected and delivered to the system.

Pleasant Prairie - Zion Energy Center

Description: The Pleasant Prairie - Zion Energy Center project consists of approximately 5.3 miles of new single-circuit, 345 kV transmission line from ATC's Pleasant Prairie Substation in Kenosha, Wisconsin to the Zion Energy Center Substation owned by Commonwealth Edison (ComEd) in northern Illinois.



Cost: Approximately $34 million.

Status: This project was approved in May 2012 by the PSCW and the Illinois Commerce Commission. Construction began in early 2013 and the line was placed in service in December 2013.

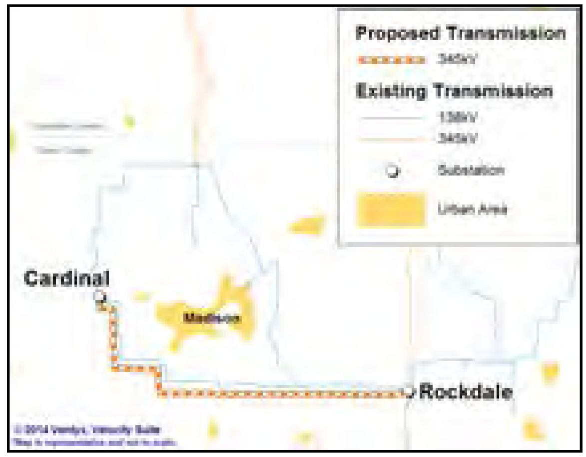
Investment Partners: None. Eligible for cost sharing as a MISO MVP project.

Benefits: The project provides savings for electric utilities and their customers by helping to relieve transmission system congestion throughout the region and enables the most efficient generators to supply power to the energy market in addition to enabling utilities to buy and sell power when it is economic to do so.

The project also improves electric system reliability, locally and regionally, by adding an additional high-voltage line to strengthen the interstate transmission connection between Wisconsin and Illinois and enabling better regional access to emergency sources of power generation.

The project is an approved MISO MVP because of its contribution in efficiently enabling renewable wind energy to be accessed by loads further east in the MISO and PJM footprints and because it provides economic savings to the MISO Energy Market footprint.

Rockdale - Cardinal



Description: The Rockdale - Cardinal project consists of approximately 32 miles of new single-circuit, 345 kV transmission line connecting the Rockdale Substation located near Christiana with the Cardinal Substation. Both substations required some equipment upgrades to support this new line.

Cost: Approximately $152 million.

Status: This project was approved in the summer of 2009 by the PSCW. Construction began in 2011 and was placed in service in February 2013.

Investment Partners: None. Received MISO Regional Expansion Criteria and Benefits I cost sharing as a Baseline Reliability Project.

Benefits: This project will improve reliability for Dane County and the MISO region. In recent years, Dane County has experienced some of the highest growth rates in the state, both in population and electricity usage. The existing transmission system in and around Dane County brings power in from outside the county to meet the needs for electricity. However, the system is operating at its limits and additional transmission lines are needed to keep pace with growing demand.

Smart Grid Investment Grant Projects

Description: The Smart Grid Investment Grant Projects consist of constructing approximately 85 miles of additional fiber optic infrastructure to connect ATC facilities, as well as the installation of 32 satellite nodes and 45 Phasor Measurement Units (PMU).

Cost: Approximately $25.4 million.

Status: ATC has negotiated a contract with the U.S. Department of Energy (DOE) that outlines reporting requirements and benefit documentation, among other metrics; the agreement was signed by the CEO in April 2010. The program of work was completed in November 2013.

Investment Partners: The U.S. DOE and the Department of Treasury, through the American Recovery and Reinvestment Act (ARRA).

Benefits: This project was developed to enhance communication reliability and data gathering capability.

Straits Flow Control

Description: The Straits Flow Control project consists of installing a VSC back-to-back HVDC device at a new Mackinac 138-kV substation and in series with the Straits - McGulpin 138 kV lines in the eastern portion of the Upper Peninsula of Michigan. The new Mackinac 138 kV substation will connect the 138 kV circuits in the area with the flow control device.

Cost: Approximately $130 million.

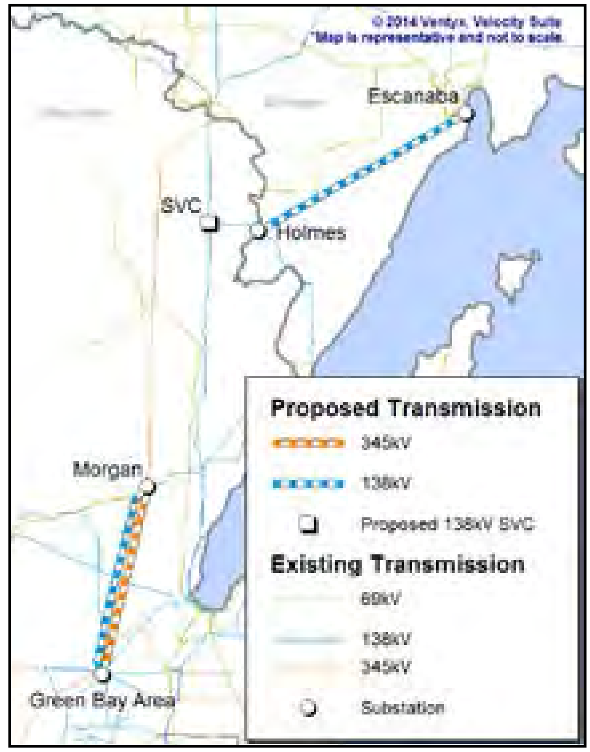
Status: Construction began in 2012 with an anticipated in-service date of August 2014.

Investment Partners: None.

Benefits: Power flow control in the eastern Upper Peninsula will adjust flows to more manageable levels, reduce system losses, improve power quality and reliability of service for local customers, and maintain reliability during maintenance work.

This project is designed to protect the Upper Peninsula system from heavy flows both east to west and west to east as system flows change. This project also has the potential to support renewable energy in the Upper Peninsula and generation changes in the Lower Peninsula.

Bay Lake Initial



Description: The initial Bay Lake project includes:

- approximately 45 miles of new single-circuit, 345 kV transmission line between a new 345-138 kV substation near the existing North Appleton substation and the existing Morgan substation north of Green Bay, Wisconsin,
- a new parallel 138 kV line,
- a new approximately 60 mile 138 kV line between Holmes and Escanaba Michigan, and
- a 150 Mvar, 138 kV SVC at a new Benson Lake Substation near Amberg, Wisconsin.

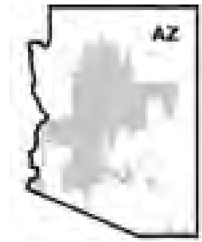
Cost: Approximately $293 - 415 million.

Status: This project has received MISO Board approval. Following public input, ATC filed an application with the Public Service Commission of Michigan for the Holmes to Escanaba portion in October 2013. ATC expects to file an application for the remaining portions of the initial project with the Public Service Commission of Wisconsin in early 2014. If approved by the Commissions, construction of the initial project could begin by 2015 with in-service dates for some project components as early as 2016 and 2017. Other phases of the project, beyond the initial, have been suspended pending future developments affecting the need for remaining phases.

Investment Partners: None. Cost sharing as a MISO reliability project.

Benefits: Addresses urgent load serving needs of Northern Wisconsin and the Upper Peninsula of Michigan due to recent changes in generation critical to reliability in the study area, operational changes underway at area generators resulting in loss of capacity, recent system performance information highlighting an increased knowledge of risk of loss of load events for this area, load increase due to impending behind-the-meter generation retirements, and multiple significant loss of load events in the past eight years.

ARIZONA PUBLIC SERVICE (APS)



Company Background:

- APS delivers electricity to more than one million customers in 11 of Arizona's 15 counties.
- System-wide, there are approximately 2,933 circuit miles of 230 kV and above high-voltage transmission lines that APS operates and either wholly or partially owns.
- APS is and has been an active participant in WestConnect.
- Planning activities and the FERC Order 1000 compliance activities are coordinated by this organization.
- Between 2003 and 2012, APS invested approximately $1.0 billion in transmission.

Hassayampa - North Gila 500 kV Project

Description: The Hassayampa - North Gila 500 kV Project consists of approximately 112 miles of new single-circuit, 500 kV transmission line between Hassayampa Switchyard located near the Palo Verde Hub (the area around the Palo Verde Nuclear Generating Station) and the existing North Gila Substation (northeast of Yuma). The line will be built on tubular or lattice tower structures 130-150 feet high, spaced approximately 600-1,800 feet apart.

Cost: Approximately $300 million.

Status: The Arizona Corporation Commission (ACC) granted APS a Certificate of Environmental Compatibility (CEC) on January 23, 2008. Most materials have been received and construction is about 20% complete. The project has an anticipated in-service date of 2015.

Investment Partners: None.

Benefits: This project will provide the electrical transmission infrastructure to import power into the high-growth Yuma area from additional generation resources around the Palo Verde Hub.

The project will improve the reliability between Arizona and California. It will also improve the reliability of the APS system in the Yuma area by providing an additional high-voltage transmission source to the region. The project will provide Arizona load serving entities access to geothermal and solar renewable resources in the Imperial Valley area of California. The project will help the development of new solar generation located along the corridor where interconnection requests have been received.

Palo Verde Substation - Delaney Substation - Sun Valley Substation - Morgan Substation - Pinnacle Peak Substation 500 kV Projects

Description: The Palo Verde Substation - Delaney Substation - Sun Valley Substation - Morgan Substation - Pinnacle Peak Substation 500 kV Projects consist of approximately 110 miles of new 500 kV transmission line connecting southwest Phoenix to northeast Phoenix. The project will consist of four segments: Palo Verde Substation to Delaney Substation; Delaney Substation to Sun Valley Substation; Sun Valley Substation to Morgan Substation; and Morgan Substation to Pinnacle Peak Substation.

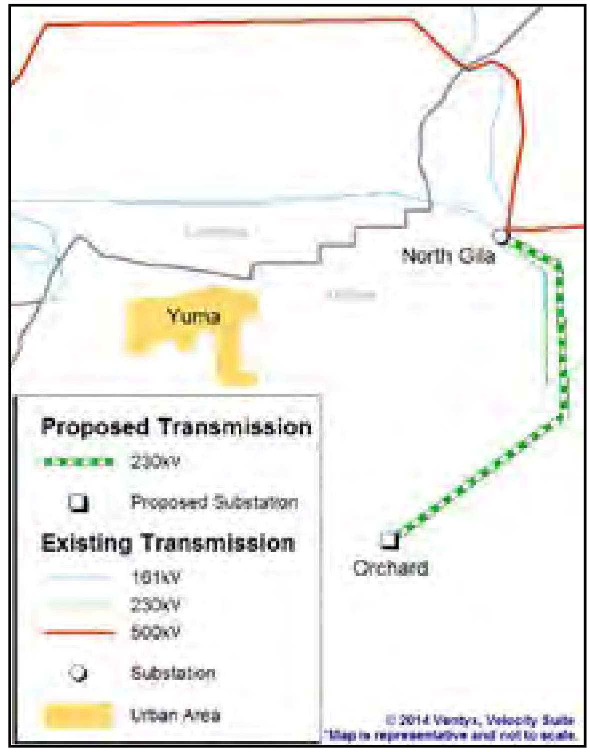
Cost: Approximately $700 million.

Status: The ACC granted APS a CEC for the Palo Verde Substation to Delaney Substation to Sun Valley Substation 500 kV Transmission Project on August 17, 2005. The Palo Verde Substation to Delaney Substation portion is planned to be completed and operational by the summer of 2016. The Delaney Substation to Sun Valley Substation 500 kV Line Project is anticipated to be in service in 2016. The Sun Valley to Morgan 500 kV Transmission Line Project is anticipated to be in service by 2018. A CEC for the Sun Valley to Morgan Project was granted by the ACC on March 17, 2009. The Morgan to Pinnacle Peak 500/230 kV Transmission Project was placed into service in October 2010 and the ACC granted APS a CEC on February 13, 2007.

Investment Partners: Central Arizona Water Conservation District.

Benefits: This project will strengthen the entire Arizona and APS transmission system by providing an additional high-voltage transmission source to the Phoenix Metropolitan area, allowing the import of an additional 1,000 MWs of power from generating sources at, or around, the Palo Verde Hub. The project will connect three major transmission systems: the Navajo South system; the Palo Verde system; and the Four Corners system. The project will also strengthen the transmission system throughout the Phoenix Metropolitan area. The project will enable the development of new large-scale solar generation projects in the area.

North Gila Substation - Orchard (formerly TS8) Substation 230 kV Project



Description: The North Gila Substation - Orchard Substation 230 kV Project consists of approximately 13 miles of new 230 kV transmission line within the Yuma, Arizona load pocket. The project will consist of 500/230 kV transformers at North Gila Substation, the 230 kV line, and a new 230/69 kV substation.

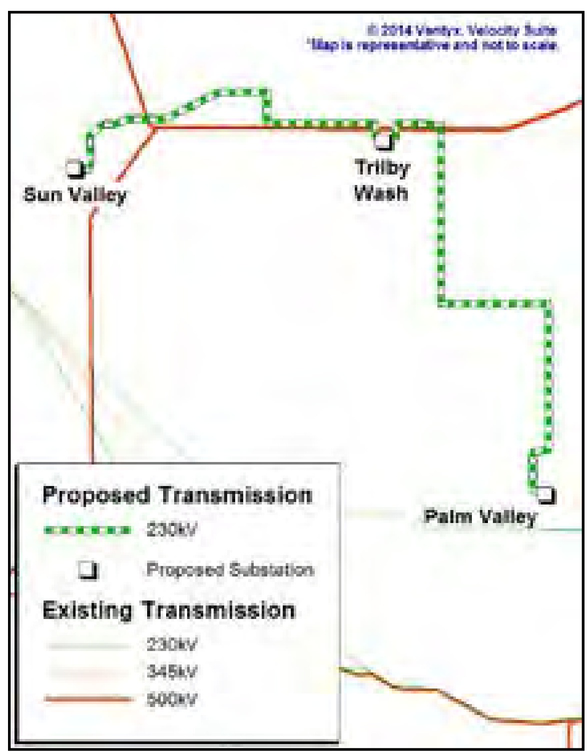
Cost: Approximately $100 million.

Status: The ACC granted APS a CEC for the North Gila Substation to Orchard Substation 230 kV Transmission Project on January 26, 2012. The North Gila 500/230 kV transformers, North Gila Substation to Orchard Substation 230 kV line, and Orchard 230/69 kV Substation are planned to be completed and operational by the summer of 2018.

Investment Partners: None.

Benefits: This project serves the need for electric energy, improved reliability, and continuity of service for the greater Yuma area.

Sun Valley – Trilby Wash – Palm Valley 230 kV Project



Description: The Sun Valley – Trilby Wash – Palm Valley 230 kV Project consists of approximately 30 miles of new 230 kV transmission line within the western Phoenix Metropolitan area. It will be built as a double-circuit capable line. However, only one circuit will be installed initially. The second circuit will be installed as needed. In addition to the 230 kV line, the project will also include a new 230/69 kV substation at Trilby Wash with one 230/69 transformer.

Cost: Approximately $72 million.

Status: The Arizona Corporation Commission (ACC) granted APS a Certificate of Environmental Compatibility (CEC) on May 5, 2005 for the Sun Valley – Trilby Wash segment and on December 22, 2003 for the Trilby Wash - Palm Valley segment. The Trilby Wash - Palm Valley 230 kV line and Trilby

Wash Substation has an anticipated in-service date of 2015. The Sun Valley - Trilby Wash 230 kV line has an anticipated in-service date of 2016.

Investment Partners: None.

Benefits: This project is required to serve the electric energy needs in the western Phoenix Metropolitan area. The project will provide more capability to import power into the Phoenix Metropolitan area along with improved reliability and continuity of service for communities in the area including El Mirage, Surprise, Youngtown, Buckeye, and unincorporated Maricopa County.

CENTERPOINT ENERGY

Company Background:

- CenterPoint Energy, Inc., headquartered in Houston, Texas, is a domestic energy delivery company that provides electric transmission and distribution service, natural gas distribution, competitive natural gas sales and services, and pipeline and field services operations.
- The company serves more than five million customers in Arkansas, Louisiana, Minnesota, Mississippi, Oklahoma, and Texas.
- Assets total nearly $23 billion.
- With over 8,700 employees, CenterPoint Energy and its predecessor companies have been in business for more than 135 years.

- CenterPoint Energy Houston Electric (CenterPoint Energy) is the regulated electric transmission and distribution utility focused strictly on energy delivery within a 5,000 square-mile service area in and around Houston.
- CenterPoint Energy's transmission infrastructure consists of approximately 3,700 circuit miles of overhead transmission lines and 26 circuit miles of underground transmission lines.
- Between 2003 and 2012, CenterPoint Energy invested approximately $750 million in transmission.

Mont Belvieu Area Upgrades

Description: The Mont Belvieu Area upgrade project consists of a new Jordan 345 kV / 138 kV substation, a new 800 MVA 345 kV / 138 kV autotransformer, and other miscellaneous transmission system upgrades. The Jordan substation will connect six 138 kV circuits (four existing and two new 0.9 mi lines) as well looping in an existing 345 kV circuit.

Cost: The project is estimated to cost approximately $42 million.

Status: The project was approved by the Electric Reliability Council of Texas (ERCOT) Regional Planning Group in March 2012. Construction began in early 2013 with several of the upgrades completed by May 2013. The overall project, including the installation of the 800 MVA 345 kV / 138 kV autotransformer is scheduled for completion by May 2014.

Investment Partners: None.

Benefits: The completion of this project will provide necessary real and reactive power support in response to significant industrial customer load growth at both existing substations and several new industrial customer substations in the area. Additional reliability will be provided for system protection purposes by limiting the number of in-series industrial customer substations and providing a dual pilot relaying scheme.

Freeport Area Upgrades

Description: The Freeport area is a 69 kV load pocket located in the far southern portion of the CenterPoint Energy transmission system. The 69kv load pocket is connected to the rest of the transmission system by two 138/69kV autotransformers that are more than 40 years old and one long 69kV transmission line. The Freeport Area Upgrades Project consists of upgrading and converting all transmission facilities in the Freeport area to 138 kV operation.

Cost: The project is estimated to cost approximately $47 million.

Status: The project was approved by the Electric Reliability Council of Texas (ERCOT) Regional Planning Group in July 2012. Construction began in early 2013 with the overall project scheduled for completion by May 2015.

Investment Partners: None.

Benefits: The project will improve reliability of the Freeport area by replacing aging transmission structures and transformers that are nearing the end of their useful life and also provide storm hardening benefits in the Freeport area which is important given its close proximity to the Gulf of Mexico. All transmission circuits in the Freeport Area will be converted to 138kV operation and upgraded with high-temperature conductor allowing for future load growth in the area.

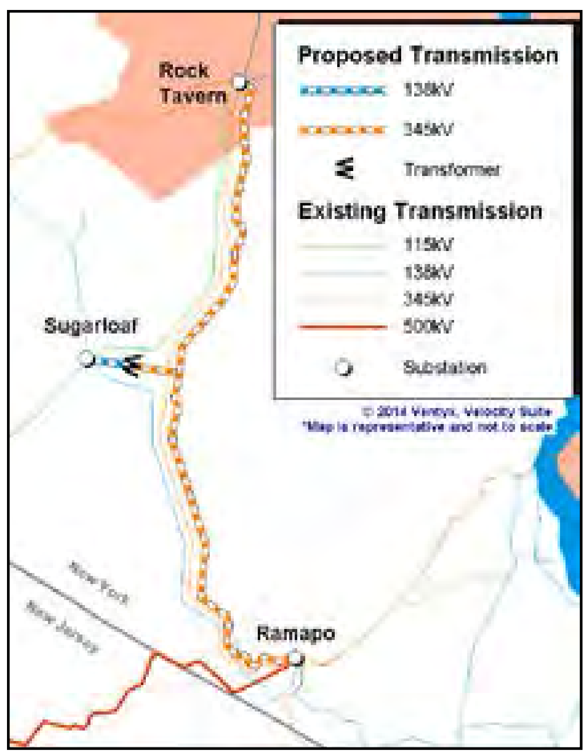
CONSOLIDATED EDISON, INC. (CON EDISON)

Company Background:

- Con Edison's regulated electric business consists of Consolidated Edison Company of New York (CECONY) and Orange & Rockland Utilities (O&R).
- CECONY provides electric service to approximately 3.3 million customers in New York City and Westchester County.
- O&R provides electric service to 300,000 customers in southeastern New York and adjacent areas of northern New Jersey and eastern Pennsylvania.
- CECONY's transmission infrastructure consists of approximately 749 circuit miles of underground electric transmission/sub-transmission and approximately 438 circuit miles of overhead electric transmission.
- O&R's transmission consists of approximately 451 circuit miles of overhead electric transmission and approximately 27 circuit miles of underground electric transmission.
- Between 2003 and 2012, Con Edison invested approximately $2.0 billion in transmission.

Ramapo – Sugarloaf 138 kV Line, Ramapo – Rock Tavern 345kV Line

Description: O&R is developing a 138 kV line, Feeder 28, which will consist of 15 miles of new bundled 345 kV conductor between its Sugarloaf 138 kV substation in Orange County and the 138 kV side of Ramapo 345/138kV substation in Rockland County. The conductor will be installed on existing double circuit towers that presently carry a 345 kV line between Rock Tavern and Ramapo substations.



The O&R transmission project will be leveraged to establish a second 345 kV transmission line between CECONY's Ramapo 345 kV substation and Central Hudson's Rock Tavern 345 kV substation in northern Orange County. The Ramapo – Rock Tavern 345 kV line will consist of converting Feeder 28 to a 345kV line and adding 27 miles of new bundled 345 kV conductor between Sugarloaf substation and Rock Tavern 345 kV substations. Converting Feeder 28 will consist of relocating the connection within the

Ramapo substation from 138kV to 345kV and installing a new 345 /138 kV step-down transformer at Sugarloaf substation.

Cost: The Ramapo – Sugarloaf 138kV (Feeder 28) project cost is approximately $30 million. The project cost for the Ramapo – Rock Tavern 345kV line is estimated at $130 million.

Status: Construction is underway for Feeder 28 and is on schedule to be in service by summer 2014. The Ramapo – Rock Tavern 345kV has been approved by New York's Public Service Commission and is on schedule to begin construction in spring 2014 and be in service by summer 2016.

Investment Partners: Feeder 28 is being developed by O&R. The Ramapo – Rock Tavern 345kV line is part of the proposed NY Transco project portfolio. NY Transco is a proposed transmission company partnership owned by the NY Transmission Owners. The project is currently being developed by CECONY and will be transferred to NY Transco once it is formed.

Benefits: Ramapo – Sugarloaf 138kV (Feeder 28) addresses a local reliability need for the O&R system. This new feeder will serve as an additional supply to O&R to accommodate load growth.

The Ramapo – Rock Tavern 345kV line increases transmission capability into Southeastern New York providing additional consumer access to efficient, cost-effective generation. The line was submitted as part of a response to the New York Public Service Commission to address the goals of New York's Energy Highway initiative. Specifically it is one of three state-approved transmission projects that address a potential reliability need in 2016 if nuclear plant Indian Point retires and is recognized for providing additional statewide benefits including developing a more robust electric grid and promoting economic development.

Staten Island Unbottling

Description: Phase One of this project will split an existing 345 kV double-leg transmission feeder, which runs between Goethals substation in Staten Island, NY and Linden Cogeneration substation in Linden, NJ, into two separate feeders. This will consist of relocating each terminal connection of the two-leg feeder into two separate connections at both Goethals and Linden substations.

Phase Two of the project will consist of installing ten refrigeration plants to force cool dielectric fluid for four underground 345kV transmission feeders running between Goethals substation and Gowanus and Farragut substations in Brooklyn.

Cost: Phase One and Phase Two project cost is approximately $250 million.

Status: The project has been approved by the New York Public Service Commission, and is on schedule to begin construction in spring 2014 and be in service by summer 2016.

Investment Partners: The project is part of the proposed NY Transco project portfolio. NY Transco is a proposed transmission company partnership owned by the NY Transmission Owners. The project is currently being developed by CECONY and will be transferred to NY Transco once it is formed.

Benefits: Phase One increases the reliability at Goethals substation by reducing the impact of losing the single existing feeder between Goethals and Linden Cogen substations. Phase Two relieves congestion by increasing transmission capacity by 200MW from Staten Island to Brooklyn, providing additional access to existing generation.

The Staten Island Unbottling project was submitted as part of a response to the New York Public Service Commission to address the goals of New York's Energy Highway initiative. Specifically it is one of three state-approved transmission projects that address a potential reliability need in 2016 if nuclear plant Indian Point retires and is recognized for providing additional statewide benefits including developing a more robust electric grid and promoting economic development.

Rainey – Corona 138 kV Line

Description: The new 138kV line within Queens County will supply power from Rainey 345kV transmission substation to Corona 138kV substation and will consist of approximately 7 miles of new underground 138kV solid dielectric cable as well as a new step-down 345/138 kV Autotransformer, a 138kV Phase Angle Regulator (PAR) and several new high voltage circuit breakers for the terminal substations.

Cost: The project cost is estimated at $220 million.

Status: The project is currently in the design engineering phase. Construction will begin in 2015 and the line is scheduled to be in service by summer 2018.

Investment Partners: None.

Benefits: The project addresses reliability deficiencies for two Transmission Load Areas encompassing Astoria, Corona, and Jamaica, Queens which were caused by the mothballing of two steam electric generation units in Astoria.

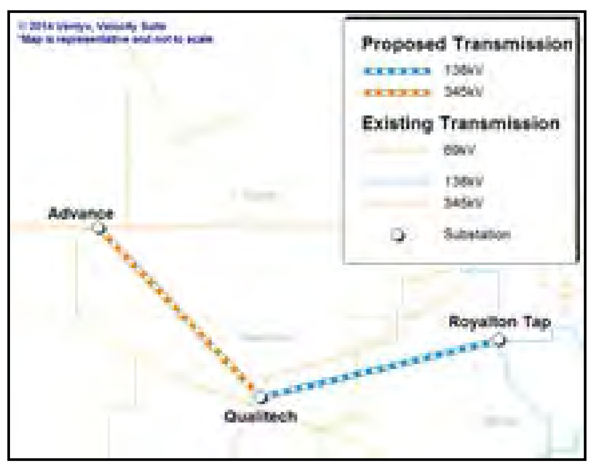
DUKE-AMERICAN TRANSMISSION COMPANY (DATC)

Company Background:

- On April 13, 2011, Duke Energy and American Transmission Co. announced the creation of Duke-American Transmission Co., a joint venture that will build, own, and operate new electric transmission infrastructure in North America.
- DATC has proposed the Midwest Portfolio, a combination of transmission line projects that includes multiple phases in five Midwestern states. This portfolio fills performance gaps in the existing transmission grid to improve electric system reliability, market efficiency, and economic benefits to local utilities and will increase delivery of high-quality renewable resources.
- In April, 2013 DATC completed purchase of 72 percent of the capacity of Path 15, an 84-mile, 500-kilovolt transmission line in central California.
- Also, DATC has purchased the rights to develop the Zephyr Power Transmission Project, a proposed 950 mile transmission line that would deliver wind energy produced in eastern Wyoming to California and the southwest United States.

DATC Midwest Portfolio Phase 1 South (mileages and costs will be further refined)

Description: DATC Midwest Portfolio Phase 1 South consists of 11 miles of 345 kV transmission lines, 13 miles of 138 kV transmission lines, and one new 345 kV substation. The project will provide a more robust network north and west of Indianapolis, supporting continued delivery of economic power to area homes and businesses.



Cost: Approximately $65 million (2013$).

Status: DATC Midwest Portfolio Phase 1 South was identified as a "Best Fit Plan" in the MISO MTEP13 Market Efficiency Project (MEP) process and has been advanced to MTEP Appendix B. The project is being reviewed for possible inter-regional benefits in the MISO-PJM cross-border planning process. An anticipated in-service date of 2022 has been identified for this project.

States Served: MISO network customer states, most prominently Indiana.

Investment Partners: All DATC projects will be jointly owned by Duke Energy and American Transmission Company LLC. If selected as a MISO MEP, this project will be eligible for regional cost sharing.

Benefits: This phase of the DATC Midwest Portfolio provides multiple benefits including system reliability, market efficiency, and economic benefits to local utilities. It also enables increased delivery of high-quality renewable resources.

DATC Midwest Portfolio Phase 1 North (mileages and costs will be further refined)

Description: DATC Midwest Portfolio Phase 1 North consists of 75 miles of 345 kV transmission line. The project will provide a more robust network to bypass historical congestion southeast of Chicago and support continued flows of economic power between Illinois and Indiana in either direction, as dictated by market conditions.

Cost: Approximately $135.8 million (2013$).

Status: DATC Midwest Portfolio Phase 1 North is included in Appendix C of the 2013 MISO MTEP and is being reviewed for inter-regional benefits in the MISO-PJM cross-border planning process. An anticipated in-service date of 2022 has been identified for this project.

States Served: MISO and PJM network customer states, most prominently Illinois and Indiana.

Investment Partners: All DATC projects will be jointly owned by Duke Energy and American Transmission Company LLC.

Benefits: This phase of the DATC Midwest Portfolio provides multiple benefits including system reliability, market efficiency, and economic benefits to local utilities. It also enables increased delivery of high-quality renewable resources.

DATC Midwest Portfolio Phase 2 (mileages and costs will be further refined)

Description: DATC Midwest Portfolio Phase 2 consists of 43 miles of 345 kV double-circuit transmission lines connecting to Tazewell and Brokaw substations in central Illinois, a 117-mile 500 kV HVDC transmission line and two HVDC terminals. The project will span from central Illinois to western Indiana.

Cost: Approximately $908 million (2013$).

Status: DATC Midwest Portfolio Phase 2 is included in Appendix C of the 2013 MISO MTEP. An anticipated in-service date of 2023 has been identified for this project.

States Served: MISO network customer states, most prominently Illinois and Indiana.

Investment Partners: All DATC projects will be jointly owned by Duke Energy and American Transmission Company LLC.

Benefits: This phase of the DATC Midwest Portfolio provides multiple benefits including system reliability, market efficiency, and economic benefits to local utilities. It enables increased delivery of high-quality renewable resources. Furthermore, Midwest Portfolio Phase 2 uses advanced technology for improved system control and efficiency which will create a bypass for chronically congested lines south of Chicago.

DATC Midwest Portfolio Phase 3 (mileages and costs will be further refined)

Description: DATC Midwest Portfolio Phase 3 consists of 50 miles of single-circuit 345 kV transmission lines and three new substations. The project will span from northeastern Illinois to the Dumont substation in north-central Indiana.

Cost: Approximately $146 million (2013$).

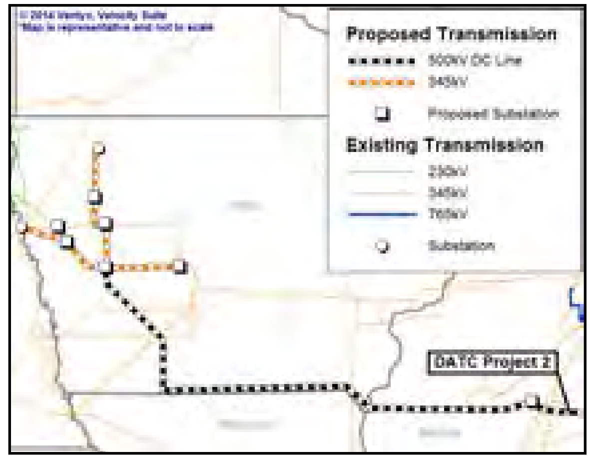
Status: DATC Midwest Portfolio Phase 3 is included in Appendix C of the 2013 MISO MTEP and is being reviewed for inter-regional benefits in the MISO-PJM cross-border planning process. An anticipated in-service date of 2022 has been identified for this project.

States Served: MISO and PJM network customer states, most prominently Illinois and Indiana.

Investment Partners: All DATC projects will be jointly owned by Duke Energy and American Transmission Company LLC.

Benefits: This phase of the DATC Midwest Portfolio provides multiple benefits including system reliability, market efficiency, and economic benefits to local utilities. It also enables increased delivery of high-quality renewable resources.

DATC Midwest Portfolio Phase 4 (mileages and costs will be further refined)



Description: DATC Midwest Portfolio Phase 4 consists of 147 miles of double-circuit 345 kV transmission lines, 99 miles of single-circuit 345 kV transmission lines, 15 miles of single-circuit 161 kV transmission lines, a 435 mile 500 kV HVDC transmission line, a new HVDC terminal and five new AC substations. The project will span from northwestern Iowa to Central Illinois.

Cost: Approximately $2.217 billion (2013$).

Status: DATC Midwest Portfolio Phase 4 is included in Appendix C of the 2013 MISO MTEP. An anticipated in-service date of 2024 has been identified for this project.

States Served: MISO network customer states, most prominently Iowa and Illinois.

Investment Partners: All DATC projects will be jointly owned by Duke Energy and American Transmission Company LLC.

Benefits: This phase of the DATC Midwest Portfolio provides multiple benefits including system reliability, market efficiency, economic benefits to local utilities and it enables increased delivery of high-quality renewable resources. Furthermore, Midwest Portfolio Phase 4 uses advanced technology for improved system control and efficiency.

DATC Midwest Portfolio Phase 5 (mileages and costs will be further refined)

Description: DATC Midwest Portfolio Phase 5 will consist of 145 miles of double-circuit 345 kV transmission lines, 36 miles of single-circuit 345 kV transmission lines and a 765-345 kV transformer.

The project will span from the Gwynneville substation in central Indiana to the Beatty substation in central Ohio.

Cost: Approximately $516 million (2013$).

Status: DATC Midwest Portfolio Phase 5 is included in Appendix C of the 2013 MISO MTEP. An anticipated in-service date of 2023 has been identified for this project.

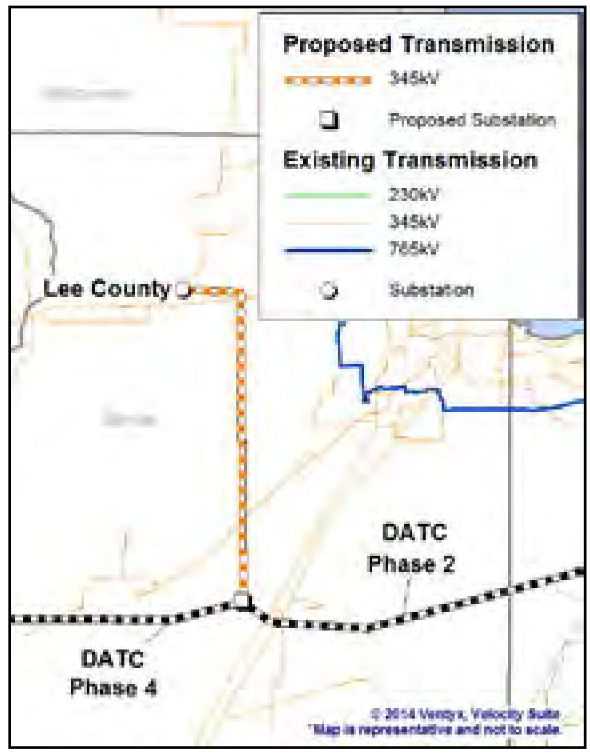
States Served: MISO and PJM network customer states, most prominently Indiana and Ohio.

Investment Partners: All DATC projects will be jointly owned by Duke Energy and American Transmission Company LLC.

Benefits: This phase of the DATC Midwest Portfolio provides multiple benefits including system reliability, market efficiency, economic benefits to local utilities and it enables increased delivery of high-quality renewable resources.

DATC Midwest Portfolio Phase 6 (mileages and costs will be further refined)

Description: DATC Midwest Portfolio Phase 6 will consist of 124 miles of double-circuit 345 kV transmission line. The project will span from the Lee County substation in north-central Illinois to the new DATC HVDC terminal in central Illinois.



Cost: Approximately $290 million (2013$).

Status: DATC Midwest Portfolio Phase 6 is included in Appendix C of the 2013 MISO MTEP. An anticipated in-service date of 2023 has been identified for this project.

States Served: MISO and PJM network customer states, most prominently Illinois.

Investment Partners: All DATC projects will be jointly owned by Duke Energy and American Transmission Company LLC.

Benefits: This phase of the DATC Midwest Portfolio provides multiple benefits including system reliability, market efficiency, economic benefits to local utilities and it enables increased delivery of high-quality renewable resources.

DATC Midwest Portfolio Phase 7 (mileages and costs will be further refined)

Description: DATC Midwest Portfolio Phase 8 will consist of a 55 mile single-circuit 345 kV line. The project will span from near the Paddock substation in southeastern Wisconsin to the Pleasant Valley substation in northeastern Illinois.

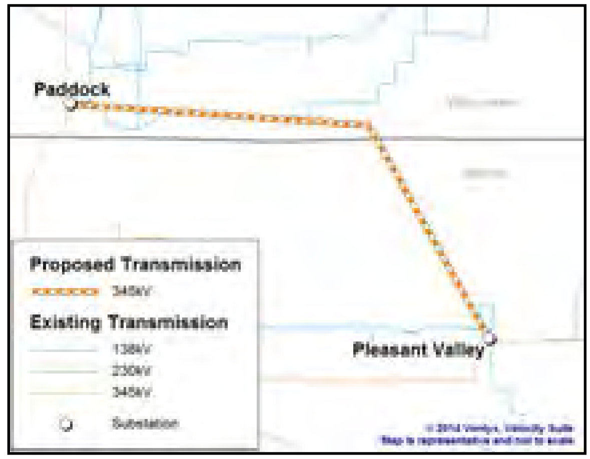
Cost: Approximately $116 million (2013$).

Status: DATC Midwest Portfolio Phase 7 is included in Appendix C of the 2013 MISO MTEP. An anticipated in-service date of 2022 has been identified for this project.

States Served: MISO and PJM network customer states, most prominently Wisconsin and Illinois.

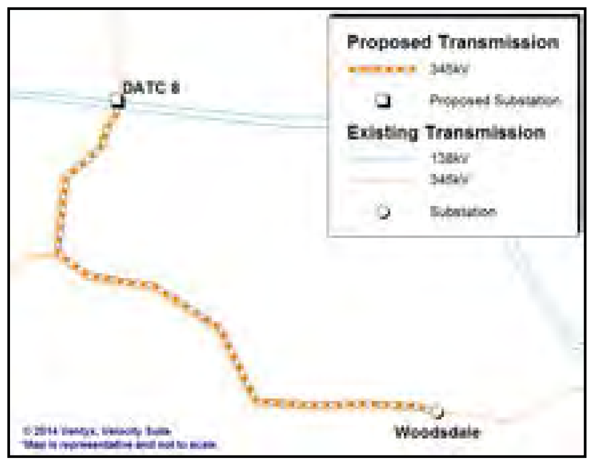
Investment Partners: All DATC projects will be jointly owned by Duke Energy and American Transmission Company LLC.

Benefits: This phase of the DATC Midwest Portfolio provides multiple benefits including system reliability, market efficiency, economic benefits to local utilities and it enables increased delivery of high-quality renewable resources.



DATC Project 8 (mileages and costs will be further refined)

Description: DATC Project 8 will consist of a 7 mile 345 kV line constructed in parallel with an existing 345 kV line to create a double circuit 345 kV line. The project will span from a new DATC 8 substation located on the Miami Fort – West Milton line to the Woodsdale substation northwest of Cincinnati.



Cost: Approximately $25 million (2013$).

Status: DATC Project 8 has been submitted to the PJM MEP process and will be evaluated for PJM regional benefits. An anticipated in-service date of 2020 has been identified for this project.

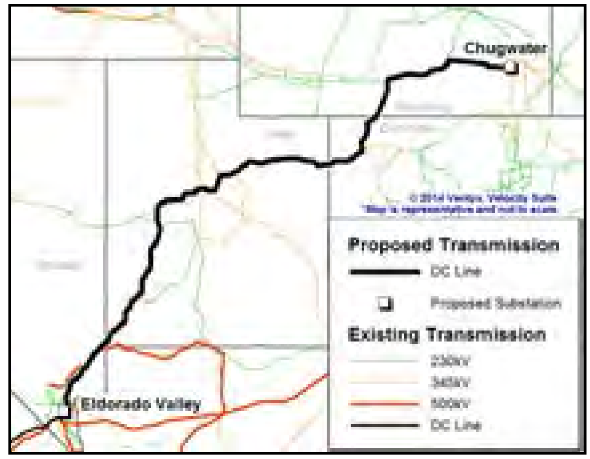
States Served: PJM network customer states, most prominently Ohio.

Investment Partners: All DATC projects will be jointly owned by Duke Energy and American Transmission Company LLC.

Benefits: This DATC project provides multiple benefits including system reliability, market efficiency, economic benefits to local utilities and it addresses multiple congested Cincinnati-area system elements.

Zephyr Power Transmission Project

Description: The Zephyr Power Transmission Project is a 950 mile 500 kV high-voltage direct-current line. The line will have a 3,000 MW capacity. The Zephyr project would originate in Chugwater, Wyoming and would terminate in the Eldorado Valley just south of Las Vegas.



Cost: Approximately $3.5 billion.

Status: The Zephyr Power Transmission Project is proposed with an anticipated in-service date of 2020.

States Served: Multiple, potentially including Wyoming, Utah, Nevada, California and others.

Investment Partners: All DATC projects will be jointly owned by Duke Energy and American Transmission Company LLC.

Benefits: DATC's Zephyr project creates a highly efficient and strategic connection between the wind-rich areas of Wyoming and electricity load centers in California and the southwestern U.S.

DUKE ENERGY

Company Background:

- Duke Energy is the largest electric power holding company in the United States with more than $100 billion in total assets.
- Duke Energy's regulated utility operations serve more than 7 million electric customers located in six states in the Southeast and Midwest (North Carolina, South Carolina, Florida, Indiana, Ohio, and Kentucky) over a 100 thousand square-mile service territory.
- Duke Energy owns six regulated retail electric utilities: Duke Energy Carolinas (DEC), Duke Energy Progress (DEP), Duke Energy Florida (DEF), Duke Energy Kentucky (DEK), Duke Energy Indiana (DEI), and Duke Energy Ohio (DEO).
- Duke Energy owns and operates approximately 32,000 circuit miles of transmission.

- Duke Energy is engaged in transmission investment within their regulated utilities as well as in subsidiary joint ventures.
- Duke Energy participates in the Eastern Interconnection Planning Collaborative as well as in MISO, PJM, the North Carolina Transmission Planning Collaborative, the Southeastern Regional Transmission Planning process, and the FRCC transmission planning region.
- Between 2003 and 2012, Duke Energy (including previous Progress Energy Inc.) invested approximately $4.0 billion in transmission.

Harris Plant – RTP 230 kV Transmission Line Project – DEP

Description: The Harris Plant – RTP 230 kV Transmission Line Project consists of approximately 14 miles of new 230 kV transmission line and converts seven miles of 115 kV transmission line to 230 kV from Harris Plant to a new RTP 230 kV substation.

Cost: Approximately $49 million.

Status: The project is under construction. The RTP 230 kV substation and 14 miles of new line are in-service. The remainder of the project is scheduled for completion by June 2014. All rights-of-way have been acquired and engineering is complete.

Investment Partners: None.

Benefits: This project benefits the regional transmission grid.

Jacksonville 230 kV Static VAR Compensator - DEP

Description: Install a 300 MVAR 230 kV Static VAR Compensator (SVC) at the Jacksonville 230 kV Substation.

Costs: Approximately $31 million.

Status: The project was placed in service in May 2013.

Investment Partners: None.

Benefits: This project was identified during a dynamic evaluation of DEP's Eastern System during periods of increased imports. The analysis indicated that under certain faulted conditions that DEP East's transmission network along the coast of North Carolina would be unable to maintain adequate voltage support. The lack of voltage support in the coastal area means that voltage recovery following certain faults is inadequate to maintain proper voltage. The addition of this static VAR compensator mitigates the voltage concern.

Intercession to Gifford - 230 kV 3000 Amp Ckt 1 Transmission Project - DEF

Description: Construct new 13 mile, 230 kV transmission line from Intercession City substation to Gifford substation.

