

The Future of the Grid

Evolving to Meet America's Needs

Hosted By



Central Region Workshop

Pre-read Materials

February 4, 2014



Prepared for the U.S. Department of Energy by New West Technologies under contract No. DE-EE0000002 in conjunction with Gridwise Alliance under contract No. 3806-P026.



TABLE OF CONTENTS

WELCOME LETTER.....	6
INTRODUCTION.....	7
WORKSHOP DISCUSSION SCENARIOS.....	9
Scenario 1: The Challenge of Balancing Supply and Demand as Grid Complexity Grows	10
Scenario 2: The Challenge of Involving Customers and Their Electrical Loads in Grid Operations.....	12
Scenario 3: The Challenge of Higher Local Reliability through Multi-customer Microgrids.....	14
Scenario 4: The Challenge of Transitioning Central Generation to Clean Energy Sources—Large-Scale Wind, Solar, and Gas.....	15
Scenario 5: The Challenge of Planning for Empowered Customers.....	16
CENTRAL REGION CONDITIONS	19
Large Wind Integraton	21
Midcontinent ISO.....	23
Southwest Power Pool.....	25
Electric Reliability Council of Texas	26
California ISO	26
Planned Transmission Projects in Central United States	27
State Renewable Energy and Energy Efficiency Standards	28
Retail Electric Providers	29
Aggregators	30
LANDSCAPE OF THE INDUSTRY	32
Customer Load and Demand Projections	32



Very Large Scale Weather Events..... 33

Central and Distributed Power Generation & Energy Storage..... 35

 Nuclear35

 Coal.....36

 Natural Gas.....36

 Wind.....37

 Solar38

 Other Renewables.....40

 Energy Storage41

Policy Trends 43

 Renewable Portfolio Standards.....43

 Energy Efficiency Resource Standards46

 Demand Response Policies.....47

 Environmental Regulations and Standards49

 Federal Smart Grid Legislation50

Condition and Reach of Existing Infrastructure..... 51

Forthcoming Technologies 52

 High Voltage Direct Current Transmission52

 Microgrids52

 “Smart Cities”53

 Demand Side Components.....54

 Electric Vehicles.....56

 Smart Grid Projects/Technologies.....58

WORKS CITED 60

APPENDIX A - KEY FINDINGS FROM NERC 2012 LONG-TERM RELIABILITY ASSESSMENT 71

LIST OF FIGURES

Figure 1. States Included in the Central Workshop 19

Figure 2. ISO RTO Operating Regions [1] 20

Figure 3. State Utility Profiles 20

Figure 4. State Generation Based on MWh 21

Figure 5. a) Capacity Factors of Wind Power, b) Electricity Prices (related to supply vs. demand) 22

Figure 6. Installed Wind Turbine Capacity Up To 2012 [3] 22

Figure 7. Clean Line Energy Partners Proposed DC Transmission Lines [24] 28

Figure 8. Renewable Portfolio Standards Policy Details [26] 28

Figure 9. Energy Efficiency Resource Standard Policy Details [26] 29

Figure 10. Weather-Related Power Outages 34



Figure 11. Wind Power Deployment _____	38
Figure 12. U.S. Deployment and Cost for Solar PV Modules [49] _____	39
Figure 13. Distributed Solar on Wal-Mart Store [56] _____	39
Figure 14. Redox Power Systems Residential Fuel Cell Design [59] _____	41
Figure 15. Power Ratings and Discharge Times for Energy Storage Technologies _____	42
Figure 16. Rooftop Thermal Energy Storage [60] _____	43
Figure 17. States with Renewable Portfolio Standards [26] _____	44
Figure 18. Total Renewable Generation Required for Combined State Renewable Portfolio Standards and Projected Total Achieved, 2012-2040 [45] _____	46
Figure 19. States with Energy Efficiency Resource Standards [26] _____	47
Figure 20. U.S. Peak Demand Forecast by Scenario [63] _____	48
Figure 21. Smart City of the Future Value Architecture [82] _____	54
Figure 22. Demographics of PEV drivers [90] _____	57
Figure 23. Residential Demand in a High PEV Penetration Neighborhood [90] _____	58

LIST OF TABLES

Table 1. MISO Allocation Categories [10] _____	24
Table 2. Comparison of 2035 Electricity Projections [31] _____	32
Table 3. Comparison of 2035 Electricity End-Use Prices [31] _____	33
Table 4. Source and Size of Power Outages _____	34
Table 5. U.S. Adoption of Incentives and Other Policies That Promote Renewable Energy [26] _____	45
Table 6. Timeline for Carbon Pollution Standards [66] _____	49
Table 7. Emissions Standards for New EGUs [72] _____	50
Table 8. Intelligent Energy Measures for Commercial Sector [88] _____	56



WELCOME LETTER

Dear Workshop Participant:

Thank you for participating in the U.S. Department of Energy's (DOE's) Office of Electricity Delivery and Energy Reliability (OE) and Gridwise Alliance's (GWA) Central Region "The Future of the Grid" Workshop. Your input is critical because this workshop will help to develop the Central Region's stakeholder-driven vision for our future electrical grid but also will serve as the Region's contribution to the broader national vision for the future of the grid.

The electrical grid – as an enabling technology – provides the foundation for America's economic success. Our digital economy, our national security, and our daily lives are highly dependent on reliable, safe, and affordable electricity. The electricity industry is now in the midst of a major transformation that likely will continue for the next two decades. By having thoughtful, provocative conversations now, we can help ensure that electrical grid reliability and security are maintained now and well into the future, innovation encouraged, and economic growth fostered during this transition period.

Our goals for this Workshop are broad and ambitious. We will debate and discuss many challenges facing the electric industry. To help maximize utilize our time during the Workshop we have compiled this document to describe the scenarios we will be discussing, as well as to provide a summary of relevant industry information. Please take a few minutes to familiarize yourself with these materials, so we can have a richer, more informative, and productive Workshop.

We look forward to hearing your view on these important issues and anticipate that the Workshop's outcomes will provide significant direction and insights on the stakeholder's vision for the future of the grid.

Sincerely,

A handwritten signature in black ink, appearing to read "Eric Lightner".

Eric Lightner

Director, Smart Grid Task Force

U.S. Department of Energy

A handwritten signature in black ink, appearing to read "Becky Harrison".

Becky Harrison

CEO

The GridWise Alliance



INTRODUCTION

It is an exciting time in the electricity sector, as major changes transform the way we generate, deliver and use electricity. There are changes being driven by both new policies and new technologies. Furthermore, the dynamics of the consumer's role in these changes and the need to maintain a secure electrical grid governed by prudent regulations are combining to create a healthy debate that will no doubt take years to play out.

Regardless of our ultimate generation resource mix or production method (i.e., large scale central plants versus smaller scale distributed plants), our electrical grid and its operation will always play a critical role in our future electricity infrastructure. In fact, the operation of our grid will become more and more complex even as it becomes more critical to the security of our nation's economy in a manner analogous to the ways the cellular network has enabled the world of smart phones and mobile applications.

There are a number of issues facing the electricity industry today. We recognize that while these are issues faced by the industry in general, they have regional and local differences that are important to understand as we explore how best to modify policies and invest in technology development.

We recognize that without thoughtful debate and planning these changes could result in unintended consequences that hinder productivity and innovation. With this in mind, the GridWise Alliance (GWA) and the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (DOE OE) are partnering to facilitate a series of four regional workshops in late 2013 and 2014 to develop a stakeholder-driven vision of the future grid, including its capabilities and operational requirements. This series of workshops will culminate with an executive summit in mid-2014 in Washington, D.C. Our goal is to identify and characterize technological capabilities, financial models, and the modifications to policies and regulations needed to support safe and reliable electricity delivery.

These regional workshops will bring together thought leaders from all stakeholder groups (utilities, regulators, state government officials, renewable energy providers, suppliers, and industry innovators) to develop the vision for the grid and grid operators in 2030. Each workshop is targeted to have approximately 60 participants to engage in a series of small, facilitated breakout discussions with their peers. The ideas from each workshop will be summarized in a brief document and provided to the participants.

The result of these efforts will inform national efforts at DOE, help guide an R&D agenda, and serve as a tool to educate all stakeholders including state and Federal policy makers and regulators. These efforts will help us develop a much better understanding of the issues that we must address to achieve the goal of an affordable, reliable, and resilient electrical system that will ensure both a vibrant national economy and protection of our national security.

WORKSHOP DISCUSSION SCENARIOS

WORKSHOP DISCUSSION SCENARIOS

Accurately characterizing what the operation of the U.S. electricity delivery system will be in 2030 is difficult if not impossible. However, in order to be prepared for the future, it is important to begin thinking and planning for it now. Individuals involved in the current operation of the grid are in the best position to understand the complexity and nuances of grid operations and how changing external factors could impact operations. There are a large number of factors that will determine how the grid must function from policy drivers, to customer expectations, to technological developments. To narrow and focus our discussion, the workshop will focus on five main scenarios. The scenarios were selected with the hope of stimulating your thinking to drive innovative ideas and possibilities while simultaneously grounding them in reality and what situations are likely today. The five scenarios are not exhaustive of all possible situations but rather have been developed to try to cover a wide range of the grid landscape while also accounting for possible regional uniqueness. During the workshop participants will be asked to engage in discussions on one of these scenarios.



SCENARIO 1: THE CHALLENGE OF BALANCING SUPPLY AND DEMAND AS GRID COMPLEXITY GROWS

Description

Today, transmission grid operators must ensure there is enough power generation both in terms of wattage and volt-amperes reactive (VARs) to service the load on their systems. To do so, the transmission grid operator continually adjusts the central generation. In some systems, they can also use a limited amount of demand response as another resource to keep the supply and load in balance. Today, for residential demand response, the operator typically sends a signal to switches on customers' air conditioners, water heaters, and/or pool pumps to cut off the load completely or cycle off for a given percentage of time in an hour. This simple but effective mechanism allows the operator to ride through a few critical peaks as an alternative to providing additional generation. In the future, with increasing penetration of distributed energy resources, the distribution grid will have to be able manage two-way power flows and must be able to balance more complex supply and demand options.

The devices on the “customer side” of the meter may include distributed generation; distributed storage; home energy management systems that can control various loads; appliances that can react to pricing signals; and options for charging or discharging electric vehicles. At the transmission level, utility scale generation will also be changing to include increasing penetration of non-dispatchable generation such as large-scale wind farms and other renewables as well as utility scale storage capabilities, all of which will require enhancements to existing balancing capabilities. This increasing dependence on devices at the “edge of the grid” will also require greater interaction between the distribution and transmission grid and grid operators to optimize the balancing of supply and demand functions.

Questions to Ponder

- What do these new balancing requirements mean to the role of the grid, Independent System operator (ISO), and the grid operator?
- What new demands will the increase in distributed energy resources create for the distribution grid and its operators?
- What new demands will increasing distributed and large non-dispatchable resources create for the transmission grid and its operators?
- What is the distribution grid operator's role versus the transmission grid operator's role versus the Independent System operator's role?
- Will ISO transmission operators need more visibility into the distribution grid?
- What new capabilities will be needed to perform this role? Are new tools/models/information needed?
- How will a shifting fuel mix (reduced coal, increased natural gas, increased renewables, etc.) drive or alter grid operational needs?
- How do current policies and regulation have to change to enable these new capabilities and roles?
- What are the financial implications of this transition? How do we ensure grid operators and owners are financially viable?

- What are the implications for the future workforce – both inside the utilities and third party providers?
- How must market structures evolve to handle new players?
- Do ISO/RTO's increase the complexity?
- What is the role of each party in this scenario?



SCENARIO 2: THE CHALLENGE OF INVOLVING CUSTOMERS AND THEIR ELECTRICAL LOADS IN GRID OPERATIONS

Description

Significant innovation is already occurring across all customer classes with smart devices now commonplace in many residences and businesses around the country. It's relatively safe to assume that by 2030 every device connected to the grid could be capable of communicating to the grid operator and receiving a control signal. Many of these will be purchased by consumers from various retail suppliers with the expectation that they will "plug and play" with grid operations. The challenge is to define an architecture and design that can optimize the loads and their responses in ways that maximize efficiency and minimize costs.

Currently customers are beginning to pay more attention to their unique requirements (such as high reliability, clean energy, and/or least cost), and this focus tends to highlight those requirements that are not easily met by the current grid design and operation. Superstorm Sandy and other natural disasters have, for example, focused attention on electric power interruptions that occur for many customers, resulting in threats to human health and safety in certain instances. Local generation tends to be the solution customers choose, but typically without consideration for their impact on grid operation when scaled from hundreds to tens of thousands of distributed scale sources.

Similarly, the push to reduce power plant emissions has resulted in a significant increase in local clean generation (such as roof top solar photovoltaic systems), electrified transportation, and ultimately storage. By 2030, it is likely that local generation and the interaction with major and critical loads will drive operational strategies that are substantially different than current ones. The challenge will be to operate the grid with this diversity at the edge of the grid, incorporating complex economics with complex physical integration. Ancillary services will increasingly be met by controlling devices at the edge of the grid, thus creating challenges of synchronizing the operation of potentially millions of these devices.

Customers will be much more in the driver's seat in this future system with more options for how they react to the price of energy and services. Australia is already experiencing falling overall electricity demand at the same time the country is seeing higher peak demand. As the price of energy increases, customers are likely to make decisions that could drive this imbalance even higher.

Transactive energy is a term coined more than a decade ago to represent this complex interaction between the physics and economics at the edge of the grid. Grid operators in the Pacific Northwest in particular are developing this concept and experimenting with applying it in practice. It represents the type of concept that will be not only important but essential in the electrical grid of 2030.

Questions to Ponder

- What impact will increasing consumer participation mean to the operation of the grid? What new capabilities are needed?
- What will end customers who generate their own electricity (prosumers) expect from the grid and the grid operator?

- How will the consumer role change from what it is today?
- How does this change the role of the grid operator?
- What new role does the distribution grid operator need to play versus the transmission grid operator versus the Independent System Operator?
- What new capabilities will be needed to perform this new role?
- How must current policies and regulation change to enable this new capability and role?
- What are the financial implications of this transition?
- How will increasing energy prices impact the transition to distributed generation and storage?
- What are the risks of having the wrong pricing strategy?
- What are the implications for the future workforce – both inside the utilities and among third party providers?
- What data sharing challenges can be foreseen?



SCENARIO 3: THE CHALLENGE OF HIGHER LOCAL RELIABILITY THROUGH MULTI-CUSTOMER MICROGRIDS

Description

Customers are becoming increasingly aware that the traditional “grid” electricity they’ve taken for granted is, in many cases, not meeting their needs. Whether customers want cleaner, more reliable, and better quality electricity or just “smarter” options, they are beginning to drive a new market for “non-grid” electricity technologies. These new customer-centric technologies are being developed and deployed at staggering rates and often without enough consideration for the impacts they might have on grid operations.

The design and operation of “local grids” – or as they are commonly called *microgrids* – is still evolving with dozens of “beta” versions being built around the country. These new systems can be under the control of a single customer or serve multiple customers, and they will typically utilize the utility grid infrastructure as part of the local microgrid that can be “islanded” as desired. These systems will become more and more sophisticated in the near future resulting in mature markets by 2020 and beyond. Additional information on microgrids is provided later in this report.

David Crane, CEO of NRG Inc., is one of the industry’s most vocal advocates for the rapid move to distributed electricity generation resources and the disruptive impact they will have on the traditional grid. NRG is currently testing several Stirling engine-based combined heating and power (CHP) devices for residential application. They plan to have units commercially available for sale in late 2014.

Whether it’s Stirling engines, rooftop solar photovoltaic modules, fuel cells, batteries, or something else, it is clear that microgrids will evolve to be a dominate force in the operation of the grid by 2030 and beyond. The challenge for grid operators will be to create the appropriate interfaces with these systems to allow optimal operation of the grid, the microgrid(s), and both together.

Questions to Ponder

- What are the implications of this new balancing requirement to the role of the grid and the grid operator?
- What exactly is the distribution operator’s role versus the transmission operator’s role?
- What new capabilities will be needed to perform these roles?
- What will the “owners” of this microgrid expect?
- What will the customers served by the microgrid expect?
- How will the increase in microgrids impact transmission planning?
- How must current policies and regulation change to enable this new capability and role?
- What are the financial implications of this transition?
- What are the implications for the future workforce – both inside the utilities and among third party providers?
- How will planning occur for these microgrids? How will it impact the grid operator role?
- How will increased microgrids impact infrastructure investments?
- Will new rate structures be needed?



SCENARIO 4: THE CHALLENGE OF TRANSITIONING CENTRAL GENERATION TO CLEAN ENERGY SOURCES—LARGE-SCALE WIND, SOLAR, AND GAS

Description

Across the U.S. and the globe we are seeing a transition of central generation from traditional fuel sources to cleaner fuel sources. This transition is being driven by policies, regulations, economics, and public sentiment. Various incentives and increasing market demand have driven down the price for wind and solar while new policies and regulations are driving up the price of coal, oil, and nuclear. Technological advances have resulted in cheap natural gas here in the U.S. Together, these conditions are driving a transition in the U.S. large-scale generation mix. This transition is also introducing new challenges and opportunities, bringing new participants into the market, and introducing new operating characteristics for the generation fleet.

This changing large-scale generation mix also brings increasing variability that the grid must accommodate and manage. This variability is resulting in having excess power at times as well as competing priorities for when the various generators should or must operate. In the Pacific Northwest, the combination of hydroelectric and wind generation has introduced the need to balance these competing priorities. To leverage fully these available resources, the grid operators must consider new ways to manage the load side of the energy value chain equation. At the same time, customers are taking more control of their energy usage. Many are lowering their overall demand for electricity through energy efficiency and changing behaviors, or by installing rooftop solar installations, buying “smart appliances,” and signing up for new third party services that can help them better manage their electricity usage.

These dynamics are changing the role of the grid and the grid operator going forward. They are also challenging traditional planning processes. In an industry where assets traditionally have a 30 year or better life span, these changes could result in overbuilding some asset capacity and underbuilding others.

Questions to Ponder

- Will these shifts to different generation fuels result in an increased regional approach to siting and leveraging future generation, and if so, what are the implications to the grid?
- What capability will be required of the grid to fully leverage non-dispatchable large generation sources such as wind?
- How does this change the role of the distribution grid and transmission grid operators?
- What role does the distribution grid operator need to play versus the transmission grid operator versus the Independent System operator?
- How must current policies and regulation change to enable this new capability and role?
- What are the financial implications of this transition?
- What are the implications for the future workforce – both inside the utilities and among third party providers?
- What are the new tools/models/information needed to handle this transition?



SCENARIO 5: THE CHALLENGE OF PLANNING FOR EMPOWERED CUSTOMERS

Description

In the past, for the majority of residential and small commercial electric customers there has been little or no choice in how they met their electric power needs. The electric utility industry has been a commodity business where much like the days when Henry Ford made his famous statement “People can have the Model T in any color – so long as it’s black”, electric customers were at the mercy of their power company. The industry mindset can even be seen in the fact that it has referred to them as “rate payers” not “customers”. In the future, grid owners and operators must change this mindset and gain a better understanding of customers’ needs, desires and ultimately their choices.

