Utility of the Future Study

Report Compiled by the University of Illinois at Urbana-Champaign

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HOW TO COMMENT:
The draft final report by Lead Facilitators Drs. George Gross and Peter Sauer of the University of Illinois at Urbana-Champaign is open for public comment until January 10, 2019.

Any comments should be sent directly to Lynnea Johnson at lsjohnso@illinois.edu.
# Table of Contents

List of Figures ........................................................................................................................................ iv  
List of Tables ........................................................................................................................................ v 
NextGrid: Illinois’ Utility of the Future Study ....................................................................................... 1  
  Recent Illinois Regulatory Developments ............................................................................................. 2  
  Grid Modernization and Illinois Efforts ................................................................................................. 4  
  The Illinois Context .............................................................................................................................. 8  
  The NextGrid Study Process ............................................................................................................... 11  
  Overview of the Final Report ............................................................................................................ 12  

1. New Technology Deployment and Grid Integration ........................................................................... 19  
  1.1 How Today’s Grid Operates and its State of Resiliency ............................................................... 19  
  1.2 Illinois Needs a Modern Grid ........................................................................................................ 21  
  1.3 The Key Elements of a Modern Grid ............................................................................................ 23  
  1.4 Customer Needs are Changing ..................................................................................................... 25  
  1.5 Values Provided by DER to the Electricity Service Network ....................................................... 26  
  1.6 How Has Restructuring Affected the Electricity Industry in Illinois? ......................................... 27  
  1.7 Evolution of Oversight and Operation of the Electricity Supply Chain ........................................ 27  
  1.8 Technologies and Policies Affecting the Distribution System ..................................................... 30  
  1.9 Opportunities and Challenges of DER Integration ........................................................................ 34  
  1.10 What is a Smart City? .................................................................................................................. 38  
  1.11 How Will Transportation Electrification Affect the Grid and its Users? ...................................... 39  
  1.12 How are Distribution System Planning and Operation Affected by DER Growth? .................... 42  
  1.13 Determinants of DER Value to the Distribution System ............................................................. 45  

2. Metering, Data and Communications ............................................................................................... 50  
  2.1 Metering ....................................................................................................................................... 51  
  2.2 Data ............................................................................................................................................. 55  
  2.3 Communications ............................................................................................................................ 60  
  2.4 Cross-Cutting Issues ...................................................................................................................... 68  

3. Reliability, Resiliency and Security ................................................................................................. 72  
  3.1 Technology .................................................................................................................................... 75  
  3.2 People.......................................................................................................................................... 82  
  3.3 Process ........................................................................................................................................ 89
3.4 Regulation and Compliance ......................................................................................... 98

4. Customer and Community Participation ....................................................................... 107
   4.1 Overview of Stakeholder Perspectives ...................................................................... 108
   4.2 Empowering Consumers to Make Energy-Smart Choices ......................................... 111
   4.3 Data Access ............................................................................................................. 113
   4.4 Roles of Utilities, ARES and Other Entities in the Provision of Services to Customers and Communities ................................................................. 116
   4.5 Pricing Options to Benefit Customers and Communities ........................................ 119
   4.6 Market Transformation ......................................................................................... 124
   4.7 Participation by Customers and Communities in DER Opportunities .................. 125
   4.8 Energy Efficiency .................................................................................................. 128
   4.9 Electric Energy Storage (Thermal, Battery) ............................................................. 129
   4.10 Demand Response .............................................................................................. 131
   4.11 DER Ownership .................................................................................................. 133
   4.12 Transportation Electrification ................................................................................ 135
   4.13 Low- and Moderate-Income Customers and Community Issues ....................... 137
   4.14 Grid Modernization and Very Large Commercial and Industrial Customers ........ 141

5. Electricity Markets ........................................................................................................ 143
   5.1 Why Retail Markets? ............................................................................................ 147
   5.2 Background, Definitions and Relevant Literature .................................................. 150
   5.3 Market Functionality Requirements and Design Principles .................................. 157

6. Regulatory and Environmental Policy Issues ................................................................ 168
   6.1 Environmental Impacts of Distributed Energy Resources ...................................... 168
   6.2 Climate and Grid Resiliency ................................................................................ 172
   6.3 Beneficial Electrification ...................................................................................... 176
   6.4 Pathways to Decarbonization ............................................................................... 180
   6.5 Concluding Remarks ............................................................................................ 185

7. Ratemaking .................................................................................................................. 187
   7.1 Current Ratemaking in Illinois ............................................................................... 192
   7.2 Time-Varying Rates ............................................................................................ 196
   7.3 Performance Regulation ....................................................................................... 199
   7.4 Valuation of DER ................................................................................................ 201
   7.5 Additional Ratemaking Issues .............................................................................. 204
   7.6 The Path Forward and Survey Responses ............................................................. 205

8. Concluding Remarks .................................................................................................... 209
References.................................................................................................................................................. 212
Appendix A: Glossary of Acronyms............................................................................................................. 222
Appendix B: Cook County Energy Efficiency Case Study .................................................................................. 227
Appendix C: CTA’s Electric Bus Program........................................................................................................ 229
Appendix D: Load Forecasting .......................................................................................................................... 231
Appendix E: BOMA/Chicago Stakeholder Perspective ..................................................................................... 234
Appendix F: Ratemaking Terms ....................................................................................................................... 238
Appendix G: Stakeholders Perspectives on Rate Mechanisms ........................................................................ 241
Appendix H: NextGrid Calendar of Meetings .................................................................................................. 244
Appendix I: List of Participating Stakeholders ............................................................................................... 247
List of Figures

Figure 1. The 2018 leading states in grid modernization as determined by GridWise Alliance & Clean Edge ............. 6
Figure 2. The geographic footprints of PJM and MISO cover complementary regions of Illinois ....................... 9
Figure 3. Sources of Illinois electricity consumption in 2017 ........................................................................... 10
Figure 4. Conventional electric power plant ........................................................................................................ 20
Figure 5. Recent-past electricity supply chain ........................................................................................................ 28
Figure 6. Emerging future structure of the electric supply chain ........................................................................ 30
Figure 7. Solar power in Illinois .......................................................................................................................... 31
Figure 8. Integration of solar with storage for optimum use .................................................................................. 32
Figure 9. Multiple DER microgrid ....................................................................................................................... 36
Figure 10. Global urban population ..................................................................................................................... 38
Figure 11. Environmental effects of urbanization and population growth ............................................................ 39
Figure 12. Distribution feeder with delivery constraint before node 3 .................................................................. 47
Figure 13. Overview of ComEd’s operational improvements resulting from its AMI Program ............................ 52
Figure 14. Schematic of the future grid ................................................................................................................ 72
Figure 15. RR&S topical areas applicable to future grid ....................................................................................... 74
Figure 16. State energy resiliency framework ...................................................................................................... 92
Figure 17. From a one-way grid to a grid of things ............................................................................................... 144
Figure 18. TKTK design thinking model ............................................................................................................. 146
Figure 19. Differences in physical network configurations .................................................................................. 151
Figure 20. A possible set of DSP platform functions .......................................................................................... 154
Figure 21. Preliminary ranking of functionality requirements ............................................................................. 164
List of Tables

Table 1. Quad chart A, technology........................................................................................................ 76
Table 2. Quad chart B, people.................................................................................................................. 84
Table 3. Quad chart C, process ............................................................................................................... 90
Table 4. Grid disruption preparedness .................................................................................................. 91
Table 5. Quad chart D, regulation & compliance.................................................................................... 100
NextGrid: Illinois’ Utility of the Future Study

Building on two decades of leadership in public utility policy and infrastructure investment in Illinois, the Illinois Commerce Commission (ICC) launched NextGrid: Illinois’ Utility of the Future Study via its resolution of March 22, 2017 [1]. The ICC, in conjunction with the utilities, selected the Department of Electrical and Computing Engineering at the University of Illinois at Urbana-Champaign (UIUC) as NextGrid Lead Facilitator. UIUC prepared this NextGrid Final Report based on the individual reports produced by the seven Working Groups (WGs) and the report is a summary of the broad range of NextGrid issues discussed by the participating WG members at the numerous sessions held.

NextGrid brought together national and local thought leaders, subject matter experts, academic researchers and stakeholders representing all sectors of the Illinois energy community to share ideas about evolving energy, in general, and the electricity landscape, in particular. The ICC emphasized that its goal was not to drive stakeholders to reach consensus on the many emerging electricity issues facing Illinois. Rather, its objectives were to:

- Develop a common knowledge base about grid modernization;
- Identify key issues, challenges and opportunities;
- Explore legal, policy, market-based and technological options for further grid modernization efforts;
- Focus on how potential changes may impact customers, markets, communities, and the utilities who serve them.

The ICC and UIUC identified seven key topics to explore within the scope of the NextGrid study. The identified topics

- New Technology Deployment and Grid Integration
- Metering, Communications and Data
- Reliability, Resiliency and Security
- Customer and Community Participation
- Electricity Markets
- Regulatory, Environmental and Policy Issues
- Ratemaking

became the basis for the creation of the seven WGs, one for each topic. Each WG’s charge was to investigate the many policy and technology issues associated with grid modernization in the topic area. The WGs were led by independent subject matter specialists. WG participants representing a cross section of Illinois stakeholder groups were selected by the WG Leader (WGL), in consultation with ICC Staff and UIUC. The WGL was responsible for the preparation of a draft chapter for the Final Report. Each WG began with the identification of key questions and issues to address in its meetings and then engaged its members and outside experts in a series of presentations and discussions. Based on the group’s input and deliberations, the WGL(s) produced the draft WG report for submission to the UIUC facilitators.

The objective of this report is to provide an overview of the capabilities of Illinois’s current grid and an evaluation for policy makers, regulators, consumer advocates and the public at large of the tools, technologies and policies that need to be carefully considered as Illinois moves forward to bring to reality its grid of the future. The Report examines options for further grid modernization and candidate updates of state regulatory policies to ensure a cost-effective, safe, reliable and resilient electricity
system design and operations to benefit customers and communities across the state and to ensure the state’s solid economic growth. The NextGrid study scope did not include the investigation of the projected costs and benefits of grid modernization investment strategies. A thorough examination of costs and benefits of each proposed initiative is an integral and essential element of its consideration by policy makers and stakeholders as part of the future grid modernization efforts.

In the remainder of the chapter, we provide an adequate background for the issues discussed in the chapters that follow. In the next section, we review the key aspects of recent Illinois regulatory developments. We follow with a discussion of grid modernization and its key thrusts. We devote a section of the specifics of the Illinois context. An overview of the NextGrid study process summarizes the key events and the nature of the elements in the study. We conclude the chapter with an outline of the chapters produced by the seven WGs.

**Recent Illinois Regulatory Developments**

Illinois has long been a pioneer and leader in electricity service and regulation, dating back more than a century to when Samuel Insull, Thomas Edison’s assistant, moved to Chicago and began to create what eventually became the modern public utility. In recent decades, Illinois’ transformation into a national energy leader began with the Electric Service Customer Choice and Rate Relief Law of 1997 [2], which restructured the electric industry and provided a transition to competitive retail markets.


Illinois’ legislative and regulatory initiatives in electricity policy and practice have resulted in multiple benefits, such as:

- Stable electricity bills;
- Lower electricity rates with respect to national averages;
- Improved electricity supply and delivery resiliency;
- Reduced adverse environmental emissions from electricity generation and consumption;
- Deployment of smart meter technology with ability to provide granular data to help consumers manage their energy usage and the potential to reduce their costs;
- Economic growth and job creation

After the enactment of the electric industry restructuring law in 1997, Illinois’ largest public utilities elected to exit the electricity generation business and sell their Illinois generation assets or transfer them to affiliated companies. ComEd and Ameren are the two major utilities responsible to provide safe, reliable and affordable electricity delivery services, as all customers now have a range of commodity—kWh—supply options in terms of the Illinois alternative retail electricity suppliers (ARES). These new entities were introduced by the restructuring act to provide competitive electricity supply options to residential and small commercial customers. The ICC is charged with the certification and oversight of ARES and the promotion of electricity choice through its Office of Retail Market Development (ORMD) [6], which tracks conditions in retail markets and presents annual data to the General Assembly.
Residential and small commercial customers can obtain the commodity via three additional supply options: a flat-rate competitively-sourced energy supply by the utility, a market-based hourly price in line with the bulk-market price outcomes, or a default service by an ARES selected through municipal aggregation. The Illinois Power Agency (IPA) [3] was established to develop electricity procurement plans for supply to customers that continue to take fixed-price bundled service from either ComEd or Ameren Illinois. The IPA conducts a competitive procurement process for the electricity supply resources identified in the IPA procurement plan and approved by the ICC in a docketed proceeding. The IPA has been given the additional responsibility to procure annually increasing quantities of renewable energy resources to meet the state’s Renewable Portfolio Standards (RPS). The Illinois RPS was initially enacted as part of the IPA Act and requires that 25% of Illinois electricity supply be procured from renewable resources by 2025.

In 2010 the IPA Act was amended to allow municipalities and counties to adopt a provision under which these entities can aggregate residential and small commercial retail electrical loads within their jurisdiction and enter into service agreements for supply of the electricity commodity to those customers [7]. Individual customers are allowed to opt-out or opt-in to an aggregation—a choice that depends on the approach chosen by the particular municipality or county—but also retain the options to choose their own supplier or take utility supply. After a transition period, the restructuring law allowed the provision of electric power and energy to the large customers—those with peak demands of at least 400 kW—of Illinois’ largest investor-owned utilities to be declared a competitive service [8]. Customers in classes with service deemed competitive must take supply service from a retail supplier or from the utility on an hourly-pricing basis. The ICC subsequently approved the extension of the classes with service deemed competitive to those with peak demand of at least 100 kW [8].

In 2011, the EIMA legislation [4] expanded “Smart Grid” investment in Illinois and authorized up to $3.3 billion in investment by ComEd and Ameren Illinois to upgrade the grid infrastructure, with recovery of the investment costs by the utilities from customers through annual “formula rate” adjustments. As of the end of 2018, ComEd has fully deployed Advanced Metering Infrastructure (AMI)—commonly known as smart meters—and Ameren Illinois is scheduled for full deployment by the end of 2019. Illinois will have more than six million smart meters deployed by the end of 2019. AMI allows customers, utilities, suppliers and researchers to leverage data from the smart grid to provide insights into electricity consumption, offer innovative customer pricing programs and improve system resiliency and efficiency.

FEJA legislation [5] in 2016 increased the state’s investment in energy efficiency (EE) and provided incentives for utilities to allow them a return on EE investment, provided they operate successful programs to reduce customer energy consumption. A FEJA provision requires the IPA to develop and implement a Zero Emission Standard Procurement Plan and a Long-Term Renewable Resources Procurement Plan, both subject to ICC approval. The renewable procurement plan charges the IPA with the acquisition of solar and wind power renewable energy credits (RECs), in compliance with the Illinois RPS. The Zero Emission Standard is conceptually similar to the RPS and requires the purchase of zero emission credits (ZECS) from nuclear facilities to support the continued operation of two of the Illinois nuclear power plants.

FEJA is also instrumental in the initiation of “community solar” programs, which allow individual customers to subscribe to larger-scale community renewable generation facilities. The solar energy produced is credited on monthly bills to the participating customer in the community project along the same lines as if the solar panels were on their own rooftop. Large solar arrays placed in suitable locations, such as the roof of a large retail or school building, can benefit from economies of scale
and enable a broader participation by customers, such as those without ownership of a suitable rooftop, in solar energy consumption. FEJA provides additional support for community solar projects that bring savings to low-income subscribers via measures that include funding to reduce electricity bills for vulnerable populations including low-income seniors, disabled veterans, small businesses and non-profit organizations with demonstrable hardship and financial support for renewable resource-related job training and targeted community outreach and education.

The NextGrid collaborative process is the latest step in continuing Illinois’ energy policy leadership. The establishment of a reliable and affordable clean energy future requires well thought out regulatory policies that align utility interests with the goals to lower electricity bills and decarbonize the economy. The NextGrid study continues Illinois’ forward-looking approach to electricity policy and practice, and is consistent with the ICC’s role as a policy-making, regulatory and rate-setting agency.

**Grid Modernization and Illinois Efforts**

The US is saddled with a dated, inefficient and, in some cases, “antiquated” power system. To effectively meet the energy challenges of the future and maintain the nation’s economic competitiveness, we must transition to a smarter, more efficient and more sustainable electrical grid that can power the economy over the foreseeable future. The electric power sector is actively pursuing the modernization of the power system through a broad range of efforts in various, distinct areas. We provide a brief overview of a representative list of such efforts in this paragraph. Most prominent among the activities is the continued integration of distributed energy resources, such as distributed generation, advanced-power-electronics-based inverters, demand response, and energy storage, at deeper penetrations. Not only do such efforts transform the existing power system, they empower customers to be actively involved in meeting the supply-demand balance around-the-clock and drive the planning, operations and legislative/regulatory policy formulation to explicitly recognize the implications and ramifications of such resources. As these resources are integrated into the distribution grid, the need for independent distribution system operators (DSOs) that provide distribution network services along analogous lines as ISOs providing bulk grid services, becomes evident. Also, associated with the creation of DSOs is the closer coordination that must be established between ISOs and DSOs. Appropriate guidelines and policies are required for the smooth functioning of DSOs and their coordination activities with ISOs. An additional concept that requires a balanced assessment is the advisability, feasibility, scope and nature of transactive energy market mechanisms at the distribution level. Many ongoing activities focus on the adoption of advances in computer, communication, control and information technologies to craft intelligent grid solutions to enable deeper penetrations of local renewable energy and storage resources, make effective use of the microgrid structure, improve power quality, develop better load and variable resource output forecasts, enhance the grid operational flexibility and ensure system resiliency. The continual implementation of a reliable, cost-effective power system that integrates local renewable energy resources with efficient, appropriate grid solutions is vital to power the nation’s increasingly electricity-reliant economy. There are also efforts focused on improvements of the physical infrastructure assets, such as, replacement of old pole-and-wire systems to allow more effective integration of rooftop solar panels with a two-way flow of energy from the customers’ premises to the grid and vice versa instead of the conventional one-way flows. The soon-to-be-completed installation of the AMI in Illinois will ensure that all customers have more detailed and actionable information to understand their energy utilization and its impacts, as well as appropriate steps to take to lower their energy expenditures, as well as consumption so as to reduce emissions.

At the same time, there are multiple efforts to formulate and implement workable policies that can drive these efforts to create conditions which can impel the more rapid and unobstructed progress on grid
modernization. As such, the adoption of the appropriate policies and the creation of a regulatory framework that makes possible steady progress on the transformation of the existing grid into the future modernized system is a critically important element to allow customers to reap the potential benefits of grid modernization.

The term grid modernization is frequently used but, is not consistently defined, nor do we have two definitions that are exactly the same. For example, the US Department of Energy has launched a very ambitious program called the Grid Modernization Initiative (GMI) that is a Department-wide collaboration to create the modern grid of the future [9]. A modern grid must imbue the following attributes: greater resilience to hazards of all types; improved reliability for everyday operations; enhanced physical and cyber security from an increasing and evolving number of threats; additional affordability to maintain the nation’s economic prosperity; superior flexibility to respond to the variability, including intermittency, and uncertainty of conditions at one or more timescales, over a range of energy future scenarios; and, increased sustainability through energy-efficient and renewable resources. The GMI efforts include collaboration with the Department’s National Laboratories and various private and public partners on a portfolio of projects. These projects focus on “the development of new architectural concepts, tools, and technologies that measure, analyze, predict, protect, and control the grid of the future, and on enabling the institutional conditions that allow for more rapid development and widespread adoption of these tools and technologies.”

To better anchor the discussion, we adopt a working definition of the term “grid modernization” that we use in this report. We include under this term all investments, technology adoption, necessary grid modifications and policy initiatives via legislative and regulatory actions to realize the envisioned capabilities and attributes of future grids. Specifically, our working definition includes investments—both foundational for the infrastructure and/or DER-enabling—that improve the reliability, resiliency, efficiency, and automation of the T&D system. Such investments can include a broad array of technologies, including sensors, data, systems, and communications networks that enable enhanced visibility, situational awareness and detailed understanding of the distribution system and control of integrated/connected devices and resources. The technology adoption and equipment acquisition aims are to facilitate broader customer engagement in areas of energy utilization/consumption and in creation of alternatives that result in reduced CO₂ emissions. Moreover, we include under the grid modernization term, the underlying systems, data management, storage, processing and analytics that facilitate situational awareness, asset management, contingency and risk analysis, outage management and restoration. These necessary core investments underpin the required focus on grid reliability, visibility, and resiliency to provide the basis for improved operational flexibility, provide customers with greater insights and more options to manage their energy usage and enable efforts toward to achieve state policy goals, such as the integration of various DERs, including storage, to bring about reductions in emissions. Equally important is the policy formulation area via appropriate new legislative acts and regulatory initiatives in the areas of ratemaking, customer services, community choice alternatives and creation of incentives to spearhead the progress on grid modernization.

The two major investor-owned electric distribution utilities—ComEd and Ameren Illinois—serve 90% of electricity customers in Illinois. ComEd is the fourth largest US electric utility, serving more than 4 million customers in a service territory covering 11,411 square miles in Northern Illinois. Ameren Illinois covers a far larger geographic area and provides service to 1.25 million customers in the central and southern sections of the state. Both companies have made considerable progress in the grid modernization arena. We provide summaries of the progress to date in the paragraphs below based on material prepared by the two utilities.
Illinois ranks second in the US for grid modernization according to the Grid Modernization Index 2018 published by The GridWise Alliance [10]. This index tracks state support, customer engagement, and grid operations to compare state performance. State support includes grid modernization plans and policies; the customer engagement metric ranks states on their rate structures, customer outreach and data collection practices; and grid operations analyzes the deployment of grid modernization technologies. As shown in Figure 1, Illinois’s rank closely trails that of California, the state considered to have made the greatest progress on the grid modernization.

![Grid Modernization Index 2018](image)

**Figure 1.** The 2018 leading states in grid modernization as determined by GridWise Alliance and Clean Edge [10]

ComEd’s plan under EIMA provisions [4] includes a cumulative total of about $1.3 billion of capital investment plus associated expenses in electric system upgrades, modernization projects and training facilities and about $1.3 billion of capital investment plus associated expenses in smart grid upgrades. The total $2.6 billion is an added increment to ComEd’s annual capital investment program. The principal investments to enhance reliability include: refurbishment or replacement of thousands of miles of underground cable; distribution automation technology to detect reliability issues and automatically re-route power flows to improve reliability indices; digital upgrades to 16 substations through installation of microprocessor-based devices that remotely monitor the health of transformers and improve visibility to the ComEd system; improved assessment capabilities in more than 31,000 manholes; inspection of more than 880,000 wood poles and reenforcement/replacement of more than 25,000 wood poles; and, improvement in vegetation management and storm-hardened circuits. ComEd
identified benefits from the EIMA-provision investments include: large capital infusions into the Illinois economy, with over $ 5.52 billion in supply chain expenditures in Illinois since 2011; creation of 4,500 full-time jobs during the peak EIMA program year; $ 1.4 billion in societal savings due to 7.6 million avoided outages since the launch of the EIMA program, with reductions in the average frequency and duration of outages by nearly 50 %; 37 % reduction in the number of ComEd customers impacted by storms since 2012; and, rate stability and affordability. In term of rates, the average residential customer bill 10 years ago, was about $ 81 and in January 2017 it was about $ 82. Indeed, ComEd’s per kWh residential rates are below the national average—almost 19 % below the top 10 US cities by population size. Some stakeholders note that the lower Illinois electricity bills are impacted by the lower electricity bulk market prices.¹

Ameren Illinois customer loads are fairly evenly split between residential—32 %, commercial—36 % and industrial—32 %. Prior to the 2008 economic recession, electricity volumes grew at an annual rate in the 1–1.5 % range. Subsequently, customer loads became flat or declined, with the most pronounced drop in the industrial sector. Ameren Illinois’ future outlook is for loads to remain flat or decline, as a result of the combined impact of various factors, such as population growth, manufacturing and commercial sector performance, GDP and economic development, energy efficiency implementation, wider distributed energy resource deployment, increased sales of electrical vehicles and additional electrification. Ameren Illinois’ EIMA related infrastructure plan includes about $ 278.2 million in capital investment plus associated expenses in electric system upgrades, modernization projects and training facilities. The plan includes also about $ 437 million of capital investment and associated expenses in smart grid upgrades. The total cumulative capital investment of $ 715.2 million under this plan is an added increment to Ameren’s annual capital investment program.

Ameren Illinois’s Modernization Action Plan has focused on the following key areas: implementation of an advanced distribution management system (ADMS) with enhanced Supervisory Control and Data Acquisition (SCADA) capabilities, with the added monitoring; enhanced communication infrastructure including for the underground network; automation of the high-voltage and primary-distribution systems; addition of remote metering and monitoring capabilities at distribution substations; replacement of electro-mechanical high voltage distribution relays by solid-state devices; enhanced voltage optimization control based on the added communication and control capabilities to voltage-control devices; and, implementation of a smart-grid test bed, with DER integration and microgrid testing infrastructure. As a result of the completion of these projects from 2013 to 2017 the following increased: distribution substations with remote control and/or monitoring capabilities from 48 to 69 %; high-voltage distribution circuits with remotely controlled and/or monitored devices from 91.0 % to 99.6 %; primary distribution circuits with remotely controlled and/or monitored devices from 57 % to 75 %; and meters served from an automated primary distribution line from 2 % to 19 %.

The investment in these projects, coupled with other infrastructure and operational initiatives, have resulted in 238,000 fewer electricity service interruptions on average and a 17% increase in overall reliability. Ameren expects to complete its AMI deployment to all of its 1.25 million Illinois customers by the end of 2019, with over one million electric smart meters installed by the end of 2018. Ameren Illinois’s radio field-area network can be leveraged for other grid-modernization efforts that require or use wireless communication channels. The company is using its smart-meter solution for billing statements, interval usage collection, customer data presentation, third-party data access, remote

¹ Information provided by ComEd.
service orders, operational analytics, its Peak Time Rewards program, integration with outage management and communication with devices connected to behind-the-meter home area networks (HANs). In 2018, Ameren Illinois initiated the collection and analysis of interval data beyond usage, including voltage, temperature and amperage to improve operations and provide better customer service.\(^2\)

While Illinois has made considerable progress in grid modernization, changes in the ways the grid is used may require continuing grid modernization efforts. The key drivers of additional grid modernization include: deepening penetrations of clean DERs; wider deployment of microgrids for delivery of electricity with increased resilience and efficiency; greater reliance on application of analytics and other data-driven tools to generate more granular electricity usage data, with potential for improved customer energy management and cost reduction; improved methodologies for protection of the system against cyber and physical attacks and for enhanced security of physical grid assets; and, development of regional transactive energy markets at the distribution level. The need for additional grid modernization investment is subject to divergent stakeholder perspectives and expectations. Some stakeholders do not anticipate need for further grid upgrades beyond those that are currently underway. These issues and views are fully explored in subsequent chapters of this NextGrid Final Report.

**The Illinois Context**

Illinois is the fifth most populous state in the nation and is anchored by Chicago, the nation’s third largest city and a global economic leader with, by some measures, the eighth largest GDP of any city in the world [11]. Chicago’s central geographic location and proximity to waterways, railroads, major highways and airports have made it a major North American transportation hub. With its navigable system of waterways leading to the Mississippi River, Chicago is the only direct maritime connection between the Great Lakes and the Mississippi River basin. O’Hare International Airport is the third busiest airport in the country and fifth busiest in the world. Moreover, the Chicago region is the nation’s main rail freight hub, with approximately 25 percent of all freight trains and 50 percent of all intermodal trains in the nation passing through metropolitan Chicago, the continent’s main interchange point between western and eastern railroads [12].

Outside the Chicago region, Illinois has approximately 27 million acres of farmland and ranks among the top 10 states in the market value of agricultural products sold. Illinois is one of the top ethanol-producing states and, is also a leader in biodiesel production capacity. It has more than 4,200 MW of utility-scale, wind-powered electricity generating capacity. Illinois is a key transportation hub for crude oil and natural gas, with eight crude oil pipelines, eight petroleum product pipelines, 18 interstate natural gas pipelines, two natural gas market centers and two petroleum ports [13].

Illinois also has the largest fleet of nuclear power plants in the nation with a total capacity of nearly 12,000 MW—one-eighth of the nation's nuclear power generation capacity. Almost half of all electricity generation in Illinois is generated by the state’s six nuclear power plants with a total of 11 units [13]. All nuclear plants in Illinois are entirely owned by Exelon Generation Company, with the exception of the Quad Cities Nuclear Generation Station, whose ownership is shared by Exelon Generation Company (75 %) and Mid-American Energy Company (25 %). Nuclear plants are under competitive pressure from low natural gas prices and new variable output generation from solar and wind facilities. The enactment of FEJA represents the strong support of the continued operation of

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\(^2\) Information provided by Ameren Illinois.
Illinois nuclear plants by Illinois legislators in light of the reliable baseload power they provide, thousands of long-term jobs and a very large source of carbon-free electricity.

Illinois’s transmission-owning utilities are members of two regional transmission organizations (RTOs), whose footprints cover different portions of the state. ComEd is a member of PJM Interconnection, while Ameren Illinois and MidAmerican Energy are members of the Midcontinent Independent System Operator (MISO). The geographic footprints of the two regional transmission organizations (RTOs) are shown in Figure 2. An RTO is an independent, not-for-profit entity regulated by the Federal Energy Regulatory Commission (FERC) that operates both the transmission grid and the associated wholesale electricity markets and also is responsible for the planning of the bulk grid in its region. An RTO is the “cop on the beat” whose primary responsibility is to ensure the grid resiliency. While an RTO does not own any assets other than its Energy Management System that controls the grid, its activities in market and system operations ensure that the second-by-second supply-demand balance is maintained around the clock and that the system operates securely and efficiently. In addition, the RTO ensures resource adequacy and is the transmission access and service provider to all entities that participate in the wholesale electricity markets.

![Figure 2](Image)

Figure 2. The geographic footprints of PJM and MISO cover complementary regions of Illinois

Illinois’ restructuring act in 1997 led to end of the vertically-integrated utility structure. The utilities divested their generation assets or transferred them to unregulated affiliate companies but retained their transmission and distribution system assets. All transmission terms, rates and conditions fall under the exclusive jurisdiction of the FERC, but states retain jurisdiction over siting issues. Illinois utility distribution systems are regulated by the ICC.

Transmission and distribution systems are commonly referred to as “grids.” The backbone of the electricity system is comprised of high-voltage transmission lines that connect the generation resources to the loads. This interconnection of the generation and load resources with the transmission network is referred to as the “bulk” power system, which is designed to move large volumes of electricity over long distances from the generation source to the point of distribution to end users. Illinois’ transmission lines transmit electricity at voltages that range from 69 kV to 765 kV.
The electric transmission system ownership in the United States is shared by various private and public electric entities. The Illinois transmission grid consists of numerous sections, each with unique ownership. The principal entities that own transmission assets in the Illinois grid are:

- ComEd transmission networks with 5,300 miles of lines;
- Ameren Illinois transmission network with 4,638 miles of lines;
- MidAmerican Energy Company’s Illinois transmission network with 336 miles of lines;
- Ameren Transmission Company of Illinois (ATXI) with 303 miles of lines;
- Several municipal and cooperative utilities also own transmission lines in Illinois.

Figure 3. Sources of Illinois electricity consumption in 2017

The distribution companies Ameren Illinois and ComEd no longer own power plants or transmission lines but they acquire their electricity supplies in the PJM and MISO markets. The sources of electricity consumption with their associated shares for Ameren and ComEd\(^3\) in 2017 are shown in Figure 3.

\(^3\) These figures constitute the aggregation of information provided by ComEd’s wholesale energy suppliers, all of whom have indicated that their source is the “PJM system mix”. The PJM system mix data is from PJM Environmental Information Services, Inc. (www.pjm-eis.com).
The NextGrid Study Process

The NextGrid initiative is a response to an effort proposed in Governor Rauner’s 2015 Transition Report “to review the implications of the ‘utility of the future’ on existing laws and regulations, ownership structure, pricing designs and incentives” [14].

The NextGrid Study is not a docketed proceeding of the Commission and there is no Commission Order pursuant to this initiative. The NextGrid collaborative effort has not involved hearings, testimony or cross-examination. Opinions of NextGrid participants and drafters of the report do not necessarily represent the views of all stakeholders or the ICC or any of its members.

The NextGrid effort was formally launched on September 28, 2017 with a one-day event held at the University of Illinois-Chicago. The launch included panel discussions on various aspects of grid modernization, an overview of the study scope by the Lead Facilitator and featured Robert F. Powelson, the former FERC commissioner, in a keynote speech. The event drew over 400 attendees.

A team of professors headed by George Gross and Peter W. Sauer from the Department of Electrical and Computer Engineering at the University of Illinois at Urbana-Champaign (UIUC) was selected to act as the NextGrid Lead Facilitator. UIUC’s College of Engineering is a world-renowned research and educational institution, with a well-earned reputation among the top-ranked engineering schools in the world. The expertise of the professorial team includes many areas related to grid modernization. The Lead Facilitator helped the ICC to structure the study and its scope, identify the major topics of interest in grid modernization, monitor and guide the work of the seven WGs instituted for the study and present progress reports to the public at large. The Lead Facilitator is also responsible to ensure that the final report is technically sound and well supported by the latest developments in research and technology.

The UIUC Lead Facilitator prepared this Final NextGrid Study Report based on the reports submitted and produced by the seven WGs. Also convened were two advisory groups, the Stakeholder Advisory Council (SAC) and the Technical Advisory Group (TAG) to provide guidance and counsel during the course of the study. The SAC membership is made up from thought leaders who represent broad range of utility industry stakeholders, including environmental groups, investors, research entities, vendors, consumer advocates and state and local policymakers. The TAG members are national and international subject matter experts, who provided valuable advice to the WGs and ICC throughout the study.

Three study update and public comment sessions were held in Chicago, Urbana and Carbondale. These sessions provided the NextGrid Lead Facilitator and WGLs the opportunity to report to the public on the progress of the Study and for the public to comment on and ask questions about NextGrid issues. Readers of this report may visit the NextGrid website [15] to view all the WG agendas, presentations, meeting summaries, surveys, reading lists, case studies cited, surveys and miscellaneous supporting documents. Two Appendices are part of the Report to summarize relevant information. Appendix H and Appendix I provide a list of all the WG meetings and a list of all participants in the WGs, TAG and SAC, respectively.

The draft version of this Report was submitted by the Lead Facilitator on December 14, 2018, to the ICC for its upload on the ICC website to allow the public to have the opportunity to review and comment. The Report does not incorporate all the comments received from the public and the seven NextGrid WG members. The Lead Facilitator read the entire set of comments and made appropriate modifications in the text in cases where such changes were warranted. This Final version incorporates the additional modifications in light of the comments submitted on the draft version.
Overview of the Final Report

The rest of the report consists of the seven chapters of the individual WG reports and one additional chapter that presents concluding remarks. In addition to the WG chapters, there are several Appendices that contain additional background information to provide the necessary background or help explain the information contained in the WG chapters. The Lead Facilitator edited each report prepared by the WGL and made the necessary changes and constructed the required bridges for the Final Report to be comprehensible. As many electricity grid issues are cross-cutting and interconnected, a particular issue was common to the scope of two or more WGs. The WGLs were responsive to the concerns of participants and so each WG’s deliberations focused on, typically, different aspects of the common topics and each WG’s members addressed their aspects through distinctly different optics. Every attempt was made to reduce repetition in the report to the extent possible.

At the kick-off plenary meeting of all the WGs, the seven WGLs were asked to consider a set of core questions within the Illinois-specific context. The set of questions consists of the following items:

- What “Smart Grid” technologies/policies/practices currently exist in Illinois? Are they being used to maximize their value? What additional needs exist that cannot be met by currently available Smart Grid elements?
- What specific opportunities for grid modernization in Illinois and how will they improve grid operations, reliability, power quality, and resilience? What are the challenges to be overcome to make those opportunities realizable?
- What changes in technologies are occurring that will provide new methods and means to provide Smart Grid products and services?
- What are the barriers to customer, utility and market adoption of beneficial technologies and new products/services?
- How can those benefits and associated costs be projected and quantified?
- How will relevant trends in technology, customer behavior, and markets affect reliability, service quality, resilience, and costs to customers and utilities?
- What are the existing statutory and regulatory goals, policies, programs, rate structures, and legal requirements, if any, covering these functions, products, and services?
- What specific policies and regulatory initiatives exist or could be implemented to encourage further development and integration of distributed generation and renewable energy resources, community initiatives such as PV and energy storage projects, and greater deployment of energy efficiency technologies.
- What is the existing and potential role of state regulatory policy regarding interconnected smart devices and appliances, micro-grids, electric vehicles, big data and analytics?
- What legal and practical steps would be needed to establish a framework allowing buyers and sellers of distribution-connected resources to conduct and settle transactions in an effectively competitive market?
- What are the options for modifying existing goals, policies, programs, rate structures, and legal requirements to optimize future outcomes for the grid and its users?
- What policies, programs, and initiatives can ensure that grid modernization will educate and empower customers and communities, drive economic development,
support innovation, and optimize the Illinois electric utility industry for the 21st Century?

Each WG had four or more meetings featuring expert presentations and group discussions conducted under the “Chatham House Rule” that provides anonymity to speakers in order to encourage open exchange of views.

We provide an overview of the body of the Final Report in the paragraphs below. The many WG sessions gave rise to a very wide range of viewpoints that are representative of the diverse group of participating stakeholders. While there were a few issues on which a modicum of agreement arose, the more typical situation was the often opposite views voiced in the many deliberations. There was no attempt to develop consensus in these discussions as such an objective was not within the scope of the NextGrid study. The WG reports, briefly summarized below, reflect these clearly and in adequate detail the diverse views that the discussions elicited.