Costs: $37.2 million.

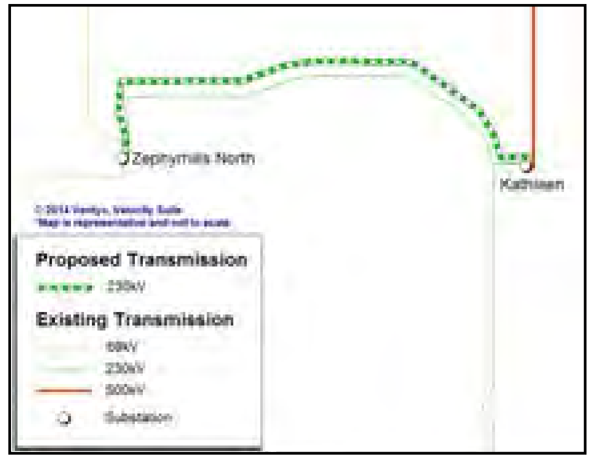
Status: The project was completed in July 2013.

Investment Partners: None.

Benefits: The new Intercession City-Gifford 230 kV relieves overloads caused by Category B and C5 contingencies, by supplying an alternate path of power-flow into Orlando load pocket. In addition to mitigating overloads, this new path will also provide support to DEF's transmission grid assisting with maintenance outages as well as contributing to reduced flows across DEF's 69 kV grid. Intercession City-Gifford 230 kV will enhance both DEF's ability as well as neighboring utilities' to provide safe and reliable electricity to homes, schools, and businesses in the region.

This new transmission line was identified as the most cost-effective and efficient means to both increase the capability of the existing 230 kV network and serve the increasing load and customer base in the central Florida region. The majority of the transmission line will reside within a TLSA certified corridor and will adhere to the applicable design, construction, operational, environmental, and safety requirements.

Kathleen to Zephyrhills N – 2nd 230 kV line Transmission Project - DEF



Description: Construct an additional 11 mile, 230 kV transmission line between the Kathleen and Zephyrhills North substations.

Cost: $22.0 million.

Status: The project was completed in September 2013.

Investment Partners: None.

Benefits: An additional source is needed to the Tarpon Springs – Zephyrhills (TZ) 69 kV line in southern Pasco County, for load and voltage support as well as redundancy for the radial Kathleen – Zephyrhills North 230 kV line. DEF plans to achieve this by building a second 230 kV line from Kathleen to Zephyrhills North.

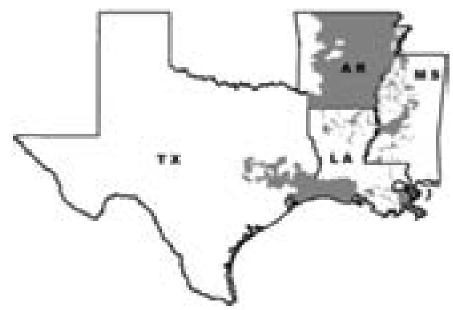
Without this proposed project, for the event of an outage of the single existing 230 kV Kathleen - Zephyrhills North line, numerous facilities will be overloaded and experience low voltages in this area between DEF, Tampa Electric Company, and Withlacoochee River Electric Cooperative. On certain high load days, the Energy Control Center Operators from the three utilities perform pre-contingency remedial switching in anticipation of the outage. If the contingency occurs, additional remedial switching may be performed, and load curtailment may be needed to alleviate overloading and undervoltages.

ENTERGY CORPORATION

Company Background:

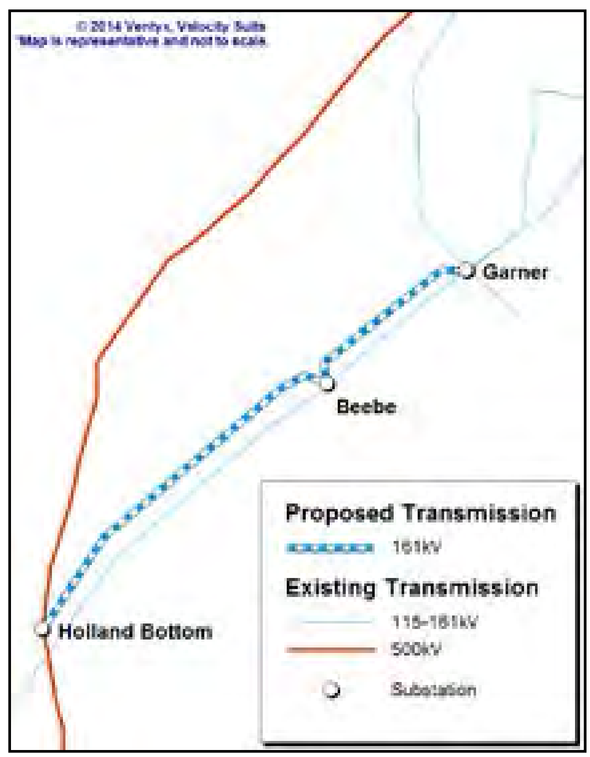
Entergy THE POWER OF PEOPLE℠

- Entergy, through its six operating companies, Entergy Arkansas, Inc., Entergy Gulf States Louisiana, L.L.C., Entergy Louisiana, LLC, Entergy Mississippi, Inc., Entergy New Orleans, Inc., and Entergy Texas, Inc., delivers electricity to 2.7 million utility customers in four states.
- Entergy's service territory covers more than 114,000 square miles in Arkansas, Louisiana, Mississippi, and Texas.
- System-wide, there are approximately 15,400 circuit miles of transmission lines.



Holland Bottom to Beebe to Garner 161 kV Project

Description: This project is located northeast of Little Rock, AR and will be constructed in two phases. Phase 1 includes constructing a new 161 kV line from the new Holland Bottom 500/161 kV substation to the existing Beebe 115 kV station, and installing a 161/115 kV autotransformer at Beebe. Phase 2 of the project includes continuing the new 161 kV line from Beebe to the existing Garner 115 kV substation and constructing a 161 kV substation to tap into the Copper Springs-to-Searcy South 161 kV line section.



Cost: Approximately $73 million.

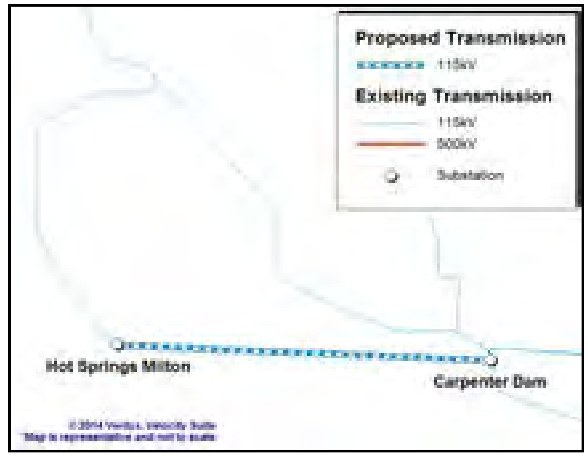
Status: Phase 1 of the project is expected to be in service by the summer of 2019; and, Phase 2 of the project is expected to be in service by the summer of 2021.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in the northeast Little Rock area.

Hot Springs Milton to Carpenter Dam 115 kV Project

Description: This project is located southwest of Hot Springs, AR and will involve the construction of a new 17-mile 115 kV line connecting Hot Springs Milton to Carpenter Dam. This new line will supply a new distribution substation and will also eliminate the radial line from Mt. Pine South to Hot Springs Milton by completing an additional loop in the Hot Springs area.



Cost: Approximately $61 million.

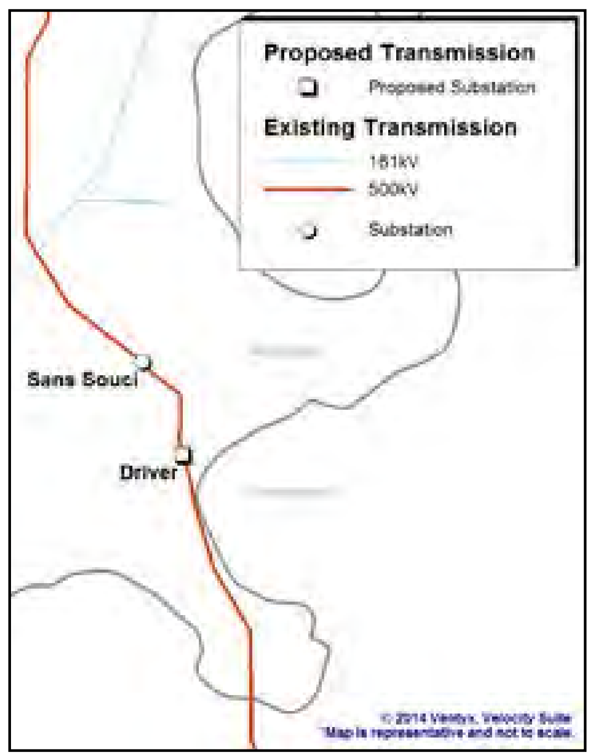
Status: This project is expected to be in service by the summer of 2016.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in the southwest Hot Springs area.

Osceola Area: Construct New 500/230 kV Substation

Description: This project, located in northeast Arkansas, involves cutting in a new Driver 500 kV substation on the existing San Souci – Shelby 500 kV line. Driver substation will be constructed with two 500/230 kV autotransformers serving the new Driver 230 kV station.



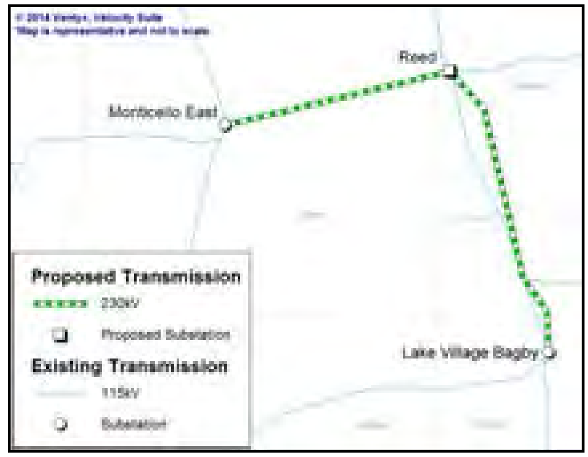
Cost: Approximately $76 million.

Status: The project is expected be placed in service by the winter of 2015.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in northeast Arkansas.

Southeast Arkansas Reliability Projects



Description: Three projects located in southeast Arkansas are involved in the construction of a new 230 kV transmission line (initially to be operated at 115 kV). Included in these projects are the construction of a new line from Lake Village Bagby to Macon Lake to Reed, and the construction of a new line from Reed to Monticello East. The projects also include the construction of a new switching substation at Reed.

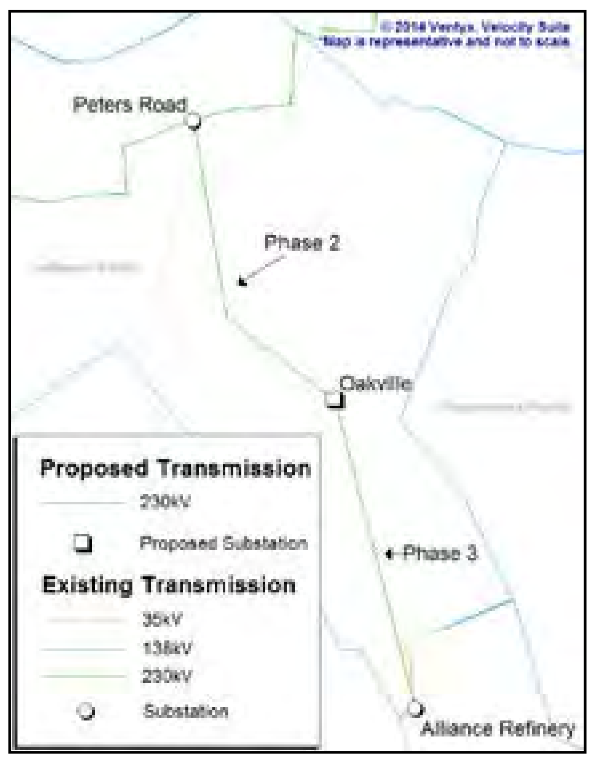
Cost: Approximately $92 million.

Status: These projects are expected to be in service as follows: Lake Village Bagby to Macon Lake (summer 2014), Macon Lake to Reed (summer 2017) and Reed to Monticello East (summer 2020).

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in the southeastern portion of Arkansas.

SELA Project Phase 2 and Phase 3



Description: The SELA Project Phase 2 and Phase 3, located in southeast Louisiana, involves the construction of a new 230 kV transmission line connecting the Peters Road 230 kV substation, a new Oakville 230 kV distribution substation, and the Alliance substation, which is located in lower Plaquemines Parish. The project also includes the installation of a 230-115 kV autotransformer at Alliance.

Cost: Approximately $58 million.

Status: Phase 2 was completed and placed in service in September 2012. Phase 3 of the project is currently under construction and is expected to be completed in 2015.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in southeast Louisiana.

Franklin to McComb 115 kV Project

Description: The Franklin to McComb 115 kV Project involves the construction of a new 230 kV transmission line (initially operated at 115 kV) from Franklin to the McComb Substation.

Cost: Approximately $60 million.

Status: This project is expected to be in service by the summer of 2020.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in the south Mississippi area.

Madison County Reliabilty Project

Description: This project includes constructing a new 230 kV line from the existing Bozeman Road 230 kV substation (currently a radial station) to the new Tinnin Road 230 kV substation, which will tap the existing Clinton Industrial to Gerald Andrus 230 kV line in northern Hinds County.

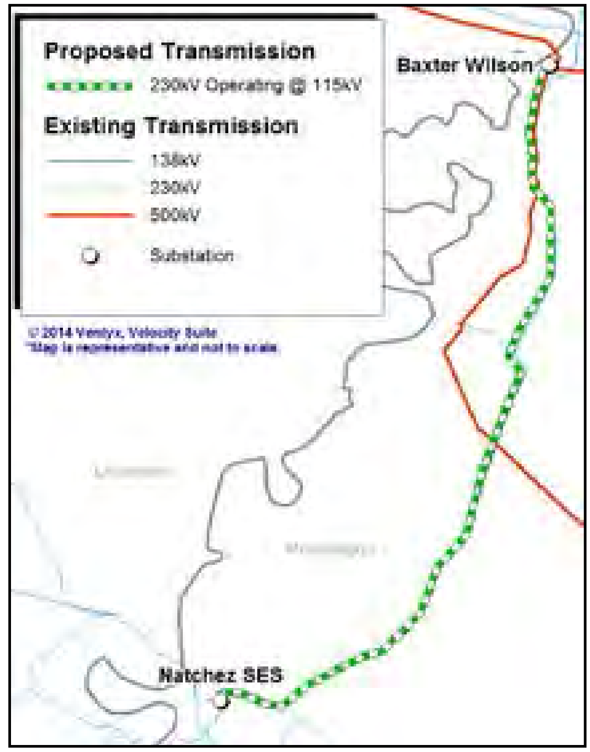
Cost: Approximately $58 million.

Status: This project is expected to be in service by the summer of 2017.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in the Madison County, Mississippi area.

Natchez Improvement Project



Description: This project includes constructing a new 230 kV line from Baxter Wilson 115 kV to Natchez SES 115 kV to initially be operated at 115 kV. The project will also include rebuilding the existing Baxter Wilson to Natchez SES 115 kV.

Cost: Approximately $146 million.

Status: This project is expected to be in service by the summer of 2018.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in the Natchez, Mississippi area.

Ponderosa to Grimes 230 kV Project

Description: The Ponderosa to Grimes 230 kV project is a long-term project located in the western area of Entergy Texas. The project includes the installation of a 345-230 kV autotransformer at Grimes, installation of a new 230-138 kV autotransformer at the Ponderosa switching station, and the construction of a new 230 kV line between Grimes and Ponderosa. The project also includes the upgrade of a 138 kV transmission line between the Ponderosa and Conroe substations.

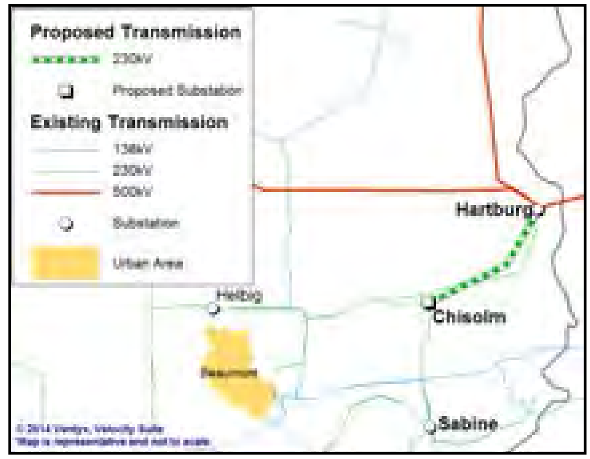
Cost: Approximately $97 million.

Status: The project is expected to be in service in the summer of 2016.

Investment Partners: None.

Benefits: This project addresses both the future load growth and reliability needs in Entergy Texas' western area as well as congestion in the Grimes substation area.

Orange County Project



Description: The Orange County project is a long-term project to be located north of the Beaumont/Port Arthur area in Texas. The project includes construction of a new 230 kV switching substation referred to as Chisolm Road, construction of a new 230 kV line from Hartburg to Chisolm Road, and cutting-in of the existing McLewis to Helbig and Georgetown to Sabine 230 kV lines. The project also includes the installation of a second 500-230 kV autotransformer at Hartburg.

Cost: Approximately $74 million.

Status: The project is expected to be in service in the summer of 2017.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in the east Texas area north of Beaumont.

Benton North to Benton South 115 kV Line

Description: This project, located in the southwest area of Little Rock, Arkansas, involves the construction of a new 115 kV transmission line and two substations to connect the Benton North and Benton South areas.

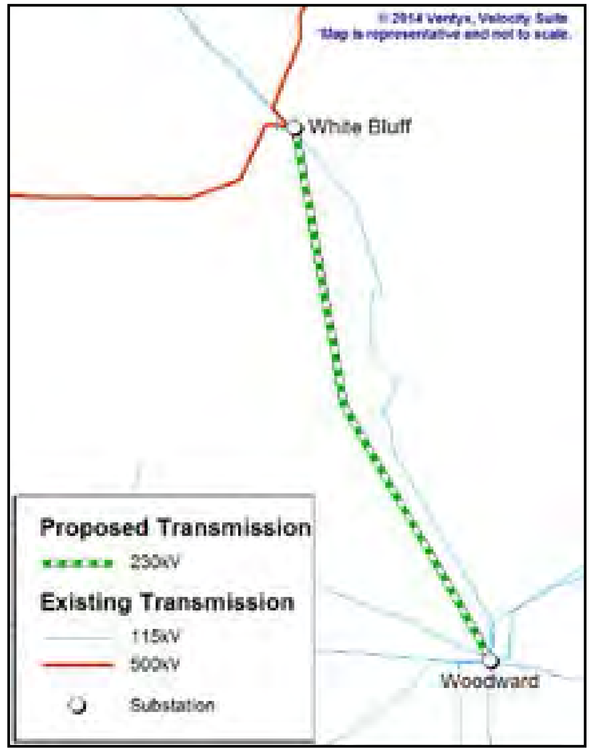
Cost: Approximately $28 million.

Status: The project was completed in April 2013.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in the southwest Little Rock area of Arkansas.

White Bluff Area Improvements



Description: These projects in the Pine Bluff area of central Arkansas include the reconfiguration of the White Bluff 500 kV substation, the addition of a new 500-230 kV autotransformer, and the construction of a new 230 kV transmission line from Entergy Arkansas' White Bluff generating facility to Woodward Substation.

Cost: Approximately $66 million.

Status: The project is expected to be placed in service in the summer of 2016.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in the White Bluff/Woodward areas of central Arkansas.

AECC Hydro Station #2 to Gillett: Construct New 115 kV Line

Description: This project, located in east-central Arkansas, involves the construction of a new 30-mile-long 115 kV transmission line connecting Entergy Arkansas' Gillett 115 kV Substation with AECC's Hydro Station #2.

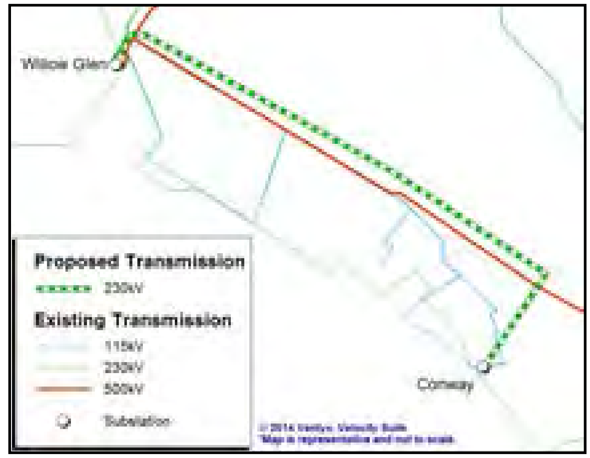
Cost: Approximately $26 million.

Status: The project is expected to be placed in service in the summer of 2016.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in the east-central area of Arkansas.

Willow Glen to Conway: Construct New 230 kV Line



Description: This project, located in the Baton Rouge industrial corridor of southeast Louisiana, involves the construction of a new 15-mile-long 230 kV transmission line between Entergy Gulf States Louisiana's Willow Glen and Conway substations.

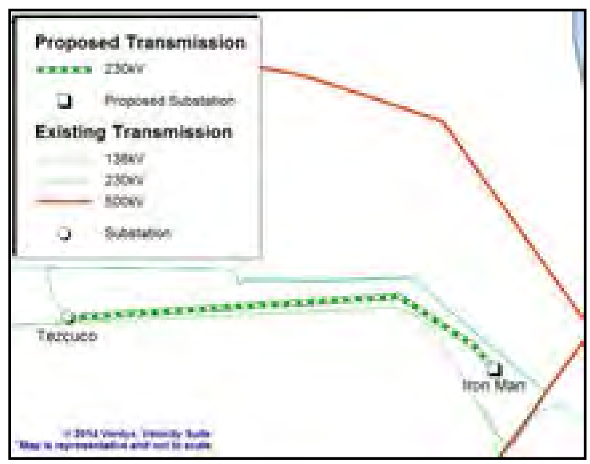
Cost: Approximately $61 million.

Status: The project is expected be placed in service by the spring of 2014.

Investment Partners: None.

Benefits: This economic project addresses future load growth and reliability needs while also helping to maintain and improve import capabilities into the Amite South area of southeast Louisiana.

Iron Man to Tezcuco: Construct New 230 kV Line



Description: This project, located in southeast Louisiana, involves the construction of a new ten-mile-long 230 kV transmission line between Entergy Louisiana's Tezcuco Substation and the new Iron Man 230 kV Switching Station.

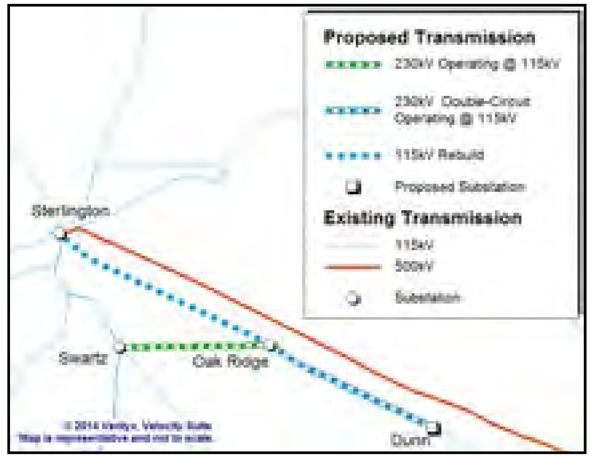
Cost: Approximately $39 million.

Status: The project, which is currently under construction, is expected be placed in service by the summer of 2015.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in southeast Louisiana.

Northeast Louisiana Improvement Projects



Description: This portfolio of projects, located in northeast Louisiana, involves three phases:

Phase 1: Construction of a new 230 kV transmission line (initially to be operated at 115 kV) between Entergy Louisiana's Swartz and Oak Ridge substations.

Phase 2: Construction of a new double-circuit 230-115 kV transmission line between Entergy Louisiana's Oakridge and the proposed Dunn substations.

Phase 3: Re-conductor of the existing Sterlington to Oak Ridge 115 kV transmission line.

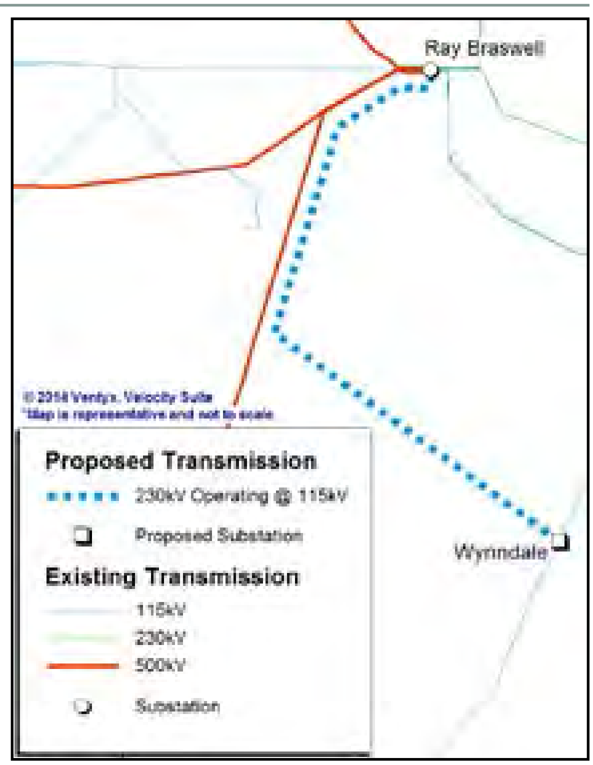
Cost: Approximately $77 million.

Status: This portfolio of projects is being constructed in multiple phases. Phase 1 was completed in 2013; Phase 2 is expected to be placed in service by the summer of 2014; and Phase 3 is expected to be placed in service by the summer of 2015.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in northeast Louisiana.

Ray Braswell to Wynndale: Construct New 115 kV Line



Description: This project, located in central Mississippi, involves the construction of a new 230 kV line (initially operated at 115 kV) transmission line between Entergy Mississippi's Ray Braswell and the proposed Wynndale substation.

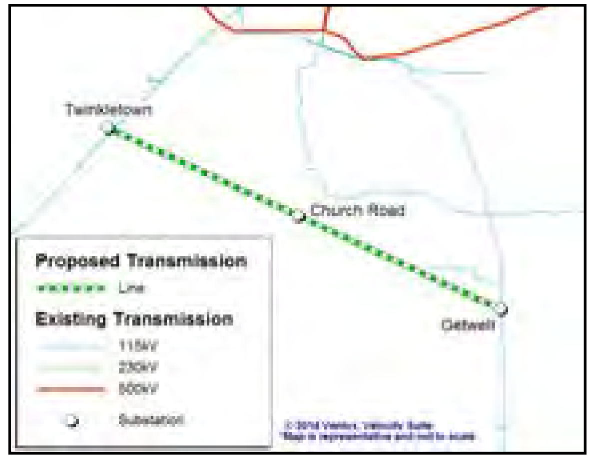
Cost: Approximately $37 million.

Status: The project was completed in November 2013.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in central Mississippi.

Church Road to Getwell: Construct new 230 kV Line



Description: This project, located in northwest Mississippi, involves the construction of a new 230 kV transmission line between Entergy Mississippi's Church Road and Getwell 230 kV substations.

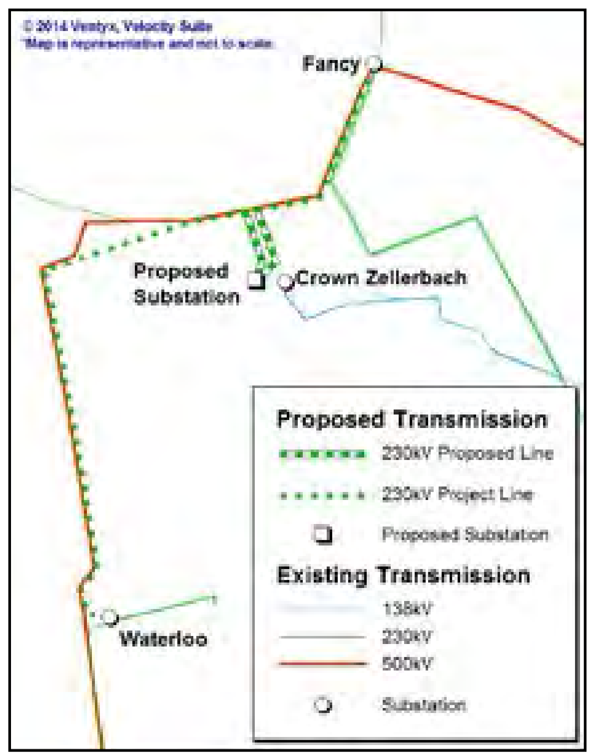
Cost: Approximately $57 million.

Status: Church Road to Getwell was completed in May 2013.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in northwest Mississippi.

Crown Zellerbach Area: Construct New 230/138 kV Substation



Description: This project, located in southeast Louisiana, involves constructing approximately 4 miles of new 230 kV transmission line to cut-in a proposed new 230-138 kV substation between the Fancy Point and Waterloo substations near the Crown Zellerbach 138 kV substation.

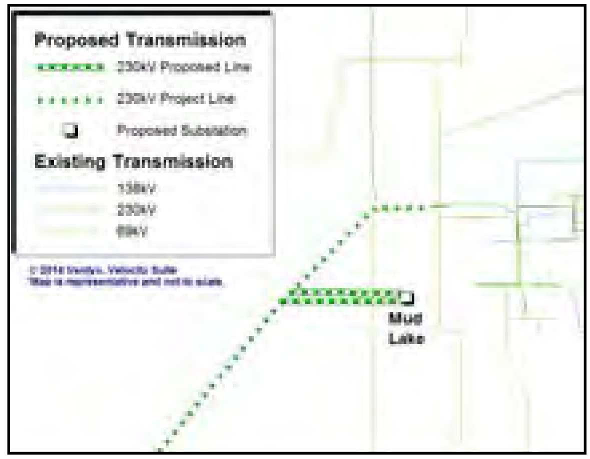
Cost: Approximately $21 million.

Status: The project is expected be placed in service by the summer of 2017.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in southeast Louisiana.

Mud Lake Area: Construct New 230 kV Substation



Description: This project, located in southwest Louisiana, involves constructing approximately 12 miles of new 230 kV transmission line to cut-in and out of the proposed new Mud Lake 230 kV substation between the Big 3 and Sabine 230 kV substations.

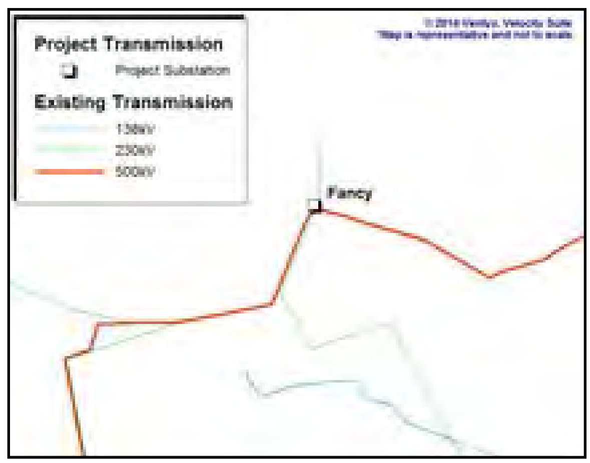
Cost: Approximately $59 million.

Status: The project is expected be placed in service by the fall of 2017.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in southwest Louisiana.

Fancy Point Substation: Add Second 500-230 kV Autotransformer



Description: This project, located in southeast Louisiana, involves the addition of a second 1,200 MVA, 500-230 kV autotransformer at the Fancy Point substation.

Cost: Approximately $21 million.

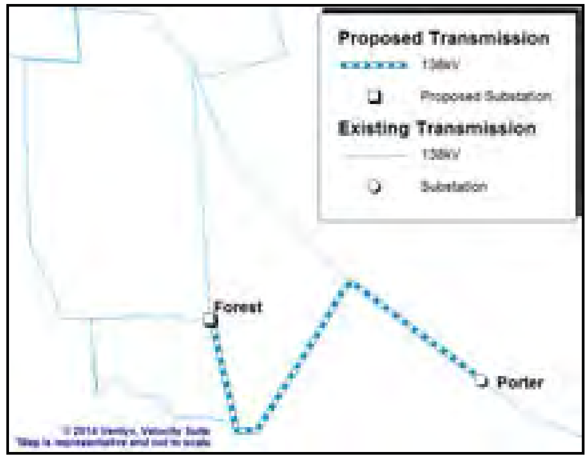
Status: The project is expected be placed in service by the summer of 2017.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in southeast Louisiana.

Porter to Forest: Construct new 138 kV Transmission Line

Description: This project, located near Conroe, Texas, involves the construction of an approximately 12-mile-long 138 kV transmission line between the existing Porter substation and the proposed Forest 138 kV substation.



Cost: Approximately $21 million.

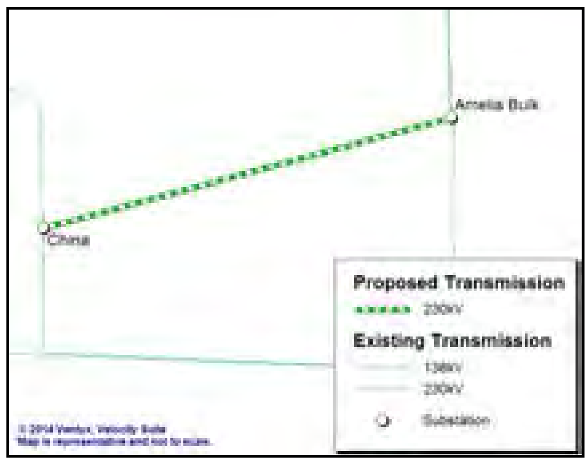
Status: The project is expected be placed in service by the summer of 2016.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in support of Entergy Texas' western region.

China to Amelia: Construct New 230 kV Line

Description: This project, located in east Texas, involves the construction of a new 230 kV transmission line between Entergy Texas' China and Amelia 230 kV substations.



Cost: Approximately $31 million.

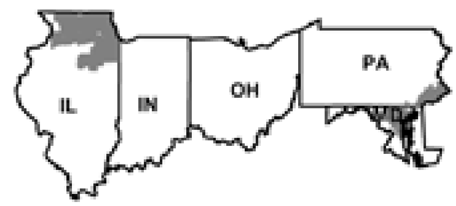
Status: The project, which is currently under construction, is expected be placed in service by the summer of 2016.

Investment Partners: None.

Benefits: This project addresses future load growth and reliability needs in east Texas.

EXELON

Company Background:



- Exelon is the leading U.S. competitive energy provider, with one of the cleanest and lowest-cost power generation fleets and largest retail customer bases in the country. The Exelon family of companies participates in every stage of the energy business, from generation to power sales to transmission to delivery. Headquartered in Chicago, the company has operations and business activities in 47 states, the District of Columbia and Canada. Exelon has approximately $23.5 billion in annual revenues and trades on the NYSE under the ticker symbol EXC.
- Through its BGE, ComEd and PECO utility subsidiaries, Exelon is one of the largest electrical and natural gas distribution companies in the nation. It delivers electricity to approximately 6.6 million customers in central Maryland (BGE), northern Illinois (ComEd) and southeastern Pennsylvania (PECO). It delivers natural gas to approximately 1.2 million customers in central Maryland (BGE) and the Philadelphia area (PECO).
- Exelon actively participates in the Eastern Interconnection Planning Collaborative (EIPC) and the PJM Regional Transmission Planning Process.

Baltimore Gas and Electric (BGE)

Company Background:

- Baltimore Gas and Electric (BGE) is a unit of Chicago-based Exelon Corporation (NYSE: EXC).
- BGE owns and operates a system of over 1,290 miles of transmission lines consisting of voltages of 115 kV, 230 kV, and 500 kV.

Conastone - Graceton - Raphael Road 230 kV Circuits

Description: The project consists of constructing and rebuilding 230 kV lines between Conastone, Graceton, and Raphael Rd. The total line length is approximately 29 miles. This improvement will create double-circuit connections between these substations with increased circuit capabilities. The existing 230 kV lines are of limited capacity and of single-circuit design.

Cost: Approximately $111 million.

Status: This project is currently in the design engineering phase. The in-service date is anticipated to be June 2017.

Investment Partners: None.

Benefits: This project maintains system reliability by avoiding NERC N-1-1 reliability criteria violations.

ComEd

ComEd
An Exelon Company

Company Background:

- Commonwealth Edison Company (ComEd) is a unit of Chicago-based Exelon Corporation (NYSE: EXC).
- ComEd owns and operates a system of over 5,000 miles of transmission lines consisting of voltages of 138 kV, 345 kV, and 765 kV, and has a peak summer load of more than 23,700 MW.

Chicago Southern Business District Burnham-Taylor 345 kV Project

Description: The Chicago Southern Business District Burnham-Taylor 345 kV Project consists of constructing approximately six miles of 345 kV XLPE cable in new duct packages (two cables per phase) between the Garfield and Taylor substations. The existing two High Pressure Fluid Filled (HPFF) cables will be reconfigured to a single-circuit and substation equipment will be upgraded to accommodate the changes.

Cost: Approximately $125 million.

Status: In progress and is targeted for completion in June 2014.

Investment Partners: None.

Benefits: This project will upgrade the existing capacity of the 345 kV system within the City of Chicago and enhance reliability.

Project to install two 300 MVAR SVCs at Prospect Heights Substation

Description: The Prospect Heights SVC Project consists of constructing two 138 kV, 300 MVAR SVCs at ComEd's Prospect Heights substation in Chicago's northwest suburbs.

Cost: Approximately $64.6 million.

Status: In progress and is targeted for completion in June 2014.

Investment Partners: None.

Benefits: This project will improve dynamic voltage recovery and system reliability.

Project to install two 300 MVAR SVCs at Crawford Substation

Description: The Crawford SVC Project consists of constructing two 138 kV, 300 MVAR SVCs at ComEd's Crawford substation in the City of Chicago.

Cost: Approximately $77.8 million.

Status: Undergoing Preliminary Engineering and targeted for completion in June 2016.

Investment Partners: None.

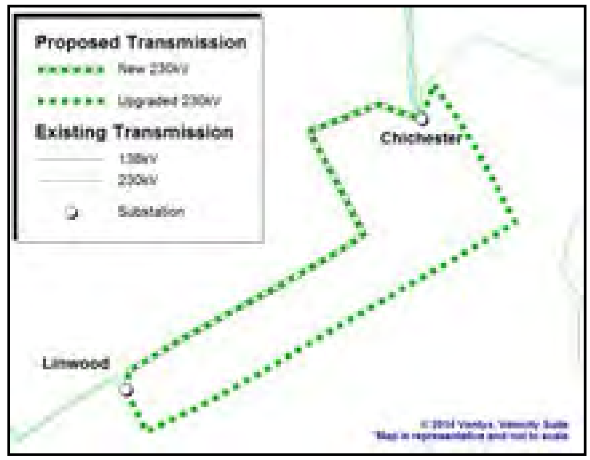
Benefits: This project will improve dynamic voltage recovery and system reliability.

PECO Energy Company (PECO)

Company Background:

- PECO is a unit of Chicago-based Exelon Corporation (NYSE: EXC)
- PECO owns and operates a system of over 1,100 miles of transmission lines consisting of voltages of 69 kV, 130 kV, 230 kV, and 500 kV.

Chichester – Linwood 230kv circuits.



Description: The project consists of constructing and upgrading 2 230 kV lines between Chichester and Linwood substations. The total length is approximately 1.5 miles. This improvement will increase the capacity of both transmission lines by combining the two existing lines into one circuit and the construction of a new combination aerial / underground line along a distinct route from the existing lines. Substation equipment at both ends of the line will be upgraded to accommodate the change.

Cost: Approximately $52 million.

Status: This project is currently in the design engineering phase. The in-service date is anticipated to be June 2018.

Investment Partners: None.

Benefits: This project will upgrade the existing capacity of the 230 kV system serving the City of Philadelphia and Delaware County, and enhance reliability.

FIRSTENERGY

Company Background:

- FirstEnergy is a leading regional energy provider headquartered in Akron, Ohio. Our subsidiaries and affiliates are involved in the generation, transmission and distribution of electricity, as well as energy management and other energy-related services.
- Our 10 utility operating companies form one of the nation's largest investor-owned electric systems based on serving 6 million customers in six states.
- Our generation subsidiaries currently control nearly 18,000 megawatts of capacity from a diversified mix of scrubbed coal, nuclear, natural gas, oil, hydroelectric pumped-storage and contracted wind and solar resources – including more than 1,900 megawatts of renewable energy.
- Our transmission subsidiaries operate approximately 24,000 miles of transmission lines connecting the Midwest and Mid-Atlantic regions. Between 2003 and 2013, FirstEnergy invested over $3 billion in transmission projects.
- We operate regional transmission control centers in Fairmont, West Virginia and Akron, Ohio.
- We produce approximately $15 billion in annual revenues, own $50 billion in assets, and have nearly 16,300 employees.

"Energizing the Future" Initiative

Description: Our "Energizing the Future" initiative is a comprehensive transmission construction program designed to enhance service reliability as power plants in the region are deactivated due to the significant cost of complying with U.S. Environmental Protection Agency mandates.

These projects include the construction of new 138 kilovolt (kV) and 345 kV transmission lines, constructing new transmission substations, and converting certain FirstEnergy generating units in northern Ohio to synchronous condensers, which are devices to regulate voltage.

Last year, we announced plans to invest an additional $2.8 billion over four years to expand this initiative. The main focus of the initial construction effort will be the 69 kV transmission power lines and substations in the Ohio Edison, The Illuminating Company, Toledo Edison and Penn Power areas.

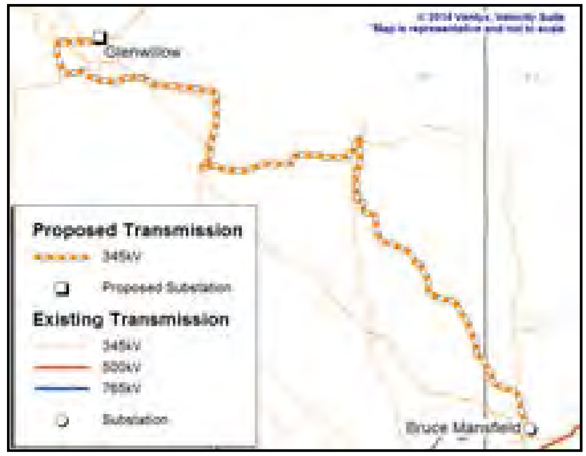
Work on these new projects is expected to begin in 2014 and continue through 2017.

As part of this program, approximately 7,500 circuit miles of 69 kV and higher transmission lines will be evaluated and rebuilt, as needed. More than 170 substations will be inspected and upgraded, along with 70,000 transmission structures that will be evaluated and rebuilt, as needed.

Overall, the new transmission projects are designed to increase FirstEnergy's load serving capability in areas where future economic growth is anticipated, particularly in Ohio's shale gas regions; improve service reliability; create more flexibility when restoring service following storms; reduce line losses; and lower the company's overall transmission maintenance costs.

Glenwillow-Bruce Mansfield Project

Description: The Glenwillow-Bruce Mansfield transmission project is part of the Energizing the Future initiative. The single-circuit 345 kV transmission line will run from the company's Bruce Mansfield Plant in Pennsylvania to the new Glenwillow Substation under construction near Cleveland, Ohio. The transmission line is 114.5 miles long with the majority of it being installed on existing transmission structures and existing rights-of-way. The line and substation were approved by the Ohio Power Siting Board in 2013.



Cost: Approximately $151.2 million.

Status: Under construction. PJM-requested in-service date is June 1, 2015.

Investment Partners: None.

Benefits: Reinforces the transmission system as a result of generation plants planned for deactivation over the next several years.

Cleveland Area Synchronous Condensers

Description: Convert several generating units in the Cleveland area to synchronous condensers to provide dynamic reactive voltage support by 2015.