Technological innovations, new market structures and changing customer expectations are changing this long held view of end users of electricity. Customers are now becoming empowered. Smart meters, distributed small scale generation options, smart appliances, home energy management systems, electric vehicles, and battery storage are some of the technology advances that are driving a paradigm shift with regards to electric customer choice. And customers are much more informed about what is possible – social media is expanding their “neighborhood” to allow them to compare experiences and options with others across the country and across the globe.

Policies are also playing a part in this evolution. Net metering rules that allow customers to get full retail credit for any power they produce from renewable sources and retail deregulations where new energy service providers can offer innovative rates are examples.

Prices are also having a significant impact on the choices customers make. As electricity prices rise and distributed generation cost decline, customers are looking at alternatives and options. It is now economically viable for customers in some areas to use rooftop solar to offset the energy they purchase from their provider. Energy efficiency is seen as a good investment by increasing numbers. Education is also starting to result in behavior changes that lower demand.

Looking out at 2030, it is not hard to imagine that electric customers will have a profound impact on the energy value chain and how it should be built and operated. As we look at the role of the future electric grid and the grid operator, consider the following questions.

Questions to Ponder

- How could this new dynamic of increasing customer expectations and choices impact the distribution grid?
- How could this new dynamic impact the transmission grid?
- How should grid operators plan for this new dynamic of customer empowerment and their associated increasing expectations?
- Will customer owned battery storage be the killer application that directly competes against grid services?
- What are the financial implications for funding grid investments and on-going operations?
- How will market structures need to change?

- How should we plan for those customers that cannot or choose not to generate their own electricity to insure their cost for electricity stays reasonable?
- Does this impact the relationship between transmission and distribution?
- What impacts and expectations will retail service providers, who own the customers in deregulated retail markets, have on the grid and the grid operator?
- What new capabilities will grid operators and the grid need in order to meet these new expectations?
- What new tools/models/information will grid operators need?
- How do current policies and regulation have to change to enable this new capability and role?
- What are the implications for the future workforce – both inside the utilities and third party providers?
- How will market structures need to evolve to handle new players?



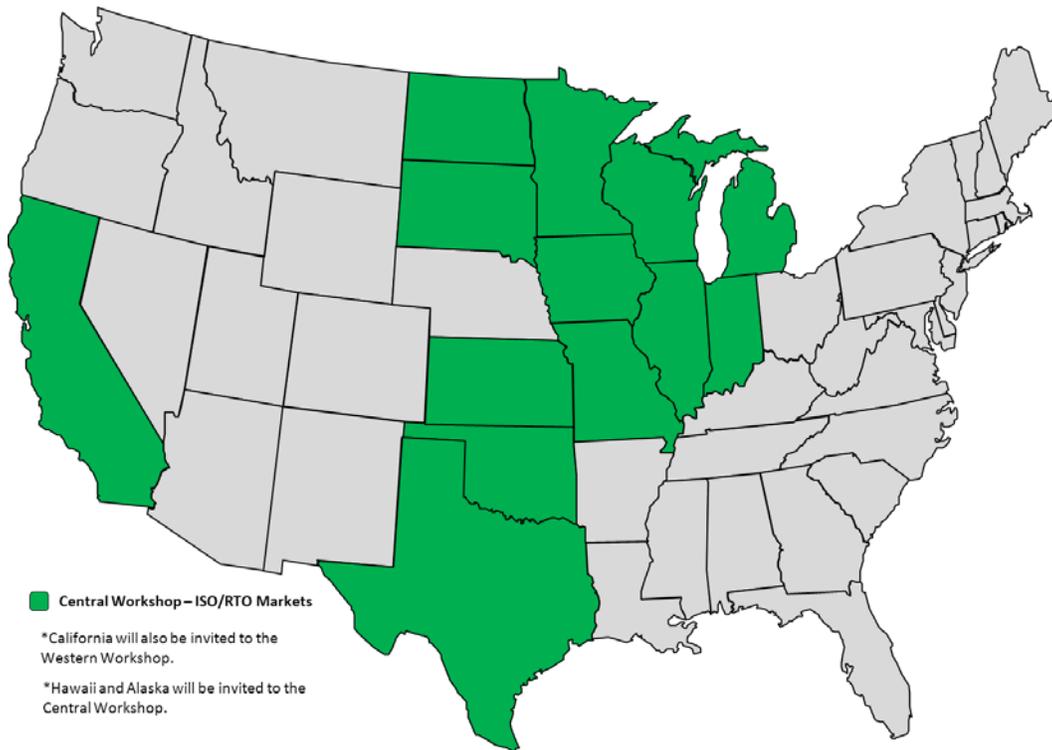
CENTRAL REGION CONDITIONS



CENTRAL REGION CONDITIONS

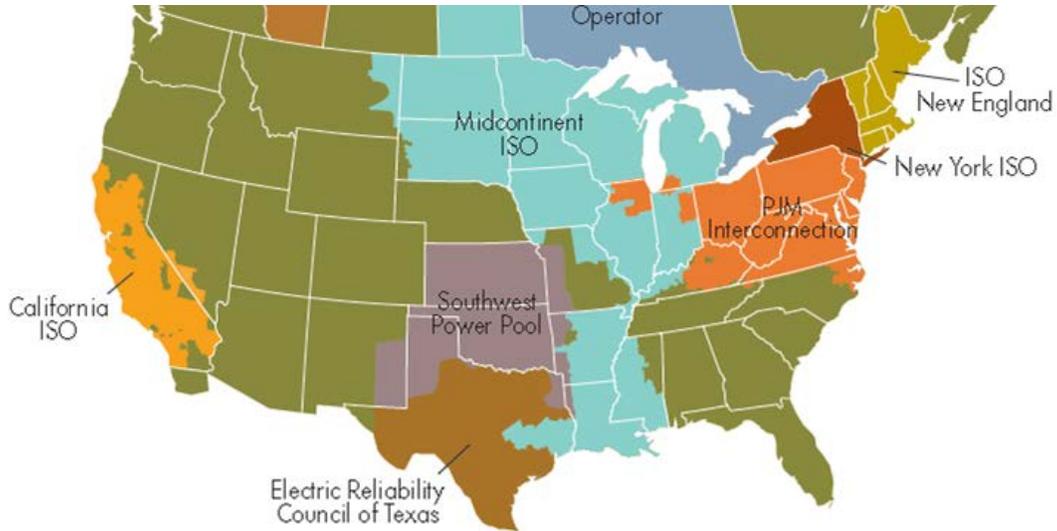
This Workshop is focused on the future of the grid in the central part of the U.S. specifically including Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT) and California ISO. California is also included in this Workshop due to its use of an ISO to regulate its wholesale market and the nature of the utility-customer relationship. The green shaded states in Figure 1 were included in the Central Workshop.

Figure 1. States Included in the Central Workshop



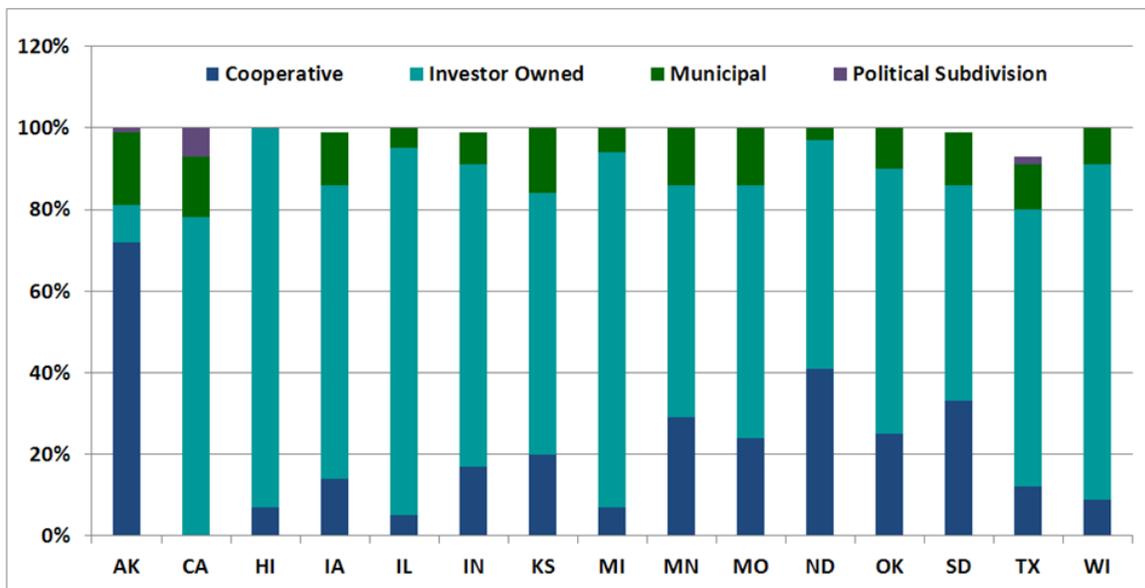
The Independent System Operators (ISO) prevalent in this region and the states they operate in are shown in Figure 2. MISO operates in nine of this region’s states specifically North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Illinois, Indiana, and parts of Missouri. SPP operates in four of the states in this region which are Kansas, Oklahoma, and parts of Texas and Missouri. ERCOT operates in Texas and California ISO operates in California.

Figure 2. ISO RTO Operating Regions [1]



The utility profiles of each state were investigated and the results of that research are shown in Figure 3 for each state included the region. Investor-owned utilities (IOUs) are common in most states in this region followed by cooperatives and municipals. There are a few states that differ from the norm. For example in Hawaii, IOUs account for 93 percent of the states' utility profile. North Dakota is more evenly split with 41 percent being cooperative and 56 percent being IOUs. South Dakota similarly has a significant amount of cooperatives at 33 percent [2].

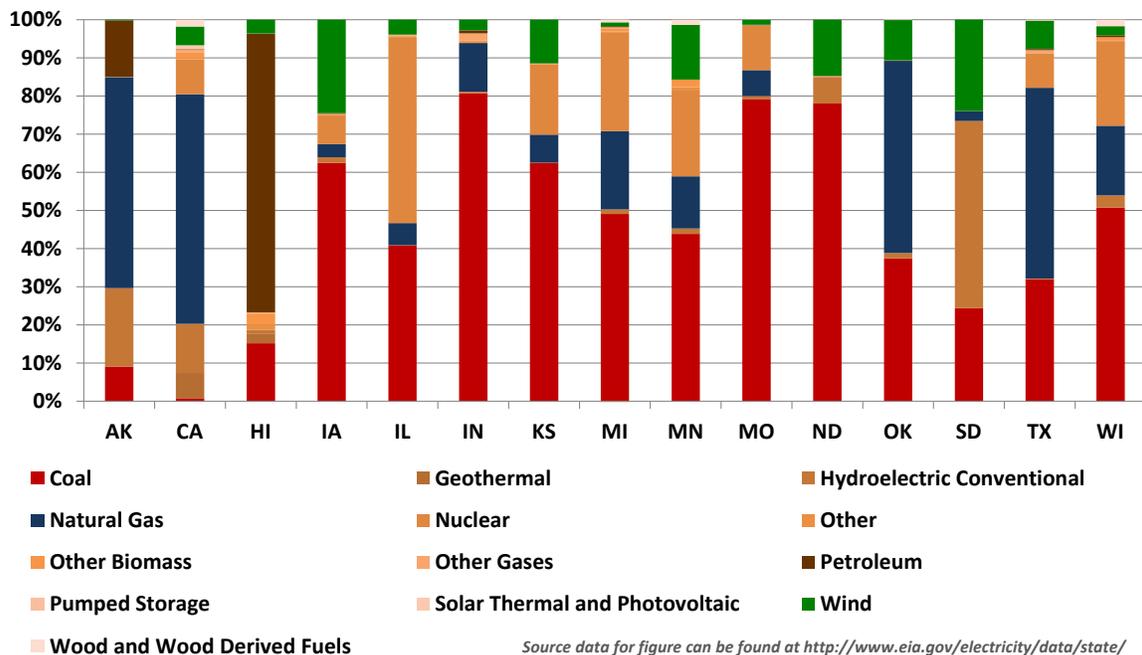
Figure 3. State Utility Profiles





The generation mix of each state was investigated and the results of that research are shown in Figure 4 for each state included the region. Coal, shown in red, is the dominant fuel in this region with the exception of Hawaii, California, and Alaska. Coal is used for more than half of the generation (based on MWh) in Iowa, Indiana, Kansas, Missouri, North Dakota, and Wisconsin. Hawaii relies heavily on petroleum shown in brown. Alaska, California, Oklahoma, and Texas rely on natural gas (shown in blue) for 50 to 60 percent of their generation [2]. Wind, a variable generation source shown in green, makes up more than 20 percent of the generation in South Dakota and Iowa. On a MWh basis only 7 percent of Texas' generation comes from wind, however it is the largest producer of wind in the U.S. with 12,214 MW of capacity in the state [2] [3]. American Wind Energy Association (AWEA) ranks states based on installed wind capacity and four the top five states are in the Central region; California with 5,544 MW (2nd), Iowa with 5,133 MW (3rd) and Illinois with 3,568 MW (4th). Oklahoma is ranked 6th with 3,134 MW of installed wind capacity [4].

Figure 4. State Generation Based on MWh



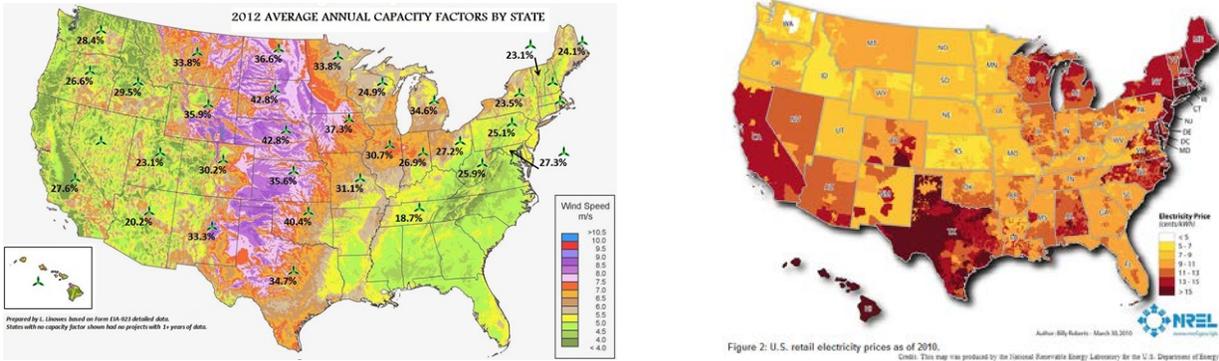
Source data for figure can be found at <http://www.eia.gov/electricity/data/state/>

LARGE WIND INTEGRATION

Because so many states are top producers of wind we draw attention here to the integration challenges. The high wind resource and high capacity factor wind areas are predominately in the Great Plains and Texas, while much of the demand and higher energy prices are along the coastlines and Texas. Capacity factors in the Great Plains wind plants are about 7 to 9 percent higher than onshore wind resources near the high-load urban centers along the East coast. Offshore plants have capacity factors on par with

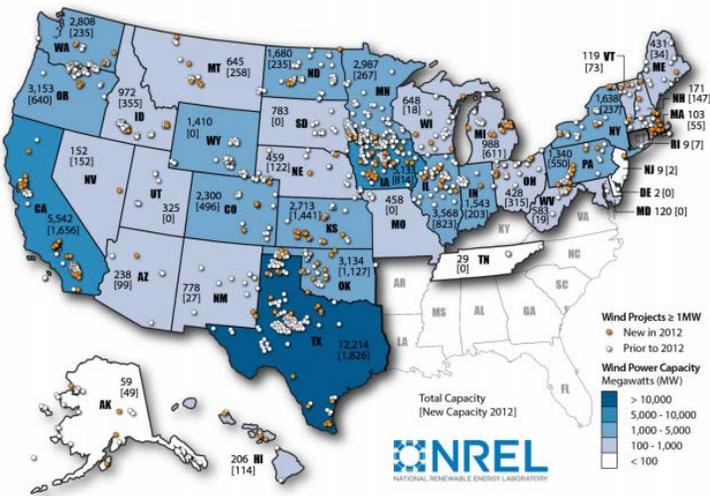
Great Plains resources but the cost of energy is higher because capital costs are higher. The correlation between wind energy resource/capacity and the demand vs. supply can be seen in Figure 5 [5] [6].

Figure 5. a) Capacity Factors of Wind Power, b) Electricity Prices (related to supply vs. demand)



Fulfilling the wind energy potential in many of the states participating in the Workshop requires addressing high voltage transmission constraints. With higher penetrations of variable, renewable generation sources, there are barriers to integration such as the impact that a decrease in synchronous generators could have on a power system like the Eastern Interconnection. With the Central region having the benefit of a much higher wind energy resource and a large portion of the wind turbine installations in recent years (Figure 6), there is a high potential for grid impacts to be compounded from this variable generation source.

Figure 6. Installed Wind Turbine Capacity Up To 2012 [3]



Note: Numbers within states represent cumulative installed wind capacity and, in brackets, annual additions in 2012.



The Southwest Power Pool (SPP) saw a record-breaking instantaneous wind generation penetration level of 30.2 percent in December of 2012 [5]. In order for the U.S. electric system to effectively integrate wind penetration at these levels knowledge of advanced system operations and flexible energy sources will be necessary. The Eastern Wind Integration and Transmission Study (EWITS) set out to examine the operational impact of 20 to 30 percent wind energy penetration on the Eastern Interconnection of the United States. Renewable generation sources like wind can inject significant amounts of variability and uncertainty on the system. One conclusion from this study determined that with large balancing areas and fully developed regional markets, the cost of integration for all scenarios is about \$5/MWh (about \$0.005/kWh) of wind electricity used by customers. By increasing the size of balancing areas in the central region, the impact of variable generation is greatly decreased and higher penetrations of wind energy become feasible [7].

Without low demand or insufficient transmission, the high wind generation capacity in this region can result in a curtailment of wind power. In 2009, ERCOT curtailed 3872 GWh of wind (17.1 percent of the potential wind generation) and the 735.5 MW Horse Hollow project had a capacity factor of just 20 percent [3]. Later that year, NextEra Energy built a private 229-mile transmission line built to move power from the Horse Hollow project into the uncongested South zone [3]. As a result, Horse Hollow’s capacity factor rose to 29 percent in 2010 [3]. In 2012 ERCOT’s wind curtailment was down to 1,038 GWh (3.7 percent of the potential wind generation) [3]. This improvement displays one possible mitigation measure to ease the integration of wind energy. In order for the lower cost wind energy of the Midwest to reach the high cost locations of the coast, a transmission expansion is necessary. The benefit of long distance and high capacity transmission lines have spurred the proposal of new lines in the central region to carry wind power from the high resource areas of the central U.S. to the high demand, lower resource areas of the Eastern interconnection [7]. In the next section we will summarize what the ISOs in this region are doing with regards to transmission.