Chapter 1 presents the report of WG1, whose focus centered on new technology deployment and grid integration. In an era of rapid technological evolution and changing social, commercial, and individual energy requirements, a high-performance electricity grid is essential to maintain a reliable and secure supply and deliverability of affordable and environmentally responsible electricity in Illinois. The WG1 report describes the emerging transformation of the electricity distribution grid (d-grid) from a one-way system designed to deliver bulk power from utility-scale generation to end-use customers, into an advanced network that can accommodate bidirectional flows between any pairs of nodes, in addition to those to and from the bulk power systems to which the distribution network is connected. The report addresses 15 questions related to the evolution of the d-grid.

In light of state mandates and ongoing electricity industry and market developments, a rapidly growing number of integrated DERs into the d-grid is anticipated in coming years. New hardware and software technologies and utility operational practices are needed to integrate DER technologies and to effectively harness their capability and value to d-grid customers. Stakeholders have different expectations regarding the pace of change and the need for grid investment and the associated regulatory adjustments, however, they generally agree that the customer value derived from new technology and DER needs to drive the pace and scope and nature of utility and regulatory response. There are extensive future grid needs for digital sensors, monitoring capability and information, communication and control technologies to enable integration of distributed energy resources (DERs) and facilitate transactions among energy market participants in regional markets associated with the d-grid. Moreover, there are needs for enhanced capability to protect and automatically optimize operations of its interconnected elements—from central and distributed generators and energy storage resources, to industrial customers and building automation systems, to demand-response providers and to residential and commercial customers and their thermostats, EVs, efficient and smart appliances, DERs, including energy storage resources (ESRs), and miscellaneous other connected devices.

Grid operations and planning become considerably more complex with the proliferation of DERs and other smart grid technology elements. Visibility and situational awareness of DERs to grid operators is essential as the grid becomes more dependent on non-grid assets and, in some cases, non-wires alternatives for reliability. In addition, their growing prominence necessitates formulation of new rules, procedures and appropriate policies. Adoption of advanced control and communication technologies, as well as sophisticated computational resources and algorithmic developments become necessary to accommodate the resultant grid changes. In addition, interdependencies of large infrastructure networks including electricity, natural gas, telecommunication, transportation, water and other “smart city”
networks need to be considered in strategic planning for electric grid modernization in a systematic manner.

Electrification of current, fossil-fueled technologies, such as on- and off-road transportation, industrial processes, buildings and farming applications, has huge potential to benefit customers, communities, the grid, the environment and the nation’s economic wellbeing. Creation of the grid of the future in Illinois may require formulation of new policies and regulatory approaches to ensure continued integrity, security and resiliency of the system and to meet societal goals of affordability, efficiency, environmental improvement, competitiveness and job creation.

Chapter 2 presents the report of WG2, whose focus centered on metering, data and communications. The WG2 report provides a comprehensive overview of the current state of metering, data collection and its frequency and the salient characteristics of the communication networks used by ComEd and Ameren Illinois to enable the reliable delivery of energy services. In addition, the chapter provides background information about how AMI deployments enable enhanced customer service and functionality, as well as collection of information on the development of private utility networks with adequate reliability, bandwidth and security to enable AMI and grid control functions. Key challenges identified by WG2 largely point out the need for common standards associated with data formats from meters and DERs and standards for how current and future network devices, including DERs, communicate with the grid, its operators and customers. Information dissemination needs include efficient mechanisms to provide real-time pricing signals to connected devices to allow timely, device-level, price-based decision making. Further issues raised include interconnection rules, availability of more granular data, rules for data access, data privacy protection and effective cost recovery mechanisms for additional data and communication-related expenditures.

WG2 members also discussed how metering, data and communications functions and infrastructure can be upgraded to meet evolving regulatory objectives and customer and grid needs. While stakeholders generally agree it is technically feasible for the grid to integrate deep DER penetrations and to enable dynamic markets, including peer-to-peer energy transactions, the needs for metering, data and communications investments depend on market structure, regulatory rules and procedures and rate constructs. WG2 recommendations include the identification of technology requirements responsive to customer needs with the appropriate levels of security, accuracy and reliability. Once technology requirements are identified, further study is needed to formulate the necessary technical standards and to modify regulations and/or enact state laws to accommodate new infrastructure design, deployment and operations.

Chapter 3 presents the report of WG3, whose focus centered on reliability, resiliency and security (RR&S) aspects of the grid. The confluence of these three critically significant grid attributes provides the basis for a meaningful evaluation of the grid performance. The discussions addressed the challenges faced in the interactions among those who protect, operate, regulate, and use the grid in an environment of rapid DER growth, uncertain grid operational flexibility and many new physical and cyber security challenges. Grid modernization needs to include tools, technologies, data and solution approaches that appropriately and cost-effectively ensure the grid operates as required and adapts to future electricity needs of Illinois with acceptable levels of RR&S. This chapter identifies the key challenges, opportunities, solutions and potential action items in the RR&S domain. The ramifications of potential actions, inactions and external factors and their impacts on consumers, utilities and the environment are carefully detailed. The various discussions shed light on the increasing reliance of grid operations on information technology advances, digital communications and control, growing sophistication of adversaries—including well-resourced nation states—and the incorporation of emerging technologies,
such as internet of things (IoT), cloud computing, software design networking (SDN), machine learning, analytics, artificial intelligence (AI) and blockchain/distributed ledgers, to mention just a few. Indeed, such reliance presents an ever-shifting and dynamic threat landscape. Success in the assurance of RR&S requires the active participation from all stakeholders, not simply just the utilities and regulators. While higher levels of RR&S are attainable, the associated high costs and the practicality of such solutions fail to meet any cost effectiveness tests. Indeed, surveys by utilities indicate the lack of willingness to pay by customers for such costly fixes. However, the definition of an acceptable risk level is a major challenge facing both utilities and regulators. Continuing interactions among consumers, vendors, grid operators, utilities, regulators and other stakeholders is highly necessary to ensure the future grid delivers efficiency, convenience and customer empowerment with adequate levels of RR&S maintained.

Chapter 4 presents the report of WG4, whose focus centered on the changes underway in the ways that customers and communities participate in an electricity system characterized by a proliferation of “behind-the-meter” energy resources, availability of finer granularity consumption data, automated demand response, increasing electrification of transportation and other industrial sector loads, continuing technological innovation and a growing array of energy product and service options for customers of all sizes. Specific topics addressed by WG4 participating stakeholders included consumer engagement, education and empowerment, retail market opportunities and challenges, market transformation, the changing roles of public utilities, ARES, and other Illinois electricity sector entities, options for electricity pricing, opportunities and challenges of DER and transportation electrification, the needs of low and moderate income (LMI) customers and the perspective of very large commercial and industrial (VLC&I) customers.

The scope, scale and specific elements of emerging trends that directly impact customers and communities are subject to various sources of uncertainty. Therefore, Illinois stakeholders expressed diverse views about policies, programs and regulatory responses, which were discussed for each issue in the WG4 sessions. Many energy policy considerations are complex and multi-faceted, with multiple objectives that may entail various tradeoffs among each other. For example, usage data must be easily accessible, but customer privacy must be protected. Consumers must have an array of competitive options, but they must be protected from false and misleading marketing. The grid must be upgraded as needed to meet the requirements of all customers and communities, but electricity services must remain affordable. Public utilities must be responsive to their customers’ changing needs, but competitive market innovation must not be stifled. The wider deployment of beneficial technologies, such as rooftop solar, energy storage and EVs requires the support of appropriate policies, but regulators must also ensure that all customers, not only the direct participants, benefit from such deployment. Large industrial and commercial customers must share in the costs to achieve the state’s energy goals, but the ability of Illinois businesses to compete in global markets must also be maintained.

These goals cannot be viewed as conflicting objectives, because energy policy is not a zero-sum game. A key theme of the lengthy WG4 deliberations is that well-thought-out policies can build on Illinois’ strengths to strike the right balance and achieve the state’s social, environmental and regulatory objectives. The construction of the appropriate answers to myriad regulatory policy questions will require further studies at a deeper level and the discussions among the WG4 members posed an extensive list of threshold questions to frame the key issues together with a set of specific issues to be addressed by policy makers. These are all deserving of in-depth investigation and comprehensive analysis to ensure that the future grid meets tomorrow’s needs as the provision of resilient, safe, reliable,
affordable, efficient and sustainable electricity service continues to all Illinois customers and communities.

Chapter 5 presents the report of WG5, whose focus centered on the possibility to establish transactive electricity markets at the distribution level nodes to allow the trade of electricity on a regional basis. The growth of consumer-oriented digital technologies to automate and manage energy use, as well as the deepening penetrations of EVs and DERs, including renewable and ESRs, bring the digital economy into electricity markets and create the opportunity for customers of all sizes to own DERs, so as to become so-called “prosumers.” WG5 focused on the identification of the opportunities that digital and DER technologies create to develop more distributed and technology-enabled retail markets through more widespread consumer-prosumer-producer participation in regional markets associated with distribution systems. WG5 participating stakeholders worked on terms and understanding of new retail market approaches and emphasized thinking about retail markets from a functional perspective rather than a role-based or entity-based perspective. The stakeholders discussed issues associated with transactive energy and the technical and economic implications of moving toward a grid services platform business model.

WG5 discussions on various methods to increase customer access to new technologies and to stimulate distribution-level market participation explored market-based platform transactions that the d-grid can enable and considered specific ways to enhance consumer access to potential future competitive markets in Illinois. The WG did not include the development of a market design within its scope, rather the WG5 participating stakeholders suggested a process and a path for the ICC to follow as it engages in a market design process intended to create a fair and open framework in which DERs are valuable resources. WG5 members explored the elements of “design thinking,” under which, questions are evaluated from the perspective of diverse parties who use the product—in this case, a market mechanism that allows all participants to engage in energy transactions in Illinois. Such a perspective requires efforts to discover preferences and empathy—the ability to project the design from different viewpoints.

The WG5 discussions suggest that the process for the ICC to explore retail market design needs to start with a vision, an idealized proposition of desired outcomes, including one which is an expanded domain of value creation for and by customers via competitive markets. From the perspective of that vision, the task is to develop a roadmap, with specified high-level incremental end points that correspond to the vision. The roadmap can be used to develop functionality requirements and design principles based on those explored in the WG5 deliberations. Some of the stakeholders suggest the importance to evaluate those functionality requirements and design principles with a view toward optionality—so as not to settle on “the answer” too early in the roadmap process. Testing of a proposed market design is crucial and is a fundamental aspect of a design thinking process. In digital market design, testing takes several forms because these markets are technology-mediated interactions. Computer simulation is a viable first step, followed by experimental economics and agent-based modeling investigations to test behavioral responses and to tune the revised market design. The efficient and effective coordination of customer demands and DERs may require the integration of various transactional market functions such as forward and real time commodity markets with service markets based on smart technology and value-added utility and third-party services. Both the transactional and service markets may be platform markets. Platform markets are multi-sided, in that they provide the infrastructure components and rules to facilitate transactions among many producers and consumers. Platform markets can lower transaction and settlement costs, enable easy access to commodities and services, engage unused capacity and accelerate innovation. The integration of efficient markets and dynamic grid services
offers opportunities to create a more affordable, resilient and environmentally sustainable power system. WG5 discussions did not include the consideration of the legislative/regulatory policies required to remove existing roadblocks to the establishment of the regional markets discussed extensively in the WG5 sessions.

Chapter 6 presents the report of WG6, whose focus centered on policy questions related to environmental and climate issues associated with electricity generation, delivery and consumption/utilization and how to address them in Illinois. WG6 discussions concentrated on three aspects of environmental and regulatory issues related to grid modernization—the DER environmental impacts, climate and grid resiliency and pathways to decarbonization. Moreover, the WG6 members selected beneficial electrification as a fourth topic to include in their deliberations.

While the participating stakeholders generally agreed on the importance to address climate change, there were different views as to the role of state policy at the current stage. Lack of a carbon policy in Illinois or at the federal level was identified as a major impediment to wider DER adoption. Absent a dollar value—be it a price or a tax—associated with carbon emissions, electricity generators, distribution utilities and customers have no financial incentives to reduce carbon pollution, transition to cleaner technologies and implement efficiency or clean energy supply strategies on a broader scale. Some stakeholders caution that there must be careful vetting of the economic impacts of any changes in environmental/regulatory policies to identify potential ramifications which may include higher electricity costs, cost-shifting among customer classes and financial harm to Illinois industry’s competitive position relative to that of other Midwest states. These concerns must be balanced against environmental and other benefits to ensure that new policy initiatives result in net benefits for Illinois customers.

WG6 members discussed various decarbonization policies, such as establishment of a price on carbon or cap and trade system at the federal level and/or for Illinois to join an existing sub-national carbon market and encourage uniform policies among neighboring states. Additional policies discussed included the institution of a state zero-emission vehicle standard, expansion of investments in DER and clean-energy technology deployment, particularly in low-income communities, enhancement of clean energy incentives and standards, adoption of non-wires alternatives to defer electricity generation and distribution upgrade investments, and provision of customers a wider range of clean energy choices and time-varying rate options. The beneficial electrification discussion examined the replacement strategies of fossil-fueled transportation and industrial process loads by electricity utilization.

In case that Illinois, through its elected officials, enacts a specific carbon reduction strategy, including a price/tax for carbon emissions, many WG6 participating stakeholders suggested that a public educational campaign needs to be undertaken to clearly articulate why such a program is required, delineate its impacts on individuals, businesses, and communities, and explain the rationale for the carbon revenue allocation and its implications.

Chapter 7 presents the report of WG7, whose focus centered on the different rate structures that may be deployed in an environment of DERs, market transactions, fine granularity data, digital technology, customer choice, and increased public involvement to meet energy objectives. Expert presentations on various time-varying rates and on a broad range of options for the future were effective to get the deliberations of the WG7 participating stakeholders into high gear. The objectives of ratemaking are framed by legislative mandates, well-established regulatory principles, judicial decisions, and specific policy objectives. Stakeholders’ emphasis was on various aspects, such as affordability of rates, the ability of utilities to earn a just return on invested capital, allocation of risk between customers and
utilities, incentives to improve performance and outcomes, promotion of operational and energy efficiency, effective price signals and rate design based on principles of cost causality and fairness to customers. ComEd and Ameren Illinois currently operate under an annual formula ratemaking framework provision of EIMA, which was extended by the Illinois legislature through 2022. The formula rates pertain to delivery services only, as electricity supply is competitively sourced and a matter of customer choice. The allocation of costs of utility-provided services among and within customer classes is determined by the ICC in triennial rate design cases.

There are multiple options for future Illinois ratemaking, beyond the further extension of formula rates through legislation. These alternatives range from a return to conventional cost of service regulation, under which utilities file proposed revenue requirements and go through a lengthy evidentiary proceeding conducted by the ICC, to a variety of alternative ratemaking structures that adjust rates and revenues based on external and internal factors that may include utility performance on a range of specified criteria, economic inflation, investment in particular technologies and other incentives to attain regulatory objectives. WG7 members engaged in robust discussions whose range was rather broad. At one end, are those who advocate a return to conventional cost of service ratemaking for utility services as appropriate given that the smart grid is fully deployed. At the other end, are those who assert that public objectives such as energy efficiency, full integration of DERs and expanded market and transactional opportunities for customers can be better advanced through alternative rate structures that attempt to align incentives with specified goals. The participating stakeholders also aired distinct views about rate design, including issues of fixed versus volumetric cost recovery for various delivery services. Some participants stressed the economics basis for efficient rate design and cost-based price signals as essential components of a well-functioning system. Others asserted that the pillar for cost allocation and rate design requires a new marginal cost study, which has not been performed by a large Illinois utility since the 1990’s. Yet, there were also those who emphasized that ratemaking must focus on the attainment of desired objectives, specifically fairness and affordability to consumers.

Additional issues discussed by WG7 participating stakeholders included alternative utility business and revenue models, standby rates for self-generators, and the proper valuation of DERs to fairly compensate the provided services, an issue that is set to be the subject of future ICC proceedings. There was general agreement among the WG7 participants that future dissemination of information and opinions, as well as, further research and outcomes of innovative rate pilots will help Illinois achieve a ratemaking outcome that results in safe, reliable, resilient, cost-effective, sustainable and secure electricity services.

The last chapter provides a summary of the key thrusts of the NextGrid Study and points out the many areas that require careful investigation.
1. New Technology Deployment and Grid Integration

This WG1 report describes the emerging transformation of the electricity distribution grid (d-grid) from a one-way system designed to deliver bulk power from utility-scale generation to end-use customers, into an advanced network accommodating bidirectional flows (to and from the bulk power systems to which the distribution network is connected) equipped with digital sensors and state-of-the-art information, communication and control technologies which will facilitate transactions among energy-market participants and enable integration of DERs.

Tomorrow’s grid will need enhanced capability to monitor, protect and automatically optimize operation of its interconnected elements—from central and distributed generators and energy-storage systems connected through the system, to industrial customers and building-automation systems, to demand-response providers, and to residential and commercial customers and their thermostats, electric vehicles (EVs), appliances, distributed generation (DG) energy storage and other connected devices.

The modern d-grid may spur innovative products and services by enabling collection, storage and retrieval of information to which data analytics can be applied for efficient deployment and utilization of system resources. It may provide customers with opportunities to minimize their energy costs by optimizing their usage patterns and facilitating participation in markets, leading to environmental benefits, including reduced carbon emissions. The underlying system may organize information and provide connectivity, allowing market participants to interact. When it completes its transformation from a one-way system for electrons into an integrated system that optimizes opportunities for customers, provides data and information and facilitates introduction of innovative products and services, the grid may become the organizing platform for a connected energy ecosystem capable of delivering increased value to customers and society.

This report based on presentations and discussions that occurred in a series of WG meetings, examines the resource and technology innovations that may be deployed by grid operators as well as by customers and other providers in the d-grid. These include a range of DERs including EVs, solar photovoltaics (PV), demand-response technologies, as well as other DG forms and storage resources. The report will also review high-level methods to value DERs from the perspectives of the distribution system and its users. It will examine how the functions performed by the utility and other electricity-system participants may change to maximize efficient integration and operation of new technologies while ensuring safety, reliability and resiliency.

1.1 How Today’s Grid Operates and its State of Resiliency

The conventional electric power system is a network of electrical components that supply, transfer and use electric power, with the electricity flowing in one direction, from power plant to the customer, as seen in Figure 4. Such an electric power system can be broadly divided into the following distinct functions:

- **Generation**—electricity supply by a producer to serve load (power plant)
- **Transmission**—electricity transfer from generation to load center at high voltage, often over long distances
- **Substation**—stepping down of electricity from transmission voltage (high) to distribution voltage (low)
- **Distribution**—electricity transfer from substations to the customer
Figure 4. Conventional electric power plant

This basic architecture has prevailed for over a century. The transmission system has become increasingly interconnected and networked, but the distribution system outside dense urban areas is still a radial system that distributes power from substations to customers.

The transmission system brings power from (sometimes) remote large generators to load centers, at high voltages—in the United States generally at 125 kilovolts (kV) and above, (up to 765 kV.) Then, sub-transmission (or high-voltage distribution) further distributes power from the transmission system to distribution substations and can be operated either networked, or radially at voltages typically between 35 kV and 69 kV. Distribution (or low-voltage distribution) is mostly radial and generally at lower voltages (although there are some specialized high-voltage facilities that perform a distribution function for very large customers).

While ac transmission and sub-transmission is always balanced three-phase, distribution can be one, two, or three phases, primarily depending on the load along a given circuit path. Service transformers step the voltage down to the 120- and 240-volt level that residences and small commercial facilities typically use, or to the 480-volt three-phase level for larger commercial facilities. Planning, engineering and operating the distribution system infrastructure are becoming more complex with the deepening penetration of DERs. Distribution system operation includes the following tasks:

- Monitor system conditions, events and integrity
- Maintain system configuration
- Facilitate work safety while maintaining service
- Adhere to protection zone
- Monitor system integrity
- Write switching requests
- Restore service

Distribution planning adds these responsibilities:
• Ensure the system’s long-term integrity and resiliency
• Manage system risk: long-term and real-time
• Arrange outage requests
• Recommend projects that address system constraints and accommodate growth and changes
• Forecast changes at the grid edge

Because major portions of distribution circuits are mounted overhead on wooden poles alongside streets and often close to or through trees, it is subject to damage-causing outages on a routine basis due to vehicles hitting poles, tree limbs falling, animals causing short circuits and so on. Severe weather may result in tens or even thousands of outages, and managing outage restoration is a major utility focus.

Utilities have also become increasingly involved in disaster preparedness. They can take advantage of a large mutual assistance network of other utilities across the country who are ready to provide resources to quickly help restore power after a major event. Preparedness also entails helping customers and critical infrastructure (hospitals, police, airports, etc.,) to be ready for low-probability but high-impact events such as earthquakes and other disasters. As the grid of the future becomes more distributed, connected and efficient, all grid participants will need to focus on reliability, resiliency, efficiency and security.

For the vast majority of Illinois utility customers, the grid performs core functions relatively well. Although there have been, and likely will continue to be, ongoing changes and improvements in grid technology options, the need for deployment of new technology on a system-wide scale should be closely evaluated by regulators. The challenge faced by policymakers, as well as utilities and energy market participants, is how best to facilitate the appropriate introduction of new technology without sacrificing reliable, low-cost service. To the extent that changes in regulation and policy are made, the primary focus should be on securing new benefits for customers. The electricity grid is paid for by customers and exists for their benefit; consequently, policy and market design should be driven by a focus on customer benefits.

1.2 Illinois Needs a Modern Grid

In an era of rapid technological evolution and changing social, commercial and individual energy requirements, a high-performing electricity grid is essential to maintaining a reliable and secure supply of affordable and environmentally responsible electricity in Illinois. The infrastructure through which electricity is provided may be increasingly challenged by severe weather due to climate change, cyber and physical threats, aging and increasingly dynamic supply and demand profiles.

Tomorrow’s grid will also face the challenges and opportunities associated with integration of new technologies and changing societal and customer expectations. Once satisfied with a simple arrangement where electric utilities provided services and most customers bought power on fixed volumetric rates, many customers of all sizes want more energy options and greater control over their energy use, energy resources and costs. In the digital age, some require higher resiliency and power quality and many are increasingly interested in seeking out new ways to lower their electricity costs and reduce their environmental impact. To achieve these objectives, many customers seek a higher level of control of their production and delivery of electricity as well as access to energy markets. Tomorrow’s grid may take advantage of a broad mix of technologies (including energy efficiency, DG, energy storage, demand response and EVs, as well as large central station power plants) to help the electricity system meet customer needs and advance reliability, resiliency, security, economic development, environmental progress and other regulatory goals.
Opportunities abound for the evolving electricity system to deliver new societal and individual benefits. More electrification would be an essential in a strategy to significantly reduce carbon emissions; it also has potential to put downward pressure on electricity rates by spreading fixed system costs over larger energy volumes. Emerging technology and market dynamics can support jobs and economic development, while providing all consumers, households and businesses with new options to enhance their well-being.

The regulated electric utilities that build and own the grid are responsible for its adequacy, efficiency and reliability, resiliency, and security (RR&S.) They are also responsible for modernizing the grid to meet changing needs and expectations. Development of the modern grid started with core “smart grid” elements that are currently being fully deployed in the Illinois service territories of ComEd and Ameren-Illinois; these include:

- Advanced metering infrastructure (AMI) coupled with state-of-the-art digital controls
- Embedded metering
- Telemetry
- Distribution automation (DA)
- Communications and sensors
- Associated analytics to enhance the grid’s self-healing capabilities

Investment by ComEd and Ameren in these technologies was provided for in legislation of the Illinois General Assembly in 2011, EIMA [4]. Full deployment of AMI will be completed by ComEd in 2018 and Ameren in 2019, making Illinois a national leader in this stage of grid modernization.

Restructuring of the Illinois electric industry to bring competition among electricity providers and retail choice to customers, which the General Assembly initiated in 1997 [2], allows more active participation of demand-side resources and DG, extending the reach of markets to the distribution system and changing the nature of power generation, transmission, distribution, operation and control. A modernized grid must monitor, protect and automatically optimize the operation of interconnected power systems and their elements. Another benefit of a modern grid would be that it would enable continuous updating of IT infrastructure to support ongoing adoption of the latest technologies as well as encourage innovation within the private sector.

From the perspective of some stakeholders, it is premature to discuss additional distribution system modernization investment, unless and until its need has been demonstrated in regulatory proceedings. They assert that the initial step in an evaluation process should be to assess customer demand for DG, electrification, energy storage and energy transactions, including documented evidence of current consumer participation in these activities. While stakeholders generally agree with the regulatory principle that benefits of utility investment must exceed their costs, some emphasize the need for transparent evidentiary proceedings prior to approval of any further utility investment, in order to demonstrate that unmet consumer needs exist and will be cost-effectively satisfied.

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4 ComEd and Ameren file annual reports with the ICC detailing investments, outcomes and performance of the smart grid elements provided for under the EIMA statute. These Advanced Metering Annual Implementation Progress Reports (AIPR) and the companies’ Infrastructure Investment Plans are available at https://www.icc.illinois.gov/electricity/utilityreporting/InfrastructureInvestmentPlans.aspxrange
1.3 The Key Elements of a Modern Grid

Broadly speaking, a modern grid requires advanced sensors to collect data from the system by means of a secure high-speed communication network to:

- enable communication among all grid components
- protect it from cyber intrusions
- allow it to quickly recover from disturbances and to use the data that it receives

Each of these elements—sensors, communications and operations—are discussed below. In addition to leveraging AMI data to capture real-time information on grid conditions, the modern grid may also feature ubiquitous sensors on grid assets, including substation transformers, breakers and line regulators, capacitor banks and even individual poles. These sensors will continually monitor the grid and provide the real-time information necessary for reliable operations. Combined with advanced control systems, they will allow monitoring and operation of substation and line devices to maintain proper voltage levels, while also reducing system losses and customers’ energy consumption through, e.g., voltage-optimization and conservation voltage-reduction programs. The information provided by these sensors will also help the utility implement improved modeling and forecasting tools to more effectively plan equipment replacements and upgrades. These new tools and processes will enable the grid to integrate DERs into both planning and operations, effectively leveraging DER capabilities as distribution system assets.

Enhanced situational awareness may be critical for modern grid operators. This may be enabled by a series of technologies, including synchrophasors. To date, they have been used primarily on the transmission system, but they may become valuable tools for distribution system operators in a dynamic environment featuring substantial DERs. Numerous applications of phasor measurement unit (PMU) data include oscillation monitoring, event (fault) location and extra-high voltage-state evaluation, which can prevent equipment damage, reduced stability margins and other operating problems. Some stakeholders assert that synchrophasors and PMUs are unlikely to be cost effective at the distribution level, and their level of speed and precision will not be necessary with moderate levels of DER penetration. This view anticipates that distribution operators can achieve the required situational awareness using SCADA, line/equipment sensors and an advanced distribution management systems (ADMS.)

Collecting real-time data requires a high-speed communication network. This network supports the ability to monitor and control time-sensitive operations, including frequency and voltage regulation, optimal dispatch of constrained generation, integration of variable-output DG, assessment of threats to grid operations, rapid response to changing system conditions, resiliency to unpredictable events and analysis of the massive data sets that enable the modern grid to maximize its value to all those connected to it.

An advanced grid would require decision-support tools to organize, manage and respond to large data flows in real time and to automate processes such as system restoration and grid operation. These tools may identify data anomalies to continually assess grid performance and compliance and to manage resource adequacy under conditions of uncertainty.

A distribution management system (DMS) is a set of integrated digital tools used to successfully operate a grid, particularly one with deep levels of DER penetration. The DMS is a repository of real-time data and power-system connectivity information (asset characteristics, connectivity and renderings). Enhanced visibility of operational conditions on the feeder may allow real-time switching,
load flow analysis, fault location and isolation. A DMS may improve reliability and resiliency by more effectively detecting system disturbances and notifying operators. It may reduce line-crew dispatch time and improve safety for line crews though enhanced communication of hazardous situations. A DMS may also improve system-planning models and allow utilities to optimize investment and expenditures. Automated distribution system devices, which use two-way communication between the device and the system operator to identify system anomalies remotely and expediently, may enable system operators to change the network topology and use DER for managing the grid (shifting loads, managing frequency and voltage) and also may reduce the time to identify and switch around network problems.

Advanced DMS would require area-wide solutions and visualization with centralized modeling and operation. This critical area of grid modernization would feature software-driven intelligence with central and distributed control systems for enhancing grid reliability, resiliency and economics. A DMS may be complemented by ADMS and distributed energy resource management systems (DERMS), software tools providing advanced system operation capabilities, additional data analytics, and management and control of distributed resources. Investment in these technologies would likely be needed for large-scale integration of DER.

Increasing levels of DER are bringing rapid change to distribution-system engineering and operations. From the point of view of grid operators, these changes include:

- The need for visibility, measurement, monitoring and control under certain circumstances of DER production behind-the-meter. Deeper penetration of DERs makes operating the distribution grid more complicated and requires additional levels of visibility beyond the substation. Implementing circuit level visibility and control are essential to safely and reliably accommodating high DER levels.
- Integrated distribution resiliency, automation, protection and communications. Because DER can be variable in their production (e.g., solar), grid operations become more dynamic and the engineering of circuit-protective relaying becomes more complex. Until now, system protection was quite distinct from system operations and it was unusual to dynamically change relay settings on line from a control system. But widespread adoption of DER would mean that this must change.
- Planning for DER outages/failure to perform. If DERs are to be used as a non-wires alternative (NWA), the resource must be available to reduce circuit loading and defer or avoid grid investments.
- More circuit configuration options. DERs can theoretically offer the possibility of switching circuit sections from one feeder to another, not just for outage response, but also to provide energy from DER to a different circuit that is more heavily loaded. This would turn such load-switching into routine operation.
- Fault location isolation and service restoration (FLISR) capabilities. This technology improves the utilities’ ability to more precisely determine a fault location on the circuit, reducing restoration time and enhancing outage response.
- Dynamic protection adjustments and dynamic islanding capabilities. System protection can be adjusted dynamically and certain DERs offer the promise of local resiliency and the ability of part of the system to become an island electrically and thus remain energized when surrounding areas are without power. This can be further leveraged using microgrids and provisional microgrids where cost effective.
- The ability to control DER power and VAr output for grid support. Smart inverters on DER can dynamically adjust their power factor, supplying or absorbing VAr, to prevent DER from causing system voltage outside the acceptable operating range. For circuits operated with a voltage optimization/conservation voltage-reduction setting, smart inverter capability also mitigates adverse impact from variable generation or load. This is critically important, as increased PV production at high penetration can cause unacceptably high voltage.

In addition to improved community aesthetics, burying power distribution lines (undergrounding) can reduce outages, improve road safety (cars hitting utility poles), reduce certain maintenance expenses (tree trimming, animal protection, etc.), as well as improve resiliency to weather and other events. However, underground installation and maintenance has historically been viewed as prohibitively expensive. While buried cables may not fail as often as overhead cables, they may fail as a result of flooding, corrosion and accidental damage by construction digging. Furthermore, reaching those buried lines for maintenance and repair is currently difficult and time-consuming. If undergrounding is not practical or cost-effective, system hardening may still occur through the installation of composite poles, animal guarding, avian construction standards and other technologies. All such initiatives must be subject to analysis, planning and regulatory oversight.

Some stakeholders assert that regulations may have to be updated to create the right incentives for expanding the grid and related services, to reflect the customer value that the grid provides and to fairly allocate costs among customers. Beyond transformative investment in the grid, realizing the future grid in Illinois may require new policies and regulatory approaches to ensure continued confidence in the system integrity and to meet societal goals of affordability, efficiency, environmental improvement, competitiveness and job creation. From this viewpoint, regulated public utilities appear uniquely positioned to enable cost-effective innovation, provide services that enhance customer value and advance those societal goals. In some cases, utilities may serve as the responsible grid owner and operator and while providing others opportunities for innovation that enhances the grid’s value.

Because of its essential nature and natural monopoly characteristics, undoubtedly the grid will remain highly regulated. However, forward-thinking policies may promote greater participation by customers and third parties and more investment in new technology and innovative goods and services—by utilities as well as other providers—resulting in greater opportunities for maximizing the value to customers. While utilities, as regulated entities that own and operate the grid, are seen as the appropriate system managers, stakeholders and regulators must have confidence that all DER is installed and operated by grid participants who are also committed to delivering safe, reliable, resilient and affordable power.

The transmission system is beyond the scope of the NextGrid study and largely not subject to state jurisdiction; however some stakeholders believe that its modernization should be a concern of state regulators. They assert that the capacity of existing transmission lines may be increased by 10 to 40% through the use of dynamic line rating, allowing accommodation of new power sources, with wind blowing across lines to cool them [16].

1.4 Customer Needs are Changing

The role of the electricity customers is evolving to be more dynamic, participatory and transactive. At the same time, customer expectations related to reliability and resiliency may continue to rise and tomorrow’s grid may need to be designed and operated to meet them. Grid-connected “prosumers”
(customers who both produce and consume electricity) can supply power via DG resources, as well as provide demand response by modulating the power they consume. The flexible demand of customers can, in some cases, provide grid capacity resources that help maintain resiliency, reduce emissions, increase resiliency and defer infrastructure investments. Making use of granular usage data, customer-facing applications may include innovative pricing options, in-home displays, smart appliances and thermostats, automatic demand-response and online and mobile-control applications.

While the potential of new technologies is attractive, a balanced evaluation of such technologies must consider their costs and benefits both now and as they evolve. Issues such as how to ensure that all customers, including low-income, special needs and underserved communities, benefit from modern grid initiatives are addressed by WG4. Assessing costs and benefits of investment paid for through utility rates is a task to be tackled through the regulatory process, as is discussed in the WG7 report.

From the perspective of large energy users—particularly very large industrial customers—some form of many of the “new” technologies discussed in this WG have been available and in use for many years. Very large energy users have also been implementing their own energy-efficiency measures for many years—long before there were state-mandated, utility-run energy-efficiency programs. In addition, some very large customers have operated behind-the-meter on-site generation for years and are well-versed in demand response and other energy-management techniques that are much newer concepts for most residential and small commercial customers. Demand response (DR) refers to a tariff, program or service coordinated with power market conditions for motivating changes in electricity consumptions by end-use customers.

Some stakeholders see the fact that demand for energy from low- or no-pollution generation is increasing due to state mandates and customer preferences as supportive of grid modernization. A Modern Grid would add technology and communication to reduce congestion, minimize curtailment, optimize delivery, and improve the cost-effective delivery of clean-energy resources to retail and wholesale market participants.

The expectations and requirements of utility call-center representatives will increase significantly as these individuals need to understand myriad customer devices, interactions of technologies behind and in front of the meter, payment and incentive structures, etc. Ensuring that all utility systems are integrated to reduce call times and maximize responsiveness to customer needs will be vital in meeting customers’ changing expectations.

Customers’ interactions with their utilities and other grid service providers should be as self-directed as possible, meaning the customer should be able to go online to understand and resolve issues without additional external support. Functions such as single sign-on are a first step in providing customers this level of service.

Not all customers will desire, or be able, to be actively engaged in their energy management, production and consumption. Ensuring “set it and forget it” options that deliver an equal level of service and benefits to these customers is equally important.

1.5 Values Provided by DER to the Electricity Service Network

The electricity service network provides value to all participants connected to it, including the DER value, as well as what the grid itself provides by enabling elements of DER. Value realized from DER by the grid and other customers connected to it is dependent on DER location and type, as will be discussed later in this report.
The potential value stream delivered by DERs may include, for example, energy, capacity, transmission capacity, ancillary services in wholesale markets and environmental and societal benefits. These value streams are compensated (or potentially compensated) through a variety of mechanisms such as renewable energy credits, PJM and MISO markets and state-mandated programs. DER value to the distribution system is a subset of the total potential value and the basis for compensation of DER providers by utilities and their customers. The determinants of DER value to the distribution system are discussed later in this report and by subsequent NextGrid WGs.

Given the rapidly changing landscape of distributed energy resources and increasingly interconnected buildings and local infrastructure systems, the role of managing the low-voltage network is becoming increasingly important. Network management systems need to provide visibility into the whole grid. A utility must be able to detect and isolate faults on the low-voltage network and model and forecast low-voltage and DER assets. Low-voltage network management systems must be able to integrate and analyze AMI, GIS, weather, DER asset performance and SCADA data.

**1.6 How Has Restructuring Affected the Electricity Industry in Illinois?**

The restructuring of the electric industry in the US has been a process over the past forty years; Illinois restructured its electric industry through an act of the General Assembly in 1997 [2], allowing utilities to separate generation assets from monopoly wires services and ushering in an era of competition among energy and capacity suppliers. This market structure has served Illinois consumers well, with average retail energy costs falling over the past 20 years relative to other states—from among the highest in the Midwest to among the lowest. The Illinois average retail electricity price of 9.38 cents/kwh is now less than the national average of 10.27 cents/kwh, according to Energy Information Administration (EIA) data. However, some stakeholders cite rising costs for transmission, distribution, capacity, ancillary services and delivery service rates components as contrary to this overall trend and are concerned that customers are also vulnerable to potential wholesale energy-market price increases.

FERC Order No. 1000 [17] issued in 2010, requires local and regional transmission planning processes to consider public policy needs and evaluate proposed solutions. It also requires public utilities to coordinate their planning efforts to develop more efficient or cost-effective solutions to their mutual needs. Illinois and its utilities participate in both PJM’s and MISO’s transmission planning process for the furtherance of Illinois’ interests.

PJM and MISO have different transmission-planning processes, models and criteria for categorizing transmission lines. These differences have impeded the planning and construction of transmission lines across the PJM-MISO seam. Some stakeholders want the ICC to be a more active advocate for harmony between the two RTOs’ transmission-planning processes so they effectively identify transmission projects across the PJM-MISO seam that can benefit Illinois.