Cost: At the time of the asset transfer filing at FERC in July 2012, the total estimated cost of conversion, including the cost of the transferred assets, was $81.5 million.

Status: The first conversion was completed at Eastlake Unit 5 in July 2013. Conversion of other units is planned for June 2014 through June 2015.

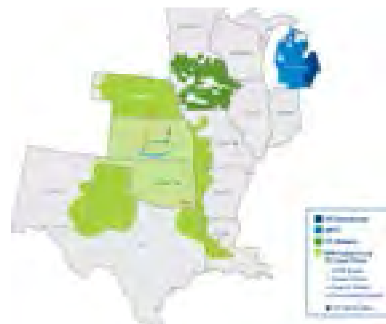
Investment Partners: None.

Benefits: The conversion of the units to synchronous condensers is a more economical, effective and expedient solution based on initial installation and long-term operation costs.

ITC HOLDINGS CORP. (ITC)

Company Background:

- ITC Holdings Corp. (NYSE: ITC) is the nation's largest independent electric transmission company.
- Headquartered in Novi, Michigan, ITC invests in the electric transmission grid to improve reliability, expand access to markets, lower the overall cost of delivered energy, and allow new generating resources to interconnect to its transmission systems.



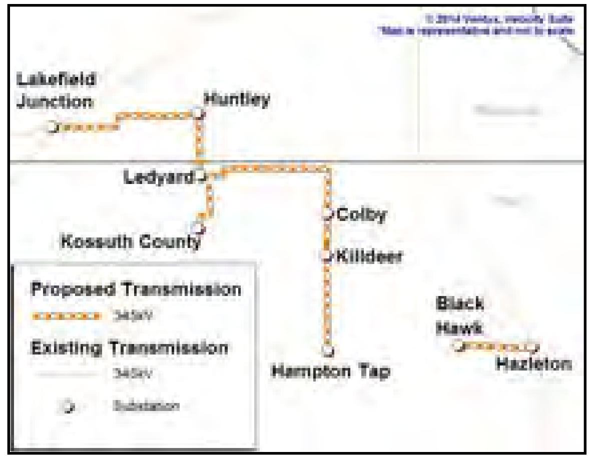
- ITC's regulated operating subsidiaries include ITC*Transmission*, Michigan Electric Transmission Company, ITC Midwest and ITC Great Plains. Through these subsidiaries, ITC owns and operates high-voltage transmission facilities in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas, and Oklahoma, serving a combined peak load exceeding 26,000 megawatts along 15,000 circuit miles of transmission line. Through ITC Grid Development and its subsidiaries, the company also focuses on expansion in areas where significant transmission system improvements are needed.
- From the company's inception in 2003 through 2012, ITC invested nearly $3.4 billion in transmission.

ITC Midwest

Company Background:

- ITC Midwest, LLC is a wholly-owned subsidiary of ITC Holdings Corp., the nation's largest independent electric transmission company. Based in Cedar Rapids, Iowa, ITC Midwest operates more than 6,600 circuit miles of transmission lines in Iowa, Minnesota, Illinois, and Missouri. ITC Midwest also maintains operating locations in Dubuque, Iowa City and Perry, Iowa; and Albert Lea, and Lakefield, Minnesota.
- ITC Midwest is a member of MISO.

Multi-Value Projects 3 & 4



Description: The proposed lines were defined in MISO's MVP study, conducted with substantial input from transmission-owning utilities, load-serving entities, generation developers, and state utility commissions. The projects represent approximately 400 total miles of 345 kilovolt (kV) lines. ITC Midwest will construct and own approximately 225 miles of those lines. Project 3 will require the construction of approximately 145 miles of 345 kV line in Iowa and 70 miles of 345 kV line in Minnesota. ITC Midwest's portion of Project 3 originates at ITC Midwest's Lakefield Junction substation in southwest Minnesota, connecting east to the Winnebago area in south central Minnesota, and south to a new MidAmerican Energy substation that will be constructed near Algona, Iowa. Project 4 will connect Project 3 to ITC Midwest's existing Hazleton 345 kV substation northeast of Waterloo, Iowa. The line will connect east to the Mason City area and then south to the Iowa Falls area, then east to the Hazleton substation. ITC Midwest will be responsible for approximately 110 miles of 345 kV line as part of Project 4.

Costs:

Multi-Value Project 3: Total estimated cost for all segments (ITC & Mid-American): $514 million.

Multi-Value Project 4: Total estimated cost for all segments (ITC & Mid-American): $591 million.

Status: ITC Midwest is currently working to identify potential routes and prepare filings to request the needed state regulatory approvals to build the line.

Investment Partners: None.

Benefits: In proposing the projects, MISO set out to accomplish several objectives, including improving the operations and efficiency of the regional energy markets, providing access to low-cost generation, reducing energy wasted because of constraints, inefficiency and line losses on the system, allowing for the optimal use of wind energy resources, and providing optionality for future energy solutions.

Salem-Hazleton Line

Description: The 345-kilovolt (kV) Salem-Hazleton line developed by ITC Midwest addresses long-standing reliability and system congestion issues in northeast Iowa. The line extends approximately 80 miles from the existing ITC Midwest Hazleton substation in Buchanan County to the company's existing Salem substation in Dubuque County. Approximately 54 miles of the new line are double-circuited with an existing 161 kV line west of the Hazleton substation. The Salem-Hazleton line completes a loop of more than 300 miles of 345 kV lines in eastern Iowa to help ensure electric reliability and reduce system congestion.

Cost: ITC Midwest estimated the line cost and costs for upgrades at termination substations at approximately $162 million.

Status: Following more than three years of RTO and regulatory review and approvals, ITC Midwest completed the line and placed it in service in the spring of 2013.

Investment Partners: None.

Benefits: The Salem-Hazleton line is needed to upgrade the electric transmission system in eastern Iowa to more reliably serve customer demand during normal operation and during times when elements of the system are unavailable due to planned or unplanned outages on the system. The Salem-Hazleton Line was studied and supported in the MISO (2006-09) Eastern Iowa Transmission Reliability Study (Eastern Iowa Study) as an efficient and cost-effective solution to correct long-standing reliability problems in eastern Iowa.

ITC Midwest Smart Grid Program

Description: The purpose of this project is to integrate the operations of the ITC Midwest electric system to an independent ITC EMS/SCADA system. Also, this project seeks to improve transmission system reliability, real-time monitoring capabilities, and event analysis capabilities by strategically implementing the following smart grid improvements to substations across the ITC Midwest: upgrading the Communications Infrastructure by deploying an advanced, digital network architecture that provides security, reliability, and greatly increased bandwidth; improving Real-Time Monitoring and Controls by deploying Remote Terminal Units (RTUs), substation intelligent alarming and asset health monitoring units that enable enhanced real-time observation and rapid analysis and response to system events; enhancing Event Analysis Capabilities by deploying GPS technology and relay communications networks to enable improved decision support and analytics capability; and migrating from Legacy, Proprietary Protocols to open, interoperable architectures that will better support additional smart grid technologies, such as SynchroPhasors, through the development of expanded, interoperable technology platforms.

This project encompasses over 150 substation RTU and relay communication networks and seven transformer monitoring units.

Cost: Approximately $35 million.

Status: This project is in the implementation stage. The project is forecasted to be completed by 2015.

Investment Partners: None.

Benefits: This project will fully transfer operations and control of the ITC Midwest electric system from Alliant Energy, the previous owner-entity of the system. The project contributes to furthering the development of smart grid functions by providing the ability to: develop, store, send, and receive digital information relevant to grid operations through intelligent devices; sense and localize disruptions or changes in power flows on the grid and communicate such information instantaneously and automatically for purposes of enabling automatic protective responses to sustain reliability and security of grid operations; detect, prevent, communicate with regard to, respond to, or recover from system security threats, including cyber security threats and terrorism, using digital information, media and devices; and support future smart grid technologies (i.e., SynchroPhasors) through the development of an expanded, interoperable technology platform.

This project will make the transmission system monitoring more robust and better able to integrate renewable energy sources. As the penetration of intermittent generation resources, such as wind, are increased on the transmission grid, the need for improved monitoring on the system also increases. Without adequate system monitoring and controls, intermittent generation creates issues for grid reliability, energy scheduling, and capacity planning. The project will enable an increased addition of renewable resources on the grid.

ITC Great Plains

Company Background:

- ITC Great Plains, LLC is a transmission-only utility with authority to construct, own, operate, and maintain a regulated, high-voltage transmission system in the Southwest Power Pool (SPP) region. Based in Topeka, Kansas, ITC Great Plains operates approximately 200 circuit miles of transmission lines in Kansas and Oklahoma. ITC Great Plains is a subsidiary of ITC Grid Development, LLC, a wholly-owned subsidiary of ITC Holdings Corp., the nation's largest independent electric transmission company.
- ITC Great Plains is a transmission-owning member of SPP.

Kansas V-Plan

Description: The Kansas V-Plan project consists of approximately 200 miles of new double-circuit, 345 kV transmission lines designed to connect central and western Kansas. In cooperation with Sunflower Electric Power Corporation and Mid-Kansas Electric Company, ITC Great Plains will design and construct two segments of the V-Plan project totaling approximately 120 miles, from Spearville south to the new Clark County substation, then east to the Thistle substation that ITC will construct east of Medicine Lodge. Prairie Wind Transmission will construct the third section of the line, from Medicine Lodge to a termination point outside Wichita.

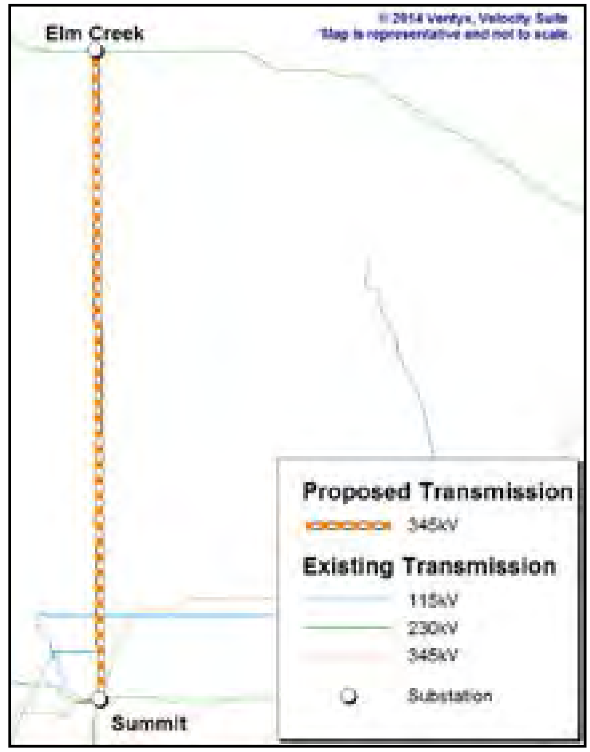
Cost: Approximately $300 million for ITC Great Plains portion.

Status: The Kansas V-Plan was approved by the SPP Board of Directors on April 27, 2010. FERC approved the novation agreement on June 24, 2011. The Kansas Corporation Commission (KCC) approved the siting application on July 12, 2011. Construction began in November 2012. The project is projected to be in service by late 2014.

Investment Partners: None.

Benefits: This project will improve electric reliability and enable renewable and other energy developers to tap into the transmission grid, further establishing a competitive energy market in the state. This will contribute to a stronger transmission grid that will benefit the entire region.

Elm Creek-Summit Project



Description: The Elm Creek to Summit Project is a new 60-mile, 345,000-volt (345 kV) line linking the existing 345 kV Summit Substation southeast of Salina, Kansas, to a new 345 kV substation southeast of Concordia, Kansas, to be located near the existing 230 kV Elm Creek Substation. ITC Great Plains, LLC (ITC), under a co-development agreement with Mid-Kansas Electric, LLC (MKEC), will construct, co-own with MKEC and operate the northern section of the line, and Westar Energy, Inc. (Westar) will construct, own, and operate the southern section. The Southwest Power Pool (SPP) requires this project to be in service no later than 2018. Currently we are targeting an in-service date of 2016.

Cost: Approximately $46.8 million for ITC Great Plains portion.

Status: The Kansas Corporation Commission approved the route for the project on August 27, 2013. The easement acquisition process began in the fourth quarter of 2013. The Southwest Power Pool (SPP) requires this project to be in service no later than 2018. Currently we are targeting an in-service date of 2016.

Investment Partners: Mid-Kansas Electric Company, LLC.

Benefits: This project will improve the reliability of the grid in central Kansas, allowing the grid to continue to meet required standards of reliability. It will benefit residents and businesses in central Kansas and beyond by easing congestion across the transmission network and improving the efficiency of the grid.

ITC*Transmission*

Company Background:

- International Transmission Company (d/b/a ITC*Transmission*) is a wholly-owned subsidiary of ITC Holdings Corp., the nation's largest independent electric transmission company. Based in Novi, Michigan, ITC*Transmission* owns, operates, and maintains approximately 2,800 circuit miles of transmission line in southeast Michigan, serving a population of 5.1 million.
- ITC*Transmission* is a member of MISO.

Michigan Thumb Loop Transmission Project

Description: The Michigan Thumb Loop Transmission Project consists of approximately 140 miles of new double-circuit, 345 kV transmission lines and four new substations that will serve as a "backbone" for wind development located in Michigan's Thumb region. Additional lines and facilities will be needed in the future as wind generators go into service and connect to the backbone system to fulfill the requirements of the state's Renewable Portfolio Standard.

The system is designed to meet the identified minimum and maximum wind energy potential of the Thumb region (2,367 and 4,236MW respectively) and is capable of supporting a maximum capacity of about 5,000 MW.

Cost: Approximately $510 million.

Status: MISO has approved the Thumb Loop project as the first MVP eligible for regional cost sharing as approved by FERC. ITC*Transmission* secured siting approval from the Michigan Public Service Commission on February 25, 2011. The project will be constructed in stages. The first segment entered service in September 2013. The remaining stages are targeted for completion by 2015.

Investment Partners: None.

Benefits: This project will serve as an efficient transmission "backbone" to support wind energy development in the Thumb region in support of Michigan's Renewable Portfolio Standard. It also will improve reliability and economic efficiency in the region. In addition to the system benefits realized by the project, it is estimated that the construction phase of this project alone will have an economic impact to Michigan of $366 million, including but not limited to employment of local contractors, vendors and suppliers.

Michigan Electric Transmission Company (METC)

Company Background:

- Michigan Electric Transmission Company, LLC (METC) is a wholly-owned subsidiary of ITC Holdings Corp., the nation's largest independent electric transmission company. Based in Novi, Michigan, METC owns, operates, and maintains approximately 5,600 circuit miles of transmission line in western and northern portions of Michigan's Lower Peninsula, serving a population of 4.9 million.
- METC is a member of MISO.

Au Sable Circuit Upgrade

Description: The 110-mile Au Sable circuit from Zilwaukee to Mio, Michigan, is important to electric reliability in northeastern Michigan. METC is rebuilding and upgrading this line from single-circuit, 138 kV to future 230 kV double-circuit design and construction standards.

Cost: Approximately $70 million.

Status: The final segment of the project will be completed by early 2014 and is projected to enter service in the second quarter of 2014.

Investment Partners: None.

Benefits: Rebuilding and upgrading this circuit will increase its capacity and reliability, including increased lightning protection, and will facilitate potential future 230 kV expansion in northern Michigan.

MIDAMERICAN ENERGY HOLDINGS COMPANY

Company Background:

- MidAmerican Energy Holdings Company, a consolidated subsidiary of Berkshire Hathaway Inc., is a global energy services provider that serves more than 8.4 million electric and natural gas customers worldwide, including more than five million electric customers located in 10 Midwestern (Illinois, Iowa, and South Dakota) and western (California, Idaho, Nevada, Oregon, Utah, Washington, and Wyoming) states.
- MidAmerican's U.S. regulated utility operations include MidAmerican Energy Company, an Iowa-based utility providing regulated electric and natural gas service; NV Energy, a Nevada-based utility providing regulated electric and natural gas service; PacifiCorp, an Oregon-based utility providing regulated electric service as Pacific Power in California, Oregon and Washington, and as Rocky Mountain Power in Idaho, Utah and Wyoming; and MidAmerican Transmission, a transmission development company that owns and operates transmission assets in several regions of the U.S. and is pursuing additional investment opportunities in organized and traditional markets in the U.S. and Canada.
- MidAmerican's U.S. utility subsidiaries own and/or operate more than 24, 000 miles of transmission and are engaged in significant transmission investment projects, both independently and through subsidiary joint ventures.
- Between 2003 and 2012, MidAmerican invested approximately $3 billion in transmission.

MidAmerican Energy Company

- MidAmerican Energy Company, based in Des Moines, Iowa, is an electric and natural gas utility serving rate-regulated retail customers in Iowa, Illinois, South Dakota, and Nebraska, and competitive retail customers in the central and eastern U.S. MidAmerican Energy is a transmission-owning member of MISO and owns an extensive transmission system within the MISO footprint. Additionally, MidAmerican Energy is actively engaged in marketing wholesale electric power in various regions.
- As of year-end 2012, MidAmerican Energy provided service to approximately 735,000 electric customers in a 10,600 square mile area. MidAmerican Energy had approximately 8,092 megawatts of owned or contracted generating capacity, including approximately 2,285 megawatts of wind-powered generation, and a peak load of 4,808 megawatts. MidAmerican Energy is a public utility within the contemplation of the Federal Power Act, and owns or operates approximately 2,200 miles of transmission facilities.

MidAmerican Energy Expansion Projects

Description: The MidAmerican Energy Expansion Projects are major new transmission facilities to be constructed in Iowa, Illinois, and Missouri as an integral part of a portfolio of MISO projects called the 2011 Multi Value Project (MVP) Portfolio. The MidAmerican Energy Expansion Projects are characterized as the Obrien County – Webster Project; the Hampton Blackhawk Project; the Oak Grove – Galesburg project; and MidAmerican Energy's share of the Ottumwa to Adair project. MidAmerican Energy's share of the MidAmerican Energy Expansion Projects are expected to consist of roughly 240 miles of new 345 kV transmission lines and include two new 345 kV substations, significant modifications to four 345 kV substations, and one new 345-161 kV-transformer.

Cost: The MidAmerican Energy Expansion Projects represent approximately $532 million to $572 million in transmission investment.

Status: The MidAmerican Energy Expansion Projects were approved for construction by the MISO Board of Directors in December 2011. Initial work on the projects has begun with projected in-service dates of the projects from 2015 through 2017.

Benefits: The MidAmerican Energy Expansion Projects, as a part of the 2011 MISO MVP Portfolio, are a unique set of transmission projects to be constructed in order to contribute to a wide variety of benefits, including public policy needs, congestion relief and fuel savings, operating reserve margin and system planning reserve margin reductions, and transmission line loss reductions. In addition, the projects will enhance wind turbine investments and allow states to meet their renewable portfolio standards.

MidAmerican Transmission, LLC

- MidAmerican Transmission, LLC is a wholly owned transmission development company of MidAmerican Energy Holdings Company. MidAmerican Transmission, LLC's subsidiary joint transmission ventures include:
    - Electric Transmission Texas, LLC (ETT): A joint venture with American Electric Power (AEP) established to invest in transmission within the Electric Reliability Council of Texas (ERCOT).
    - Electric Transmission America, LLC (ETA): A second joint venture with AEP* that includes Prairie Wind Transmission, LLC - A joint venture between ETA and Westar Energy to develop high-voltage transmission in the Southwest Power Pool region.
      * See the AEP section for additional information on these joint venture projects.

Prairie Wind Transmission, LLC

ETT CREZ

Gates-Gregg 230 kV Transmission Line Project

Description: Gates-Gregg 230 kV transmission line. PG&E, MidAmerican Transmission, and Citizens Energy Corporation have formed a consortium to construct as a single circuit 230 kV line on double-circuit towers to accommodate future growth. The line will span 70 miles from the Gates-to-Gregg substations.

Cost: The California ISO estimates the cost to be approximately $115m to $145m excluding indirect project costs such as environmental mitigation, land acquisition, permitting and licensing, public outreach costs, or inflation.

Status: On November 6, 2013, the ISO announced the consortium of Pacific Gas and Electric and Citizens Energy Corporation and MidAmerican Transmission has been selected over four other qualified bidders to develop, own and operate the 230 kV transmission line.

Investment Partners: PG&E, MidAmerican Transmission and Citizens Energy Corporation.

Benefits:

- Improve reliability in the Greater Fresno Area.
- Alleviates constraints at Helms Pump Storage Plant.
- Supports delivery and integration of renewable power to support California's 33% renewable portfolio standard (RPS).

NV Energy

Company Background:

- NV Energy, Inc. is an investor-owned public utility holding company, which wholly owns Sierra Pacific Power Company and Nevada Power Company (collectively, "NV Energy"), both regulated public utility companies. NV Energy, Inc. is the newest member of MidAmerican Energy Holdings Company, the acquisition being completed on December 19, 2013. NV Energy serves approximately 1.2 million customers over a 54,500 square mile area in southern and northern Nevada.
- System wide there are approximately 3,850 miles of FERC classified circuit mile transmission.
- Between 2003 and 2012, NV Energy invested approximately $800 million in transmission.

One Nevada 500 kV Transmission Intertie (NVES & NVEN)

Description: NV Energy has completed a 235 mile 500 kV transmission line from northern Nevada (near Ely, Nevada) to southern Nevada (NE Las Vegas) tying Nevada's electrical grid together by creating a direct interconnection between the Northern and Southern NV Energy systems. The project also adds one 500/345 kV substation.

Cost: $552 million excluding AFUDC.

Status: The Joint NV Energy / Great Basin Transmission South, LLC One Nevada Transmission Line Project (ON Line) was placed in service late in the evening of December 31, 2013 and was available for commercial operation in hour one of January 1, 2014.

- 231-mile 500 kV transmission line Robinson Summit - Harry Allen
- Robinson Summit 500/345 kV substation Northern Terminal
- Falcon-Gonder 345 kV Line Fold 4 miles
- Series compensation on the existing Falcon – Gonder 345 kV line added to the Falcon-Robinson Segment totaling 70 % compensation 35 % at Falcon 35% at Robinson
- Harry Allen Terminal

With the completion of ON Line, the Sierra Pacific Power Company (SPPC) Balancing Authority Area (BAA) was consolidated into the Nevada Power Company (NPC) BAA. NV Energy worked with the Western Electricity Coordinating Council Planning Coordination Committee (PCC), Technical Studies Subcommittee and formed a project review group (PRG) to review the consolidation of the Western Electricity Coordinating Council ratings in both BAAs. This consolidation included re-definition of the existing path #81 (Centennial) into a "Southern Nevada Transmission Interface" (SNTI) and removal of the ON Line project from the three phase rating process.

- The SNTI studies were completed and the Final Report was approved by the PRG on September 27, 2013.
- The SNTI underwent a 30-day review by PCC from October 2, 2013 – November 1, 2013. No comments were received and on November 4, 2013, the SNTI was granted an Accepted Rating of 4,533 MW North-South and 3,970 MW South-to-North effective with the ON Line Project going into service.

Investment Partners: Great Basin Transmission South, LLC.

Benefits:

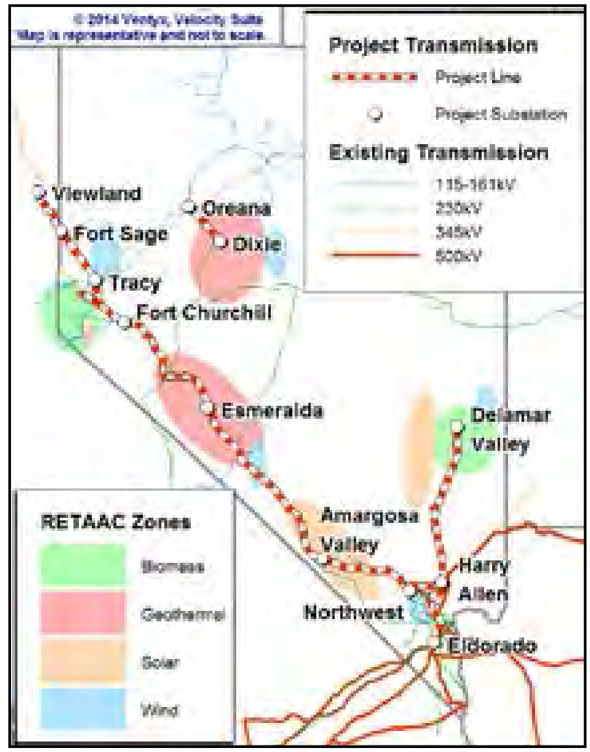
- Facilitated combining the BAA, which provides numerous benefits, including:
    - scheduling,
    - optimal dispatch, and
    - reduced planning and operating generation reserves.
- Delivers renewable energy from Northern to Southern Nevada.
- Utilizes the Southwest Intertie Project (SWIP) for future interconnection between Southern Nevada/Arizona with Idaho System (SWIP-North).
- Provides foundation for the delivery of renewable energy & other future generation from the North/NE (Idaho, Wyoming, Utah) to Southern Nevada/Arizona/California.

SB123: "NVision"

SB123 is a Nevada Senate Bill for an Emission Reduction and Capacity Replacement Plan approved in June, 2013. The bill requires NVE-South to retire or eliminate 800 MW of coal by 2019.

- NVE-South to retire or eliminate Reid Gardner # 1, 2 & 3 in 2014, Reid Gardner # 4 in 2017 and Navajo in 2019.
- Requires NVE to replace coal with company owned 550 MW of generation either constructed or acquired: Generation type not specified
- Requires annual RFPs for 100 MW of new renewables in 2014, 15, 16
- Requires 50 MW of company-owned renewables

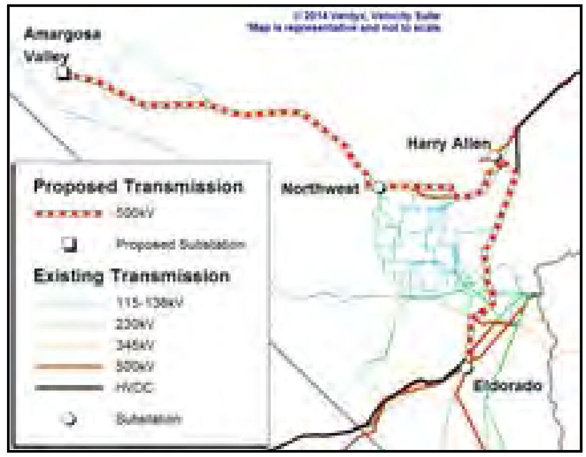
Renewable Energy Transmission Initiative (RTI)



The 2009 Nevada legislature passed Assembly Bill 387, making transmission development to support renewable generation public policy. AB 387 required NV Energy to identify transmission plans and costs to access Renewable Energy Transmission Access Advisory Committee (RETACC)/Nevada Public Utilities Commission approved renewable energy zones.

- In July 2011, NV Energy introduced its Renewable Transmission Initiative (RTI) as a customer driven process to determine market interest in developing the RETAAC Zones.
- In the 2012 Sierra Integrated Resource Plan (IRP) a plan to access these zones was published as the Renewable Energy Zone Transmission Plan (REZTP).
- The RTI received a significant initial response. NV Energy received over 5,000 MWs of Statements of Interest in the RTI. There was sufficient interest to study RTI facilities capable of delivering from Points of Receipt 1 (Dixie valley), 2 (Esmeralda region), and 3 (Armargosa valley) to Point of Delivery C (Eldorado substation in the Eldorado valley).
- Participant meetings were held to discuss the findings of the studies. The participants then held the option to elect to proceed into the permitting phase of RTI. Unfortunately, there was insufficient interest from participants to continue the RTI as an aggregated process.

Centennial II



With the termination of its Renewable Transmission Initiative (RTI) efforts due to lack of participant interest, NV Energy has proposed the Centennial II Project. The Centennial II Project is proposed to facilitate the integration of additional renewable energy resources, provide mutually beneficial reserve sharing for renewable energy, meet requests for transmission service, and provide expanded load service to the Las Vegas Valley (the three transmission corridors discussed below):

The proposed Centennial II Project would consist of approximately 138 miles of new overhead electric transmission lines and associated facilities, construction of a new 500/230 kV substation, upgrading of two existing substations. All segments of the proposed Centennial II Project would require new structures and in some cases, double circuits on these structures would be required. A map of the proposed Centennial II Project is depicted in Exhibit A.

The UEPA application for Centennial II modifies the initial UEPA application prepared by NV Energy for the RTI. This was submitted to the State of Nevada Public Utility Commission in May 2011 (Docket No. 11-05002). The UEPA and SF299 applications cover the following corridors:

- A transmission corridor beginning at the existing Harry Allen substation in the northeast Las Vegas Valley and traversing south approximately 51 miles to the existing Eldorado substation in the Eldorado Valley. This segment of the transmission route would consist of a new 500 kV AC double circuit overhead transmission structures and Optical Ground Wire (OPGW).
- A transmission corridor beginning at the existing Northwest substation and traversing approximately 36 miles east and then north-northeast to the existing Harry Allen substation. This segment of the transmission route would include: a set of two new transmission structures allowing one overhead 500 kV AC circuit in one set of structures and a separate overhead 230 kV double circuit configuration in the other set, both with OPGW.
- A transmission corridor and new substation facility beginning at the new Sagebrush substation, located in the Amargosa Valley in Nye County, and traversing approximately 51.5 miles east and then southeast to the existing Northwest substation. This segment of the proposed transmission route would include a set of two new transmission structures allowing one overhead 500 kV AC circuit in one set of structures and a separate overhead 230 kV double circuit configuration in the other, both with OPGW.

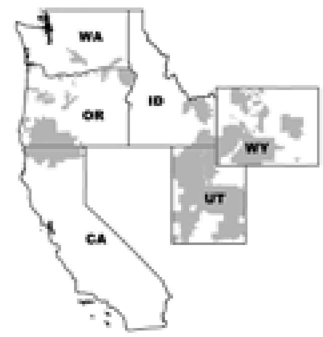
The proposed Project would be constructed, operated, and maintained by NV Energy and would follow, where feasible, existing transmission lines and/or previously identified federal and/or state established transmission corridors.

PacifiCorp

PACIFICORP

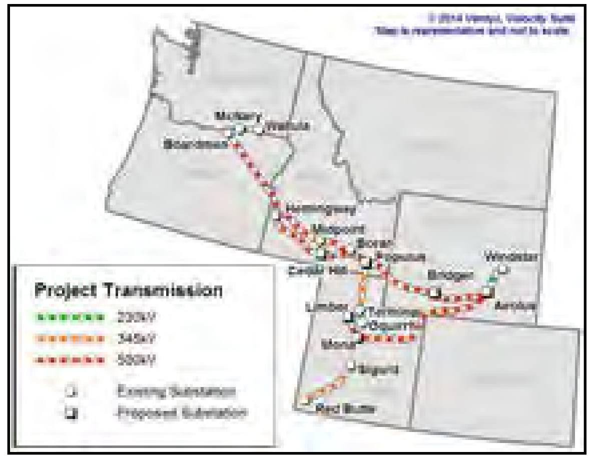
Company Background:

- PacifiCorp owns and operates one of the largest privately held transmission systems in the U.S., consisting of more than 16,200 circuit miles of transmission lines ranging from 46 kV to 500 kV.
- PacifiCorp provides electric service to 1.8 million customers in 750 communities across six western states with a service territory that covers approximately 136,000 square miles in Oregon, Washington, California, Wyoming, Utah, and Idaho.
- PacifiCorp is interconnected with more than 80 generation plants and 13 adjacent control areas at approximately 152 points of interconnection.



- To provide electric service to its retail customers, PacifiCorp owns or has interest in generation resources directly interconnected to its transmission system, with an average monthly system peak of over 15,000 MWs. This generation capacity includes a diverse mix of resources including coal, hydro, wind power, natural gas simple cycle and combined cycle combustion turbines, and geothermal.

Energy Gateway



Description: PacifiCorp's Energy Gateway transmission plan is a major transmission expansion program announced in May 2007 that will add approximately 2,000 miles of new transmission lines across the West. The project is comprised of eight segments, the majority of which are categorized as part of Gateway West, Gateway South, or Gateway Central (see Energy Gateway map for segment information). Energy Gateway is the largest and most extensive transmission project PacifiCorp has ever undertaken.

Cost: Energy Gateway is a multi-year project with an approximate $6 billion investment plan.

Status: The $832 million Populus to Terminal line, energized November 2010, was the first completed segment of Energy Gateway, adding approximately 135 miles of new double-circuit 345 kV line from southeast Idaho into northern Utah. The second segment, the estimated $370 million Mona to Oquirrh project, consists of approximately 100 miles of single-circuit 500 kV and double-circuit 345 kV transmission line in central Utah, and was placed in service in May 2013. Construction began in May 2013 on the third segment, the approximately $380 million Sigurd to Red Butte project, which adds approximately 170 miles of new single- circuit 345 kV line in southwest Utah and is scheduled for completion in June 2015. Outreach, siting, and permitting efforts continue for several other segments of Energy Gateway, with additional segments scheduled to be in service in 2016 and beyond. See the Energy Gateway website for additional project information (www.pacificorp.com/energygateway).

Investment Partners: At the initiation of Energy Gateway, PacifiCorp entered into a permitting agreement with Idaho Power on the Gateway West project. PacifiCorp has a permitting agreement with Idaho Power and Bonneville Power Administration on Idaho Power's Boardman to Hemingway 500 kilovolt transmission project.

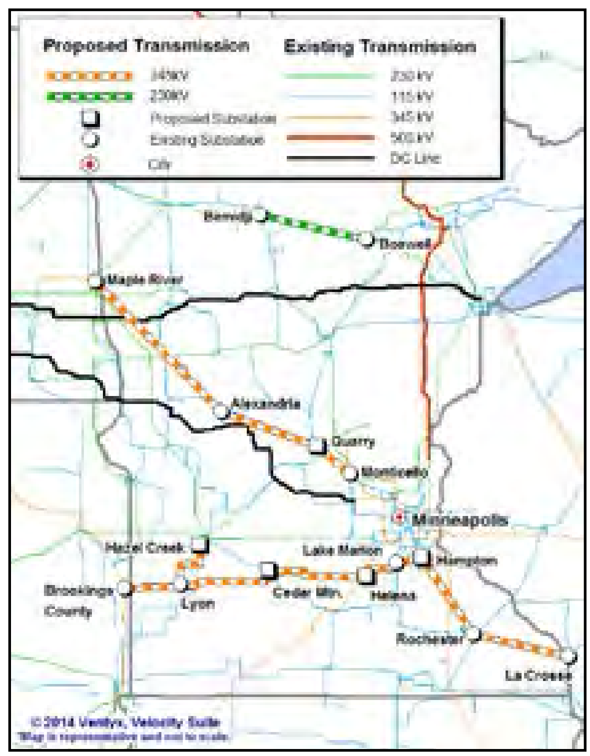
Benefits: The Energy Gateway transmission expansion program is designed to provide the company with improved infrastructure to meet its tariff requirements and reliably serve the growing needs of its customers. As an important part of the company's integrated resource planning process, the project will strengthen the connections between PacifiCorp's two control areas and provide more flexibility to move energy resources where they are needed, helping to maintain low-cost delivery and service reliability for all network customers. The project will also provide long-term regional benefits to the Western Interconnection by providing additional high-voltage backbone transmission for efficient, flexible, and diverse resource development in resource rich areas.

MINNESOTA POWER

Company Background:

- Minnesota Power, a division of ALLETE, provides electricity in a 26,000 square mile electric service territory located in northeastern Minnesota. Minnesota Power supplies retail electric service to 144,000 retail customers and wholesale electric service to 16 municipalities.
- Transmission and distribution components include 8,866 circuit miles of lines and 169 substations. Minnesota Power's transmission network is interconnected with the transmission grid to promote reliability and is part of a larger regional transmission organization; MISO.
- Between 2003 and 2012, Minnesota Power invested approximately $170 million in transmission.

CapX2020 Transmission Plan



Description: The CapX2020 Transmission Plan consists of approximately 240 miles of new single-circuit, 345 kV transmission line between Brookings County, South Dakota, and Hampton, Minnesota, plus a related 345 kV transmission line between Marshall and Granite Falls, Minnesota; approximately 240 miles of new single-circuit, 345 kV transmission line between Fargo, North Dakota, and St. Cloud and Monticello, Minnesota; approximately 125 miles of new single-circuit, 345 kV transmission line between Hampton and Rochester, Minnesota, continuing on to La Crosse, Wisconsin; and approximately 70 miles of new single-circuit, 230 kV transmission line between Bemidji and Grand Rapids, Minnesota.

Cost: The four lines will cost between $1.4 and $1.7 billion with an additional $200 million to provide for future double-circuit 345 kV lines. Of this total, approximately $700 million is associated with the wind generation-supporting Brookings County-Hampton line.

This project is a joint initiative of 11 transmission owning utilities, including Minnesota Power, in the Upper Midwest to expand the electric transmission grid to ensure continued reliable service to 2020 and beyond. Planning studies show that customer demand for electricity will increase by 4,000 to 6,000 MWs by 2020.

Of these new transmission lines, Minnesota Power is involved in the Bemidji - Grand Rapids 230 kV Line, the Fargo - St. Cloud 345 kV Line, and the St. Cloud - Monticello 345 kV Line.

Status: The Minnesota Public Utilities Commission (MN PUC) approved Certificate of Need applications for all four projects in 2009. Minnesota Route Permit applications were filed for three of the projects in 2008, with the fourth filed in January 2010. Filing for the North Dakota, South Dakota, and Wisconsin regulatory permits were completed and filed in 2011.

Minnesota Route Permits were received in 2010 for the Bemidji - Grand Rapids 230 kV Line and the St. Cloud - Monticello 345 kV Line. Construction of the St. Cloud - Monticello Line started in late 2010 and this line section was placed in-service in December 2011. The North Dakota permits for the Fargo - St. Cloud 345 kV Line were received in 2012. Construction on this section of the line has begun. Construction of the Bemidji - Grand Rapids 230 kV Line was started in January 2011 and the line was placed in service in September 2012.

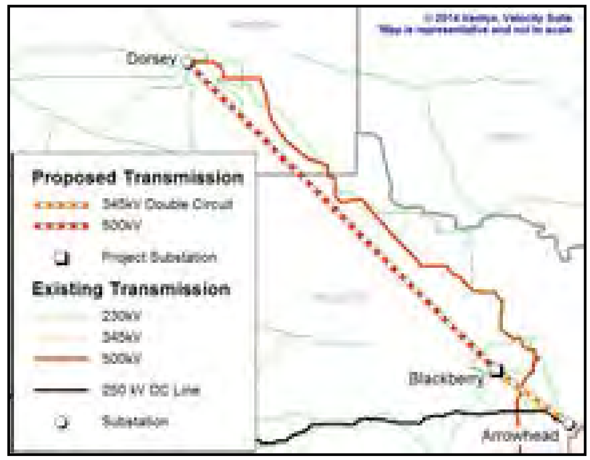
Investment Partners: Minnesota Power, Central Minnesota Municipal Power Agency, Dairyland Power Cooperative, Great River Energy, Southern Minnesota Municipal Power Agency, Minnkota Power Cooperative, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, WPPI Energy, and Xcel Energy.

Benefits: The CapX2020 Projects will alleviate emerging electric reliability issues around the Upper Midwest and strengthen the regional transmission system. In addition, the Brookings County to Hampton line will add capacity for an additional 700 MWs of generation in southwest Minnesota and eastern South Dakota. The Brookings County to Hampton line was also included as one of 16 Multi Value Projects (MVP) MISO Board of Directors approved in December 2011. These MVP transmission projects will provide broad regional benefits commensurate with costs and also supports approved state and federal energy policy mandates in the MISO region.

Great Northern Transmission Line

Description: Minnesota Power, in partnership with Manitoba Hydro, is proposing to construct a new interconnection from southern Manitoba to northeastern Minnesota. The Great Northern Transmission Line Project is needed to bring clean, emission-free energy into Minnesota, meet growing energy demands, and strengthen system reliability. In the early planning stages of the Project, Minnesota Power anticipated development of two transmission lines and associated facilities – the 500 kV Great Northern Transmission Line between Winnipeg, Manitoba, Canada, and the Iron Range in northeastern Minnesota, and a separate 345 kV transmission line between the Iron Range and Hermantown, Minnesota. Subsequently, Minnesota Power and Manitoba Hydro determined that there are not sufficient transmission service requests to support the 345 kV transmission line. In order to meet a June 1, 2020, in-service date, Minnesota Power is moving forward with the routing, siting, and permitting process for the 500 kV Great Northern Transmission Line Project.

The Great Northern Transmission Line Project is required to facilitate at least 750 MW of incremental Manitoba – United States transfer capability, including 383 MW of hydropower and wind storage energy products to serve Minnesota Power's customers. Minnesota Power's 250 MW Power Purchase Agreement and 133 MW Renewable Energy Optimization Agreement with Manitoba Hydro both require that new transmission facilities be in place by June 1, 2020, to facilitate the transactions. Further power purchase agreements between Manitoba Hydro and utilities in the United States may require up to 1,100 MW of incremental Manitoba to United States transfer capability, which the 345 kV build was designed to facilitate. The Manitoba hydropower purchases made possible by the Great Northern Transmission Line will provide Minnesota Power and other utilities in the Upper Midwest access to reasonably priced, predominantly emission-free energy supply that has a unique combination of baseload supply characteristics, price certainty, and resource optimization flexibility not available in comparable alternatives for meeting customer requirements.



The Great Northern Transmission Line Project includes the new 500 kV transmission line and expansion of the existing Blackberry Substation to accommodate the new line and 500/230 kV transformation. The Project is planned to be in-service by June 1, 2020, in order to meet the terms of Minnesota Power's PPA and ROA. When it becomes necessary, the 345 kV build will consist of expansion of the Blackberry 500 kV Substation to include 500/345 kV transformation and a new double-circuit 345 kV line from Blackberry to the Arrowhead Substation. The 345 kV build of the project has been deferred until the need for additional deliveries becomes more well-defined.

Cost: 500 kV Build: Approximately $500 million.

Cost: 345 kV Build: Approximately $280 million.

Status: In anticipation of the Project's aggressive schedule and needing to meet a June 1, 2020, in-service date, Minnesota Power initiated a proactive public outreach program to key agency stakeholders and the public starting in mid-2012. Through this program, hundreds of landowners, the public, and federal, state, and local agency stakeholders have already been engaged through a variety of means, including three rounds of voluntary public open house meetings held throughout the Project area. On October 21, 2013, Minnesota Power submitted an Application for a Certificate of Need to construct the 500 kV Great Northern Transmission Line and associated facilities to the Minnesota Public Utilities Commission. This was the first major step in a regulatory review process that will also include a Route Permit Application and a Presidential Permit Application, to be submitted to the Minnesota Public Utilities Commission and the United States Department of Energy, respectively, in early 2014.

500 kV Build Project Investment Partners: Minnesota Power, Manitoba Hydro.

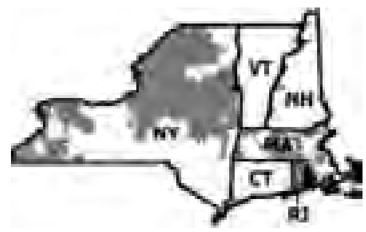
345 kV Build Project Investment Partners: TBD.

Benefits: The Manitoba hydropower purchases made possible by the Great Northern Transmission Line will provide Minnesota Power and other utilities in the Upper Midwest access to a reasonably priced, predominantly emission-free energy supply that has a unique combination of baseload supply characteristics, price certainty, and resource optimization flexibility not available in comparable alternatives for meeting customer requirements.

NATIONAL GRID

nationalgrid

Company Background:



- National Grid is an international electricity and gas company. In the U.S., National Grid distributes electricity to approximately 3.4 million customers in Massachusetts, New York, and Rhode Island. National Grid owns over 3,800 MWs of contracted electricity generation that provides power to over one million Long Island Power Authority customers.
- National Grid owns and operates over 8,800 circuit miles of transmission in the United States.
- Between 2003 and 2012, National Grid has invested approximately $2.2 billion in transmission.

Northeast Energy Link

Description: The Northeast Energy Link project consists of approximately 230 miles of new 1,100 MW HVDC transmission line from Orrington, Maine to eastern Massachusetts.