MIDCONTINENT ISO

MISO manages over 176,000 MW of market generation capacity in 15 states and one Canadian province [8]. MISO is “addressing significant challenges from a changing resource mix, compliance with environmental regulations and a paradigm shift in system planning from utilities using transmission as a way to serve their load from their own generation, to transmission being used to enable efficient use of all resources in the region” [9]. To provide the least-cost delivered energy for all customers while facing these challenges, MISO has developed a plan with six strategic elements;

- Facilitate integrated infrastructure investment,
- Continue to deliver and communicate benefits identified in MISO’s Value Proposition,
- Sustain and grow the membership,
- Enhance products and performance,
- Achieve high performance through people, process and technology, and
- Expand MISO’s role as an independent public policy educator [9].

The business drivers for this plan are federal and state policy, resource development, transmission development, RTO performance, and stakeholder satisfaction [9].



The Federal Energy Regulatory Commission’s (FERC) Order 1000 which builds upon Order 890 mandates how public utility transmission providers plan for and allocate the costs of new projects on a regional and interregional basis. MISO’s uses the MVP cost allocation method which it applies to a class of projects labeled Multi-Value Projects (MVPs). The annual planning process results in MISO Transmission Expansion Plans or MTEP which identify MVPs. MISO matches the appropriate cost allocation method with each project’s driver and business case to ensure project costs are spread commensurate with benefits. Table 1 shows the various types of projects and the allocation of the costs based on the MISO MVP cost allocation approach [10].

Table 1. MISO Allocation Categories [10]

Allocation Category	Driver(s)	Allocation to Beneficiaries
Participant Funded ("Other")	Transmission Owner identified project that does not qualify for other cost allocation mechanisms.	Paid by requestor (local pricing zone)
Transmission Delivery Service Project	Transmission Service Request	Generally paid for by Transmission Customer; Transmission Owner can elect to roll-in into local pricing zone rates
Generation Interconnection Project	Interconnection Request	Primarily paid for by requestor; 345 kV and above 10% postage stamp to load
Baseline Reliability Project	NERC Reliability Criteria	Paid by local pricing zone
Market Efficiency Project	Reduce market congestion when benefits are 1.25 times in excess of cost	345 kV and above: 80% distributed to local resource zones (LRZs) commensurate with expected benefit, 20% postage stamp to load
Multi-Value Project	Address energy policy laws and/or provide widespread benefits across footprint	100% postage stamp to load

The MISO transmission planning process focuses on maximizing value while minimizing the energy, capacity and transmission costs. The MISO Transmission Expansion Plan for 2012, or MTEP12, recommended \$1.5 billion in new transmission investment across 242 projects. MTEP11 included the first MVP portfolio. This portfolio provides value in excess of cost under a variety of future policy and economic conditions. The portfolio of 17 projects will create benefits for consumers ranging from 1.8 to 3.0 times the portfolio’s costs [11]. The MVP portfolios deliver reliability, public policy and economic benefits across the system, specifically, the 2011 MVP has a projected benefit of \$15.6 billion to \$49.3 billion, the creation of between 28,400 and 74,000 total jobs and \$23 annual return on an \$11 per year investment for a proposed capital cost of \$5.2 billion [12].

MISO has also made efforts to improve wide-area visibility on the system through a Smart Grid Investment Grant (SGIG) of \$17.25 million from DOE to deploy synchrophasor technology throughout its service footprint. The program which began in March 2010 has more than 230 synchrophasors throughout MISO’s Midwest footprint assist grid operators in monitoring system conditions and



maintaining reliability. Expected benefits are from the project come from maximizing the existing transmission system for an annual benefit of \$3 to \$4 million and from a reduction in frequency of a large-scale outage from a 1 in 20-year event to a 1 in 30-year event. Reduced large-scale outages would provide an annual benefit of \$100 to \$160 million [13].

SOUTHWEST POWER POOL

Southwest Power Pool (SPP) administers reliability coordination, wholesale markets, and transmission services for over five million customers across nine states [14]. Their strategic plan released in 2010 covers the next five years but is based on SPP's vision of the industry over the next decade. To maintain or improve its value proposition in the face of a rapidly-changing environment, SPP has developed a plan with three interdependent foundational strategies;

- Build a robust transmission system,
- Develop efficient market processes, and
- Create member value [14].

Under each of the strategies SPP has five or six initiatives that provide primary support. An initiative under develop efficient market processes strategy is demand response integration [14].

SPP has a three-year study process known as the Integrated Transmission Planning (ITP) process that includes 20-Year, 10-Year and Near Term Assessments. The 20-Year Assessment identifies 300 kV and above transmission projects needed to provide a grid flexible enough to provide benefits to the region across multiple scenarios. The 10-Year Assessment looks at 100 kV facilities and above over a ten-year horizon to see if they meet system needs. The Near Term Assessment, performed annually, assesses system upgrades required in the near term planning horizon to address reliability needs. The ITP process promotes transmission investment that will meet reliability, economic, and public policy needs intended to create a cost-effective, flexible, and robust transmission network that will improve access to the region's diverse generating resources. In the 2014 ITP Near-Term Assessment Report SPP estimates \$697 million for upgrades of which \$487 million comes from new projects and \$210 million for upgrades recommended [15].

SPP uses a transmission upgrade cost allocation method called the "Highway/Byway" method that was proposed to FERC and approved in 2010. The Highway/Byway method moves away from allocating costs on a zonal basis to a broader SPP-wide basis based on the voltage level of the specific facility [16]. The three allocation categories are;

- "Electric Highways" (high voltage transmission 300 kV and above)— 100% of the costs will be allocated to electric utilities' load across SPP's entire system based on their historic use of the region's transmission system;
- "Electric Byways" (lower voltage transmission projects above 100 kV and below 300 kV)—1/3 of the costs will be allocated across the entire SPP region and 2/3 will be allocated to the utilities in whose zone the project is located; and
- "Electric Byways" (100 kV and below)—100% of the costs will be allocated to the utilities in whose zone the project is located [16].



ELECTRIC RELIABILITY COUNCIL OF TEXAS

“ERCOT manages the flow of electric power to approximately 23 million Texas customers — representing 85 percent of the state’s electric load and 75 percent of the Texas land area” [17]. To ensure their high level of service to this region over the next five years, ERCOT developed a plan that rests on four main strategic “pillars” defined as

- Operational Reliability
- Flexible Market Design
- Data Transparency and Access
- Committee Strategic Alignment [17].

Under each of the pillars ERCOT will pursue key strategic initiatives that will help ERCOT remain focused on its core mission of transmission network reliability in operations and planning and the operation of open access and efficient electricity markets [17]. This strategic plan is a uniquely Texan approach to key trends facing ERCOT:

- Resource adequacy,
- Trends in fuel prices and installed resource costs,
- Single fuel dependency,
- Gas / electric market coordination issues,
- Increased need for flexible resources,
- Regulatory impacts,
- “Downstream” distribution technology change,
- “Upstream” transmission and generation technology change,
- Impact of water on resource adequacy,
- Continuing growth of renewables penetration,
- New and uncertain resource technologies and cyber security [17].

In ERCOT’s planning process it has a five year transmission plan which describes the projects planned to address existing and potential constraints that could create reliability concerns or increase power costs for consumers in the next five years. ERCOT also has a long-term system assessment that is updated every two years and provides an evaluation of system needs over the next 10 to 20 years [18]. Based on these planning processes, ERCOT expects Texas transmission providers to complete improvement projects totaling \$8.9 billion by the end of 2017 including the Competitive Renewable Energy Zone (CREZ) projects. CREZ projects are the construction of nearly 2,400 miles of new transmission circuits designed to deliver up to 18,500 MW of wind generation on the ERCOT System [19].

CALIFORNIA ISO

The California ISO manages about 80 percent of California’s electricity flow and a portion of Nevada which equates to 30 million customers, 60 MW of capacity and nearly 760 power plants [20]. California projects that by 2015 nearly 25 percent of its load will be served by renewable resources, compared to just 17 percent in 2010 [21]. To response to this and other changes over the next three years, California ISO has developed a plan with three broad strategic efforts;



- Lead the transition to renewable energy,
- Reliably manage the grid during the industry transformation and
- Expand regional collaboration to unlock mutual benefits [21].

Under each of these efforts California ISO will pursue five to seven initiatives that will benefit the consumers. For example, an initiative under reliably manage the grid during the industry transformation is to work cooperatively to streamline generation interconnections on both the distribution and transmission systems [21]. This strategic plan will allow California ISO to continue to efficiently manage a highly reliable electric grid, using markets to provide consumers with the best value from transmission and generation resources [21].

A core responsibility of the ISO is to plan and approve additions and upgrades to transmission infrastructure to provide a well-functioning wholesale power market through reliable, safe and efficient electric transmission service. To fulfill this responsibility California ISO has annual transmission planning process whereby it identifies upgrades needed to successfully meet California’s policy goals and examines conventional grid reliability requirements and projects that can bring economic benefits to consumers. Most recently, the state’s 33 percent RPS goal has become the principal driver with California ISO identifying transmission needed to support meeting the 33 percent RPS goals over a diverse range of renewable generation portfolio scenarios. The 2012-2013 California Independent System Operator Corporation transmission plan identified 36 transmission projects to maintain transmission system reliability with an estimated cost of approximately \$1.35 billion as needed [22].

As part of the Western Electricity Coordinating Council’s the California ISO is one of nine members participating in the Western Interconnection Synchrophasor Program. DOE provided a Smart Grid Investment Grant (SGIG) of \$53.9 million towards the project to speed data transfers essential for reliability, from once every four seconds to 800 times in four seconds. As of 2009, California ISO had installed 57 synchrophasors which it planned to grow to 200 over time [23].

PLANNED TRANSMISSION PROJECTS IN CENTRAL UNITED STATES

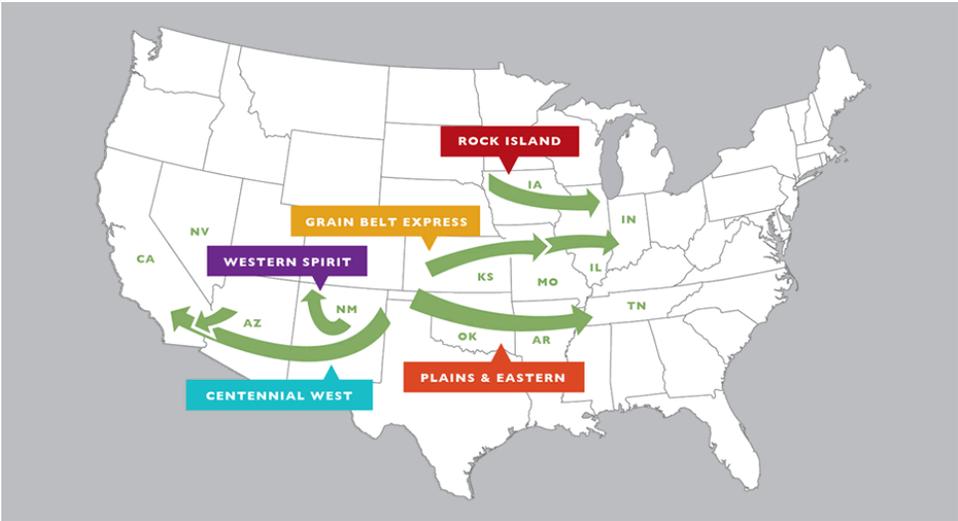
Larger balancing areas will play a large role in the future operation of the power system and will help to decrease the impact of variable, asynchronous generators. Many large capacity and long distance transmission lines have been proposed to expand the infrastructure within the central United States to move power to within an RTO or ISO more efficiently.

As mentioned above The MTEP12 recommended \$1.5 billion in new transmission investment across 242 projects. Together with previously approved transmission projects, the total number of MISO-approved transmission projects included in MTEP12 is 598, representing 6,463 circuit miles of new or upgraded transmission lines and about \$10.8 billion in potential transmission investment through 2022 [3].

ERCOT’s Competitive Renewable Energy Zone (CREZ) program completed at the end of 2013 includes almost 3,600 circuit miles of new transmission lines expected to accommodate a total of 18,500 MW of wind power capacity [3]. Texas’ current wind power capacity is 12,214 MW.

Clean Line Energy is developing a series of direct current (DC) transmission lines to deliver thousands of megawatts of renewable power from the windiest areas of the U.S. to cities with a strong demand for clean, reliable energy. DC results in overall higher efficiency and reliability than an equivalently-sized alternating current (AC) system moving the same amount of power [24]. One of Clean Line Energy’s projects, a 750-mile DC transmission line known as the Grain Belt Express Clean Line, has been granted a siting permit to construct the 370-mile Kansas portion [25]. As envisioned this line will deliver up to 3,500 megawatts of low-cost wind power from western Kansas to Missouri, Illinois, and Indiana. This and other transmission projects by this company in this region are shown in Figure 7.

Figure 7. Clean Line Energy Partners Proposed DC Transmission Lines [24]



STATE RENEWABLE ENERGY AND ENERGY EFFICIENCY STANDARDS

In this region, ten states have renewable portfolio standards; California, Hawaii, Illinois, Iowa, Kansas, Michigan, Minnesota, Missouri, Texas, and Wisconsin. Four states in this region have renewable portfolio goals; Indiana, North Dakota, Oklahoma, and South Dakota. Alaska does not have a standard or goal. The standard or goal for each of the states is shown in Figure 8.

Figure 8. Renewable Portfolio Standards Policy Details [26]

<p>Alaska: No RPS.</p> <p>California: 33% by 2020.</p> <p>Hawaii: 40% by 2030.</p> <p>Illinois: 25% by 2025 - 2026.</p> <p>Indiana: Has a Renewable Portfolio Goal of 10% by 2025. Goal includes non-renewable alternative resources</p> <p>Iowa: 105 MW of renewable generating capacity .</p>	<p>Kansas: 20% by 2020.</p> <p>Michigan: 10% and 1,100 MW by 2015.</p> <p>Minnesota: 25% by 2025. Xcel has its own individual standard of 30% by 2020. Extra credit is provided for solar or customer-sited renewables.</p> <p>Missouri: 15% by 2021.</p> <p>North Dakota: Has a Renewable Portfolio Goal of 10% by 2015.</p>	<p>Oklahoma: Has a Renewable Portfolio Goal of 15% by 2015.</p> <p>South Dakota: Has a Renewable Portfolio Goal of 10% by 2015.</p> <p>Texas: 5,880 MW by 2015. Extra credit is provided for solar or customer-sited renewables.</p> <p>Wisconsin: Varies by utility, approximately 10% by 2015 statewide.</p>
---	--	--



Alaska, Kansas, North Dakota, Oklahoma and South Dakota do not have energy efficiency resource standards. Three states in this region have energy efficiency resource goals; Texas, Missouri, and Wisconsin. The remaining seven states have energy efficiency resource standards. The energy efficiency resource standard or goal for each of the states is shown in Figure 9.

Figure 9. Energy Efficiency Resource Standard Policy Details [26]

<p>Alaska: No EERS.</p> <p>California: Varies by utility.</p> <p>Hawaii: 4,300 GWh reduction in electricity use by 2030.</p> <p>Illinois: 2.0% reduction of 2008 electricity sales by 2015; 1.1% reduction of 2008 peak load demand by 2018; 8.6% cumulative natural gas savings by 2020.</p> <p>Indiana: 2.0% electricity sales reduction by 2019.</p> <p>Iowa: Varies by utility.</p>	<p>Kansas: No EERS.</p> <p>Michigan: 1.0% annual reduction of previous year retail electricity sales by 2012; 0.75% annual reduction of previous year retail natural gas sales by 2012.</p> <p>Minnesota: 1.5% reduction of previous 3-year average retail electric sales by 2010; 1.5% reduction of previous 3-year average retail natural gas sales by 2010.</p> <p>Missouri: 9.9% cumulative electricity savings by 2020; an additional 1.9% each year thereafter. 9% cumulative peak reduction by 2020; an additional 1% each year thereafter.</p>	<p>North Dakota: No EERS.</p> <p>Oklahoma: No EERS.</p> <p>South Dakota: No EERS.</p> <p>Texas: 25% reduction in annual growth in demand 2012; 30% reduction in annual growth in demand 2013.</p> <p>Wisconsin: 2011-2014: Net annual electric energy savings of 1,816,320,000 kWh; net annual natural gas savings of 73,040,000 therms.</p>
---	--	---

RETAIL ELECTRIC PROVIDERS

In 2002, the Texas retail electric market was deregulated, giving most Texas consumers the ability to purchase electrical services from the retail electric provider of their choosing. In Texas’ approach to deregulation, the power generation companies sell electricity into the deregulated power market, and deregulated retail electric providers (REPs) purchase power and resell it to consumers. However, the transmission and distribution (or wires) companies are still regulated and since consumers choose their REPs, the wires companies no longer own customers. There are some exceptions to deregulation, specifically, municipal utilities or power cooperatives could opt out.

In this market, REPs take care of all the customer service and billing and are the primary interface with consumers. According to the Public Utility Commission of Texas there are a total of 114 REPs currently doing business in Texas. Deregulation allows electricity rates to be set through competitive pricing by the market, not by the utility companies. Deregulation has had its challenges. The expectation is lower prices however the Texas Coalition for Affordable Power (TCAP) reported an increase of about 48% in Texas residential electricity prices from 1999 to 2012 [27]. While other factors, such as fuel costs, could have been at play, fourteen other deregulated states saw residential prices increase in the same time period [27].

By July 2008 about 44 percent of Texans had switched to electric service other than that offered by the old legacy providers [27]. JD Powers reported in late 2013 that customers were generally more satisfied with their retail electricity provider than customers who are still served by a regulated utility. The primary factor was cost [28]. The Public Utility Commission of Texas completed a study on the Scope of Competition and found that even though retail competition exists in other states, including New York, Michigan, Illinois and several New England states, few REPs competed for residential customers in those states and few residential customers switched providers [29].

AGGREGATORS

Aggregators are independent third parties (companies) that are typically authorized by the state to work with the local utilities and grid operators to reduce the state's electricity usage during periods of high electricity demand, high wholesale electricity prices, grid constraints or congestion and/or emergencies. In some instances aggregators have agreements with the bulk power system operators and in other instances they have agreements with the local distribution utilities. Each state that allows for these arrangements provides a set of rules and procedures that must be followed to protect both the grid and the consumer from harm. While interruptible loads are not a new concept in the industry, the role of the aggregator has evolved largely over the past ten years and in fact continues to evolve.

LANDSCAPE OF THE INDUSTRY



LANDSCAPE OF THE INDUSTRY

Almost everything written about the electric power industry these days refers to change: changing customer demands, changing policies, changing technologies, and even changing business models. Such a dynamic landscape is difficult to characterize and impossible to capture in this brief document. Nevertheless, we attempt in this section to provide key highlights that provide some indication of the direction, speed, and magnitude of the changes that will influence the nature of grid operations in 2030 and beyond. The information provided here is not new, but is based on the most important and readily referenced documents we could find.