**1.7 Evolution of Oversight and Operation of the Electricity Supply Chain**

Illinois has two regional transmission organizations/independent system operators (RTO/ISO) covering different regions of the state. ComEd is a member of PJM and Ameren Illinois is part of MISO. RTO/ISO organizations are not-for-profit, independent entities overseen by FERC, that do not generate or transmit electricity but operate wholesale markets and, in cooperation with the North American Electric Reliability Corporation (NERC) and other entities, set the rules to ensure resiliency. The FERC-mandated characteristics of an RTO are: 1) independence; 2) scope and regional configuration; 3) operational authority; and 4) responsibility for short-term resiliency. RTO/ISOs provide operational and oversight services to broad regions of the bulk electric system. In this capacity, they have developed...
market systems that provide non-discriminatory access to market participants in the wholesale electricity markets they operate and oversee.

The RTO/ISOs have created electricity products that allow many components of the electricity value stack to be monetized and traded in competitive markets. Locational values in the stack are priced on a nodal basis at discrete time intervals, establishing what are called *locational marginal prices* (LMPs), at specific places on the transmission system. The typical RTO/ISO market has nodes that number in the thousands and pricing-time intervals as short as 5 minutes. The availability of advanced information technology (IT) and communications systems has enabled the situational awareness, price discovery and settlement capability required for market competition to emerge in the bulk electric/wholesale market segments of the electricity supply chain.

About half of all states (including Illinois) restructured their electricity markets to allow competitive generation pricing to flow to retail customers. The combination of restructuring and the beginning of disaggregation of elements of the vertically integrated electricity supply chain under the RTO/ISO’s allowed for the emergence of market competition for many electricity services. Retail electric suppliers (RES), or in Illinois also referred to as alternative retail electric suppliers (ARES), became market participants as load-serving entities in the RTO/ISO markets. In 2007, the Illinois General Assembly created a state agency, the Illinois Power Agency (IPA) [3], to design procurement plans for power and energy provision to residential and small commercial customers choosing to remain on utility-supply service as shown in Figure 5.

**Figure 5.** Recent-past electricity supply chain

ComEd and Ameren Illinois offer some demand-response programs to small-volume customers. However, in RTO/ISO markets most demand-response is transacted by third parties. These curtailment service providers (CSPs) aggregate the capability of multiple end-use customers to reduce demand simultaneously for execution in the wholesale market. This aggregation of DER capability requires sophisticated IT and communication systems to provide the situational awareness, control and settlement capabilities required to transact distribution level activity at the bulk power system/wholesale market level. Distributed generation, primarily in the form of standby generation,
can compete in the RTO/ISO markets as a load-modifying resource, provided it meets the required availability and emissions standards.

After choosing to divest their generation assets in the late 1990’s, either to unregulated affiliate companies or independent power producers, Illinois utilities retained their transmission and distribution system assets. Public utilities, municipal utilities, cooperatives and independent transmission companies (ITCs) can all develop and operate transmission assets under applicable federal law and regulations and under Illinois law governing siting. Transmission services using those assets are subject to FERC regulation and the applicable RTO/ISO open access transmission tariffs (OATT). Distribution systems that fall under state jurisdiction and distribution systems of public utilities in Illinois are under the jurisdiction of the ICC.

Even before the advent of the smart grid, there was a trend toward digitization in utility protection and control equipment. SCADA and DMS began to be deployed by utilities to reduce outage frequency and duration. The pace of deployment was dictated by the traditional rate-making processes. Customer requirements for power quality and resiliency became more differentiated during this time period, mainly due to the proliferation of IT and data communications systems as end-use devices. Large customers often employed energy storage and power-conditioning technology in the form of uninterruptable power supplies (UPS) in their facilities to provide the increased level of resiliency required for their processes that exceeded what may be economically provided by the combined bulk electric system and the utility distribution system segments of the electricity supply chain.

The other noteworthy addition to this recent version of the electricity supply chain was the emergence of renewable generation at multiple points along the chain. In the beginning stages of the RTO/ISO era (2000—2010) the installed capacity of variable-output renewable generation was low enough that its presence did not cause any significant operational or financial challenges. However, the combination of falling renewable power costs, renewable procurement mandates, zero fuel costs and production tax credits (PTC) for wind generation allow it to be a price taker in RTO/ISO wholesale markets. The result is that, when end-user volume is low (primarily at night) and wind resources are operating at high capacity, wind generation has reduced market prices, benefitting energy customers but hurting the bottom line of baseload generators.

Solar power generation creates less competition for baseload generation since the sun shines at times of increased customer loads. However, solar output has potential to cause temporary localized voltage-regulation issues due to cloud passage and regional generation ramp-rate issues during the afternoon-evening period when its generation output is falling while the system load may be rising to its peak. Solar generation is also more likely to be installed at the customer distribution level as DER, where its integration creates both opportunities and challenges, as discussed in the next sections of this report.

In Figure 6 the modern electricity supply chain is beginning to emerge. It shows deep penetrations of DERs including renewable and conventional DG, energy-storage systems, enhanced and embedded demand-response capability, distribution grid path re-configuration and islanding capability and market-transactive technologies that allow producers and consumers to trade across the system. However, at least in the near term, the electricity supply chain will continue to rely on large, capital intensive generation.

Deepening penetration of DER’s in the supply chain has potential to affect the business models of distribution utilities, since those models remain based in the concepts of natural monopolies, regulated tariff ratemaking and single-direction power flows. Additionally, the de-carbonization value of renewable generation is an externality to the electricity market and its supply chain.
In Illinois, transmission and distribution facilities are generally operated by monopoly service providers, including private companies, regulated utilities, cooperatives and municipal utilities. At the same time, technologies embodied in wholesale markets administered by the RTO/ISOs provide a platform for operations, transactions and market settlements in the bulk electric system segments of the electricity supply chain and to a lesser extent between the distribution and bulk system levels. No such platform yet exists to support a similar suite of functions across the distribution grid.

1.8 Technologies and Policies Affecting the Distribution System

This section describes technologies that are changing the way Illinoisans produce, use and manage consumption. At the center of these is the emergence of DER. A broad definition of DER includes any generation, storage, or load managing resource connected to the distribution grid. This definition includes, but is not limited to, solar PV, wind, other customer-sited or small-scale generation including combined heat and power (CHP), energy storage (battery, thermal, flywheel, compressed air, hydraulic, etc.), energy/load management systems, EVs and DR resources. EIA data shows that nation-wide renewable energy accounted for 6% of US energy production in 2016, primarily from wind, with solar producing less than 0.1%. Each type of DER has its own operating characteristics and capabilities and provides different value to the grid, to the customer and to society. Each type of DER also has its own interconnection and operating requirements. Following are descriptions of DER and their development and potential in Illinois. In most cases, policies are likely to have a bigger impact on the evolution of the distribution system than evolutionary technology.

A. Solar Photovoltaic (PV) Generation

At year-end 2016, ComEd reported 824 solar installations with a total capacity of 9,661 kilowatts. Ameren Illinois reported 699 solar installations, with installed capacity of 5,384 kilowatts. These very small levels are anticipated to increase substantially in coming years as costs decline, technology improves and new state policies are implemented. However, barriers to participation in rooftop solar may exist for some customers, included those with shaded rooftops, those without rooftop access (in multi-unit buildings) and those who lack initial capital to invest. The concept of “Community Solar,”
which allows consumers without their own rooftop array to participate in solar projects, is a key part of the Illinois solar energy expansion plan being implemented under the 2017 Future Energy Jobs Act (FEJA) [5].

One important provision in FEJA to boost Illinois solar power is the adjustable block program (ABP), which covers all distributed solar projects under 2MW. Under the ABP program, qualifying customers and developers installing distributed solar will receive 15-year fixed-price renewable energy certificate (REC) contracts, paid out over a 5-year period, which will significantly improve the economics and payback periods for distributed solar technologies. Shown in the Figure 7 are target blocks by system size for the Ameren Illinois and ComEd service territories, according to the plan developed by the IPA [3].

![Figure 7. Solar power in Illinois](image)

The ABP program, if successful, may result in significant growth in community and distributed solar—from a few thousand installations and about 60 MW capacity today to tens of thousands of installations and hundreds of MW in the next few years. This is one of several initiatives to reach Illinois’ goal of 25% renewables by 2025. However:

- The growth likely will not be as linear as shown in this graph in Figure 7, as there are many factors that cannot be precisely forecasted
- At these levels of penetration, Illinois will likely have lower solar levels than many other states where solar is making significant inroads

FEJA goes beyond solar energy—ComEd, for example, is required to spend $1.4 billion over the next several years on energy-efficiency programs, including rebates for smart thermostats (which provide both energy efficiency and peak-demand reduction benefits) and incentives for CHP. Also, FEJA requires both Ameren Illinois and ComEd to invest in voltage optimization.
Rooftop solar has the potential to be paired with battery-storage technology. Although still an emerging area and not yet the norm in Illinois, this is becoming a cost-effective combination in states with relatively high electric rates, such as California, and as technology improves and storage costs decline, this pairing may reach Illinois. Such a solar+storage system can be optimized for time-of-use rates, reduced demand charges, two-meter/buy all-sell all, back-up power, grid services and self-supply—determining when to use stored energy and when to use energy from the grid.

Using a behind-the-meter storage system can maximize the benefit of solar to the grid by targeting peak hours. For example, as shown in Figure 8 solar charges the battery in the morning while also offsetting use, but in the afternoon the battery can be discharged to the grid during peak-demand hours, which generally coincide with peak solar output.

![Figure 8. Integration of solar with storage for optimum use](image)

**B. Energy Storage**

Electricity can be stored thermally in a hot or cold medium, or as electrochemical energy in a variety of technologies, including batteries. Larger-scale storage systems include pumped hydro, compressed air, or inertial flywheel technology. Energy storage is currently not playing a significant role in Illinois. While electricity storage at the scale of a residential customer has not yet been shown to be cost-effective at prevailing rates in Illinois, a Lazard study of the lifetime levelized cost of a 2MW lithium-ion battery serving a typical large commercial building in the PJM region found that it may produce an 11% internal rate of return [18]. However, as battery and thermal storage technologies improve and costs decline, a future in which even smaller volume consumers are able to store off-peak or self-generated energy to meet peak needs is coming into focus. The arrival of that era may be hastened by the issuance of FERC Order 841 [19], which is intended to require RTOs and ISOs to fully open their capacity, energy and ancillary service markets to energy storage.

**C. Demand Response**

DR resources can provide a range of grid-supportive functions. Examples of significant existing DR program models:
• Price-elasticity DR (based LMP): participating consumers curtail loads voluntarily in response to LMPs. In this case, customers shift their less-critical loads to periods when electricity prices are lower
• Thermostatically controlled DR (based on a contracted baseline): participating customers are compensated for measured baseline load reductions. The baseline load reduction is calculated as the difference between the customer baseline load and the actual electricity consumption
• Direct load control (DLC), under which participating customers agree to have specific appliances (often air conditioners or electric water heaters) turned down or off under central control when system conditions require load reductions

To encourage DR participation, FERC Order 745 ensures that DR stakeholders can participate in wholesale energy markets and be paid at LMPs for energy. Effective DR opportunities will:

• Improve the system load shape
• Enhance the economics of power systems
• Reduce peak demand and LMP volatility
• Eliminate the need for some peaking units
• Defer or eliminate infrastructure investments
• Reduce carbon emissions

D. Wind Generation

Though wind generation can be a DER, it has traditionally been installed on a utility-scale and is located in areas of highest wind resource, which are often remote from load centers. Illinois has significant and growing wind-power facilities, which are beyond the scope of the NextGrid study.

E. Energy Efficiency

Unlike energy conservation, energy efficiency (EE) is the ability to get the same or better functionality with less energy consumption. Innovative technology and smart-grid applications allow customers to accomplish the same goals but with less energy.

Though customers want to use less energy, it has been shown that even highly cost-effective EE investments are often passed up by consumers for a variety of reasons, including lack of access to capital, lack of information and lack of attention. In Illinois, FEJA allows ComEd and Ameren Illinois to earn a return on investment in EE, provided they deploy successful programs.

FEJA makes all EE programs the responsibility of utilities instead of a shared effort with the state, including market transformation efforts (MT). MT is the use of strategic interventions to speed up the adoption of energy efficient technologies, products and services in ways that reduce transaction and administration costs. MT in Illinois has focused on increasing EE knowledge and/or skills of all participants in the EE supply chain. Existing R&D and emerging technology programs can identify promising energy-saving technologies and the MT program can evaluate the barriers to market adoption and design a program to reduce them.

An example of how a government agency can use policies and technologies to enhance its energy efficiency is provided by Cook County in Illinois. Cook County’s building portfolio consists of 19 million square feet and 170 buildings and campuses, spread across three portfolios: health and hospitals, public safety and government. Its jail is the County’s largest energy user. Cook County government has an annual energy usage of approximately 237 GWh and 12.2 million therms. The County has a goal
to reduce carbon emissions by 80% by 2050 from a 2010 baseline. As of 2017, the County had achieved a 19% reduction towards this goal.

Cook County just completed a $112M capital-improvement project focused on energy efficiency that impacted 75% of the County’s building portfolio and focused on the “low hanging fruit,” such as lighting upgrades, BAS upgrades, boiler and chiller replacement, etc. The 19% reduction includes the carbon emission reductions from the $112MM capital-improvement projects. The county is now focused on the remaining 60% reduction needed to meet the 2050 goal.

In order to accomplish these goals, Cook County will have to focus on high performance and zero-energy building design, and operation and deployment of renewable energy and microgrid technology. Cook County provides an example of an EE program implementation; Appendix B provides details on this case study.

F. Internet of Things

The Internet of Things (IoT) is another emerging technology that will likely have an impact on distribution systems. Just as mobile devices increased the internet value by bringing more people online, IoT is expected to repeat that feat on an even grander scale by connecting billions of devices. For cities, utilities and enterprises, IoT represents more than hype; it signals a fundamental shift in how critical infrastructure operates and provides benefits for citizens and companies.

The rapid growth in the number and diversity of IoT devices may also benefit modern power distribution systems. IoT technologies interconnect disparate devices, platforms and services from virtually anywhere to manage electricity generation, delivery and consumption. As IoT devices are growing increasingly ubiquitous and powerful, they are also expanding their potential in active distribution networks (ADNs). IoT technologies provide a promising solution for remote real-time control, fault diagnosis and predictive maintenance on DERs. For example, IoT devices embedded in DERs enable automated notifications when DERs are to be maintained or replaced, eliminating the need for on-site inspection.

In comparison with conventional control options over utility assets (e.g., voltage regulators, capacitors) located at remote sites in which power-system operators use a pre-defined configuration, IoT-driven solutions offer more efficient and flexible ADN operations. Advanced control entities (e.g., static VAr compensators, on-load tap-changing transformers, switchable lines) dispersed in ADN may initiate self-actuated control commands for a rapid network reconfiguration, following the instructive signals issued by power system operators. For example, power system operators may reconfigure the ADN topology (normally designed with a meshed topology including redundant lines) at runtime by remotely manipulating the status of switchable lines in order to mitigate voltage increases and line congestion caused by DER.

1.9 Opportunities and Challenges of DER Integration

DERs can provide a range of previously identified benefits to its owners and those who participate in DER programs and activities. In addition, well-managed DERs deployed in optimal locations can provide the grid and customers connected to it with a range of benefits which, depending upon DER type and where and how it is interconnected, can include enhanced system reliability, resiliency and efficiency, reduction of peak-power requirements, deferral of transmission and distribution upgrades, provision of some ancillary services (e.g., reactive power, support for voltage control, active power control for frequency regulation), reductions in land-use effects and right-of-way acquisition costs, and reduced vulnerability to disruption and attacks.
The pace of DER interconnection to the Illinois grid will likely accelerate as FEJA is implemented and markets develop. With continued technology improvement and improved communication and computing power, newer DER may have enhanced capabilities, allowing full integration into the distribution grid. The task for utilities and regulators is to facilitate adoption of DER through rules and policies that allow for their efficient, beneficial and cost-effective integration into the grid.

Interconnection merely requires that the DER be connected to and able to interact with the grid, safely and reliably. To date, interconnection of DER has been mainly focused on doing no harm, i.e., maintaining the same resiliency level prior to interconnection. Conventional interconnection practices have focused on this safety and resiliency aspect, as well as methods to fairly calculate the interconnection costs and to recover them from the appropriate cost causer. Utility and regulatory policies will need to adapt as DER capabilities and levels rise. As the DER number interconnection requests rises, so do customer expectations and DER providers as to the interconnection speed and ease.

Integration, on the other hand, uses DER capabilities to support the grid or otherwise provide value to customers, including the ability to transact in competitive energy product markets. Integration also increases complexity in grid operations. Full integration means that DERs will become essential resources that grid operators must be able to count on. Regulators will need to consider ways to ensure that the compensated DERs function as expected and provide the promised services when needed. Integration capabilities will continue to evolve as DER capabilities levels grow. At significant penetration levels, DER integration will require the careful attention of utilities and regulators to ensure that policies and procedures are in place to protect consumers and the grid. Comprehensive DER integrating requires full consideration of and adherence to system engineering realities. Emerging technologies are placing new demands on a distribution system not originally designed to accommodate them, and their integration must be accomplished without disrupting or threatening the utilities’ ability to fulfill their central responsibility to ensure the safety, resiliency, security of the grid and service to its customers.

Although typical distribution systems may be able to accommodate significant DER levels without the need for major upgrades, today’s electricity grid was not engineered for DER integration. Widespread DER deployment likely would require modernization in grid design and resource-integration technology, including smart inverters and adaptive protection and control systems. With the relatively low penetrations to date, DER is managed today through simple controls and default settings, using predominantly non-smart inverters and without real-time visibility, communication or control. High DER growth will entail their active management, via smart inverters and advanced communication and controls.

The concept of the microgrid was first introduced as a way to allow small sections of the grid to be isolated for resiliency and as a solution for the reliable integration of DERs, including energy storage systems (ESSs) and controllable loads. Microgrids are self-controlled entities interconnecting on-site DERs and operating in either grid-connected or islanded modes (and being able to transition between both these modes in a seamless manner). Also, they are perceived by the main grid as a single element (interconnected at the point of common coupling) responding to appropriate control signals.

A schematic diagram of a generic multiple-DER microgrid is shown below in Figure 9. Microgrids are perceived by the main grid as a single element responding to appropriate control signals. They are self-controlled entities interconnecting on-site DERs and operating in either grid-connected or islanded modes.

A behind-the-meter, or single-customer microgrid is a cluster of loads, DGs and ESSs connected to the
host distribution system at a single point of connection (PCC) and operated in coordination to reliably supply electricity. This microgrid concept is attractive because it addresses the fact that existing distribution system infrastructure is extensive, aging and difficult to change. It enables deep DER penetration without requiring re-design or re-engineering of the existing distribution system.

![Microgrid diagram](image)

**Figure 9.** Multiple DER microgrid

One goal of a behind-the-meter microgrid is to accelerate realization of many benefits of smaller-scale DG, such as their ability to supply waste heat at the point of need (avoiding extensive thermal distribution networks) or to provide higher power quality to some, but not all, loads within a facility. When a strong coupling exists between the operation of different energy-carrier systems (heating, hot water, etc.), microgrids can integrate, operate and coordinate all these energy carriers. The smaller size of emerging generation technologies permits generators to be placed optimally in relation to heat loads allowing for use of waste heat. The coordination of multiple DG units throughout a bulk power system is considered a virtual power plant (VPP) solution, which can more than double overall system efficiencies.

Each innovation embodied in the microgrid concept (e.g., intelligent and hierarchical control, smart switches for grid disconnect and resynchronization) was created to improve the resiliency of smaller-scale DG systems (those with installed capacities from ten to hundreds of kW). A smart microgrid that can operate in both grid-tied as well as islanded modes typically integrates the following components, including:

- Power plants capable of meeting local demand as well as feeding excess energy back to the grid
- Local and distributed energy storage
- Smart meters and sensors capable of measuring a multitude of consumption parameters
- A communication infrastructure to exchange information and commands securely and reliably
- Smart terminations, loads and appliances capable of two-way communication
• An intelligent core, composed of integrated networking, computing and communication infrastructure elements

The key differences between a behind-the-meter microgrid and the broader electric power system are as follows:
• A microgrid allows a facility to operate even when disconnected from the utility grid.
• Generation sources in microgrids are of much smaller capacity than the large generators in conventional power plants.
• DG power generated as distribution voltage can be directly fed into the distribution network portion of the electric power system.
• Elements are normally installed close to loads, so that electrical/heat demand can be efficiently supplied with satisfactory voltage and frequency while incurring negligible line losses.

From the distribution-grid point of view, the main advantage of a behind-the-meter microgrid is that it is a controllable entity within the electric power system. A microgrid can be operated as a single aggregated load which operates in compliance with grid rules and regulations without hampering the resiliency and security of the power utility. From the environmental point of view, microgrids reduce environmental pollution and global warming through utilization of low-carbon technology.

Ultimately, if sufficiently capable DERs or single-customer microgrids are integrated in an appropriately designed section of the grid, the electric grid itself may serve as the network that allows otherwise independent DERs to operate as a microgrid. These “on-grid” microgrids may ultimately develop into a future grid that resembles a series of interconnected microgrids—operating the majority of the time as a fully connected grid, but with the capability to island sections as needed to preserve resiliency.

As part of its DER integration program, Ameren Illinois is operating a multi-sourced microgrid in Champaign, Illinois. The microgrid includes solar PV, wind and natural gas generation, as well as battery storage, all connected at a 12 kV distribution voltage. The microgrid is capable of islanding while serving approximately 192 customers in the Champaign area. Ameren Illinois is leveraging the infrastructure to test use cases related to DER integration, microgrid operations, economic dispatch and transactional platforms.

The ICC has approved a microgrid demonstration project of ComEd in Chicago’s Bronzeville neighborhood, which will be contiguous with the existing microgrid encompassing the Illinois Institute of Technology campus and will be able to cluster with it. Microgrids are widely seen as potentially beneficial to customers within them, but there are divergent views as to who should develop them and whether their public benefits are sufficient to justify allocating their costs to all utility customers. The Shedd Aquarium offers an example of an unusual microgrid in development, one that contributes to a sustainable environment for more than 1,500 species, including fish, marine mammals, birds, snakes, amphibians and insects.

For stable and secure operation, a number of technical, regulatory and economic issues have to be resolved before microgrids can become commonplace. An area that requires attention is lack of standards and regulations for operating microgrids in synchrony with the utility. Many initiatives
around the world are aimed at further developing the concept of microgrid through research, development and demonstration.

1.10 What is a Smart City?

Large cities increasingly face economic, social and environmental challenges in daily operations. The number and percentage of urban dwellers have grown from one billion (30 %) in 1950, to 3.9 billion (55 %) in 2018 and is expected to grow to 6.5 billion (70 %) of the world by 2050, see Figure 10.

![Figure 10. Global urban population](image)

Cities use 75 % of global energy resources and account for 70 % of global greenhouse gas emission, even though they only occupy about 5 % of the total land mass. Optimal energy management in major cities may play a key role in a global response to challenges posed by urbanization. Smart city infrastructures can support a variety of sociotechnical and socioeconomic initiatives for improving civil services, promoting residents’ well-being and advancing socio-economic competitiveness. The environmental effects of urbanization and population growth are visible in Figure 11.
Figure 11. Environmental effects of urbanization and population growth

Smart utility networks can be a digital foundation for economic growth and participation. A specific example already being deployed is intelligent street lighting. Public lighting infrastructure can be owned by the city but managed by the utility (or it can be owned by the utility). But with street lights consuming as much as 40% of a city's energy budget, it is important for city and utility stakeholders to work closely together to cut energy usage while providing a safe, secure and reliable environment. Street lights connected to an intelligent network can be controlled in many ways—dimmed at the right time to reduce usage and costs and brightened where and when needed to help create safer streets.

Smart street lights across a city create a network canopy upon which innovative services can be deployed. They can be controlled by emergency responders as necessary and have potential for multiple services—as sensors of conditions such as traffic and air quality, and potentially as a hub for IoT interaction and management. Utilities like ComEd are taking a leadership role in this trend. And major cities like Copenhagen, Paris, Glasgow and Bristol are leveraging their networked street-lights program to deploy citywide IoT networks.

In addition to its lighting infrastructure, the utilities’ communication infrastructure can be leveraged to support smart-city services. As mentioned above, grid modernization requires a secure, high-speed communication network as its information backbone, in order to enable communication among all grid components, from generation to customer devices and to protect the power system from cyber intrusions and allow it to quickly recover from disturbances. This communication backbone may be readily available to support smart-city applications as well. Infrastructure in many cities suffers from critical issues including capacity insufficiency, functional deterioration, deferred maintenance and technological obsolescence. Legacy infrastructure is under perpetual stress, and cities are vulnerable to economic losses and natural disasters.

1.11 How Will Transportation Electrification Affect the Grid and its Users?

Driven by various technical advances and incentivizations, electric vehicles (EVs) are entering the transportation mainstream. The number of plug-in electric vehicles (PEV) is expected to increase dramatically over the next decade.
While market penetration forecasts vary, EVs may soon become a major presence on Illinois roads. Illinois is estimated to have about 15,000 PEVs registered in the state through 2017, making it among the top 10 states in EV penetration (though that number represents a tiny percentage of the 4.5 million passenger vehicles in Illinois). A Rocky Mountain Institute (RMI) report on the growth trends, costs and benefits of EV notes that national EV sales have grown, on average, 32% year over year for the past four years [20]. However, EVs were just 1% of total vehicle sales nationally as of 2016. The proliferation of EVs provides many opportunities for individual, social and environmental benefits, but their full and beneficial integration into the electric system raises new issues for policymakers. Key questions include:

- Should state policy be directed toward supporting growth in the EV and EV-charging markets?
- What regulatory policies may maximize the system value of transportation electrification?
- Are there other transportation technologies (such as hydrogen or natural-gas vehicles) that should be incentivized?

A state-specific long-term study performed for Illinois by M.J. Bradley (commissioned by the Midwest Transportation Electrification Collaborative) details some of the potential economic and consumer benefits of a transition to EVs:

- reduced electricity bills for all customers through increased grid utilization and system efficiency
- societal (environmental and public health) benefits due to reduced air pollution from internal combustion engine (ICE) vehicles
- savings to the consumer from a total cost of ownership perspective

Any forecast going out to 2050 involves a high degree of uncertainty—political, regulatory, technological and economic. However, Bloomberg New Energy Finance projects that EVs will become less expensive than ICE vehicles on a total cost of ownership basis by 2025 and on an upfront cost basis by 2030 [21]. EVs will have a significant effect on the electric system, because plugging in an average all-electric car can add 35-40% to the annual energy usage of a typical household.\(^5\) If charging is done during off-peak hours for the electric system and the local circuit, the new load can fill in the “valleys” of system-load shape and be served without upgrading distribution infrastructure. In this case, the fixed costs of the utility system would be spread over a higher volume of energy usage, putting downward pressure on per/kWh electric rates for all customers. However, if EV owners plug in at peak times or if enough EVs charge simultaneously to raise the system or circuit peak, distribution system upgrades may be needed. Innovative policies to motivate EV drivers to charge their cars at optimal times may include new time-varying EV rate designs and “smart charging” programs that allow central-charge management of participating vehicles. In addition, fleet conversion and public bus conversion would have substantial effects on the distribution system, and direct current “fast charge” stations (DCFC) may add significant and less manageable new demand.

Another set of questions facing regulators and market participants will be raised by the need for public charging stations and related infrastructure known as electric vehicle supply equipment (EVSE.) 90% of EV-charging is currently done at home and at work, indicating that local trips are within the range

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\(^5\) Approximate estimate calculated assuming 3.2 miles of EV travel per kWh, thus using 3,750 kWh to drive 12,000 miles; percentage assumes typical household usage of 10,000 kWh/year.
of most EVs [22]. However, longer distance driving requires recharging the EV battery along the way. Additionally, many EV owners and potential EV owners, especially those in multi-unit dwellings, simply do not have access to home charging and may rely significantly or entirely on public charging, a dynamic that likely will increase as EVs reach the broader market. An EV will become more appealing if consumers know they will have widespread ready access to reliable public charging. So the answer, in part, depends on one’s view of the state regulation role in advancing transportation electrification and addressing this “chicken and egg” dilemma, especially considering the lack of a working business model for private companies to offer public charging services directly to drivers. This uncertainty has resulted in a lack of private investment in public charging infrastructure. This issue is complicated by the fact that DCFC infrastructure is costly and highway charge stations may be used mainly by drivers who don’t reside in the local area.

Costs of charging infrastructure are upfront capital, ongoing operation and maintenance. Costs are much higher for DCFC than for AC Level 2. The value proposition for site hosts to install and operate charging stations includes business promotion, customer attraction, employee retention and meeting sustainability goals. Some stakeholders assert that building codes should be modified to ensure that wiring and conduit is in place to facilitate EVSE installation. Some EVs and charging equipment have the capability to undertake load management functions and ensure the efficient energy use. In the future it may be possible for connected EVs to discharge to the grid in peak periods, a concept known as “V2G.”

Other countries in Europe and Asia (most notably China) are developing their EV markets, including related EV-charging infrastructure, at a significantly faster pace than we are in Illinois and the United States. A National Renewable Energy Laboratory (NREL) study determined that to facilitate 15 million plug-in EVs in the US by 2030, there is a potential need to develop approximately 600,000 public chargers.

The pace of transportation electrification depends upon the complex interaction of public policy, customer choice, cost (of EVs themselves as well as the relative prices of electricity and gasoline), market forces, transit agency adoption, technology/performance development, availability of charging infrastructure and economic conditions. There may also be dramatically different adoption rates in different locations. The “neighbor” effect has already been shown to cause clusters of consumer EV adoption, and initial adoption is in higher income areas.

There are many reasons why some stakeholders advocate a strong utility role in developing EVSE. These include the benefits of systemic planning, maintaining a reliable system for voltage and VAr as more DERs are introduced, supporting cyber and physical security, intelligently integrating dynamic EV loads, ensuring system-net benefits from such loads, having full access on reasonable terms to the “big data” that EVSE will generate as deployed, and ensuring that sufficient charging infrastructure exists in all areas, including otherwise underserved communities. Such stakeholders assert that without a significant role for utilities, needed EVSE will not be built and growth of beneficial electrification will be hindered. Other stakeholders point to the success of Tesla’s privately funded nationwide supercharger network as evidence that a significant role for utilities is unnecessary.

In formulating policy, lawmakers and regulators must consider whether advantages of using utilities to build out public-charging infrastructure outweigh concerns that utility-owned charging facilities may shut out competitors and stifle innovation. They must balance such concerns against arguments and data that suggest that utility involvement, instead, can support competition and innovation, address market failures and accelerate the market to the benefit of all participants. In addition to being service-
and price-regulated and accountable to state regulators, utilities generally have access to low-cost capital, ability to integrate EVs as DER, call-center capability, established customer relationships and other incumbent and legacy advantages.

Therefore, it seems reasonable that utilities would play some role in supporting, promoting, or otherwise incentivizing public-charging infrastructure, especially in areas where this infrastructure has not otherwise been developed. Construction and operation of EV facilities may or may not be within the core competency of utilities, as they may lack the incentives and entrepreneurial culture of unregulated firms. But perhaps they may extend the benefits of conventional utility asset maintenance and resiliency core competencies to public EVSE. Costs and risks of utility investment may be borne by non-participants, and customers may be at greater risk of stranded costs in the event of underperforming or obsolete facilities. At the same time, as previously discussed, most studies suggest significant net benefits to the grid from accelerating transportation electrification, mitigating concerns of potential cross-subsidization.

An additional stakeholder perspective is that deployment of a variety of smart technologies can support transportation electrification. The vast majority of EV charging occurs at the home where there is flexibility in when the vehicle is charged. Drivers are therefore willing, with the right incentives, to defer charging to optimal times for the grid. Utilities are in the unique position to evaluate the most efficient, effective and accurate means to encourage optimized charging at the home and to ensure that new EV load is incorporated in a safe, reliable and efficient manner. Some stakeholders advocate an EV-only utility time of use (TOU) rate option, as opposed to a single rate for all household usage. However, the cost of an additional meter can be prohibitive and there are alternative methods, such as “smart EVSE,” to allow EV-specific rates without installing a second meter.

Some stakeholders assert that it is crucial to keep in mind that the primary purpose of EVs and EV-charging stations is to support the conveyance of drivers, riders and goods between destinations. These critical transportation functions cannot be held secondary to their potential value as energy storage or grid service providers, without limiting the ability to support widespread adoption of these technologies. In this view V2G is unlikely to emerge as a viable service because of the deleterious effect on batteries of increased charge/discharge cycles. Many NextGrid stakeholders assert that it is incumbent on all stakeholders—not just the regulated utilities but also the auto, truck and bus manufacturers, environmental NGOs, consumer advocates, low and moderate income (LMI) advocates and others—to engage now in the discussion of EV issues that present great opportunities but also significant challenges to business.

Transportation electrification is not limited to personal vehicles. Urban transit systems such as the Chicago Transit Authority (CTA) rail network have long been electrified, and electric buses now show great potential to produce long-term social and customer benefits. Appendix C provides details on the CTA’s bus electrification program.

1.12 How are Distribution System Planning and Operation Affected by DER Growth?

Building, operating and planning the distribution system all play a crucial, integrated role in maintaining its functionality, ensuring there is sufficient capacity to meet the peak demand of every part of the system for every hour of the year across the planning horizon. A typical distribution system is very complex. For example, in ComEd’s service territory, approximately four million customers rely on an electric distribution system of more than 70,000 miles of power lines in an 11,400-square-mile
territory, with more than 5,500 feeders and over 800 substations. In Ameren Illinois’ service territory, approximately 1.2 million customers relay on an electric distribution system of more than 46,000 miles of power lines in a 43,700—square mile territory, with more than 2500 feeders and over 1500 substations.

Planning this large, complex, integrated system is challenging, requiring physical assets and technical expertise to do so safely and reliably. Even without the expected proliferation of DER and two-way power flows, the distribution system requires continual maintenance, changes, repair and upgrades in some cases, on a real-time basis. Current practices are therefore summarized here.

In assessing future needs, utility planners have always considered historical load patterns, under the presumption that the electricity demand in the past is indicative of what may be needed in the future. That historical background is shaped into a projection using external data on changing economic conditions, granular data about customer-service requests for new or expanded local businesses and more general macroeconomic data such as population inflow and outflow and change in GDP that affect electricity demand. Utilities also consider the climate context of the historical load data and analyze how once-in-ten-year weather conditions (that typically occur in the hottest months of July and August) might lead to different conclusions.

With these projections, utility planners can identify and prepare for issues on every feeder and every substation on the system. Distribution system planning is done to avoid issues that might emerge over short, medium and long-term timeframes, each requiring a different set of investments. ComEd uses two-year, five-year, twenty-year and emergency planning cycles, each considering the appropriate solutions to a given problem. Typically, circuit forecasts are prepared for a two-year period and substation forecasts are prepared for five- or twenty-year periods. Circuit reconfiguration, line extensions, re-conductoring, new feeders and new substation transformers have all been potential solutions to address capacity issues.

At Ameren Illinois, the distribution circuits and distribution substation transformers are analyzed annually to assess the adequacy of these facilities and identify any reinforcements or upgrades needed to address load growth based on the most recent peak-load conditions. A five-year substation transformer load forecast is prepared annually, taking into consideration load-growth trends, anticipated new load additions and planned customer expansions. Subtransmission and distribution plans typically cover a time period of at least ten years and include a five-year construction plan and horizon strategy. When transmission system additions or reinforcements are necessary, the study period extends beyond ten years because of longer lead times and larger investment requirements.

The focus of the utility-planning process is on achieving resiliency and allowing for flexibility as conditions change. Resiliency is typically defined using metrics like customer average interruption duration index (CAIDI), system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI), with comparison to historical performance along with future expectations. Additionally, issues relating to asset performance and improvement targets are considered as alternative means to meet resiliency goals. Redundancy and operational flexibility are important both as for enabling future planning decisions and giving distribution system operators the options they need to ensure continued service under adverse conditions. Appendix D provides details on how load-forecasting is done today and challenges for forecasting in the planning landscape.

As the distribution system develops, planning and operations, as well as assets and infrastructure, must adapt to support integration of emerging technologies and varying functions. For example, demand curves may change in response to time-based pricing. Simultaneously, deepened penetration of behind-
the-meter generation and storage, if not properly tracked and managed, can produce the phenomenon of “masked load.” Finally, the deep penetration of DERs may alter radial-distribution system flows from being strictly unidirectional—with power going from generators through the transmission and distribution systems to customers—to being increasingly bidirectional. These reverse power flows create challenges for grid operators, so future distribution system planners need to consider new and more granular data, such as the solar irradiance levels that can help project how much solar energy would be generated at a given time in a particular location.

Deepening DER penetrations entail significant changes to planning and operations of the distribution system. Those changes need to be appropriately represented in the transmission grid planning and operations. The optimal use of generation on the transmission and the distribution grids is a desirable objective in order to bring the greatest benefits to consumers. However, without the detailed information on the distribution network changes to integrate the DERs made available to the transmission system operators and planners such an optimization cannot be performed. A more pressing issue is the changes underway in FERC regulation to permit DERs to provide energy and ancillary services to the bulk grid. Moreover, transmission system owners are subject to the mandatory and enforceable NERC standards that are approved by FERC. Specifically, it is the NERC Reliability Standards that ensure that the bulk transmission grid can serve as the necessary backbone to enable the distribution companies to reliably serve their end use customers. The NERC Reliability Standards cover virtually every aspect of grid, including: Resource and Demand Balancing; Critical Infrastructure Protection; Communications; Emergency Preparedness and Operations; Facilities Design Construction and Maintenance; Interchange Scheduling and Coordination; Interconnection Reliability Operations and Coordination; Modeling, Data and Analysis; Nuclear; Personnel Performance, Training and Qualifications; Protection and Control; Transmission Operations; Transmission Planning; and Voltage and Reactive. Strict compliance is needed as NERC has the authority to impose severe monetary fines. As the wider deployment of DERs continues, explicit steps are necessary for closer cooperation between the bulk grid operators and distribution system operators.