Cost: Estimated $2 billion.

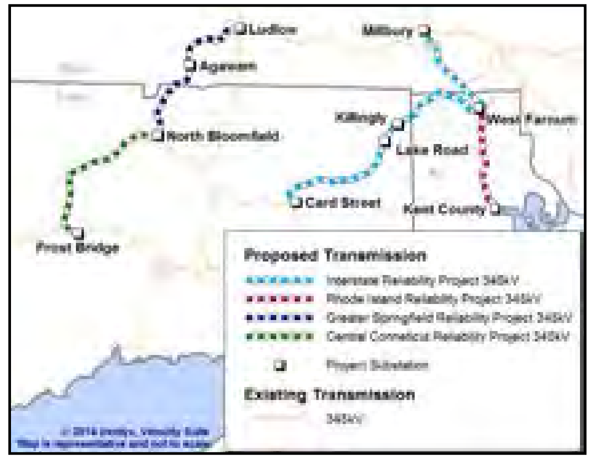
Status: Preliminary engineering and permitting work is underway. Economic studies and preliminary siting and routing analysis have been performed. On May 17, 2012, FERC issued an order granting NEL's Petition for Declaratory Order seeking the Commission's approval that the proposed sale of the line's capacity is consistent with FERC policy and precedent. Preparations are being made to seek other regulatory approvals. The project in-service date is expected to be late 2018.

Investment Partners: Emera Maine.

Benefits: NEL will deliver cost-effective renewable and low carbon resources from northern New England and the Canadian Maritime to southern New England customers, providing energy to meet state Renewable Portfolio Standard requirements. By facilitating the development of additional renewable and low-carbon resources in the region, NEL will also benefit customers by lowering market clearing prices, expanding fuel diversity, and improving system reliability by reducing transmission congestion and thermal losses.

New England East - West Solutions (NEEWS)

Description: The New England East – West Solution (NEEWS) is a set of four projects that will upgrade the New England transmission system in Massachusetts, Connecticut and Rhode Island. The projects developed collaboratively by National Grid and Northeast Utilities (NU), involve more than 150 circuit miles of new and/or reconstructed 345 kV and 115 kV transmission lines, significant upgrades to several major substations, a new substation, a new switching station and a number of related system upgrades. The four NEEWS projects are:



- Interstate Reliability Project (NU and National Grid);
- Rhode Island Reliability Project (National Grid);
- Central Connecticut Reliability Project (NU); and
- Greater Springfield Reliability Project (NU).

Cost: National Grid's total capital investment in the above NEEWS projects and the associated advanced NEEWS projects is estimated to be approximately $744 million.

Benefits: The four NEEWS Projects work together to address a multitude of regional transmission needs identified by ISO-New England in its Regional System Plan, including:

- Constrained east-to-west and west-to-east power flow deliverability across New England;
- Constraints in serving load across the region;
- Thermal and voltage issues in the Springfield, Massachusetts area;
- Interstate transfer capacity;
- Limits affecting Connecticut reliability;
- Constrained east-to-west power flow across Connecticut; and
- Interstate transfer capacity limits and voltage concerns affecting Rhode Island reliability.

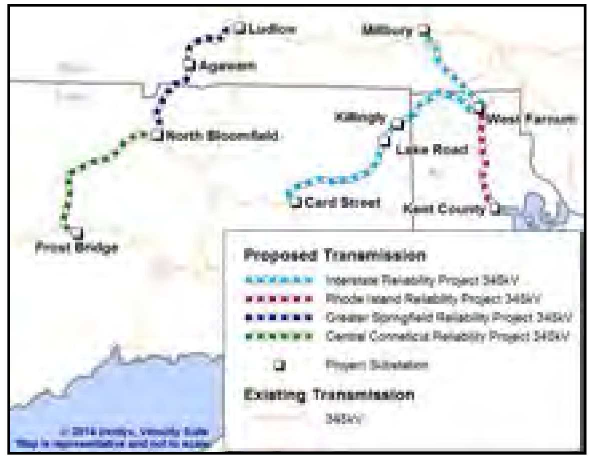
NEEWS - Interstate Reliability Project (IRP)

Description: The IRP consists of approximately 74.7 miles of new single-circuit, 345 kV transmission line. National Grid will construct the Massachusetts and Rhode Island portion of the transmission line terminating at Millbury, Massachusetts. NU will construct the Connecticut portion of the transmission line. The IRP will address east-to-west and west-to-east transmission constraints of power across Connecticut, Rhode Island and Massachusetts.

Status: The in-service date for the IRP is expected to be 2015/16.

Investment Partners: Northeast Utilities.

NEEWS - Rhode Island Reliability Project (RIRP)



Description: The RIRP is collection of projects aimed at improving the reliability and performance of the Rhode Island transmission network. The RIRP consists of 21.4 miles of new single-circuit 345 kV and 115 kV overhead lines, further line reconductoring, substation upgrades and expansions, and terminal upgrades. The project is designed to address transmission reliability issues in Rhode Island.

Status: The Rhode Island Reliability portion of the project completed permitting and licensing activities, and commenced construction in October 2010. The Rhode Island Reliability group of projects were completed and placed in service in 2013.

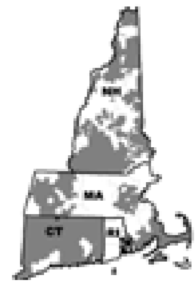
Investment Partners: None.

NORTHEAST UTILITIES (NU)

Company Background:

Northeast Utilities System

- The NU Electric operating companies include: the Connecticut Light and Power Company (CL&P), NSTAR Electric, Public Service Company of New Hampshire (PSNH), and Western Massachusetts Electric Company (WMECO).
- Gas companies include: Yankee Gas (YG), NSTAR Gas, and Hopkinton LNG Corporation.
- NU delivers electricity to more than 3.6 million customers through over 4,500 circuit miles of transmission line.
- NU companies coordinate transmission planning with ISO New England (ISO-NE) and are making substantial investments in new transmission facilities.



- Between 2001 and 2012, legacy NU (i.e., prior to the merger with NSTAR) invested approximately $4.2 billion into its transmission system.
- During 2013, NU invested approximately $0.7 billion into its transmission system.
- Between 2014 and 2018, NU expects to invest $4.0 billion into transmission system upgrades.

Northern Pass Transmission Project (NPT Project)

Description: The NPT Project consists of approximately 153 miles of new 300 kV HVDC transmission line and an associated 34 mile radial 345 kV transmission line that will interconnect Québec with the bulk power system in New Hampshire for the purpose of importing 1,200 MWs of low-carbon emissions power into New England. The owner of the NPT Project is Northern Pass Transmission LLC, a wholly owned subsidiary of Northeast Utilities. The U.S. portion of the HVDC line is about 153 miles in length and includes an AC/DC HVDC converter terminal in Franklin, New Hampshire. The AC radial line is about 34 miles in length, connecting the converter terminal to the Deerfield Substation in Deerfield, New Hampshire. The project will be participant-funded via a transmission service agreement with Hydro Renewable Energy, Inc. (Hydro Renewable), a U.S. subsidiary of Hydro-Quebec.

Cost: The estimated capital cost for the U.S. portion of the line is approximately $1.4 billion.

Status: On February 11, 2011, NPT received the FERC order approving the arrangements of a Transmission Service Agreement between NPT and Hydro Renewable. In October 2010, NPT filed an application for Presidential Permit with the Department of Energy, and in June 2011, filed a Special Use Agreement application with U.S. Forest Service. In 2013, NPT filed amendments to both the DOE and U.S. Forest Service applications. On December 31, 2013, NPT received I.3.9 approval from ISO-NE. The target in-service date for this project is anticipated for mid-2017.

Investment Partners: None.

Benefits: This is an economic and environmental project that will provide a competitively priced, reliable supply of large quantities of primarily (98 percent) hydroelectric power energy, a low greenhouse gas emitting source of energy. Power sold into the New England markets by Hydro Renewable would largely displace less efficient fossil fuel-fired generation in New England, and greenhouse gas emissions associated with the production of electricity will be reduced by up to five million tons of CO2 per year. This will help New Hampshire achieve the goals of the New Hampshire Climate Action Plan, and assist New England in meeting its targets under the Regional Greenhouse Gas Initiative (RGGI), an initiative that all New England states have signed, and under potential future cap and trade program or carbon tax adopted at the federal level.

Other Highlights: International Project, Low Carbon.

Greater Springfield Reliability Project (GSRP)

Description: The GSRP consists of approximately 35 miles of new single and double-circuit, 345 kV transmission lines in Connecticut and Massachusetts and 60 circuit miles of new and reconstructed single and double-circuit, 115 kV overhead transmission lines in Massachusetts. The project also includes three major substation upgrades, two new switching stations and work on eight other switching stations and substations.

Cost: The project was completed at a final cost of over $40M below the original estimate of $718M.

Status: The project was placed into service on November 20, 2013.

Investment Partners: United Illuminating has invested approximately 8.4 percent of the cost of the Connecticut portion of the project.

Benefits: The GSRP is designed to address transmission system reliability.

Interstate Reliability Project (IRP)

Description: The IRP consists of approximately 75 miles of new single-circuit, 345 kV transmission line. The NU portion of the line consists of 37 miles of new single-circuit, 345 kV transmission line built parallel to existing 345 kV circuits in the same right-of-way. The line will begin at the Card Street Substation in Lebanon, Connecticut, proceed through the Lake Road substation in Killingly, Connecticut and cross the Rhode Island/Connecticut border into National Grid territory. National Grid will then construct approximately 38 miles of the transmission line through Rhode Island terminating at Millbury, Massachusetts.

Cost: The preliminary cost estimate of the Connecticut portion of the IRP is $218 million.

Status: Siting approvals have been received in both Connecticut and Rhode Island and all State environmental permits have been received. For the Massachusetts portion of the Project, a siting application was filed in mid-2012, with evidentiary hearings complete in the summer of 2013. The Massachusetts siting decision and the Federal environmental permit are expected in early 2014 with construction slated to begin immediately thereafter. The in-service date is projected to be 2015.

Investment Partners: National Grid will construct and own its portion of the line in Rhode Island and Massachusetts, and United Illuminating is investing approximately 8.4 percent of the cost of the Connecticut portion of the project.

Benefits: The IRP will address weaknesses in both the east-to-west and west-to-east transmission of power across Connecticut, Rhode Island, and Massachusetts. By providing more direct routes between power sources and eastern Connecticut, and increasing the overall capacity of the transmission system, the IRP will mean that access to cleaner, competitively priced power will be routinely possible. The project also includes upgrades to seven substations (three each in Connecticut and Massachusetts, and one in Rhode Island), providing a stronger transmission connection between Massachusetts and Connecticut. Recent generation retirements in New England exacerbate the need for IRP.

Greater Hartford Central Connecticut Reliability Projects (GHCC)

Description: The GHCC is currently in the planning phase, being studied by ISO-NE with a focus both on local and regional reliability problems in four areas across the State of Connecticut and across the Western Connecticut Import Interface. ISO-NE presented its preliminary need analysis to the Planning Advisory Committee (PAC) in August of 2012, which showed severe voltage violations and thermal overloads existing under normal and contingency conditions. ISO-NE also presented the results of its Market Resource Alternatives (MRA) Study over the course of additional PAC meetings, wherein ISO-NE determined that greater than 1,200 MWs of simultaneously occurring MRAs in specified locations would be required to fully resolve the reliability violations. ISO-NE presented its final need analysis in late 2013 and is completing its needs report. Transmission solutions are currently being assessed with results anticipated in the first half of 2014.

Status: Preliminary results of the GHCC need assessment were presented to stakeholders in August of 2012 with the final presentation given in November 2013. Currently, it is anticipated that the preferred solution set will be identified in the first half of 2014 and may include multiple 115 kV upgrades across Connecticut.

Cost: Current estimates range from $300 million to $350 million and will be updated upon selection of the preferred solution.

Investment Partners: Once a solution set has been identified and a project or projects are developed, a determination will be made regarding investment partners.

Benefits: The GHCC project will address local area reliability issues in four Connecticut load sub-pockets as well as regional reliability violations caused by power flow constraints across the Western Connecticut Import Interface (formerly known as the East-West Interface).

Lower SEMA Transmission Project

Description: The Lower SEMA Project addresses system reliability concerns in the lower southeastern Massachusetts area, which includes Cape Cod. The Lower SEMA Transmission Projects consists of an approximately 18 mile, new 345 kV transmission line on existing rights of way from the Carver substation crossing the Cape Cod Canal to a new 345/115 kV substation west of Barnstable on Cape Cod.

Cost: The estimated capital cost of the project is approximately $106.5 million.

Status: The project received siting approval in April 2012. Construction began in October 2012. The 345kV line to Cape Cod was energized in June 2013 and the new 345/115kV substation was placed in service in October 2013. Some additional 115kV work remains, and the project is expected to be completed prior to the summer.

Investment Partners: None.

Benefits: This is a reliability project that will strengthen the transmission system for southeastern Massachusetts and Cape Cod and increase the load serving capability to Cape Cod.

Other Highlights: The project also includes separation of an existing double-circuit 345 kV transmission line crossing the Cape Cod Canal onto separate sets of structures.

Pittsfield-Greenfield Area Solution

Description: The Pittsfield-Greenfield Area Solution involves a family of smaller projects designed to reinforce the transmission system in western and north-central areas of Massachusetts to comply with regional and national reliability standards. The individual reinforcements include:

- Installing a 345/115-kV autotransformer;
- Constructing a new 115-kV switching station;
- Constructing a new one mile 115-kV line;
- Rebuilding and reconductoring portions of an existing 115-kV line;
- Adding 115-kV capacitor banks (two of three sites are already in service); and
- Completing structure replacements to remove sag limits on two lines.

Cost: Current estimates for the combined reinforcements total over $100 million excluding National Grid estimates for associated upgrades.

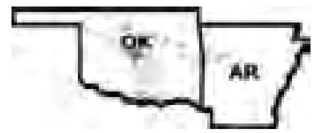
Status: The Pittsfield-Greenfield Area Solution received formal technical approval from ISO-NE in late 2012. Detailed engineering as well as siting/permitting activities have already begun and will continue into 2014. Some limited construction and commissioning activities were completed in 2013. The in-service dates for the remaining reinforcements are expected to be phased in during 2014, 2015, and 2016.

Investment Partners: None.

Benefits: The Pittsfield-Greenfield Area Solution reinforcements address reliability concerns that alleviate thermal overloads and resolve voltage issues found on the two major transmission paths in western Massachusetts.

OGE ENERGY CORP. (OGE)

Company Background:

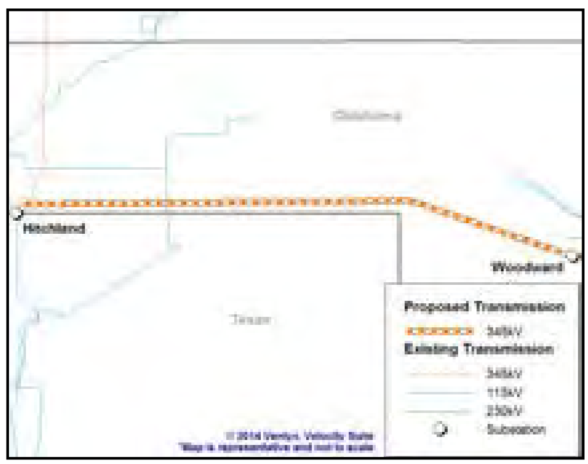


- OGE Energy Corp., through its electric utility subsidiary OG&E Electric Services, serves over 789,000 customers in its 30,000 square mile service territory in Oklahoma and western Arkansas.
- OGE owns over 4,900 circuit miles of transmission lines from 69 kV to 500 kV.
- OGE is a member and its transmission facilities are under the operational control of the Southwest Power Pool (SPP).
- Between 2003 and 2012, OGE invested approximately $1.1 billion in transmission.

Transmission Related Smart Grid Initiatives:

OGE has deployed synchrophasor technology on approximately one-third of its transmission network, including 100 percent of the EHV system and 1.7GWs of wind power plant assets. The technology has proved useful for monitoring system oscillations, detecting failing equipment, and locating system disturbances.

Hitchland – Woodward District EHV Double-circuit 345 kV Line



Description: The Hitchland - Woodward District EHV project consists of 130 miles of new 345 kV, double-circuit transmission line that will extend from OG&E's Woodward District EHV substation to Southwestern Public Service Company's (SPS) Hitchland substation. OG&E will build and own approximately 82 miles of the new line. SPS will construct and own the remaining portion of the line. Associated upgrades to the Woodward District EHV Substation include increasing the substation bus capacity to 5,000 A and installing a 60 MVAR switchable shunt line reactor on each circuit of the new line.

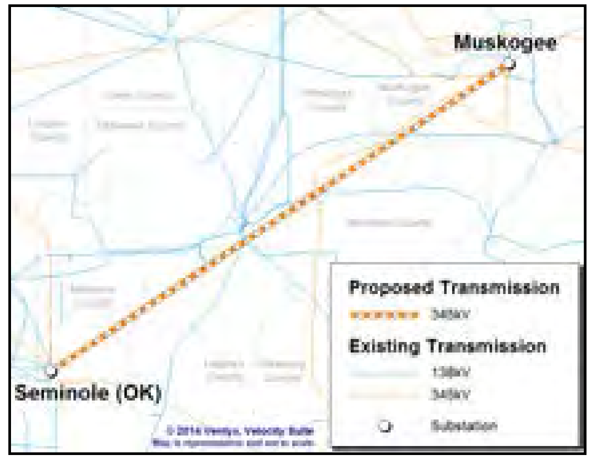
Cost: OG&E's cost is approximately $165 million.

Status: Preliminary line routing and engineering has been completed. Construction of the line began December 2012 and the project has an estimated in-service date of June 2014.

Investment Partners: The SPP provided OG&E and SPS notices to construct separate portions of the transmission line.

Benefits: This project was directed to be built by the SPP as a "Priority Project" to enhance the reliability of the SPP transmission system, to facilitate the integration of wind resources, and enable west-east transfers across the SPP region.

Seminole – Muskogee 345 kV Line



Description: The Seminole - Muskogee project consists of approximately 120 miles of new 345 kV transmission line that will extend from OG&E's Seminole substation to OG&E's Muskogee substation. Associated upgrades to both the Seminole and the Muskogee substations are required to facilitate the new line.

Cost: Approximately $170 million.

Status: This project was placed into service December 2013.

Investment Partners: None.

Benefits: This project has been approved as part of the SPP Balanced Portfolio 3E projects to enable economic transfers and enhance regional transmission reliability.

Sooner – Cleveland 345 kV Line

Description: The Sooner - Cleveland project consists of approximately 38 miles of new 345 kV transmission line to be constructed from OG&E's Sooner substation to the Grand River Dam Authority's Cleveland substation, as well as associated upgrades to the Sooner Substation. OG&E will construct and operate the entire Sooner Cleveland line.

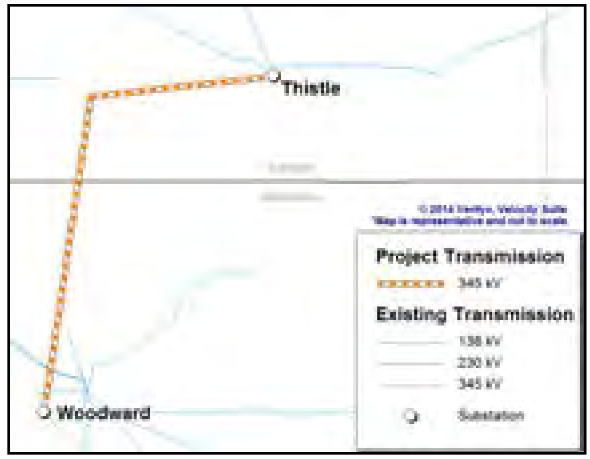
Cost: Approximately $46 million.

Status: This project was placed into service in February 2013.

Investment Partners: None.

Benefits: This project is required for transmission service as directed by the SPP.

Woodward – Thistle Double-Circuit 345 kV Line



Description: The Woodward - Thistle project consists of 110 miles of new double-circuit, 345 kV transmission line to be built from OG&E's Woodward District EHV Substation to the new Thistle substation which will be constructed and owned by ITC Great Plains. OG&E will build and operate approximately 80 miles of the line from Woodward EHV substation to the Oklahoma-Kansas border. ITC Great plains will construct and own the transmission line from the Oklahoma-Kansas border to their new Thistle substation. Associated upgrades to the Woodward District EHV Substation include increasing the substation bus capacity to 5,000 A and installing a 55 MVAR switchable shunt line reactor on each circuit of the new line.

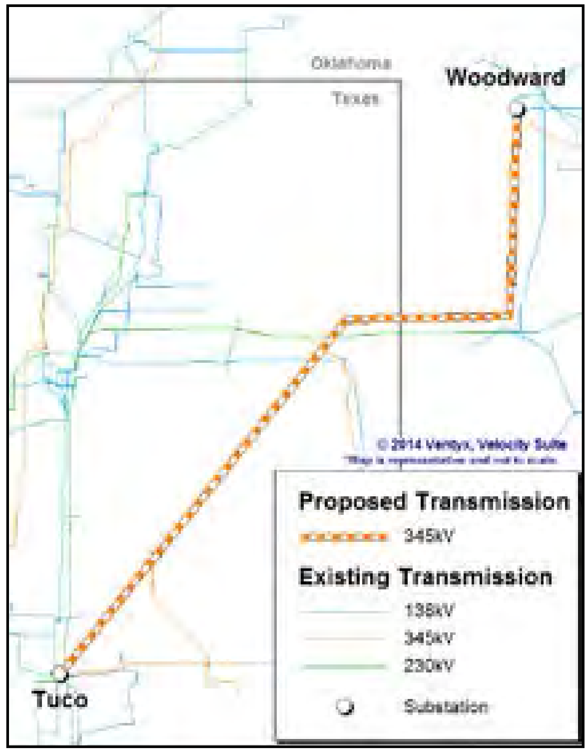
Cost: OG&E's cost is approximately $145 million.

Status: Construction is proceeding. The project has an estimated in-service date of December 2014.

Investment Partners: The SPP provided OG&E and ITC Great Plains notices to construct separate portions of the transmission line.

Benefits: This project was directed to be built by the SPP as a "Priority Project" to enhance the reliability of the SPP transmission system, facilitate the integration of wind resources, and enable west-east transfers across the SPP.

Woodward – Tuco 345 kV Line



Description: The Tuco - Woodward project consists of approximately 265 miles of new 345 kV transmission line from OG&E's Woodward District EHV substation to Southwestern Public Service Company's (SPS) Tuco substation. The OG&E portion of the Tuco - Woodward project is 95 miles in length and will terminate at the new OG&E Border substation located on the Oklahoma – Texas border south of I-40. The new Border substation will include a 75 MVAR shunt reactor on the Woodward EHV – Tuco line.

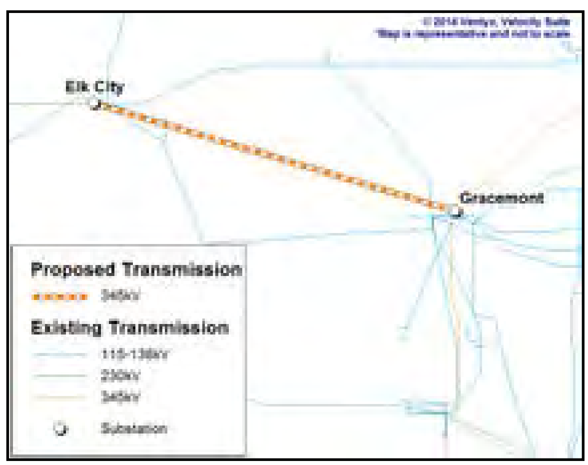
Cost: OG&E's estimated cost is $147 million.

Status: This project is estimated to be in service by May 2014.

Investment Partners: The SPP provided OG&E and SPS notices to construct separate portions of the transmission line.

Benefits: This 345 kV line was approved as part of the SPP Balanced Portfolio 3E Projects to enable economic transfers and enhance regional transmission reliability. This project supports the integration of wind generation and system reliability.

Chisholm - Gracemont 345 kV Line



Description: The Chisholm - Gracemont project consists of 93 miles of new 345 kV transmission line to be built from OG&E's Gracemont substation to the new Public Service Company of Oklahoma (AEP) Elk City substation. OG&E will build and operate approximately 30 miles of the line from Gracemont substation.

Cost: OG&E's estimated cost is $45 million.

Status: Preliminary line route investigation began in 2012. The project has an estimated in-service date of March 2018.

Investment Partners: The SPP provided OG&E and AEP notices to construct separate portions of the transmission line.

Benefits: This project was directed to be built by the SPP as part of the Integrated Transmission Planning 10-year (ITP10) Assessment. The project will enhance the reliability of the SPP transmission system, facilitate the integration of wind resources, and enable west-east transfers across the SPP.

Cimarron - Mathewson Double-Circuit 345 kV Line

Description: The Cimarron – Mathewson project consists of the new 345/138 kV Mathewson substation and 16 miles of new 345 kV, double-circuit transmission line to be built from Cimarron substation to the new Mathewson substation.

Mathewson substation will create a point of connection between the 345 kV Cimarron to Woodring line and the 345 kV Tatonga to Northwest transmission line.

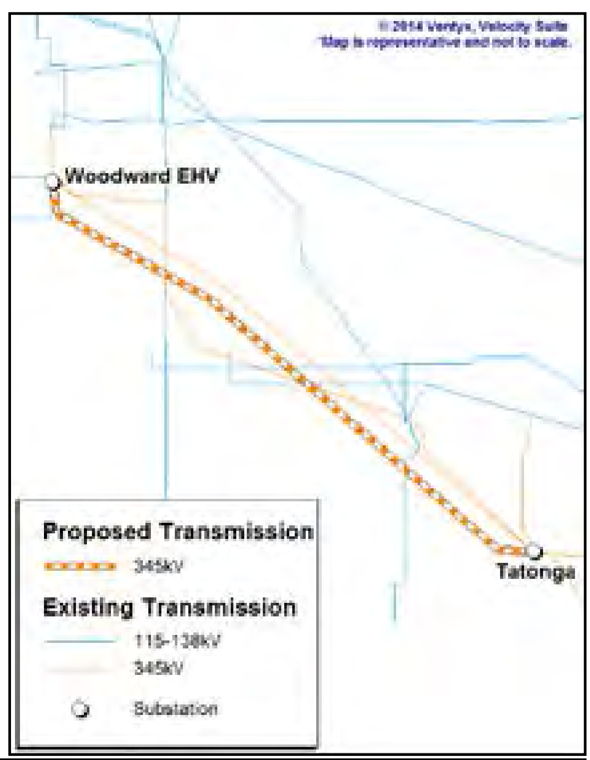
Cost: Approximately $53 million.

Status: Preliminary line route investigation began in 2012. The project has an estimated in-service date of March 1, 2021.

Investment Partners: None.

Benefits: This project was directed to be built by the SPP as part of the ITP10 Assessment. The project will enhance the reliability of the SPP transmission system, facilitate the integration of wind resources, and enable west-east transfers across the SPP.

Woodward District EHV – Tatonga 2nd Circuit 345 kV Line



Description: The Woodward District EHV - Tatonga project consists of 50 miles of new 345 kV transmission line to be built from Woodward District EHV substation to Tatonga substation. The line will be the second circuit of an existing 345 kV line between Woodward District EHV and Tatonga.

Cost: Approximately $59 million.

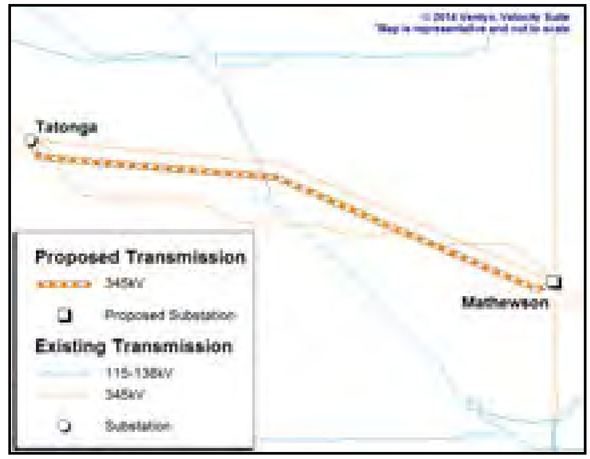
Status: The project has an estimated in-service date of March 1, 2021.

Investment Partners: None.

Benefits: This project was directed to be built by the SPP as part of the ITP10 Assessment. The project will enhance the reliability of the SPP transmission system, facilitate the integration of wind resources, and enable west-east transfers across the SPP.

Mathewson - Tatonga 2nd Circuit 345 kV Line

Description: The Mathewson - Tatonga project consists of 60 miles of new 345 kV transmission line to be built from the new OG&E Mathewson substation to Tatonga substation. The line will be the second circuit of an existing 345 kV line between Mathewson and Tatonga.



Cost: Approximately $66 million.

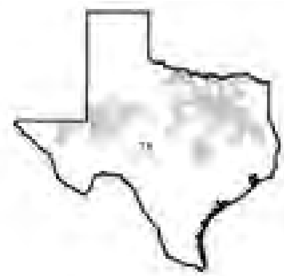
Status: The project has an estimated in-service date of March 1, 2021.

Investment Partners: None.

Benefits: This project was directed to be built by the SPP as part of the ITP10 Assessment. The project will enhance the reliability of the SPP transmission system, facilitate the integration of wind resources, and enable west-east transfers across the SPP.

ONCOR ELECTRIC DELIVERY COMPANY, LLC (ONCOR)

Company Background:

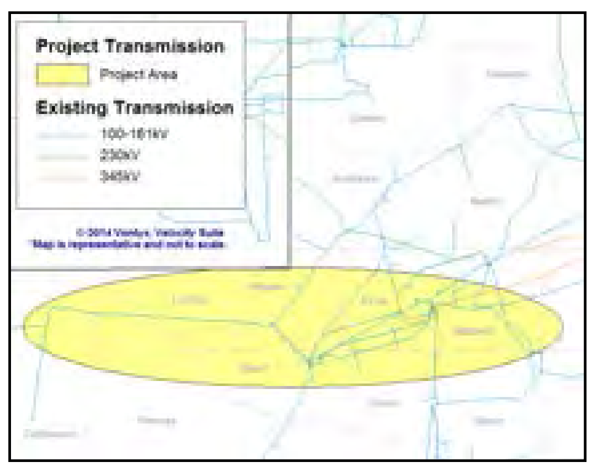


- Oncor is a regulated electricity distribution and transmission business. Oncor operates and is governed as a separate and independent company from Energy Future Holdings Corporation.
- Oncor operates the largest distribution and transmission system in Texas and is the sixth-largest system in the nation. The company delivers power to approximately three million homes and businesses, or about one-third of the state's population.
- Oncor operates approximately 15,000 circuit miles of transmission lines in Texas, including more than 5,000 circuit miles of 345 kV lines.
- Between 2001 and 2012 Oncor invested approximately $5.1 billion into its transmission system.

Transmission Related Smart Grid Initiatives:

- Oncor has consistently upgraded its transmission management and control systems with the latest smart grid technology. With more than 92 percent of transmission relays now electronic, digital fault recorders and relay records are automatically moved to a central system for rapid analysis.

West Texas Congestion



Description: ERCOT Staff performed the 2012 West Texas Sensitivity Study with extensive review and input by NERC registered Transmission Planners (TPs), Transmission Owners (TOs), such as Oncor, and other stakeholders, which addresses reliability and economic transmission needs to meet the growing electric demand being driven by the oil and natural gas industry in the Permian Basin, and the associated economic expansion in supporting residential, commercial and supporting industries in the ERCOT West and Far West weather zones. ERCOT's "2012 West Texas Sensitivity Study Report" revised September 17, 2013 (WTS Study) identified approximately 65 projects that resolve thermal loading and voltage issues across the interconnected system of all TOs operating in the West Texas area. Approximately 22 of the ERCOT proposed projects are within Oncor's footprint, 13 of which Oncor previously identified, and are currently under development. The project completion years and scope of each project stated in the WTS Study were selected to timely address reliability and economic needs based upon the study results. Oncor will work with ERCOT and other TOs to determine if scope and completion dates need to be adjusted based on factors such as changes in assumptions, identification of better alternatives, availability of construction clearances, time required to receive required regulatory or governmental approvals, equipment availability, time required to design the projects, land acquisition and resource constraints. Projects will be submitted for ERCOT Regional Planning Group (RPG) review, as needed.

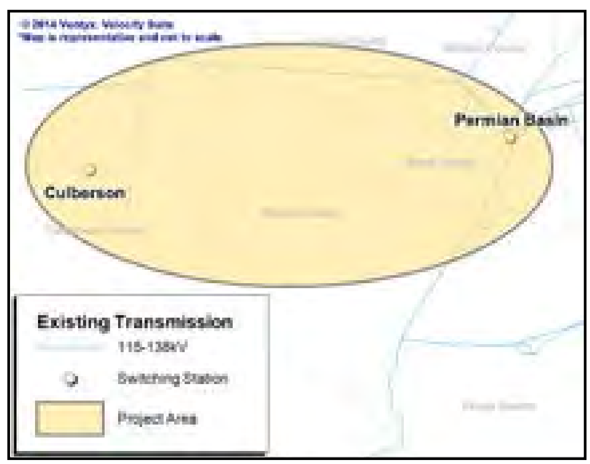
Cost: Approximately $130 million.

Status: Oncor submitted West Texas Area projects from the ERCOT WTS Study for RPG review. The submittal to RPG describes the need for Oncor to proceed with constructing two new 345/138 kV switching stations and a new 138 kV line to Midessa. These three projects were identified in the WTS Study and provide a new 345 kV source fed from the Oncor Moss – Midland East 345 kV Line into the underlying Oncor 138 kV facilities in Ector, Midland and Andrews counties. Other existing Oncor projects already in progress in West Texas are not included in the RPG submittal.

Investment Partners: None.

Permian Basin - Culberson 138 kV Transmission Line

Description: The need to expand Oncor transmission facilities in West Texas is being driven by the oil and natural gas industry. To meet anticipated electric demand, a new 138 kV transmission line from the Permian Basin 138 kV Switching Station in Ward County to the existing Culberson 138 kV Switching Station located in Culberson County is being proposed.



Cost: Approximately $73 million.

Status: The Permian Basin – Culberson 138 kV Line Project has been approved by the ERCOT Regional Planning Group (RPG). Oncor will file an application for an amendment to its Certificate of Convenience and Necessity (CCN) for the proposed Permian Basin – Culberson 138 kV Transmission Line in the second quarter of 2014.

Investment Partners: None.

Benefits: Completion of the Oncor project will provide an effective solution that creates a transmission loop for serving the existing customers and future load growth anticipated in the Permian Basin and surrounding areas while adding valuable transmission capacity to the entire transmission system. This project will help ensure continued reliable electric service to the entire local region.

Dynamic Line Ratings

Description: Oncor participated in the Department of Energy (DOE) SmartGrid Demonstration Projects program addressing the use of Dynamic Line Rating (DLR) to improve the efficiency of the existing transmission infrastructure and to reduce congestion costs.

Cost: Cost is being shared with DOE.

Status: Oncor has installed primary and secondary dynamic line rating equipment on eight transmission circuits. The primary system, CAT-1 equipment, streams real-time data through the System Control and Data Acquisition (SCADA) system to the Oncor Energy Management System environment. That data will be processed and dynamic ratings posted to the operations departments at Oncor and ERCOT. The secondary systems, Sagometers and Promethean RTTLMS, provide offline data for performing statistical validation of the dynamic ratings and their "reach" from installation point down the transmission line to capture the characteristics of line sections rather than point locations.

The DOE is particularly interested in assessing the impact of DLR on congestion of transmission lines. Analysis has shown that congestion is very difficult to predict from a location, timing and extent perspective. With ERCOT support, Oncor has calculated the projected impact of having increased line capacity on six transmission lines that have exhibited extreme congestion levels in 2011 and 2012. The analysis shows positive impacts on mitigating the congestion on the target lines.

Increased capacity to meet load growth and line capacity needs is also being assessed based on the statistical analysis of the DLR capacity relative to Static and Ambient Adjusted Ratings.

The project ran from January 1, 2010 through December 30, 2012. The Final Report has been submitted. The DLR equipment installed on the line continues to feed ratings to the Oncor control center and ERCOT.

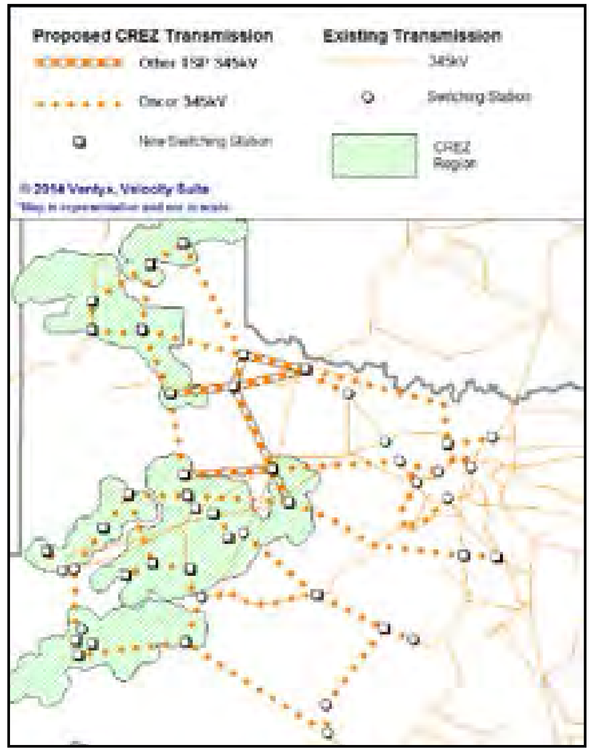
The DLR project was successful and a decision was made to add DLR capabilities to five lines in the Midland – Odessa area for summer of 2013 operation. The CAT-1 devices were installed and ratings were integrated into the system telemetry on June 17, 2013. Two of the lines were since reconductored in the fall of 2013, and the DLR equipment was removed.

Investment Partners: None.

Benefits: The project has several benefit objectives in the technical area as well as economic. Technically, the project will validate the DLR protocol and optimize the application of instrumentation. The lessons learned from the project will be developed into a "guide" for future deployment of DLR systems by other utilities. Technical studies will also be designed to identify the amount of increased capacity over static ratings and its probability of occurrence and persistence to be available for different periods of time, i.e., the next 15 minutes up to 2 or 3 hours. Economic benefits will compare the impact of increased capacity to relieve congestion in the grid and for its application to identify capital investment deferments where the solution used DLR rather than physical upgrades or new construction.

West Texas installation cost: $1.2 million.

Oncor CREZ Development



Description: In 2005, the Texas Legislature directed the Public Utility Commission of Texas (PUCT) to develop a transmission plan to meet the State's increased renewable energy goals. From 2005 to 2008, the PUCT identified five Competitive Renewable Energy Zones (CREZ) to which lines would be built, adopted a transmission plan, and developed the process to select transmission companies to build the lines. The PUCT ultimately selected eight companies to build the new lines and upgrade existing stations and lines.

The PUCT awarded Oncor more than one-quarter of the total CREZ transmission project buildout, encompassing over 1,000 miles of new transmission lines.

CREZ projects are grouped into one of three categories: Default, Priority and Subsequent projects. The Default Category, which represented 20 percent of Oncor's total CREZ spend, included upgrades to existing station and transmission line facilities. The Priority Category, which represented 40 percent of Oncor's CREZ spend, included new transmission lines and stations for existing (constrained) wind that is currently installed but could not come to market due to transmission flow constraints. The Subsequent Category, which represents 40 percent of Oncor's CREZ spend, included new transmission lines and stations for renewable generation to be brought to the market.

The Default Category projects include twelve stations and eleven transmission lines totaling 256 miles. The Priority Projects include ten stations and nine transmission lines totaling 377 miles. The Subsequent Projects include nine stations and five transmission lines totaling 404 miles.

The CREZ Reactive Compensation Study was issued by ERCOT in December 2010 to outline the reactive support requirements for CREZ, accomplished through the addition of static and dynamic reactive devices, including the installation of three Static Var Compensators (SVCs), series compensation equipment and shunt reactive devices. Oncor has assessed the scope of work and developed revised plans in accordance with the study results.

Cost: Approximately $2 billion.

Status: The Default Category projects received two CCNs and the Priority Category projects received seven CCNs. All Default and Priority projects were completed at the end of 2012. The Subsequent Category received five CCNs and all projects were completed and energized by December 2013.

Investment Partners: None.

Benefits: The CREZ transmission project provides the infrastructure necessary to approximately double Texas' current renewable energy capacity in West Texas. This will allow the State to meet increased renewable energy goals while reducing greenhouse gas emissions. CREZ will also improve ERCOT's ability to move power produced from all generation sources within the State as energy demand increases, as well as improve overall grid reliability.

Static Var Compensation

Description: Oncor has deployed the world's largest cluster of Static Var Compensators (SVCs) in the north Texas area, adding to the reliability of Oncor's grid. This technology will maintain grid reliability in the urban environment as generators are retired and not replaced. Additionally, 3 SVC projects are being installed as part of the CREZ initiative.

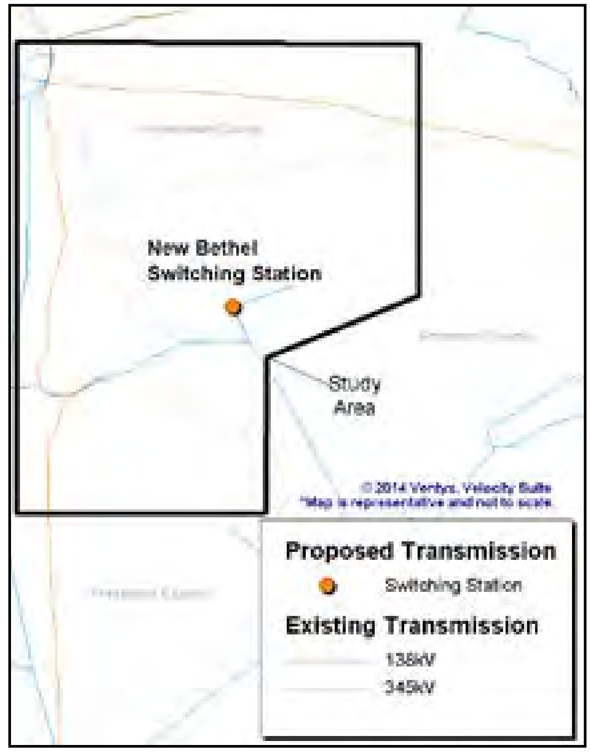
Cost: More than $50 million per site.

Status: A total of four SVC projects are currently in-service at Oncor. The first unit was operational in Dallas in June 2009; a second unit was placed in service in December 2010, and two additional units were placed in service in early 2011. Currently three SVC projects are in progress as part of the CREZ initiative with expected in service during the first quarter 2014.

Investment Partners: None.

Benefits: SVC technology will help in controlling voltage and rapidly responding to changes in grid conditions. SVC provides the needed voltage control without the need for generation close to population centers. It will also accommodate for the future use of wind power and other forms of remote and renewable energy generation.

New Bethel Energy Center 345 kV Transmission Line



Description: The State of Texas is continuing to promote and increase the integration of renewable and clean energy into the Texas electric market. Reliable electric facilities must be in place to support increased levels of renewable energy and to provide efficient means for this electric power to reach consumers. Oncor has received a request to interconnect a new, proposed 317 MW Compressed Air Energy Storage (CAES) electric generation facility, located in East Texas, with the Electric Reliability Council of Texas (ERCOT) grid. Oncor is proposing to construct a new double-circuit 345 kV electric transmission line to interconnect the proposed plant to the electric grid.

Cost: Approximately $60 million.

Status: Oncor will file an application for an amendment to its Certificate of Convenience and Necessity (CCN) for the proposed New Bethel Energy Center 345 kV Transmission Line in the second quarter of 2014.

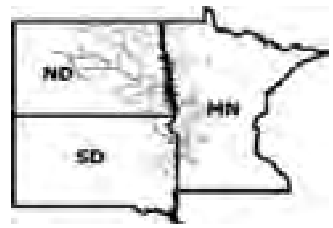
Investment Partners: None.