In the North American Electric Reliability Corporation (NERC) *2012 Long-Term Reliability Assessment* published earlier this year [30], NERC identified broad issues that are impacting the industry and its ability to maintain the reliability of the bulk power system at mandated levels. These findings shown in Appendix A represent a comprehensive look at grid reliability and do not necessarily reflect specific regional or local issues. While they do address a ten year view of the industry, they do not necessarily reflect the organic innovation taking place both in the utility industry and among customers.

CUSTOMER LOAD AND DEMAND PROJECTIONS

Projections for future electricity needs are being estimated by several organizations. Table 2 shows projections for 2035 electricity sales ranging from 4,421 billion kWh to 5,316 billion kWh with residential sales increasing between 16 and 48 percent as compared to the 2011 baseline. Residential sales are the largest component of electricity sales in all but the Energy Ventures Analysis (EVA) projection. Not shown in this table is the transportation sector. Because of improvements in fuel economy standards, transportation sector energy use is expected to stay constant through 2040. However, electricity sold to the transportation sector is expected to triple to 19 billion kWh in 2040 with increasing sales of electric plug-in LDVs [31] [32]. While small compared to these other areas, electric vehicles might be important at the local distribution level and thus are discussed further in the Forthcoming Technologies section.

Table 2. Comparison of 2035 Electricity Projections [31]

	2035 Projections in billion kilowatt-hours (kWh) ¹					
	2011 (baseline)	EIA (AEO2013)	IHGSI	INFORUM	NREL	EVA
Electricity Sales	3,725	4,421	5,316	4,406	4,824	4,923
Residential	1,424	1,661	2,001	1,718	<i>Not reported</i>	2,116
Commercial/ Other Use	1,326	1,618	1,983	1,710	<i>Not reported</i>	2,292
Industrial	976	1,142	1,332	978	<i>Not reported</i>	515

¹ Projections were made by the Energy Information Administration (EIA), IHS Global Insight, Inc. (IHGSI), Interindustry Forecasting Project at the University of Maryland (INFORUM), National Renewable Energy Laboratory (NREL), and Energy Ventures Analysis (EVA).



Table 3 shows projections for 2035 electricity prices ranging from 10.1 to 11.9 cents per kWh with the highest prices occurring in the residential sector.

Table 3. Comparison of 2035 Electricity End-Use Prices [31]

	2035 Electricity Prices in 2011 cents per kWh ¹				
	2011 (baseline)	EIA (AEO 2013)	IHGSI	INFORUM	NREL
Average price	9.9	10.1	11.9	10.5	11.7
Residential	11.7	12.1	14.1	12.2	<i>Not reported</i>
Commercial	10.2	10.1	12.3	10.6	<i>Not reported</i>
Industrial	6.8	7.1	8.1	7.1	<i>Not reported</i>

EIA projects average electricity demand per household to decline by 6 percent by 2040 based on less consumption from lighting, PCs, laundry, and refrigeration and increased consumption from HVACs, TVs and other devices [31] [32]. For comparison, an American Council for an Energy-Efficient Economy (ACEEE) study on the long-term energy efficiency potential projects a 2 percent decrease in residential energy use by 2050 with savings coming from heating and lighting [33].

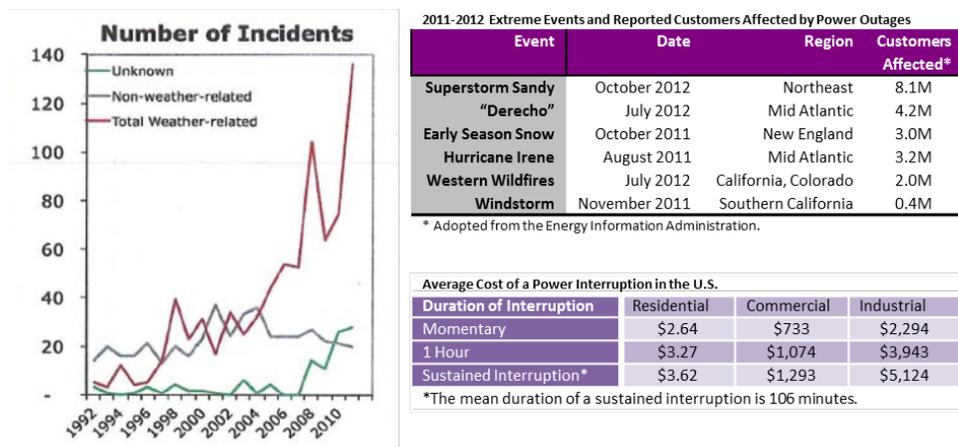
VERY LARGE SCALE WEATHER EVENTS

On October 29, 2012, Hurricane (“Superstorm”) Sandy made landfall in southern New Jersey. Sandy pummeled the most densely populated region of the U.S. with estimated damage totaling \$65 billion and left tens of millions of people without electricity for days or even weeks [34]. Recovery in the affected area continues more than a year later.

In the last two years there have been at least six very large scale events (VLSEs) in the U.S. including floods, windstorms, snowstorms, hurricanes, and prolonged droughts that trigger wildfires. These VLSEs are listed in Figure 10 in the top right table. Power delivery systems are vulnerable to these events and data on the left side of Figure 10 suggests that outages from weather-related events are on the rise.

These outages have real cost implications to utilities and consumers. Various studies have concluded that storm-related power outages cost the U.S. economy between \$20 billion and \$55 billion in a typical year. Depending on the outage duration the interruption could cost an industrial consumer over \$4,000 [35]. The true impact on customers is difficult to measure and includes not only inconvenience but often threats to safety and health.

Figure 10. Weather-Related Power Outages



Sources:
 Weather-Related Power Outages and Electric System Resiliency.
 The Gridwise Alliance. Lessons Learned from Superstorm Sandy and Other Extreme Events. June 2013.

Table 4 shows the variety of causes for outages including weather-related and other causes and the estimated total impact for each cause.

Table 4. Source and Size of Power Outages

	% of events	Mean size in MW	Mean size in customers
Weather Related Outages	Earthquake	0.8	375,900
	Tornado	2.8	115,439
	Hurricane/tropical storm	4.2	782,695
	Ice storm	5.0	343,448
	Lightning	11.3	70,944
	Wind/rain	14.8	185,199
	Other cold weather	5.5	150,255
Other causes of outages	Fire	5.2	111,244
	Intentional attack	1.6	24,572
	Supply shortage	5.3	138,957
	Other external cause	4.8	246,071
	Equipment failure	29.7	57,140
	Operator error	10.1	105,322
	Voltage reduction	7.7	212,900
Volunteer reduction	5.9	134,543	

Since Superstorm Sandy, much more attention is being given to reliability by local leaders, who are looking at a variety of options for local generation to address the most critical loads. In these cases cost becomes less important, and investments are being made in distributed power systems where standard economic arguments breakdown.



CENTRAL AND DISTRIBUTED POWER GENERATION & ENERGY STORAGE

Technological advancements and policies are moving the U.S. generation mix away from coal and towards cleaner technologies such as natural gas, wind, and solar. One executive action directs the Department of Interior to permit 10 gigawatts renewables projects (such as wind and solar) on public lands by 2020 [36]. This will impact where and how power is generated on the electrical grid. The variability of wind and solar generation presents more complex control and economic scenarios for grid operators. Energy storage systems are being added to reduce the impact of supply variability and peak demand on transmission and distribution. While providing value they are another component in the system that needs to be monitored, controlled, and optimized. Smaller scale distributed power generation is becoming more economical and widespread, especially when it provides additional features such as high reliability.

Nuclear

The level of nuclear capacity in the U.S. has remained relatively constant, accounting for an approximate 20 percent share of national power generation, since the last new reactor came online in Tennessee in 1996. Although five reactors went offline between 1997 and 1998, modifications to existing reactors have compensated for the loss in capacity. Nuclear plants are able to produce energy at rates much closer to their designed capacity than other forms of energy. This allows a relatively small number of plants (104 reactors located in 65 plants as of 2012) to make up a significant share of the US's actual power generation, generating the most after coal and natural gas in 2011 [37].

Looking ahead, as more reactors are taken offline and electricity demand increases, nuclear energy's share of generation capacity will inevitably decrease in the near term. The U.S. Energy Information Administration's reference case in the 2014 Annual Energy Outlook predicts a decrease in nuclear capacity from 102 GW in 2012 to 98 GW in 2020, despite 6.2 GW of new and updated capacity coming online during this period. Challenging economic conditions which are increasing the operations and maintenance costs of nuclear plants are cited as the reason for many predicted closures. However, EIA goes on to predict that after 2025, as additional reactors are built, nuclear capacity will return to its original overall capacity [38].

Due to the unique approval process for nuclear power plants, it can be many years between conception and full online status for a reactor. The extensive application, licensing, and regulatory processes and complex construction surrounding nuclear power plants, make it difficult to pinpoint individual completion dates. The Nuclear Regulatory Commission (NRC) has active applications for 28 new reactors as of 2012, and four new reactors (Vogtle Units 3 and 4 and Summer Units 2 and 3) are expected to come online between 2017 and 2019 [39]. All four have begun construction. The Vogtle reactors, the first to receive construction approval in 30 years, are expected to have a combined capacity of 2.2 GW [40]. The V.C. Summer units are also designed with a 2.2 GW capacity [41]. These are large capacity plants that serve base loads well but have less flexibility for variable demand.

Worldwide support for nuclear energy understandably dipped after the 2011 Fukushima nuclear disaster. The American Enterprise Institute conducted a public opinion study and while 57 percent of



Americans surveyed favored using nuclear energy, 62 percent would disapprove a nuclear power plant in their community [42]. Clearly Americans are divided over nuclear power. According to a March 2013 Gallup survey 37 percent saying they would like more emphasis on nuclear power, 32 percent saying they would like less emphasis, and 28 percent saying they would like the same emphasis [42].

Coal

According to the EIA, in 2012, coal was used for about 37 percent of the 4 trillion kilowatt hours of electricity generated in the U.S [43]. The National Energy Technology Laboratory (NETL) tracks the development of new coal plants and has found that actual capacity of completed plants has been significantly less than proposed capacity. NETL's 2002 report listed 11,455 MW of proposed capacity for the year 2005 but only 329 MW were actually constructed. In 2011 1,599 MW of new capacity was announced and 2,890 MW were canceled. Combined capacity of plants scheduled for retirement by 2020 is 24.7 GW or 7 percent of the total U.S. coal generation capacity [44].

There are several projections on coal's viability as a generation source over the intermediate and long-term, and they make differing predictions. NERC showed coal's contribution to be approximately 30 percent in 2012 and projects its share of the market will drop to under 27 percent by 2022 based on 16 GW of capacity retirement [30]. EIA's reference case shows coal-fired plants as the largest source of electricity generation in 2011 at 42 percent with its market share declining to 35 percent in 2040. Other EIA scenarios show coal-fired generation could be between 28 percent and 40 percent by 2040 [45]. EIA also projects that by 2040, 15 percent of the coal plants active in 2011 will be retired while only 3 percent of new generation capacity added will be from coal. This is due to Federal and state environmental regulations and uncertainty about future limits on GHG emissions [31] [32].

One example of where regulations are affecting coal generation is at the Tennessee Valley Authority (TVA). In 2010 the TVA entered into consent agreements with the U.S. Environmental Protection Agency, four states, and several environmental groups over the pollution from its 11 coal-fired power plants. TVA is in the process of retiring 30 percent of its coal fleet and evaluating the compliance cost for much of the rest [46]. Economic decisions based on environmental regulations, life of the plants, and presently inexpensive natural gas are contributing to the shifting capacity mix. Large power plants have high capital costs that are recuperated over the life of the plant, typically 20 or more years. Once coal-fired generation is replaced, it is unlikely that utilities will switch back. While newer generation technologies are cleaner, their capital and operational costs will be different, and utilities will need to address these issues in their business models.

Natural Gas

There has been a surge in production of natural gas in the U.S. due to the shale revolution bringing down prices for this fuel. Low natural gas prices have created more demand for natural gas from the power sector [47].



According to the EIA, in 2012, coal was used for about 30 percent of the U.S. electricity generated [43]. There are several projections on natural gas as an electricity generation source. The Joint Institute for Strategic Energy Analysis (JISEA) studied natural gas in the energy sector and in their “Baseline – Mid-EUR” case projected natural gas combined-cycle and natural gas combustion-turbine capacities nearly doubling from 2010 to 2050 [48]. NERC showed natural gas generation to be 38.5% in 2012 and projects the natural gas share of the market will increase to 39.7 percent by 2022 based on 32 GW of capacity additions, although conception projections show an additional 68 GW [30]. EIA shows natural gas generation increasing its market share from 24 percent in 2011 to 30 percent in 2040 with natural gas-fired plants accounting for 63 percent of capacity additions during that period. Inexpensive natural gas makes existing natural gas plants more competitive with coal and lower capital costs makes natural gas-fired plants a viable choice for new generation capacity [45].

Forecasts of the future price of natural gas vary significantly. To hedge against increasing natural gas prices many utilities lock in fuel prices from suppliers. Should natural gas prices increase in the future the utilities will typically pass those costs along to consumers with a potentially major impact on the cost of their electricity.

Wind

In the last five years, there has been a surge in wind power deployments across consumer, industrial, and commercial sectors in the U.S. In 2012 cumulative land-based wind deployment was 60 GW as compared to 12 GW five years earlier. In 2012, wind deployment accounted for 43 percent of new electrical generation capacity in the U.S., the most of any generation technology. Additionally, the combined potential of land-based and off-shore wind is about 140 quads (quadrillion BTUs), which is 10 times U.S. electricity consumption today [49].

The success of wind deployments can be attributed to a variety of factors. These include the increase in turbine size which lowers the cost; the larger production volumes also helps to lower costs; production tax credits; and the improved capacity factor of plants from sophisticated operators, which increase the time plants are operational and thus producing revenues [49].

Looking ahead, DOE estimates that as much as 20 percent of projected U.S. electricity demand could be met by wind power by 2030 given policy support and continued technological improvements [50]. Although wind represents at present only 3.5 percent of the total electricity market, it is growing rapidly and regionally where the resource is abundant. For this reason, wind power is poised to be disruptive to other power generation technologies. Integration studies such as *Western Wind and Solar Integration Study* and the *Eastern Renewable Generation Integration Study* are being completed to examine the impact large penetrations of variable generation sources will have on the electrical grid, and the development of planning and operations tools for flexibility and stability of the electrical grid [51] [52].

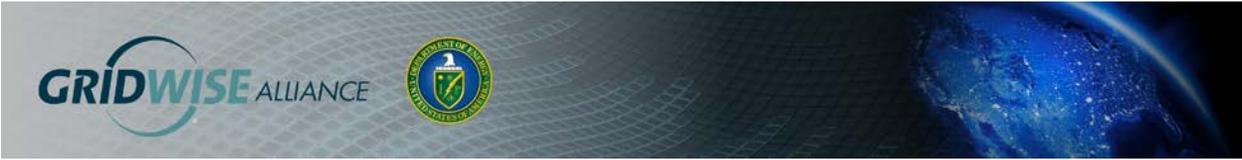
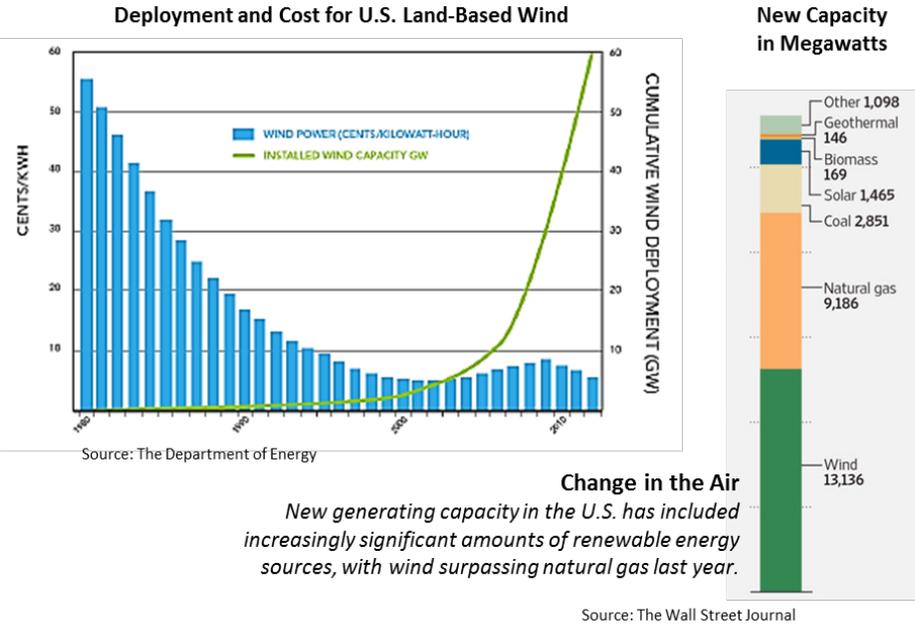


Figure 11 provides an overview of land-based wind energy assets in the United States including a time-series chart of the deployment (installed capacity in GW) and cost (in cents/kWh) and a bar chart of new capacity additions in 2012.

There has been tremendous growth in wind energy outside the United States, especially in Europe. By the end of 2012, Europe had 110 GW of wind capacity on the grid [53]. Germany is home to over 21,500 wind turbines, a fact that has posed some interesting challenges for the country. When generation exceeds demand and energy storage is not feasible, generation must be shed. However, German energy laws stipulate that non-green power generation must be shed first, lowering the capacity factor and revenues for those plants. Another challenge has been the variable nature and high concentration of wind on the electrical grid. This has resulted in large changes in capacity requiring new tools and methods for system operations to improve flexibility and maintain network stability [54].

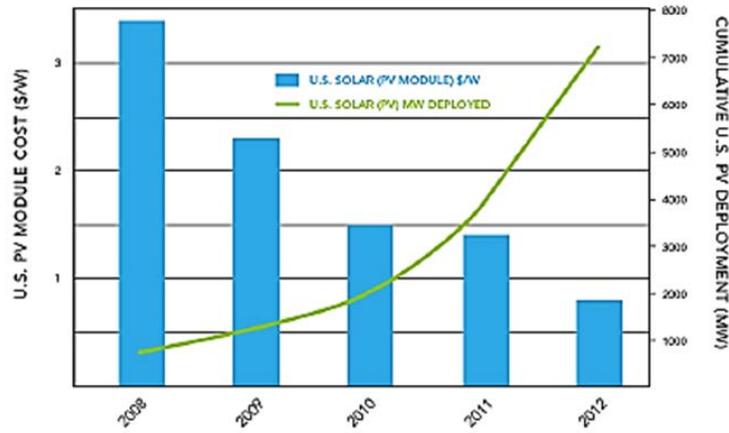
Figure 11. Wind Power Deployment



Solar

Solar is another renewable power generation technology that has made tremendous strides in recent years. As shown in Figure 12, in 2012 cumulative solar photovoltaic (PV) deployment was 7.3 GW, 10 times the deployment capacity of 2008. The EIA *Annual Energy Outlook* projects commercial PV capacity increasing between 6.5 and 7.4 percent annually through 2040 depending on various policy scenarios [45]. As with wind, solar represents a small portion of total electricity market, but it is growing rapidly and regionally where the resource is abundant. For this reason, it too can be both disruptive to other power generation technologies and pose challenges to the electrical grid.