Deep penetrations of DERs imply planners will have to pay attention to peak usage (to ensure sufficient capacity to meet maximum demand), and also to minimum load for potentially all 8760 hours of the year. High DER output at the time of the lowest annual daytime minimum load—typically a sunny Sunday in spring or fall—may create voltage violations or reverse power flows. Thus, more time-series analyses will likely have to be used by distribution-system planners, reflecting the additional system complexity and taking into account that change will occur at a different pace in each location. More broadly, because much of this development is dependent on external factors, including global economic conditions, new technology innovations and policy inputs, it is difficult to predict distribution-system evolution in coming decades. It becomes necessary for planners to rely less on single projections, and consider multiple scenarios of how DER may emerge on different parts.

Some stakeholders assert that in an era of increasing DER deployment by customers and third parties, a successful utility-planning process must become more accessible to ongoing and active participation by others. DERs would be treated as potential resources to make the system more reliable, resilient and environmentally responsible. Under a new paradigm of integrated distribution planning (IDP), the utility would work with others throughout the planning process as, alongside its historical planning considerations, it also considers:

- Forecasting and including DER impacts in load projections
- Integration with DER interconnection and EE, DR programs
- System locations where DER can be accommodated without upgrades (hosting capacity)
• System locations where DER deployment would provide particular locational value
• Consideration of customer and third-party DER solutions as NWA
• NWA acquisition using pricing, programs and competitive procurement
• Ongoing DER monitoring and management (by utility and/or third party)

For IDP to be successful in ensuring the safety, resiliency and efficiency of the distribution grid, DER providers would need to bear responsibility for the DER availability and operation. Oversight mechanisms and regulatory constructs, in addition to financial arrangements, would need to be in place to ensure DERs delivered on their anticipated performance. Today, utility resiliency metrics are clearly defined and reported under EIMA. If the grid becomes more dependent on non-grid assets for resiliency, a broader review and consideration of new rules and procedures will be needed.

Another stakeholder perspective is that since 1) utilities in Illinois already consider DER as an alternative to conventional capacity planning investments; 2) utilities have utilized DER alternatives in the past and created tariffs to facilitate customer participation and compensation for DER programs; 3) utilities have committed to continuing to consider DER as potential solutions to distribution-system needs; 4) pilots have been utilized and remain a useful tool to test DER functionality; and 5) utilities are interested in encouraging DER and solar; therefore understanding and capturing value from DER is a good addition to the conventional planning process. This should not require changes to the entire, complicated planning process.

With regard to NWA, some stakeholders assert that the New York PSC has provided a model that may be of value to Illinois. In New York, NWA are organized in a formal program. The regulatory compact has been updated to include compensation for utility companies for NWA investments in 3rd parties, incorporation of payment for deferred revenue, and allowance for the utility to participate in providing NWA. The NY Public Service Commission (PSC) has attempted to align utility incentives with the public-policy goal of promoting cost-effective NWA. In particular, the NY PSC has reiterated the need to make utilities open to investing in conventional rate-base distribution capital projects and supporting the growth of NWA, along with other distribution-level solutions that would increase operating expenses and may displace or defer conventional utility rate base investments. The NY PSC has employed the following three mechanisms: (1) allow utilities to defer recovery of NWA costs and earn a return on unrecovered balances, (2) allow utilities to share in the NWA savings solution relative to the conventional solution, and (3) allow utilities to be awarded a return on investment incentive on deferred NWA costs, if it meets certain project-achievement goals.

1.13 Determinants of DER Value to the Distribution System

Though DER can be energy storage, generation, or DR, the size is typically small compared to the utility-scale installations that provide most power to the grid. The broad concept of DER value can reference a wide range of electric system benefits, including:
• energy, capacity and ancillary services
• compensation for customers and third parties for investments providing service to the grid
• avoided utility investment costs and lower operational costs
• potential enhanced reliability, resiliency and power-quality choice

Many direct monetizable DER benefits flow to the owner/operator of a resource, with value denominated in terms of the avoided cost to the consumer—the difference between what the consumer would have paid had he or she purchased from the centralized grid compared to the amount that is paid
when the DER is co-located with the consumer. DERs also can derive value through sales into the wholesale market, and sometimes DERs are beneficiaries of subsidies that reduce the initial technology cost or increase the revenues earned. For example, an owner of a rooftop solar array can be compensated for the environmental value of its energy output through issuance of RECs and may also be eligible for other rebates and credits to reduce its costs.

In the context of a regulated distribution system, DER value is a function of the physical and economic results that DER brings to the network itself, which can vary with time. Accurate valuation is crucial because the network costs are socialized among all customers. If the DER monetary calculation—the amount that the system operator will pay for the DER output—is set at a level that does not correspond to the real system value, cross-subsidies would result and rates of other customers may not be “just and reasonable.” When DER worth to the distribution system is considered, an accurate methodology takes into account the locational and temporal granularity of value that a particular form of DER can provide.

This has been recognized in FEJA [5]. It requires that the rebate formula in Illinois ultimately approved by the Commission “reflect the value of the DG to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based and performance-based benefits, as well as technological capabilities and present and future grid needs.” What to include when determining DER worth and how to calculate it are the subjects of ICC workshops (jointly conducted with the Pacific Northwest National Laboratory) in anticipation of future regulatory proceedings mandated under FEJA.

Any value that DERs can provide is dependent on what, when and where they provide distribution system output. This varies, based on which of the hundreds of substations where the DER is connected, or even each of the thousands of feeders, and potentially where within any given individual feeder the DER is located and when it is providing. There is no intrinsic value difference between a unit of energy (kWh) or of reactive power (kVAR) generated from roof-top solar or from a storage battery. In the simplest terms, the value is a function of the sum of or combination of:

- What product is being delivered to or consumed from the network
- Where the product is being delivered or consumed
- When the product is being delivered or consumed

Within the distribution system (and beyond) there are at least four highly interrelated products that DERs can deliver. These are:

- Real power (kW)
- Reactive power (kVAR)
- Reserves (future kW and VAr)
- Capacity (kW)

While a DER can produce varying amounts of each of these, there is a limit to the sum at any given time. The limit is the DER's apparent power (kVA), which is the sum of real power (kW) and reactive power (kVAR) and can be characterized as the instantaneous or a future market reserve. At any point in time any given DER may be able to provide any one or a combination of these outputs and services into the distribution system. However, they are not independent of each other, i.e., no DER can provide 100% of their capability in kW, in kVAR, or in reserves at the same time. kW and kVAR are in all instances complementary. To produce and deliver kVAR, some quantity of kW must be foregone. If a DER finds it most economical to provide 100% of its kW capability into the market (or committed to the distribution operator) under a fixed contract, it can provide no kVAR and no reserves for delivery at
a future time within the fixed contract period. DERs that provide capacity and associated resiliency must also be taken into account. DER may reduce consumers’ peak load contribution (PLC), which provides benefits not only to the specific consumer but to the grid as a whole.

The application value in the distribution system is dependent on the location within the feeder. Using the same general concepts as in the wholesale system—LMP—the worth within the distribution system is defined as LMV at each node at each point in time that is reflective of the specific feeder condition both upstream and downstream and of the upstream system to which the feeder is connected. Figure 12 below provides a schematic of a distribution feeder with a delivery constraint—(kWh) before node 3 as shown.

**Figure 12.** Distribution feeder with delivery constraint before node 3

Within the radial distribution system (unlike the networked transmission system), there is no possibility of providing the demanded kWh to customers at node 3 and beyond unless added kWh can be brought on at Node 3. Were this the transmission system, the nodal value at 3 would represent the LMP of providing the energy through other generators and paths in the network. That option generally does not exist in the distribution system. As a result, the only DER that has a value to the distribution system in terms of assuring delivery to customers at node 3 and beyond is the energy available at node 3. DERs at nodes 1 and 2 have no value in reducing or removing the constraint at node 3. In oversimplified terms, the value of the kWh at node 3 is the per kWh value of lost customer load adjusted for line losses.

Only if the DER is capable of providing real, reserve or reactive power or reducing or shifting load at the precise moment when it is needed can its system value be leveraged. The value of DER to the distribution system or DSO only occurs at times when there are system needs, i.e., at times of constraint in kWh or kVAR or when it is possible to acquire reserves for a known period in the future.

This explains why the actual DER value to the grid cannot be determined merely by system, or even feeder, averages that may result in insufficient incentives to stakeholders to install DER, where they can provide value or excess returns to DERs, which increase distribution system costs without providing fair value to the other customers who pay those socialized costs. Connecting DER to the grid may also require the utility to make modifications to its distribution grid.

Accurate estimation of DER gain to the distribution system starts with a rigorous engineering grid analysis. By focusing strictly on the DER contributions to the distribution system, this approach is technology-agnostic—it focuses on what, where and when DER provides worth rather than the
technology type. A distribution system-focused valuation methodology can ensure that future system planning leverages the DER system benefits without unnecessarily incurring new risk. Capabilities that must be considered for full value realization include advanced load and DER forecasting, advanced power-system modeling, hosting capacity analysis, locational value assessment, streamlined interconnection, utilization of market transformation techniques, real-time feedback to optimize the delivery of energy-efficiency products and services and DER sourcing.

In addition to benefits, DERs can also pose challenges to a distribution system not originally designed to host distributed resources. These can include voltage issues such as over-voltage or flicker, thermal issues such as over-current, and protection needs including coordination, loss of reach, back-feed and changes to existing automation schemes. The tendency of DER to cause over-voltage conditions is particularly challenging on circuits where voltage optimization and conservation voltage reduction are being applied. Determining not just the DER gross value, but the net value, which considers the costs of mitigating the challenges it can pose, is therefore part of the task.

The Electric Power Research Institute (EPRI) conducted a study regarding integrating stationary generation and DER into the grid. It concluded: “The successful integration of DER depends on the existing electric power grid. That grid, especially its distribution systems, was not designed to accommodate a deep penetration of DER while sustaining high levels of electric quality and resiliency. The technical characteristics of certain types of DER, such as variability and intermittency, are quite different from central power stations. To realize fully the value of DER and to serve all consumers at established standards of quality and resiliency, the need has arisen to integrate DER in the planning and operation of the electricity grid and to expand its scope to include DER operation—what EPRI is calling the Integrated Grid” [23].

1.14 What Is the Distribution Platform Concept and How Might It Be Valuable?

Providing DER access to markets in which energy products and services are bought and sold is a key goal of a modern distribution system. Efficient communication, trading and settlement involving very large numbers of small transactions may be best facilitated through creation of a distribution-level market platform (distribution system platform or DSP). While some functions would have similar characteristics to those performed by an RTO/ISO (it would need to manage nodal pricing and it would be IT intensive), they would also need to include additional functionality to handle attributes unique to the distribution system and the variety of DERs that can be connected to it.

The decision to develop and deploy a DSP model is a policy/regulatory decision that will take significant time and should be based on clear evidence of its value to customers. Planning, deployment and operation of additional distribution-system functionality would entail financial costs requiring recovery assurance and mechanisms. Both the policy and cost issues create uncertainty in the path toward implementation of a distribution platform, the success of which will depend on identifying, quantifying and providing system, customer and social benefits exceeding its costs.

Additional functions of a DSP would have to be carefully and seamlessly combined with the planning, construction, operation and maintenance functions already done by utilities today. Utilities are adapting their practices to integrate a variety of customer-side resources and accommodate grid-edge customer-market participation. Therefore, it seems reasonable to many stakeholders that the distribution utility would naturally transition to become the distribution system operator (DSO), with responsibility for non-discriminatory DSP operation. However, some stakeholders hold open the possibility that the DSO function may be performed by a non-utility entity.
While there may be a future need to provide balancing functionalities at the distribution level similar to those which the ISOs currently do at the regional level and also to enable retail market transactions for customers and DER owners, the conditions and technologies required to support such a market have not been developed. These DSP/DSO concepts may be further explored in future studies.

Movement toward development of a distribution market should be incremental and reflect actual DER growth in Illinois over time. If additional market functions, along with the grid-operation functions, are indeed required in a future distribution system, there would need to be significant new technical capabilities, including high-speed communications infrastructure to transmit information and advanced analytical capabilities to process data. Indeed, many advanced technologies will be necessary regardless of whether or not we arrive at a point of implementing a distribution market to support deeper levels of DER penetration. Some stakeholders assert that new functional or structural separation requirements would need to be imposed on the utility in the event that it were to perform these functions, particularly if a utility were to remain affiliated with providers of generation and other competitive products and services.

Given the success of competitive energy markets in Illinois and nationally, Building Owners and Managers Association of Chicago (BOMA/Chicago)\(^6\) believes that market mechanisms should continue to be a key guidepost to empower customers. BOMA/Chicago also believes that decisions about what technologies and innovations best serve customers should be made, first and foremost, by customers themselves, through transparent market mechanisms. Regulation or policy preferences should be predicated upon transparent information and process, cost benefit analysis from the customer perspective and openness to examining both monopoly utility and non-monopoly utility models as the means to best serve customers. Appendix E provides more detail on BOMA/Chicago’s thinking and position on the matter.

Although we start from a relatively small DER base, technology advances, cost reductions and increasing clean energy goals are all pointing toward significant growth for DER in Illinois. New technologies with potential to increase the productivity of and value delivered by the electric supply system will continue to emerge, especially technologies connected to and impacting the distribution system. In a hypothetical free market, new technologies can easily enter the market and compete on their value-delivery merits for an overall market share. However, there is no good substitute for electricity or for the grid. The regulatory framework must be designed to maximize customer and public interests and participation while maintaining safe, reliable, affordable and resilient service and just and reasonable rates. The ultimate energy cost is determined by the interaction between markets and regulation, and the challenge for energy policy is to get this mix right.

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\(^6\) BOMA/Chicago is a trade association that has represented the interests of the Chicago office building industry since 1902. Membership includes 239 commercial offices, institutional and public buildings and 169 companies that provide commercial building services to support operational excellence. BOMA/Chicago members constitute approximately 80% of all rentable office space and more than 98% of rentable space in Class A buildings in downtown Chicago.
2. Metering, Data and Communications

The US power grid is undergoing tremendous change from a centralized, unidirectional system that pushes power from large-scale, centralized power generation facilities, to a multi-directional system that can distribute generation from a variety of resources and locations. The grid will increasingly integrate DERs for improved power quality, system resiliency and reliability and will require advanced intelligence capabilities, such as AMI and smart switches. Notably, even without the expected growth of interconnected DERs, the grid requires continuous improvements to maintain the reliability and resiliency of the system and services that customers depend upon every day. What can be done today to integrate the desired products and services and transition to a reliable and resilient smart grid? Aside from the technology, we need to develop appropriate standards, practices and mechanisms to support the technology and continue to operate the system in a reliable manner.

Electric power consumption is currently measured via an electric meter, at physical structures and units, such as individual apartments, homes and commercial and industrial locations. Charges are largely based on factors that include consumption and, for an increasing number of utilities, the time that consumption and peak use occurs. Most distribution utility operational costs, such as maintenance of transmission and distribution infrastructure, customer service etc., are fixed, meaning that these costs do not fluctuate based on the amount of electricity consumed and are primarily a function of peak use. DERs can help alter demand patterns and thus make more-efficient use of existing grid assets, thereby reducing fixed costs and savings for the consumer.

The need to address expanded metering functions is demonstrated in California, where approximately 5% of all households currently have rooftop solar systems. The implications of that percentage are profound. More than 700,000 rooftop solar systems across the state have contributed significantly to a shift in California’s peak-load hours, which dictate the required availability of central generation assets for safe and reliable grid operation. According to recent filings by the California Public Utilities Commission (CPUC), the California Independent System Operator (CAISO) sought to modify its “availability assessment hours,” a five-consecutive hour block intended to capture peak load periods, in 2018 to account for shifting demand. In 2017, CAISO set its available assessment hours from 1-6 pm for the April to October timeframe and 4-9 pm for the November through March timeframe. In 2018, CAISO sought to shift these hours to 4-9 pm for the entire year. The ability to implement these programs was a direct result of having a flexible metering and communication infrastructure in place that may report detailed data.

Electric-vehicle charging may also impose energy-demand management challenges on the distribution system. Direct current, rapid-charging systems, for example, will impact feeder loadings as local pockets of large intermittent charging may potentially overload individual feeder sections. Accurate information about the load on different parts of the system will support effective planning.

Deploying more sensor technology into the power system provides more information about its current state. With this information, grid operators and planners can better identify conditions that might lead to outage. For instance, one can utilize the data to identify voltage issues that, if corrected, may prevent equipment failure over time. Detailed information about real-time conditions allows an operator to isolate, restore, and repair faulty equipment more efficiently.

Utilizing AMI’s ability to monitor consumption and communicate with high-load devices, such as an EV charger or heating ventilation and air conditioning (HVAC) system, rates may be offered that incentivize consumption to match grid capacity. This would reduce fixed operating costs as well as
match the supply of renewable energy. Today the grid is managed by dispatching the power supply. As the penetration of distributed and renewable assets continues to grow, the ability to alter demand will become as important as dispatching supply.

The distribution system has conventionally supported one-way power-flow designed to deliver energy from central generation facilities connected to the transmission system and substations onto the distribution system. Owing to the improved abilities of individual grid consumers to also produce power through enhancements in DG and energy storage systems, newer challenges and complexities have been introduced on the conventional planning and operational aspects of the distribution system.

With the increased penetration of DERs, there needs to be increased capabilities to mitigate the potential adverse impact of bi-directional flow and voltage fluctuations in the distribution grid. This gives new opportunities to optimize system performance but also presents the challenge of sensing and sharing system information with all market participants. An example is the addition of metering technology that can sense reactive power or frequency and the ability to share this information in real-time with aggregators.

WG2 was convened to address the future of metering, data and communications within the state of Illinois. WG members included representatives from community and customer stakeholders, third-party technology vendors, engineering and construction service providers, educational and research institutions, Ameren Illinois and ComEd. During the WG meetings, Ameren Illinois and ComEd representatives presented key aspects of their ongoing AMI implementations and the current state of their ongoing Smart Grid initiatives, what the future of electric metering may involve and how data from advanced sensors and communication networks may provide for enhanced levels of DER integration. The WG did not focus on the implications of or creation of a real-time or transactive distribution market, or the security impacts discussion topics may have on the grid.

This chapter provides a comprehensive overview of the current state of metering, data collection and frequency and the communication networks used by Illinois utilities, ComEd and Ameren Illinois, to support the reliable delivery of energy services today. It provides background information regarding how ongoing AMI deployments have enabled enhanced customer service and functionality, as well as extensive background information on the development of private utility networks to enable AMI and grid-control functions.

The background information is necessary to understand the challenges and opportunities that stem from enabling greater integration of DER assets at the distribution level, which the WG discussed in-depth. Key challenges identified by the WG largely center on the need for common standards associated with data formats from meters and DER devices and standards for how current and future network devices, including DERs, will communicate with the grid and the customers.

Opportunities centered on how metering, data and communications functions and infrastructure may be broadened to meet NextGrid objectives. While it was widely agreed it is technologically possible to enable widespread DER integration and evolve the grid to enable dynamic markets, such as a peer-to-peer transactive energy market, associated metering, data and communications investments will be largely dependent upon the ultimate regulatory and market structure.

2.1 Metering

The US Government defines AMI as an integrated system of electronic meters, communication networks and data management systems that enable two-way communication between utilities and customers. Customer systems include in-home displays, HANs, energy management systems and other
behind-the-meter equipment that enables more resolute usage information allowing customers to better manage energy use within residential, commercial and industrial facilities. Illinois law more precisely defines AMI as “the communications hardware and software and associated system software that enables Smart Grid functions by creating a network between advanced meters and utility business systems and allowing collection and distribution of information to customers and other parties in addition to providing information to the utility itself.” [4]

Within the state of Illinois, Ameren Illinois and ComEd are in the final phases of their respective AMI deployments to all residential, commercial and industrial customers. By year-end 2018, Ameren Illinois expects to have 1 million AMI meters deployed, with the completion of its deployment to all of its 1.25 million metered accounts by year-end 2019. ComEd anticipates completion of its AMI deployment to its 4.2 million metered accounts by year-end 2018. As of March 31, 2018, ComEd had replaced more than 3.9 million meters of its 4.2 million metered accounts.

Today’s “smart” AMI meters are capable of sending and receiving data through a utility’s field-area communication network, eliminating the need for a utility employee to manually read meters each month and enabling utilities to provide additional services in a timely manner, without the need to dispatch a utility worker. Modern meters also have tamper monitors to reduce loss and are programmed to give a proactive notice into the voltage being provided giving an indication of service issues and outages. They also contain disconnect switches allowing the utilities to de-energize customers when necessary without the need for physical presence; those switches also facilitate the restoration of service and the establishment of service to new or relocating customers.

![Figure 13. Overview of ComEd’s operational improvements resulting from its AMI Program](image)

Both Ameren Illinois and ComEd (see Figure 13) presented the WG with an overview of their ongoing AMI programs and highlighted improvements within operations and customer service functions as a result of their respective deployments. AMI has enabled both utilities to:
- Provide remote connect and disconnect services for residential and small commercial customers and remote service orders, such as on-demand reads for opening/closing accounts
- Improve outage-management processes
- Improve revenue protection through reductions in unaccounted for energy
- Reduce estimated customer bills
- Support voltage optimization (power-quality) efforts statewide
- Enable customers to monitor and manage energy use

Today’s “smart” AMI meters, such as those deployed by ComEd and Ameren Illinois, include internal Zigbee radios and speak Smart Energy Profile 1.1, which allows the meter to broadcast real-time demand and pricing information into the HAN. However, there are few devices that use these networks today. Most smart home-energy devices use Wi-Fi and the internet to enable connection and control through smartphone applications. This occurred because the smart devices are being deployed by the customer for the benefit of improving comfort and reducing consumption and, thus, cost. At the present time, these applications are not taking into account the real-time cost of electricity and thus did not have a need to get real-time energy prices from the HAN. Even with the need for this information they may look for a common application interface on the Internet to obtain this information if it is more convenient for the customer to configure. The building managers association of Chicago in a letter to the WG pointed out the value of utilizing other devices, such as variable frequency drives which have metering built into them, participate in the HAN or internet-connected methods of sharing data about power flows behind-the-meter.

Volt/Var optimization and conservation voltage reduction are energy-saving techniques that enable a utility to optimize voltage throughout the feeders, reducing losses. Without AMI and other distribution sensors, power was distributed without the ability for Volt/Var compensation to reduce losses and increase energy efficiency. With AMI and other sensors on the distribution system, utilities gain real-time access to voltage levels at different nodes including the meters, which enable them to, where appropriate, reduce voltage levels in the system. This conserves energy. Both Ameren Illinois and ComEd will enable the collection of voltage measurements on their deployed AMI meters to support the statewide rollout of a voltage and VAR optimization program, per the requirements within FEJA [5].

From a technological standpoint, a meter may be any device that accurately and reliably measures and records the quantity, degree, or rate of something, such as the use of a commodity, be it electricity, gas, or water. Theoretically, any sensor that accurately and reliably measures the relevant characteristics of the customers’ energy use and makes that data practically available may be used by the utility to account for and charge for services provided. For example, a meter within an EV-charging system may be used to administer a specific EV-charging rate. Similarly, photocells on street-light controllers are being retrofitted to be dynamically dimmed on a per-fixture basis. These controllers may be used to meter power to what used to be constant-burn street lights. However, it will be important that these devices provide high degrees of accuracy, equivalent to today’s meters and produce data that is practically usable.

In 2015, Xcel Energy gained approval to provide a 40 % late-night EV rate discount for customers who charged their vehicles within their garage. However, the program required the costly installation of a second meter, hindering user adoption. According to Xcel’s filings with the Minnesota Public Utilities Commission (PUC), only 150 customers were participating in its discounted rate program as
compared to the approximately 5,700 EVs registered within its service territory. To address this challenge and encourage additional participation in its special EV charging-rate program, Xcel Energy recently gained approval from the Minnesota PUC [24] to update the program to use meters within the charging equipment to meter EV charging separately from home usage. This new pilot was deemed necessary to encourage further participation in its ongoing EV charging-rate discount program.

As the Xcel Energy example shows, many devices have the capability to act as meters. However, Illinois statutes and relevant portions of Title 83 Illinois Administrative Code [25] and the applicable utilities’ tariffs impose functional and regulatory requirements to protect customers and the grid and promote accurate billing. Entities other than the utility can provide metering services in the state but must be registered as a metering service provider (MSP) and meet all specifications associated with that function.

Today, electric meters are owned and operated by the MSP. Currently, this is the electric utility, as there are no third-party MSPs operating in Illinois. The MSP is responsible for verifying accuracy of their metering devices as defined by ANSI C.12 standards [26]. From a cybersecurity standpoint, MSPs hold the administrative electronic access to the device and control the code testing and deployment responsibilities. For physical security, (utilities) MSPs have a seal on the enclosure to prevent tampering. If metering functions are to expand, specific considerations are needed to ensure the accuracy and security of new metering assets, such as:

- How will the utility or MSP test meters within other devices, per ANSI C.12 and other applicable standards that do not have a consistent form factor?
- How will the utility or MSP secure the metering device to prevent tampering or unintentional damage or destruction?
- How can devices provide a local display of some form to meet statutory requirements to act as a meter?

Methods must be developed and implemented to address these concerns. In addition, a key identified opportunity is to determine when and how core metering functions can be served by distributed energy assets that have the technical ability to act as meters. Such methods may include:

- Testing the hardware—Ensure compliance with the applicable standards
- Physical security—Establishing standards for security through the use of potting of the circuits used to prevent device tampering and an inspection window provided for verification
- Cybersecurity—From a cyber standpoint, the metrology code may stand alone and be cryptographically signed to verify that it has not been altered
- Accuracy—Developing a standard connection form-factor to a test stand to allow common device testing to verify each is performing as stated
- Communications—Developing ways to accurately communicate data as needed for physical and economic needs

The deployment of AMI has provided a robust metering platform that benefits all market participants. The major impact on metering will be the need for more meter points and how to use the sensors that are in the smart DER assets as revenue metering locations. In the Data section, we will cover what data is being collected on the AMI infrastructure and how DER assets may affect the information collection rate.
2.2 Data

AMI and distribution network sensors are generating exponentially increasing amounts of data. However, data is only valuable and useful when it is analyzed and converted into actionable information. For example, AMI meters do not directly signal utilities of potential energy theft. Rather, data gained from interval reads is analyzed within the operations center to identify areas of potential unauthorized activity.

Prior to the development of AMI meters and associated smart infrastructure, most residential electric meters only measured the cumulative watt-hour reading of the monthly energy consumption at a customer’s premise. Meters at larger customers typically recorded peak demand and also interval data, although that data was usually only available through direct readings on site. When the Illinois General Assembly passed EIMA [4] in 2011, it required Ameren Illinois and ComEd to invest in AMI that would have greater capabilities and that legislation outlined explicit expectations that such investments be cost beneficial for customers by reducing estimated bills, write-offs, unaccounted for energy and consumption at inactive premises.

Technology advancements and legislative requirements have expanded what data is collected, the frequency of data collection and how data is used to improve customer service, reduce costs and conserve electricity. WG2 examined current data collection and uses, how meter data is shared and how customers can better leverage data for a variety of purposes including with respect to DERs.

As of April 2018, Ameren Illinois is collecting hourly interval data from 63 % of their electric customers and 46 % of their gas customers in Illinois. Data is collected from the meters every four hours, using a Landis+Gyr metering system. The company plans to begin collecting interval temperature and amperage data at 15-minute intervals for all customers by the end of the first quarter of 2019. ComEd is currently collecting 30-minute interval data from 92 % of their electric customers in Illinois. Its AMI meters enable it to capture information regarding energy delivered to a premise, energy received from a premise, and voltage and temperature data. Both ComEd and Ameren Illinois are currently reading meters at 15-minute intervals, where the rate requires, for commercial and industrial customers.

Ameren Illinois and ComEd deploy residential, commercial and industrial smart meters which support 8 and 16 channels, respectively, of analog information. They currently utilize four channels for collecting information: energy consumed, energy produced, power and meter temperature. Meters of 200 amps or less provide data on the state of the disconnect switch and include tamper alarms, such as accelerometer movement and voltage on the load side. Modern meters also report a loss of power supply to the utility in a final transmission before powering down.

Both ComEd and Ameren Illinois use data gathered to improve customer service and operations. Both utilities use AMI data to detect customer outages; identify potential theft and reduce unaccounted for energy; implement demand-side management programs; administer time-of-use rate programs; and support energy conservation through volt/var optimization, in accordance with FEJA [5].

In addition to improving day-to-day operations, Ameren Illinois and ComEd use meter data to support some operational planning functions through trend analysis on energy consumption. Both utilities currently keep usage data generated from customer meters for at least two years. The WG generally agreed that, since energy consumption is largely tied to weather conditions, two years of data is appropriate to support individual loads analysis, although different periods are often used for ratemaking.
The ICC has allowed for anonymous, aggregated data to be shared with third parties for research, pursuant to the “15/15 rule” applied to a zip+4 geography. This rule states there must be a minimum of 15 customers’ data included in the data set and one customer may not be more than 15% of the data set load.

WG2 discussed data availability. Specifically, utilities are collecting metering data throughout the day, but this data only becomes available to customers and third parties at one time the next day. Currently, once a day’s data is collected, it is processed to verify completeness and accuracy and used to estimate a customer’s monthly bill to date. Anomalies, such as missing, or abnormal reads, are corrected by requesting additional data from the meters to fill in or verify information. Both utilities post data to customers’ account information from the previous day by 9am the following morning. It is available on their websites. There is also data, such as voltage, that is not posted on the website for third parties to access.

Customers have the ability to access data in close to real time, with data noted as an estimate of their usage, through a HAN device. However, in Illinois, there are only approximately 30 HAN devices authorized to communicate to meters. Most of them are internet gateway devices that allow a customer to get real-time information via their smartphone or send data to a third party.

Further understanding of power flow behind the meter provides information that all market participants can use to optimize customer behavior and system capacity and, in some cases, may be able to aid in system planning or operations. Building managers articulated the issues they have in utilizing AMI meters to manage the building. First, they identified data privacy issues that limit who has direct access to meter information and asks that the consumer who owns the data have the ability to grant access to a third party, such as a building owner, allowing them the same level of user access that the consumer receives. Secondly, they identified the necessity for near real-time information and increased bandwidth to support these applications. Thirdly, they identified the importance of varying the data-collection rate, based on the information demand. By making it variable, meter value can be derived from the AMI assets without driving up the cost for consumers who are not using the information. Lastly, the data should be available via an application interface on the internet in addition to anything offered on the HAN interface. They have been using ZigBee in large buildings where the meter and customer space can be large and prevent this technology from working.

The building owners also mentioned the value of being able to use third-party devices that have metering capabilities to share power utilization information with the AMI meter or internet gateway to allow the utility’s retail service providers better access to what is occurring within the service location. This information would be inserted into the meter data stream, as additional meter data channels on the field-area network-meter (FAN) readings. Examples of metering values for this purpose may be solar production rates, battery state-of-charge and rate-of-charge or discharge, EV-charging rate and a rate of deferred consumption due to demand response. The building managers also wanted to point out the value demand-response assets in large commercial and industrial operations to contribute to grid operations. They have more dispatchable capacity than a residential customer has.

Each utility shared statistics on which type of data their customers are accessing each month. Cumulatively, out of millions of metered accounts between ComEd and Ameren Illinois, only a small fraction of Illinois customers currently access their data each month:

- Approximately 20,000 customers access their bill history each month
- Approximately 3,000 customers access their bill analysis data each month
• Approximately 1,000 customers download their data each month via Green Button or CSV format

The consensus within the WG is that, today, customers are only accessing their data to investigate billing questions; consider a change to their retail energy provider; or to investigate a new rate structure or change to their home, such as an efficiency improvement.

One topic discussed is the time of the interval data record creation and the period over which these records are collected by the network. Collecting more channels, from all meters, at all times, will increase system costs. As such, a significant amount of that data will mostly go unutilized. However, there are specific cases for a subset of meters where this information would provide value to the consumer.

The deployment of DER assets on the network will require smaller time periods between data collection. This may be, for example, from five minutes to a few seconds for some applications, such as voltage and frequency control. Existing AMI networks can only support this level of data for a small number of devices and would require modifications to the communications architecture to support this level of data gathering across the board.

It was identified that some use cases may benefit from having more granular, or different kinds of data, such as five-minute interval data collected for defined time periods, such as over one month, for customers participating in specific demand-response programs. The retail electric providers made the point that they would like the ability to call for a study on specific meters for a period of time with a smaller interval read rate. They also requested the ability to enable specific meters to provide data more frequently than four hours. Specifically, they are interested in more frequent information from certain customers whom the retail service provider may use to market their customer’s change into a real-time power market. However, gathering, processing and retaining such data will increase the service costs. Policy choices in this area will face tradeoffs.

Today, the provision of metering information collection and storage is a service that falls within the definition of *utility service* under Article III of the PUA [8]. In most cases, the costs associated with these services provided by the utility are recovered from all customers within existing rate structures. Service studies attempt to allocate these costs to groups and classes according to their respective contributions. The WG discussed the growing demand for more granular information and whether the cost to collect and store such data should be socialized when considering that few customers directly benefit from this information. For example, should the cost to purchase additional server storage in order to provide a subset of customers with one-minute interval data be borne by that customer group through a service fee, or socialized across all customers?

Having specific fees would increase the cost of specific programs and become a barrier to their adoption. If the increased fees make the program unattractive, then the entire business case for that program would be questioned. One way to reduce the information storage cost, but not the communication costs, would be to only select the more granular data for specific users who need it and keep it for a short duration. Over time, values may be added to greater summary units as you get further from real-time. When each minute of real-time data is sent in from the meter, it is kept in the servers for the next week as detailed data, but after that week, it is converted into 5-minute interval data. After a month, this data is turned into 15-minute interval data. Maybe all data after two years is turned into hourly interval data. Thus, you can keep a long history of data, but over time the costs of storing such data are decreased because as time passes, detailed data becomes less valuable.
One way the volume of information may be managed is to report changes rather than having the meters continuously report interval data. In this scenario, for a given variable, the meter would report when the value has changed by more than a given percentage. This would reduce the overall amount of data continuously transmitted and collected while still providing visibility into system performance. However, this option may also impose a significant load on the communications network in the event a single disturbance results in all meters on a feeder reporting simultaneously.

Recognizing the relatively low data-utilization rates among customers, the WG discussed at length strategies for improving data utilization. Specifically, current data utilization suggests that customers are using data when they have a reason to analyze it and act upon the information provided, most notably to reduce their energy costs.

One example offered was an automatic TOU rate interaction between thermostats and the grid that would modify energy consumption based on TOU rate data being published and showing the customer the specific amount of savings per month. It was believed that a change of $8–10 per month would be needed to entice most customers into modifying their systems or behavior. There are near real-time applications that retail service providers would like to implement such as marketing of demand services into the wholesale market. This would utilize data from meters as soon as it is available and does not require the level of data verification that is used for monthly billing. ComEd offers the ability to access the raw data in near real-time.

Providing customers with measurable financial benefit can be important in meeting state and utility objectives, although not necessarily at the cost of providing inaccurate information or creating artificial incentives. An example of where a measurable benefit coupled with more education may help customers is the 2016 study ComEd shared with the WG that showed most of its customers would benefit from moving into the TOU rate structure, yet adoption rates for that program remain low.

From the perspective of retail electric service providers acting as aggregators, allowing the customer direct access to voltage and current readings in real-time via the HAN where they can aggregate the information via the internet is desired. Service providers would like to participate in the real-time voltage reduction market. Without access to that information via the HAN interface, they have to install their own sensor for this data. Also, sharing the same data source allows all parties to be operating in the market with the same information without giving any participant an advantage. The concern is that data aggregated via the FAN is made available about 9am; it is hours old. Additionally, the website information is not the complete data the meters collect. Consumption data is included, but voltage and demand data are not provided on the web-portal. A lack of demand for the information is one reason why it is not being shared. The cost and investment for information for all customers to access it do not justify the expense. In the future, costs and benefits must continue to be considered.

Retail energy service providers within the WG suggested reducing the level of customer effort needed to grant third-party access to their data by enabling a “Click to Consent” model. Such a model would involve the third party requesting a customer provide consent and utility customer information, such as their account number, to access their data. Upon receiving the request from the third party, the utility would then verify customer consent, via phone or email communication and grant access in near real time.

Such an approach may lower the barrier that some service providers have with customers either not knowing or not wanting to take the time to use their utility customer login information to grant access. The result would be that when engaging a customer, the retail provider may show them what benefit they may provide, such as what the cost of their bill under a new rate might look like. It was noted that
the states of Texas and California have been modifying the data-access process to reduce the number of clicks for sharing information to address these issues. However, the laws in those states concerning information access differ.

The building owners noted the need for them to be considered a third party who can access the consumption data of the customer who grants them permission to do so. They need to see and demonstrate the complete building consumption and currently, privacy rules make this information sharing cumbersome.

The ICC has several dockets regarding information sharing which can be referenced on the commission's website [27].

- 13-0506—Anonymous Data Protocol
- 14-0701—RES Access to Usage Data for Non-Billing Purposes
- 15-0073—Non-RES Access to Usage Data
- 14-0507—Pen Data Access Framework

It was shared that most customers benefited and that other states such as Maryland and California are moving all customers into a TOU and peak-time rebate pricing, respectively. Both of these changes would improve price signaling and encourage customer participation in matching load to supply and grid capacity. In addition to enabling service providers to participate in real-time pricing, there also needs to be mechanisms to provide pricing signals to the devices to allow device-level price-based decision capability. These features would be applicable to possibly time-varying price signals sent to residential and commercial EV-charging stations.