Benefits: Completion of the Oncor project will provide the necessary interconnection of the proposed generation station and the ERCOT grid, which will supply additional clean energy into the Texas electric market.

OTTER TAIL POWER COMPANY

Company Background:

- Otter Tail Power Company is an electric utility that has operations in three states (Minnesota, North Dakota, and South Dakota) serving 129,800 customers.
- System-wide it has about 5,300 miles of transmission lines.
- Between 2003 and 2012, Otter Tail Power Company has invested approximately $96 million into its transmission system.



CapX2020 Transmission Plan

Description: The CapX2020 transmission plan consists of approximately 250 miles of new double-circuit, 345 kV transmission line between Brookings County, South Dakota, and Hampton, Minnesota, with a double-circuit capable line portion from Helena, Minnesota, to Hampton, Minnesota, plus a related 23 mile double-circuit capable, 345 kV transmission line between Lyon County, Minnesota, and Hazel Creek, Minnesota; approximately 240 miles of new double-circuit capable, 345 kV transmission line between Fargo, North Dakota, and St. Cloud and Monticello, Minnesota; and approximately 70 miles of new single-circuit, 230 kV transmission line between Bemidji and Grand Rapids, Minnesota.

This project is a joint initiative of 11 transmission owning utilities, including Otter Tail Power Company, in the Upper Midwest to expand the electric transmission grid to ensure continued reliable service to the year 2020 and beyond.

The Brookings County - Hampton Project provides access to wind generation in southwest Minnesota and eastern South Dakota. The line is expected to increase the delivery of wind generation by 700 MWs. While the other CapX2020 lines are driven primarily by reliability needs, they will also facilitate future generation outlet, including wind development, by providing the necessary infrastructure to support other wind-focused transmission additions. The Brookings County - Hampton Project was approved in December 2011 by the MISO Board of Directors as part of the Multi Value Project (MVP) Portfolio.

Big Stone South to Brookings County

Description: Big Stone South - Brookings County will consist of an approximately 70 mile long, 345 kV transmission line from a connection near Big Stone City, South Dakota, to the Brookings County Substation near Brookings, South Dakota. It also will include two 2 mile long, 230 kV lines from the Big Stone substation to a new Big Stone South substation.

Cost: Approximately $210 to $230 million, depending on final route determination.

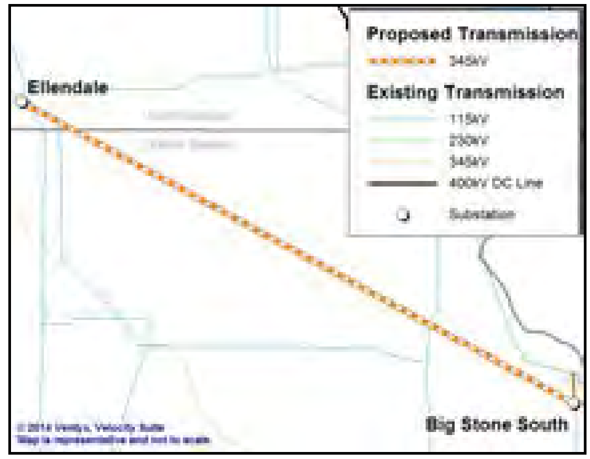
Status: The MISO Board of Directors approved this project in December 2011 as an MVP. It is estimated to be in service in 2017.

Investment Partners: The project is being jointly developed by Otter Tail Power Company and Xcel Energy.

Benefits: As part of the MVP portfolio, this project will provide regional reliability, economic value and support public policy requirements.

Big Stone South to Ellendale

Description: Big Stone South - Ellendale is an approximately 160 to 170 mile long, 345 kV transmission line between the Big Stone South Substation near Big Stone City, South Dakota, and Ellendale Substation near Ellendale, North Dakota.



Cost: Approximately $293 to $370 million depending on final route determination.

Status: The MISO Board of Directors approved this project in December 2011 as an MVP. It is estimated to be in service in 2019.

Investment Partners: The project is being developed by Otter Tail Power Company and Montana-Dakota Utilities Co.

Benefits: As part of the MVP portfolio, this project will provide regional reliability, economic value and support public policy requirements.

PACIFIC GAS AND ELECTRIC (PG&E)

PG&E Corporation

Company Background:

- PG&E serves over five million electric customers in northern California over a 70,000 square-mile service area.
- At December 31, 2012, PG&E owned approximately 18,100 circuit miles of interconnected transmission lines operated at voltages of 60 kV to 500 kV.
- PG&E is a member of the California Transmission Planning Group (CTPG).
- Between 2003 and 2012, PG&E invested approximately $5.6 billion in transmission.

Gates-Gregg 230 kV Transmission Line

Description: The 70-mile line spans from PG&E's Gates to Gregg substations in the Fresno area. In addition to enhancing our reliability performance throughout Fresno, Kings and Madera counties, the increased capacity provided by this line will also assist in the integration and development of renewable energy. The Greater Fresno area is served by local area generation including the Helms Pumped Storage, hydro-generation, thermal generation, and solar generation.

Cost: The California ISO estimates the total project cost to be approximately $115M-$145M in direct costs, i.e. excluding indirect costs such as environmental mitigation, land acquisition, permitting and licensing, public outreach costs, or inflation.

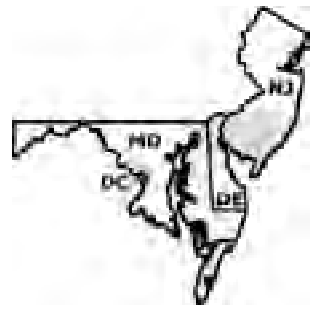
Status: Anticipated in-service date is 2020.

Investment Partners: PG&E, MidAmerican Transmission, and Citizens Energy Corporation have formed a consortium.

Benefits: Benefits include 1) improving transmission reliability in the Greater Fresno Area; 2) helping to meet California's Renewables Portfolio Standard (RPS) goals by integrating renewable resources and delivering renewable power; and (3) alleviating constraints at Helms Pumped Storage Plant.

PEPCO HOLDINGS, INC.

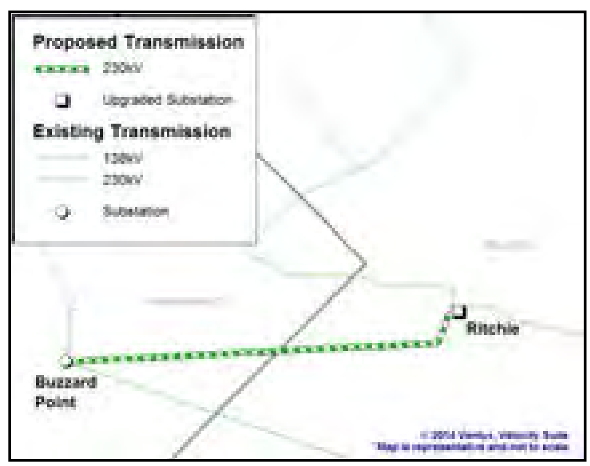
Company Background:



- Pepco Holdings, Inc. (PHI) delivers electricity to approximately 2 million customers in Delaware, the District of Columbia, Maryland, New Jersey, and Virginia.
- PHI's energy-related businesses include:
    - Pepco – a regulated electric utility delivering electricity to more than 793,000 customers in Washington, D.C., and its Maryland suburbs;
    - Atlantic City Electric – a regulated electric utility serving nearly 544,000 customers in southern New Jersey;
    - Delmarva Power – a regulated utility serving more than 502,000 customers in Delaware and the Delmarva Peninsula.
- System-wide, there are approximately 3,750 circuit miles of transmission lines.
- Region-wide efforts include participation in PJM Interconnection, Edison Electric Institute, Reliability First Corporation, and the Eastern Interconnection Planning Collaborative.
- Between 2003 and 2012, PEPCO invested approximately $1.6 billion in transmission.

Ritchie to Buzzard Point N-1-1 Compliance Project

Description: The Ritchie to Buzzard Point N-1- 1 Compliance Project consists of converting an existing 11.0 mile long 138 kV circuit to 230 kV operation and upgrading an existing 11.0 mile long 230 kV circuit from Pepco's Ritchie Substation, located in Seat Pleasant, Maryland, to Pepco's Buzzard Point Substation, located in the southwest portion of the District of Columbia. The project also includes the addition of a new 230/138 kV transformer and 100 MVAR shunt reactor at Buzzard Point. The project is required to insure that the supply feeders into Buzzard Point are N-1-1 compliant.



Cost: Approximately $100 million.

Status: The project has received most of the regulatory approvals and permits and is currently under construction. Construction of the project started in the fall of 2012, the first phase of the project is expected to be in service June 1, 2014, with the second phase scheduled for completion June 1, 2018.

Investment Partners: None.

Benefits: The addition of this project will allow the Pepco system to meet the NERC N-1-1 Reliability Standard TPL-003-0 for Bulk Electric System facilities. Additionally, approximately 240 MWs of combustion turbines were recently retired at the Buzzard Point substation and this project helps to account for this loss of capacity.

PJM N-1-1 Projects (Southern Delmarva)

Description: The PJM N-1-1 Delmarva Projects consist of constructing new and upgrading existing 138 kV and 230 kV infrastructure in the Southern Delmarva zone. Approximately 67 circuit miles of new transmission will be constructed. Additionally, two-230/138 kV autotransformers and a 138 kV Static VAR Compensator (SVC) installation are part of the project. The N-1-1 efforts span the entire PHI service territory, however, an emphasis has been placed on the efforts in the Southern Delmarva zone due to significant outage, resource, and environmental coordination which will be imperative to meet the required in-service dates.

Cost: Approximately $151 million.

Status: There are many sub-projects within the overall N-1-1 initiative which will be completed over multiple years. The majority of projects which have been identified thus far have in-service dates spanning from 2012 – 2017. These projects are in the completed, engineering, and regulatory approval phases. Within the state of Maryland, the requirement to procure Certificates of Public Convenience and Need (CPCN) necessitate providing detailed information inclusive of the specifics of the projects well in advance of the in-service date.

Investment Partners: None.

Benefits: The projects will improve reliability for Maryland and the Delmarva Peninsula by placing the necessary infrastructure in place to mitigate the harmful effects of an N-1-1 event (as per NERC TPL-003 Category C). Strengthening of the transmission system along with the growing Delmarva Peninsula will be a beneficial outcome of the efforts.

Burtonsville-Bowie-Oak Grove Transmission Project

Description: The Burtonsville-Bowie-Oak Grove Transmission Project consists of reconductoring two existing 21 mile long 230 kV circuits from Pepco's Burtonsville Substation, located in Laurel, Maryland, to Pepco's Oak Grove Substation, located in Upper Malboro, Maryland. The project also includes the upgrade of terminal equipment at each Substation. The project is required to meet PJM's Generation Deliverability Common Mode Outage Criteria.

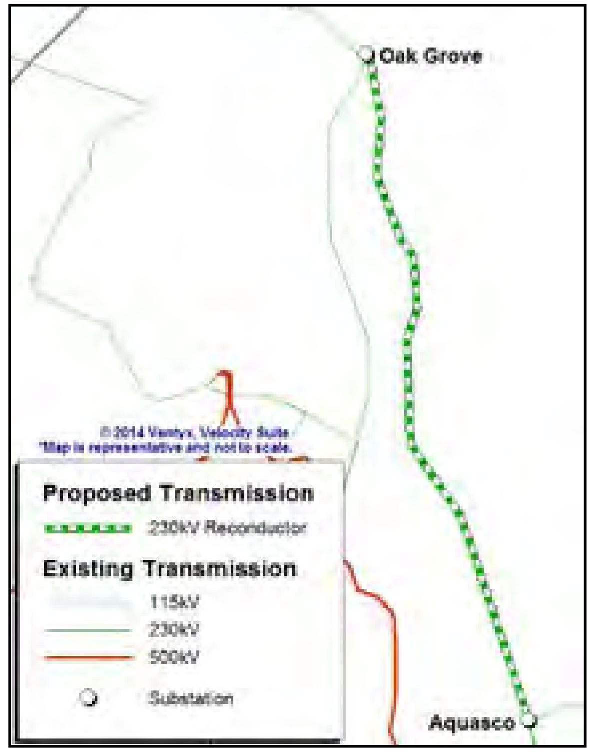
Cost: Approximately $50 million.

Status: The project was approved by PJM in 2011 and it is in the planning phase. The scheduled in-service date is June 2016.

Investment Partners: None.

Benefits: The addition of this project will allow the Pepco system to meet the PJM Generation Deliverability Common Mode Outage criteria, which ensures that the system is reliable and capable of exporting generation.

Oak Grove-Aquasco Transmission Project



Description: The Oak Grove-Aquasco project consists of reconductoring an existing 18 mile long 230 kV circuit from Pepco's Oak Grove Substation, located in Upper Malboro, Maryland, to Pepco's Aquasco Substation, located in Aquasco Maryland. The project also includes the upgrade of terminal equipment at each substation. The project is required to meet PJM's Generation Deliverability Common Mode Outage Criteria.

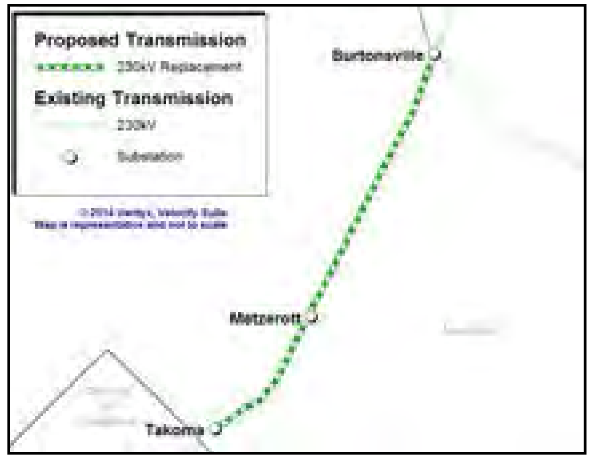
Cost: Approximately $27 million.

Status: The project was approved by PJM in 2011 and it is in the planning phase. The scheduled in-service date is June 2016.

Investment Partners: None.

Benefits: The addition of this project will allow the Pepco system to meet the PJM Generation Deliverability Common Mode Outage criteria, which ensures that the system is reliable and capable of exporting generation.

Burtonsville-Metzerott-Takoma Transmission Project



Description: The Burtonsville-Metzerott-Takoma Transmission Project consists of replacing approximately 10 miles of an existing double-circuit 230 kV transmission line between the Burtonsville Substation, located in Laurel Maryland, to the Takoma Substation, located in Takoma, Maryland. The project also includes terminal upgrades at each substation. The project is required due to aging infrastructure and it is also driven by the need to address potential winter load reliability issues, which would prevent scheduling the tower outage for construction.

Cost: Approximately $30 million.

Status: This project is in the planning phase and it is expected to be in service by June 2015.

Investment Partners: None.

Benefits: The addition of this project will increase the transmission capacity into the Takoma and Metzerott area. In addition, the project will provide a wider operational range for the local transmission system.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY (PSE&G)

Company Background:

- Public Service Electric and Gas Company (PSE&G) serves 2.2 million electric customers and 1.8 million gas customers in New Jersey. These customers reside in a 2,600 square mile diagonal corridor across the state from Bergen to Gloucester Counties.
- System-wide there are approximately 1,500 circuit miles of transmission line.
- Between 2003 and 2012, PSE&G invested approximately $3.0 billion in transmission.

Burlington - Camden 230 kV Network Reinforcement Project

Description: The Burlington - Camden 230 kV Network Reinforcement Project consists of upgrading 37 circuit miles (30 miles of overhead and seven miles of underground) of transmission operating from 138 kV to 230 kV, constructing a new 230 kV switching station at Burlington and converting five existing stations to 230 kV operation. The upgraded stations are Levittown, Cinnaminson, Camden, Gloucester, and Cuthbert Boulevard. This project is a proposed electric reliability transmission baseline upgrade to the PJM transmission system, extending from the Burlington Switching Station to the Camden Switching Station and continuing on to the Gloucester Switching Station in Southern New Jersey. PSE&G will be responsible to design, procure, and construct all transmission facilities within the scope of this project. All circuits to be upgraded are located within existing rights-of-way (ROW) between Burlington and Gloucester Switching Stations.

Cost: Approximately $399 million.

Status: This project was approved by the PJM Board of Managers in February 2010 with an in-service date of June 1, 2014. The project is currently 99 percent engineered and construction commenced on the project in July 2012 after receiving the required construction permits. The total project is approximately 85% complete.

Investment Partners: None.

Benefits: The project is needed to maintain transmission system reliability by addressing several PJM-identified voltage violations that are anticipated to occur beginning in 2014. The project will prevent these violations and reinforce the transmission system in Southern New Jersey.

Northeast Grid Reliability Transmission Project

Description: The Northeast Grid Reliability Transmission Project consists of upgrading approximately 50 miles of overhead transmission circuits from 138 kV to 230 kV operation, constructing a new 230 kV underground circuit from Bergen to Athenia Stations looping through Saddle Brook Station, constructing a new underground circuit from South Waterfront to Hudson Stations, and upgrading the 230 kV or converting to 230 kV operation at 12 existing stations. Those stations are Roseland, West Caldwell, Cook Road, Kingsland, Turnpike, Kearny, Essex, Hudson, Bergen, Saddle Brook, Athenia, and South Waterfront. This is a proposed electric reliability transmission baseline upgrade to the PJM transmission system. PSE&G will be responsible to design, procure, and construct all transmission facilities within the scope of this project. All overhead transmission circuits to be upgraded are located within existing ROW between Hudson and Roseland Stations. The two new underground circuits may require acquisition of a new ROW as the route has not been finalized at this time.

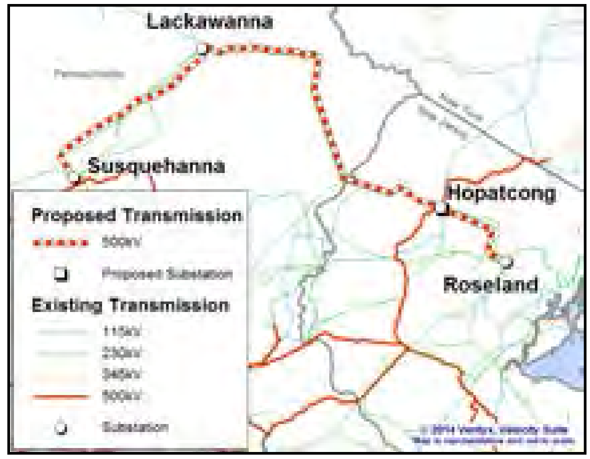
Cost: Approximately $907 million.

Status: This project was approved by the PJM Board of Managers in October 2010. The projected in-service date is June 1, 2015. The project is currently in the engineering/design phase. While some permit application approvals are pending, many permit approvals have been received. The majority of long lead time material has been ordered and underground circuit construction has begun.

Investment Partners: None.

Benefits: This project is needed to maintain transmission system reliability by addressing several PJM-identified voltage violations that are anticipated to occur beginning in 2015. The project will prevent these violations and reinforce the transmission system in northern New Jersey.

Susquehanna - Roseland 500 kV Transmission Line Project



Description: The Susquehanna - Roseland 500 kV Transmission Line Project consists of approximately 45 miles of new 500 kV transmission line running from the Delaware Water Gap east to the Roseland Switching Station, and two new 500 kV switching stations; one in Hopatcong and one in Roseland. This project is a proposed electric reliability transmission baseline upgrade to the PJM transmission system, extending from the Berwick area in Pennsylvania to the Roseland-East Hanover area in northern New Jersey. PSE&G will construct the New Jersey portion of the project, while PPL Electric Utilities will construct the Pennsylvania portion of the project. All of the circuits in New Jersey will be built along existing ROW by removing existing 230 kV circuits between Roseland, Montville, Newton, and Bushkill, Pennsylvania and building 500/230 kV tower lines in their place.

Cost: Approximately $1.33 billion, of which approximately $790 million will be PSE&G's responsibility.

Status: This project was approved by the PJM Board of Managers in June 2007 with an in-service date of June 1, 2012. The National Park Service (NPS) review of that portion of the Project to be built in the Delaware Water Gap National Park was approved in October 2012. Subsequent to the NPS approval, NJDEP issued permits in October 2012. Based on those approvals, the Roseland to Hopatcong portion of the Project is currently expected to be in service by June 2014. The remainder of the Project is anticipated to be completed by June 2015.

Investment Partners: PPL Electric Utilities.

Benefits: The project is needed to maintain reliability by addressing several PJM-identified reliability criteria violations that were anticipated to occur beginning in 2012. The project will prevent overloads on existing power lines in New Jersey and Pennsylvania.

North-Central Reliability Project (formerly the West Orange 230 kV Project)

Description: The North-Central Reliability Project consists of upgrading four 138 kV transmission lines 35 miles and six existing stations to 230 kV operation. The upgraded stations are West Orange, Marion Drive, Laurel Avenue, Fanwood, New Dover, and Woodbridge. This project is a proposed electric reliability transmission baseline upgrade to the PJM transmission system, extending from the West Orange Switching Station to the Sewaren Switching Station in Central New Jersey. PSE&G will be responsible to design, procure and construct all transmission facilities within the scope of this project. All circuits to be upgraded are located within existing ROW between West Orange and Sewaren Switching Stations.

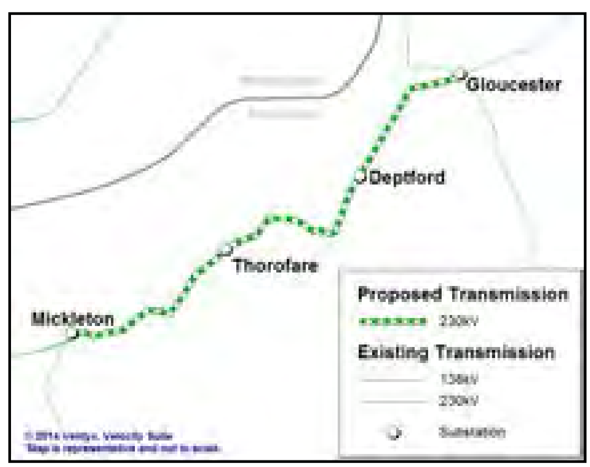
Cost: Approximately $390 million.

Status: This project was approved by the PJM Board of Managers in February of 2010 with an in-service date of June 1, 2014. The Project was submitted to the BPU in May of 2011 and an approval was received on June 18, 2012. The project is currently in the construction phase and is on schedule to be completed by the anticipated in-service date.

Investment Partners: None.

Benefits: The project is needed to maintain transmission system reliability by addressing several PJM-identified voltage violations that are anticipated to occur beginning in 2014. The project will prevent these violations and reinforce the transmission system in Central New Jersey.

Mickleton-Gloucester-Camden Reinforcement Project



Description: The Mickleton-Gloucester-Camden Reinforcement Project (referred to as Southern Reinforcement Project) scope consists of building two new 230 kV underground circuits from Gloucester Switch to Camden Switch looping one into Cuthbert Boulevard Substation, building a second parallel overhead circuit from Gloucester Switch to Atlantic City Electric's Mickleton Station, and re-conductoring the existing Gloucester– Mickleton. The project will install 36 miles of transmission line, ten miles of overhead reconductoring, ten miles of new overhead, and 16 miles of new underground. The station upgrades will be completed at Mickleton (by Atlantic City Electric), Thorofare, Deptford, Eagle Point (by Sunoco), Cuthbert, Gloucester, and Camden. PSE&G will be responsible to design, procure, and construct all transmission facilities within the scope of this project. The required PJM project in-service date is June 2015.

Cost: Approximately $435 million.

Status: This project was approved by the PJM Board of Managers in February 2010 with an in-service date of June 1, 2015. The project is currently in the planning and detailed engineering phase. Construction began in November 2012.

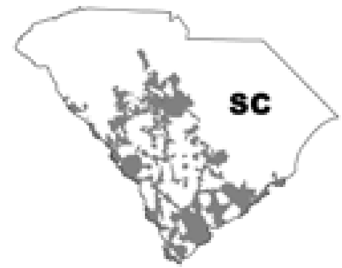
Investment Partners: None.

Benefits: The project is needed to maintain transmission system reliability by addressing several PJM-identified thermal overloads that are anticipated to occur beginning in 2015. The project will prevent these violations and reinforce the transmission system in Southern New Jersey.

SCANA CORPORATION

Company Background:

South Carolina Electric & Gas (SCE&G) delivers electricity to more than 668,000 retail and wholesale customers throughout South Carolina. SCE&G owns more than 3650 miles of transmission lines and participates in numerous transmission assessment and planning efforts; including the Eastern Interconnection Planning Collaborative (EIPC), SERC reliability assessment activities, the Carolinas Transmission Coordination Arrangement (CTRA) and the South Carolina Regional Transmission Planning (SCRTP) process.



V.C. Summer #2 and #3 Interconnection Project

Description: The V.C. Summer #2 and #3 Interconnection Project includes four (4) new 230 kV transmission circuits originating at the V.C. Summer Nuclear Station and connecting to existing and new transmission substations within the SCE&G system. These 4 circuits will reliably interconnect and integrate these generators into the electrical transmission grid. These 4 circuits total over 250 miles of new construction including the V.C. Summer – Killian 230 kV line (37 miles), the V.C. Summer – Lake Murray 230 kV #2 line (22 miles) and the V.C. Summer – St. George double circuit 230 kV lines (96 miles each). All but 6 miles of this transmission construction will be located on existing rights-of-way. Because 245 miles of this construction will be on existing rights-of-way, a significant amount of existing 115 kV circuits is being rebuilt/relocated on these existing rights-of-way to provide space for the new 230 kV construction. These circuits will be located entirely within the state of South Carolina.

Cost: The estimated cost of these 4 circuits is $272 million.

Status: The estimated in-service date for the: V.C. Summer – Killian 230 kV line is May 2014, V.C. Summer – Lake Murray #2 230 kV line is December 2014 and for the V.C. Summer – St. George 230 kV lines is January 2018.

Investment Partners: None.

Benefits: This transmission project will reliably interconnect the V.C. Summer #2 and #3 Nuclear Generators, which will provide continued electric power to meet South Carolina's energy needs.

SOUTHERN CALIFORNIA EDISON (SCE)

Company Background:

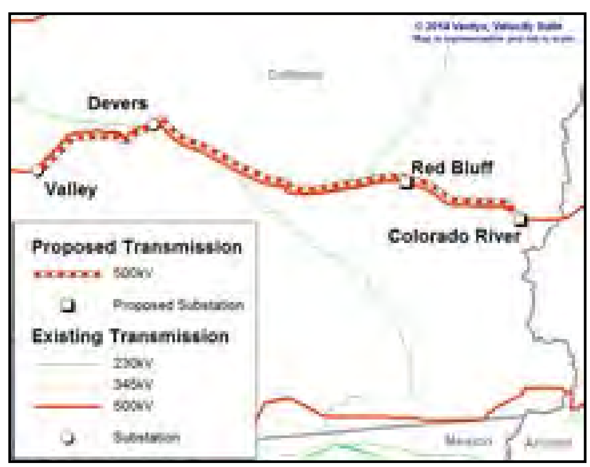
- SCE provides power to 180 cities in 50,000 square miles encompassing 11 counties in central, coastal, and Southern California serving 13 million people and nearly 300,000 businesses.
- The SCE-owned transmission grid is under the operational control of the California Independent System Operator (CAISO).
- SCE's system consists of over 12,000 circuit miles of transmission lines.
- Between 2006 and 2012, SCE invested approximately $3.8 billion (direct costs in nominal dollars, excluding corporate overheads) in transmission.
- SCE plans to invest over $2.1 billion (estimated direct costs in nominal dollars, excluding corporate overheads) of capital in transmission projects from 2013 through 2015.

Transmission Related Smart Grid Initiatives:

SCE is also making substantial investments in advanced technologies that will move SCE towards a more integrated Smart Grid. Three such projects are the PHASOR Program, Centralized Remedial Action System (CRAS), and Tehachapi Wind Energy Storage Project (TSP).

Devers – Colorado River and Devers – Valley No. 2 Transmission Project; also known as the California Portion of Devers – Palo Verde 2 (DPV2) Transmission Project

Description: The Devers-Colorado River/Devers-Valley No. 2 Transmission Project consists of the approximate 153 mile California-only portion of the former DPV2 project and is comprised of :



- Approximately 111 miles of new 500 kV transmission line between the existing Devers Substation, near Palm Springs, California and a new Colorado River Substation, near Blythe, California (along this route there is also a new Red Bluff Substation, near Desert Center, California which was separately licensed), and
- Approximately 42 miles of new 500 kV transmission line between the Devers Substation and the existing Valley Substation near Romoland, California.

Cost: Approximately $800 million (estimated direct costs in nominal dollars, excluding corporate overheads).

Status: Construction commenced January 2012 and the project went in service in September 2013.

Investment Partners: None.

Benefits: This project will provide interconnection and electrical transmission for numerous solar energy facilities, as well as conventional generation facilities, including large-scale solar projects in California and Nevada, to serve load centers in Los Angeles and San Bernardino Counties in California.

Eldorado – Ivanpah Transmission Project (EITP)

Description: The EITP project consists of a new 220/115 kV substation near Primm, Nevada and approximately 35 miles of new double-circuit, 220 kV transmission line that extends from the Ivanpah Dry Lake Area in Southern California to Eldorado Substation in southern Nevada. EITP will provide greater access to the renewable resource rich areas of the Mojave Desert along the California - Nevada border around Primm, Nevada.

Cost: Approximately $350 million (estimated direct costs in nominal dollars, excluding corporate overheads).

Status: CPUC and Bureau of Land Management permitting was completed in May 2011. Construction began in March 2012 and the project went in service in July 2013.

Investment Partners: None.

Benefits: EITP will support renewable generation development, assisting California in meeting Renewables Portfolio Standard (RPS) goals.

San Joaquin Cross Valley Loop (SJXVL)

Description: The SJXVL project consists of approximately 23 miles of new and upgraded double-circuit, 220 kV high-voltage transmission line and associated substation facilities. SJXVL will extend from Rector Substation located in Visalia, California and traverse portions of the San Joaquin Valley to a location near Woodlake in Tulare County, California.

Cost: Approximately $190 million (estimated direct costs in nominal dollars, excluding corporate overheads).

Status: CPUC project approval based on SCE's route alternative 2 was granted in July 2010. As of October 2011, SCE engaged in Section 10 - Habitat Conservation Plan (HCP) consultation with USF&W and obtained approval in October 2013. Construction activities are in progress and forecast to complete subsequent to Golden Eagle nesting activities in 2014.

Investment Partners: None.

Benefits: This project will improve the reliability of the California transmission grid by increasing the transmission capacity between the Big Creek Hydroelectric Project and Rector Substation to mitigate overload conditions; serve forecasted electrical demand in the southeastern portion of the San Joaquin Valley; reduce the need to interrupt customer electrical services under transmission line outage conditions; and minimize the need to reduce Big Creek Hydroelectric Project generation under transmission line outage conditions.

Tehachapi Renewable Transmission Project (TRTP)

Description: The TRTP is an 11 segment project consisting of new and upgraded 220 kV and 500 kV transmission lines and associated substations built primarily to assist the development of renewable energy generation projects in remote areas of eastern Kern County, California. Segments 1-3 consist of 83 miles of new transmission and TRTP Segments 4-11 consist of 173 miles of transmission.

- TRTP Segments 1-3 are specific to the Tehachapi Wind Resource Area in southern Kern County and Los Angeles County, and include:
    - Segment 1: 26.5 miles of 500 kV transmission line from Santa Clarita to Lancaster;
    - Segment 2: 21 miles of new 500 kV and 220 kV transmission lines and modifications at the Vincent Substation in Lancaster;
    - Segment 3a: 25.6 miles of 500 kV and 220 kV transmission lines connecting SCE's Antelope Substation in Lancaster to a new substation west of Mojave in Kern County; and
    - Segment 3b: 9.6 miles of 220 kV transmission line from Mojave to east of Tehachapi.
- TRTP Segments 4-11 are specific to new and upgraded electric transmission lines and substations between eastern Kern County and San Bernardino County, and include:
    - Segment 4: Construction of the new 15 mile 500 kV transmission line from Whirlwind Substation to Vincent Substation. Construction would be in a new ROW, parallel to the existing ROW;
    - Segment 5: Construction of a new 18 mile 500 kV transmission line that would connect SCE's existing Antelope Substation with SCE's existing Vincent Substation near Acton. This new line would be built next to an identical existing 500 kV line and would replace two 220 kV lines that would be removed. An existing ROW would be utilized. This new line would be initially energized at 220 kV;
    - Segment 6: Replacement of approximately 16 miles of an existing 220 kV transmission line that runs from SCE's existing Vincent Substation to the southern edge of the Angeles National Forest (ANF) near the city of Duarte with a new 500 kV transmission line that would initially be energized at 220 kV. An existing ROW would be utilized. Replacement of approximately five miles of an existing SCE 220kV transmission line between Vincent Substation and the northern border of the ANF with a new 500 kV transmission line;

- Segment 7: Replacement of 16 miles of the existing 220 kV line from the ANF border near the city of Duarte south to SCE's existing Rio Hondo Substation in the city of Irwindale and then continuing southwest across various San Gabriel Valley cities toward SCE's existing Mesa Substation in the Monterey Park/Montebello area with a double-circuit, 500 kV transmission line. Existing ROWs would be utilized and various lower-voltage subtransmission lines between the Rio Hondo and Mesa Substations would require relocation within existing ROW or public ROW;
- Segment 8: Replacement of existing single-circuit, 220 kV line that runs from the existing Mesa Substation area to the Chino Substation area and existing double-circuit, 220 kV line from Chino Substation to the existing Mira Loma Substation with a 33 mile double-circuit, 500 kV line. Replacement of approximately seven miles of existing 220 kV line that run from SCE's Chino Substation to its Mira Loma Substation located in the city of Ontario with a double-circuit, 220 kV line. Existing ROWs would be utilized except for where approximately three miles of new ROW would be required in limited areas. Various lower-voltage sub-transmission lines in the Chino area would require relocation within existing ROW or public ROW;
- Segment 9: Installation of equipment and upgrades at Antelope, Vincent, Windhub, and Whirlwind Substations to connect new 220 kV and 500 kV transmission lines to facilitate interconnection of renewable resources;
- Segment 10: Construction of 17 miles of new single-circuit, 500 kV transmission line to connect the proposed Whirlwind Substation (Segment 4) with the Windhub2 Collector substation. New ROW would be required; and
- Segment 11: Replacement of approximately 20 miles of 220 kV transmission line between the existing Vincent Substation and Gould Substation near La Cañada Flintridge with 17 miles of new single-circuit, 500 kV transmission line. Installation of a second 220 kV transmission line on the currently empty side of the transmission towers that already extend from the area of Gould Substation across various San Gabriel Valley cities to the area of Mesa Substation in Monterey Park. An existing ROW would be utilized.
- Chino Hills Underground: Construction of approximately 3.5 miles of underground single-circuit 500kV transmission line in existing ROW through Chino Hills.

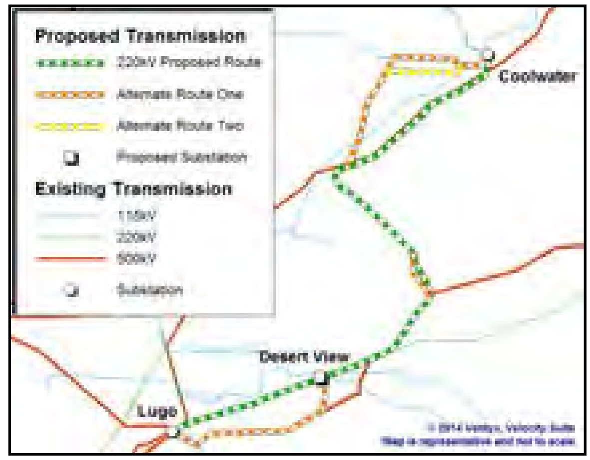
Cost: Approximately $2.9 billion (estimated direct costs in nominal dollars, excluding corporate overheads).

Status: Regulatory approvals granted for Tehachapi Segments 4-11 include: CPUC CPCN in December 2009, US Forest Service Biological Opinion in July 2010, US Forest Service Record of Decision (ROD) in October 2010, US Army Corp of Engineers ROD in February 2011, and Angeles National Forest Special Use Permit in September 2011. Construction of segments 4-11 began in 2010. A Petition for Modification was filed with the CPUC in October 2011 and a July 2013 decision directed SCE to underground a 500 kV transmission line segment through Chino Hills. A Petition for Modification to implement Federal Aviation Authority (FAA) mitigations was filed with the CPUC in October 2011 and was approved in October 2013. Segments 1-5, 9, 10, Windhub, Whirlwind, and Highwind Substations are in service. The remaining segments are in construction to meet the forecast in-service dates ranging from 2014 through 2016.

Investment Partners: None.

Benefits: TRTP will support interconnection of up to 4,500 MWs of generation, most of which are expected to be renewable resources. This will assist California to meet its RPS goals; improve the reliability of the California transmission grid by enabling the expansion of the transfer capability of Path 26; serve load growth in the Antelope Valley; and ease transmission constraints in the Los Angeles basin.

Coolwater-Lugo Transmission Project (previously South of Kramer)



Description: The proposed Coolwater-Lugo project consists of approximately 63 miles of primarily double-circuit, 220 kV transmission line between SCE's existing Coolwater 220/115 kV Substation in Daggett, and SCE's existing Lugo 500/220 kV Substation in Hesperia, California. In addition, the project involves siting of a proposed future 500/220 kV Desert View Substation, and 16 miles of transmission line between Desert View and Lugo substations, consisting of 500 kV single-circuit transmission line and towers, initially energized at 220 kV until the future Desert View Substation becomes operational.

Cost: Approximately $700 - $800 million (estimated direct costs in nominal dollars, excluding corporate overheads).

Status: The Coolwater-Lugo project is in the licensing stage. Site and route evaluation, community and agency outreach activities are underway. SCE filed a CPCN application with the CPUC in August 2013 and submitted a Plan of Development (POD) to the BLM in November 2013. The project is forecast to be in service by 2018.

Investment Partners: None.

Benefits: Construction of Coolwater-Lugo will remedy the reliability and congestion problems that would result from the development and interconnection of over 2,400 MWs of renewable solar and wind generation in the Mojave Desert region of Southern California.

West of Devers (WOD) Upgrade Project

Description: The proposed West of Devers Upgrade Project facilities will be located in San Bernardino and Riverside Counties in southern California. WOD entails the removal and rebuilding of five existing 220 kV lines: Devers-Vista #1 and #2, Devers-San Bernardino, Devers-El Casco, and El Casco-San Bernardino. The upgraded 220 kV lines are needed to allow full delivery of multiple generation projects interconnecting at SCE's new Colorado River and Red Bluff Substations.

Cost: Approximately $1.0 billion (estimated direct costs in nominal dollars, excluding corporate overheads).

Status: The WOD Upgrade Project is in the licensing stage. Site and route evaluation, community and agency outreach activities are underway. SCE filed a CPCN application with the CPUC in October 2013. The project is forecast to be in service by 2020.

Investment Partners: None.

Benefits: Construction of WOD Upgrade Project will increase the transfer capability of the existing WOD corridor and provide for the full delivery of new renewable solar generation being developed in California.

Path 42

Description: The proposed Path 42 project, in partnership with Imperial Irrigation District (IID), will enable the delivery of additional renewable energy to the CAISO controlled grid. The SCE portion of this project primarily consists of the construction of approximately 15 miles of the Devers – Mirage #1 and Devers – Mirage #2 230 kV transmission lines along with various upgrades at both the Devers Substation and Mirage Substation.

Cost (SCE Portion): Approximately $50 million (estimated direct costs in nominal dollars excluding corporate overheads).

Status: Development activities, including preliminary engineering and environmental permitting, are in progress. IID is preparing the California Environmental Quality Act and National Environmental Policy Act documents for the environmental review process. The project is forecasted to be complete in 2014.

Investment Partners: Imperial Irrigation District.

Benefits: This project will enable transfer of approximately 1,090 MWs of additional renewable energy from IID to SCE's portion of the CAISO controlled grid. This project will contribute to meeting California's RPS goal of 33 percent of retail load served by renewable resources by 2020.

Tehachapi Wind Energy Storage Project (TSP):

Description: The Tehachapi Wind Energy Storage Project (TSP) will evaluate the performance of an eight MW, four hour (32 MWh) battery energy storage system (BESS) to improve grid performance and assist in the integration of large-scale variable energy resourced generation. Project performance will be measured with 13 specific operational uses: provide voltage support and grid stabilization; decrease transmission losses; diminish congestion; increase system reliability; defer transmission investment; optimize renewable-related transmission; provide system capacity and resources adequacy; integrate renewable energy (smoothing); shift wind generation output; frequency regulation; spin/non-spin replacement reserves; ramp management; and energy price arbitrage. Most of the operations either shift other generation resources to meet peak load and other electricity system needs with stored electricity, or resolve grid stability and capacity concerns that result from the interconnection of variable energy resources. SCE will also demonstrate the ability of lithium-ion battery storage to provide nearly instantaneous maximum capacity for supply-side ramp rate control.

Cost: Approximately $57 million: $25 million Department of Energy (DOE) funding, remainder of project costs funded by SCE and its partners (estimated direct costs in nominal dollars, excluding corporate overheads).

Status: Battery system building construction began at Monolith Substation in February 2012 and is substantially complete. Battery system commissioning scheduled in 2014. Operations, measurement, and testing scheduled to be completed in 2016.

Investment Partners: DOE through an American Recovery and Reinvestment Act project grant.

Benefits: The objective of the project is to evaluate the capability of utility scale lithium-ion battery technology to improve grid performance and assist in the integration of variable energy resources. Though lithium-ion battery technology has been tested at a smaller scale and is currently being used in hybrid and electric vehicles, it has not been proven for large-scale utility purposes.

Centralized Remedial Action Schemes (CRAS):

Description: The Centralized Remedial Action Schemes (CRAS) project will centralize control and operation of SCE's special protection systems on the SCE transmission grid. The CRAS will transition existing special protection systems from an Intelligent Electronic Device (IED) at substations to a redundant and highly secure centralized processing system. The CRAS will accommodate complex special protection systems that would not be possible with individual IED systems.

Cost: Approximately $50 million (estimated direct costs in nominal dollars, excluding corporate overheads).

Status: The project is anticipated to be completed during the fourth quarter of 2014.

Investment Partners: None.

Benefits: The CRAS will 1) mitigate and permit existing and new generation projects to connect to the grid and to meet California's RPS goal; 2) enhance the coordination and effectiveness of existing special protection technology; 3) enhance the ability to build new schemes to enable a more efficient generator interconnection process; and 4) improve the efficiency of managing and maintaining existing and new special protection systems.

PHASOR Program (previously Wide-Area Situation Awareness System)

Description: SCE's PHASOR Program (previously referred to as the Wide-Area Situational Awareness System or WASAS) consists of: (1) Digital Fault Recorder/Phasor Measurement Unit (DFR/PMU) Infrastructure Replacement; and (2) PHASOR System. The DFR/PMU Infrastructure Replacement program involves the installation of combined DFR/PMU devices to enable SCE 500 kV and 220 kV transmission substations to have synchrophasor measurement capability. The PHASOR System provides the basic infrastructure necessary for a synchrophasor data management system. The PHASOR System will collect, store, and share PMU data that SCE acquires from DFR/PMU devices on the grid. It is designed to provide Western Electricity Coordinating Council (WECC) utilities and system operators with information about the operating status of the bulk power system through the Western Interconnection Synchrophasor Program (WISP).

Cost: Approximately $25 million (estimated direct costs in nominal dollars, excluding corporate overheads).

Status: The system was placed in service in 2013.

Investment Partners: None.

Benefits: Phasor measurement systems are powerful tools that provide bulk power system information at speeds previously unavailable. SCE will be able to manage in real time the extensive data collected from the phasor measurement devices and other data sources to enable smarter, faster decision-making. Armed with the information provided by the system, SCE system operators will be able to take proactive corrective measures to avoid large-scale blackouts before the system reaches a breaking point. At the same time, having better information on the system's breaking point will eventually allow system operators to optimize the use of existing transmission facilities by safely operating closer to the edge.