Figure 12. U.S. Deployment and Cost for Solar PV Modules [49]



Solar deployment costs are comprised of the PV module and any inverters or batteries (i.e., equipment costs) and the so-called “soft costs” for permitting and installation. The drop in cost for a PV module is partly responsible for the dramatic increase in deployment. As the blue bars in Figure 12 show, PV module costs since 2008 have dropped by a factor of four to a 2012 price of about \$0.80/Watt. Soft costs in the U.S. are still high, about \$3.34/Watt or approximately five times those of Germany. However, utility incentives, new financing options, and the current 30 percent Federal investment tax credit (scheduled to revert to 10 percent in 2017) have helped this technology achieve cost parity with electrical generation from gas, coal, and oil in many parts of the U.S. and put this technology within reach for the average homeowner or business [45] [49]. By 2030 local solar projects likely will be of sufficient scale to impact the operations of many local utilities. There are several large examples of distributed solar generation coming on-line in the U.S. The retail giant Wal-Mart has installed solar PV modules on about 200 of its ~100,000 square foot stores delivering over 71 million kilowatt hours of energy annually. With about 4,500 stores in the U.S., and a goal of being served by 100 percent renewable energy, this could be a significant impact on the electrical grid [55] [56]. Figure 13 shows one such Wal-Mart store with a large rooftop array of solar PV modules.

Figure 13. Distributed Solar on Wal-Mart Store [56]





In Arizona roughly 500 new rooftop solar installations are completed each month. The State's largest utility, Arizona Public Service (APS), has 20,000 homes in its territory with solar PV modules. Residential systems are generally on the order of 7 kilowatts, resulting in a reduction of about two-thirds in the electrical utility bills for these houses. However, Arizona utilities argued that with the net metering practice, these homeowners were unfairly benefiting from the electrical grid's 24/7 power supply without paying for the maintenance costs for power plants and transmission lines. This past November, the Arizona Corporation Commission voted to add a monthly fee of \$0.70/kW to the bills of all customers that install new solar systems. In other states, utilities have the same argument so this Arizona vote may create momentum to levy a similar fee in other states [57].

Europe's experience with integrating solar energy could benefit the U.S. By the end of 2012, Europe had 70 GW of solar capacity on the grid with 22.3 GW in Germany [53]. As with other renewable resources, solar generation is variable and in February 2013, Germany experienced a large positive system imbalance due to this variability. On this day there was quite a bit of snow on the PV modules that did not melt as estimated, which resulted in the system imbalance and an activation of reserves [53]. Forecasting accuracy of solar generation will be increasingly important as more PV modules are installed.

Other Renewables

While wind and solar energy will tend to dominate in the next decade and beyond, other renewable resources will also have an impact. The EIA *Annual Energy Outlook* shows renewable generating capacity accounts for nearly one-fifth of total generating capacity in 2040 [45]. The National Renewable Energy Laboratory (NREL) concluded in their Renewable Electricity Futures Study that a combination of a flexible electric system with today's commercially-available renewable electricity generation technologies can supply 80 percent of total U.S. electricity generation by 2050 [58].

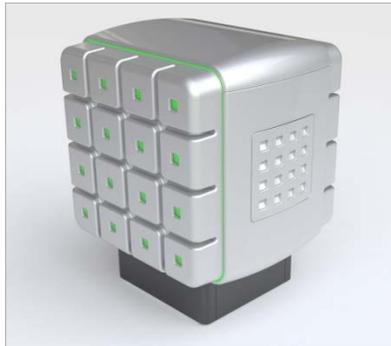
Geothermal resources are found primarily in the American West and Southwest. The technology is emerging still but the potential for this resource is about 500 GW according to NREL. Hydroelectric ("hydropower") is already a primary source of energy in the Pacific Northwest. NREL estimates the U.S. hydropower potential is 152 to 228 GW. Biopower is available in many regions and with an increase in energy crops and harvesting technologies in the future, NREL estimated a corresponding 100 GW of dedicated biopower capacity [58]. EIA's study projects much smaller amounts of geothermal (5 GW) and biopower (7 GW) plants entering operation. While these numbers are much less than wind and solar, they nevertheless represent a doubling in biopower capacity and a tripling in geothermal capacity from 2010 to 2040 [45].

Appliance-size fuel cells that provide both heat and power are just emerging today, but they may very well be common place in 2030 and beyond. These systems will decrease vulnerability associated with electrical grid outages by generating their own electricity for users with a system nearly impervious to hurricanes, thunderstorms, and similar dangers, while simultaneously helping the environment.



Redox Power Systems is working on a solid oxide fuel cell for residential applications that is 1/10th the size and cost of commercial units today with a nameplate capacity of 25 kW. Figure 14 shows a picture of such a residential fuel cell design. The system uses natural gas fuel to electrochemically convert methane to electricity. The goal is to generate onsite power and, optionally, off the grid capability at a price competitive with current energy sources [59].

Figure 14. Redox Power Systems Residential Fuel Cell Design [59]

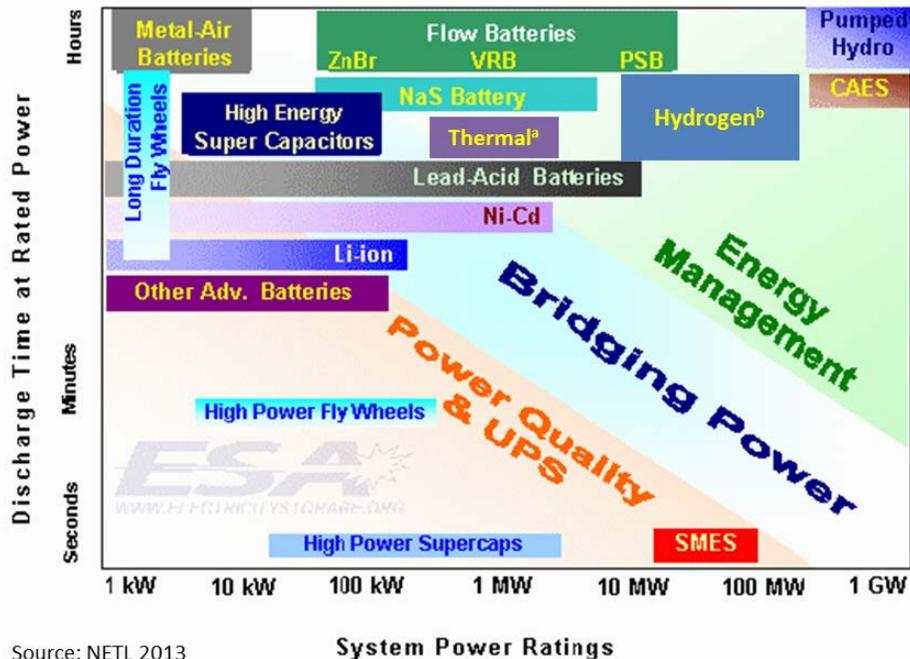


Energy Storage

Today's grid operator manages most fluctuations on the electrical grid by adjusting generation to maintain reliability and to adhere to strict conventions on voltage and frequency. In the future, clean variable generation such as wind and solar will have significantly increased, and policies are already in place or underway in most states to give them preference in meeting demand needs. Given the increased variability, energy storage technologies may provide flexible solutions throughout the electricity value chain.

Energy storage systems are designed with different energy densities, response times, time of operation, and power depending on the target application. The primary issues energy storage systems address are energy management, bridging power, and power quality. There are several technologies available that perform these energy storage functions from pumped hydro, which is a fairly mature technology, to capacitors and flywheels, which are only feasible in niche markets today. Figure 15 shows the discharge time for different types of energy storage systems (i.e., different system power ratings) and the primary issues that each type addresses.

Figure 15. Power Ratings and Discharge Times for Energy Storage Technologies



Source: NETL 2013

a. Source: Sopogy 2013.

b. Source: NREL 2010.

CAES = compressed air energy storage; Li-ion = lithium-ion; Ni-Cd = nickel cadmium; NaS = sodium sulfur; PSB = polysulfide bromide; SMES = superconducting magnetic energy storage; VRB = vanadium redox battery; ZnBr = zinc bromide

There are several examples of these technologies already deployed within the grid. Sodium sulfur (NaS) batteries have been in commercial use for over 10 years at the megawatt scale with over 300 MW installed globally. On the consumer side thermal energy storage systems are being used for bridging power applications and to help shave peak demand. Thermal storage uses off-peak electricity to store cooling energy or heat energy, then during peak demand uses that energy to meet power needs. The fashion retail store Nordstrom at the Ala Moana Center in Honolulu uses this technology to produce 43 tons of ice every night which helps cool the 210,000 square foot store during the day. Figure 16 shows the rooftop thermal energy storage system at the Ala Moana Center. As a result, the three-story store uses about half the electricity of a similarly sized retailer during daytime hours [60].



Figure 16. Rooftop Thermal Energy Storage [60]



Energy storage is gaining state support. California now has a mandate for increasing energy storage requiring that the state’s investor-owned utilities must begin buying a combined 200 MW of energy storage technology by 2014 and reaching 1,325 MW by the end of 2020. This recent decision was made in accordance with state law AB 2514, which was passed in 2010 and calls for the integration of renewable energy and the reduction of greenhouse gas emissions of 80 percent below 1990 levels by 2050 [61].

POLICY TRENDS

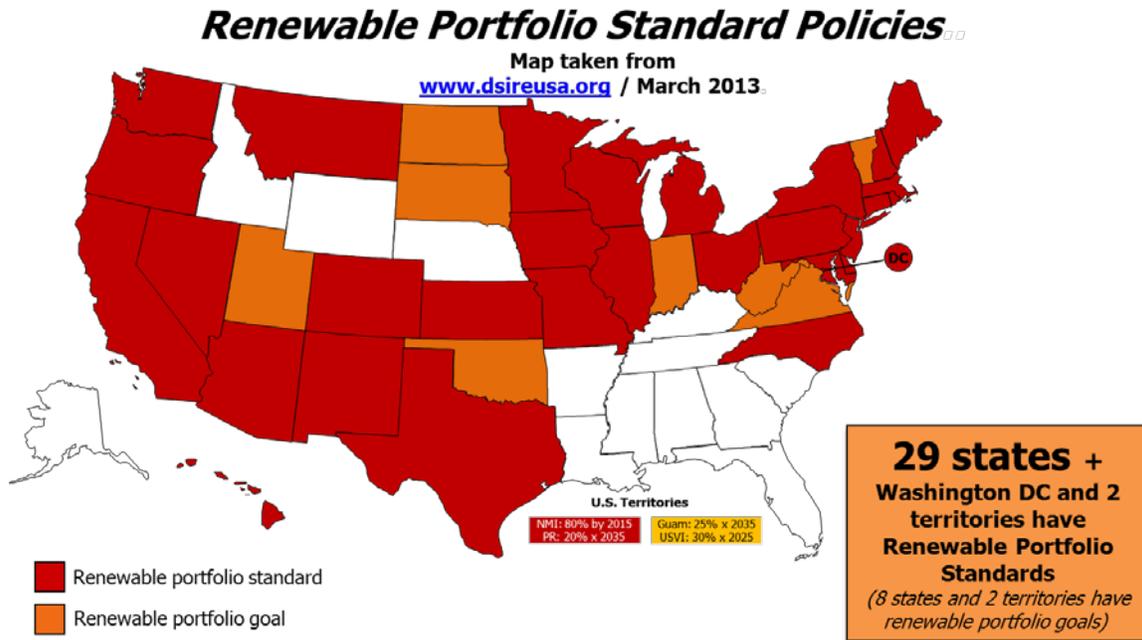
Federal, state, and local policies are all having an impact on the changes taking place to the grid. This section highlights the most important developments and trends in these new policies. While the shifting U.S. political landscape will certainly affect the speed of policy changes, it is unlikely to significantly alter their fundamental direction.

Renewable Portfolio Standards

States with renewable portfolio standard (RPS) policies have seen an increase in the amount of electricity generated from eligible renewable resources. Figure 17 shows the U.S. states as of March 2013 that have implemented RPS policies with legally mandated standards, despite the lack of a national-level RPS program. Figure 17 also shows the eight U.S. states that have implemented RPS goals that reflect desired rather than legally mandated targets.

RPSs vary widely in terms of program structure, enforcement mechanisms, size, and application, but they all have some common features. Most RPS policies set a minimum requirement for the share of electricity to be supplied from designated renewable energy resources by a certain date/year. Another feature several states use to meet these requirements is a Renewable Electricity Credit (REC) trading system structured to minimize the costs of compliance [26].

Figure 17. States with Renewable Portfolio Standards [26]



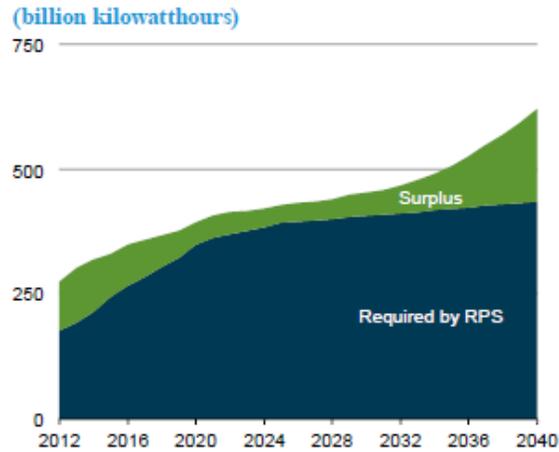
DSIRE has summary maps similar to the one shown in Figure 17 for certain financial incentives and other policies that promote renewable energy in the U.S. The data from some of those maps is summarized in Table 5. The right column lists the financial incentive or policy. In the next three columns their adoption levels across the U.S. is summarized [26].

Table 5. U.S. Adoption of Incentives and Other Policies That Promote Renewable Energy [26]

Financial Incentive or Regulatory Policy	# of States	D.C.	# of Territories
3rd Party Solar PPA Policies	At least 22	Yes	1
Grant Programs for Renewables	22	No	2
Interconnection Policies	43	Yes	1
Loan Program for Renewables	41	No	0
Net Metering Policies	43	Yes	4
PACE Financing Policies	29	Yes	0
Property Tax Incentives for Renewables	38	Yes	1
Public Benefits Funds for Renewables	15	Yes	1
Rebates Programs for Renewables	16	Yes	2
Sales Tax Incentives for Renewables	28	No	1
Tax Credits for Renewables	24	No	0

The aggregate RPS requirement for the various state programs as modeled in the EIA’s Annual Energy Outlook 2013 Reference Case (AEO2013) is shown in Figure 18. States generally are projected to meet their ultimate RPS targets in the model that accounts for the impacts of state laws requiring the addition of renewable generation or capacity by utilities doing business in the states. According to the EIA’s Annual Energy Outlook released in April 2013, “most states are meeting or exceeding their required levels of renewable generation based on qualified generation” [45]. This is partially due to expiring Federal incentives and cost reductions in wind and solar energy. Most RPS targets are tied to retail electricity sales. With relatively slow growth in electricity sales throughout most of the country, the renewable generation entering service recently has gone farther toward meeting proportionally lower targets for absolute amounts of energy (that is, for kilowatt hours of energy, as opposed to energy as a percentage of sales) [45].

Figure 18. Total Renewable Generation Required for Combined State Renewable Portfolio Standards and Projected Total Achieved, 2012-2040 [45]



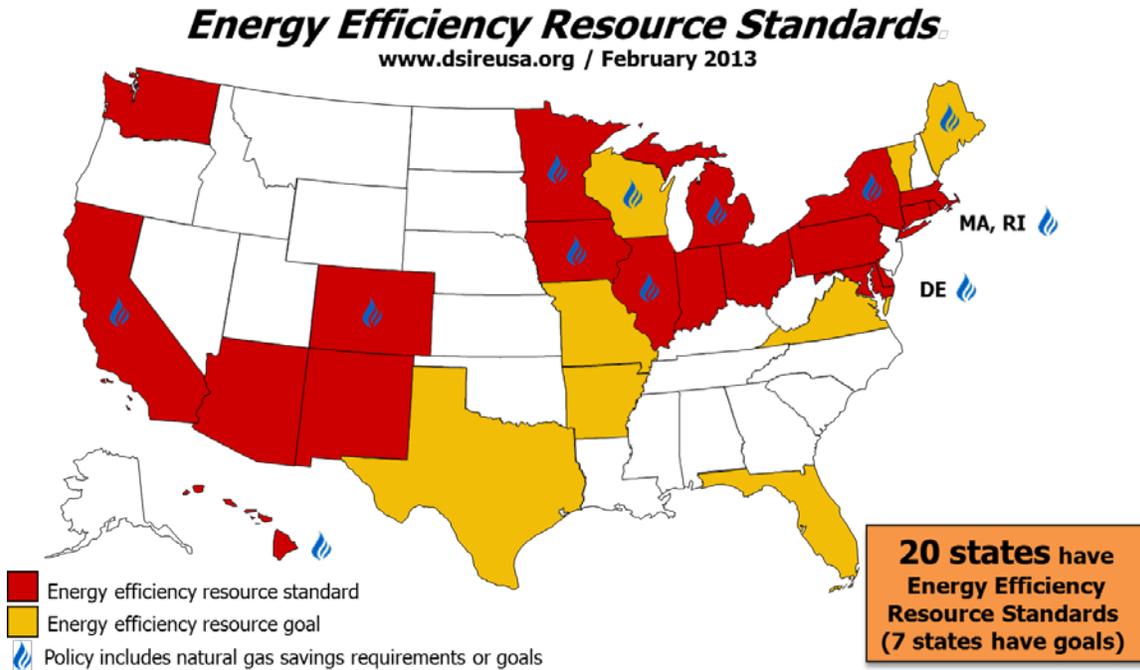
Based on the adoption rate of RPS's, the majority of the country is driving towards a minimum share of electricity to be supplied from renewable energy even without a national-level RPS program. Figure 18 projects that the amount of renewable generation meeting RPS is greater than the generation which is required by RPS as indicated by the green area labeled 'surplus'. The grid will need to accommodate this additional renewable energy, therefore it will be necessary to forecast and communicate with these generation resources at different places on the grid.

Energy Efficiency Resource Standards

Energy efficiency resource standards (EERS) require utilities to meet specific targets for energy savings. An EERS policy is sometimes coupled with a state's RPS and is included as a lower-tier resource [62]. Figure 19 shows the U.S. states as of February 2013 that have implemented EERSs.