Commercial, industrial and residential customers may better match their demand to the grid capacity with real-time pricing signals. In Illinois, there are real-time energy rates which all customers can use to take advantage of lower off-peak prices. For example, an EV owner charging off-peak benefits from reduced real-time energy costs if the charging occurs in those periods. The limitation of this approach is it treats the entire distribution system in the area as a common system. As EV penetration rates increase, a new rate form may have to be established in Illinois to create a market and real-time rates for supply location, in addition to energy. This local price may then be dependent on the load on a given feeder. Eventually, this may result in pricing points as small as the distribution transformer to manage the system capacity for charging load under widespread deployments.

Representatives from the transit authority discussed their plans for on-route bus charging and how real-time pricing information may influence its charging operations. The transit authority plans for implementing 500kW on-route chargers may significantly impact the distribution grid and the grid capacity to support charging loads. Real-time metering and pricing information may help the transit authority to determine optimal charging times for its fleet. For example, such information may incentivize them to charge their fleet as much as possible throughout the mid-day hours to consume excess solar power and potentially avoid charging during peak evening hours. As with any consumer, there is a limit to this behavior and a point when a customer must continue operations regardless of price.

Some group participants suggested that standards for data reporting should be consistent across the country. However, there are also issues of Illinois law and policy, which may resolve issues differently from other states. The form of data lies within the scope of ICC regulation and standardization may also occur within the state of Illinois. The Green Button initiative is focused on this goal with having a common extensible markup language (XML) data format for all utility metering data across the country.
Ameren Illinois and ComEd have joined the Green Button alliance and provided XML data. However, they also support data download via a comma-separated values (CSV) file.

Ameren Illinois and ComEd currently have the ability to collect and store metering data. Data collection frequency depends on data use and can range from hourly to sub-second intervals. As the penetration of DERs deepens, as well as electrification of fleets, the data collected will need to be at high resolution in real time to be useful for the various DERs voltage-response programs and to allow a reduction in peak demand.

2.3 Communications

The utility communications and controls networks put the “smart” in “smart grid.” It is what enables a utility to collect and share more data in a timely manner than automatic meter reading (AMR) systems may. It allows them to provide enhanced services, such as dynamic, time-of-use rates, automated power on and off and the ability to enhance energy-efficiency efforts through Volt/VAr optimization. In essence, the utility communication networks are comparable to the human body’s central nervous system in that sensors throughout the network capture and relay data to the central control system.

Any changes to metering and data collection and use will likely impact the architecture and require a scale of existing or new communication networks. For example, the near real-time sharing of usage data from a subset of meters to third parties using an internet portal as requested by the building managers. The WG discussed how these critical networks might need to evolve to meet future needs.

Utility networks are largely segmented to account for unique requirements throughout their enterprise operations. The following provides a high-level overview of a few of the typical utility communication network requirements:

- **Enterprise Business Network:** Like many corporate and commercial organizations, utilities require an enterprise business network to support business functions (e.g., email, file servers, corporate operations, etc.). Where possible, these functions are carried out over the utility’s private network to reduce operational costs.
- **Control Network:** Control applications, such as SCADA, require high reliability, confidentiality and integrity. The divergence between the steadfast requirements of reliability and security for utility-control applications and public carrier business drivers has increasingly pushed utilities to invest in their own private networks to improve operational performance and reduce costs.
- **AMI Network:** The AMI network enables a utility to collect data from the millions of sensors and smart meters across its service territory.

Today, most utilities within the state of Illinois, including Ameren Illinois and ComEd, have large private networks and are migrating as many remaining services to them as possible, to support delivery of services, as opposed to outsourcing communications to a public carrier network. The move toward private networks by utilities nationwide largely began with the deployment of microwave networks and has moved to fiber networks. Prior to the move toward fiber, utilities nationwide relied largely on leased, four-wire voice-frequency facilities for SCADA control and protection. Since that time, increasing technology, operational and cost considerations have further supported a utility’s need to invest in private communication networks. These networks are also designed to meet utilities’ specialized needs and are important to providing reliable service. Finally, the group heard that building and maintenance grid-related communication networks fall within the scope of functions required for utility services and that private networks can be necessary to provide reliable service to customers.
The use of fiber for communication applications provides for more reliable service to customers, because fiber cables are immune to noise and require less maintenance. Fiber-enabled utilities leverage their rights-of-way and install fiber within optical ground wires at a small, marginal cost when constructing or renovating a line.

Another primary driver for maintaining private utility networks is the move by common carriers to Ethernet-based services and the subsequent retirement of legacy services that are essential for power-grid control. The retirement of four-wire analog phone circuits, for example, is driving many aspects of the utility network to be modernized and moved from common carrier to private networks, because a suitable replacement has not been established that offers the same level of consistent latency for the protective relaying application. In addition, public carriers do not provide specific features that utilities require, such as proactive communication about network status and estimated repair time, similar to the outage-management systems utilities have made available to their customers on their websites.

Utilities and public carriers also do not generally align in the area of technology lifecycles. Within the public carrier space, there is a constant, intense competition among providers to lure customers through the deployment of the fastest, most reliable network with the greatest geographic coverage. Utilities, on the other hand, are driven and regulated to manage costs in the delivery of reliable electric power services. For example, utilities often use cellular modems in their networks for non-critical applications. These devices can provide 10 years or more of service in the utility environment, but the lifecycle for supporting a given deployment has decreased in the common carrier space to under seven years.

Over the past 10 years, all first- and second-generation modems were replaced with generation-three devices, which are now being replaced with generation-four devices as carriers deploy generation-five networks. These upgrades have not provided any benefit to utility applications and were only conducted to maintain compatibility with the network they are receiving service from. The continual redeployment of devices to maintain compatibility with the wider world is a challenge for most utilities. This challenge becomes acute when considering notification by the public carrier of planned network retirements has historically varied from six months to three years, creating planning challenges for utilities which generally require one-to-three years to design and build a replacement network or implement network upgrades. By owning the communications infrastructure, the utility has better control over their investment lifecycle costs.

By owning the communications asset, utilities have visibility into all aspects of the network operation, such as health of remote-terminal cabinet batteries and maintenance of cables on their lines. Visibility into network operations enables a utility to identify network issues and the impact of each to their operations. This enables them to allocate resources in response to an incident or outage in line with their operational needs.

During WG meetings, utility representatives shared an example of an incident that demonstrates their need for network visibility. During a recent storm event, when power was out to key communications nodes, they saw that the generator at the main site, which is a pinch point in the power system, had failed. The utility was able to prevent further degradation at this constrained point in the power system by sending staff there.

Ultimately, communication providers’ focus is on restoring service to all of their customers while the electric utility is focused on restoring service for all electric customers. The alignment of what is critical for a utility may not be the same as the communications provider responding to the same incident. For example, communication cables to a large, rural extra-high voltage switching station are vitally important to power grid operations and restoration of such a line is critical to restoring power to
customers in the event of an outage. From a public carrier standpoint, these communication lines are on a long radial distribution line with only a few customers and are, therefore, not a top priority for their restoration efforts.

Other WG members asked why this level of service may not be provided by a third party. Utility representatives noted that it was possible for third-parties to provide this level of service; however, at this time service providers do not want to share the level of detail requested, nor do they want to commit to the level of redundancy and reliability. The market for communication services in utility applications has resulted in the utilities increasing their investment to meet their need. Common carriers have not invested in the level of service required. A regulation act would be required to realign these interests.

By owning the communications infrastructure, the utility is the sole administrator of the network. On the private network, the utility has control of how protection and control traffic is classified along with enterprise and other data streams. On wired facilities, common carriers offer minimum committed information rates and offer the ability to classify information within that rate. However, on a wireless network, a utility has no ability to classify their important business traffic over any other cell phone user.

Lack of prioritization on the wireless network has resulted in instances where the network is not damaged, but wireless transmissions cannot get through. An example is the east coast earthquake in November 2011. Even though the earthquake resulted in minimal damage, the network was congested all day with network users sharing their experiences.

The use of FirstNet, the dedicated public-safety network, for wireless requirements was considered for utilities. However, utility operations are classified as a secondary service behind public-safety agencies, even though utility personnel, like first responders, are deployed to the disaster scene to support the recovery effort. As such, utility communications are only prioritized on FirstNet on a case-by-case basis. WG members asked if private networks provided enhanced security over public networks. This statement has implications with three aspects of utility operations: control, reliability and cybersecurity.

As noted, private networks provide utilities with more control over who accesses their facilities and when changes are made. Workers making changes on the network are the top cause of communication outages and there is no evidence that private ownership of the network reduces this risk. However, the ability of the owner to restrict when changes occur allows them to schedule work at times that minimize the operational impact of a potential outage. For an electric utility, the main concerns are avoiding high-load days and adverse weather conditions to minimize such an impact. With regard to scheduling maintenance or network improvements, utilities generally prefer to make a change during standard working hours when they have their full workforce in place rather than at night when they must call people in. In contrast, common carriers prefer to make changes at night, when the majority of their users are not using the network.

From a reliability standpoint, when utilities build networks, the network electronics are deployed using industrial standards for design and construction which call for more backup time, greater isolation and more redundant components in the system. The links between electronics nodes are built of fiber and microwave systems. The fiber is installed on transmission lines whose rights-of-way are cleared of trees and often set back from roads, reducing outages from tree fall, vehicle strikes and ice-damage. Radio towers are built to withstand severe weather events. The result is more reliability than for a network built to commercial standards, typically the standards to which public carrier networks are built.
With regard to cybersecurity, private networks are often thought of as being more secure, benefiting from fewer access points and more restricted access to the networks. However, as more devices are added, the benefits of these network attributes diminish. Therefore, the presumption of security by ownership should be replaced with methods for authentication to access the network, authorize activity and ensure the integrity of the information that is being transmitted.

The utility business structure licenses them to spend capital which they can recover at a fixed rate of return for all items that are used and useful in the power delivery. This provides utilities with a significant incentive to invest in network infrastructure, as the utilities can then receive a fixed rate of recovery on that investment. In contrast, costs associated with leasing facilities and services from a public carrier are considered a business expense recovered at cost.

Clarifying the leasing requirements for which a utility can get recovery may, in some cases, incentivize them to lease rather than build capital assets. For example, clarifying the accounting rules regarding 10- and 20-year irrefutable right-of-use agreements for fiber, where the utility is taking possession of fiber strands, rather than a whole cable, may encourage them to seek lease agreements along existing routes instead of building new infrastructure. This may also apply to wireless networks. If a service provider were to build a hardened wireless network with device access and service rolled into a single fee that may be capitalized, this would align with the utility business model.

There are also cases emerging around the country and the world, where utilities are building their own fiber networks and leasing the extra capacity. Electric utilities have unique synergies with their poles, underground conduit systems and real estate at substations that can allow them to deploy these systems more efficiently than others.

ComEd currently operates a fiber-based network using synchronous optical networking (SONET) and multiprotocol label switching (MPLS) technology to connect control centers to key substations and operation centers. They use broadband, point-to-point microwave links to extend the reach of their private transport network. They are using narrowband SCADA radio to connect the remaining control sites. A current leased-line replacement program is moving the remaining protection and SCADA circuits off leased facilities onto their private transport network. ComEd’s AMI network is standards-based (IPv6) and designed to support some services beyond electric metering, such as distribution automation and the Internet of Things, depending on bandwidth and latency needs.

Ameren Illinois operates a fiber network today and is expanding it with their Intelligrid program to move all SCADA and protection circuits off leased facilities onto their private network using MPLS technology. They also operate fixed, point-to-point microwave links to extend the network beyond fibers reach. To access field devices and smaller substations that will not have fiber, they are building out a private long-term evolution (LTE) network.

For its AMI network, Ameren Illinois deployed a FAN that covers its 44,000 square-mile service territory and leverages unlicensed spectrum. For its backhaul requirements, the utility currently uses public-carrier take-out points to transmit metering data to data centers. For behind-the-meter applications, such as In-Home Display or Gateway devices, the utility has enabled a HAN using a higher frequency, unlicensed spectrum.

ComEd and Ameren Illinois smart meters are equipped with Zigbee radios and employ Smart Energy Profile 1.1 that enables the meter to broadcast energy consumed, real-time demand and pricing information into the HAN. The WG discussed how Zigbee HANs were the planned method for communication between every consumption device and meter in the home; however, today most smart
home-energy devices use WiFi instead of Zigbee for their communication. This occurred because the smart devices are providing benefit to the customer by being connected to their smartphone and letting the consumer interact with it directly using the consumer's internet connection and WiFi.

As stated in the previous chapter, distributed energy resources are using the internet for connectivity. This trend is likely to continue for the foreseeable future. For example, EV commercial charging stations all include LTE modems and small rooftop solar, consumer storage, commercial storage, and HVAC thermostats all rely on a local internet connection via a gateway. All of these devices have a cloud connection and the ability to deploy grid-response programs using these cloud and, thus, internet connections. This trend will continue until the connected supply and load have grown to the point where maintaining the grid stability requires the use of the intelligent devices consumers have decided to install. A WG member supporting a utility suggested the IEEE 2030.5 protocol [28]. This protocol provides client-server architecture with methods to allow individual consumers/devices, as well as aggregators working with cloud services and many devices, to share the same system.

However, the WG believes that the internet, while its ubiquity and openness are alluring for the implementation of the two-way power grid, there are three key issues this does not address. First, grid reliability cannot depend on the internet, because it does not offer guaranteed availability and time to repair. Losing access to an individual device is not critical to the overall distribution system and many applications provide efficiencies that, if not realized, do not prevent the reliable delivery of power. However, at some point, there will be a need to move to a dedicated control network. In other areas of this chapter, we have discussed reasons for this. Second, not all customers have internet access and the utility has to offer its rates to all customers. Requiring internet access is not equitable to all consumers. Third, security of an open-internet connection is a concern by the utility that would require a solution. Therefore, the likely source of reliable communications will be with the meter using IEEE 2030.5 over the HAN. You may think of this connection as just another path from DER device to central servers and any given device may use either or both paths.

There is concern regarding the ability to upgrade existing meters with Smart Energy Profile 1.0 or 1.1 configurations to IEEE 2030.5, which is essentially the Smart Energy Profile 2.0. Since Ameren Illinois and ComEd deployments are in their final phases, it is desirable that existing meters remain in place for their expected life without having to be replaced to support this functionality. For customer-facing data, Green Button and bolstering its deployment for customer access to their data was the focus.

While most existing control and AMI networks, including ComEd and Ameren Illinois,’ have untapped, excess capacity, these networks are not built to support more frequent data collection (every few seconds to every five minutes as opposed to every 15 minutes) on every metering device across the enterprise.

Increasing communication network requirements, costs and regulations are pushing utilities nationwide to bring together their disparate networks to deliver required functionality and reduce network costs. By creating a flatter network which meets all application needs, increased value is provided to the customer by allowing for rapid deployment and sharing of information between customers, retailers and the utility. It increases the value of these investments to the customer. Ameren Illinois and ComEd representatives presented the WG with an overview of ongoing efforts within their organizations to study, design and implement a converged network using a three-tiered strategy to address their growing bandwidth, reliability, cost and security requirements.

In executing a three-tiered network-convergence strategy, utilities first implement a fiber backbone from data centers to transmission and distribution substations. Second, the network is expanded to
include smaller substations using high-speed, low-latency radio networks. Finally, utilities will draw upon the existing mesh AMI network to connect all locations and provide a HAN. Ameren Illinois representatives noted their organization plans to deploy a long term evolution network for providing private radio communications to connect the mesh network to the high-speed fiber network. ComEd is currently using WiMAX radios to connect its mesh and fiber networks and is evaluating LTE technology for potential use.

The WG discussed at length how communication between DERs and the grid and among other DERs, might occur. They focused on installations to the grid through an existing service, not on large-scale installations, where a specific technical study and control and communication details are specified.

Technically, there are three primary ways to connect a DER asset to a utility’s FAN: through the HAN, a direct interface (such as cable or radio), or a cellular modem. The WG agreed that a wireless connection is desirable to facilitate installations in many installation types without having to install dedicated cabling.

While all three options have merit, the WG discussed the potential limitations of each based on existing and planned network improvements:

- Use of mesh field-area network: ComEd has a Silver Springs Network mesh that would require customers to purchase radios from Silver Spring in order to directly join the mesh. The mesh being deployed by Ameren is manufactured by Landis & Gyr and is being upgraded to use an industry standard 802.15.4g standards-based communication protocol by the end of 2019. While this opens up the radio for third parties to integrate into the wireless network, there are administrative issues with allowing third-party devices to join the mesh, including authenticating and authorizing devices, conformance validation and testing, management system compatibility and coordinating system upgrades, that make this option not desirable in most situations.

- Use of the internet or cellular modems: Because of the high-bandwidth low-latency characteristics of the 4G network, which will be enhanced with 5G deployments, the use of cellular modems is an attractive option. This should be supported for devices communicating to manufacturer, aggregator, or building owner. However, cellular network reliability and the rapid pace of change of cellular standards do not make this a preferred choice for critical control communications required to maintain reliability.

- HAN connection: Both investor-owned utilities in Illinois have deployed HAN networks which leverage the Zigbee communication protocol to connect behind-the-meter assets to the FAN. However, meters will require an upgrade from SmartEnergy Profile 1.1 to IEEE 2032.5, which is an update to the profile on the meter, to support distributed energy assets.

Based on the characteristics of existing utility networks and the listed technology options for each deployment, the merits of each options should be considered and selected for each deployment. Using the Internet Protocol and a common cellular configuration with private cellular technology may also be a way of providing all of the benefits listed above in the internet option, while maintaining the reliability needed for grid operations.

With high levels of distributed energy production, the protection and control settings of the line-field equipment will be more dynamic than they are today. There are safety concerns that protection settings will not be well coordinated if power flows change in magnitude and direction throughout the day. In
addition, voltage regulators and capacitors will have to have tighter control settings to account for large loads and excess solar production on distribution lines.

As a result of these changing requirements, it is likely that all automatic line equipment will have to become communicating devices so that their protective-settings groups can be adjusted multiple times per day. A distribution management system that can evaluate power flows on the feeders and adjust settings on regular intervals will also need to be deployed. This may be a simple change, such as disabling the reverse power-flow setting on a recloser during times of excess solar production, or changing the group coordination curve for a recloser with high amounts of solar behind it, so it will trip on a relatively low infeed current to keep overall fault currents within feeder-design principles.

The control system will also need to coordinate with solar and storage inverters to provide coordination curves. All these new data points and frequent data collection will require high-bandwidth, low-latency communication to allow the systems to gather data they need and provide necessary control messages.

To accommodate new meter-channel data coming from HAN devices and provide real-time data updates and control messages, changes in the FAN architecture may need to be made. Such changes may include reducing latency by decreasing the number of hops in the network. The result is a network that looks more like a point-to-multipoint network than a mesh, with some nodes repeating the signal to get to fill in spots that may not be reached from the collector/base stations. Therefore, it is expected that utilities will build private broadband point-to-multipoint networks to provide control as the distributed energy asset penetration deepens on the power system.

Common communication standards are needed to enable the increased use and integration of DERs within the grid. The WG agreed that IEEE 1547 [29] and IEEE 2030.5 [28] should be the basis for establishing interconnection and communication standards for DER integration within the state of Illinois. The commission is encouraged to look at how California implemented their requirement using tariff Rule 21, [30] instead of implementing it by law. The following provides an overview of the recommended IEEE standards:

- IEEE 1547: Initially published in 2003, this standard focuses on the technical requirements for interconnections and defines details, such as voltage frequency performance, how devices should respond to a disturbance and testing these devices. Since its initial publication, there have been seven additions that have provided added functionality. The latest provided for more capabilities of DER assets to provide grid support during abnormal conditions, notably, advanced inverters connected to a solar installation.

- IEEE 2032.5: This standard specifies how inter-operation will occur between power system equipment and information systems regarding the information model, functional interfaces and logical connections and data flows. It focuses strictly on the intercommunication between DER devices or aggregators and the utility, and only specifies the minimum communication requirements. It does not leave any optional capabilities to improve inter-operability.

Communication provides for updating operating curves for autonomous operation, updating immediate device controls, status update gathering and device group management. Each inverter belongs to a group based on what system, sub-transmission region, substation, feeder, feeder segment, service transformer and service point the DER is connected to. This allows settings to be issued for whole groups of devices, such as all devices on one feeder.
This standard incorporates security models similar to how users connect to secure websites. The utility assigns a globally unique identifier (GUID) to a device to avoid confusion in naming each inverter. All communications are imitated by the inverter or aggregator using transport layer security (TLS) encryption. The inverters should check in twice a day to get new configurations and provide status-updated information every 48 hours. All scheduled communications should be random so as not to overload the communications infrastructure or servers. All alarms should be transmitted immediately; these alarms should only be general, such as the device is offline, as the utility is not responsible for the device operation and, therefore, does not require detailed alarms. The utility transmits the time to each device to coordinate operations. The utility can send multiple commands simultaneously, specifying different operations based on time. This allows for the simultaneous implementation of multiple programs at the same time.

While IEEE 2030.5 [28] deals extensively with obtaining operational metering data from devices, it does not contemplate being the revenue system. Rather, the AMI network would be the system of record for all financial transactions. The development of these standards, and this aspect of the industry, is dynamic. Therefore, rules for standardization should be clear and detailed by each utility in a public procedure that is harmonized to the degree possible, yet flexible enough to be regularly updated as the market matures. It is the utilities’ desire to lead this standardization effort and include requirements that meet customers’ needs, provide simple inter-operability and integration and reduce costs by using common implementations across multiple utilities and states.

A key consideration for encouraging greater levels of DER integration and investment by consumers is their ability to connect assets to the grid in a timely manner. Other commissions, such as Massachusetts, have indicated that 10 days from submitting a request, to completion of DER provisioning is an acceptable time frame.

When an AMI meter is present, completing the provisioning of some types of DER may be as simple as changing the meter configuration and updating company records. The provisioning change would consist of putting the customer on a net-metering rate and meter configuration that recognizes two-way power flow. It authorizes the DER asset to speak to the HAN device and it updates systems to indicate the asset is present and how it should be tracked and operated. There might have to be an inspection of the new device to make sure the interconnection meets utility standards for identification, safety and operation. However, technical considerations must define what and when DER can be afforded this treatment.

Before any standards for completing a DER interconnection request are implemented, it is important to ensure that the required communication infrastructure is in place, is ready to accept customers and is able to support the information-sharing required for the application. For example, if solar needed to share one-minute interval operation with the grid, this would have to be accommodated.

Among the key goals of an electric system are reliable operations, planning and efficient markets. Maintaining a reliable power system is the first priority and, in some cases, may require direct control signals to ensure the grid reliability. Efficient markets may help drive price signals that act as an overlay to optimize operations and planning considers the system reliability and helps in providing price signals on short and longer terms for the market. These price signals would be the primary form of control. Only when these signals do not drive the result necessary for reliable operation, would a direct control signal be used. For example, direct signaling of some rooftop solar panels may curtail solar production, if system voltage is getting too high and market signals have not addressed the issue.
To limit the scope, the group discussed necessary communication requirements based on the assumption that such a market would involve the ability of customers, from a handful of nodes to potentially thousands, to coordinate amongst themselves to provide electric services through devices on a single feeder where there is sufficient supply to meet demand. WG discussions focused on what may occur. What is presented here addresses technical issues regarding grid control.

The distribution system operator would serve two roles to ensure reliable electricity supply to the customer. First is the technical role, where it identifies the grid state and then sectionalizes and shares with nodes the network state around it. It is assumed that there would be a distributed control system within each region of the network. One needs to limit the reliance on communication systems to minimize exposure to communication failures. In case of failures, the controller would operate a microgrid that aims to balance supply and demand within the grid segment that is still operational. It would have to have an operational electrical model, and account for variation in topology and other system functionalities, such as the ability to gather current status information, compute the optimal configuration, send control signals, ensure system operation within safe tolerances, etc. Checks must be performed on a daily basis to ensure reliable operation under dynamic conditions.

Secondly, when operating in an isolated grid, the distributed control system would have to establish a market using price signals to balance supply with demand while recording those transactions for settling after the grid was restored. The technical considerations of stable operations are defined for the point of common coupling within IEEE 1547 [29] and communicated through IEEE 2030.5 [28], where operational ranges are established and, regardless of market desire, assets will operate within those tolerances. For example, if an inverter has a contract to supply power, if it can, is the appropriate curve loaded for a given mode, such as a power frequency curve. If the grid frequency is dropping, the inverter will supply more power.

While the WG addressed the many technical components regarding grid control, a cross-cutting issue that needs to be examined is how the market is set up and settled. The market structure would have a significant impact on the role of the utility network and the technical functionality that is required to serve such a role.

### 2.4 Cross-Cutting Issues

WG7, Ratemaking, was tasked with identifying potential rate structures and regulatory models that would enable and support the vision of future grid development. The outcomes of this group will directly impact future metering, data and communications requirements. Specifically, future rate and market scenarios, such as enabling a peer-to-peer transactive market, directly influence what will be metered, the frequency of data collection and subsequent network investments to enable expanded metering, data collection and control capabilities.

Adoption of statewide standards for DER network integration, data formatting and sharing and verifying metering accuracy and security, are critical for maintaining cost-effective and secure grid operations in the future and mitigating cost risks for customers, such as having to update or replace DER technologies before their end of useful life. Such standards will also inform network investments and architectural changes, where required.

The need to maintain and possibly enhance, data security represents another cross-cutting issue to be addressed by WG3, Reliability, Resiliency and Cyber Security. The need to address this issue is particularly acute when considering the desire among multiple stakeholders to streamline the data-sharing process. Currently, the incentives to abuse consumption data are low. In the future, if price and
consumption data are more closely linked, incentives for data abuse will be increased. There is currently an ICC document hearing on Ease-of-Data Access to further examine this issue.

As discussed in the future state for communication networks, utilities need broadband wireless networks, which meet the reliability standards of operating the power grid. Today many aspects of the grid operation depend on the cellular telephone network. As discussed in several sections, building reliable broadband networks is important for providing the reliable power that customers are accustomed to. While owning the infrastructure, such as radio towers and fiber necessary to construct a wireless network, having the technical ability to build and operate a network-dedicated spectrum specifically for utility operations standardized across the whole country is essential. The allocation of 10 MHz for this purpose will provide a key resource required to upgrade the communications infrastructure to meet the objectives set out for adding renewable energy to the power system. This spectrum should deploy the latest cellular radio standards providing open, interoperable interfaces for equipment today and in the future.

Expansion of communication networks to enable the secure and timely collection and distribution of data and control operations represents potentially significant investments and the deployment of new or additional communication devices. However, deployment of new technologies on utility-owned assets that may enable the connection of third-party DERs and devices have specific regulatory challenges associated with permitting and right-of-way on private property and private-party easements. Specifically, during WG sessions, utility representatives spoke about the challenges they had installing Smart Meter Collectors due to existing easements covering the installation of communications equipment on existing structures on private property where an easement was obtained to install their facilities.

While not necessarily the law in Illinois, a Missouri case against Sho-Me Power for the installation of optical ground wire (OPGW) on existing transmission line illustrates the issues that may be posed. There, the court held that easements over private land must be obtained for communications equipment to be installed on power poles if that communications infrastructure was going to be used for more than telemetry and power system control. Since AMI was contemplating supporting third-party applications, due diligence had to be conducted to review the easement of each site selected for installed, dedicated communications equipment in the form of a Smart Meter Collector. However, mesh networks retransmission of metering data for a third-party utility requires the utility to amend the easement for the installation of their facilities on private property where an easement was obtained to install their facilities.

Equipment installed on poles located on public lands owned by municipal and state rights of way or in common utility easements are not a concern. Their easements allow for the installation of communications equipment if you have a franchise agreement that considers the communications facilities installation. Private party easements often do not address communications facilities, or, list their use for telemetry and control, so the selling of excess capacity to a third party is not accounted for and thus requires modification. The cost of paying for the easement itself is generally not the main concern. Typically, the main concern is the administrative cost of amending the easement agreements with each landowner, often costlier than the payment of the right when considering the hundreds of thousands, to potentially millions, of agreements that would have to be modified.

When there is a public good for third parties—or at least those with a public-service purpose—to have access to this capacity, the creation of a streamlined process may facilitate the deployment of Smart Cities and, potentially, to foster rural broadband adoption. In addition to easements, other agreements
that provide for the installation of utility facilities must be considered, including franchise agreements and joint occupancy agreements, among others.

Other regulatory issues to be considered by WG6, Regulatory and Environmental Policy, include the number of permits needed for making modifications to a pole, which, depending upon location, may include right-of-way construction permits, traffic control permits and zoning or planning commission approval of the additional devices being installed on the pole. The ability to obtain a blanket permit for this work, or the ability to perform this work under existing blanket agreements, would streamline the widespread deployment of new communications facilities and reduce deployment costs.

The need to account for network costs is a cross-cutting issue. One solution examined by this WG was the potential for utilities to lease or sell access to their network for DER connection. Determining the equitable distribution of financial benefit of such services requires further examination by the WG7, Ratemaking. Options for such an arrangement may include leasing access to an unregulated entity under the utility, which, in turn, leases that access to the public and reimburses the ratepayer for the asset. Another option may involve the utility leasing access directly to a customer or entity, with the ratio of the funds split between utility ratepayers and shareholders.

Key unanswered questions from the WG sessions largely focused on the development of a resilient communications network capable of integrating and managing potentially millions of devices that have sufficient bandwidth to collect and relay data as needed to meet market and operational demands. While most of these questions are largely addressed through identified cross-cutting issues, a key question regarding who should own the network infrastructure remained.

We provided information on why utilities have moved forward with the development of their own private networks and their move away from leasing private-carrier services. To meet future network requirements and gain access to constrained wireless spectrum, the WG asked, “Should public carriers be regulated to provide utility-grade services?”

Any such regulations should address consistency and the repair rate for those services. As noted, utilities and common carriers have diverging business drivers and requirements. The following provides examples regarding the gaps between services public carriers offer and what utilities require to meet reliability standards for wireline and wireless networks.

Wireline: In the past, utilities would lease “Class A” circuits that were conditioned to operate during an electrical fault; had a 24-hour backup power supply; and a four-hour time limit to repair service-level agreement. Because they are static circuits, Class A circuits also had a guaranteed level of latency in the 2 to 4 ms range.

Today, these copper four-wire voice-frequency circuits are being retired and replaced by packet-based fiber circuits. While these new fiber circuits provide a service that can work for utilities, their operation is not guaranteed. The provider does not provide notices for maintenance on the circuits between midnight and 6 am and time to repair is not guaranteed. The power supply needed for the circuits is not often in small roadside cabinets and not designed for 24 hours of operation. In addition, they are not maintained and often do not have the backup time they were designed for, as alleged in a lawsuit by the Communications Workers of America against Verizon. Maximum latencies are guaranteed in the 100’s of milliseconds.

Wireless: For wireless services, public-carrier coverage and speeds have increased and had the potential to meet evolving utility network needs. However, public-carrier wireless networks are not designed to standards that make it disaster-tolerant, as available on-site power sources have eight hours or less of
backup time and a limited number of backup generators. Furthermore, backhaul circuits from the sites are not redundant, nor are these circuits hardened against storm damage. Existing circuits, both copper and fiber, are often installed on distribution lines that can be damaged in a storm. Finally, public-carrier structures are typically designed to withstand strong winds up to only 90 miles per hour (MPH) where utility and public safety towers are rated to withstand 120 MPH winds.

When considering the rapid development of emerging technologies and the growing services electric power utilities provide, today's electric power industry is facing challenges like those of the industry's very early days. In those days, industry leaders sought to determine how and what to measure for electric services. Initially, because electric power was replacing gas to provide lighting services, they sought to create a gas-equivalent metric. But as the industry expanded to provide more than just lighting services and as “behind-the-meter” applications grew because of inventions such as the Edison light bulb and the adoption of alternating current became the standard, the industry had to evolve in what services it delivered and charged customers for said services.

Unlike those early days, today virtually all households, businesses and public services are connected to the grid and are dependent on reliable electric services. No other industry has the national security requirements and broad public good dependency on the reliable service delivery. This makes it daunting to change the fundamental structure of the delivery of electrics services.

As noted throughout this chapter, changes to metering, data and communications functions and infrastructure will be largely dependent upon desired rate structures, regulatory models and market structure. Therefore, it is the recommendation of this WG to create cross-functional WGs to identify technology requirements that fulfill stakeholder needs and provide for appropriate security levels. Once technology requirements are identified, further work will be needed to create the necessary technical standards and modify existing regulations and/or state laws to accommodate associated technology and infrastructure design, deployment and operations.
3. Reliability, Resiliency and Security

The challenge of WG3 was to review, discuss and assess the reliability, resiliency and security (RR&S) of the grid. The confluence of these three critical areas is an interesting backdrop for a focused discussion on how the grid and those who support, operate, advise, regulate and interact with it take appropriate steps to identify and maximize opportunities that advance grid modernization. Modernization should consider actions that cost-effectively ensure that the grid operates as intended and adapts to future needs while remaining reliable, resilient and secure.

This section will identify various challenges, opportunities, solutions and potential action items specific to RR&S. It supports the overall NextGrid goal, as this study strives to provide thoughtful insight and information in support of broad efforts to achieve grid modernization through effective policies and best practices that direct and support the industry and its consumers. It will explain how potential actions, inactions and outside factors may impact consumers, utilities and the environment.

The goal of WG3 is to promote continuous and trustworthy levels of RR&S, notwithstanding the many obstacles and challenges to consistent achievement of a grid that adapts and functions as expected by those who rely on it. The potential scope of the WG was broad in order to provide meaningful insights. The group narrowed the focus to issues and topics that cover the elements of how utilities and other stakeholders, who support and interact with the utilities, can design, implement, support, assess, protect and successfully operate all the critical components of the grid.

The future grid, Figure 14, is envisioned to achieve increased efficiency, reliability and resiliency, integration of renewable energy sources and reduced overall energy costs. To achieve this vision, the following characteristics are imperative: two-way flow of energy and information, integration of renewables, decentralized architecture for protection and control, advanced monitoring, analytics and visualization, integration of EVs, optimal use of information and communication technologies and increased customer participation.

Figure 14. Schematic of the future grid
For purposes of this discussion and evaluation of the critical areas that will impact the future of the grid we are using the following definitions: for resiliency; “ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components,” for resiliency; “ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions,” and for security; “ability of a system or its components to withstand attacks (including physical and cyber incidents) on its integrity and operations.” [31]

WG3 organized this topic into four categories: technology, people, process and regulation and compliance. This allowed a focus on specific topics so the group may share ideas and gain insight from experts from consumer advocacy groups, academia, national labs, governmental entities and industry representatives through presentations and open discussions. The following themes permeated this process:

- Having the right people fully engaged and focusing on RR&S is essential to the grid’s current and future success. That includes workforce development, recruiting, training and supporting the careers of key individuals that execute on the well-designed plans and processes, implement and improve the technology that is continuously changing the landscape upon which the grid operates and review, assess and confirm their compliance with the many regulations in place to protect and support the successful operation.

- Collaboration among industry stakeholders is crucial. Fostering organizational culture that prioritizes RR&S is essential and requires visibility, presence and buy-in at all levels. Independent approaches to solving such a complex, elusive and interwoven set of opposing dynamics is no longer a viable solution. Critical Infrastructure [32], especially those entities charged with operating the grid are coming together to share intelligence, seeking ways to cooperate in order to tackle the challenges to reliability, resiliency and security of the grid that include both natural events and the emerging and escalating threats from nation states and other groups or individuals who are intent on interrupting grid operations.

- The timely sharing of information is imperative to RR&S. There is general agreement that an extended lag between the identification, classification, de-classification and dissemination of beneficial critical-threat information back into the hands of utility operations interferes with a collaborative, highly efficient, timely and responsive defense posture. To achieve and fully support effective collaboration among industry stakeholders and government (in particular the many facets of the intelligence community), successfully navigating the chasm that currently exists between identification, collection, analysis and interpretation of continuous threats to the stability of critical infrastructures is crucial. WG3 discussed reasons for the time-lag that include: protecting sources, streamlining information delivery, creation and clarification of responsibilities, ensuring access to useful and appropriate information and balancing transparency and appropriate denial of access.

- Technology is crucial to the continued achievement of advancements in both operational and economic efficiencies while operating a system as complicated and dispersed as the grid. Technology is also the source of tremendous complexity and the introduction of escalating risk and threats, particularly considering the depth and breadth of modern supply chains. The tension between efficiencies and
complexities presents both opportunities and risks we don’t yet fully understand. The convergence of operational technology (OT) and information technology (IT) is a key ongoing challenge, as every utility is navigating the confluence of these two previously separate disciplines. Moreover, the emergence of the internet of things, machine learning / artificial intelligence, quantum computing, smart devices, blockchain, DERs and energy storage and EVs, drives the quest for data and resulting potential from its study and analytics.

- Care must be given to ensure that RR&S interventions are operating as intended on a regular basis. Quantitative and scenario-based metrics for RR&S should be employed to assess the effectiveness of interventions [33] and ensure that compliance activities do not result in unintentional negative impact on RR&S. Finite resources require maximizing the intersection of compliance activities and those that improve RR&S while achieving a balance for initiatives, programs, or activities in which the two do not directly intersect.

- The report explores RR&S from an Illinois specific perspective. With separate generation, transmission and distribution functions and the uniqueness of Illinois’ current rapid acceleration of new technologies and integration of new technology deployments (such as AMI, microgrids, smart inverters, wind and solar, other inverter-based technologies such as storage and EVs) may create an environment where RR&S can be impacted in ways that might differ from other states.

WG3 recognizes that the opportunities, solutions and possible action items proposed herein also create the potential for significant associated costs. While cost considerations are critical, the report proposes that such discussions are beyond the scope of WG3. Physical security is an important consideration for the RR&S and was discussed by WG3; however, a comprehensive analysis of physical security is outside of the scope of this study.