SOUTHERN COMPANY

Company Background:

- With 4.4 million customers, Southern Company utilities serve a 120,000 square mile service territory spanning most of Georgia and Alabama, southeastern Mississippi, and the panhandle region of Florida.
- Southern Company owns four regulated retail electric utilities: Alabama Power; Georgia Power; Gulf Power; and Mississippi Power.
- System-wide there are approximately 27,000 circuit miles of transmission line.
- Between 2003 and 2012, Southern Company invested over $3.5 billion in transmission.

Transmission Related Smart Grid Initiatives:

Southern Company has been utilizing Smart Grid technologies for a number of years through its robust communication network and data acquisition and outage management tools that optimize system performance and reliability. Southern Company is planning to invest approximately $216 million between 2013 and 2018 by installing new Smart Grid technologies or replacing existing telecommunications equipment and fiber that has reached the end of life. These technologies advance Smart Substation applications and Transmission Line Automation.

Central Alabama Projects

Description: The Central Alabama CC projects consist of a new 500/230 kV autobank at Autagaville TS and two new bundled 230kV lines (.6 and .7 miles) from the Autaugaville 500/230 kV substation to the Harris 230 kV Substation; a new 230/115 kV autobank at County Line Road TS; a new 120 MVAR capacitor bank; reconductoring approximately 40.1 miles of existing single-circuit, 230 kV transmission line; reconductoring 4.5 miles of existing single- circuit, 115 kV transmission line; and upgrading approximately six miles of 230 kV line.

Cost: Approximately $87 million.

Status: These projects are currently scheduled to be in service the summer of 2014.

Investment Partners: None.

Benefits: The transmission improvements will meet the future network resource requirements for Gulf Power Company.

East Pelham 230/115 kV Transmission Substation Project

Description: The East Pelham 230/115 kV Transmission Substation project includes approximately one mile of new single-circuit, 230 kV transmission line; 33.5 miles of new single-circuit, 115 kV transmission line; upgraded structures on approximately 18 miles of single-circuit, 230 kV transmission line; constructs a new 400 MVA, 230/115 kV substation on a 26 acre site; and constructs two new 115 kV switching stations (Alabaster and East Chelsea).

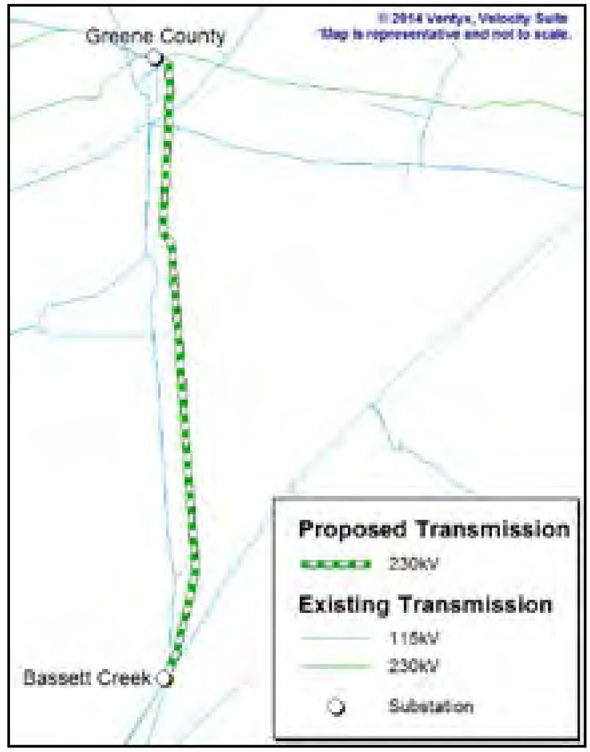
Cost: Approximately $57 million.

Status: This project is currently scheduled to be in service the summer of 2015.

Investment Partners: None.

Benefits: This project will meet load growth and alleviate thermal overloads in the Birmingham, Alabama area.

Greene County - Bassett Creek 230 kV Line Project



Description: The Greene County - Bassett Creek 230 kV line project consists of approximately 58 miles of new single-circuit, 230 kV transmission line between Greene County SP and Bassett Creek 230/115 kV Substations.

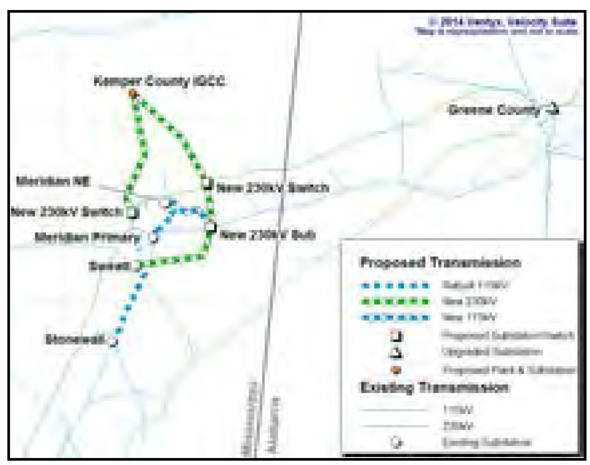
Cost: Approximately $103 million.

Status: This project is currently scheduled to be in service the summer of 2015.

Investment Partners: None.

Benefits: This project is for infrastructure reliability in the Thomasville area of Alabama.

Kemper County IGCC Plant



Description: The Kemper County IGCC Plant project consists of a new 600 MW IGCC plant constructed by Mississippi Power Company. Transmission improvements associated with this plant consist of a 230 kV switchyard and collector bus; two new 230 kV switching stations; a new 230/115 kV substation in Meridian, MS; approximately 55 miles of new 230 kV transmission line; ten miles of new 115 kV transmission line; and upgrades to 24 miles of existing 115 kV transmission line in Kemper County and Meridian areas of Mississippi.

Cost: Approximately $120 million.

Status: This project is currently scheduled to be in service the summer of 2014.

Investment Partners: None.

Benefits: The new generation and transmission improvements will meet the future network resource requirements for Mississippi Power Company.

Mobile Area Network Project

Description: The Mobile Area Network Project consists of constructing a 115 kV six terminal switching station at North Crichton; approximately 14 miles of new single-circuit, 115 kV transmission line; reconductoring 28 miles of existing single and double-circuit, 115 kV transmission line; and installing associated network switches and distance relaying.

Cost: Approximately $74 million.

Status: This project is currently scheduled to be in service the summer of 2016.

Investment Partners: None.

Benefits: This project is for infrastructure reliability and operational flexibility in the Mobile Metropolitan area of Mobile County, Alabama.

North Brewton - Alligator Swamp 230 kV Line Project

Description: The North Brewton - Alligator Swamp 230 kV line project consists of approximately 54.7 miles of new single-circuit, 230 kV transmission line between North Brewton 230/115 kV and Alligator Swamp 230 kV Substations.

Cost: Approximately $73 million.

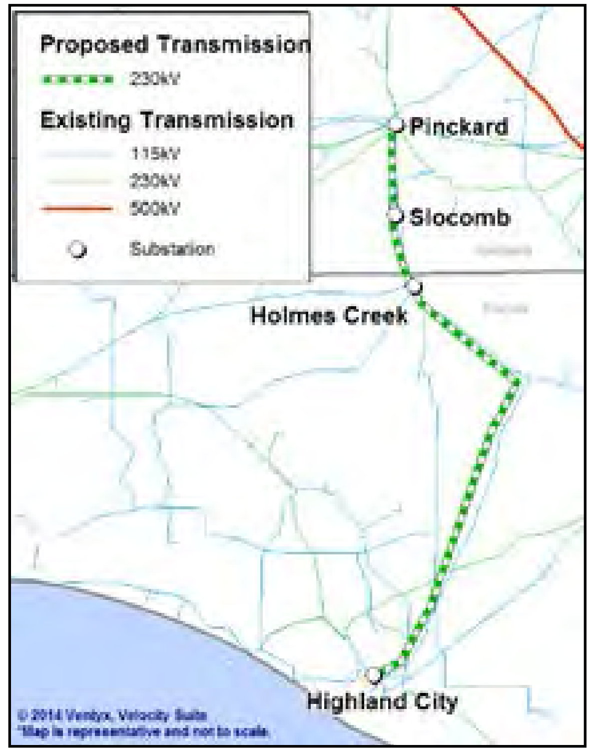
Status: This project is currently scheduled to be in service the summer of 2015.

Investment Partners: None.

Benefits: This project is for infrastructure reliability in the Pensacola area of Florida.

Pinckard - Holmes Creek - Highland City 230 kV Transmission Line Project

Description: The Pinckard - Holmes Creek - Highland City 230 kV Transmission Line Project consists of approximately 73 miles of new single-circuit, 230 kV transmission line from the Holmes Creek Substation to the Highland City Substation (in the northeastern area of the Florida Panhandle) and rebuilding the existing Pinckard TS - Holmes Creek 115 kV transmission line and converting it to 230 kV operation.



Cost: Approximately $92 million.

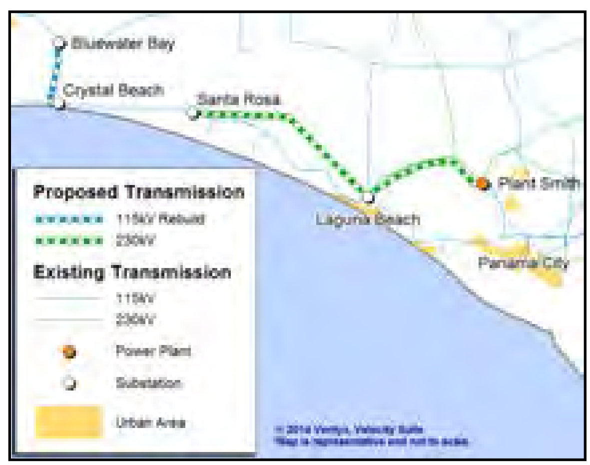
Status: This project is currently scheduled to be in service the summer of 2015.

Investment Partners: None.

Benefits: This project is for load growth and reliability in Southeast Alabama and in the central Panhandle, Panama City, and Destin areas of Florida.

Plant Smith - Laguna Beach - Santa Rosa 230 kV Transmission Line Project

Description: The Plant Smith - Laguna Beach - Santa Rosa 230 kV Transmission Line Project consists of converting 14 miles of existing single-circuit, 115 kV line to 230 kV operation between Plant Smith and Laguna Beach Substations; a second 230 kV Autobank at Laguna Beach Substation; replace Laguna Beach - Santa Rosa #1 115 kV transmission line with a 230 kV transmission line; rebuild Crystal Beach – Bluewater Bay 115kV transmission line ; and add a new Santa Rosa 230 kV Substation with one, 400 MVA transformer bank (in the Central Florida Panhandle, Destin, and Panama City Beach areas).



Cost: Approximately $69 million.

Status: This project is currently planned in two phases, with the second phase scheduled to be in service the summer of 2020.

Investment Partners: None.

Benefits: This project is for load growth and reliability in the Panama City and Destin areas of the Florida Panhandle.

Plant Vogtle Network Improvement Project

Description: The Plant Vogtle Network Improvement Project consists of approximately 50 miles of new single-circuit, 500 kV transmission line between Vogtle and Thomson 500/230 kV Substations, and expanding the 500 kV switchyard at Plant Vogtle.

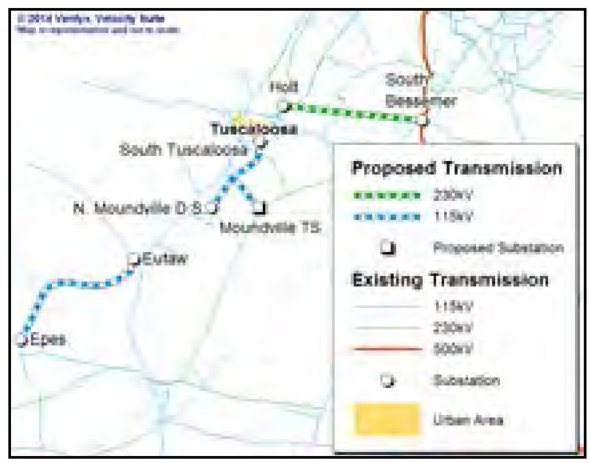
Cost: Approximately $132 million.

Status: This project is currently scheduled to be in service the summer of 2017.

Investment Partners: None.

Benefits: This project will address generator stability issues related to the expansion of the existing Plant Vogtle facility.

Tuscaloosa Area Solution



Description: The South Tuscaloosa - Eutaw Area Network Project consists of 23 miles of new single-circuit, 115 kV transmission line from the Epes Substation to the Eutaw Substation; a new 230/115 kV substation at Moundville T.S.; approximately 21.2 miles of new single-circuit, 115 kV transmission line; converting two 46 kV substations to 115 kV operation; and constructing approximately 25 miles of new single-circuit 230kV transmission line.

Cost: Approximately $96 million.

Status: This project is currently planned in three phases, with the third phase scheduled to be in service the summer of 2019.

Investment Partners: None.

Benefits: This project is for load growth, infrastructure reliability and operational flexibility in the Tuscaloosa County and Greene County areas of Alabama.

Wadley 500/230 kV Project

Description: The Wadley 500/230 kV Project consists of expanding the existing Wadley 230/115 kV substation by constructing a 500 kV ring bus and installing a new 2,016 MVA 500/230 kV autotransformer.

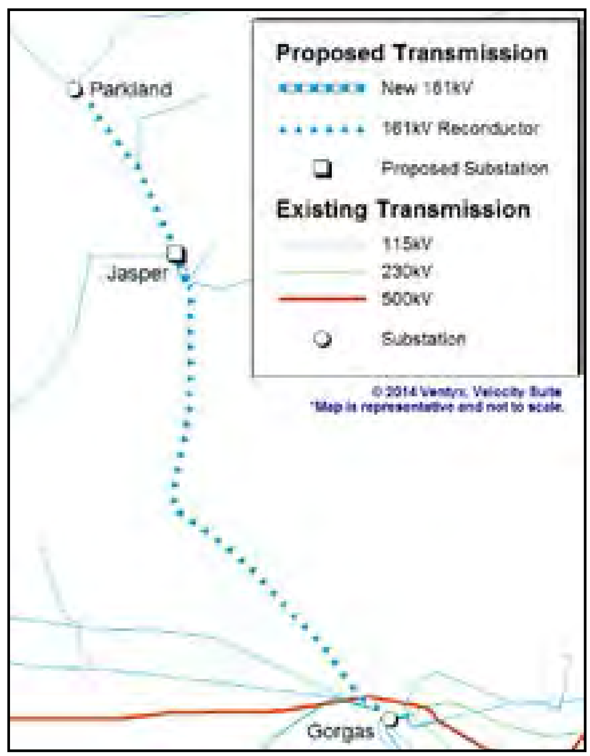
Cost: Approximately $56 million.

Status: This project is currently scheduled to be in service the summer of 2018.

Investment Partners: Municipal Electric Authority of Georgia (MEAG Power).

Benefits: This project will address generator stability issues related to the expansion of the existing Plant Vogtle facility.

Jasper 161kV Area Improvements



Description: The Jasper Area Improvement Project consists of reconductoring 20 miles of existing 161kV line; constructing approximately 1 mile of new 161kV line; and adding a new 5-breaker 161kV switching station.

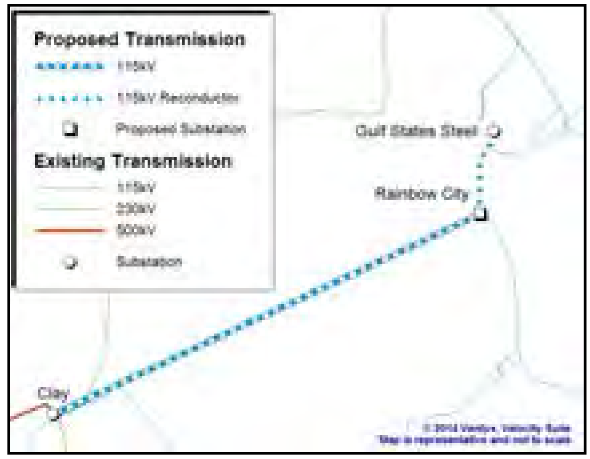
Cost: Approximately $28 million.

Status: This project is currently scheduled to be in service the summer of 2017.

Investment Partners: None.

Benefits: This project is for load growth, infrastructure reliability and operational flexibility in the Jasper area.

Eastern Area Improvements



Description: The Eastern Area Improvement Project consists of reconductoring approximately 5 miles of existing 115kV line; adding a new 115kV switching station; and constructing approximately 34 miles of new 115kV line.

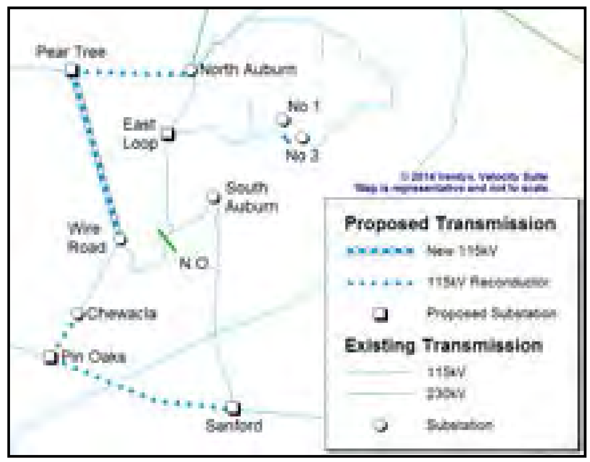
Cost: Approximately $41 million.

Status: This project is currently scheduled to be in service the summer of 2019.

Investment Partners: None.

Benefits: This project is for load growth, infrastructure reliability and operational flexibility in the Anniston and Gadsden areas.

Auburn – Opelika 115kV Networking



Description: The Auburn – Opelika 115kV Networking project consists of constructing four new 115kV switching stations, reconductoring approximately 23 miles of existing 115kV line and constructing 4 miles of new 115kV line.

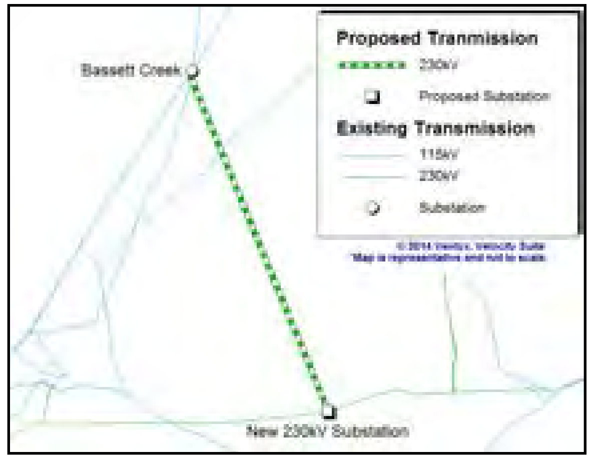
Cost: Approximately $34 million.

Status: This project is currently scheduled to be in service the summer of 2019.

Investment Partners: None.

Benefits: This project is for load growth, infrastructure reliability and operational flexibility in the Auburn and Opelika areas.

Bassett Creek South 230kV Improvements



Description: The Bassett Creek South 230kV Improvements consist of a new 25 mile 230kV line from Bassett Creek to a new switching station on the Lowman – Belleville 230kV line.

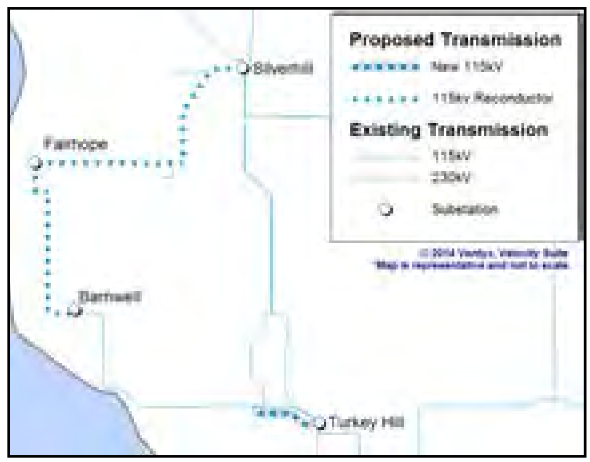
Cost: Approximately $40 million.

Status: This project is currently scheduled to be in service the summer of 2020.

Investment Partners: None.

Benefits: This project is for infrastructure reliability and operational flexibility in the Bassett Creek and McIntosh areas.

Turkey Hill Networking



Description: The Turkey Hill Networking plan consists of 2.75 miles of new 115kV line and reconductoring approximately 17.6 miles of existing 115kV line.

Cost: Approximately $22 million.

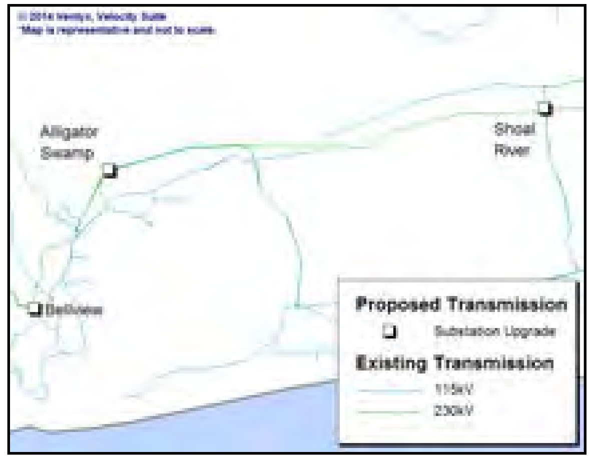
Status: This project is currently scheduled to be in service the summer of 2018.

Investment Partners: None.

Benefits: This project is for load growth, voltage support, infrastructure reliability and operational flexibility in the Silverhill and Turkey Hill areas.

Pensacola Area Voltage Improvements

Description: The Pensacola Area Voltage Improvements consist of looping the Crist – Shoal River 230kV line into Alligator Swamp and adding two (2) new 120 MVAR 230kV filtered capacitor banks and two (2) new +125/-100 MVAR 230kV Static Var Systems in the area.



Cost: Approximately $50 million.

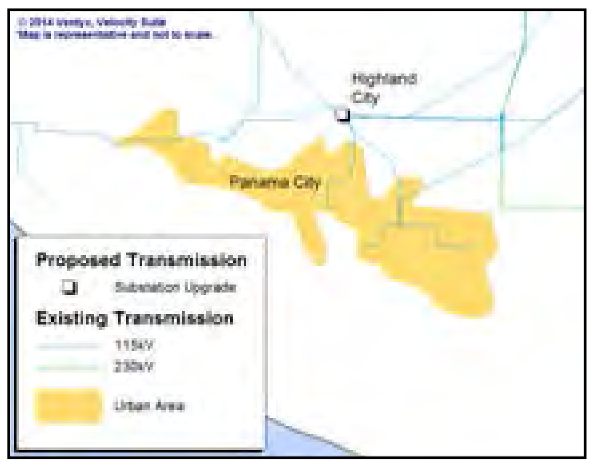
Status: This project is currently scheduled in two phases with the second phase to be in service the summer of 2022.

Investment Partners: None.

Benefits: This project will provide dynamic voltage support for the Pensacola area.

Panama City Area Voltage Improvements

Description: The Panama City Area Voltage Improvements consist of a new +125/-100 MVAR 230kV Static Var System in the area.



Cost: Approximately $20 million.

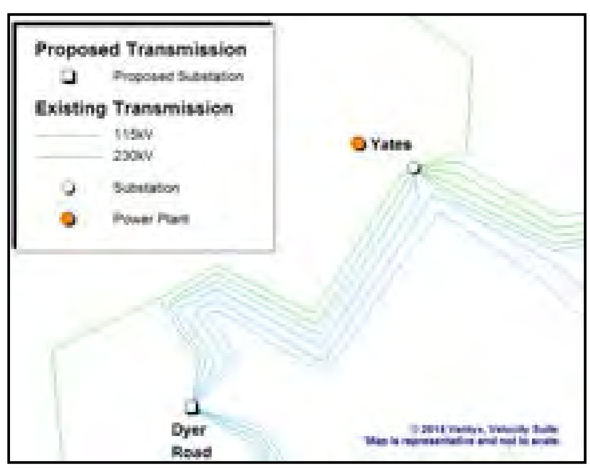
Status: This project is currently scheduled to be in service the summer of 2015.

Investment Partners: None.

Benefits: This project will provide dynamic voltage support for the Panama City area.

Dyer Road 230/115kV Substation Project

Description: The Dyer Road 230/115 kV Project consists of constructing a new 230/115kV substation by creating three element 230kV ring bus, installing 400MVA 230/115kV autotransformer, and creating an eight element 115kV ring bus.



Cost: Approximately $23 million.

Status: This project was placed in service on December 31, 2013.

Investment Partners: None.

Benefits: This project is for infrastructure reliability and operational flexibility in the South Metro Atlanta area of Georgia.

Jasper – Pine Grove Primary 115kV Project

Description: The Jasper – Pine Grove Primary 115kV rebuild project consists of rebuilding approximately 22 miles with 230kV constructed single pole structures with 100˚C 1351 ASCR conductor.

Cost: Approximately $26 million.

Status: This project is currently scheduled to be in service the fall of 2014. The Duke Energy portion will be completed by summer 2015.

Investment Partners: Georgia Transmission Corporation (GTC).

Benefits: This project is for infrastructure reliability in the Valdosta area of Georgia.

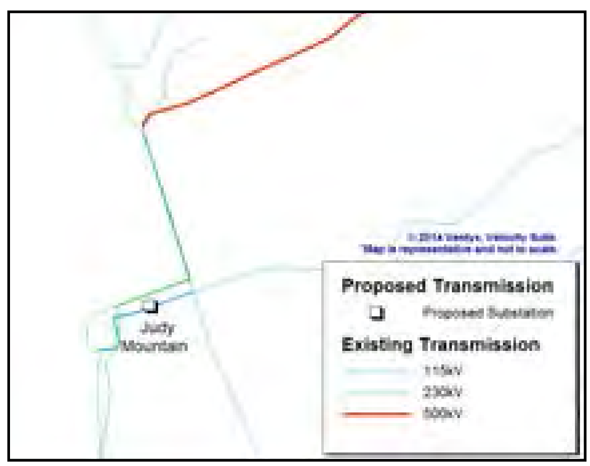
Judy Mountain 230/115kV Substation Project

Description: The Judy Mountain 230/115 kV Project consists of constructing a new 230/115kV substation by creating five element 230kV ring bus, installing 400MVA 230/115kV autotransformer, and creating an five element 115kV ring bus.

Cost: Approximately $22 million.

Status: This project is currently scheduled to be in service the summer of 2014.

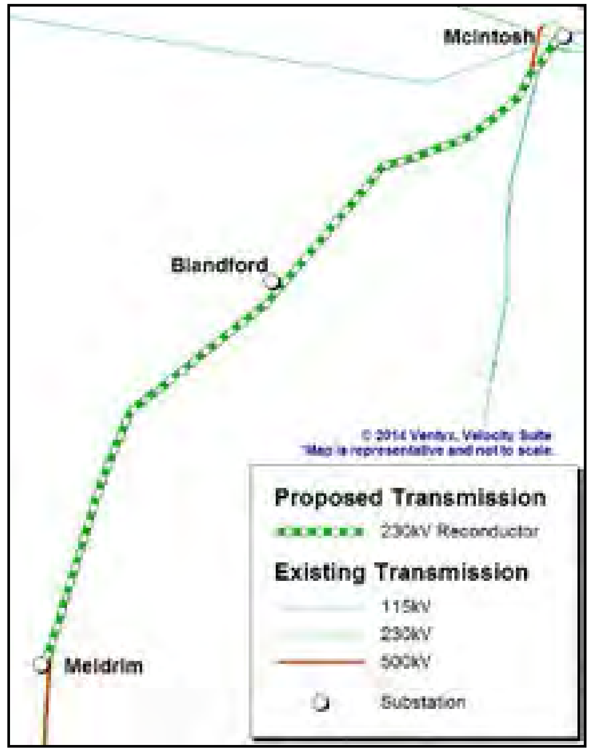
Investment Partners: Georgia Transmission Corporation (GTC).



Benefits: This project is for infrastructure reliability and operational flexibility in the Rome area of Georgia.

McIntosh – Blandford – Meldrim 230kV Reconductor Project

Description: The McIntosh – Blandford – Meldrim 230kV Black and White line reconductor project consists of reconductoring 18.2 miles of 230kV transmission line with 210˚C 1622 ACCR conductor.



Cost: Approximately $30 million.

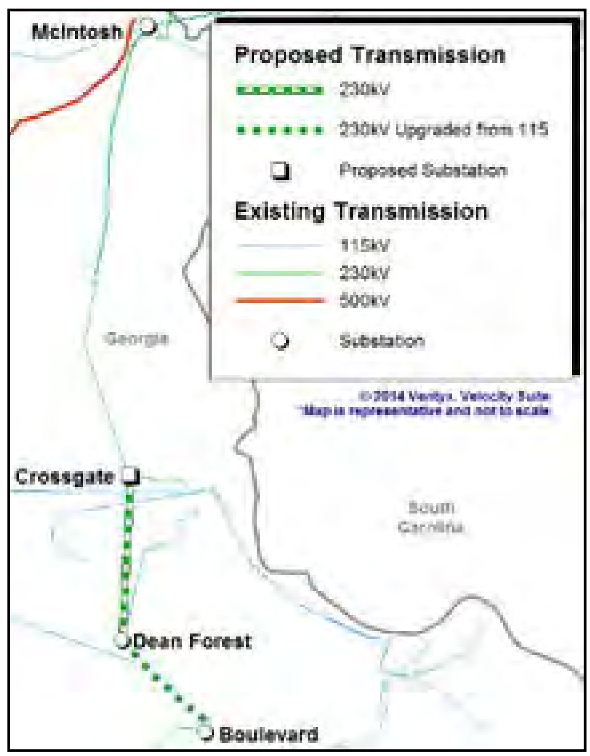
Status: This project is currently scheduled to be in service the summer of 2014.

Investment Partners: None.

Benefits: This project is for infrastructure reliability and operational flexibility in the Savannah area of Georgia.

Boulevard 230/115kV Project

Description: At the Boulevard 115/46/13.8-kV substation, install a 230/115-kV, 400 MVA transformer. Increase the capacity of the 36 MVAR, 115-kV capacitor to 60 MVAR. Terminate the Dean Forest 230-kV line. This will require a complete rebuild of the Boulevard substation.



Rebuild the Boulevard – Dean Forest 115-kV Black/White common tower lines, to 230-kV specs using 170C, 1351 ACSS conductor. Operate one side at 230-kV and the other side at 115-kV.

Expand the Dean Forest 230-kV ring-bus and terminate the Boulevard 230-kV line and the Crossgate 230-kV line.

At a point approximately 2.0 miles from Plant Kraft on the Kraft – McIntosh 230-kV Black/White lines, construct a three-element, 230-kV ring-bus switching station. Tap the Kraft – McIntosh 230-kV White line creating the Dean Forest, Kraft and McIntosh 230-kV lines.Construct a 5.5 mile, Crossgate - Dean Forest 230-kV line using 170C, 1351 ACSS conductor.

Cost: Approximately $70 million.

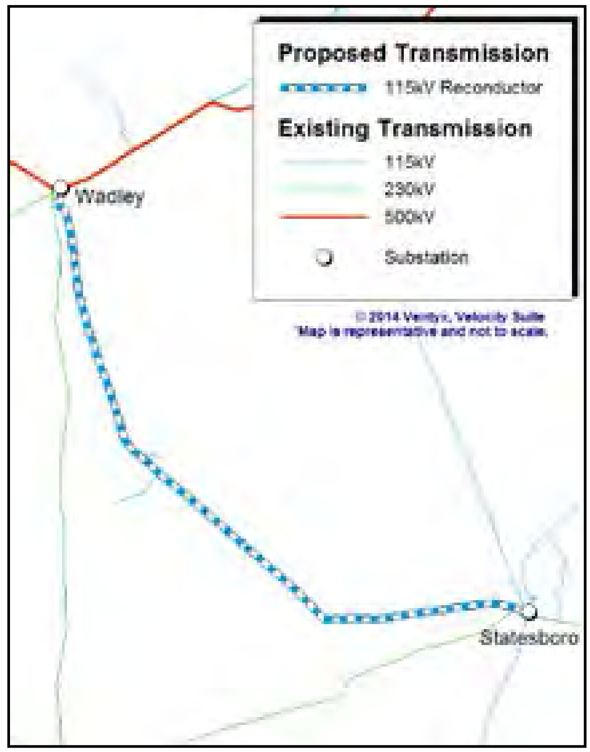
Status: This project is currently scheduled to be in service the summer of 2015.

Investment Partners: None.

Benefits: This project is for infrastructure reliability and operational flexibility in the Savannah area of Georgia.

Statesboro Primary – Wadley Primary 115kV Project

Description: The Statesboro Primary – Wadley Primary 115kV project consists of reconductoring approximately 22 miles of transmission line with 100˚C 1033 ACSR conductor.



Cost: Approximately $21 million.

Status: This project is currently scheduled to be in service the summer of 2021.

Investment Partners: None.

Benefits: This project is for infrastructure reliability in the Statesboro area of Georgia.

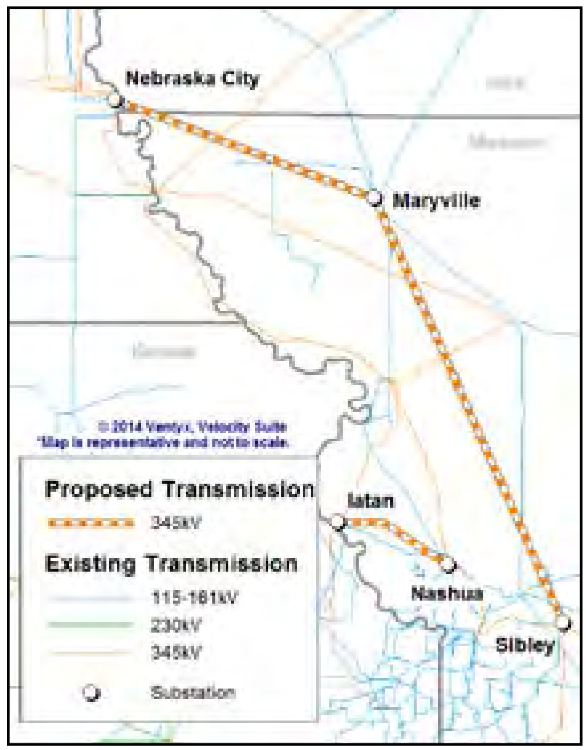
TRANSOURCE

Company Background:

- Transource is a joint venture between American Electric Power (AEP) and Great Plains Energy (GPE) purposed with pursuing the competitive transmission market.
- Transource has approximately $400 million of transmission assets under development located in the SPP region and is actively engaged in additional project opportunities as they emerge.

Nebraska City - Sibley Line and Iatan - Nashua Line

Description: The Missouri portion of the Nebraska City - Sibley line is a 135 mile, 345 kV line. An additional 45 miles of line in Nebraska will be built and owned by Omaha Public Power District (OPPD). The Iatan - Nashua line is a 30 mile, 345 kV line.



Cost: The total estimated cost of the two SPP-approved projects in Missouri is approximately $400 million. The Missouri portion of the Nebraska City - Sibley project is estimated to cost $332 million and the Iatan - Nashua project is estimated to cost $65 million.

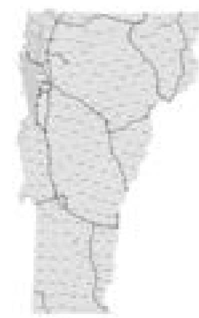
Status: Both projects have established routes and are in varying stages of construction. The Missouri portion of the projects were transferred from GPE to Transource Missouri in January 2014. The Iatan - Nashua project has an in-service date of 2015 and the Nebraska City - Sibley project has an in-service date of 2017.

Investment Partners: Missouri segments: Transource. Nebraska segment: OPPD.

Benefits: The Nebraska City - Sibley line will reduce regional congestion in one of SPP's most heavily constrained areas and also helps to integrate as much as 5,000 MW of wind generation. The Iatan - Nashua line will reduce regional congestion and provide regional trade and production benefits.

VERMONT ELECTRIC POWER COMPANY (VELCO)

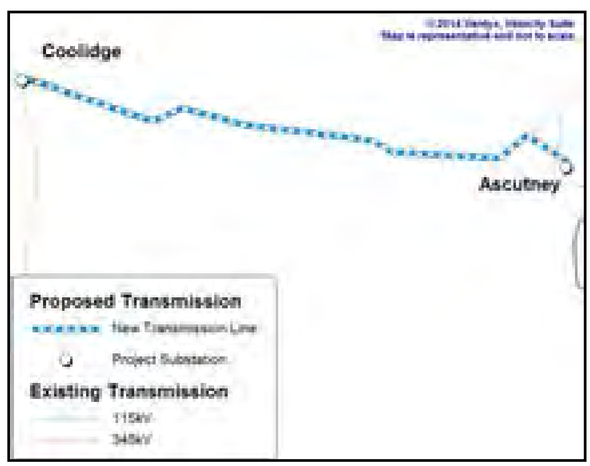
Company Background:



- VELCO was formed in 1956 when local utilities joined together to create the nation's first statewide, "transmission only" company in order to provide access to clean hydro power and build and maintain the state's high-voltage transmission grid.
- VELCO manages a system that includes 738 circuit miles of transmission lines, 55 substations and over 1,300 miles of high-speed fiber optic cable.
- VELCO is also the administrator for the $69 million in American Recovery and Reinvestment Act Smart Grid Investment Grant funds as part of the state's distribution utilities' $138 million eEnergy Vermont statewide Smart Grid deployment program.
- Between 2003 and 2012, VELCO invested approximately $641 million in transmission.
- In the next five years, VELCO expects to invest approximately $239 million in planned transmission upgrades.

Connecticut River Valley Upgrades

Description: Although development of the project is on-going, it is expected that this project will include the reconstruction of an existing 13.5 mile 115kV line. The project also includes the expansion of the Ascutney Substation and the reconstruction of the Chelsea Substation.



Cost: Approximately $93 million.

Status: This project is under permitting development and is scheduled to be put in service in summer of 2016.

Investment Partners: None.

Benefits: This project addresses a western/eastern New England load area system deficiency between Vermont, western Massachusetts, Connecticut, and New Hampshire, Maine, eastern Massachusetts, and Rhode Island. The overload is affected by power transfer between these regions. The project will address these areas of concern and meet present and future system needs.

Transmission System Improvements

Description: New substation upgrade efforts in 2014 consist of the refurbishment of an existing static synchronous compensator (STATCOM) at the Essex Substation. In addition, VELCO has initiated a project to evaluate and replace aged/insufficient transmission line infrastructure. This project will include a condition assessment and engineering analysis and consists of the replacement of multiple transmission line structures located throughout the state and an 115kV submarine cable between Vermont and New York.

Cost: Approximately $146 million.

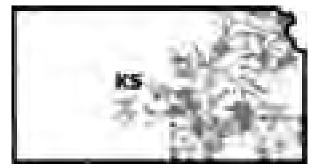
Status: These projects are underway and are expected to be completed between 2015-2017.

Investment Partners: None.

Benefits: These projects address reliability concerns associated with aged and inadequate transmission infrastructure and will result in an overall improvement of the structural integrity and reliability of VELCO's transmission system.

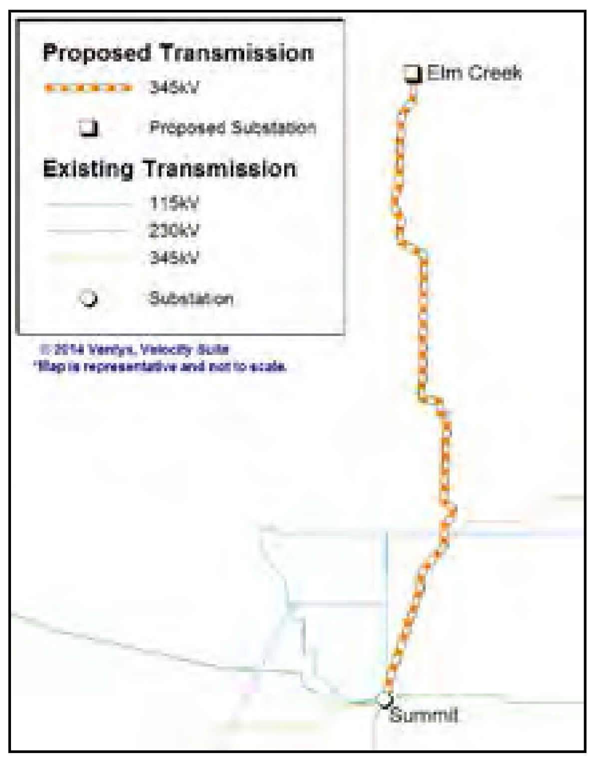
WESTAR ENERGY, INC.

Company Background:



- Westar Energy is an investor-owned, vertically integrated electric utility serving 686,000 retail customers in Kansas. Westar has served Kansas for more than 100 years and is the state's largest electric utility.
- Westar Energy has about 7,100 MWs of electric generation capacity.
- System-wide there are approximately 4,388 circuit miles of 69 kV and above transmission line.
- Westar Energy is a member of the Southwest Power Pool (SPP).
- Between 2003 and 2012, Westar Energy invested approximately $975 million in transmission.

Summit to Elm Creek 345 kV Transmission Line



Description: The Summit - Elm Creek 345 kV project consists of approximately 60 miles of new single-circuit 345 kV transmission line linking the existing 345 kV Summit Substation southeast of Salina, Kansas, to a new 345 kV substation southeast of Concordia, Kansas to be located near the existing 230 kV Elm Creek Substation. Westar Energy will construct, own, and operate 29 miles of the southern section, located from Justice Road in Ottawa County, south to Summit Substation. ITC Great Plains, LLC, under a co-development agreement with Mid-Kansas Electric, LLC (MKEC), will construct, co-own with MKEC, and operate 30 miles of the northern section of the line, from Justice Road in Ottawa County, north to the new 345 kV substation.

Cost: Westar Energy's cost is approximately $66 million.

Status: The following is an approximate timeline for the Summit - Elm Creek Project:

- 2012 - 2013 Routing
- 2014 Right-of-Way acquisition and engineering design

- 2015 - 2016 Construction
- December 31, 2016 Project in-service

Investment Partners: None.

Benefits: The Elm Creek to Summit project will improve the reliability of the grid in central Kansas, allowing the grid to continue to meet required standards of reliability. It will benefit residents and businesses in central Kansas and beyond by easing congestion across the transmission network and improving the efficiency of the grid. It will also provide tax revenue, construction jobs, and local expenditures, and will expand capabilities for future investment in area industry.

Prairie Wind Transmission, LLC

Company Background:

Prairie Wind Transmission, LLC., is a joint venture formed by Westar Energy and Electric Transmission America (ETA), a joint venture of subsidiaries of American Electric Power (AEP) and MidAmerican Energy Holdings Company, to build and own new electric transmission assets in Kansas.

Wichita - Medicine Lodge - Woodward 345 kV Transmission Line

Description: The Wichita - Medicine Lodge - Woodward 345 kV Transmission Line project consists of approximately 108 miles of new double-circuit, high-voltage, 345 kV transmission line linking an existing 345 kV substation near Wichita, Kansas to a new 345 kV substation northeast of Medicine Lodge, Kansas, near the new Flat Ridge Wind Farm jointly owned by Westar Energy and BP Alternative, and then south to the Kansas-Oklahoma border. OG&E will build approximately 80 miles of line from the border to Woodward Substation.

Cost: Prairie Wind Transmission's cost is approximately $170 million. Westar Energy and ETA will each invest $85 million.

Status: The project broke ground on August 1, 2012, and is currently under construction. The project is estimated to be in service by December 2014.

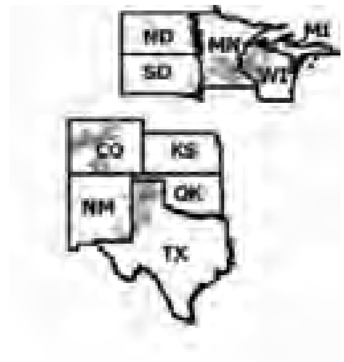
Investment Partners: Westar Energy and ETA.