Figure 19. States with Energy Efficiency Resource Standards [26]

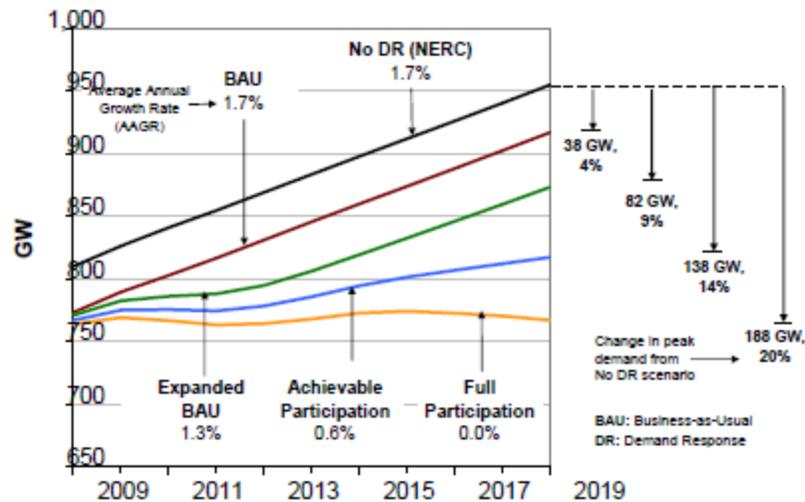


Demand Response Policies

Demand response encompasses a range of incentive mechanisms aimed at reducing customers' demands for electricity. These mechanisms typically consist of: incentive payments, dynamic pricing plans, and other strategies used to change the consumption patterns of end-users. Although generally aimed at reducing loads at times of peak demand, demand response can include actions that change any part of a utility's load profile.

A 2009 Federal Energy Regulatory Commission (FERC) study of demand response potential predicted varying levels of reduction in peak demand based on a number of different scenarios [63]. Figure 20 shows various a peak demand forecasts under the various scenarios presented in the FERC study projected running through 2018.

Figure 20. U.S. Peak Demand Forecast by Scenario [63]



If existing demand response policies were to continue, shown on the graph in Figure 20 as the “Business-as-Usual (BAU)” scenario, the U.S. could expect to see a 38 GW, or 4 percent, reduction in peak demand from the base case by 2019. By contrast, assuming a nationwide adoption of demand response programs where dynamic pricing is the norm, this model indicates a 188 GW, or 20 percent reduction in peak demand by 2019. This would not only keep pace with the annual growth rate, but it would also reduce the peak load from its starting point in 2009. This shows that effective demand response policies can have significant impacts on the nation’s energy consumption and prices as well as saving utilities and customers substantial amounts of money.

Demand response is being encouraged by FERC through its National Action Plan on Demand Response, by Pacific Gas & Electric’s InterAct tool, and a host of other national, state, and local actions. Legislative plans have been set in motion in several states that put forth goals for reduction of peak demand. For example, the Michigan Public Service Commission’s *Michigan’s 21st Century Energy Plan* and the State of New Jersey’s Board of Public Utilities’ *Energy Master Plan* both call on utilities to employ demand response practices. In 2009, legislation was passed in both Maryland and Colorado that set goals for energy consumption and peak demand reduction with the latter allowing cooperatively-owned utilities to set inclining block rates for residential customers [64]. This means that the more energy a household uses, the higher its’ per kilowatt hour cost, thus incentivizing the household to reduce its consumption. These actions help lower the overall demand for electricity, which may help counter the need for upgrades to transmission and distribution infrastructure due to additional loads entering into the grid.

Oftentimes states’ demand response actions are implemented through retail programs, some of which may not require new enabling technologies such as smart meters. This was the case in Arizona, where its two major utilities offered time-of-use (TOU) pricing that attracted 30 to 40 percent of the residential market without requiring new equipment to be installed in most cases.



California has had demand response regulations in place for some time including TOU pricing since 1978. These policies have contributed to the fact that the state’s energy usage has remained constant for 30 years despite the overall increase for the U.S. as a whole [64]. In addition, California’s Energy Action Plan has gained recognition for deploying advanced metering initiatives and dynamic pricing. In what was the country’s first dynamic pricing pilot, California adjusted rates for 2,500 customers to reflect the changing demand and account for peak loads. The program was considered a success, as it provided valuable data about customers’ willingness to participate in a demand response program, and many customers elected to keep the experimental pricing scheme.

Environmental Regulations and Standards

Environmental regulations and standards are an important topic within the industry today. Current uncertainty and future regulations could have a significant impact on the future generation mix.

The U.S. Environmental Protection Agency (EPA) is authorized under Section 111 of the Clean Air Act to “develop regulations for categories of sources which cause or significantly contribute to air pollution which may endanger public health or welfare” [65]. As part of the Climate Action Plan, a presidential memorandum in June 2013 directed the EPA to issue proposed standards, regulations or guidelines to address carbon pollution from modified, reconstructed and existing power plants by June 2014 and to provide a revised proposal for carbon pollution standards for future power plants by September 2013 [66]. The timeline for these and other actions set by the President is shown in Table 6.

Table 6. Timeline for Carbon Pollution Standards [66]

Activity	Deadline
Issue a new proposal for Carbon Pollution Standards for Future Power Plants	September 20, 2013
Issue proposed carbon pollution standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants	June 1, 2014
Issue final standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants	June 1, 2015
States submission of implementation plans to EPA	June 1, 2016

In September 2013, EPA began proposing standards for carbon emissions from new plants. The proposal has since been revised and is the public comment stage as of January 2014. The current action proposes an emission limit of 1,100 lb CO₂/MWh for coal-powered plants using integrated gasification combined cycle (IGCC) technology [67]. For efficient natural gas combined cycle (NGCC) plants, proposed emission limits are 1,000 lb CO₂/MWh for larger units and 1,100 lb CO₂/MWh for smaller units [67].



Currently, there are no proposed EPA emissions standards for CO₂ in existing power plants. There are federal guidelines developed by EPA, which are used by individual states to facilitate in formation of their own emissions reduction plan. States have a significant amount of flexibility and autonomy when setting their standards, however the plans are subject to review by the EPA [68].

In addition to Carbon Pollution Standards, there are Mercury and Air Toxics Standards (MATS), enacted in 2011, that require power plants to limit their emissions of toxic air pollutants such as mercury, and arsenic. These standards apply to all hazardous air pollutants emitted by coal-fired and oil-fired electrical generating units (EGU) with a capacity of 25 MW or greater [69]. Existing sources of air pollution have four years (since the publishing in 2012) to comply with MATS and EPA has estimated that this should be sufficient time for most, if not all, sources to come into compliance [69].

On March 28, 2013 EPA finalized updates to emission standards for new power plants as shown in Table 7. Included in these standards are limits for particulate matter, mercury, sulfur dioxide (SO₂), and other pollutants such as heavy metals and acidic gases [70]. According to EPA, there are approximately 1,100 existing coal-fired units and 300 oil-fired units affected by the MATS [71].

Table 7. Emissions Standards for New EGUs [72]

TABLE 1—REVISED EMISSION LIMITATIONS FOR NEW EGUS			
Subcategory	Filterable particulate matter, lb/MWh	Hydrogen chloride, lb/MWh	Mercury, lb/GWh
New—Unit not designed for low rank virgin coal	9.0E-2	1.0E-2 ^a	3.0E-3
New—Unit designed for low rank virgin coal	9.0E-2	1.0E-2 ^a	NR
New—IGCC	7.0E-2 ^b	2.0E-3	3.0E-3
New—Solid oil-derived	9.0E-2 ^b	NR	NR
New—Liquid oil—continental	3.0E-2	NR	NR
	3.0E-1	NR	NR

Note: lb/MWh = pounds pollutant per megawatt-hour electric output (gross).
 lb/GWh = pounds pollutant per gigawatt-hour electric output (gross).
 NR = limit not opened for reconsideration (77 FR 9304; February 16, 2012).
^a Beyond-the-floor value.
^b Duct burners on syngas; based on permit levels in comments received.
^c Duct burners on natural gas; based on permit levels in comments received.

TABLE 2—REVISED ALTERNATE EMISSION LIMITATIONS FOR NEW EGUS			
Subcategory/pollutant	Coal-fired EGUs	IGCC ^a	Solid oil-derived
SO ₂	1.0 lb/MWh	4.0E-1 lb/MWh ^b	1.0 lb/MWh
Total non-mercury metals	NR	4.0E-1 lb/GWh	NR
Antimony, Sb	NR	2.0E-2 lb/GWh	NR
Arsenic, As	NR	2.0E-2 lb/GWh	NR
Beryllium, Be	NR	1.0E-3 lb/GWh	NR
Cadmium, Cd	NR	2.0E-3 lb/GWh	NR
Chromium, Cr	NR	4.0E-2 lb/GWh	NR
Cobalt, Co	NR	4.0E-3 lb/GWh	NR
Lead, Pb	2.0E-2 lb/GWh	9.0E-3 lb/GWh	NR
Mercury, Hg	NR	NA	NR
Manganese, Mn	NR	2.0E-2 lb/GWh	NR
Nickel, Ni	NR	7.0E-2 lb/GWh	NR
Selenium, Se	5.0E-2 lb/GWh	3.0E-1 lb/GWh	NR

NA = not applicable.
 NR = limit not opened for reconsideration (77 FR 9304; February 16, 2012).
^a Based on best-performing similar source.
^b Based on DOE information.

Federal Smart Grid Legislation

Increasingly over the past decade Congress has taken a serious interest in electrical grid issues by passing various laws to address it. In 2007, the Energy Independence and Security Act (EISA) included Title XIII that is specific to the smart grid. Often overlooked in Title XIII is an opening paragraph stating that “it is the policy of the United States to support the modernizations of the Nation’s electricity transmission and distribution system....” Title XIII goes on to define 10 key features of a modern



electrical grid system including things such as dynamic optimization of grid operations, integration of distributed resources, integration of smart consumer devices, etc. Title XIII also provides for demonstration projects, interoperability, the Smart Grid Task Force, and Federal matching funds for smart grid investments by utilities. These provisions provide the basis for funds allocated under the American Recovery and Reinvestment Act in 2009.

Congress continues to consider new legislation to address cyber security concerns, privacy and data access for consumers, and other policies to accelerate investments in the future grid. In the next year, Congress is expected to launch a bipartisan caucus specifically focused on the future grid as well as to introduce new comprehensive grid legislation.

CONDITION AND REACH OF EXISTING INFRASTRUCTURE

The electrical grid connects approximately 144 million end-use customers with about 5,800 major power plants and includes over 450,000 miles of high voltage transmission lines [73]. In recent decades, the majority of transmission investment has been directed toward constructing new facilities to meet customer load demands. Meanwhile, relatively little has been invested in refurbishing existing facilities. This has resulted in much of the current power system infrastructure, whether generation, transmission, or distribution equipment, becoming outdated and in need of refurbishment, replacement, or upgrades in order to comply with new standards and meet demand [30]. Nearly 70 percent of the grid’s transmission lines and power transformers are now over 25 years old and the average age of power plants is over 30 years [73]. Some transmission and distribution components are over 80 years old. In the latter half of the upcoming 10-year period, a number of nuclear units are expected to undergo refurbishment or retirement. Many coal units will cease burning coal by 2014, with conversion to other fuels being considered as just one of several options [30].

Updating the existing infrastructure will present many challenges such as the availability of spare parts, the obsolescence of older equipment, the ability to maintain equipment due to outage scheduling restrictions, and the aging of the work force and resulting lost knowledge due to personnel retirements. Although many companies have sustainment programs in place for asset renewal, NERC asserts that it is the overall scope of the problem that presents the greatest challenge [30].

These updates will become more and more necessary as the age of infrastructure begins to show. The grid resiliency report entitled *Economic Benefits of Increasing Electric Grid Resilience to Weather Outages* issued by the Executive Office of the President in August of 2013 states the following:

“The age of the grid’s components has contributed to an increased incidence of weather-related power outages. For example, the response time of grid operators to mechanical failures is constrained by a lack of automated sensors. Older transmission lines dissipate more energy than new ones, constraining supply during periods of high energy demand. And, grid deterioration increases the system’s vulnerability to severe weather given that the majority of the grid exists above ground” [73].

However, the carrying capacity of existing lines is expensive and time consuming to upgrade. Analysis currently underway at the Idaho National Laboratory, funded by DOE, aims to increase transmission capacity during windy conditions through concurrent cooling of the transmission line, through



monitoring and controls of a Dynamic Line Rating Tool. An increase in wind speed of 5 mph blowing at a right angle to a high-voltage line can cool the line enough to increase its carrying capacity 30 to 50 percent. By applying this knowledge to the Dynamic Line Rating Tool, the existing infrastructure in the can allow for increased levels of generation with minimal grid upgrades [74].

In addition to analysis, the Federal government has allocated billions of dollars to replace, expand, and refine grid infrastructure. The American Recovery and Reinvestment Act of 2009 allocated \$4.5 billion for investments in technologies to modernize grid. These smart grid technologies utilize remote control and automation to better monitor and operate the grid. Between June 2011 and February 2013, Recovery Act funds have been used to deploy 343 advanced grid sensors, upgrade 3,000 distribution circuits with digital technology, install 6.2 million smart meters, and invest in 16 energy storage projects. These investments have contributed to significant increases in grid resilience, efficiency, and reliability [73].

FORTHCOMING TECHNOLOGIES

New companies are emerging that are focused on providing new energy products to consumers. Established companies such as Home Depot, Lowes and Best Buy are focused on relatively inexpensive products that integrate energy management devices with other home automation products. Other companies are focused on commercial scale energy storage, fuel cells, etc. with an emphasis on convenience and security. While there will be winners and losers in these emerging markets, it is clear that innovation is just beginning.

High Voltage Direct Current Transmission

High voltage direct current (HVDC) was the first means of transmitting electric power over a distance. Today this technology is re-emerging as a possible replacement for AC high voltage lines. DC lines result in overall higher efficiency and reliability than an equivalently-sized alternating current (AC) system [24]. There are approximately 4,000 circuit miles High Voltage DC lines in the U.S. whereas there are over 180,000 circuit miles of AC lines [75]. Countries like Sweden, Germany, China and Brazil also have HVDC transmission lines. Clean Line Energy is developing a series of direct current (DC) transmission lines to deliver thousands of megawatts of renewable power from the windiest areas of the U.S. to cities with a strong demand for clean, reliable energy. They are proposing to develop four high-voltage, direct-current transmission lines, each capable of transporting up to 3,500 MW of renewable energy from renewable-rich regions in the Midwest to load centers in the Eastern and Western U.S. [76].

Microgrids

A microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode [77].



North America is the leading market for microgrids, featuring 63 percent (992 MW) of the total worldwide installed microgrid capacity of 1,581 MW. This worldwide capacity is expected to increase to over 9,100 MW by 2020 with North America's share of this capacity expected to grow to almost 6,000 MW. Worldwide annual revenue from microgrids is expected to reach between \$30 million and \$60 million by 2020 [78].

The U.S. Department of Defense (DoD), as the single largest energy consumer in the world, is a crucial driver of microgrid development owing to its extreme sensitivity to T&D disruptions at its various bases around the world. Roughly two dozen facilities across all branches of the military are engaged in some form of microgrid implementation, often including the integration of renewable energy generation such as wind or solar [79].

Beyond the DoD, public investment has come from various state and federal agencies including DOE, the Federal Emergency Management Agency, and the California Energy Commission. Some of the larger projects are occurring at the University of California, San Diego; in Salem, Oregon; and in Bridgeport, Connecticut. Islanding, EV integration, environmental disaster response, and distributed renewable energy generation management are the focus of most of these projects.

Managing microgrid integration is an important aspect of grid evolution, both because this integration requires careful planning, and because this is a crucial element in solving current grid issues such as distributed renewable energy generation and increasing grid resiliency during natural disasters.

“Smart Cities”

The term “Smart City” currently has a number of different connotations depending on where and how the term is specified. For some cities, this is as simple as smart street lighting; for others, it refers to a highly integrated sensor network that provides real-time information regarding city service usage such as beaches, libraries, and parking. European cities such as Málaga [80] and Eindhoven [81] fall into the former category, while cities such as Santander [82] exemplify the latter concept. Generally, the term refers to the real-time creation and consumption of data streams in order to provide an adaptive or informed response to a citizen need or demand. Planning organizations are just starting to design smart cities, making it a clear priority looking forward and already impacting energy consumption data availability in many cities.

The amount of data being created and collected by municipalities and utilities is growing rapidly; by some estimates it is expected to double every two years until 2020 [83]. The data will, largely, be generated by vast automated sensor networks. This “Internet of Things” is expected to generate an estimated 40 trillion Gigabytes of data [83]. Leveraging the data will be fundamental for municipalities to understand, because it is one of the basic components of the value architecture of future smart cities. Without understanding what is being measured and what that measurement says, municipalities and utility operators run the risk of being drowned by a metaphorical tsunami of unintelligible data points and statistics, or, worse yet, drawing the wrong conclusions by using answers to questions they did not

want to ask [84]. Figure 21 provides a schematic representation of this smart city value architecture. It shows high-level characteristics as well as more specific features, components, and desired outcomes.

Moving forward, grid stakeholders need to be both intelligent providers and consumers of smart city data and services. This means planning grid development in conjunction with local and regional planning authorities in order to maximize participation in smart cities.

Figure 21. Smart City of the Future Value Architecture [83]



While still in their infancy, these kinds of plans represent the next evolution of large scale city planning, and have many details to work out (privacy concerns, etc.).

Demand Side Components

Data from the Buildings Energy Data Book of March 2012 shows residential and commercial buildings consume 74 percent of the U.S. electricity, and this figure is forecasted to grow a few percentage points by 2030 [85]. Some of the end-use consumption is from lighting, PCs, water heating, refrigeration, cooking, and HVACs. Lighting in particular has undergone a dramatic change in recent years as described below. In addition, low-cost, high-power computing has created opportunities for network-connected smart appliances with alert and remote control features for residential use. Commercial and industrial organizations are often looking to reduce bottom line operational costs through operational



efficiency improvements. As a result, improvements in the end-use components have the potential to significantly affect how electricity is consumed.

Light Emitting Diode (LED) Lighting

Both residential and commercial consumers are making the switch to LED lights. In 2009, fewer than 400,000 LED lights were deployed across the U.S., but by 2013, deployment had grown to nearly 20 million LED lights. Although LEDs cost more up front, they also last as much as 25 times longer than the traditional incandescent light bulb. In 2012 some LED lighting products cost \$50 each, but one year later many of today's LEDs cost less than \$15 [49].

Additionally, the consumer gains quite a bit from a LED lighting product's efficiency. Consider that a standard 60-Watt incandescent light bulb can be replaced by a ~9-Watt LED light that is 84 percent more efficient and with much less wasted heat. With the LED lasting over two decades, consumers could save over \$140 for every incandescent bulb swapped for an LED replacement. DOE's Office of Energy Efficiency and Renewable Energy projects that by 2030 LED lighting will save Americans over \$30 billion a year in electricity costs and cut America's energy consumption for lighting in half [49].

This transition in lighting impacts not only utilities' revenues but also their operating costs. Incandescent bulbs have a power factor (PF) of about 1, which means the actual power consumed (in Watts) and the apparent power (in volt-amperes) are equal. However, Energy Star has a minimum PF of 0.70 for LED lights greater than 5-Watts and no minimum PF for LED lights less than 5-Watts [86]. This means a 10-Watt LED with a PF of 0.7 pays for 10 Watts, but the utility would have to generate 1.4 times that power in volt-amps to run that light and pay for the additional generation. At the individual bulb level this is not significant but as LED lighting products gain more market share, the aggregate additional power needs will become an important consideration for utilities [87].