![Image of RR&S topical areas](image.png)

**Figure 15.** RR&S topical areas applicable to future grid
As identified in Figure 15, WG3 recognized that achieving enhanced RR&S for the future grid occurs at the intersection of technology, people, process and regulation and compliance. Many utilities and other critical infrastructure owner-operators implement current security best practices, coordinate with federal, state and local agencies and strategically share valuable information. Though the landscape is not uniform, the industry is evolving to keep pace with technological trends and address emerging threats. As a result, WG3 seeks to identify, highlight and promote continuous adoption of appropriate technologies, best practices and processes that achieve efficient and cost-effective RR&S of the future grid.

3.1 Technology

The modern electric power grid is a complex cyber-physical critical infrastructure that forms the lifeline of our society; its reliable, secure and resilient operation is of paramount importance to national security and economic well-being. The grid is a highly automated network, wherein a multitude of sensors, computing systems and communication networks are interconnected to the physical electric grid for monitoring, protection, control and market functions. A major cyber incident in the bulk power (electric) system may have serious consequences in the grid operation in terms of blackouts, equipment damage and/or economic impacts. A report jointly by the NERC and the Department of Energy (DOE) titled, “High Impact, Low Frequency (HILF) Event Risk to the North American Bulk Power System,” identified coordinated cyber-attacks as one of the possible rare events that can cause catastrophic damages to the North American power grid [34].

In recent years, several authoritative sources have acknowledged the rapidly-evolving and sophisticated nature of cyber threats, including the two recent cyber-attacks on the Ukrainian grid (2015 and 2016.) There have been numerous attempts to infiltrate grid infrastructures of nations around the world. There is an urgent need to protect the grid against such threats/attacks. In addition, naturally occurring extreme events such as hurricanes, winter storms and earthquakes, some of which are increasing in frequency and severity and have the potential to cause significant damage to grid infrastructure, have resulted in power outages. To plan, mitigate and restore the grid while dealing with both types of events, there is greater need for advanced technologies, robust operating procedures and advanced analytical tools.

Table 1, Quad chart A, technology identifies a broad range of challenges, opportunities, solutions and potential action items discussed by WG3 with respect to technology aspects of the future grid. The following section presents a consolidated perspective addressing the following challenges: (1) dynamic threat landscape and increasing attack surface; (2) convergence of IT and OT in transition from legacy to modern grid; (3) RR&S of distribution grid with increased DERs; (4) feeder segmentation for increased resiliency and security of the Distribution Grid; (5) securing the supply chain, including third-party access.
Table 1. Quad chart A, technology

<table>
<thead>
<tr>
<th>Challenges</th>
<th>Opportunities</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Harmonizing:</strong></td>
<td><strong>Promoting:</strong></td>
</tr>
<tr>
<td>• The pace of IT and OT deployment cycles</td>
<td>• Best practices for robust architecture for technology/platform/server integration</td>
</tr>
<tr>
<td>• Integration of new technologies into legacy infrastructures</td>
<td>• Strategic integration of emerging technologies: IoT, Cloud, SDN, AI, blockchain, etc.</td>
</tr>
<tr>
<td>• Integration of DERs and utility-scale intermittent energy sources while maintaining reliability and resiliency</td>
<td>• Implementation of new IoT-based risk-assessment methodologies</td>
</tr>
<tr>
<td>• Microgrids, Smart Inverters, ADMS, PMUs and DERMS into the future grid</td>
<td>• Use of attack-surface reduction techniques</td>
</tr>
<tr>
<td><strong>Addressing:</strong></td>
<td><strong>Enhancing capabilities:</strong></td>
</tr>
<tr>
<td>• Integrating security of emerging technologies (IoT, Cloud, etc.) into the grid</td>
<td>• To respond to naturally occurring extreme events (tornados, earthquakes, geomagnetic disturbance event, etc.)</td>
</tr>
<tr>
<td>• Risks introduced by third-party infrastructures, platforms, products and services</td>
<td>• To detect, isolate/contain and recover from targeted physical and cyber-attacks on communication networks to support the evolving requirements of security, reliability and resiliency</td>
</tr>
<tr>
<td>• Security of external interactions with customers, vendors and other industry entities</td>
<td><strong>Solutions</strong></td>
</tr>
<tr>
<td>• Dynamic threat landscape and expanding attack surface</td>
<td>• Develop and implement a cost-effective, holistic technical framework encompassing attack deterrence, prevention, detection, mitigation and resiliency and potential for attribution/forensics</td>
</tr>
<tr>
<td><strong>Opportunities</strong></td>
<td><strong>Potential Action Items</strong></td>
</tr>
<tr>
<td><strong>Promoting:</strong></td>
<td><strong>Implement technology and processes to proactively adopt cybersecurity guidelines, standards and best practices developed by federal agencies (e.g., NIST, NERC), standard bodies and R&amp;D organizations</strong></td>
</tr>
<tr>
<td>• Best practices for robust architecture for technology/platform/server integration</td>
<td><strong>Implement a risk-based approach to cybersecurity</strong></td>
</tr>
<tr>
<td>• Strategic integration of emerging technologies: IoT, Cloud, SDN, AI, blockchain, etc.</td>
<td><strong>Proactively collaborate with federal and state agencies in such programs as GridEx, CSIRT and implement technical controls to mitigate identified weaknesses</strong></td>
</tr>
<tr>
<td>• Implementation of new IoT-based risk-assessment methodologies</td>
<td><strong>Incorporate technologies such as microgrid solutions, PMUs, energy storage, high-speed communications and cloud-computing capabilities</strong></td>
</tr>
<tr>
<td>• Use of attack-surface reduction techniques</td>
<td></td>
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</table>
Challenge 1: Dynamic Threat Landscape and Increasing Attack Surface

The growing deployment of smart grid technologies to improve efficiency, reliability and resiliency will produce a grid increasingly dependent on its cyber infrastructure. However, securing the grid against stealthy cyber-attacks is a challenging task due to the legacy nature of the infrastructure coupled with the dynamic nature of threat landscapes and an ever-growing sophistication of the adversaries. Additionally, the grid’s attack surface continues to grow with the increased dependence on digital communications and control that now extends to each consumer through smart meters and DERs. Unfortunately, this broadened attack surface may increase the chance that adversaries are able to exploit vulnerabilities in the grid. As a result, critical control systems in both substations and control centers may be compromised, leading to outages that may ultimately affect the consumer.

Although the challenge of securing the grid is increasingly complex, there are several technological solutions that can be leveraged and adapted into future grid infrastructure. The future grid architecture should enable seamless and modular integration of IT-OT technologies, platforms and services to make the grid sustainable, scalable and agile as it incorporates such emerging IT technologies as IoT, Cloud computing, Software Defined Networks (SDN) [35], machine learning, big data analytics, advanced visualization, artificial intelligence / machine learning and blockchain. While these technologies are attractive from performance and economic perspectives, care must be exercised to ensure they do not introduce adverse impacts on grid resiliency and safety or create unanticipated security and privacy risks. From an algorithmic perspective, machine learning and data analytics are promising areas which may be used to fuse data from multiple disparate sources and make operational decisions that improve the grid reliability, security and resiliency. Machine learning may be effective for threat intelligence analysis and anomaly detection by correlating data from multiple sources (both cyber and physical) across various temporal and spatial scales.

The goal of achieving an “acceptable security level” for the overall grid is challenging due to the lack of uniformity in quantifiable metrics and methods to assess it. Moreover, this notion does not account for cost and benefits associated with security investments. An alternate way to look at this challenge is to adopt a pragmatic “risk-based approach” that enumerates all possible types of scenarios with their likelihood of occurrence and their consequence to system operation in terms of resiliency, stability and economics. This approach establishes a baseline for “acceptable risk levels” and triggers risk-mitigation actions for specific events/scenarios, whose risk exceeds the baseline. Establishment of a baseline may include development of a list of acceptable breakdown events/scenarios agreed upon by all stakeholders with one or more recovery options for each scenario.

Risk mitigation also involves investment analysis focusing on mitigating critical/high risk scenarios using a balanced investment strategy. With better information about risks, consequences and costs, financial decision makers are better able to correlate investments with anticipated positive impacts to risk mitigation. Such an approach accounts for reducing the attack surface by securing/hardening the weakest link/subsystem. The following list contains examples of steps that can be taken to address the increasing threat landscape and attack surface. Plans should be developed to:

- Adopt a risk-based approach to assess and mitigate cyber threats that have impact on grid reliability and resiliency. Integrate consideration of cyber threats into
conventional operational risk assessment and evaluation practices. This will serve to both address cyber threats to reliability and resiliency and to foster collaboration between IT and OT professionals. “DOE Risk Management Guidelines” [36] is a good source.

- Adopt cybersecurity guidelines and best practices developed by federal agencies, such as National Institute of Technology (NIST), DOE, DHS and others to achieve a baseline security that is both sustainable and, where appropriate, is beyond the security requirements mandated by regulatory bodies such as NERC or public utility commissions.
- Collaboration with federal and state agencies in such programs as threat information sharing such as the North American Electricity Reliability Corporation (NERC E-ISAC) [37] and incident response Department of Homeland Security CSIRT, [38].
- Implement architectural solutions that include: network segmentation, defense-in-depth, strong access control, protection against malware and the ability to isolate and operate OT systems from IT systems during emergencies.
- Deploy surface-reduction technologies, such as anomaly detection, moving target defense, attack-resilient SCADA and EMS/DMS going beyond the conventional IT security technologies.

**Challenge 2. Convergence of IT and OT in Transition from Legacy to Modern Grid**

The IT innovation and deployment cycle outpaces the OT, which introduces a significant challenge from the perspective of integrating these two technologies within the overall grid’s cyber infrastructure. Since OT has a long deployment cycle, it’s not uncommon to have devices/platforms in the field for decades. Conversely, IT’s shorter deployment cycles include 3-4 year refreshes of newer technologies that must be used to improve or maintain security of the evolving grid environment. Moreover, the fast pace of vulnerability discovery in IT and OT systems makes it harder to utilize mitigation and appropriate patches [39]. Therefore, the challenge lies in assessing when and how best to consistently enhance legacy grid infrastructure with state-of-the-art technologies while balancing the need for new technologies with utilizing effective existing technologies. The technology convergence in terms of interoperability and ensuring required real-time performance and resiliency of the grid, coupled with segmentation of IT and OT infrastructures requires a careful implementation plan.

From a cybersecurity perspective, adversaries have the benefit of leveraging state-of-the-art attack techniques/tools to exploit vulnerabilities in legacy OT infrastructures and launch attacks on the grid. A typical legacy OT environment may lack adequate security features and is often difficult to retrofit with advanced security technologies. Moreover, many legacy technologies used in the grid environment have inadequate tech support from the vendors and/or are no longer being supported. For example, Microsoft indicated that it is officially stopping support of its Windows XP product which is present in many grid environments.7

The incremental implementation of smart-grid technologies with strong security capabilities will help to reduce potential mismatches. In addition, proven IT security architectures including network segmentation and defense-in-depth solutions may be leveraged into OT environments.

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7 Mainstream support has ended, however, extended support for a limited set of embedded systems ends in 2019.
Providing or maintaining the ability to revert to manual operations gives additional protection. Collaboration and coordination between IT and OT vendors and utilities, including appropriate grid investments, may also mitigate this challenge.

A consortium of industry stakeholders may develop a multi-pronged long-term solution to address this challenge: develop a holistic framework that encompasses entire life-cycle of an attack (identify, prevent, detect, respond, recover) together with resiliency and the potential for attribution or forensics; adopt a “systems approach” to security encompassing device security, network security and application security; develop “bump-in-the-wire”8 or “proxy-based”9 solution to secure critical communication channels by retrofitting security technologies into the legacy environment; develop a vendor agnostic cyber-attack-resilient architecture for the grid with defense-in-depth and network segmentation capabilities. Segment the OT network from IT networks and include multiple layers of defense—secure communication channels, firewalls, anomaly detection and strong authentication and access control policies. When any of these proven IT solutions is adapted into the grid environment, adequate testing and validation must be carried out to make sure these solutions do not adversely affect real-time power grid performance and reliable operation. Some ideas are:

- Adoption of a risk-based approach for cybersecurity
- Implement cybersecurity architecture and controls specified by industry compliance/guidelines, such as NERC CIP [40] and NIST CSF [41]
- Implement network segmentation and defense-in-depth solution for the OT environment
- Secure critical communication links and devices connected with DERs

**Challenge 3. Security, Reliability and Resiliency of Distribution Grid with Increased DERs**

The bulk power system (bulk generation and transmission) has gone through automation over decades and regulation/compliance for resiliency, security and resiliency are in place. In contrast, the distribution grid has witnessed a significant level of automation only in recent years and the standards/regulation/compliance for resiliency, security and resiliency are still evolving. Moreover, there has been a marked growth of renewable resources (wind and solar) into the grid, which introduces uncertainty in the grid’s operation and control due to the intermittent nature of these resources.

From a cybersecurity perspective, the distribution grid may be challenging to defend and may provide a target-rich environment for adversaries to exploit. A coordinated attack on multiple distribution control centers/substations may have a comparable effect to that of an attack on a bulk power system; the Ukraine 2015 grid attack is an example. Therefore, cybersecurity and distribution-grid resiliency requires more attention.

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8 As the name suggests, “bump-in-the-wire” refers to devices that can be added to systems without alteration to the underlying communications architecture or endpoints. These devices are often used in legacy systems that cannot be easily upgraded to use new communications protocols.

9 In network security, a proxy is an intermediary server that, on behalf of a client, access resources on another server. This approach can protect a client or network segment.
Opportunities to be considered include: the integration of emerging technologies such as microgrids, smart inverters and storage into the distribution grid; Adapting a combination of risk-based and compliance-based processes for the bulk power system to assess and mitigate cyber threats that impact the distribution grid.

As an illustration: in 2016, a fire in California caused one utility to lose about of 1,200 MW of solar PV generation. After this event, NERC released a report "1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report" which discusses the event and identified some solutions. The issue is a rapid power loss or gain, which causes large voltage and frequency fluctuations thus impacting grid resiliency. The utilities and grid operators’-protection settings may affect the protection settings of DERs such as solar PV generation on their systems. Examples of industry standards relevant to this incident include: “The standard for interconnection and interoperability of DERs with associated electric power systems interfaces” [30] and “voltage and frequency relay setting requirements for generating resources” [42].

The implementation of ADMS coupled with DERs present an opportunity for architecting the distribution grid with a hybrid architecture having both centralized and decentralized monitoring, protection, control and restoration capabilities. According to reports published by the Union of Concerned Scientists (UCS), renewable energy paired with storage systems, especially in a microgrid, can help prevent or mitigate outages during a cascading failure event such as the one seen after Hurricane Irma. Storage, combined with DG and/or a microgrid, can also allow a consumer or a section of the grid to operate independently during a wider power outage [43]. In the August 2003 Blackout, a series of unrelated events triggered a cascading failure that caused a wide-spread blackout affecting large portions of the Northeast [44]. Availability of storage and renewable resources may arguably have mitigated the impact.

Key solutions focus on RR&S of the distribution grid, including: re-architecting the distribution grid with microgrid integration and integrating advanced technologies for FLISR; exploring the synergy among DERs, microgrid and other decentralized systems and ADMS, coupled with increased data analytics and visualization capabilities for grid monitoring, control, restoration and outage management; positioning an electronic security perimeter around all critical cyber assets of distribution grid and securing all critical communication channels. Possible solutions include:

- Establishing standards for distribution grid security and resiliency. This requires collaboration between PUCs and utility industries. Leverage industry cyber security standards such as IEC 62351 [45] and IEC 62443 [46]
- Explore cost-effective, consumer-supported, operating procedures for going beyond (N-1) contingency to deal with extreme weather events and coordinated cyber-attacks
- Monitor the penetration of inverter-based technologies in Illinois and adapt that experience in other Illinois regions
- Use distribution state-estimation tools to improve distribution grid and data-corruption detection

**Challenge 4. Feeder Segmentation for Increased Resiliency and Security**

Distribution feeders are typically protected using substation breakers and a few remote controllable switching points on the feeders to segment them into smaller “chunks.” This limits the number of customers that experience a power outage or other grid disturbances. Conventionally, the system is manually switched by utility personnel at the control center when an outage or disturbance...
occurred, which requires time to find the issue, isolate it and then restore power via manual switching operations. Manual switching may lead to longer-than-necessary outages or unnecessary switching operations; both impact grid resiliency. Increasing concerns focus on cyberattacks compromising a single device (such as a substation breaker) that may result in an entire feeder or substation losing power, along with all customers served by them.

Opportunities exist for additional feeder-segmentation to be achieved; along with automatic restoration schemes to limit the outage area even further and speed up restoration when outages occur. However, additional feeder-segmentation strategies also introduce cost considerations, especially in rural environments. When done in more of a decentralized approach where the field devices themselves perform the isolation and restoration action, they give additional security, as a single system is not performing all actions.

There are technologies utilities can set up for tighter protection coordination between the substation breakers and feeder switch devices. The technology relies on accurate sensing capabilities along with high-speed communications to enable applications such as communications assisted coordination and automatic FLISR on the feeders themselves as a component of distributed automation (DA).

When used with a higher-speed communications network, this technology can give better feeder segmentation (i.e., reduce the number of customers between switching points) and restore service in under a minute, in most cases. And since the automatic restoration application resides at the feeder level, it provides additional security, as there is no single device or system that may be compromised and create a feeder or substation-wide outage. Other potential development plans include:

- Develop a plan to allow additional feeder segmentation and extend automated restoration systems where cost effective
- Develop a “security-in-depth” approach that considers both feeder-level automation systems as well as centralized control systems such that they can be segmented to provide additional security while maintaining operational capabilities
- Consider evaluation and expanded microgrid use
- Support deeper penetration of DERs through hosting capacity calculations

Challenge 5. Securing the Supply Chain, Including Third-Party Access

The increasing reliance on wide-area communication and internet connectivity to third-party infrastructures, such as cloud services and vendor access for remote maintenance, enlarges the attack surface for the grid. Moreover, the reliance on vendor products that embed third-party software/services present cyber risks to the infrastructure. The emergence of IoT technologies and its integration into the grid ecosystem to implement services, such as demand-response programs present potential risks to the overall grid environment.

Supply-chain security is not unique to grid environments. Critical sectors such as avionics and defense have established frameworks and guidelines for supply-chain security. These can be used to protect the grid infrastructure. One possible solution would be for distribution systems to follow NERC CIP-013 [40] to address supply-chain security.

One solution would be to develop a plan for integration of emerging technologies in the supply chain such as IoT, cloud, SDN, artificial intelligence (e.g., machine learning), block chain, etc.,
with careful consideration for the benefits and potential risks they present, from the perspective of cybersecurity, data security and privacy. Other potential development plans include:

- Implementation of robust architecture for technology/platform/service integration
- Assessment of the supply-chain security and means to mitigate risks
- Assessment of integrating IoT into grid from the perspective of data security, privacy and the overall cyber risk
- Consideration of integrating parts of NERC CIP-013 or a similar compliance requirement into a robust risk-management program for both bulk power-system and distribution-grid environments

### 3.2 People

The North American electric grid relies on access to a knowledgeable, well-educated and creative workforce both within utilities and those organizations that interact with them. That workforce is responsible for ensuring the RR&S of the modern grid. While technology, process and regulation and compliance are critical to achieving RR&S, sustaining a highly-skilled, well-trained workforce will determine the industry’s success in solidifying a modern grid. The future grid’s operation relies on the interaction of many categories of people including: consumers, vendors, grid operators, utility employees, regulators and other stakeholders. Customers will, through technological advancement, become more interwoven into the fabric of grid operation, generation and responsibility for grid security.

Third-party manufacturers, distributors and other suppliers (including contractors and consultants) continue to play a critical role in providing utilities with resources necessary to sustain efficiency, reliability, resiliency and, ultimately, grid physical and cyber security. Federal and State regulators and legislators work on enforcing rules and policies to balance sometimes competing interests in promoting safety, industry cost allocations, meeting service demands and other ancillary requirements. Those government employees must also straddle both the need to access and review the utilities’ activities and protect related information. Government employees must balance their mandate to collect, review and process various forms of critical infrastructure while protecting that information and making determinations (while consulting and coordinating with data owners) regarding what information can be shared with whom.

A general misperception may also exist that it is solely the responsibility of the utility industry and, in some cases, their regulators to prevent or diminish potential cyber incidents from arising in relation to grid operation and its connectivity to consumers. The grid will be more secure if consumers do not unintentionally introduce elements that pose a threat. While ultimately the utilities, with regulatory oversight, will drive and manage most of the risk mitigation activities, unintentional risk creation may result from lack of information, or failure to identify threat vectors, as well as failure to follow minimum prudent levels of cyber activity. Rather than expecting the industry to unilaterally address the grid RR&S, consumers should actively participate in protecting it through careful attention to potential risks.

Much emphasis should be placed on addressing the identified challenges in a way that supports and empowers a critical workforce, consumer and regulatory community to both guard itself against actions that jeopardize full grid functionality and support a thriving segment of the
workforce that plays a critical role in delivering tremendous value through effectively securing the modern grid from intentional disruptions.

Cybersecurity for the power grid is an interdisciplinary field and there is a growing need for a skilled workforce that understands cybersecurity and power systems. Today, silos separate power-system engineers who understand system operation, control and protection from IT specialists whose expertise is in communication networks, software and cybersecurity. A significant knowledge gap exists between IT-OT that demands improved collaboration and coordination between system engineers and IT specialists.

Table 2, Quad Chart B People, identifies a broad range of challenges, opportunities, solutions and potential action items discussed by WG3 with respect to the people aspects of the future grid.
<table>
<thead>
<tr>
<th>Challenges Addressing:</th>
<th>Opportunities</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Increasing need for cybersecurity workforce and the skill gap</td>
<td>• Building resiliency throughout the ecosystem by bridging IT/OT skill gap</td>
</tr>
<tr>
<td>• Investing in development of future capabilities, knowledge and talent pool</td>
<td>• Developing future security subject-matter expertise to address workforce transitions</td>
</tr>
<tr>
<td>• Institutional mindset and culture to optimize problem-solving capabilities</td>
<td>• Streamlining process for security clearances and timely coordination for real-time intel sharing</td>
</tr>
</tbody>
</table>

Ensuring:

• Industry-wide collaborative and consistent approach to achieving enhanced reliability, resiliency and cyber and physical security
• Streamlined data sharing, gaining security clearances and timely access to necessary intelligence while balancing need to protect critical infrastructure information

Understanding:

• Stakeholder expectations
• Adversary behavior: tactics, capabilities, tools, strategies, growing sophistication, identity of the adversaries, including insider threats
• Role of customers, utilities, ISO/RTOs, vendors & third parties in securing the grid

Solutions

• Measurement and certification of baseline and advanced capabilities
• Mitigate sensory-data overload through machine learning and data visualization
• Expedite credible and accurate threat intel sharing through: (1) improvement of government information declassification (2) improvement of processes for sharing information
• Defining customer role in ensuring security; understanding true customer resiliency expectations and cost sensitivity, including among different customer types (e.g., residential, business, CI)
• Attracting/retaining talent; Automation, AI, to support and enhance human capital; marketing breadth of opportunities; fully utilizing existing programs such as hackathons
• Develop a plan for cybersecurity education and training programs to reduce skill gap and achieve sustainable workforce

Potential Action Items

• Communicating an inspirational vision (e.g., how to get people excited about internship at utility v. Apple or NASA)
• Crafting programs that prepare future employees for the workforce in a way that anticipates future needs and directs students ahead of the problems
• Balancing emerging technology with cyber-security integration, in a way that is not a staple-on-later but part of the solution
• Partnering with the education community to drive awareness in younger learners who may gain interest in utility industry careers, including under-represented communities
• Partnering with universities to revise power-engineering curricula to include cyber and physical security technology and processes.
• Implement a 24/7 cybersecurity workforce where appropriate
The industry is faced with significant challenges related to identifying, hiring, developing and retaining a workforce capable of supporting grid complexity from a security standpoint. Some issues to consider are:

- Ensure that continued investment in education and marketing is available to foster a capable and needed future workforce.
- Emphasize optimizing creative problem-solving capabilities.
- Recognize that working in isolation to solve the ever-escalating threat to grid security and resiliency is no longer a viable option.
- Promote collaboration as critical to the industry as it moves rapidly toward a cooperative approach to collecting threat data, anonymizing critical elements, sharing useful and timely data within the utility industry and learn, share and implement best practices.

It is also necessary to optimize problem-solving capabilities and avoid “failure of imagination” going forward. In the past, problems and risks arose from degrees of overconfidence in existing levels of system functionality, impenetrability, reliability and resiliency as well as expected system stability in the face of emerging threats. The workforce needs to dynamically adjust itself to the dynamics of advanced technologies entering the industry.

Utilities are aware that they can no longer operate separately from the rest of the connected world—that the air gap is increasingly an unrealistic ideal. Employees are being actively trained by utilities on how to take a more creative approach anticipating how the marriage of conventional operations with increasingly complex and pervasive information technology systems and capabilities will develop into new threats. It is essential that those responsible for operating and securing the grid approach grid security so as to assume threats will come from anywhere, may already be present in parts of the environment and are possible even, when conventional thinking would have rejected the possibility.

Understanding, supporting and managing stakeholder expectations are crucial to overcoming RR&S grid challenges. Stakeholder expectations can and should be flexible and considerate of how they impact grid RR&S. Consumers, legislators, regulators, businesses and industry partners can support this rapid shift by recognizing that this challenge will not easily be overcome, continuous prudent and appropriate investments will be needed and that we each play our role in creating awareness of security risks and appropriate precautions.

A major challenge is overcoming the current and projected ongoing insufficient cybersecurity workforce. To keep up with escalating threats and potential disruptions now primarily driven by intentional, tactical, automated attack approaches that multiply exponentially, the workforce will have to be trained in a strategic and cost-effective manner. Synergies with advanced technologies must be leveraged where possible.

Addressing data privacy and data protection is a critical challenge for the industry. Key considerations include the role of the workforce in protecting and using customer information, the expansion of data collection and analytics to drive smarter decision making about resource allocations, energy consumption and informed decision making and determining what information can be used, shared and what must be separated or anonymized. Existing standards focus on information protection for the bulk power system. However, data privacy and protection considerations extend to customer information and information held by other entities that may not
be adequately covered by existing standards. The industry can create, identify and take advantage of opportunities in a way that makes the modern grid an even more reliable, resilient and secure economic support engine for Illinois and the rest of the country.

An opportunity exists to further fortify grid security through a deliberate focus on ecosystem development from the ground up. By promoting awareness campaigns and expanding and developing a cybersecurity-oriented skill set, as well as attracting new skill sets from those not conventionally employed in the utility sector, utilities can continue to increase their potential for threat identification, risk mitigation and reduce instances of human error that may increase threat surfaces. Utilities should actively engage customers and partner with them to address and/or prevent potential risks from turning into disruptions. Community buy in to the importance and impact of prudent behaviors, especially those related to information handling, system use and risk identification and avoidance is critical.

Active collaboration should focus on securing an ever-expanding array of IoT devices that connect to the grid through actions by utilities, consumers and businesses that leverage new technologies. These emerging informed workforces will need to integrate highly sophisticated and capable workers with advanced technologies, such as artificial intelligence, machine learning, data analytics, as well as energizing innovations, to provide opportunities leveraging a strategic workforce with productive tools into the decision-making process.

The group agreed that it is imperative that employees be spared sensory data overload through use of tools like machine learning, data visualization and other technology-enabled platforms and tools available to supplement conventional security approaches and techniques that formerly were primarily hands-on manual review and assessment techniques. Increased public/private partnerships to facilitate information and best practices sharing may aid in addressing this issue.

Define the consumer’s role in ensuring security; understand true consumer resiliency expectations and cost sensitivity, including among different customer types (e.g., residential, business, CI), emphasize attraction and retention of critical talent while supporting workforce through streamlined utilization of information analysis and automation scaling (i.e., artificial intelligence solutions) to optimize and enhance human capital skill sets, measure employee skills at a baseline and track improvements to promote institutional knowledge specific to capabilities. The following are immediate steps and a series of actions WG3 felt would drive positive impact to the industry and would make the grid more reliable, resilient and secure. The action items fall into four groups: (1) collaboration, (2) promoting diversity, (3) educational approaches and (4) workforce and career development.

**Collaboration**

It is no longer possible for individual companies to achieve desired levels of RR&S without learning from each other, engaging in exercises, best-practice adoption, standards assimilation and general collaboration on threat intelligence and successful approaches to security critical infrastructure. Specific examples include:

- Partnership between industry and government in threat-intelligence sharing, grid exercises, training programs and adopting best practices
- Partnership among industries in sharing best practices in RR&S, operating procedures and workforce development
Partnership between utility industry and vendors in developing standards and products that are secure and resilient

Participating in industry-wide exercises such as Grid Ex and Operation Power Play, FEMA NLE, Cyber Storm

Partnership between industry and academia in research, education and outreach programs, such as degree programs, graduate certificates, continuing education programs, hackathons and K-12 education

**Promoting Diversity**

Proposed solutions include addressing the diversity issue that permeate this field. Some studies indicate “women comprise only 11% of the information security workforce” [47]. Because security skills are as much a way of thinking as a technical discipline, to be truly effective, the long-term solution should focus on increasing technology and cybersecurity. Exposure and awareness of cybersecurity should begin as early as K-12 and continue throughout post-secondary education (with particular focus on population segments generally overlooked and underrepresented), by requiring all undergraduate programs to include cybersecurity education, such as safe social media usage, digital etiquette and cyber-threat identification.

- Offering apprenticeships, emphasizing employee tuition-reimbursement programs, or covering the cost of post-secondary education in exchange for a term of employment
- Identify existing employees, particularly those from under-represented communities who would be interested in being sponsored to develop some of the necessary skills
- Utilizing gamification to make training more appealing and engaging for the workforce
- Continue incentivizing secure behavior in a variety of ways. Integrate cybersecurity curriculum into degree programs.
- Support and expand trade apprenticeship programs and early learning to develop an intelligent and capable workforce of the future.
- Utilities can develop programs to teach career-relevant skills to potential employees and collaborate with existing programs with expertise in developing technical skills in under-represented communities.
- Advise existing programs at universities, community colleges and trade schools regarding industry needs
- Consider the necessity of relaxing certain formal educational requirements pertaining to specific position descriptions when hiring experienced cybersecurity professionals to meet current workforce needs

**Educational Approaches**

There are also many paths to a cybersecurity career beyond conventional IT. Undergraduate programs such as psychology, sociology, political science, criminal justice and others may all have cybersecurity applications and lead to a rewarding career in the field. Estimates suggest that as many as 75% of workers in cybersecurity are not computer programmer or “hackers.” This misperception may be a contributing factor to lower than expected interest in the field in our youth across the country. Hiring managers can also look to partner with workforce development agencies...
such as The Center for Energy Workforce Development, The Cyber Leadership Alliance, Girls Who Code, Codecademy or the Illinois Office of Employment and Training.

- K-12 programs are created in cybersecurity for critical infrastructure via synergistic partnership between post-secondary educational institutions and the electric utilities charged with implementing these approaches.
- Programs are created such as cyber-defense competitions or hack-o-thon for critical infrastructure systems via partnership between universities, energy industries, vendors and national guards. In addition, “gamification” aspects in education and training programs may attract more students into this emerging area of nation’s workforce need.
- Encourage electrical and mechanical engineers to join in and participate in the future design and integration of new technologies into the grid.
- Candidates with marketing, education, or auditing backgrounds may bring unique perspectives to problem solving.

**Workforce and Career Development**

Competition for the limited cybersecurity workforce will continue to intensify as “the pool of qualified professionals required to fill those positions hasn’t kept pace with the growth” [48]. This well-reported cybersecurity talent gap both reduces the ability of critical infrastructure entities to manage an effective cybersecurity program and places a strain on the currently available workforce. According to a research study by the Information Systems Security Association (ISSA) and independent industry analyst firm Enterprise Strategy Group (ESG), “38 % of survey respondents say that the cybersecurity-skills shortage has led to high rates of employee burnout and employee attrition” [49]. The reality is that experienced staff may look for less stressful working environments, or leave the cybersecurity workforce altogether. Efforts can be made to ensure that:

- More accurate portrayals are made of cyber-career options in the utility industry
- Develop cyber-security testbeds environments (by utilities) that integrate both OT and IT technologies provide a platform to test, validate and evaluate the effectiveness of cybersecurity solutions before being deployed
- Consider DoD or other government employees who may have little or no commercial experience, but who are highly trained in cyber or other aspects of security and often already have security clearances that enable access to classified information
- Continue investment in advertising how a career in the utility industry will be both challenging and rewarding [50].

While many schools are introducing more technology and cybersecurity-related education, "media portrayals and popular culture have left cybersecurity with a horrible branding problem” [51]. Engaging with educators to get real cybersecurity professionals in front of young students may be one way to begin putting a dent in stereotypes. By reexamining job qualifications for cybersecurity positions, hiring managers may be able to expand the pool of candidates for individual openings. Advertising overly specific “ideal candidate” qualifications, we may be discouraging workers from entering the cybersecurity workforce because they don't believe they "have the right skills to work in cybersecurity” [52]. NIST NICE Cybersecurity Workforce Framework offers a path for
companies and educators to standardize the lexicon in describing functions, skills and positions employers need [41].

One area where WG3 experienced varied perspectives and shared many potential obstacles that might preclude full consensus and a workable solution was related to cyber educational requirements. The group engaged in a lengthy dialogue over the merits of some form of educational requirement for users of systems both operational and consumer. An analogy was put forth of a digital driver's license. People are required in each state to successfully pass a test and demonstrate basic competency to receive a driver’s license to use a vehicle, but there is no such requirement for users of complex technology systems that, if used improperly, may cause significant negative impact to other people (in this case the grid). While some level of assurance is likely appropriate for industry employees as well as consumers themselves, a driver’s license type approach did not seem to have much initial support. Privacy, misuse, credibility, inequity and other issues were raised in a robust and productive discussion. The group recommends that this issue be further studied to determine whether there is any viable solution to establishing baseline skills for those utilizing technologies that potentially increase risk to the grid.

### 3.3 Process

As discussed in the Technology section, utility operations have become increasingly interconnected and interdependent. This complexity requires vigilance in designing and maintaining processes to ensure RR&S. RR&S processes include coordination among people from areas of responsibility including: incident response, situational awareness, forensic analysis, asset configuration and management, threat analysis, risk management, mitigations and interventions, information sharing, making investment decisions, quantitative and qualitative evaluation and measurement of capabilities, as well as testing of those capabilities.

Table 3. Quad Chart C, Process identifies a broad range of challenges, opportunities, solutions and potential action items discussed by WG3 with respect to process aspects of the future grid.
Table 3. Quad chart C, process

<table>
<thead>
<tr>
<th>Challenges</th>
<th>Opportunities</th>
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</thead>
<tbody>
<tr>
<td><strong>Prioritizing:</strong></td>
<td>• Adopt effective business practices (e.g., NERC CIP, NIST, C2M2) and mature risk management programs (e.g., DOE cybersecurity risk-management process)</td>
</tr>
<tr>
<td>• Effective, regular and consistent evaluation and testing of core capabilities</td>
<td>• Secure supply chain and ensure vendors incorporate and integrate security-protection capabilities</td>
</tr>
<tr>
<td>• Industry to adopt a standardized set of approaches to increase operational efficiency</td>
<td>• Integrate third-party assessment into continuous process improvement</td>
</tr>
<tr>
<td>• Integrated return on investment strategy that includes physical and cyber security management (workforce, technology, process)</td>
<td>• Ensure security planning is incorporated in strategic planning and business processes; evaluate resiliency attributes in transmission planning</td>
</tr>
<tr>
<td><strong>Addressing:</strong></td>
<td>• Promote increased cross-utility information-sharing with regard to threat identification and incident response, complimentary to role of ISACs. Define need for information. Recognize differing needs and goals</td>
</tr>
<tr>
<td>• Metrics to quantify effectiveness of interventions</td>
<td>• Improve and expedite process for threat-intelligence sharing while protecting sources, means and methods</td>
</tr>
<tr>
<td>• Harmonized framework for information sharing, incident-response management and contingency planning/analysis criteria</td>
<td>• Test and exercise crisis and incident-management capabilities across multiple jurisdictions</td>
</tr>
<tr>
<td>• Impediments to intelligence community sharing intelligence with utilities</td>
<td>• Engage industry in developing, enhancing and deploying RR&amp;S standards (e.g., IEEE, IEC, NERC)</td>
</tr>
<tr>
<td><strong>Measuring:</strong></td>
<td>• Study effectiveness of incentives-based security training and compliance programs</td>
</tr>
<tr>
<td>• Vendor capabilities, practices and competencies when introducing their products into grid operations (including multiple tiers in the supply chain)</td>
<td>• Develop safe and timely information-sharing schemes</td>
</tr>
<tr>
<td>• Effectiveness of process integration to impact grid security</td>
<td>• Examine emerging technologies, prior to adoption, minimizing introduction of additional risks</td>
</tr>
<tr>
<td>• Effectiveness of risk-assessment approaches</td>
<td>• Examine and incorporate post-incident investigation, issue identification and remediation strategies practiced by regulatory authorities</td>
</tr>
<tr>
<td>• Effectiveness of investment in risk-mitigation processes and tools</td>
<td>• Exercise response capabilities through local, regional and national coordinated exercises (CSIRT, GridEx, etc.)</td>
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<table>
<thead>
<tr>
<th>Solutions</th>
<th>Potential Action Items</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Examine processes to certify people in best-practice use when interacting with OT and IT</td>
<td>• Continue development of ESCC Cyber Mutual Assistance program to coordinate utilities in the event of an attack</td>
</tr>
<tr>
<td>• Build resiliency throughout ecosystem with supply-chain security: including cloud, 3rd party and consumer-grade products</td>
<td>• Encourage public utilities commission to drive awareness and challenge utilities and other industry stakeholders to continuously demand improved security processes from suppliers throughout the supply chain</td>
</tr>
<tr>
<td>• Establish metrics for reliability, resiliency and cybersecurity</td>
<td>• Study effectiveness of incentives-based security training and compliance programs</td>
</tr>
<tr>
<td>• Incorporate change management into overall project plans</td>
<td>• Develop safe and timely information-sharing schemes</td>
</tr>
<tr>
<td>• Increase public private/partnerships to facilitate information and best practices sharing. Enhance operations across RTO seams (processes and tools); Manage responsive congestion across RTO seams. Integrate emerging technologies to improve process</td>
<td>• Examine emerging technologies, prior to adoption, minimizing introduction of additional risks</td>
</tr>
<tr>
<td>• Exercise response capabilities through local, regional and national coordinated exercises (CSIRT, GridEx, etc.)</td>
<td>• Examine and incorporate post-incident investigation, issue identification and remediation strategies practiced by regulatory authorities</td>
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</table>
Challenge 1. Frameworks and Standards Adoption
Operational efficiency is at the core of this heavily regulated industry, in which all outlays and expenditures are scrutinized with the goal of providing least-cost service to ratepayers. It is important to continually reexamine procedures and processes to improve and update operations. Standardization helps to avoid duplication of efforts, increase compatibility, promote knowledge sharing and support operational efficiency. One area of interest in this topic is to encourage industry to gravitate toward adoption of a standardized set of approaches to increase operational efficiency.