Benefits: The project will enhance electricity transport capabilities across SPP and Kansas and will support expansion of renewable electricity generation in the region.

XCEL ENERGY INC.

Company Background:

- Xcel Energy Inc. has operations in ten western and midwestern states (Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wisconsin) serving 3.3 million electric customers.
- Northern States Power (NSP) Companies, Public Service of Colorado (PSCo) and Southwestern Public Service (SPS) are subsidiaries of Xcel Energy Inc.
- System-wide there are approximately 18,700 circuit miles of transmission line.
- Between 2003 and 2012, Xcel Energy invested over $3.5 billion in transmission.



Northern States Power Companies (NSP Companies)

Company Background:

- Northern States Power Company (NSPM), a Minnesota corporation, and Northern States Power Company (NSPW), a Wisconsin corporation (jointly NSP Companies), operate an integrated system in Minnesota, North Dakota and South Dakota, and Wisconsin and the Michigan Upper Peninsula.
- The NSP Companies have approximately 1.4 million retail and wholesale customers, and operate approximately 7,000 circuit miles of transmission.

Transmission Related Smart Grid Initiatives:

NSP is participating in MISO's SynchroPhasor Project installing equipment at power plants to track the relative phase angle of generators on the grid.

CapX2020 Transmission Plan

Description: The CapX2020 Transmission Plan consists of approximately 250 miles of new double-circuit capable, 345 kV transmission line between Brookings County, South Dakota, and Hampton, Minnesota, including a related 23 mile double-circuit capable, 345 kV transmission line between Lyon County, Minnesota and Hazel Creek, Minnesota; approximately 240 miles of new double-circuit capable, 345 kV transmission line between Fargo, North Dakota, and St. Cloud and Monticello, Minnesota; approximately 150 miles of new single-circuit, 345 kV transmission line between Hampton and Rochester, Minnesota, continuing to La Crosse, Wisconsin; and approximately 70 miles of new single-circuit, 230 kV transmission line between Bemidji and Grand Rapids, Minnesota.

This project is a joint initiative of 11 transmission owning utilities, including the NSP Companies, in the Upper Midwest to expand the electric transmission grid to ensure continued reliable service to 2020 and beyond.

The Brookings County - Hampton Project provides access to wind generation in southwest Minnesota and eastern South Dakota. The line is expected to increase the delivery of wind generation by 700 MWs. While the other lines are driven primarily for reliability needs, they will also facilitate future wind development by providing the necessary infrastructure to support other wind-focused transmission additions. In addition, the Brookings County-Hampton Project is part of the Multi Value Project (MVP) Portfolio approved by the MISO Board of Directors in December 2011.

Cost: The four lines will cost approximately $1.7 billion with an additional $200 million to provide for double-circuit capable 345 kV lines. Of this total, approximately $639 million is associated with the wind generation supporting Brookings County-Hampton Project. The

Brookings County-Hampton project will be subject to the newly established MVP Portfolio cost allocation methodology. The MVP cost allocation spreads the cost of the project over the entire MISO footprint on the energy usage basis. NSP will pay approximately 9.1percent of the total cost for all the MVP projects while maintaining the original CapX ownership arrangements.

Status: The 28-mile St Cloud-Monticello 345 kV project was completed and energized in December 2011 and the Bemidji-Grand Rapids 230 kV line was completed and energized in September 2012. Construction continues on the Fargo-St Cloud, Brookings County-Hampton and Hampton-Rochester-La Crosse 345 kV projects with an in-service date of 2015 for all three.

Investment Partners: Central Minnesota Municipal Power Agency (CMMPA), Dairyland Power Cooperative, Great River Energy, Southern Minnesota Municipal Power Agency, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Otter Tail Power, Rochester Public Utilities, Xcel Energy, and WPPI Energy.

Benefits: This project will alleviate emerging electric reliability issues around the Upper Midwest and strengthen the regional transmission system. In addition, the Brookings County - Hampton line will add capacity for an additional 700 MWs of generation in southwest Minnesota and eastern South Dakota. The project will also provide the foundation for future transmission projects from wind-rich regions of western Minnesota and North and South Dakota.

MISO Multi Value Project Portfolio

Description: The MISO MVP Portfolio consists of 17 individual 345 kV and above projects in the MISO footprint. The NSP Companies have partial ownership of three of the 17 projects. The projects are the CapX2020 Brookings County-Hampton and the Big Stone South-Brookings County 345 kV lines and the 150 mile, single-circuit, 345 kV transmission line between La Crosse, Wisconsin and Madison, Wisconsin (Badger Coulee). This MVP portfolio is part of a regional plan to fulfill the Renewable Portfolio Standards of all states in the MISO footprint. The projects, approved as a complete portfolio, will enable enough wind integration into the MISO footprint to fulfill RPS goals through at least 2026.

Cost: The MVP portfolio will cost approximately $5.2 billion. The entire total is associated with the integration of wind generation into the MISO footprint. The MVP cost allocation spreads the cost of the project over the entire MISO footprint on the energy usage basis. NSP will pay approximately 9.1percent of the total cost for all the MVP projects while maintaining the original CapX2020 ownership arrangement for Brookings County-Hampton. NSP has joint ownership with Otter Tail Power (OTP) in the Big Stone South-Brookings County project and with American Transmission Company (ATC) in the La Crosse-Madison (Badger Coulee) project.

Status: Construction started on the Brookings County-Hampton project in May 2012. The South Dakota Public Utilities Commission approved an application for the Big Stone South-Brookings County project in February 2014; the project has an in-service date of 2017. NSP and ATC filed an application with the Public Service Commission of Wisconsin in 2013 for the Badger Coulee project with an in-service date of 2018.

Investment Partners: The entire MISO footprint will share costs based on annual energy consumption.

Benefits: The portfolio of projects allows the MISO footprint to fully meet the RPS goals of all the states in the MISO footprint, provides significant cost savings through better generation dispatch, and provides improved system stability and voltage support to the major load centers.

Scott County 345 kV Substation Expansion

Description: This project is to expand the existing 115 kV Scott County Substation in Shakopee, Minnesota to include 345 kV yard. This project will include adding two new 345/115 kV, 672 MVA transformers. The 345 kV portion of the project will build a 4 position ring bus to accommodate the transformers and the new terminations on the existing Blue Lake-Helena 345 kV line. The 115 kV bus will also be expanded to allow for more terminations.

Cost: Approximately $27 million.

Status: Construction is scheduled for start in 2014 with an in-service date by the end of 2015.

Investment Partners: None.

Benefits: This project is needed for area load growth and will help alleviate transformer loadings on the existing Eden Prairie transformers on the west side of the Twin Cities Metro area.

Bayfield Loop

Description: This project will construct a new 115 kV transmission line into the Bayfield, Wisconsin's area existing 34.5 kV looped transmission system. This will add a new 115/34.5 kV substation into the area tying into the 34.5 kV system. In addition to the new line, the 34.5 kV section from Cornucopia-Bayfield will be rebuild once this new 115 kV portion of the project is in-service.

Cost: Approximately $55 million.

Status: Construction is scheduled for start in 2015 with an in-service date by summer of 2018.

Investment Partners: None.

Benefits: This project is needed for area load growth and will help with operations of the system in the area. It will help alleviate low voltage conditions under contingency.

Bayfront to Ironwood 88 kV

Description: This project will rebuild the existing 88 kV line from the Ashland, Wisconsin area to the Ironwood, Wisconsin area in northern Wisconsin to 115 kV. There is approximately 40 miles of line to rebuild and several substation modifications and conversions will be needed for this project.

Cost: Approximately $50 million.

Status: Construction is scheduled for start in 2017 with an in-service date by the end of 2021.

Investment Partners: None.

Benefits: This project is needed for several C3 contingencies in the area. In addition age and condition is an issue with this line.

Couderay-Osprey 161 kV Line

Description: This project will construct approximately 40 miles of new 161 kV transmission lines from the Osprey substation and a new Couderay substation near the Town of Ladysmith Wisconsin. The new Couderay substation will tie into the existing 115 kV line with a 161/115 kV, 187 MVA transformer.

Cost: Approximately $46 million.

Status: Construction was scheduled for start in 2013 with an in-service date by the end of 2015.

Investment Partners: None.

Benefits: This project is needed for area industrial load growth. In addition this project will provide support for the existing hydro units in the area to be restarted after an outage on the Hydro Lane transmission source.

PUBLIC SERVICE OF COLORADO (PSCO)

Company Background:

- PSCo operates in Colorado, and owns approximately 4,360 circuit miles of transmission lines 44 kV and above.
- PSCo has approximately 1.4 million retail and wholesale customers in Colorado.

CO Senate Bill 100 Plan Projects

Pawnee - Daniels Park 345 kV Transmission Line

Description: The Pawnee - Daniels Park 345 kV Transmission Line proposed project would consist of approximately 120 miles of 345 kV transmission from PSCo's Pawnee Substation in northeastern Colorado to its Daniels Park Substation south of the Denver metro area. The first 95 miles of the project would expand the existing Pawnee - Smoky Hill 345 kV transmission line to a double-circuit, 345 kV transmission line between Pawnee and Smoky Hill Substations. One circuit being the Pawnee - Smoky Hill 345 kV line, and the second circuit would be one section of the Pawnee - Daniels Park 345 kV line. For the remaining 25 miles between PSCo's Smoky Hill and Daniels Park Substations, a new double-circuit, 345 kV transmission line is proposed to be constructed. One of the two circuits would be the second section of the Pawnee - Daniels Park 345 kV line. The second circuit would create a new 345 kV transmission line between PSCo's Smoky Hill Substation and the Daniels Park Substation.

Cost: Approximately $150 million.

Status: This is a planned project with an expected in-service date of 2019. The Company is required to seek approval from the Public Utilities Commission prior to construction.

Investment Partners: None.

Benefits: This project is expected to accommodate at least 500 MWs of new generation resources, interconnecting at or near the Pawnee Substation in north central and northeastern Colorado.

Pawnee - Smoky Hill 345 kV Transmission Project

Description: The Pawnee - Smoky Hill 345 kV Transmission Project is a new 345 kV transmission line that connects PSCo's existing Pawnee Substation near Brush, Colorado, to PSCo's Smoky Hill Substation near Aurora, Colorado. The project also interconnects with PSCo's Missile Site Substation near Deer Trail, Colorado. The line is approximately 95 miles long.

Cost: Approximately $140 million.

Status: PSCo filed for regulatory approval in October 2007, which was approved in February 2009. This project was completed in the summer of 2013.

Investment Partners: None.

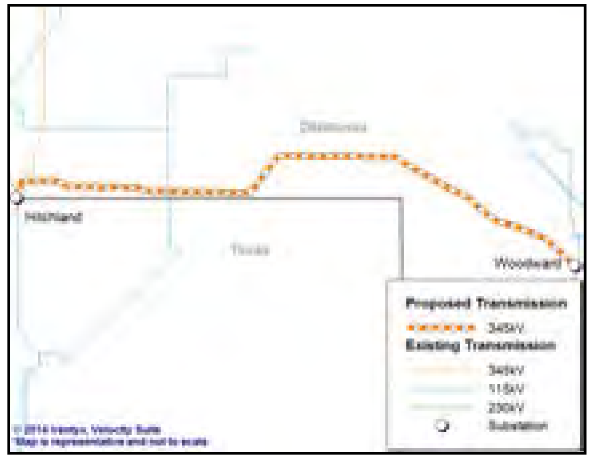
Benefits: : The line has allowed interconnection of over 1200 MW of new wind generation at Pawnee and Missile Site.

Southwestern Public Service (SPS)

Company Background:

- SPS operates transmission facilities in Texas, New Mexico, Kansas, and Oklahoma.
- SPS has approximately 400,000 retail and wholesale customers.
- SPS operates approximately 6,703 circuit miles of transmission lines.

Hitchland - Woodward 345 kV Transmission Line



Description: The Hitchland - Woodward 345 kV Transmission Line project consists of approximately 120 miles of new double-circuit 345 kV transmission line from Hitchland Substation to the OG&E interception point from the Woodward District EHV Substation. This project was approved as one of the Southwest Power Pool (SPP) Priority Projects providing multiple benefits including reliability and an additional generation outlet including renewable resources.

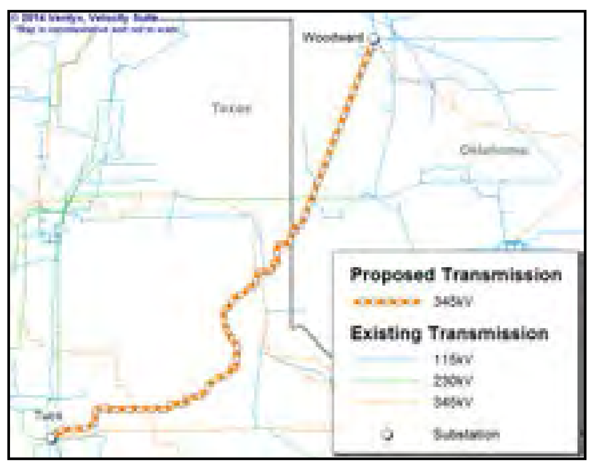
Cost: Approximately $247 million, of which approximately $62 million will be SPS' responsibility.

Status: In-service date of 2014.

Investment Partners: OG&E.

Benefits: This project is a Priority Project under the SPP Transmission Tariff providing multiple benefits including reliability and additional generation outlet including renewable resources.

Tuco - Woodward District 345 kV Transmission Line



Description: The Tuco - Texas/Oklahoma Interconnect 345 kV Transmission Line project consists of approximately 202 miles of new 345 kV transmission line from TUCO Substation to the OG&E interception around the Texas-Oklahoma state line. This project was approved as part of the SPP Balanced Portfolio 3E Projects to enable economic transfers and enhance regional transmission reliability.

Cost: Approximately $367 million, of which approximately $186 million will be SPS' responsibility.

Status: In-service date of 2014.

Investment Partners: OG&E.

Benefits: This project is a Balanced Portfolio Project under the SPP Transmission Tariff and will enable economic transfers, enhance regional transmission reliability, and provide outlet for additional wind generation in the Texas Panhandle, eastern New Mexico, and western Oklahoma.

INTERSTATE TRANSMISSION PROJECTS

These interstate projects span two or more states, and often present additional challenges for siting, permitting, cost allocation and cost recovery. Interstate projects account for approximately 7,700 miles and $26.2 billion in this report (nominal $).

- Big Stone South to Ellendale
- CAPX2020 Transmission Plan
- Cardinal Bluffs
- “Energizing the Future” Initiative - Bruce Mansfield-Glenwillow
- Energy Gateway
- Grand Rivers Projects
- Greater Springfield Reliability Project
- Great Northern Transmission Line
- Interstate Reliability Project
- MidAmerican Energy Expansion Projects
- Midwest Portfolio Phase 1 North
- Midwest Portfolio Phase 2
- Midwest Portfolio Phase 3
- Midwest Portfolio Phase 4
- Midwest Portfolio Phase 5
- Midwest Portfolio Phase 7
- New England East - West Solutions (NEEWS)
- Northeast Energy Link
- Northern Pass Transmission Project
- Pinckard - Holmes Creek - Highland County 230 kV Transmission Line Project
- PJM N-1-1 Projects (Southern Delmarva)
- Pleasant Prairie - Zion Energy Center0
- Ritchie to Buzzard Point N-1-1 Compliance Project
- Susquehanna - Roseland 500 kV Transmission Line Project
- Tuco - Woodward District 345 kV Transmission Line
- Woodward - Thistle Double Circuit 345 kV Line
- Woodward - Tuco 345 kV Line0
- Zephyr Power Transmission Project

TRANSMISSION PROJECTS DEVELOPED BY MULTIPLE PROJECT PARTNERS

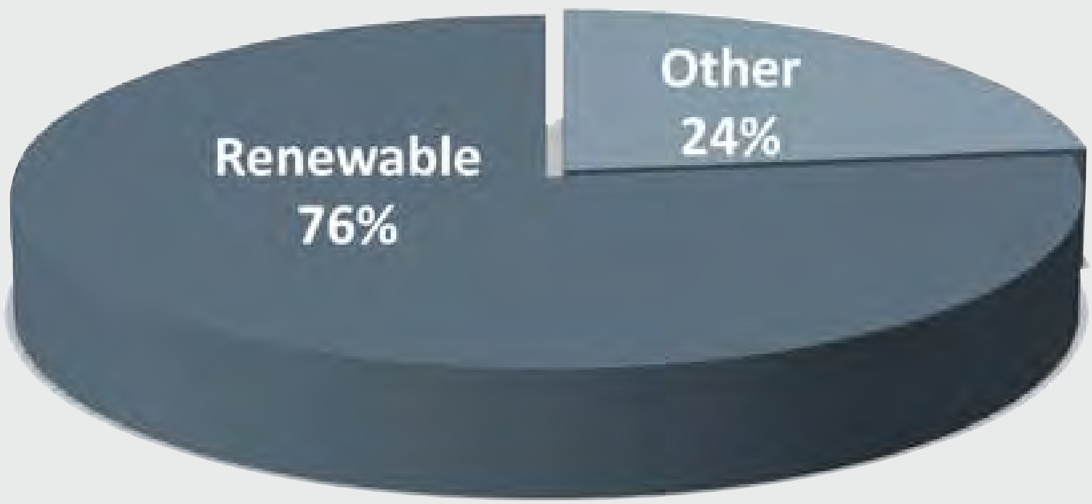
Given the unique risks and challenges of developing transmission, among other things, several EEI member companies are collaborating with other utilities, including non-EEI members, to develop large-scale transmission projects. This collaboration allows entities to spread the investment risks while also leveraging each other's experience in developing needed transmission. Projects where multiple project partners are collaborating account for approximately 10,000 miles, representing a cost of approximately $29.8 billion in this report (nominal $).

- Badger Coulee
- Big Stone South to Brookings County
- Big Stone South to Ellendale
- CAPX2020 Transmission Plan
- Cardinal Bluffs
- Chisholm - Gracemont 345 kV Line
- ETT CREZ
- ETT Valley Import Project & Cross Valley Project
- Energy Gateway
- Gates-Gregg 230 kV Transmission Line
- Greater Springfield Reliability Project
- Great Northern Transmission Line
- Hitchland - Woodward District EHV Double Circuit 345 kV Line
- Iatan - Nashua Line
- Interstate Reliability Project
- Jasper - Pine Grove Primary 115 kV Project
- Judy Mountain 230/115 kV Substation Project
- Midwest Portfolio Phase 1 North
- Midwest Portfolio Phase 1 South
- Midwest Portfolio Phase 2
- Midwest Portfolio Phase 3
- Midwest Portfolio Phase 4
- Midwest Portfolio Phase 5
- Midwest Portfolio Phase 6
- Midwest Portfolio Phase 7
- Multi-Value Projects 3 & 4
- Nebraska City - Sibley Line
- New England East - West Solutions (NEEWS)
- Northeast Energy Link
- One Nevada 500 kV Transmission Intertie
- Path 42
- Pioneer Transmission, LLC
- Prairie Wind Transmission, LLC

- Project 8
- Ramapo - Rock Tavern 345 kV Line
- Smart Grid Investment Grant Projects
- Staten Island Unbottling
- Summit to Elm Creek 345 kV Transmission Line
- Susquehanna - Roseland 500 kV Transmission Line Project
- Tehachapi Wind Energy Storage Project
- Tuco - Woodward District 345 kV Transmission Line
- Wadley 500/230 kV Project
- Woodward - Thistle Double Circuit 345 kV Line
- Woodward - Tuco 345 kV Line
- Zephyr Power Transmission Project

TRANSMISSION SUPPORTING THE INTEGRATION OF RENEWABLE RESOURCES

These projects support the integration of renewable resource generation. Renewable energy technologies include: wind power, solar power, hydroelectricity, geothermal, biomass and biofuels. Highlighted projects that facilitate the integration of renewable resources reflect the addition or upgrade of 12,200 miles of transmission with an accompanying investment cost of approximately $46.1 billion in this report (nominal $).

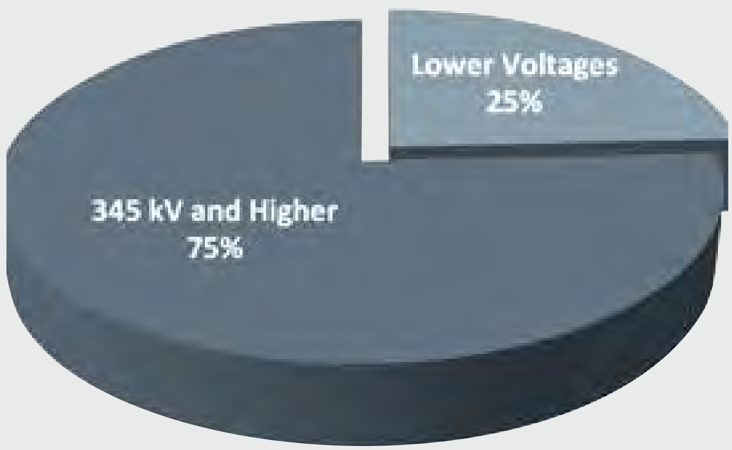


- Badger Coulee
- Big Stone South to Brookings County
- Big Stone South to Ellendale
- CAPX2020 Transmission Plan
- Cardinal Bluffs
- Chisholm - Gracemont 345 kV Line
- Cimarron - Mathewson Double Circuit 345 kV Line
- Coolwater - Lugo Transmission Project
- Couderay - Osprey 161 kV Line
- Eldorado - Ivanpah Transmission Project
- Energy Gateway
- ETT CREZ
- Devers - Colorado River and Devers - Valley No. 2 Transmission Project
- Gates-Gregg 230 kV Transmission Line
- Grand Rivers Projects
- Greater Fresno Area Upgrade Project
- Great Northern Transmission Line
- Pioneer Transmission, LLC
- Prairie Wind Transmission, LLC
- Hitchland - Woodward District EHV Double Circuit 345 kV Line
- Kansas V-Plan
- RiteLine
- Mathewson - Tatonga 2nd Circuit 345 kV Line
- Michigan Thumb Loop Transmission Project
- MidAmerican Energy Expansion Projects
- Midwest Portfolio Phase 1 North
- Midwest Portfolio Phase 1 South
- Midwest Portfolio Phase 2
- Midwest Portfolio Phase 3
- Midwest Portfolio Phase 4
- Midwest Portfolio Phase 5

- Midwest Portfolio Phase 6
- Midwest Portfolio Phase 7
- Multi-Value Projects 3 & 4
- Nebraska City - Sibley Line
- New Bethel Energy Center 345 kV Transmission Line
- Northeast Energy Link
- Northern Pass Transmission Project
- Oncor CREZ Development
- One Nevada 500 kV Transmission Intertie
- Palo Verde Hub - North Gila 500 kV Project
- Palo Verde Substation - Delaney Substation - Sun Valley Substation - Morgan Substation - Pinnacle Peak Substation 500 kV Projects0
- Path 42
- Pawnee - Daniels Park 345 kV Transmission Line
- Pawnee - Smoky Hill 345 kV Transmission Project
- Prairie Wind Transmission, LLC
- San Joaquin Cross Valley Loop
- Tehachapi Renewable Transmission Project
- Tehachapi Wind Energy Storage Project
- Tuco - Woodward District 345 kV Transmission Line
- West of Devers Upgrade Project
- Woodward - Thistle Double Circuit 345 kV Line
- Woodward - Tuco 345 kV Line
- Woodward District EHV - Tatonga 2nd Circuit 345 kV Line
- Zephyr Power Transmission Project

HIGH-VOLTAGE TRANSMISSION PROJECTS

Although some member companies have shifted their focus towards upgrades and implementation of modern technologies on the existing grid, there is still a commitment among the industry to develop large high-voltage projects to accommodate changing generation sources and customer needs. As more renewable generation, which is typically located far from load, enters the supply mix, high-voltage transmission lines are vital in transporting that generation over long distances. High-voltage projects consisting of 345 kV and higher represent approximately 13,000 miles and an investment cost of over $45 billion in this report (nominal $).



- Badger Coulee
- Bay Lake Initial
- Big Stone South to Brookings County
- Big Stone South to Ellendale
- Brokaw - South Bloomington
- CAPX2020 Transmission Plan
- Cardinal Bluffs
- Chicago Southern Business District Burnham - Taylor 345 kV Project
- Chisholm - Gracemont 345 kV Line
- Cimarron - Mathewson Double Circuit 345 kV Line
- Devers - Colorado River and Devers - Valley No. 2 Transmission Project
- Elm Creek - Summit Project
- "Energizing the Future" Initiative - Bruce Mansfield-Glenwillow
- Energy Gateway
- ETT CREZ
- ETT Valley Import Project & Cross Valley Project
- Fancy Point Substation
- Fargo - Mapleridge
- Grand Rivers Projects
- Greater Springfield Reliability Project
- Great Northern Transmission Line
- Hitchland - Woodward District EHV Double Circuit 345 kV Line
- Holland Bottom to Beebe to Garner
- Iatan - Nashua Line
- Interstate Reliability Project
- Kammer 345/138 kVRebuild Expansion
- Kansas V-Plan
- Latham - Oreana
- Lower SEMA Transmission Project
- Lutesville - Heritage
- Mathewson - Tatonga 2nd Circuit 345 kV Line
- Michigan Thumb Loop Transmission Project
- MidAmerican Energy Expansion Projects
- Midwest Portfolio Phase 1 North
- Midwest Portfolio Phase 1 South
- Midwest Portfolio Phase 2
- Midwest Portfolio Phase 3
- Midwest Portfolio Phase 4

- Midwest Portfolio Phase 5
- Midwest Portfolio Phase 6
- Midwest Portfolio Phase 7
- Mont Belvieu Area Upgrades
- Multi-Value Projects 3 & 4
- Nebraska City - Sibley Line
- New Bethel Energy Center 345 kV Transmission Line
- New England East - West Solutions (NEEWS)
- Northern Pass Transmission Project
- One Nevada 500 kV Transmission Intertie
- Osceola Area Substation
- Palo Verde Hub - North Gila 500 kV Project
- Palo Verde Substation - Delaney Substation - Sun Valley Substation - Morgan Substation - Pinnacle Peak Substation 500 kV Projects
- Pawnee - Daniels Park 345 kV Transmission Line
- Pawnee - Smoky Hill 345 kV Transmission Project
- Pioneer Transmission, LLC
- Plant Vogtle Network Improvement Project
- Pleasant Prairie - Zion Energy Center
- Prairie Wind Transmission, LLC
- Project 8
- Ramapo - Rock Tavern 345 kV Line
- Rockdale – Cardinal
- Salem-Hazleton Line
- Scott County 345 kV Substation Expansion
- Seminole - Muskogee 345 kV Line
- Sooner - Cleveland 345 kV Line
- Sorenson 765/345 kV New Station Lines
- Staten Island Unbottling
- Summit to Elm Creek 345 kV Transmission Line
- Susquehanna - Roseland 500 kV Transmission Line Project
- Tehachapi Renewable Transmission Project
- Tuco - Woodward District 345 kV Transmission Line
- Wadley 500/230 kV Project
- White Bluff Area Improvements
- Woodward District EHV - Tatonga 2nd Circuit 345 kV Line
- Woodward - Thistle Double Circuit 345 kV Line
- Woodward - Tuco 345 kV Line
- Zephyr Power Transmission Project

National Commission on Energy Policy

NATIONAL COMMISSION ON ENERGY POLICY'S

TASK FORCE ON AMERICA'S FUTURE ENERGY JOBS

EXECUTIVE SUMMARY AND POLICY RECOMMENDATIONS

Disclaimer

This report is a product of a Task Force with participants of diverse expertise and affiliations, addressing many complex and contentious topics. It is inevitable that arriving at a consensus document in these circumstances entailed compromises. Accordingly, it should not be assumed that every member is entirely satisfied with every formulation in this document, or even that all participants would agree with any given recommendation if it were taken in isolation. Rather, this group reached consensus on these recommendations as a package, which taken as a whole offers a balanced approach to the issue.

It is also important to note that this report is a product solely of the participants from the NCEP convened Task Force on America's Future Energy Jobs. The views expressed here do not necessarily reflect those of the National Commission on Energy Policy.

Acknowledgements

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NATIONAL COMMISSION ON ENERGY POLICY'S

TASK FORCE ON AMERICA'S FUTURE ENERGY JOBS

EXECUTIVE SUMMARY AND POLICY RECOMMENDATIONS

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CONTENTS

POLICY CONTEXT

In 2009, the National Commission on Energy Policy (NCEP) convened a task force to explore the workforce needs of the U.S. energy sector and develop recommendations concerning how best to address the intertwined challenges of preserving American jobs and competitiveness, while also tackling energy security and climate change. NCEP's Task Force on America's Future Energy Jobs issued its first report in October 2009. Writing in the foreword to that report, Task Force co-chairs Norman Augustine and Senator Peter Domenici (retired) emphasized the urgency of energy workforce issues in the context of high unemployment and looming skill shortages in critical energy industries.

One year later, with the national unemployment rate still close to 10 percent (the unemployment rate in the construction sector is more than 20 percent) and with Congress deadlocked over energy and climate legislation, the case for a coherent, targeted national policy to meet evolving energy-sector workforce demands remains as compelling as ever.

This report revisits the Task Force recommendations and adds detail concerning the specific steps that should be taken to implement them. Specifically, we discuss concrete actions to improve workforce training programs, improve workforce data collection and management, develop industry credentials, provide funding for energy-related workforce training and education, strengthen basic math and science skills, and increase awareness of energy-sector career opportunities. We believe all of these steps are important as part of a comprehensive strategy for preparing U.S. workers to participate in and benefit from the job opportunities associated with transitioning to a low-carbon economy. Most important, however, will be greater clarity and certainty about the future direction of energy and environmental policy in the United States more broadly. During the fall of 2009, Congress and the Administration appeared to be making progress in advancing a new long-term energy agenda for the nation through stimulus funding and House-passed energy and climate legislation. Indeed, the 2009 American Recovery and Reinvestment Act provided funding to begin addressing some of the specific needs highlighted in the Task Force report, such as funding for regional energy training partnerships. Broader energy and climate legislation, however, has since stalled in the Senate.

The current political stalemate perpetuates uncertainties that threaten to undermine efforts to prepare for the energy workforce needs of the future because it discourages the investment in the next generation of energy technologies and infrastructure that could ignite a wave of new job and career opportunities in the energy sector. Without some regulatory certainty,

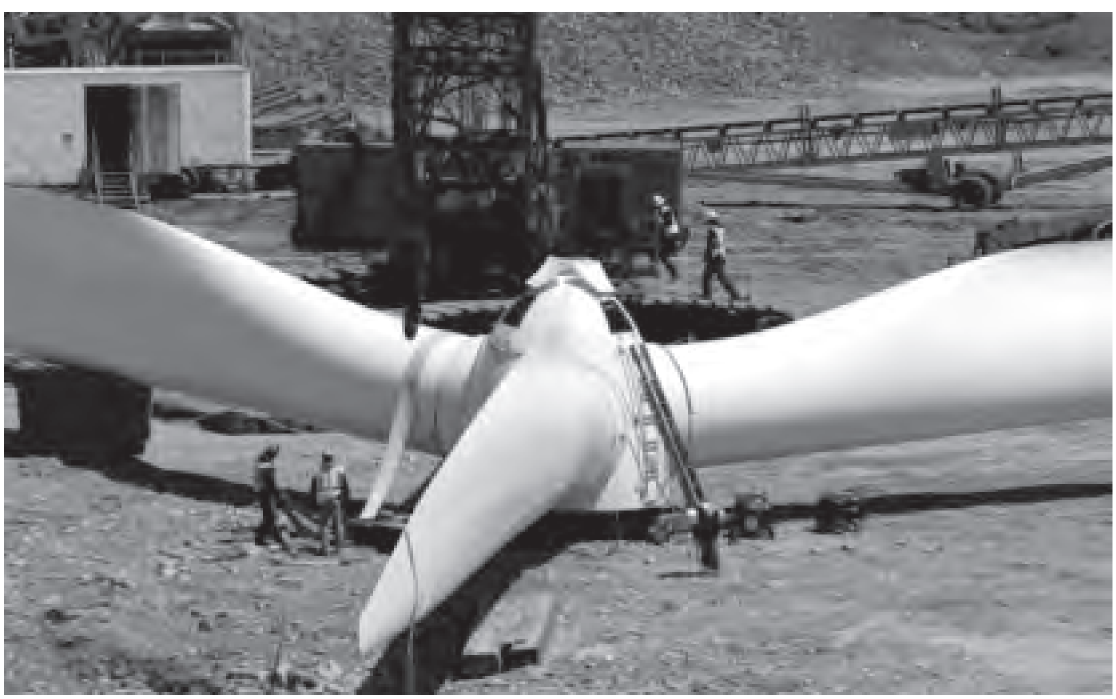
The case for a coherent, targeted national policy to meet evolving energy-sector workforce demands remains as compelling as ever.

particularly as regards to future carbon and renewable energy policies, the electric power sector will continue to defer many of the large capital investments needed to build new power plants and transmission capacity, let alone wind farms, solar installations, nuclear plants, and other low-carbon technologies. And without a sense of future investment patterns or a clear policy path forward, it is difficult to predict the types of skills that will be needed and when new kinds of job opportunities will become available. Interest in related training programs or professional degrees and opportunities to develop skills through apprenticeship programs will suffer accordingly. In sum, the lack of a long-term energy strategy for the United States is more than just a climate issue, a competitiveness issue or an energy security issue—it is a jobs issue. The longer Congress delays action on difficult but critical policy questions, the longer investments will be delayed, the less time there will be to prepare American workers, and the more likely it is that technologies will be imported and domestic job opportunities will be lost.

Without some regulatory certainty, the electric power sector will continue to defer many of the large capital investments needed to build new power plants and transmission capacity, let alone wind farms, solar installations, nuclear plants, and other low-carbon technologies.

Of course, Task Force members recognize that some near-term workforce challenges, particularly in the electric sector, have shifted since we first met at the beginning of 2009. In particular, concerns about a lack of qualified applicants to replace retiring workers moved a little further away as employees postponed retirement in response to the economic crisis. Longer term, however, this issue is likely to re-emerge. As the economy begins to rebound and employee retirement savings recover, the industry could face an even larger wave of retirements (a "silver tsunami") as some employees who postponed retirement leave the work force at the same time as those who are retiring on schedule.

The recommendations and specific implementation steps outlined in this follow-up Task Force report will help to ensure that the electric utility industry can find workers with the skills to fill these vacancies. More broadly, they aim to ensure that America's workers are equipped to undertake—and benefit from—a technology revolution that must sooner or later transform our nation's energy systems and the larger economy.



EXECUTIVE SUMMARY

In January of 2009, the National Commission on Energy Policy (NCEP) convened a group of stakeholders with expertise in the workforce of the U.S. electric power industry. The NCEP Task Force on America's Future Energy Jobs brought together representatives from labor, the electric power industry, and the training and educational sectors to explore—over a series of three meetings in six months—the existing demographic makeup and anticipated workforce needs of the electric power sector, along with the training institutions and programs that support this sector. This report summarizes the insights and conclusions resulting from this effort.

Broadly speaking, the Task Force believes the United States is facing a critical shortage of trained professionals to maintain the existing electric power system and design, build, and operate the future electric power system. The implications of this shortfall are wide-ranging and, in the view of the Task Force, of national significance. The ability to maintain a highly reliable, economically affordable electric power system while modernizing the nation's generating infrastructure to support an advanced, low-carbon technology portfolio is in serious jeopardy. This report highlights the main forces driving this situation and lays out a series of recommendations for addressing the dominant workforce challenges that will confront the electric power industry over the next several years. Ensuring the proper systems and institutions are in place to respond to these challenges is important, not only in terms of advancing critical public policy goals with respect to energy, the economy, and the environment, but because a substantial opportunity exists to create new high-skill, high-paying jobs in the energy sector at a time when growing numbers of Americans are unemployed or underemployed and face the prospect of financial insecurity.

There have, of course, been significant changes in the political and economic landscape since the the Task Force was formed. The Obama Administration is committed to an energy policy that aims to reduce the nation's consumption of fossil fuels and contribution to global greenhouse gas emissions. At the same time, an unprecedented economic crisis has crippled global financial markets, halted global economic growth, and led to massive job losses in the United States and elsewhere. Against this backdrop, the Task Force set about examining workforce supply and demand dynamics in the electric power industry. The American Recovery and Reinvestment Act (ARRA) passed in 2009 provided a near-term infusion of resources that have the potential to facilitate many of the actions recommended in this report. To ensure that these short-term investments build the long-term capacity needed to address multi-decade challenges like climate change, policymakers should consider the actions recommended in

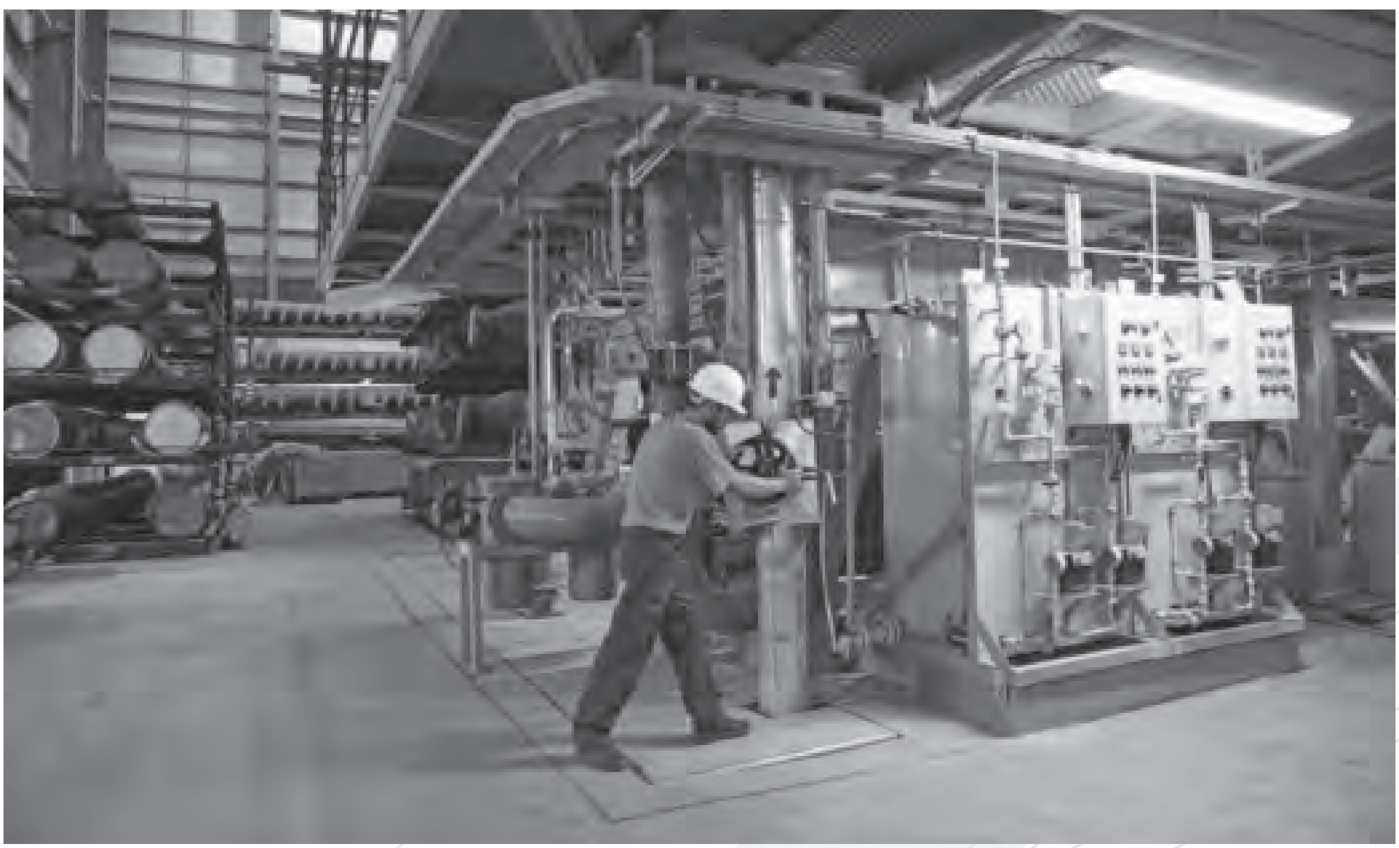
THE UNITED STATES IS FACING A CRITICAL SHORTAGE OF TRAINED PROFESSIONALS TO MAINTAIN THE EXISTING ELECTRIC POWER SYSTEM AND DESIGN, BUILD, AND OPERATE THE FUTURE ELECTRIC POWER SYSTEM.

this report when reauthorizing the Workforce Investment Act (WIA) and crafting climate and energy legislation.

Data and Definitions

NCEP conducted significant background analytical work to better assess the challenges that are often reported anecdotally by concerned parties. One of the most important conclusions from this work is that data collection and measurement systems needed to gauge the state of our nation's energy workforce are woefully inadequate. For this reason, the NCEP team endeavored to commission new work and access available information to characterize the challenges. While the data collected and presented in this report represent a significant contribution to the debate, we believe that this assessment is best used as an illustrative guide to current workforce issues. We have not attempted to develop a precise projection of future workforce needs. Additionally, our report is not intended to take the place of state and regional workforce assessments that can provide the insights needed to identify specific focus areas for individual training programs or education systems. As described further in the report, we believe that bringing together major stakeholder groups at a local or regional level is the best way to evaluate specific training needs.

A theme that seems to resonate broadly across the energy workforce debate is that "green jobs" are a positive outcome to be promoted. However, a universally accepted definition for what constitutes a green job does not exist. Organizations of all types tend to attach the "green" label when describing activities they support and promote, which highlights the ambiguity in using the term. While it is generally safe to assume that jobs directly involved in the deployment



of energy efficiency and renewable energy technologies would be considered "green," a number of complexities quickly emerge as soon as one attempts to apply even this seemingly simple definition. For example, a lineworker building a transmission line that connects a wind farm to the electric grid would be viewed by most people as having a green job. If that same transmission line carries electricity generated from nearby coal-fired power plants, the "greenness" of that job may not be as clear. This example illustrates that the skills needed to perform what many think of as a green job are often the same as or very similar to traditional energy-related jobs.

The NCEP Task Force on America's Future Energy Jobs believes debating the definition of green jobs may become a distraction. In fact, we do not use this term elsewhere in this report. Rather, because our effort is focused on workforce needs associated with building and supporting energy infrastructure for a future low-carbon energy system, we believe the term "future energy job" is more appropriate for our focus. It implies that all types of jobs that support an energy system consistent with a long-term goal of reducing greenhouse gas emissions should be seen in the same light. Some of the jobs related to the transition to a carbon constrained economy will be new and will require new skill sets. But many more will use skills that are already in demand today, such as those required for sheet metal workers, transmission lineworkers, and electricians.[1] In effect, if the underlying policy framework reflects the objectives embedded in the term "green job" then future energy jobs *are* green jobs.

Overarching Challenges

As a starting point, Task Force members shared a common recognition that the electric power sector faces near- and long-term workforce challenges. Its workforce is aging and will need to be replaced. Facing a wave of retirements over the next decade, the electric power industry will need to expand hiring and training programs just to maintain the level of qualified workers required to operate existing facilities. In fact, new workers will be needed to fill as many as one-third of the nation's 400,000 current electric power jobs by 2013.[2] In the face of this surge in demand, companies are finding that applicants for open positions at electricity companies are not as prepared as they were in decades past. Companies are finding that U.S. students are not graduating at the same rates in the relevant fields and with the same qualifications as in the past. While the Task Force focused on direct electric power sector jobs, the Task Force members recognize that other economic sectors, such as the manufacturing sector, face similar demographic, education, and training challenges.

The NCEP Task Force on America's Future Energy Jobs believes debating the definition of green jobs may become a distraction ... we believe the term "future energy job" is more appropriate for our focus.