Residential

New refrigerators, dishwashers, washers, dryers, thermostats, carbon monoxide detectors, and smoke detectors are being sold with embedded computers capable of providing consumers monitoring, user habit learning, customizability, remote notification, and 24/7 remote control. Appliances such as washing machines and dishwashers can be programmed to operate during times convenient for the consumer or during the evening to minimize the noise disturbance from the operation. In the future, these appliances could be configured to respond to demand response signals or time differentiated rates to maximize savings for the customer, to modify peak demand, and in general to help improve grid operations. These appliances only represent a tiny fraction of the market today, but they are expected to become increasingly mainstream in market penetration through the 2010s and could reach up to \$35 billion in sales by 2020 [88].

Commercial and Industrial

Building energy demand, a major cost component of any business operation, can be broadly divided into lighting, general heating and cooling, and plug load. By implementing smart efficiency measures, such as those listed in Table 8, it is estimated that by 2035 the annual savings for the commercial sector from these technologies could reach \$30 billion to \$60 billion [89]. Similarly, for the industrial sector, annual

savings by 2035 could range from \$8 billion to \$25 billion [89]. This expected improved building efficiency could help reduce electricity demand growth as the technologies become more widely deployed and even newer technologies are developed. These technologies will increasingly allow buildings to respond in near real-time to grid conditions such as voltage and frequency levels.

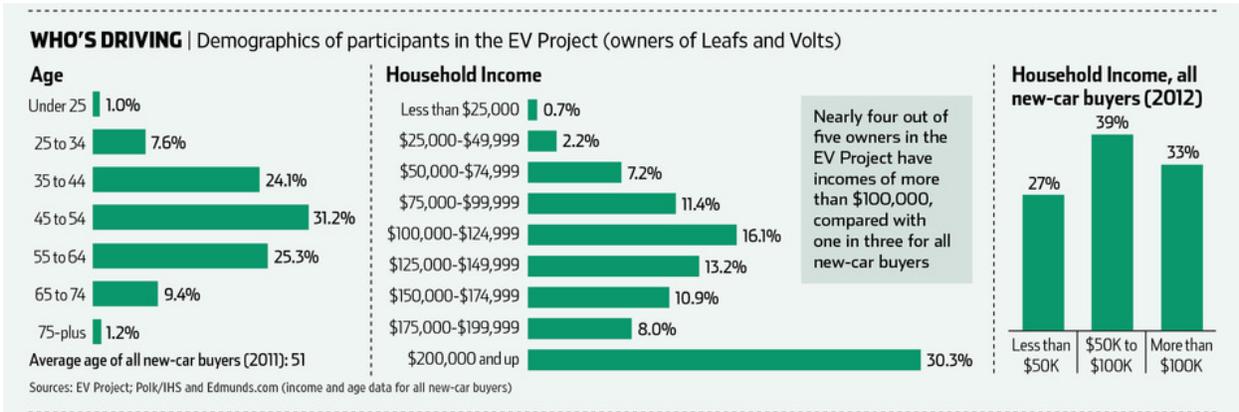
Table 8. Intelligent Energy Measures for Commercial Sector [89]

Measure	Savings Range	Estimated Applicability
Smart Building Components	5%-20%	10%
Smart Lighting	0%-75%	35%
Smart HVAC Components	15%	10%-15%
Advanced Building Mgmt. Systems (BMS)	10%-30%	10%-20%
Smart Grid	10%	10%
User Interfaces	10%-20%	10%
Office Equipment and Cloud Computing	2%-50%	50%
Refrigeration Energy Management	30%	30%
Smart Fume Hoods	10%-30%	15%
Miscellaneous	20%-50%	2%

Electric Vehicles

Electric vehicle sales account for less than 1% of total new light duty vehicle sales but several incentives are aimed at boosting their adoption [90]. Today’s EV purchasers today are primarily city dwellers in places such as Los Angeles, San Francisco, Seattle, New York, and Atlanta. Figure 22 provides a demographic snapshot of who drives EVs and includes information on age and household income. The largest group of purchasers tends to be between the ages of 45 and 54 with household incomes greater than \$100,000. EV drivers typically drive 9,000 miles per year as compared to 13,500 miles per year for all cars in the United States [91]. It also compares this to the 2012 household income of all new-car buyers.

Figure 22. Demographics of PEV drivers [91]



Despite the limited demographic purchasing EVs, there are several factors at play helping to increase the general market penetration, such as:

- President Obama’s launch of the EV Everywhere Grand Challenge to make the cost of plug-in EVs on par with gasoline-powered vehicles by 2022;
- Nearly 50 percent drop in the cost of EV batteries in the past four years through high volume production [92];
- DOE’s efforts with industry and academia to double the battery pack energy density [92]; and
- State support, in particular, eight states (California, Connecticut, Maryland, Massachusetts, New York, Oregon, Rhode Island, and Vermont) that have pledged to adopt measures to make it easier to own an EV. Collectively these states represent nearly one-quarter of America's auto market. Their goal is to achieve sales of at least 3.3 million zero-emissions vehicles by 2025. This would represent 25 percent of the light duty vehicle (LDV) annual sales [93].

“In March 2012, President Obama announced the *EV Everywhere Grand Challenge*—to produce plug-in electric vehicles (PEVs) as affordable and convenient for the American family as gasoline-powered vehicles by 2022.” [100]

Other factors positively influencing EV market share are purchasing incentives such as the Federal government tax credit up to \$7,500 and state government incentives such as tax credits and rebates [94]. Lastly, there is the large difference in fueling costs between EVs and conventional gasoline-powered vehicles. Nationally, EV fueling costs are about three times less than those for vehicles running on gasoline.

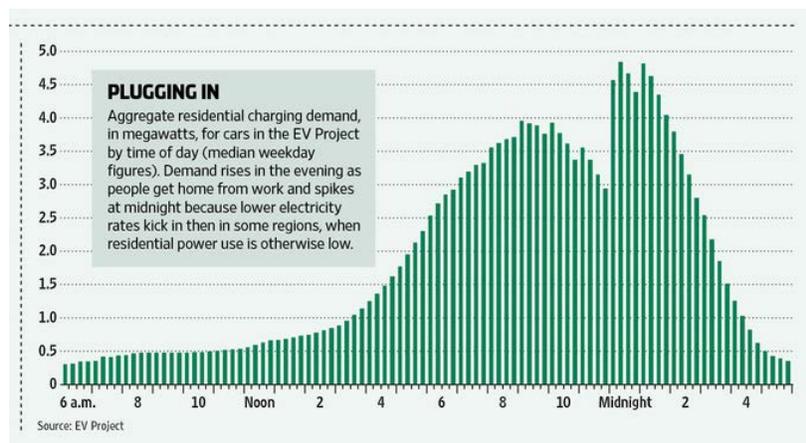
Together, all of these factors are aligned with promoting and expanding EV market share. With this increased market penetration, though, will come significantly increased transportation sector demands for electricity.

The vehicle industry has been working tirelessly installing charging stations nationwide. As of June 2013, there were over 18,000 charging stations (both public and private) across the U.S. with approximately one dozen states (MA, NY, NC, TN, FL, TX, MI, IL, OR, WA, CA, and AZ) representing the majority of all

installations [95]. In support of the President’s EV Everywhere Challenge, DOE has launched the Workplace Charging Challenge aimed at increasing by tenfold over the next five years the number of U.S. employers offering charging installations [96].

Already there are several neighborhoods with high EV concentration. Pecan Street Research (PSR) Analytics analyzed over 2,500 vehicle charge events between June 1, 2013 and August 31, 2013 in a randomly selected subset of 30 homes in Austin, Texas. It found that charging behavior is more diverse than predicted and thus representing a much more manageable energy load [97]. However, how charging will impact the grid still remains to be seen. Today a majority of residential charging is done with Level 1 and Level 2 chargers. In the State of Washington, some of the 14 DC quick chargers on the West Coast Green Highway were used 10 times more often than others [98]. In 20 years, technological advancements could make these quick chargers, wireless charging, or some other charging method common in the home. With states supporting a larger number of EVs in the market place, utilities will need to evaluate their distribution systems against these possible demand scenarios. Figure 23 shows aggregate residential charging demand (in MW) over the course of a typical day.

Figure 23. Residential Demand in a High PEV Penetration Neighborhood [91]



Smart Grid Projects/Technologies

The American Recovery and Reinvestment Act of 2009 tasked the Department of Energy (DOE) with distributing \$4.5 billion in funding to smart grid projects across the country. This program has the potential to drastically change the power grid landscape of the United States. The two largest initiatives are the Smart Grid Investment Grant (SGIG) program and the Smart Grid Demonstration Program (SGDP). DOE’s Office of Electricity Delivery and Energy Reliability (OE) is responsible for managing these five-year programs [99].

The first of these large initiatives, SGIG, focuses on deploying existing smart grid technologies, tools, and techniques to improve grid performance. Meanwhile, the other large initiative, SGDP, explores advanced smart grid and energy storage systems and evaluates performance for future applications.



These projects are focused on regional demonstration projects and energy storage projects. For information about individual smart grid projects under the American Recovery and Reinvestment Act of 2009, visit http://www.smartgrid.gov/recovery_act/project_information.

The impact of these investments is still being analyzed in most cases, but the benefits are clear. Based on the results of these projects, the industry will develop new and better solutions and fine tune the design and implementation for future projects to maximize the benefits.



WORKS CITED

- [1] ISO/RTO Council, "ISO/RTO Council Map," 2011. [Online]. Available: <http://www.isorto.org/site/c.jhKQIZPBIImE/b.2604471/k.B14E/Map.htm>. [Accessed 16 January 2014].
- [2] Gridwise Alliance, *Visioning State Data 10_07_13*, Washington DC: Gridwise Alliance, 2013.
- [3] National Renewable Energy Laboratory (NREL), "Wind Technologies Market Report," 2013. [Online]. Available: http://www1.eere.energy.gov/wind/pdfs/2012_wind_technologies_market_report.pdf. [Accessed 16 January 2014].
- [4] American Wind Energy Association (AWEA), "Get the Facts. Industry Statistics. State-by-State.," American Wind Energy Association (AWEA), 2013. [Online]. Available: <http://www.awea.org/resources/statefactsheets.aspx?itemnumber=890>. [Accessed 26 January 2014].
- [5] M. Goggin, "Southwest Power Pool Achieves Wind Penetration Record," AWEA, 12 December 2012. [Online]. Available: http://www.awea.org/blog/index.cfm?customel_dataPageID_1699=20642. [Accessed 16 January 2014].
- [6] National Renewable Energy Laboratory (NREL), "Electricity Supply and Demand in the United States," 2011. [Online]. Available: <https://www.e-education.psu.edu/eme801/node/490>. [Accessed 16 January 2014].
- [7] National Renewable Energy Laboratory (NREL), "Eastern Wind Integration and Transmission Study," 2011. [Online]. Available: <http://www.nrel.gov/docs/fy11osti/47078.pdf>. [Accessed 16 January 2014].
- [8] Midcontinent Independent System Operator, Inc., "MISO Corporate Information Fact Sheet," January 2014. [Online]. Available: <https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/Corporate%20Fact%20Sheet.pdf>. [Accessed 25 January 2014].
- [9] Midcontinent Independent System Operator, Inc., "2012 - 2016 Strategic Plan," 7 March 2013. [Online]. Available: https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/MISO%20Strategic%20Plan/MISO%20Strategic%20Plan%202012_2016%20Web.pdf. [Accessed 12 January 2014].



- [10] Midcontinent ISO (MISO), "MISO Transmission Cost Allocation Overview," 21 October 2013. [Online]. Available: <https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Transmission%20Cost%20Allocation%20Overview.pdf>. [Accessed 14 January 2014].
- [11] Midcontinent ISO (MISO), "MISO Transmission Expansion Plan (MTEP)," 12 November 2013. [Online]. Available: <https://www.misoenergy.org/Library/Repository/Communication%20Material/One-Pagers/MTEP.pdf>. [Accessed 26 January 2014].
- [12] Midcontinent ISO (MISO), "MVPs Create Jobs, Better for States," [Online]. Available: <https://www.misoenergy.org/Library/Repository/Communication%20Material/One-Pagers/MVP%20Benefits%20-%20Total%20Footprint.pdf>. [Accessed 26 January 2014].
- [13] Midcontinent ISO (MISO), "Creating a Smarter Grid," 24 July 2013. [Online]. Available: <https://www.misoenergy.org/Library/Repository/Communication%20Material/One-Pagers/Synchrophasors.pdf>. [Accessed 14 January 2014].
- [14] Southwest Power Pool Strategic Planning Committee, "2010 Southwest Power Pool Strategic Plan," July 2010. [Online]. Available: http://www.spp.org/publications/2010_SPP_Strategic_Plan.pdf. [Accessed 12 January 2104].
- [15] Southwest Power Pool (SPP), "the 2014 Integrated Transmission Plan Near-Term Assessment Report," 9 December 2013. [Online]. Available: <http://www.spp.org/section.asp?group=2042&pageID=27>. [Accessed 26 January 2014].
- [16] Troutman Sanders LLP, "SPP Files New "Highway-Byway" Transmission Cost Allocation Methodology," [Online]. Available: <http://www.troutmansandersenergyreport.com/2010/04/spp-files-new-%E2%80%9Chighway-byway%E2%80%9D-transmission-cost-allocation-methodology/>. [Accessed 26 January 2014].
- [17] DNV KEMA Energy & Sustainability with ERCOT, " Electric Reliability Council of Texas, Inc," November 2013. [Online]. Available: <http://www.ercot.com/content/news/presentations/2014/ERCOT%20Strat%20Plan%20FINAL%20112213.pdf>. [Accessed 12 January 2014].
- [18] Electric Reliability Council of Texas (ERCOT), "News Release. ERCOT transmission studies identify upcoming transmission projects and potential long-term needs," 10 January 2013. [Online]. Available: http://www.ercot.com/news/press_releases/show/26375. [Accessed 26 January 2014].



- [19] Electric Reliability Council of Texas (ERCOT), "Report on Existing and Potential Electric System Constraints and Needs," December 2012. [Online]. Available: <http://www.ercot.com/content/news/presentations/2013/2012%20Constraints%20and%20Needs%20Report.pdf>. [Accessed 26 January 2014].
- [20] California ISO, "Company Information," California ISO, 26 November 2013. [Online]. Available: http://www.caiso.com/Documents/CompanyInformation_Facts.pdf. [Accessed 17 January 2014].
- [21] California ISO, "Building a Sustainable Energy Future. 2014 - 2016 Strategic Plan.," 24 September 2013. [Online]. Available: http://www.caiso.com/about/Pages/OurBusiness/Publications_CorporateDocuments.aspx. [Accessed 17 January 2014].
- [22] California ISO, "2012 - 2013 Transmission Plan," 20 March 2013. [Online]. Available: <http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf>. [Accessed 26 January 2014].
- [23] California ISO, "2009 Annual Report," [Online]. Available: <http://www.caiso.com/Documents/2009CaliforniaISOAnnualReport.pdf>. [Accessed 26 January 2014].
- [24] Clean Line Energy Partners, "Projects," [Online]. Available: <http://www.cleanlineenergy.com/projects>. [Accessed 26 January 2104].
- [25] S. Bray, "Kansas Corporation Commission unanimously approves route for the grain belt express clean line in Kansas," Clean Line Energy Partners, 7 November 2013. [Online]. Available: http://www.cleanlineenergy.com/sites/cleanline/media/news/Grain_Belt_Express_KCC_Order_Press_Release_Finalcopy.pdf. [Accessed 26 January 2014].
- [26] North Carolina State University, "Summary Maps. Database of State Incentives for Renewables & Efficiency (DSIRE)," March 2013. [Online]. Available: <http://www.dsireusa.org/summarymaps/index.cfm?ee=0&RE=0>. [Accessed 17 January 2014].
- [27] Texas Coalition for Affordable Power, "Deregulated Electricity in Texas: A History of Retail Competition - The First 10 Years," December 2012. [Online]. Available: <http://historyofderegulation.tcaptx.com/chapter/year-2008/>. [Accessed 26 January 2014].
- [28] J.D. Power, "2013 Texas Residential Retail Electric Provider Customer Satisfaction Study," 13 August 2013. [Online]. Available: <http://jdpower.com/content/press-release/kVNNnIQ/2013-texas-residential-retail-electric-provider-customer-satisfaction-study.htm>. [Accessed 22 January 2014].



- [29] Public Utility Commission of Texas, "Scope of Competition in Electric Markets in Texas," January 2009. [Online]. Available: http://www.puc.texas.gov/industry/electric/reports/scope/2009/2009scope_elec.pdf. [Accessed 26 January 2014].
- [30] North American Electric Reliability Corporation, "NERC 2012 Long-Term Reliability Assessment," November 2012. [Online]. Available: http://www.nerc.com/files/2012_ltra_final.pdf. [Accessed 18 November 2013].
- [31] U.S. Energy Information Administration, "Market Trends — Electricity," May 2013. [Online]. Available: http://www.eia.gov/forecasts/aeo/MT_electric.cfm. [Accessed 5 November 2013].
- [32] U.S. Energy Information Administration, "Today in Energy: State Fact Sheets on Residential Energy Consumption," 19 August 2013. [Online]. Available: <http://www.eia.gov/todayinenergy/detail.cfm?id=12591>. [Accessed 5 November 2013].
- [33] J. A. Laitner, "The Long-Term Energy Efficiency Potential: What the Evidence Suggests," American Council for an Energy-Efficient Economy (ACEEE), 2012.
- [34] N. C. Abi-Samra, "One Year Later: Superstorm Sandy Underscores Need for a Resilient Grid," IEEE Spectrum, 4 November 2013. [Online]. Available: <http://spectrum.ieee.org/energy/the-smarter-grid/one-year-later-superstorm-sandy-underscores-need-for-a-resilient-grid>. [Accessed 11 November 2013].
- [35] K. H. LaCommare and J. H. Eto, "Understanding the Cost of Power Interruptions to U.S.," Ernesto Orlando Lawrence Berkeley National Laboratory (LBNL), September 2004. [Online]. Available: <http://certs.lbl.gov/pdf/55718.pdf>. [Accessed 30 November 2013].
- [36] Executive Office of the President, "The President's Climate Action Plan," The White House, June 2013. [Online]. Available: <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>. [Accessed 23 November 2013].
- [37] U.S. Energy Information Administration, "Energy in Brief," 14 December 2012. [Online]. Available: http://www.eia.gov/energy_in_brief/article/nuclear_industry.cfm. [Accessed 27 December 2013].
- [38] U.S. Energy Information Administration, "Annual Energy Outlook 2014 Early Release," 2013. [Online]. Available: [http://www.eia.gov/forecasts/aeo/er/pdf/0383er\(2014\).pdf](http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf). [Accessed 27 December 2013].