A trend exists for adopting business practices, even when not required, because they make sense and are effective (e.g., NERC CIP, NIST CSF, NIST SP 800-53, NISTIR 7628 and the C2M2). Many utilities apply heightened cyber requirements, emulating those required by NERC CIP and other regulations. However, cybersecurity resources and capabilities vary widely between and within organizations, though many utilities incorporate cyber risk as part of their corporate risk-management strategy and have increasingly mature risk-management programs. There is also an opportunity to raise the bar set by regulations and standards.

The following table lists potential sources of grid disruption and identifies tactical planning and preparation activities and resources for further reading.

Table 4. Grid disruption preparedness

<table>
<thead>
<tr>
<th>Grid Disruption Preparedness</th>
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<tbody>
<tr>
<td><strong>Potential Grid Impact Events:</strong></td>
</tr>
<tr>
<td>• Winter storms, floods, tornados, earthquakes (high probability/medium to high impact)</td>
</tr>
<tr>
<td>• Coronal mass ejections/geo-magnetic storms, New Madrid Fault (low probability/high impact)</td>
</tr>
<tr>
<td>• Electro-magnetic pulse (EMP) (low probability/high to extreme impact)</td>
</tr>
<tr>
<td>• Physical destruction (medium to high probability/low to extreme impact)</td>
</tr>
<tr>
<td>• Cyber incidents, unintentional or malicious (high probability/low to extreme impact)</td>
</tr>
<tr>
<td><strong>Key Preparation Steps for Disruption Responses:</strong></td>
</tr>
<tr>
<td>• Ensure COOP plans address and factor-in electricity loss on a protracted basis</td>
</tr>
<tr>
<td>• Prepare for and anticipate unavailability of trained, qualified professional personnel required to remain in an area during response and recovery (when considering family-assistance concerns)</td>
</tr>
<tr>
<td>• Establish an adjustable state-level critical infrastructure priority list for crisis implementation</td>
</tr>
<tr>
<td>• Re-enforce bottom-up planning and execution inside our top-down frameworks</td>
</tr>
<tr>
<td>• Emphasize realization that different organizations bring different priority perspectives to a crisis, especially as it extends over protracted periods</td>
</tr>
<tr>
<td>• Identify sector-specific areas of improvement to enable expedited response and recovery</td>
</tr>
<tr>
<td>• Establish collaborative strategies and priorities for response and recovery</td>
</tr>
<tr>
<td>• Drive proactive, pre-event prioritized objective discussions between public and private infrastructures to align partner priorities with respective stages of response and recovery</td>
</tr>
<tr>
<td>• Continuously evaluate and explore options for making alternative energy sources available during disruptions</td>
</tr>
</tbody>
</table>
• Recognize and focus on intersection of threat identification and potential critical infrastructure impacts during advanced planning

**Selected Learning and Advisory Resources:**
• State Energy Resiliency Framework (Argonne Lab Global Security Sciences Division)
• Electric Infrastructure Security Council (EPRO Resource Family @ http://eiscouncil.org/)
• Government Accountability Office (GAO Highlights Reports)
• Electricity Subsector Coordinating Council (ESCC) Playbook 2017

**Selected Knowledge and Collaboration Opportunities with Key Support Organizations:**
National Guard, Federal Departments of (Defense, Justice, & Homeland Security) and the FBI, Critical Infrastructure ISACs (Information Sharing and Analysis Centers), National Labs, Department of Energy-Funded Universities Research Projects, Cyber Shield/Cyber Guard and other Industry-focused associations

**Selected Exercise Participation Opportunities:**
NERC GridEx, DOE Cyber Defense Competitions, EarthEx, & Operation Power Play

Additionally, DOE has published a cybersecurity risk management plan (RMP) guideline. It was developed by the DOE, NIST and NERC to enable organizations of all sizes and governance structures to apply effective and efficient risk-management processes, such as the NIST CSF [41]. The guideline is based on NIST Special Publication 800-39, NISTIR 7628 and NERC CIP and intended for use by entities involved in generation, transmission, distribution, wholesale market operations and supporting organizations such as vendors.

![State Energy Resiliency Framework](image)

**Figure 16. State energy resiliency framework**

Another state- specific resource is the State Energy Resiliency Framework released by the Argonne National Laboratory Global Security Sciences Division in December 2016, which unifies
resiliency enhancement against natural hazards, direct intentional attacks and other threats by first considering stakeholders’ needs and requirements [53]. Figure 16 shows an overview of the State Energy Resiliency Framework.

The DHS Infrastructure Survey Tool (IST) process is another existing program critical sectors can use to evaluate site-specific strengths and vulnerabilities. WG3 had robust discussions on how to achieve a baseline level of security competency within organizations. All personnel who interact with IT or OT assets should have a baseline level of security competency. A potential solution to ensuring such competency is to formalize processes to certify people in best-practice use when interacting with OT and IT.

Authentication is necessary in the grid environment to verify the user identity for accessing critical services and data. An example control policy is role-based access control (RBAC), in which subject- (people) to object- (services, data) mapping is clearly defined and enforced. Other policies such as attribute-based access control (ABAC) may be applicable to specific contexts. Clear delegation of authority and a well-established authorization process is important to establish user limits. It is important that the granting, modification and revocation of authenticity, access control and authorization be properly managed.

- Establish NERC CIP-like cybersecurity compliance process to create baseline security for distribution grid.
- Create a culture and possibly offer incentives to achieve security beyond the baseline.

Uniformity in approach can have positive and negative aspects. Both standardization and high-performing outliers can drive economic growth. Outliers or lack of uniformity can also mean that the same risks do not exist in all systems. Design criteria can vary based on the needs. Utilities do not all operate in the same geographical, regulatory, jurisdictional, historical, demographic and economic environments and many other factors require idiosyncratic or tailored solutions. Further study is warranted to assess the effect of uniformity in products, planning and risk-mitigation approaches.

**Challenge 2. Collaboration and Information Sharing**

Efficient and effective industry-wide engagement requires harmonizing framework adoption for information sharing, incident-response management and contingency planning/analysis criteria. Grid operations at all levels (e.g., generation, transmission and distribution) require real-time situational awareness to address threats from both malicious attacks and natural catastrophes. While obvious to some, it is worth emphasizing the complex interconnected nature and interdependencies among critical infrastructures that make effective collaboration crucial. For example, oil and natural gas industries provide fuel for electric generation, which, in turn, provide power to telecom, enabling SCADA communications for the transportation networks to transport fuel to enable electric generation, all of which require water for cooling [53]. These issues are beginning to gain recognition at both the state and federal levels and harmonization of frameworks and regulations may optimize information sharing, incident response and contingency planning.

“What happens to one of us happens to all of us” is both a laudable ideal mindset and too often a harsh reality. There is an opportunity to promote increased cross-utility information-sharing about threat identification and incident response, complimentary to the role of ISACs, which define the need for information and recognize differing needs and goals. To reduce cyber and physical security risks, E-ISAC [37] continues to serve as a source of analysis and sharing of electricity-
industry security information, providing insights and leading to collaboration. Currently, E-ISAC is a source of threat analysis and information-sharing that provides analysis of NERC Alerts, publishes incident bulletins, conducts weekly, monthly and annual summary reports, authors issue-specific reports and offers a variety of other programs. Further development of collaboration with the newly formed DOE Office of Cybersecurity, Energy Security and Emergency Responses (CESER), the National Guard, FBI field offices, DHS Protective Security Advisors, FEMA, state-emergency management and local emergency responders should be encouraged.

The CEO-led Electricity Subsector Coordinating Council (ESCC) serves as the principal liaison between the federal government and the electric power industry. The ESCC includes electric company CEOs and trade association leaders representing all segments of the industry. ESCC Playbook serves as a framework for senior industry and government executives to coordinate response and recovery efforts and communication to the public.

Increased public/private partnerships to facilitate information and best-practices sharing, such as those highlighted above, continue to be ideal solutions. In addition, the jurisdictional environment of Illinois with service territories in both MISO and PJM means it should be a priority to enhance coordination across RTO seams (processes and tools) and continue development responsiveness. Increased collaboration between private entities should be encouraged as well, with larger utilities providing assistance to smaller ones to ensure RR&S. For example, PJM launched a stakeholder process to study fuel security vulnerabilities within PJM. Other RTOs and utilities can benefit and learn from PJM’s findings.

With an overwhelming amount of information coming from a variety of entities, synthesizing it and maintaining wide-area situational awareness may be difficult. Integrating emerging technologies to improve processes as detailed in the People section is essential. Cyber mutual assistance capabilities should be supported to better enable the sector to understand impacts and take appropriate measures to identify, protect, detect, respond and recover against all threats and hazards. Further development is needed to build resilient communication channels and operational/response plans that are robust to handle regional, not just local, disruptions.

One pressing challenge is the difficulty encountered in removing obstacles for the intelligence community to share intelligence with utilities. For good reason, the intelligence community is protective of sources, means and methods of obtaining information. However, there is an opportunity and a pressing need, for the private sector to receive that information in a manner that does not compromise sources, means and methods. Specifically, there are opportunities to improve the quality and timeliness of threat information, as well as to improve the coordination across federal and state jurisdictions, among the states, across utilities and across sectors.

Utilities require timely, actionable intelligence to proactively protect the grid. There is often a 1-2-week delay before information reaches a utility. This hampers preventive action. In addition, critical entities do not always have a representative with a sufficient security clearance. This restricts the information sharing. Utilities and the intelligence community need a safe “tent” in which to share and receive information. States such as NJ and NY have had success establishing state-level organizations for such purposes. Getting such a safe information-sharing scheme is critical to protecting the grid and, consequently, the nation. Such an information-sharing facility can also help utility regulators make sure the utilities are making the right decisions in protecting the grid. Potential action items include:
• Develop safe and timely information-sharing schemes
• Develop other strategies to shorten information delay, protect information sources and improve actionability

Challenge 3. Vendor Supply Chains and Other Third Parties
The interdependent relationship identified in the previous section extends to vendors because of the increase in automation and reliance on information technology, the increasingly dynamic supply and demand due to DER penetration and an increasingly mobile workforce. Whether performed by utilities directly or by an independent certifying body and verified by the utilities, vendor capabilities, practices and competencies must be measured before their products are introduced into grid operations (including multiple tiers in the supply chain). Increased connectivity of smart-grid devices and behind-the-meter/customer premises DER and IoT increase the attack surface. Mission-critical information and operational technologies rely on a global supply chain to provide hardware, software and services. Increased outsourced specialization has expanded the number of suppliers in the supply chain, which is leading to a compounded threat vector for the utility industry.

Trade publications have recently indicated instances in which vendors have added “backdoors” and other components—for troubleshooting and other reasons—that can be considered vulnerabilities potentially affecting security of the products and by extension, of the grid as utilities increasingly introduce such products and solutions into their environments [54], [55].

Securing the supply chain and ensuring vendors incorporate and integrate security protection capabilities requires cooperation throughout all levels within the industry. As utility-vendor relationships permeate the supply chain, contract terms and conditions can be designed to promote supply-chain security. To build resiliency throughout the ecosystem, supply-chain security for cloud, third-party and consumer-grade products is needed. Utilities should fully integrate risk mitigation practices throughout their operations. Vendors may have extensive access to resources and assets within the enterprise environment or to an organization’s customer environments, some of which may be sensitive in nature. Vendors are also, in most instances, in the best position to mitigate risks or fix vulnerabilities in their own products.

For example, as of 2018, PJM has embarked on an effort to build security controls throughout the supply chain. The effort identified and analyzed risks and new issues to create a risk-management document and assess effectiveness of interventions. Requiring contractual safeguards that lead to ramifications if the terms are breached may be appropriate. There are also IEEE and IEC standards that vendors and utilities can use, detailed in the referenced EPRI metrics documents [56].

Public utility commissions can drive awareness and challenge utilities and other industry stakeholders to continuously demand improved security processes from suppliers throughout the supply chain. Integration of third-party services will require development of common cloud-security models for cyber-physical systems. Focus should be on raising awareness and purposeful exploration of emerging technologies such as blockchain for supply-chain security, light-weight encryption schemes for low-powered IoT devices, adoption of industry-wide standards and supporting sensible requirements through judicious procurement practices. Establishing non-disclosure agreements with third-party vendors and others as part of the procurement agreement may facilitate productive discussions and efficient solutions.
As supply and demand become more dynamic, with deepening penetration of DERs and persistent calls for operational efficiencies, there has been a symbiotic feedback loop with automation, connectivity and efficiency: improved information technology and connectivity enable increased automation, which assist in achieving more efficient operations that decrease the margins for error and increase reliance and therefore foster investment in improved information technologies. Closer examination of DER integration and resiliency requirements of customer premise generation are needed and may require additional regulatory frameworks for these sources. There are potential risks associated with other emerging technologies, such as SDN, blockchain and automation via machine learning or otherwise and need careful study. There may also be dependencies among potential interventions that should be identified through further study.

**Challenge 4. Organizational Culture and Buy-in**

There is an opportunity, notwithstanding potential challenges to conventional approaches, to promote an integrated return-on-investment strategy that includes physical and cybersecurity management (workforce, technology and process). In addition, unbundling of generation and distribution and environmental policies leading to development of DERs and EE in accordance with Illinois law, have led to significant generation and storage assets not owned or operated by the utility. Utilities must navigate dynamic governance relationships.

Conventionally, security has often been treated as a necessary function separate from but in support of core business processes. Future approaches must ensure RR&S planning is incorporated in strategic planning and business processes; including exploring the potential valuation of resiliency attributes in distribution and transmission planning.

An integrated approach also requires incorporating change management into overall project plans. As detailed in the section on Technology, there has been a trend towards convergence of IT and OT. Utilities can correlate events in both environments conventionally considered as the corporate/business network and operational control network. This requires integration of incident response (ISOC, IDS/IPS, forensics and security data analytics), situational awareness (real-time knowledge of dynamic operating environment, common operating picture), threat management (threat intelligence from IT and OT, tactics, techniques, procedures or TTP and also tools and targets) and asset and configuration management (device identification, configuration management and change management to minimize disruptions and identify misconfigurations). Risk identification and mitigation on the multi-party grid also require a multi-party grid-risk model.

**Challenge 5. Testing, Exercises and Metrics**

Interventions identified above to address these challenges needs to be tested and measured in order to ensure they are working as intended. The industry must address the need for metrics. Security metrics provide value to various stakeholders. The security team needs to (1) find out what works and what does not; (2) communicate security posture, threats and risks; and (3) demonstrate value of their work. IT/OT management needs to (1) make sound decisions on security technology, resource allocation, etc.; (2) monitor the effectiveness of security controls over time; and (3) make recommendations to senior management on security priorities. Senior Management / The Board can use security metrics to assess the cybersecurity risk and make strategic decisions on cybersecurity risk management. Lastly and most importantly, the consumers, the stakeholders who rely on electric power for their operations, including customers who operate other critical
infrastructure, have questions such as “Is our data secure?” and “Is our power grid secure?” that can be addressed with security metrics.

There exists an opportunity for uniform adoption of risk assessment and capability maturity models. To evaluate security-program processes, metrics must be integrated into the business process to address challenges for security operations in the power-delivery systems. Organizations like EPRI’s Cyber Security Research Lab provide value ranging from thought leadership to hands-on demonstrations. Security is already a vital risk management function for utilities, which have cyber and physical security Key Risk Indicators (KRI) that look at root causes of drivers that may lead to risk events that may impact future performance. KRIs provide an early signal or warning about changing risk exposures. In contrast, Key Performance Indicators (KPIs) look at past performance/trends to gain insight on future performance. KPIs are lagging indicators used to demonstrate the success of completed business activities. KRIs and KPIs can be aligned to the NIST Cybersecurity Framework, which can provide insights into security trends for decision making and mitigation planning.

Third-party assessments can have certain advantages. Utilities and public utility commissions (PUCs) with relatively limited cybersecurity-related resources can lean on the knowledge and skills of auditing and other professional local services organizations. However, there is well-placed concern over trusting the same people in the organization who are responsible for ensuring RR&S to assess their own efforts and risks associated with allowing outside parties to access such critical assets and information.

Efforts are underway to establish metrics for reliability, resiliency and cybersecurity. One potential solution is the Electricity Sector Cybersecurity Capability Maturity Model (ES-C2M2) [57]. There is an opportunity to learn from other domains and use existing data to make better security and investment decisions using quantitative, probabilistic and scenario-based methods.

The effectiveness of these and other interventions, cannot be taken for granted, but rather undergo effective, regular and consistent evaluation. The ICC currently requires utilities certify that that cybersecurity plans and other governance requirements are in place and reviewed and exercised at least annually. Testing and exercising crisis and incident management capabilities across multiple jurisdictions will help ensure a uniform level of baseline capabilities on which additional capabilities are built. Specifically, there is an opportunity for more exercises in which utilities in different service territories or sectors come together to share knowledge, lessons and best practices.

Such capabilities should be tested through efforts to exercise response capabilities through local, regional and national coordinated exercises (CSIRT, Cyber Storm, FEMA NLE, GridEx, Operation PowerPlay etc.). GridEx is NERC’s “biennial exercise designed to simulate a cyber/physical attack on electric and other critical infrastructure across North America.” [58]. The exercise involves electric utilities, regional (local, state, provincial) and federal government entities, law enforcement, first responders, intelligence agencies, ISACs and supply-chain stakeholders. State PUCs, including the ICC and other state level entities, have increasingly participated in GridEx in various capacities.

Finally, WG3 discussed the possible need to study potential dependencies among interventions to derive a sensible implementation timeline, as well as prioritization of interventions:

Careful examination of emerging technologies to minimize introduction of additional risks by application of quantitative metrics is required as new technologies and methods are introduced.
• Continued development of ESCC Cyber Mutual Assistance program to coordinate between utilities in the event of an attack
• Examination and incorporation, where appropriate, of post-incident investigation, issue identification and remediation strategies practiced by regulatory authorities in other industries such as the FAA (air travel) and the NHTSA (automotive)

3.4 Regulation and Compliance

The North American electric grid operates under a broad and interwoven set of laws, rules, policies and requirements. Grid operation is subject to regular measurements, regulations and supervision by parties responsible for oversight and regulation of the complex concert of entities that make up the grid. They have a mutual goal of making the grid reliable, resilient and secure as well as a cost-effective economic backbone upon which much of commerce in North America can function and flourish. NERC has developed standards and regulations that cover aspects of reliability, cybersecurity and resiliency compliance. Existing regulatory regimes have created distinct oversight authorities with both overlaps and gaps that have contributed to a disaggregated regulatory environment.

A utility’s core goals include assurance of consistent availability of essential services to consumers (including individuals, businesses and governments) at economically appropriate and reasonable cost. The electric industry includes natural monopolies enabling economies of scale to optimize transmission and distribution at a lower total cost than any combination of smaller entities may. Regulation is necessary where competition cannot be relied upon to achieve the public interest for this essential service. In this case, the public interest is focused on ensuring that each regulated utility operates in a reliable, resilient and secure manner to consistently meet the public demand for electricity at the least cost through risk identification, mitigation and recovery preparation, should services be disrupted naturally, accidentally or intentionally. This also includes ensuring that investments are prudent and reasonable.

The focus of specific utility regulations has evolved over time. Following a series of remarkable blackouts and smaller outages that took place during the end of the 20th and the early years of the 21st century, grid resiliency and security functions have migrated away from a cooperative environment with many independent entities responsible for their own oversight into a more complex fabric of regulated and deregulated entities. This enhanced oversight and regulation was designed to further the public interest in a reliable, resilient and secure system. Compliance accompanies regulation, so it is important to strike a balance between assessing the effectiveness of existing regulations (avoiding compliance over security) while considering the introduction of new regulations. While regulations drive behavior, that behavior should be focused on improving RR&S in the most efficient manner considering time, resources and cost.

Regulators are challenged with overseeing an information and process exchange that entails much of the investment, activity and associated business decisions made by utilities and balancing the consumer needs with those of highly complex entities mandated to cost-effectively deliver on those expectations in the face of escalating threats, changing climate and economic factors. To achieve and maintain an effective balance, while simultaneously ensuring RR&S, certain key elements identified herein as challenges that must be addressed.

Overcoming those challenges will rely on the agreement of multiple parties to work together to strike a balance between those interests that at times are in alignment and other times are at odds.
Challenges include defining what an acceptable level of security means and who should make that determination and consistently measuring and assessing the effectiveness of those regulations when considering the resources necessary to affect the compliance process on both sides. Optimizing collection of, access to and the appropriate flow of threat intelligence between utilities, governments and other parties also becomes a challenge when regulators direct utilities to share threat information in a manner that reconciles expectations of confidentiality, discretion, urgency and public interest.

See Table 5, Quad Chart D, Regulation and Compliance for a high-level summary of these key points.
<table>
<thead>
<tr>
<th>Challenges</th>
<th>Achieve:</th>
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<tr>
<td>Sustainable environment for the introduction of appropriate standards and regulations while considering the operational impact of additional compliance activities</td>
<td>• Regulatory balance between utility asset owners and those vendors that design, manufacture and distribute products to support utility operations</td>
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<tr>
<td>An acceptable level of physical and cyber security across industry stakeholders</td>
<td>• An &quot;appropriate security level&quot; acceptable to all stakeholders. How to define security? What is “secure,” who defines “secure enough”?</td>
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<th>Define:</th>
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<tr>
<td>An &quot;appropriate security level&quot; acceptable to all stakeholders. How to define security? What is “secure,” who defines “secure enough”?</td>
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<th>Measure:</th>
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<td>Effectiveness of multiple compliance requirements and a segmented regulatory focus (e.g., distribution-level regulations are not uniform and not standardized)</td>
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<tr>
<td>• Reconnaissance and penetration of vulnerable systems</td>
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<th>Navigate, Balance and Assure:</th>
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<tbody>
<tr>
<td>The unique Illinois jurisdictional environment when considering: unbundled delivery and supply, MISO/PJM seam, Future Energy Jobs Act (existing nuclear fleet and anticipated increase in solar and wind DER)</td>
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<th>Opportunities</th>
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<tr>
<td>Offer &quot;NERC CIP Compliant&quot; processes, implementations and products. Regional entities currently will work with vendors to ensure requirements are met if properly implemented. Is certifying body needed? Consumers want choice and access, can be incentivized, but need low-friction design.</td>
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| • Leverage standards and best practices from other jurisdictions to support unique aspects of evolving parts of Illinois grid | • Align security activities with various sources, including statutory compliance, policy and industry standards, as well as federal and state regulations. |
| • Create a flexible and customizable regulatory framework to appropriately target necessary levels of security and resiliency across industry stakeholders—utilities, vendors, IPPs, suppliers and others | • Foster an industry-wide and evolving regulatory approach that effectively supports and enhances operational efficiency while focusing on economic achievement of operational security |
| • Reach agreement for security and baseline definition of considering reliability and resiliency | • Emphasize measuring and communicating level of actual security rather than compliance activities that decrease direct utility control |
| • Reassure regulators that utilities can and have achieved an appropriate level of preparedness | • Devise better methods to encourage intended behavior that measurably increase RR&S through incentives-based approaches instead of relying solely on static compliance-based assessments |

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<th>Solutions</th>
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<tr>
<td>• Support a regulatory framework emphasizing security over compliance activities</td>
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<td>• Resolve or reduce the tension between prescriptive and objectives-based approaches. NIST framework considers compliance a component of risk</td>
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<tr>
<td>• Utilities should effectively communicate achievement of increased security levels to satisfy regulator and stakeholder expectations</td>
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<th>Potential Action Items</th>
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<tr>
<td>• Develop process for utilities and regulators to collaboratively define metrics that demonstrate appropriate levels of RR&amp;S</td>
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| • Determine cost of sustaining and exceeding future RR&S standards. |
**Challenge 1.** Achieve a sustainable environment for the introduction of appropriate standards and regulations while considering the operational impact of additional compliance activities. A regulatory balance is necessary between utility asset owners and vendors that design, manufacture and distribute products in support of utility operations. Physical and cyber security should exist at an acceptable level across investor-owned, co-operative and municipal as well as independent power producers, consumer DERs, aggregators and other entities.

The introduction of any regulations should optimize both assessment and achievement of a more secure and reliable environment for utilities. Today’s regulations focus primarily on the activities of asset owners, even though vendors and consumers are increasingly connected to and interact with the infrastructure that was previously under the control of asset owners alone.

Creation of additional regulation in a complex marketplace is challenging; however, a partially regulated industry creates weak points where exploitation may easily occur around the edges where transitions exist from one environment to the other. Addressing the disconnect between a highly regulated asset owner and its many manufacturers, suppliers and solution providers, is essential to addressing a wide range of potential risk. Vendors who design and place functional products into the grid fabric should also be held to a consistent securitization level for their products and services. Establishing, enforcing and measuring against standards, in a compliant and minimally disruptive manner, would reduce risk considerably to asset owners. Ideally, any potential increase in product costs associated with required vendor risk-mitigation activities would be offset by a reduction in the cost of asset owners performing those activities themselves. Third-party security audits/assessments may work to enhance overall security of the grid and reduce expanding threat vectors.

There was disagreement within the WG on the effectiveness of regulations and their possible effects on innovation and resource allocation when compared with encouraging adoption of risk-based approaches and maturity models. Certain members of the WG raised concerns that static regulations may result in an entity's compliance but may be harmful to the ongoing assessment and mitigation of cybersecurity risks. Instead, it was suggested that the approach should be focused solely on a risk-based model. Consideration should be given as how to accurately measure the success of a solely risk-based model. Ultimately, the challenge is to determine how to effectively integrate a risk-based model into a regulatory backdrop through efficient allocation of resources in a way that promotes RR&S.

Opportunities: Integrating inter-operable solutions, from diverse vendors and third-parties, requiring common cyber-secure standards development that measure vendor capabilities, practices and competencies serve to reduce risk potential when those products are integrated within grid operations. Direct DOE research partnerships to focus equally on evolutionary RD&D and practical and impactful solutions to current and evolving challenges that have market penetration potential in real time. Future power-system components and architectures should integrate strong cybersecurity functionality early design phases. They should include interoperability with new energy-delivery systems and component product lines while demonstrating consistent interoperability across diverse vendors.

Cement an industry-wide approach to incorporate incident reporting for electricity specific entities, through NERC CIP [40], DOE [36] and E-ISAC [37] requirements. Process improvement should
be emphasized over compliance-focused activities. Effort should continue to be placed on high quality and timely coordination among reporting mechanisms.

Solutions and Potential Action Items: Influence marketplace behavior to increase emphasis on security-compliant practices at the foundational level of product development throughout the supply chain. Utilizing consistent enforceable supply-chain contract terms and conditions that include cybersecurity focused requirements will promote consistent approaches to providing more secure products and services to grid operators. Focus on NERC standards and other, more comprehensive guidelines, such as the NIST CSF [41], to achieve enhanced levels of cyber and physical security. Best practices should include isolation of critical cyber assets within restricted networks, segmented from the enterprise IT environment and the internet. The assets should be continuously monitored for malicious activity and routinely evaluated for vulnerabilities.

- Consider having regularly reviewed, exercised and audited, business continuity plans for all critical business functions based on a business impact-analysis study of functionality loss.
- Consistency in the adoption of standardized cybersecurity approaches can allow efficient regulation and compliance activities that help to effectively assess adherence in ways that promote increased security over achieving compliance, while recognizing diverse approaches and technologies can also have security benefits.
- Encourage further utilization of risk based, intelligence-driven security approaches to implementing a comprehensive set of cyber and physical security controls (consistent with NIST Cybersecurity Framework) to effectively identify, protect, detect, respond to and recover from a spectrum of threats, mitigating the likelihood of successful attacks and their potential impacts.
- Participate in the continued development of the NIST Cybersecurity Framework, NIST CSF and NERC CIP Standards.
- Adopt a NERC CIP 13-like standard or NIST-CSF approach for vendors of both BPS and distribution grid that drive a consistent approach and behaviors, as well as a compliance validation process, that serves to enhance the baseline security of products across the marketplace prior to integration into grid operations.

Appeal to lawmakers and regulatory bodies to avoid establishing or increasing static cybersecurity requirements and instead focus on creating a rewards system that encourages entities to voluntarily adopt and demonstrate robust cybersecurity practices. Overall risk(s) posed to critical infrastructure by malicious cyber actors may be decreased by augmenting or replacing cybersecurity compliance requirements with rewards-based incentives for actions that implement strong cybersecurity measures. Those incentives will need to be predicated upon an entity meeting certain measurable criteria, for example, continuing improvement towards a target tier using the NIST CSF, demonstrable and continuing reduction of cybersecurity risk, or repeated instances of implementing cybersecurity best practices that exceed basic compliance requirements. It was also emphasized that incentives need not be financial. Further, a strictly monetary benefit may not produce the desired behavior. A monetary benefit may only reward the entity and not the personnel who were responsible for designing, implementing and managing a cybersecurity program. Those members advocating for the alternate approach proposed that examples of incentives might include: relaxing audit frequency (or granularity) and reduced severity of audit findings for best
practice efforts, even if not strictly compliant public recognition of leadership in producing results and funds supporting development of innovative ideas.

**Challenge 2.** Navigating the unique Illinois jurisdictional environment when considering: unbundled delivery and supply, MISO/PJM seam and the particular generation mix for the region (including the effects of the FEJA on the existing nuclear fleet and anticipated increase in solar and wind DERs), balancing tradeoffs between meeting regulatory compliance and operational security, while integrating DERs, EV penetration and other sources that decrease direct utility control over connectivity that impacts grid security.

Opportunity: Utilities and others in the industry need to effectively communicate achievement of increased security levels to support regulator and stakeholder concerns and expectations. Smart Grid investments must be continually assessed and prioritized as they evolve.

Solutions and Potential Action Items: Continue to deploy defense of in-depth approach to security, encompassing physical security, prevention and response policies and procedures, education, software and hardware controls. Test systems regularly to ensure that highest standards of cybersecurity are maintained. Consistently employ multi-factor authentication processes for each connection to secured data sources.

- As the conventionally centralized and one-way flow of data and kilowatts becomes more decentralized and bi-directional, we need rapid new vulnerability migration. The future distribution system will require utilities to make additional infrastructure investments to maintain system resiliency and integrity.
- Continue efforts by the utilities to improve data security, grid resiliency and recovery, including new technologies, customer-engagement strategies and control systems, consistent with the utilities’ ability to plan and determine security-related infrastructure needs and evaluate alternatives in a prudent manner that guarantees long-term grid performance.
- Design appropriate security-related terms and conditions to third-party devices and systems that will interact with the grid to the extent they interact with and impact grid systems and data.
- Develop a robust coordination plan for critical entities (both BPS and distribution level) to ensure information sharing, risk assessment, risk mitigation and incident response are effectively implemented.

**Challenge 3.** Measure and assess the effectiveness of multiple compliance requirements with a segmented regulatory focus. Distribution-level regulations are not uniform or standardized. Cooperatives and municipalities continue to be self-regulated under current state law. While many achieve secure environments notwithstanding limited budgets and resources, it is difficult for industry stakeholders to determine which entities have not sufficiently improved their security posture and identify those entities that need assistance. WG3 also believes it is important to consider the potential impact to BEP systems that may result from RR&S decisions of co-ops and municipal-owned utilities related to reconnaissance and penetration of vulnerable systems and exploitation of those vulnerable systems.

Opportunity: Survey compliance activities of various sources, including statutory, policy and industry standards, as well as federal and state regulations. Be aware that conformity may inadvertently create uniform vulnerabilities. Work towards adopting better business practices even when not required, because they make sense and are effective (e.g. NERC CIP, NIST, C2M2).
Solutions and Potential Action Items: Distribution-system modernization focuses on improvements in operability and resiliency by addressing obsolete equipment and improving system design to confront the top threats to the grid (such as hurricane, earthquake, cyber-attacks, physical attacks, electromagnetic pulse and geomagnetic disturbance).

- Entities should adhere to or follow an industry recognized framework such as NIST CSF [41], NERC CIP standards [40], the DoE’s C2M2 [57] and other frameworks to help identify and quantify risk, threat, vulnerability, threat actors and potential targets and to understand our adversary classes and intentions.
- Entities should continue to work with government and private sector partners to share and analyze information and encourage further participation in such information-sharing partnerships.
- Voluntary frameworks allow companies/industries to be agile in updating controls as new threats and vulnerabilities are discovered. Frameworks can be updated with industry and government as needed.
- Mandatory and static regulatory requirements in security may be less flexible and agile than a voluntary framework.

**Challenge 4.** Defining what is an "appropriate security level" acceptable to all stakeholders. How to define security? What is “secure”, who defines “secure enough?” First, define the critical system elements and then work to establish a consistent level of security across the industry. Those critical parts are different for each part of the system. Moreover, established levels of security, reliability, or resiliency may also be affected by and/or reflected in, PUC-approved rates and terms of service.

Solutions and Potential Action Items:

- Leverage the engagement of consumers, utilities, vendors, legislators, regulators, other critical infrastructure asset owners.
- Define the stakeholders who can decide what is and what is not acceptable (e.g., consumer representatives, utilities, public utility commission members, etc.) and bring them together for an initial discussion about what matters.
- Identify a process through which a common set of requirements can be agreed upon and targets for completion can be proposed with input from industry stakeholders.

**Challenge 5.** Reassure regulators that utilities can and have achieved an appropriate level of preparedness. Continue and increase collaboration between utilities and regulators to discuss existing and emerging threats and how utilities are advancing their security postures. Current methods of enforcing static security compliance requirements, typically involving audits, may not always achieve intended results. This approach may also provide a false sense of security by encouraging checklist-style, compliance-based security. It is not possible for static compliance requirements to keep pace with the rapidly changing attack vectors and tactics used by malicious actors. This is not to suggest that compliance audits are not useful in the right environment. Ultimately, the goal is to measure actual improvements in security behavior and activities. Research suggests that it may be counterproductive to scare people into action; instead, a reward-based approach may be more successful in increasing security across the industry [59]. In a compliance-based environment, there is typically no reward for meeting or exceeding the standard, only punishment for failure to do so. Rewards-based incentives for implementing strong cybersecurity measures can decrease the overall risk posed to the grid. Incentives may be targeted
towards achievement of certain identified metrics, for example, continuing improvement towards a target tier using the NIST CSF.

- Appeal to lawmakers and regulatory bodies to avoid establishing or increasing static cybersecurity requirements
- Implement a rewards system to encourage entities to voluntarily adopt and demonstrate robust cybersecurity practices
- Formalize a process by which rewards-based systems may replace static compliance-based assessment approaches where appropriate
- Continue engagement between utilities and regulators in closed-door meetings where utilities can explain approaches and their level of preparedness with appropriate detail
- Develop formal WGs between utilities and regulators to explore and discuss the best approaches to ensuring security frameworks across the industry in Illinois

EV penetration and other sources that decrease direct utility control over RR&S or make the exercise of that control more complex.

Opportunity: Regulation of cybersecurity operations and activities exists today as a mix of mandatory requirements and regulatory pressure to increase voluntary efforts. The bulk electric system is wholly regulated for cybersecurity activities, while at the distribution level, state regulators have begun to insert basic cybersecurity regulations. The progress and investment the electric industry has made towards cybersecurity may be attributed to mandatory NERC standards. While utilities look to best practices, ongoing learning, customer service, responsibility for protecting assets as fulcrums for investment strategies, some in the WG argued that certain investments may not have been made if the NERC CIP standards were voluntary. Discussions should continue among state regulators, utilities and others in support of determining the best way to ensure the cybersecurity of increasingly-connected sources that are not currently regulated but present potential risks to the grid.

Solutions and Potential Actions Items: Moving forward, entities should establish strong governance structures, accountability frameworks and compliance programs. These are typically not areas of focus within IT and security organizations. Entities should establish regulatory monitoring and change models to track applicable regulatory activity and be able to respond quickly. This includes impact assessments, input on the regulations and implementation planning with sufficient time to address all required changes to current activities.