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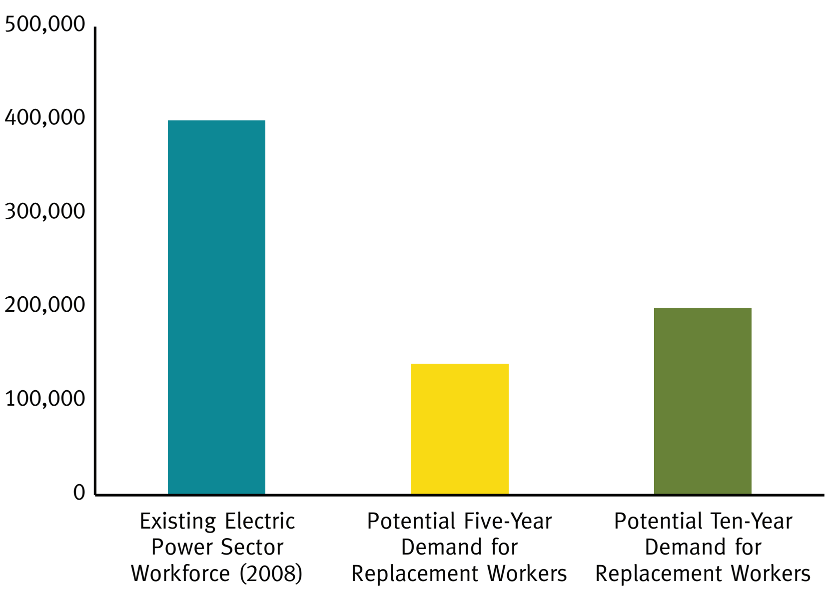
[1] Apollo Alliance and Green For All with Center for American Progress and Center on Wisconsin Strategy, "Green-Collar Jobs in America's Cities: Building Pathways out of Poverty and Careers in the Clean Energy Economy." 2008. Available http://www.greenforall.org/resources/green-collar-jobs-in-america2019s-cities.

[2] While the Task Force future scenarios focus on electric power generation, transmission, and distribution, we recognize that electric utilities are frequently integrated with natural gas utilities and that natural gas utilities face similar workforce pressures. According to the Bureau of Labor Statistics, natural gas utilities employ about 106,000 people. The CEWD data referenced in this report combine natural gas utility workforce estimates with the electric utility workforce estimates.

In the long-term, the deployment of new technologies and generating assets—including new energy efficiency, nuclear, renewable, advanced coal with carbon capture, and smart grid technologies—will require new design, construction, operation, and maintenance skills. This is an important opportunity for new job creation and economic growth. If too few individuals with the necessary expertise are available when they are needed, workforce bottlenecks could slow the transition to a low-carbon economy *regardless* of the commercial readiness of the underlying technologies. If the result is to delay the efficient adoption of improved low-carbon alternatives, workforce shortages would represent more than a lost opportunity—they could impose substantial costs, both in terms of economic burden and environmental damages and could damage U.S. global competitiveness.

Figure 1. Comparison of the Workers Needed to Replace Workers Retiring or Leaving the Industry for Other Reasons to Existing Employment Levels



Task Force Approach

The Task Force focused on three broad categories of jobs:

- Jobs associated with operating and maintaining the existing electric power infrastructure;
- Jobs associated with designing and building new electric generation capacity to meet future low-carbon energy needs; and
- Jobs associated with operating and maintaining the electric power industry of the future.

The first chapter summarizes the Task Force's findings on existing power industry labor markets. Rapid attrition due to retirements from an aging pool of workers is the primary concern. Chapter 2 examines what happens when an expected surge in demand for new low-carbon energy technologies is layered on top of this declining base. Comparing pending workforce requirements against the existing education and training pipeline is the focus of the third chapter. Chapter 4 presents suggested policy solutions and Task Force recommendations.

We summarize key insights from the original report along with our primary recommendations below. References for the data are included in the corresponding chapters.

Chapter 1 Critical Insights – Existing Electric Power Sector Workforce

- The electric power generation, transmission, and distribution industry employs about 400,000 people.

- A large fraction (30–40 percent) of electric power workers will be eligible for retirement or leave the industry for other reasons by 2013.

- Of the 120,000 to 160,000 electric power workers that will be eligible for retirement or leave the industry for other reasons by 2013, industry surveys suggest 58,200 will be skilled craft workers and another 11,200 will be engineers.

Table I. CEWD Survey Results by Job Category

Job Category	Estimated Number of Potential Replacements by 2013
Electric Power Skilled Craft	58,200
Technicians	20,300
Non-Nuclear Plant Operators	8,900
Pipefitters/Pipelayers	6,500
Lineworkers	22,500
Engineers	11,200

- While recent industry estimates anticipate that workers will delay retirement due to the current economic downturn, it is impossible to predict how long workers will extend employment. There is a concern in the industry that delayed retirement could lead to more acute worker shortages at some point in the future if many workers retire around the same time.

Chapter 2 Critical Insights – Potential Workforce Demand Surge under a Federal Climate Policy

- In addition to needing skilled workers to replace retiring workers, the industry will need skilled construction workers to design and construct new electric sector infrastructure. We estimate that in 2022, design and construction work for the electric sector will require about 150,000 professional and skilled craft workers from the construction sector. This construction workforce is about 40 percent the size of the existing electric power workforce.

- Demand for skilled workers to operate and maintain the electric generation systems of the future will increase steadily as new technologies come online. The number of additional workers that will be needed by 2030 is roughly 60,000—an increase of almost 15 percent.

Table 2. Projected O&M Jobs in 2030 Given the Projected New Generation under the EPRI Prism Analysis

Job Category	Range of Expected Demand
Skilled Electric Power Craft Workers	35,000 to 70,000
Professional Staff	18,500 to 35,000
Total	53,500 to 105,000

- The deployment trajectory for new generation technologies directly impacts workforce demand. In scenarios with steady annual deployment of new generating assets, workforce demands will peak at a lower level and will be spread out over more years. In scenarios where construction is delayed and several generating assets are planned to come into operation in the same year, the workforce peak is higher and the demand is more concentrated around the peak year. This variability reinforces the need for local and regional

A large fraction (30–40 percent) of electric power workers will be eligible for retirement or leave the industry for other reasons by 2013.

assessments of workforce demand as climate policy becomes clearer.

- The industry needs to prepare to meet a long-term, sustained need for training, beyond the retirement gap.

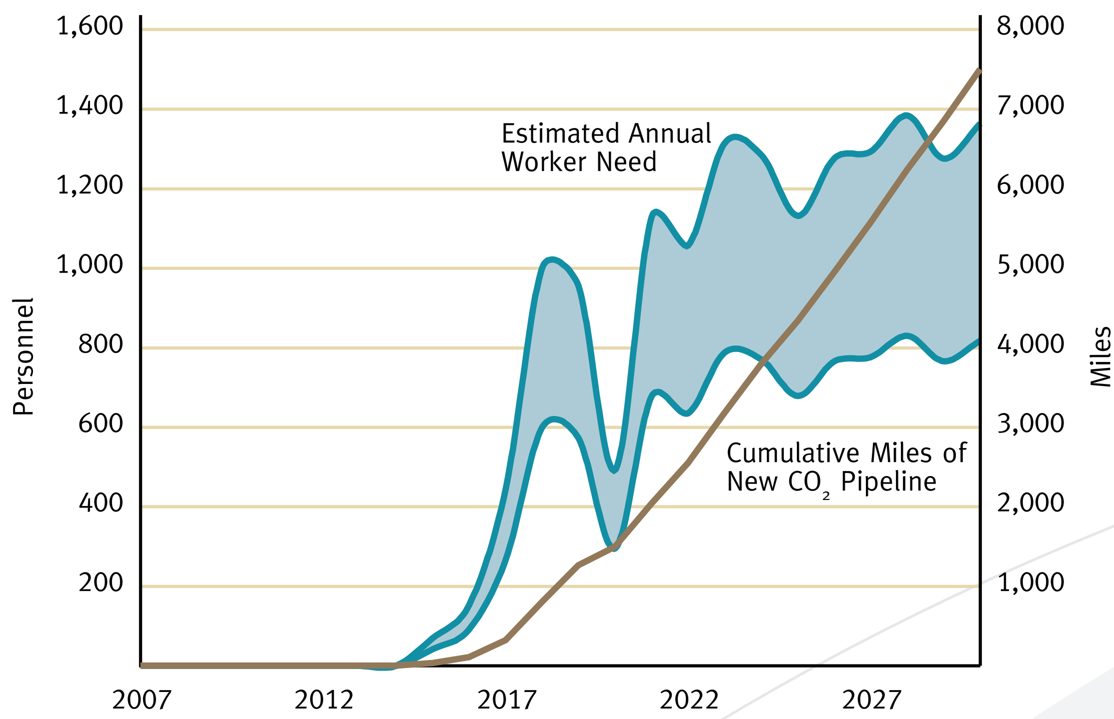
With respect to the design, construction, and operation and maintenance (O&M) of infrastructure and supporting technologies:

- Demand for construction labor to build new high-voltage transmission lines and substations is expected to spike, especially in light of the transmission investments anticipated under the recent economic stimulus package. We estimate the peak demand for construction labor and skilled crafts to be about 10,000 to 15,000. However, policy and regulatory delays have affected the construction timetable of a number of proposed transmission lines. These delays increase the uncertainty around projections of future workforce demand.

- The near-term deployment of smart grid technologies will require over 90,000 workers. However, smart grid deployment will result in about 25,000 electricity power industry workers looking to transition to new positions. This supply of workers highlights the need for training programs that retrain existing workers to take advantage of new opportunities within the industry.

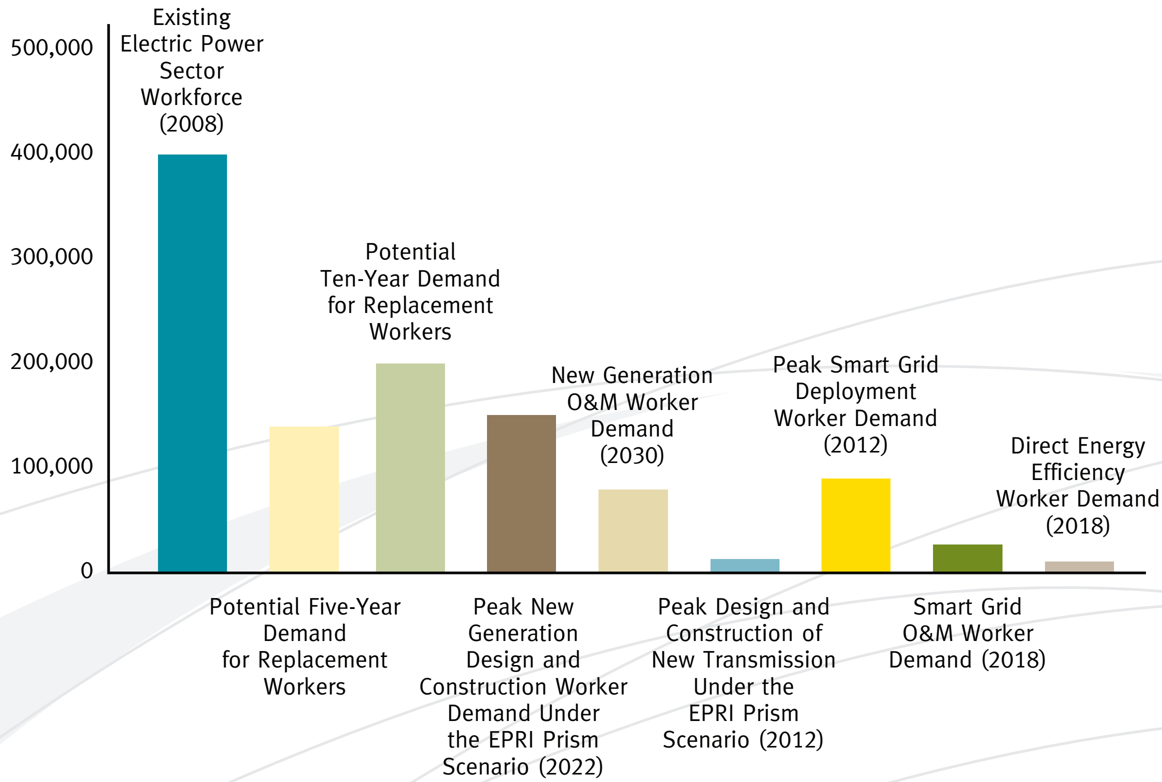
- Construction and maintenance of CO2 pipelines as part of a commitment to expanded carbon capture and storage (CCS) will marginally add to the demand for skilled workers. While not directly calculated as part of the NCEP Task Force estimates, additional workers will be needed to retrofit fossil fuel-fired power plants with carbon capture technologies.

Figure 2. Estimated Workforce to Design and Construct CO_2 Pipelines to Support EPRI Prism CCS Deployment



- Running energy efficiency programs requires people to design and administer programs and people to promote those programs and sign up new customers. We estimate that utility or other third-party managed energy efficiency programs in the United States will require all or part of the time of approximately 11,000 employees per year through 2030. Additionally, we expect the program managers to hire contractors to implement or deploy efficiency technologies. These contractors are expected to significantly outnumber the number of direct employees required to administer and promote customer-side efficiency programs and could number in the thousands for each program. While these jobs will be an important component of future energy jobs, the Task Force decided not to seek to quantify these jobs.

Figure 3. Comparison of Major Sources of Worker Demand to Existing Employment Levels



New workers will have to come from a training system that needs to be refocused and reinvigorated.

Chapter 3 Challenges – Training the Future Energy Workforce

- Challenges to preparing students in grades K-12:
  - Low Graduation Rates. Of the approximately four million students who will begin high school this fall in the United States, less than three million are expected to complete high school.
  - Lack of Technical Skills. Of those who complete high school, many are ill-prepared to pursue a career that requires basic technical skills.
  - Lack of Industry-Specific Training for Educators. Teacher training and retraining is a key component of repairing our basic educational system.
- Challenges to training and educating skilled craft workers:
  - Individuals can acquire the technical skills and training to enter the skilled craft electric power or construction workforce from several types of institutions or programs, including:
    - community colleges,
    - community-based organizations (CBOs),
    - apprenticeship programs,
    - company-specific training programs, and
    - worker retraining programs.
  - Understanding the Electric Power Sector Demand for Skilled Workers. A key challenge is aligning training programs with the demand for workers. This challenge is compounded by the current system used by the Bureau of Labor Statistics (BLS) to estimate future industry demand. That system relies on historical trends to project future industry growth and does not include estimates for replacing positions lost through retirements or other attrition.
  - Lack of Communication among Stakeholder Groups. Compounding the assessment challenge noted above is the fact that better communication is needed among stakeholders—particularly between training institutions and the electric power sector.
  - Lack of Credential Portability. A lack of standardized skill sets and curricula for some of the skilled crafts within the electric power sector presents a significant challenge for students, community colleges, and employers. This issue is specific to a subset of skilled crafts within the electric power sector—it does not apply to skilled crafts in the construction sector.
  - Collecting and Tracking Skilled Workforce Data. Information on the number of people that pass through existing training systems and their ultimate employment is currently not well captured.
  - Costs of Education. Even students who have adequate education in technical skills

Figure 4. U.S. High School Graduation Rate and Science Proficiency

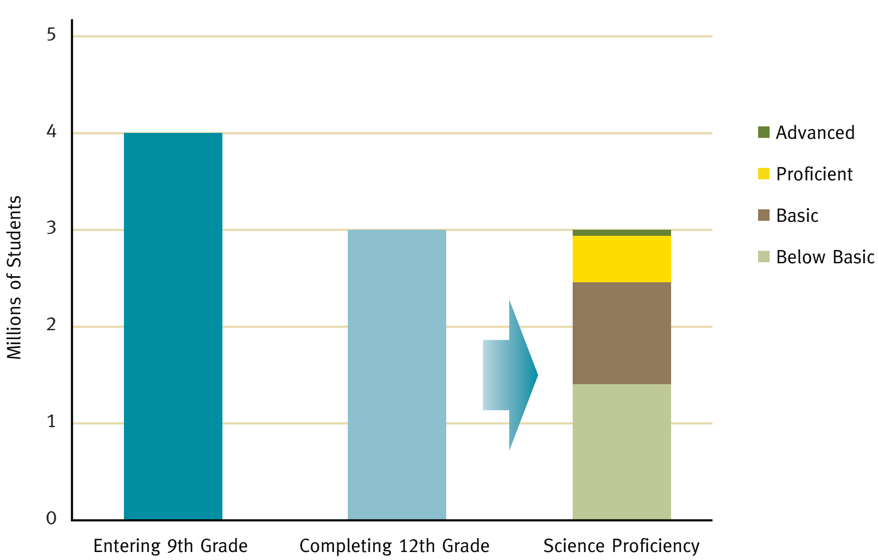
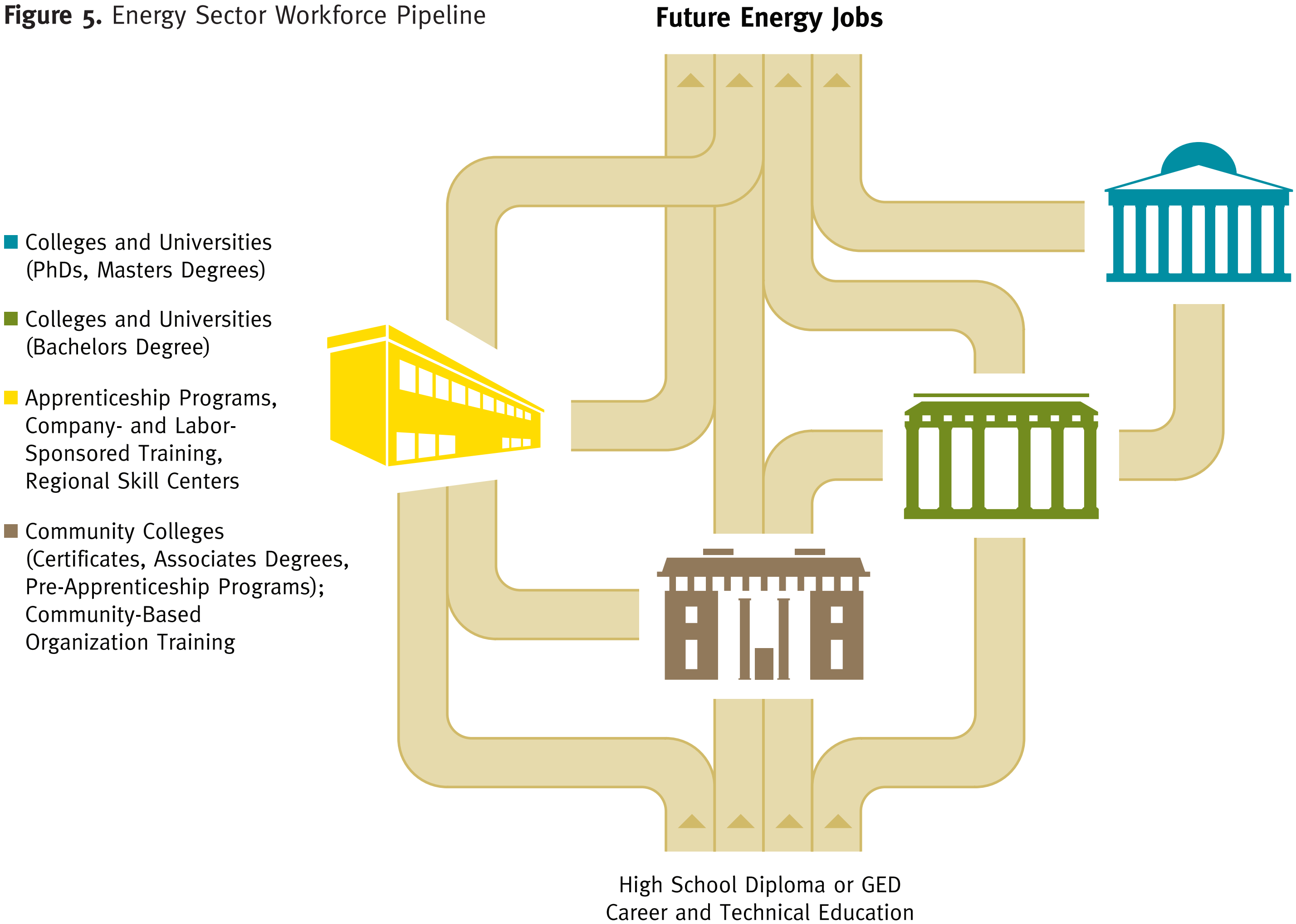


Figure 5. Energy Sector Workforce Pipeline



may have trouble paying for post-secondary education.

- Improving the Image of Electricity Industry Careers. Students and parents often do not view apprenticeship programs or other programs outside the four-year degree construct as providing similar or better opportunities for career and salary potential.

- Lack of Career Preparatory Skills within the Workforce. Because of a lack of technical skills among the potential workforce, introductory courses have become more prevalent at the community college level.

- Challenges to training and educating engineers:

  - Lack of math and science skills in the population of high school graduates.

  - Mobilizing the Research Community. Professional engineers are needed to develop, design and implement new, low-carbon technologies that produce electricity. There is a need for active and invigorated research programs in power engineering and related areas. To appropriately engage students, faculty need to be engaged through the development of research programs, including programs that are multidisciplinary in their approach and thinking.

  - Encouraging Students to Work in the Electric Power Sector. In addition to stimulating research, it is important to foster mechanisms for pulling both research and students into the electric power sector.

  - Costs of Education. The cost of education in the United States is daunting and can be a barrier to entry.

TASK FORCE RECOMMENDATIONS

The workforce challenges identified by the Task Force are significant and addressing them will take a concerted and sustained effort by many stakeholders. To advance that process, the Task Force developed a set of five primary recommendations for federal policy. While these recommendations are specifically focused on the development of direct future energy jobs associated with design, construction, and operation of assets in the energy sector, many of the insights could be applied to job training associated with deploying energy efficiency and manufacturing the materials and equipment needed to build and operate the future energy system.

Recommendation 1: Evaluate regional training needs and facilitate multi-stakeholder energy sector training programs across the country. In addition to the work currently underway at DOL and DOE to address the workforce gaps associated with projected retirements and the initiatives in the American Recovery and Reinvestment Act of 2009, Congress should appropriate funds through existing funding mechanisms that allow DOL and DOE to work with existing state or regional energy workforce consortia or establish new state or regional energy workforce consortia, as appropriate. These consortia should be tasked with evaluating near- and long-term needs for a skilled workforce, including:

- Workforce gaps at existing facilities over the next ten years associated with workforce retirements;

- Workforce gaps over the next twenty years associated with

  - constructing new low-carbon generating assets and retrofitting existing generating assets,

  - constructing the additional electric infrastructure needed to effectively use new and

  - retrofitted generating assets (e.g. transmission lines, CO_2 pipelines, local distribution systems),

  - operating and maintaining new and retrofitted generating assets and the accompanying infrastructure, and

  - deploying energy efficiency in the retrofitting of the nation's building stock and in Smart Grid technologies.

As a part of this evaluation, DOL, DOE, and each state or regional energy workforce consortium should highlight any policy uncertainties that are currently delaying or have the potential to delay the deployment of new generating assets, retrofit technologies, and infrastructure that are essential to the transition to a low carbon economy.

In regions of the country where workforce gaps have been identified, Congress should provide

Many of these insights could be applied to job training associated with deploying energy efficiency and manufacturing the materials and equipment needed to build and operate the future energy system.

financial resources and coordination assistance to support the development of targeted local or regional training programs for energy sector workers. DOL should award funding on a competitive basis through the Green Jobs Act, or other appropriate federal funding mechanisms, to training programs that meet the following criteria:

- Involve a wide range of stakeholders from industry, education, labor, professional organizations, and workforce development agencies or non-profit community groups that focus on workforce development in all stages of program development.

- Coordinate the use of resources at a regional level while recruiting and matching skills to jobs at a local level. For example,

  - Recruit prospective employees from local populations using local groups, such as community-based organizations or workforce investment boards, that have a deep knowledge of the community and a capacity to prepare prospective employees through education and training; and

  - Integrate regional employer needs into the curriculum development process.

- Build upon existing programs and infrastructure, including training and education programs run by community-based organizations, technical or community colleges, and stakeholder companies, and joint labor-management apprenticeship programs.

- Include curricula and course content that utilize industry skill standards and lead to industry-recognized credentials.

- Use best practices (identified under Recommendation 3) in developing training and education programs.

- Encourage development of accredited, credential-focused programs that put individuals on a long-term career track. Programs should allow transferability of credits throughout the industry and should develop skills that translate from one program to the next. Programs should issue 'stackable' credentials that allow individuals to develop the building blocks of a career in the energy sector.

- Develop innovative strategies to engage populations that have traditionally been underrepresented in the energy sector workforce, in particular communities of color, and to address the needs of lower-skilled, low-income workers to enable them to access career pathways into the energy sector workforce.

- Include a strategy for sustaining the program over the long term.

Implementation Steps

As part of implementing the above recommendations, any funding provided for energy sector workforce training through new or existing mechanisms should:

- Be distributed through a peer-review process that involves representatives from industry, the education community, and labor groups in developing solicitations and awarding grants, and

- Prioritize grant recipients that provide training towards industry-recognized credentials, and who also develop training materials and programs that can be replicated and readily shared (as described in Recommendation 3).

In addition, the criteria described as part of this set of recommendations should be used as a template for awarding funds through any new grant programs and through existing or reauthorized mechanisms, such as the Workforce Investment Act (WIA). Specifically, the Task Force supports a number of modifications to WIA that have been proposed by the AFL-CIO, the American Association of Community Colleges, and the Association for Career and Technical Education and urges Congress to consider the following recommendations in the context of WIA reauthorization:

- Modify performance indicators to recognize skill attainment and allow for longer term training:

  - WIA performance indicators strongly influence the approach taken by local boards and One Stop Career Centers in providing the longer-term training that many workers, especially low-skilled workers, need. The current performance indicators, which put a heavy emphasis on job placement, retention and earnings, are "work first" measures. They should be modified to count interim and progressive indicators of skill attainment, including measures of "work readiness" for very low-skilled workers. Similarly, one of the "core indicators" in the WIA performance standards is "earnings received in unsubsidized employment." The value of fringe benefits should be added to the calculation of earnings for this performance standard.

- Expand representation on workforce boards:

  - While it is important to keep Workforce Investment Boards (WIBs) to a manageable size to ensure effectiveness, strengthening connections between education, labor, business, and workforce groups requires a true partnership. Congress should continue efforts to bring together key stakeholders in states, regions and localities to plan effective workforce and economic development activities. At the state level, workforce boards should include representation from business, labor, education/training, and

In regions of the country where workforce gaps have been identified, Congress should provide financial resources and coordination assistance to support the development of targeted local or regional training programs for energy sector workers.

government. In addition, at the local level, the workforce investment board should have a *minimum* level of representation from the following four sectors: business (15 percent), labor (15 percent), community (15 percent), and education (15 percent).

- Promote regional workforce investment areas:

  - Regional industry partnerships allow businesses, labor unions, educators, and the public workforce system to establish or expand industry or sector partnerships that help workers train for and advance in high-demand and emerging industries. Sector strategies would identify skilled workforce needs within the targeted industry or sector, and develop training and educational strategies using career pathways to ensure that employers have the skilled workers to meet their needs. This coordinated approach would help more individuals access the education and training they need for successful careers. One implementation option would be to use the Secretary of Labor's challenge grants to provide incentives for WIBs to expand their geographic scope to encompass areas that correspond to regional labor markets, industry clusters, and commuting patterns.

- Strengthen Data sharing and common measures:

  - Failure to coordinate federal reporting requirements across programs can create burdens for WIA and other workforce-related initiatives. Sharing data across programs would make it easier for programs and providers to collect accountability information, and foster an environment of collaboration and efficiency in the workforce and education systems. Further efforts are needed to align data systems at the state and local levels and to reduce barriers to data sharing. Interpretations of the Family Educational Rights and Privacy Act of 1976 (FERPA) combined with prohibitions on sharing unemployment insurance wage data across states have contributed to these barriers. By contrast, Section 113(b)(2)(F) of the Carl D. Perkins Act gives programs flexibility to use "substantially similar information gathered for other state and federal programs" in measuring performance, but this language is rarely utilized. Similar language and more practical mechanisms to promote data sharing should be included in WIA.

- The use of common measures would facilitate collaboration and coordination across workforce programs and facilitate a greater alignment of their goals. Improvements that increase the efficiency of workforce programs such as WIA, Perkins, Trade Adjustment Assistance, and adult education and family literacy can benefit participants to the extent they lead to better coordination and targeting of services. The point is not to measure everything that is important to each program, but to concentrate on outcomes that are important for all workforce development programs and to leave room for adding new measures as required.

- Incentive grants should be structured to reward coordination. Under the current incentive grant program, states may apply for funds under Title I and Title II of the WIA. To be eligible for funds, states must exceed relevant performance targets. Grant recipients are encouraged to use these funds for activities that (a) promote coordination and collaboration among the agencies administering WIA Title I and Title II programs, (b) are innovative, and (c) are targeted to improve performance. The Task Force recommends continuing this grant program. Additionally, we believe Congress should consider providing further incentives to states that take concrete steps toward sharing data and using common measures.

- Utilize youth services to create strong skills training pathways for students:

  - Young people in the workforce development system have needs that are different from those of most adults and dislocated workers. To address them requires a separate funding stream targeted to providing activities and assessing accountability for the youth population. At the same time, better coordination is needed, especially across WIA and other federally funded programs. Both the education and workforce systems have a unique role to play in serving the youth population.

  - The current allocation of funds across in-school and out-of-school youth programs allows local WIBs to make spending decisions based on the unique needs of their communities and should be maintained. Programs that reach students during the summer and after the school day can play a critical role in reducing drop-out rates and preparing young people to become productive members of the community. Changes to the current allocation, on the other hand, could mean a cut in services to many at-risk students and reduced opportunities for coordination and reinforcement across different programs. Additionally, options to integrate WIB services, such as One Stop Career Centers, with campus career centers should also be explored.

Recommendation 2: Improve energy sector workforce data collection and performance measurement metrics and tools. Improve the collection, management, and availability of workforce data for the energy sector to facilitate the measurement of progress in addressing identified needs and to enable more effective identification of future needs. Workforce data should include people entering energy sector-specific training programs and/or the energy workforce; these data should be measured against the workforce targets identified by the state energy workforce consortia in Recommendation 1.

BLS should be provided with the resources to accurately assess workforce needs in the energy industry and to incorporate industry input on growth and staffing patterns. This will allow for improved forecasts of future demand for different types of skills, including emerging skills associated with the build out of low-carbon energy infrastructure.

Implementation Steps

Federal agencies should work to improve existing systems for collecting, managing, and disseminating workforce data relevant to the energy sector. This would facilitate efforts to measure progress toward addressing identified workforce needs while also enabling more effective identification of future needs. In addition, it is essential to understand how proposed legislative initiatives, such as an energy or climate bill, will impact the energy-sector workforce. To implement this recommendation, the Task Force believes that Congress should:

- Direct the Department of Education (ED) to lead a multi-stakeholder task force to standardize CIP (Classification of Instructional Program) codes for the energy industry. Such a task force should:
    - Organize CIP codes by industry / career cluster
    - Develop a process for tracking the number of individuals who complete programs at private institutions, apprenticeship programs, and non-credit bearing programs to more accurately reflect the potential supply of talent

- Direct the BLS to track data on the demand for skilled workers in the energy sector. BLS should:

  - Modify energy-related Standard Occupational Classification System (SOC) codes to more accurately reflect groupings of skill requirements. These changes should be made prior to the next scheduled SOC codes revision in 2018. BLS should seek industry input on any revisions.

  - Reconcile differences in codes to allow for comprehensive data collection and to more accurately reflect future demand for different types of skills, including emerging skills associated with the build out of low-carbon energy infrastructure.

  - Develop a mechanism to facilitate industry input to BLS forecasts with the aim of incorporating industry projections of growth and staffing patterns and accurately assessing future energy workforce needs. State forecasts should incorporate input from state energy workforce consortia to improve assessments of future needs at the state level.

  - Build capability for developing workforce scenarios and projections as a tool for analyzing the impacts of proposed legislation, including especially legislation concerning energy, climate change, and related issues.

- Direct DOE, ED, and DOL to create a national longitudinal data collection system, in coordination with the repository described in Recommendation 3, to track student progress from secondary through post-secondary education and employment.

Recommendation 3: Identify training standards and best practices for energy sector jobs. DOL in consultation with industry, labor, and education stakeholders, including ED and DOE, should develop a repository of best practices for electric power sector job training that is widely accessible, transparently managed, and maintained by a public entity. This repository should include existing skill standards and registered apprenticeship programs for electric power sector jobs. Examples of best practices can be found at energy career academies at the secondary level, and at pre-apprenticeship, certificate, associate degree, apprenticeship, and community-based training programs at the post-secondary level.

The purpose of the repository should be threefold: (1) it should be a resource for employers to evaluate training programs and potential employees, (2) it should be a resource for individuals to evaluate training options as they move through a career, and (3) it should be a resource for educators as they develop courses and curricula.

As a part of this initiative, this group should identify skill areas where best practices or training standards do not exist or should be expanded, and work to fill such gaps.

Implementation Steps

To promote the development and use of industry-recognized credentials, Congress should direct DOL to work with DOE and ED to organize and monitor the development of such credentials and appropriate funds as necessary to support these efforts. Specifically, the agencies should:

As a part of this initiative, this group should identify skill areas where best practices or training standards do not exist or should be expanded, and work to fill such gaps.

- Identify existing industry-recognized credentials,
- Support (through grants or other funding mechanisms) the development of new industry-recognized credentials where there are gaps, and
- Create a central repository for these credentials.

Since the publication of the Task Force report, the Center for Energy Workforce Development (an Advisor to the Task Force), has been working with stakeholders to develop industry-recognized credentials for the energy sector. Based on this work, the Task Force offers the following recommendations concerning the development of an industry-recognized credential repository:

- All energy credentials should follow the definitions used by the American National Standards Institute (ANSI).[3]
    - Credentials for utility technicians and non-nuclear plant operators should be issued consistent with the American National Standard, ASTM 2659 – Standard Practice for Certificate Programs.
    - Credentials for lineworkers *may* be issued through a certificate or certification that would meet the accreditation requirements of the American National Standards Institute.
- DOE should use the repository of validated industry-recognized credentials for grant making, curriculum development, and training programs, such as certified apprenticeship programs.
- Credentials or certifications for positions outside the nuclear industry should be developed by a neutral third-party and should include input from subject matter experts to identify relevant competencies, design skill assessments, if needed, and develop effective curricula. Credentials for positions in the nuclear industry comply with Nuclear Regulatory Commission regulations, but are typically developed based on consensus standards and detailed job task analyses.
- Industry credentials should be embedded in a pathway that is linked to a job or series of jobs or to specialized skill(s) associated with a job. Some jobs may require multiple credentials. In those cases, required credentials should build on one another and should not necessitate investments of money and time in duplicative education or training programs.

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[3] The nuclear industry works through INPO and that National Academy of Nuclear Training and adheres to Nuclear Regulatory Commission regulations for training plant operators and technicians.

Credentialing in the Energy Sector

Credentialing is becoming more important in many industries, including the energy industry. It is increasingly being tied to education programs, both secondary and post-secondary, to grants from the Department of Labor and other sources, Perkins funding, and employment. As the need for credentialing grows, so does the misunderstanding of what the term “credentialing” means. For example, the term “certification” is often understood as having the same meaning as credentialing, even when it really means simply getting a certificate or occupational license. This confusion is common not only among the general public, but in the education and business worlds, and even within credentialing organizations.

The American National Standards Institute (ANSI) accredits developers of standards as well as certification bodies and certificate issuers; it is thus a leading authority on the development and differentiation of standards for various credentials. ANSI defines different forms of credentials as follows:

Certificates

- Generally associated with education and training – educational process
- Indicates that the content has been learned in an educational event
- May or may not have an assessment
- Course/training is generally designed by an instructor or group of experts
- Generally good for life – no renewal period
- Owned by the individual – “cannot be taken away” by the educational institution

Certification

- Focus is on the “job”, “occupation” or “practice”
- Determining the competencies to successfully practice – job/practice analysis
- Results from an assessment process (examination or demonstration of skills)
- Is a third party, independent judgment regarding whether competencies have been achieved
- Time limited – must re-certify within a designated period of time
- Certification does not belong to the individual – can be taken away

Licensure

- Generally associated with “State” Licensure but there are federal licenses, e.g. FAA, EPA (although they call their examinations “certification”)
- State Licensure
    - Legal right to practice in a job/occupation/profession
    - Scope of practice is determined by the state legislature
    - Sometimes based on a national “Certification”
    - Time limited – must re-license within a designated period of time
    - Professions are licensed to “protect the public”
    - Examinations are often created by “Federations”

Degrees and diplomas are also considered credentials, but both industry and the public have a common understanding of these credentials.

The workforce training pipeline for the energy sector includes a variety of programs and institutions. These should be reviewed to determine if there are barriers to funding for training and education, especially for skilled craft workers in the electric sector.

Recommendation 4: Provide funding support to individuals seeking energy sector related training and education. The Task Force recommends that financial support, targeted to those most in need, be provided to individuals pursuing energy-related technical and professional training (or retraining) and to students pursuing post-secondary degrees in engineering and other energy-related technical fields. Using existing funding mechanisms as appropriate, Congress should consider:

- Developing a program that provides financial support through educational scholarships or grants to individuals,
- Providing worker training tax credits to energy companies who support apprenticeships and internships, and
- Clarifying and streamlining support for apprenticeships, technical certifications, and on-the-job training for veterans by combining the benefits of the Post-9/11 GI Bill and the Montgomery GI Bill into one program.

Implementation Steps

Financial support for energy-sector training and education can be provided by modifying and expanding existing programs. Specifically, the Task Force recommends the following actions:

- Reconcile differences between the Montgomery GI Bill and the Post 9/11 GI Bill. These are the two programs currently being used to provide GI benefits. While the Post-9/11 GI Bill expanded and streamlined benefits for service members who wished to pursue higher education, it did not do the same for service members who wished to pursue apprenticeship and on-the-job training opportunities. This is significant because of the disparity in benefits between the Montgomery and Post 9/11 Bills and the enrollment process for the Montgomery GI Bill. With respect to benefits, the Post-9/11 GI Bill includes college tuition payments for the service member or a family member, as well as a housing allowance and a book allowance. By contrast, the Montgomery GI Bill provides support in the form of a monthly stipend, which is set annually and is the same throughout the country. Given this disparity, it is unlikely that a service member would choose to apply for support under the Montgomery GI Bill instead of the Post-9/11 GI Bill unless he or she were interested in apprenticeship or job training, which is not covered by the Post-9/11 GI Bill. Differences in the enrollment process for the two programs further disadvantage funding support for apprenticeships and on-the-job training. To use the Montgomery GI program, service members must enroll at the time of enlistment and agree to pay $100 per month for the first year of enlistment. This means that service members interested in pursuing apprenticeship or job training not only have access to less generous benefits, they must know their plans, decide what type of program to pursue, and begin paying fees much earlier. This creates a significant disparity in favor of veterans choosing college rather than apprenticeship and job training.

Senator Daniel Akaka, Chairman of the Senate Committee on Veterans' Affairs, recently introduced a bill (S. 3447) with two cosponsors, Senators Mark Begich and Debbie Stabenow, that begins to address many of these disparities. Most significantly, the proposed legislation would provide benefits through the Post-9/11 GI Bill to veterans pursuing on-the-job training and apprenticeship programs. While S. 3447 is still working its way through Congress, the Task Force supports Senator Akaka's efforts.

- Increase the tax deduction for employees who receive education assistance from their employer. Section 127 of the tax code allows taxpayers to exclude up to $5,250 per year in employer-provided educational assistance when figuring their gross income for tax purposes. The amount of this deduction has not changed since 1986. The Task Force recommends that it be increased to at least $10,000 for employees seeking their first undergraduate degree or for employees seeking less than a bachelor's degree. In addition, current IRS policy limits the tax deduction to employees who intend to remain in their current jobs. The Task Force recommends that the deduction be expanded to include employees who wish to pursue further education to qualify for a new job.

- Review existing educational grant programs for opportunities to promote energy-sector workforce training. As discussed in the Task Force report, the workforce training pipeline for the energy sector includes a variety of programs and institutions. These should be reviewed to determine if there are barriers to funding for training and education, especially for skilled craft workers in the electric sector. For example:

  - Pell Grants are an important source of support for training. In 2007–2008, this program provided grants ranging from $400 to $4,310 to more than 5.5 million; overall funding provided through Pell Grants totaled nearly $15 billion. Current rules limit Pell Grants for career and technical training to those programs that "prepare students for gainful employment in a recognized occupation." The problem is that those terms are not currently well-defined. The Task Force supports efforts by the Department of Education to clarify this requirement so that more support can be provided for career and technical training.

  - Grants authorized by the Carl D. Perkins Career and Technical Education Act represent the largest source of federal funding for secondary schools and the primary source of federal funding for education programs that provide individuals with the knowledge and skills to compete in the

Engage the next generation of energy scientists and engineers by following through on and expanding commitments to U.S.-based research and development efforts.

workforce. The Task Force supports efforts to increase funding for Perkins Grants. At a minimum, funding for Perkins Grants should be indexed to inflation.

Recommendation 5: Aggressively focus on revitalizing the math and science skills, education, and career counseling of individuals who have the interest and skills to work in the energy sector. Enhance preparatory skill training for technically rigorous careers by:

- Improving and expanding contextual education in science, technology, engineering, math, and environmental literacy for students in all grades from kindergarten through 12th grade,
- Expanding the use of instructional technology at all levels to provide access to computerized and on-line educational resources and information about science, technology, engineering and math,

- Integrating lessons in applied math and science into the foundational curriculum for all students, with a particular emphasis on early (K–4) education,
- Expanding educational opportunities that include reading, writing, and applied math and science for adults who wish to enter the energy workforce,
- Providing opportunities for teachers and instructors to learn about the energy sector and greenhouse gas emissions through off-site programs organized by local colleges, universities, and industry partners,
- Ensuring that students are at or above grade level in math,
- Developing energy-related, contextual modules for math and science teacher training carried out at colleges and universities, including historically black colleges and universities or other minority institutions,
- Developing robust programs to train and retrain our teachers in math and science,
- Engaging retired professionals and helping them transition from a career in energy to the education system, and
- Creating seamless pathways from K–12 through post-secondary education.

Engage the next generation of energy scientists and engineers by following through on and expanding commitments to U.S.-based research and development efforts. This should include:

- Finishing the ten-year doubling[4] of the budgets for the National Science Foundation (NSF), DOE Office of Science, and the National Institutes of Standards and Technology (NIST), with a special emphasis on (1) encouraging high-risk, high-return research; (2) supporting researchers at the beginning of their careers; and (3) research focused on low-carbon energy sources and technologies.

- Investing in sustained research programs and academic tracks that support advanced energy systems.

Increase awareness of opportunities in the energy sector by:

- Creating targeted career awareness material that addresses specific audiences including youth, adults, minority populations, veterans, government officials, and educators,
- Developing messaging materials that (1) highlight how critically important technically educated individuals are for addressing our long-term energy and environmental challenges and (2) address a lack of public awareness about the security, pay, and job satisfaction associated with careers in the electric sector,
- Supporting community-based organizations that help to match potential job seekers and employers,
- Informing career counselors and educators about job opportunities and experiences in the energy sector, and
- Communicating that skilled trades are a vital component of the American economy and should be viewed as desirable options for individuals seeking career training.

Implementation Steps

A number of initiatives to improve education and increase awareness of energy-sector jobs are currently underway at the Department of Labor and at other federal agencies. To augment these ongoing efforts, Congress should reauthorize the America COMPETES Act, which was originally passed in response to the *Rising Above the Gathering Storm* report. The America COMPETES Act provides for investments in STEM education; sets budgets for science research agencies (such as NIST, NSF, and the DOE Office of Science) on a path to doubling; and continues support for the new Advanced Research projects Agency for Energy (ARPA-E).[5]

[4] White House Office of Management and Budget. "A New Era of Responsibility: Renewing America's Promise (FY2010 Budget). February 26, 2009. Available at www.whitehouse.gov/omb/assets/fy2010_new_era/a_new_era_of_responsibility2.pdf

[5] ARPA-E was created to pursue advances in high-risk, high-reward energy technologies.

Notes

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