- [39] US Department of Energy, "Quarterly Nuclear Deployment Scorecard - October 2013," Office of Nuclear Energy, October 2013. [Online]. Available: <http://energy.gov/ne/downloads/quarterly-nuclear-deployment-scorecard-october-2013>. [Accessed 27 12 2013].
- [40] Georgia Power, "Plant Vogtle Units 3 and 4," [Online]. Available: <http://www.southerncompany.com/what-doing/energy-innovation/nuclear-energy/pdfs/vogtle-nuclear-brochure.pdf>. [Accessed 27 December 2013].
- [41] International Atomic Energy Association, "PRIS - Country Details: United States," IAEA Power Reactor Information System, 26 December 2013. [Online]. Available: <http://www.iaea.org/PRIS/CountryStatistics/CountryDetails.aspx?current=US>. [Accessed 26 December 2013].
- [42] American Enterprise Institute, "Polls on the environment, energy, global warming, and nuclear power," 17 April 2013. [Online]. Available: <http://www.aei.org/article/politics-and-public-opinion/polls/polls-on-the-environment-energy-global-warming-and-nuclear-power-april-2013/>. [Accessed 16 January 2014].
- [43] U.S. Energy Information Administration, "Energy Explained. Electricity in the U.S.," 5 November 2013. [Online]. Available: http://www.eia.gov/energyexplained/index.cfm?page=electricity_in_the_united_states. [Accessed 26 January 2014].
- [44] National Energy Technology Laboratory, "Tracking New Coal-Fired Power Plants," 12 January 2012. [Online]. Available: <http://www.netl.doe.gov/coal/refshelf/ncp.pdf>. [Accessed 15 November 2013].
- [45] U.S. Energy Information Administration, "Annual Energy Outlook 2013," April 2013. [Online]. Available: [http://www.eia.gov/forecasts/aeo/pdf/0383\(2013\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf). [Accessed 14 November 2013].
- [46] K. Otterbourg, "UNCLE SAM'S RIVER," 28 October 2013. [Online]. Available: <http://www.kenotterbourg.com/TVA.pdf>. [Accessed 9 November 2013].
- [47] Moody's Investor Services, "Moody's: Growth prospects for Canada's largest pipelines diverge," 7 November 2013. [Online]. Available: https://www.moody.com/research/Moodys-Growth-prospects-for-Canadas-largest-pipelines-diverge--PR_286209. [Accessed 17 November 2013].
- [48] J. Logan, "Natural Gas and the Transformation of the U.S. Energy Sector: Electricity," NREL/TP-6A50-55538 The Joint Institute for Strategic Energy Analysis, 2012.



- [49] L. Tillemann, "Revolution Now. The Future Arrives for Four Clean Energy Technologies," 17 September 2013. [Online]. Available: <http://energy.gov/sites/prod/files/2013/09/f2/Revolution%20Now%20--%20The%20Future%20Arrives%20for%20Four%20Clean%20Energy%20Technologies.pdf>. [Accessed 18 November 2013].
- [50] "2012 Wind Technologies Report; 20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply," U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, 2012, 2008.
- [51] National Renewable Energy Laboratory (NREL), "Western Wind and Solar Integration Study," September 2013. [Online]. Available: http://www.nrel.gov/electricity/transmission/western_wind.html. [Accessed November 2013].
- [52] National Renewable Energy Laboratory (NREL), "Eastern Renewable Generation Integration Study," 2010. [Online]. Available: http://www.nrel.gov/electricity/transmission/eastern_renewable.html. [Accessed November 2013].
- [53] K. De Vos, "Wind and PV integration: European Experiences".
- [54] R. Fuchs, "Wind energy surplus threatens eastern German power grid," European Dialogue, January 2011. [Online]. Available: <http://www.euromdialogue.org/Wind-energy-surplus-threatens-eastern-German-power-grid>. [Accessed November 2013].
- [55] Walmart, "Renewable Energy," 2013. [Online]. Available: <http://corporate.walmart.com/global-responsibility/environment-sustainability/renewable-energy>. [Accessed November 2013].
- [56] D. Hull, "Walmart's Solar Strategy," Silicon Beat, 11 March 2013. [Online]. Available: <http://www.siliconbeat.com/2013/03/11/walmarts-solar-strategy/>. [Accessed 16 November 2013].
- [57] "Arizona Regulators Raise Solar Rates," [Online]. Available: <http://abcnews.go.com/US/wireStory/arizona-regulators-raise-solar-rates-month-20895284>. [Accessed 16 November 2013].
- [58] T. Mai, D. Sandor, R. Wiser and T. Schneider, "Renewable Electricity Futures Study: Executive Summary. NREL/TP-6A20-52409-ES," National Renewable Energy Laboratory, Golden, CO, 2012.



- [59] W. Pentland, "Redox Power Plans To Roll Out Dishwasher-Sized Fuel Cells That Cost 90% Less Than Currently Available Fuel Cells," 14 August 2013. [Online]. Available: <http://www.forbes.com/sites/williampentland/2013/08/14/redox-power-plans-to-roll-out-dishwasher-sized-fuel-cells-that-cost-90-less-than-currently-available-fuel-cells/>. [Accessed 17 November 2013].
- [60] J. Song, "Nordstrom keeping customers cool with ice.," Honolulu Advertiser, 18 March 2008. [Online]. Available: <http://the.honoluluadvertiser.com/article/2008/Mar/18/bz/hawaii803180341.html> . [Accessed 10 May 2013].
- [61] R. L. Hales, "California's New Energy Storage Initiative," San Diego Loves Green, 19 October 2013. [Online]. Available: <http://www.sandiegolovesgreen.com/cpuc-decides-that-utilities-must-start-buying-energy-storage-technology/>. [Accessed 23 November 2013].
- [62] North Carolina State University, "Glossary. Database of State Incentives for Renewables & Efficiency (DSIRE)," 2013. [Online]. Available: <http://www.dsireusa.org/glossary/>. [Accessed 16 January 2014].
- [63] Brattle Group, "A National Assessment of Demand Response Potential," Federal Energy Regulatory Commission, 2009.
- [64] Federal Energy Regulatory Commission (FERC), "National Action Plan on Demand Response," 17 June 2010. [Online]. Available: <https://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf>. [Accessed November 2013].
- [65] U.S. Environmental Protection Agency (EPA), "Section 111(d) Plans," 14 March 2013. [Online]. Available: <http://www.epa.gov/region07/air/rules/111d.htm>. [Accessed 16 January 2014].
- [66] Office of the Press Secretary, "Presidential Memorandum -- Power Sector Carbon Pollution Standards," The White House, 25 June 2013. [Online]. Available: <http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards>. [Accessed 27 January 2014].
- [67] U.S. Environmental Protection Agency (EPA), "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units," 8 January 2014. [Online]. Available: <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0495-0001>. [Accessed 16 January 2014].
- [68] U.S. Environmental Protection Agency (EPA), "What is EPA Doing | Carbon Pollution Standards," 23 September 2013. [Online]. Available: <http://www2.epa.gov/carbon-pollution-standards/what-epa-doing>. [Accessed 16 January 2014].



- [69] U.S. Environmental Protection Agency (EPA), "Basic Information | Mercury and Air Toxics Standards," 10 April 2012. [Online]. Available: <http://www.epa.gov/mats/basic.html>. [Accessed 12 December 2013].
- [70] U.S. Environmental Protection Agency (EPA), "Fact Sheet: Updates on the Limits for New Power Plants Under the Mercury and Air Toxics Standards (MATS)," 28 March 2013. [Online]. Available: <http://www.epa.gov/mats/pdfs/20130328fs.pdf>. [Accessed 30 December 2013].
- [71] U.S. Environmental Protection Agency (EPA), "Fact Sheet: Mercury and Air Toxics Standards for Power Plants," 21 December 2011. [Online]. Available: <http://www.epa.gov/mats/pdfs/20111221MATSummaryfs.pdf>. [Accessed 30 December 2013].
- [72] U.S. Environmental Protection Agency (EPA), "40 CFR Parts 60 and 63: National Emission Standards for Hazardous Air Pollutants From Coal-and Oil-Fired Electric Utility Steam Generating Units, Federal Register Volume 78, Number 79," 24 April 2013. [Online]. Available: <http://www.gpo.gov/fdsys/pkg/FR-2013-04-24/pdf/2013-07859.pdf>. [Accessed 30 December 2013].
- [73] President's Council of Economic Advisers, "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages," August 2013. [Online]. Available: http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf. [Accessed 13 November 2013].
- [74] Idaho National Laboratory (INL), "Concurrent Cooling and Dynamic Line Rating Tool," 2013. [Online]. Available: http://www1.eere.energy.gov/wind/pdfs/inl_powerline_cooling_factsheet.pdf. [Accessed 16 January 2014].
- [75] U.S. Energy Information Administration, "Table 8.10.A Existing Transmission Capacity by High Voltage Size, 2012," 12 December 2013. [Online]. Available: <http://www.eia.gov/electricity/annual/>. [Accessed 27 January 2014].
- [76] CleanLine Energy Partners, "Transmission Projects Overview," January 2014. [Online]. Available: <http://www.cleanlineenergy.com/projects>. [Accessed 16 January 2014].
- [77] D. T. a. M. Smith, *Microgrid Exchange Group*, Washington DC: DOE.
- [78] Navigant Research, "Market Data: Microgrids - Forecasts for Commercial/Industrial, Community/Utility, Campus/Institutional, Military, and Remote Microgrids: 2013-2020," Q1 2013.



- [79] Pike Research, "Military Microgrids - Stationary Base, Forward Operating Base, and Mobile Smart Grid Networks for Renewables Integration, Demand Response, and Mission-Critical Security," 4Q 2012.
- [80] Endesa Red S.A., "Smart Grids," Endesa Red S.A., 2012. [Online]. Available: <http://www.smartcitymalaga.es/>. [Accessed October 2013].
- [81] Eindhoven, "Eindhoven to launch prototype trials for intelligent lighting applications," 2013. [Online]. Available: <http://www.eindhoven.nl/inwonersplein/leefomgeving/slim-licht.htm>. [Accessed October 2013].
- [82] Santander, "Smart Santander," [Online]. Available: <http://www.smartsantander.eu/>. [Accessed October 2013].
- [83] IDC Government Insights, "Smart Cities and the Internet of Everything: The Foundation for Delivering Next-Generation Citizen Services," IDC Government Insights, October 2013.
- [84] N. Silver, The Signal and the Noise: Why Most Predictions Fail - but Some Don't, Penguin Group, April 2013.
- [85] U. S. Department of Energy, "Buildings Energy Data Book, 1.1: Buildings Sector Energy Consumption," March 2012. [Online]. Available: <http://buildingsdatabook.eren.doe.gov/TableView.aspx?table=1.1.9>. [Accessed 30 November 2013].
- [86] U.S. Environmental Protection Agency (EPA), "ENERGY STAR® Program Requirements for Integral LED Lamps," 13 May 2011. [Online]. Available: http://www.energystar.gov/ia/partners/product_specs/program_reqs/Integral_LED_Lamps_Program_Requirements.pdf. [Accessed 29 November 2013].
- [87] B. Ehrlich, "LED and Power: Quality Matters," GreenSpec, 18 October 2012. [Online]. Available: <http://greenspec.buildinggreen.com/blogs/led-and-power-quality-matters>. [Accessed 29 November 2013].
- [88] Navigant Research, "Smart Appliance Market to Reach Nearly \$35 Billion Annually by 2020," Navigant Research, 6 February 2013. [Online]. Available: <http://www.navigantresearch.com/newsroom/smart-appliance-market-to-reach-nearly-35-billion-annually-by-2020>. [Accessed October 2013].
- [89] E. A. Rogers, R. N. Elliott, S. Kwatra, D. Trombley and V. Nadadur, "Intelligent Efficiency: Opportunities, Barriers, and Solutions," 24 October 2013. [Online]. Available: <http://www.aceee.org/research-report/e13j>. [Accessed 23 November 2013].



- [90] Inside EVs, "Monthly Plug-In Sales Scorecard," Inside EVs, November 2013. [Online]. Available: <http://insideevs.com/monthly-plug-in-sales-scorecard/>. [Accessed 13 November 2013].
- [91] Y. Chernova, "Who Drives Electric Cars? A close-up look at a small but fast-growing group of Americans," Wall Street Journal, 23 September 2013. [Online]. Available: <http://online.wsj.com/news/articles/SB10001424127887324123004579055112450200336>. [Accessed 23 November 2013].
- [92] U.S. Department of Energy, "EV Everywhere Grand Challenge Blueprint," 31 January 2013. [Online]. Available: http://www1.eere.energy.gov/vehiclesandfuels/electric_vehicles/pdfs/everywhere_blueprint.pdf. [Accessed November 2013].
- [93] M. L. Wald, "8 States Teaming Up to Support Electric Cars," NY Times, 24 October 2013. [Online]. Available: <http://www.nytimes.com/2013/10/25/business/energy-environment/coalition-of-states-seeks-to-spur-use-of-electric-cars.html?ref=earth&r=2&>. [Accessed 23 November 2013].
- [94] U.S. Department of Energy, "Fact #789: Comparison of State Incentives for Plug-In Electric Vehicle Purchases," 22 July 2013. [Online]. Available: http://www1.eere.energy.gov/vehiclesandfuels/facts/2013_fotw789.html. [Accessed 5 November 2013].
- [95] U. S. Department of Energy, "Fact #795: Electric Vehicle Charging Stations by State," 2 September 2013. [Online]. Available: http://www1.eere.energy.gov/vehiclesandfuels/facts/2013_fotw795.html. [Accessed November 2013].
- [96] U.S. Department of Energy, "EV Everywhere Charges Up the Workplace," 31 January 2013. [Online]. Available: <http://energy.gov/articles/ev-everywhere-charges-workplace>. [Accessed November 2013].
- [97] Pecan Street Research Institute, "Report: Impact of Electric Vehicle Charging on Electric Grid Operations Could Be More Benign than Feared," 24 October 2013. [Online]. Available: <http://www.pecanstreet.org/2013/10/report-impact-of-electric-vehicle-charging-on-electric-grid-operations-could-be-more-benign-than-feared/>. [Accessed November 2013].
- [98] E. Loveday, "Washington State: 14 Quick-Charge Stations Record Over 10,000 Charging Sessions Since May 2012," Inside EVs, November 2013. [Online]. Available: <http://insideevs.com/washington-state-14-quick-charge-stations-record-over-10000-charging-sessions-since-may-2012/>. [Accessed November 2013].

- [99] U.S. Department of Energy, "Smartgrid.gov: Recovery Act Smart Grid Programs," [Online]. Available: http://www.smartgrid.gov/recovery_act/overview. [Accessed 1 December 2013].
- [100] U.S. Department of Energy, "EV Everywhere Grand Challenge Blueprint," 31 January 2013. [Online]. Available: http://www1.eere.energy.gov/vehiclesandfuels/electric_vehicles/pdfs/everywhere_blueprint.pdf. [Accessed 13 November 2013].

APPENDIX A - KEY FINDINGS FROM NERC 2012 LONG-TERM RELIABILITY ASSESSMENT

Significant Fossil-Fired Generator Retirements Over Next Five Years

Due largely to the unique confluence of final and potential environmental regulations, low natural gas prices, and other economic factors, about 71 GW of fossil-fired generation is projected to retire by 2022, with over 90 percent retiring by 2017. With the exception of the Electric Reliability Council of Texas (ERCOT), the retirement of this capacity does not pose significant resource adequacy concerns. Reserve Margins are likely to be reduced, but to levels that are still above targets. However, retirements over the next three to four years may raise issues related to system stability and the need for transmission enhancements, which if not addressed could cause reliability concerns in some areas.

Increased Risk of Capacity Deficiencies in ERCOT as Planning Reserve Margins Projected to Fall Below Targets

Starting as early as next year, the ERCOT Planning Reserve Margin is anticipated to be 13.4 percent, which is below the NERC Reference Margin Level and ERCOT planning target of 13.75 percent. At these levels, the risk of insufficient generation resources to meet peak demand increases beyond reliability targets.

Resources Sufficient to Meet Reliability Targets in Most Areas

For the majority of the bulk power system, Planning Reserve Margins appear sufficient to maintain reliability through the long-term horizon. However, there are significant challenges facing the electric industry that may shift industry projections, adding considerable uncertainty to the long term assessment. Future uncertainties include electricity market changes, fuel-prices (natural gas, in particular), potential environmental regulations, and renewable portfolio standards.

Increased Dependence on Natural Gas for Electricity Generation

Increased dependence on natural gas for electricity in some areas has increased the need for all gas users, electric system planners and operators, and policy makers to focus more sharply on the interaction between the electric and gas industries. The adoption of highly efficient combined-cycle technology by the electric power industry and the emergence of shale gas have altered the relative economics of gas-fired generation. As a result, the dependence on natural gas by the electric power sector has increased significantly. Trends in fuel-mix changes highlighted in this assessment identify gas-fired generation as the primary choice for new capacity with almost 100 GW of Planned and Conceptual capacity expected over the next 10 years, which represents almost half of all new generation capacity.

Long-Term Generator Maintenance Outages for Environmental Retrofits

A significant generation retrofit effort is expected over the next 10 years in order to comply with Federal and state-level environmental regulations. A majority of environmental controls are expected to be put in place to meet air regulations by April 2016. In total, 339 unit-level retrofits on fossil-fired generation will be needed, totaling about 160 GW. However, there is still significant uncertainty in the forecasted values as maintenance schedules have not yet been fully evaluated by all areas.

Renewable Resource Additions Introduce New Planning and Operational Challenges

Renewable resources are growing in importance in many areas of North America as the number of new facilities continues to increase. The share of capacity from renewable resources will continue to grow, especially as significant additions are projected for both wind and solar throughout North America. In 2012, renewable generation, including hydro, made up 15.6 percent of all on-peak capacity resources and is expected to reach almost 17 percent in 2022. Contributing to this growth is approximately 20 GW of on-peak Future-Planned capacity and an additional 21.5 GW of on-peak Conceptual capacity. It is vital that these variable resources are integrated reliably and in a way that supports the continued performance of the BPS and addresses both planning and operational challenges.

Transmission Growth to Accommodate New and Distant Resources

As recent as five years ago, transmission was being constructed at a rate of about 1,000 circuit miles per year. In the last five years, over 2,300 circuit miles were constructed per year, more than doubling actual builds in the previous five years. With the current plans in place, that rate is expected to increase to 3,600 miles per year over the next five years. NERC-wide, almost a quarter of new transmission is specifically linked to the integration of renewable generation.

Increases in Demand-Side Management Help Offset Future Resource Needs

All areas are projecting at least some increased availability of Demand-Side Management (DSM) over the next 10 years to reduce peak demands, contributing either to the deferral of new generating capacity or improving operator flexibility in day-ahead or real-time time operations. NERC-wide, DSM is projected to total roughly 80,000 MW by 2022 (or about 7 percent of the on-peak resource portfolio), offsetting approximately six years of peak demand growth. However, unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of DSM involve greater forecasting uncertainty—particularly with Demand Response resources.