- Utilities should periodically provide feedback on how specific regulation and compliance activities impact RR&S by requiring additional resources (e.g., time, personnel and cost) that may otherwise be allocated towards strengthening RR&S of the grid
- Estimate the costs of meeting future standards for cybersecurity and resiliency
- Streamline central authority for cybersecurity preparedness direction for the entire grid. Today the FERC and NERC have authority over cybersecurity standards development and compliance for the bulk power system, but there is no formal regulatory oversight of compliance with cybersecurity standards at the distribution level and for smaller aggregations of DERs. Consideration should include
recognition of the scope, costs and potential time delays of establishing any new regulatory regime.\textsuperscript{10}

\textsuperscript{10}FERC has also initiated a proceeding investigating resiliency. (See FERC Docket No. AD18-7.) FERC has obtained extensive filings from RTOs and other industry participants on resiliency including on how resiliency should be defined, whether there is a resiliency problem (and, if so, what is its nature) and what mechanisms can be developed to ensure that resiliency is maintained.
4. Customer and Community Participation

Customers are the end users of the energy supplied by the electricity grid and communities are the networks of customers brought together to meet a common goal. A household, a building, or a business may be a member of multiple communities—each based on different characteristics such as categories of geography (urban, suburban, rural), residence in a specific town, city or neighborhood, household income level, business type, ethnicity, religion, vocation, age, other demographic and economic characteristics, as well as interests, activities, views and orientations. All communities depend on electricity to enable the functionalities of modern life: lighting, heating, cooling, communications, appliances, production of goods and services and, more recently, electrification of transportation, connectivity and mobile information. The electricity grid exists to benefit all customers and its costs are recovered in the regulated revenues collected by public utilities. The key word in “Customer and Community Participation” is the last one. Illinois energy policy must empower all customers to participate in emerging energy opportunities in order to leverage new technologies and markets for system benefits, while ensuring accessible, sustainable, reliable, resilient, safe, secure and affordable high-quality electric service.

Utility customers in Illinois have the ability to make individual choices about technology, energy sources, uses and pricing plans. Customers and communities are affected not only by their own choices and behaviors but by the countless decisions and actions of all consumers and producers connected to the grid that serves them. The affordability and resiliency of electric service, as well as the physical and social environments of communities, are also impacted by decisions made by utilities and regulators regarding investments, expenditures, rate options, collection practices and other policies. This chapter examines a range of relevant issues and reflects the perspectives of the participating stakeholders as to how outcomes might be optimized for individuals, communities and the grid system.

Within the limited available time to take up a broad set of complex topics, there was no attempt to forge consensus regarding the many issues about which stakeholders have divergent views, opinions and expectations. Rather, the intent of the participant interactions and of this report is to provide information about the issues covered, elucidate stakeholder perspectives and lay out options discussed and, in some cases, recommended by individual WG participants to address identified issues. Not all issues may be identified and covered in-depth and not all ideas were the subject of group discussion. The group’s scope of activities did not include the performance of cost analyses of policy and technology options, nor the evaluation of costs and benefits of potential strategies. These are important subjects for further analysis by policy makers and stakeholders.

Building on the WG1 examination of new technologies, WG4 focused on the different ways that groups of customers and communities may participate in the evolving energy marketplace. We explore the policies and options that may emerge in an interconnected world featuring DERs, the availability of more granular data, automated demand response, growing electrification of transportation and other economic sectors, continuing technological innovation and an expanding array of energy product and service options for customers of all sizes. The topics covered in this chapter include consumer engagement, education and empowerment, retail market opportunities and challenges, market transformation, the changing roles of public utilities, ARES and other entities, options for electricity pricing, opportunities and challenges of DER and transportation electrification, the needs of LMI customers and the perspective of very large commercial and industrial (VLC&I) customers. The diverse opinions of participating stakeholders about identified
issues and their proposals to address them are discussed for each topic. Due to the overlapping subject matter there may be different ideas and perspectives presented by other WGs on these topics.

At the first meeting, each participant was asked to identify a key issue raised by emerging changes in the way electricity is produced, delivered and used in Illinois and what, from their perspective, will be a long-term positive outcome and a negative outcome for customers and communities, as well as how the issue might be addressed through public policy initiatives. At subsequent meetings, presentations were made by the following stakeholder groups: Office of Illinois Attorney General, Elevate Energy, Citizens Utility Board, Ameren Illinois, ComEd, IGS Energy (a retail energy supplier), Charter Dura-Bar (a large industrial customer), Delta Institute, Advocate Health Care and Northwestern Memorial Healthcare. The final meeting was devoted to discussion of the initial draft report that was subsequently the subject of comments and suggested edits by participants prior to its finalization for submission to the NextGrid senior facilitators.

As part of the collaborative process, WG4 participants were invited by the WG leader to submit ideas for “3Ps”—Programs, Policies and Pilots—that the stakeholder group or individual proposes to address emerging electricity issues affecting customers and communities. Specific proposals and options included in this chapter are based on the discussions that occurred over the two-month course of the WG process and in responsive comments as well as the 3P exercise results. Documents and links provided by participants and the WG leader on a shared drive were additional source materials in this chapter preparation.

Some stakeholders, including the Office of the Attorney General, asserted that the report will be more edifying if the views described were attributed to individuals and groups expressing them; however, in the view of some others, the goals of giving all perspectives equal consideration regardless of source and encouraging open discussion are best served by not attributing views to individuals or groups. Therefore, as laid out at the beginning of the NextGrid study process, all WGs operate according to “Chatham House Rules,” under which points raised are not attributed to particular individuals or groups with which they are affiliated. That attribution-free format was followed in writing this report, which was initially drafted by the WG leader and revised following extensive comments and suggested edits by the WG4 members.

4.1 Overview of Stakeholder Perspectives

In the 125 years since the 1893 Chicago World’s Fair astonished people with its electric lighting, the consumer uses of electricity evolved from lighting to motors and appliances, to heating, air-conditioning, television and computers and smartphones—plus all the other devices and processes that have become essential to a modern lifestyle and are electricity dependent. Transportation is emerging as the next major step in lifestyle electrification, perhaps soon to be followed by “self-driving” electric vehicles. On the supply side, large central-station power plants facing competition from a variety of new energy resources, including wind turbines and smaller-scale distributed technologies, such as rooftop solar photovoltaic generators. Variable-output renewable generation increasingly may be paired with energy storage as that technology improves in performance and its costs decline.

The goals of delivering safe and reliable utility service at rates that “are affordable and therefore preserve the availability of such services to all citizens,” [60] have evolved to include environmental protection, i.e., to reduce pollution and carbon dioxide emissions. In addition, the Illinois General Assembly has directed that the ICC “should act to promote the development of an
effectively competitive electricity market that operates efficiently and is equitable to all consumers,” and that the state should “encourage the adoption and deployment of cost-effective distributed energy resource technologies and devices” [61].

Energy efficiency is part of the modern grid goals and is accompanied by associated regulatory requirements. Using less energy results in lower and more stable bills for consumers, environmental and health-related improvement, and a lessened need for system-capacity expansion over the long term. However, lower- or flattened-usage may not always mean correspondingly lower costs to run the grid, which must be continuously operated, maintained and upgraded to meet around-the-clock customer needs. Smart grid and advanced technology deployment have brought about improvements in the key resiliency metrics of outage frequency and duration for ComEd and Ameren Illinois in each of the years since enactment of the EIMA [4].

The rapid pace of technology innovation, the expansion of data collection and analysis and the growth in the number and diversity of connected devices drive consumer demand for increased choices, more control capability and enhanced convenience in energy transactions. These preferences may result in providing energy products and services in ways that customer and social value will no longer flow from a simple two-way exchange between the utility and the electricity user. Future solutions are evolving toward a multi-dimensional collection of interactions among the utility, supply-side players, providers of value-added products and services and the consumers/prosumers on the grid.

Policy formulation is becoming more complex and requires thorough examination of costs, benefits and additional ramifications of proposed regulatory innovation and technology deployment. Stakeholders have proposed a range of preliminary questions to consider in the evaluation of the effects of policies, programs and investments on customers and communities, such as:

- What is the nature of the challenge being addressed?
- What are its scope, scale and timeframe?
- What are the customer and community benefits of proposed solutions? How can they be quantified? Do they differ between customers or classes?
- What are the additional benefits and who are potential beneficiaries—e.g., society as a whole, utilities, vendors or markets?
- How can barriers that may prevent certain customers or classes from realizing benefits be reduced or completely eliminated?
- What public utility role will best serve the public interest?
- Can a specific challenge be solved by harnessing market forces? Is there a feasible and practical combination of market and regulatory policy that is able to effectively address it?
- What are the projected costs and how will they be allocated?
- What will be the effects of different solution approaches on customer rates?
- What incentives can lead to optimal outcomes for customers and communities?
- What is the level, if any, of necessary regulatory oversight of implementation and operation?

Illinois has a robust regulatory process, open to participation by all stakeholders, to consider the equity issues inherent in delivering electricity services. A critical task is to ensure that benefits of
any grid innovation include all Illinois communities, regardless of socioeconomic, locational or other considerations.

A key goal of the NextGrid process is to identify and elucidate the principal issues in an evolving energy and climate context. As to the core elements of regulatory policy affecting customers and communities in an era of changing technology and priorities, some key questions posed by stakeholders for consideration by policy makers are listed below in an unprioritized order:

- What new policies, if any, are needed to produce greater choice and price-constraining competition for energy products and services?
- What new policies, if any, are required to ensure simple and timely interconnection for behind-the-meter DERs?
- What specific policies, if any, are warranted to inform and educate customers about programs, rates and options that can improve their energy experience at reduced costs?
- What new policies, if any, are needed to provide accurate and effective price signals to customers?
- What new policies, if any, are needed to appropriately allocate incurred costs to cost-causers?
- What new policies, if any, are needed to ensure that customers are compensated for the value they provide to the grid?
- What new policies, if any, are needed to fairly allocate costs among customer classes and address the possibility of uneconomic bypass?
- What new policies, if any, are required to allow access to customer information and data to support competition in energy products and service markets?
- What new policies, if any, are needed to provide access to customer interval meter data on an equal basis to ARES, consistent with customer privacy and authorization rules?
- What additional policies, if any, are necessary to protect consumers from deceptive and fraudulent behavior by energy product and service marketers?
- What new policies, if any, are needed to protect limited State and Federal Low-Income Home Energy Assistance Program dollars from being spent on high-priced energy supply provided by unregulated entities?
- What new policies, if any, are needed to improve resiliency and customer satisfaction?
- What new policies, if any, are needed to ensure the benefits of utility investment in new technologies flow to all customers and communities?
- What new policies, if any, are needed to provide all customers, including those of LMI, with access to the full range of product, service and pricing options enabled by new technology?
- What new policies, if any, are needed to ensure energy affordability for LMI customers?
- What new policies and mechanisms, if any, are needed to estimate costs associated with new policies or infrastructure proposals?
- What new policies, if any, are needed to equitably share risks of investment in new system beneficial technology?
• What new policies, if any, are needed to evaluate and respond to the value different groups of customers place on different forms and levels of resiliency and their associated costs?
• What new policies, if any, are needed for utilities to flexibly respond to changes in customer requirements and expectations?
• What new policies, if any, are needed to allow utilities to respond to potential grid exit?
• What new policies, if any, are needed to recover stranded costs associated with customers who leave the distribution system?
• What new policies, if any, are needed to effectively and securely improve data sharing capabilities with third parties as utility usage data becomes more granular?
• What new policies, if any, are needed to address the risks to cybersecurity of additional interconnection and digitization of the grid as well as to protect customer privacy?
• What new policies, if any, are needed to provide an appropriate level of community and government access to information and input into utility infrastructure decision making and siting?

These and related questions are deserving of comprehensive evaluation to ensure that the grid meets tomorrow’s needs while continuing to deliver resilient, safe, reliable, affordable, efficient and sustainable electricity service to all Illinois customers and communities.

4.2 Empowering Consumers to Make Energy-Smart Choices

In the first century of electricity, after an initial “shake-out” period of competition and self-generation, the regulated public utility was created as a response to the natural monopoly scale and scope characteristics of electricity supply, given the technology at the time. From the point of view of most “ratepayers,” the only data that mattered was the monthly bill amount and the only thing a residential customer had to know was how to turn the switch on and off and never to touch live wires. Choices were few and nobody spent much time on energy management. Even large industrial customers, with the technical ability to self-generate, saw value in being grid-connected to benefit from regulated pricing and policies.

Demand was seen as inelastic and the main question was how fast to expand the system to meet ever growing loads and reduce unit costs. People noticed when their bills went up to pay for added capacity and higher-level usage, but otherwise most small-volume customers thought little about electricity. However, by the 1970s, unit costs began rising after the construction of large power plants without the forecasted increases in demand. At the federal level, policy to grant non-utility generators access to the transmission system allowed advanced generation technology to compete in the newly-created wholesale electricity markets. The advent of competitive electricity markets eventually led Illinois to restructure its electric power industry in 1997 [2] to capture the benefits of competition. The Illinois restructuring effort has largely been viewed as successful, as it has given all customers access to lower wholesale-electricity-market supply costs and an increasing array of consumer options for energy products and services [62].

Stakeholders hold a variety of views about what today’s consumers want from their utilities and other energy providers. Some suggest that, spurred by concerns about pollution, climate change, resource depletion and the opportunity to reduce energy costs, many consumers are becoming more energy conscious, changing their usage patterns and adopting state-of-the-art technologies.
From this perspective, customers are responsive and make choices that benefit themselves and the broader community, provided they have easy access to trustworthy, easily understood and actionable information.

However, customers are not uniform in either their desires for or their abilities to adapt to technologies, rate designs and policy innovations. Some stakeholders believe that customers generally want the utility to focus on its core function to provide low-cost reliable electricity and to supply actionable information about how to use less energy and save money. Though they acknowledge that technological innovation is providing additional options, they question whether customers’ energy concerns and needs are changing. Others point to a familiar example of the way innovative products have historically shaped demand: people didn’t know they needed a smart phone until they had one.

For consumers to derive value from their energy options requires that they understand them. Informed customers who choose to adopt advanced technologies can produce commercial, environmental and societal benefits. Stakeholders agree that utilities, suppliers in energy markets, regulators and advocates must engage customers and provide accurate information about rates, products and service options; provide them design tools to help make choices; communicate factual energy costs and savings projections; and shield consumers from deceptive practices. Future customer satisfaction may depend, not only on provision of reliable and affordable services, but also on utilities’ and marketers’ abilities to deliver a customer experience that meets the consumer expectations in the Amazon era.

Utilities are changing in response to the emergence of recent technologies, evolving regulatory goals and policies and empowered customers. In addition to its role as network provider and system operator, the utility’s responsibility to improve the resiliency, efficiency, affordability and accessibility of its services entails efforts to engage and educate customers and provide appropriate information and usage data to help customers manage their consumption choices to reduce energy costs. Customer education is a core utility function and it will continue to play a key role in driving customer awareness, interest and adoption of new and/or enhanced offerings that create customer benefits.

The utility is a key repository of vast amounts of consumption data that can be analyzed for information to aid customers. Because utilities are subject to regulatory oversight, some customers view them as unbiased and trustworthy information sources. There are numerous other energy-information sources, including government agencies, trusted experts, community groups, various non-governmental organizations, vendors, brokers and suppliers of energy products and services. Under a provision of EIMA [4], ComEd and Ameren Illinois fund the Illinois Science and Energy Innovation Foundation (ISEIF) for the ten-year period ending in 2022. ISEIF was created by the General Assembly to help inform and engage Illinois consumers in the transition to a digital grid.

The full deployment of AMI makes available more detailed usage data for each customer, opening up options for individualized analysis and recommendation of optimal energy-management solutions for customers. Optimized usage can benefit both individual consumers and the grid and other customers. Access to such individualized customer usage cannot be dependent on how a customer pays for utility service. Facilitation of active and meaningful consumer participation within an evolving energy marketplace will require support from utilities as well as many other market participants and stakeholders.
The articulated customer service objectives of Illinois utilities reflect the changing utility role. ComEd has a stated goal to deliver the so-called “Premier Customer Experience”—personalized service for each customer that is simple and automated, transparent and understandable, flexible to suit the customer’s preferences, proactive in anticipating issues before they actually arise and responsive to customers’ needs. The company is deploying new online smart-meter-enabled tools to organize and present data that customers can use to manage their electricity consumption and their relationship with the utility. Bills have modified design with customer messaging and include additional information, such as high-bill alerts, power-outage information and peak-time savings bulletins. These can be accessed via text, email, phone calls and pushed-app notifications. All customer information including bill payment and personal profile is available through the ComEd mobile app.

ComEd has become one of the nation’s first utilities to provide access to Internet of Things (IoT) applets that enable automatic response of smart appliances to real-time conditions, such as changing the temperature on a smart thermostat when time-varying prices fluctuate or pre-cooling in advance of an expected curtailment event. Also available from the utility is Smart Meter Connected Device (SMCD) service which provides near real-time usage data and estimated electricity cost information to in-home displays and energy-management equipment. However, IoT is at an early stage, the overall benefits remain unclear and most customers do not yet utilize—or even know about—the potential to use new technology to optimize energy consumption and reduce their energy bills and their carbon footprints.

Ameren Illinois is also redesigning its customer engagement programs to meet its customers’ expectations in order to provide each customer an increasingly personalized experience, with timely response to customer preferences and easy access to information needed to make choices and manage costs. The utility uses internal and third-party studies, surveys, focus groups and data analytics and it conducts analyses of its residential customers to determine customer-satisfaction drivers and test the effects of marketing and communication strategies. Ameren Illinois commissioned a study which classified its customer households into five identified energy-demand segments, each with specific characteristics, profiles and priorities. The classification allows outreach messages to be tailored to meet their concerns and, eventually, to potentially identify service options that best fit the customer’s needs and expectations. Some stakeholders have questioned whether a similar segmentation study might be valuable for understanding larger commercial and industrial customers as well.

Similarly to ComEd, Ameren Illinois continues to expand its online portal to provide customized data to each customer—which also includes natural gas information. Ameren Illinois has also enabled the ability for customers to connect each home area network (HAN) device to their AMI meter. The HAN functionality allows customers to receive energy data in near real time and use such data to make energy choices, including automatic response by appliances and HVAC systems.

### 4.3 Data Access

With system-wide completion of AMI deployment, smart-meter interval data will become available to all customers and their suppliers. Analysis and utilization of granular data have potential to open up energy opportunities for all customers, provided that data are accessible to the providers. Combined with supply, demand and control technologies, data allow customers to become grid-interactive participants around-the-clock, rather than passive loads, with more complex but also more manageable energy usage patterns. The availability of granular data helps
the supplier and utility to better understand each retail customer’s behavior and provides the opportunity to establish a customer’s cost responsibilities on an hourly or other periodic or interval basis. In a not too distant future, households may produce, store, manage, buy and sell electricity—as well as consume it. These interactions and transactions may become seamless and automatic, with little effort on the customer’s part.

AMI data must be accessible to customers and authorized third parties who can use it to manage the provision of various services. In addition to their ARES portals, Ameren Illinois and ComEd have adopted the “Green Button” protocols developed by an industry non-profit group to enable consumers to access their detailed energy usage data in a standardized downloadable format, so they can securely manage their consumption and make better-informed energy decisions [63].

Innovative applications, including those using the Green Button data format, have the potential to transform the way people use energy. ComEd makes interval usage data available to customers, retail suppliers and third-party vendors via multiple modalities—ES Portal access to historical interval usage (HIU) data, Green Button Connect and Anonymous Data Usage access. ComEd leverages data to enable customers to lower their bills through energy-efficiency programs and reaches out to affordable-housing residents through its Community Energy Management initiative.

Analysis of energy data by third parties, including retail electric suppliers, demand-response aggregators, utilities and other service providers may bring about new customized products and services. Finer resolution anonymous usage data for statistically meaningful periods of time can be analyzed by academic experts and stakeholder groups and used to inform strategies intended to achieve additional benefits for customers and communities.

Household energy usage data constitute private information protected under Illinois law. Such data cannot be released by the utility without authorization by the customer (except in the form of anonymized research data under specified conditions) but implementation policies are the responsibility of the ICC. Several cases have been, or are in, litigation before the ICC as to the required authorization form and how data are made available [64]. The issues addressed by the Commission include, but are not limited to:

- whether or not a third party, such as an ARES, may access usage data directly from the utility after being authorized to do so by the customer
- the required form of a customer authorization (written, verbal, electronic, wet signature)
- the required authorization language and disclosure to the customer of how the data will be used
- the length of time for authorization to be effective
- the rules for non-ARES to access data for other purposes
- the restrictions on access to anonymous usage data for research and non-sales purposes
- the rules and practices to prevent inadvertent release of customer information, or theft of customer information by malefactors due to failure of third-party vendors to protect the data to the same level as required by the utility
- the measurement and allocation of any costs for making data available

The details of how customer data are accessed are important because customers are accustomed to a seamless online experience and may be frustrated by a multi-step process requiring them to separately visit the web sites of utility and a third party in order to investigate service options.
the same time, customers must be assured that their personal usage and identification data will not fall into unauthorized hands. Utilities play a key role in protecting the privacy of customer data and protecting the grid against security threats, while utilizing data to empower customers and enable third-party vendors. Although there are significant security, privacy, safety and intellectual property considerations associated with granular data sharing, competitive market participants must have reasonable access to data in order to ensure a competitive market environment. The utility already serves as the repository of grid and customer data and has the capability to oversee the data-sharing process.

The availability of finer data granularity can lead to the development of new tools to disaggregate electricity usage to the appliance level via the application of artificial intelligence to whole-home meter data. This information can be used to help customers gain better understanding of their electricity consumption and take measures to lower their costs, providing utilities and service providers another potential level of personalized customer engagement. The net benefits of such software will have to be assessed prior to its deployment, and any utility costs need to be appropriately allocated.

We provide below a list of policy options offered by various stakeholders as potential topics of interest for further analysis and assessment. The list of topics does not reflect agreement among the WG members on their importance or priority, and so the topics are issues that may need consideration in future discussions.

- Promotion of data-authorization protocols: Green Button Connect provides the customer with the ability to transfer data more seamlessly to third-party developers to help accelerate technology applications and deploy analytics based on AMI data. Green Button Connect has enabled ComEd residential and C&I customers to authorize third-party service providers to receive direct access to their energy-usage analytics through an electronic, web-based interface. As of February 2018, there have been approximately 2,000 Green Button downloads with 17 participating Green Button Connect third parties.

- OpenID Connect Assessment: In the view of some stakeholders, Green Button Connect, as it is currently implemented, does not provide a simple and user-friendly customer experience. To authorize data access to a third party, a user needs to separately authenticate on a utility website and then be sent back to the third-party site. Many large industries with similarly sensitive data, such as banking, provide analogous functionality through OpenID software instead of a user interaction. Some stakeholders suggest that employing other data-authorization protocols such as OpenID may make the experience more user friendly while maintaining customer privacy protection [65]. The introduction of additional authorization methods may require ICC authorization.

- OpenID connects through existing channels: Some other stakeholders suggest that authentication also may be enabled through other data-authorization protocols in use on social media—e.g., Facebook, Google and Twitter. They state that such an alternative makes the path to energy data access familiar to those customers who frequently use these social media platforms. However, other stakeholders caution that lack of transparency in data-management practices incurs risk for security breaches and therefore is cause for concern.
• Assessment of a Pilot DSS with SSO option: To achieve a high-quality digital engagement experience from interactions with utilities, one option advocated by a stakeholder is digital self-service (DSS), combined with single sign-on (SSO) capability. SSO allows each customer to use one username and password to securely access personalized data within the utility platform—rates, usage, disaggregation and other types of information.

• Expansion of data-sharing capability: Usage data currently is provided to customer-authorized third parties by the utility once per day. This option allows the utility to review all data for their integrity and explicitly considers the current limitations of utility backend services, which were designed for monthly billing purposes. Some stakeholders suggest that providing data to both customers and suppliers in near real time must be studied, and a pilot project be considered to assess the associated costs and benefits. Such a project will entail construction of the infrastructure needed to offer streams of granular data to third parties in a so-called “sandbox”—an isolated software-testing environment—to a limited set of customers to experiment with actual data.

• Further deployment of data with finer granularity: The effective utilization of more-granular data can provide additional benefits. However, opportunities for such added benefits are currently only available only through smart meter connected devices (SMCD), which cost the user and also require in-home internet service. There are numerous challenges and opportunities associated with alternative methods to access the data, such as direct access to the meter via a HAN. The potential cost-effectiveness of such methods must be thoroughly assessed.

• Investigation of deployment of disaggregation software in utility energy-efficiency programs: The goal is to evaluate the costs and benefits of alternative data-analytic tools for improved program design.

These issues need to be considered in future discussions about data, its management/processing, and the effective data analytics deployment.

4.4 Roles of Utilities, ARES and Other Entities in the Provision of Services to Customers and Communities

The primary function of electric utilities is the provision of safe, reliable and non-discriminatory electric power service to all customers. As the electric grid provides a platform in an increasingly interconnected economy, it has the potential to deliver added value to customers in dynamic and customized ways, provided that the safety, security, reliability and resiliency of the electricity system are maintained at acceptable and affordable levels. A central question for policy makers focuses on what are the most effective ways to produce additional value streams for customers.

Since the electricity industry restructuring in 1997 Illinois regulatory policy has promoted the growth of competitive markets to spur innovation and reduce energy costs. However, stakeholder opinions diverge as to the extent of reliance on competitive markets to provide the products and services necessary to capture the potential benefits of AMI and other smart-grid utility investments. While WG4 members generally share the opinion that tomorrow’s energy landscape must include an array of customer choices, they have individual and distinct ideas about the public policy role in designing and advancing choices to address perceived needs of customers, communities and the grid.
Some stakeholders assert that part of public utilities’ job is to maximize the value of new technology for customers, communities, economies and the environment by providing new services, products and pricing options in a regulated environment in order to ensure consistency with cost-recovery principles. Others view the utility’s offering products and services that can be provided by competitive vendors as detrimental to the interest of other market participants. From this perspective, the role of regulation is to protect a level playing field on which the competitive, non-utility providers are enabled to deliver innovative energy products and services. Other stakeholders think that utilities must provide a limited menu of options in cases where the investment costs of enabling technology are recovered through customer rates, so as to guarantee realization of the intended benefits of those investments.

Stakeholder positions on the utilities’ role to maintain a broader array of services/products often are associated with different perspectives on the appropriate regulatory framework. From one perspective, all utility expenditures should be proven reasonable and prudent in regulatory proceedings before they are recoverable through rates charged to customers. This viewpoint is consistent with the conventional regulatory principles that require applying least-cost determination and cost/benefit analysis to all utility investment decisions and rate-recovery requests. A different position is that the public interest is best served when utilities are financially motivated to invest in new technology intended to attain public policy objectives, such as enhanced resiliency and improved asset utilization, broader use of renewable energy, increased reliance on higher energy efficiency, beneficial electrification, increased energy storage deployment and long-run cost reductions.

While some stakeholders see conventional regulatory incentives as sufficient to achieve these objectives, others believe alternative regulatory constructs can bring about better alignment of utility and customer interests through mechanisms including performance-based incentives, formula rates and pre-approved investments determined by policy makers to be in the public interest. From this perspective, these investments might otherwise not be undertaken by the utility due to significant associated recovery risks. Some of these issues are addressed further in the discussions of WG7.

Many stakeholders see consumer protection as a critical issue in retail energy markets. They assert that deceptive practices cannot be allowed for an essential service such as electricity, particularly when options are not well understood by consumers and mistaken choices can have costly repercussions. Stakeholders presented various views on the question of whether better consumer protection will be needed in the future, in light of experience in the existing retail-energy supply market. We discuss next the issues that have arisen.

Retail supplier choice by individual residential customers in Illinois began in 2002 but did not result in significant movement to alternative suppliers until after the 2009 introduction of Utility Consolidated Billing and Purchase of Receivables (UCB/POR) [66]. Under these statutory mandates, ComEd and Ameren Illinois became the billers and collectors for registered ARES, mitigating both the alternative providers’ cost of billing their customers and their risk of uncollectible bills. ARES receivables are sold at a discount to utilities, who recover uncollectible debt in charges to all utility customers. UCB/POR provisions were essential for ARES to enter the retail supply market, but it was not until implementation of “municipal aggregation” legislation in 2009 for Ameren Illinois and 2010 for ComEd that ARES gained a foothold in the residential market. The aggregation law allowed towns, cities and counties to pass ordinances and referenda
to authorize the governmental unit to choose the default provider of the electricity commodity supply for their residents and small businesses.

Individual customers may opt out of municipal aggregation and choose their own supplier or remain with the incumbent utility. In general, few residential and small commercial customers opted out because the municipal aggregation contracts generally provided a lower supply price. This cost savings was largely due to the fact that the 2007 law that established the IPA [3] included long-term power contracts intended to stabilize retail energy rates as parts of the initial supply portfolios. When a conflux of events, including the economic downturn of 2008, the emergence of low-cost new sources of natural gas and the growth of wind power, caused wholesale market energy prices to fall, the higher-priced long-term contracts for a large portion of utility-supplied power meant there was “headroom” for alternative suppliers to bid below the utility price. Other factors influencing participation in municipal aggregation may have included many consumers’ lack of awareness of available choices. At its peak in 2013, three out of four customers were served through municipal aggregations, but upon the expiration of the above-market utility supply contracts in 2012 and 2013, the ARES price advantage evaporated. Since then, 31% of communities, including Chicago, did not renew their municipal supply contracts and the percentage of customers taking service from an ARES through municipal aggregation fell to 20% in 2017 [8].

ARES now largely focus their attention on marketing to individual customers. The 73 ARES operating in the ComEd service territory and the 37 in the Ameren Illinois territory supply energy to 1,881,134 residential customers in the state as of May 2017—a nearly 10% decline from the 2,068,574 customers served in May 2016. However, it has proven difficult for some retailers to beat the flat rate price of utility commodity supply obtained through the competitive wholesale bidding conducted under IPA procurement plans, particularly since retailers must cover their marketing and administrative costs, plus earn a profit, whereas utility supply is offered without additional markup. ARES have argued that some costs of utility-supply administration are included in the rates of all delivery service customers; however, others point to the allocation of customer-care costs to utility supply as leveling the playing field with respect to administrative costs.

ARES differentiate their products from utility commodity supply by offering longer term fixed-price commitments, lower introductory rates, various premiums, and also by supplying renewable energy beyond levels required by the Renewable Portfolio Standard applicable to all suppliers. ARES assert that because they operate in a competitive market, they must be responsive to consumer needs and preferences. For that reason, some ARES say they eventually will offer products and services beyond commodity energy, such as energy-management tools, and they intend to offer innovative time-variant products after the AMI deployment is completed throughout each utility’s system.

Some stakeholders assert that utilities and retail suppliers have complementary roles in serving customers. Under this view, utilities provide delivery and billing services, real-time access to smart-meter data, RTO settlement on capacity and energy charges and third-party access to rebate incentives and utility programs, while ARES sell customers competitive product and service bundles. However, other stakeholders state that during the 16 years of ARES participation in the Illinois market, with rather few exceptions, ARES have offered largely undifferentiated commodity energy instead of creating innovative packages of energy products and services. Moreover, the ICC’s ORMD estimated in its 2018 Annual Report [6] that in 2017 ARES customers paid a cumulative total of $227.6 million more than they will have paid had they obtained their
energy supply directly from the incumbent utilities. Indeed, the overpayment amounts to a total of $551 million over the three years 2014–2017. ARES representatives respond that this estimate provides an incomplete comparison with utility supply prices and fails to reflect the ORMD report’s disclaimers regarding the difference between the products compared.

The residential retail electricity market in Illinois, in the view of some stakeholders, has been hindered not only by its difficulties to date in the delivery of savings or innovative products, but by the false and misleading marketing by various ARES, whose market presence has tarnished the industry and seriously harmed retail customers. These marketing tactics are difficult to police, in part because solicitations are sometimes conducted by ARES agents using telemarketing and door-to-door sales techniques. Solicitations have included false claims of bill savings, false description of the billing elements, false association of the supplier with the utility, prices above the published rates, false statements implying that a customer is required to make a choice, short-term “teaser” rates that lead to marked jumps after a few months, inflated prices of green-energy products far above the incremental cost of REC purchases, and the targeting of vulnerable populations such as the elderly, non-English speaking and low-income households. The utilities, the Attorney General, the Citizens Utility Board and the ICC have received and acted upon numerous consumer complaints; however, ARES assert that the complaint number is relatively low compared to the aggregate customer number they serve, and that some of these issues have been addressed by revisions in part 412 of the administrative rules under which ARES operate.

Some stakeholders assert that analysis of the problems in the retail energy-supply market, along with vigorous enforcement of the Consumer Fraud Act and revocation of the ARES certification for suppliers found to have engaged in or operated under fraudulent marketing, must be the first steps to protect consumers and promote effective competition. The development of a healthy and consumer-friendly competitive market for DER products and services will become increasingly important as opportunities for DER deployment expand. For example, the IPA has included a detailed set of contract and disclosure requirements for community solar programs, which some stakeholders view as a useful contribution to the development of workable and effective consumer protection in other retail energy markets [67].

4.5 Pricing Options to Benefit Customers and Communities

All electricity supply is competitively sourced in Illinois, either via individual customers’ acquisition decisions, ARES contracts, municipal aggregations, hourly wholesale prices or the competitive auctions conducted by the IPA for utility default supply. Under current law and regulatory policy, large commercial and industrial customers can purchase electricity from retail providers or they can access hourly wholesale market procurement through the utility. Small commercial and residential customers have additional fixed-priced tariff-utility-supply service options, with the utility supply purchased through competitive auctions administered by the IPA. Some stakeholders advocate that utilities be required to provide a broader range of pricing options under direct ICC oversight. Another group of stakeholders is concerned that permission for utilities to offer additional options may stifle the competitive retail market.

An inherent property of electricity supply is that its costs vary as a function of time, location and several other factors. If the only goal of regulation was to achieve economically efficient production and consumption, all prices would reflect these cost factors. However, there are many other regulatory considerations including stability, fairness, predictability and affordability that
are considered in cost allocation and rate design. Ratemaking issues are further considered in the discussions of WG7.

Granular usage data made available through AMI allows customers to be provided with a price signal reflecting the fact that the cost to produce a MWh at midnight is often different than at noon. Customers operating under time-variant prices can make consumption decisions to reflect these market conditions. Illinois law requires that hourly rates for energy supply be available as an option to all customers of ComEd and Ameren Illinois, as we will discuss below.

Some stakeholders assert that when customers pay the time-varying price for electricity, they develop a better understanding of the financial and environmental impacts of their energy utilization and can choose to modify their consumption patterns accordingly. From this perspective, in addition to potentially lowering many customers’ electric bills, time-varying rates may reduce pollution and carbon dioxide emissions in systems with strong dependence on fossil fuels as raw energy sources. Moreover, such consumption decisions may improve grid resiliency and potentially increase renewable energy consumption. Other stakeholders argue, however, that many customers prefer the familiarity, certainty and simplicity of basic flat rates, despite the associated loss in economic efficiency. Because some residential customers may be unable to shift any usage to off-peak period due to characteristics of appliances in the home, medical conditions requiring use of medical devices, work and school schedules and other factors, they might be at risk of higher bills under time-varying prices.

There are two basic types of time-varying rates. One type is hourly pricing, under which supply prices are closely tied to the wholesale market prices and so have the same level of volatility as wholesale markets. Another type is time of use (TOU) rates, which are set for defined periods of consumption, such as peak, off-peak, shoulder peak and weekend and may or may not be based on actual market outcomes as opposed to forecasted prices or other regulatory considerations.

Factors precipitating potential changes in the predominance of flat volumetric pricing, include but are not limited to: new technology to increase potential customer response and benefits from time-varying rates, changes in customer-load profiles, smart-meter deployment with capability to manage rate designs and better customer understanding of potential benefits of alternative rates. We note that not all cost components such as, energy, capacity, transmission and delivery service, nor all customer classes are necessarily appropriate for TOU treatment. Rate-design options of Illinois customers are not limited to those offered by public utilities, so any discussion about the attainment of specific objectives—e.g., peak-load reduction—through rate design must explicitly consider the diversity of options available in Illinois’ competitive retail market.

Illinois is unique in that the state has a law that mandates utilities to offer customers the option of market-based hourly pricing through utility procurement from wholesale energy markets operated by either MISO for Ameren Illinois customers or PJM for ComEd customers. The law requires residential hourly pricing programs to be administered by a non-utility third party. Ameren Illinois and ComEd have selected Elevate Energy, an independent Illinois non-profit organization, as the current program manager for their respective customers. The programs are very similar and provide supply service that follows the wholesale market hourly prices but the Ameren Illinois Power Smart Pricing program uses day-ahead hourly prices, whereas the ComEd Hourly Pricing program uses hourly real-time prices. We note that the hourly pricing applies to the commodity portion of the supply only, as the participating customers pay standard tariff rates for the distribution utility delivery service.
The charges to customer to recover the hourly energy costs are assessed on an hourly kWh price basis. Customers who choose this type of supply service are also charged a peak load contribution (PLC) whose kW basis is determined during the June through September months, averaging the customer’s peak demands at the time of the five PJM system peaks. The PLC is assigned to the customer as a uniform monthly amount during the subsequent June through May bills. A dedicated website and a mobile app provide hourly pricing participants with detailed information about their energy consumption and costs, with comparisons to standard utility supply price alerts, energy-saving tips, customized annual performance reports and a personalized savings portal that displays historical and current data.

Since their inception in 2007, participants in the ComEd and Ameren Illinois residential hourly pricing programs have seen average energy cost savings of 22% and 16%, respectively, compared to the payments for the same usage on volumetric flat rates, not including any amounts saved by reduced usage in response to price signals [68]. An analysis conducted by CUB and the Environmental Defense Fund (EDF) found that 97% of residential customers will have saved money in 2016 on hourly pricing, even without modifying their usage in response to fluctuating prices [69]. This result is consistent with expectations for years in which average wholesale market prices are low, since hourly pricing can sometimes mitigate both the risk premium included in longer-term locked-in flat rates and the costs and profit margins for intermediary entities, besides the costs of the program administrator [70]. Moreover, the results to date are inconclusive for the Illinois situation because the study points out: “While the 2016 data set is large and includes a higher percentage of low-income customers than the overall service territory, it is not necessarily representative of the rural areas in the ComEd service territory. Performance of the analysis over multiple years—and with a larger number of utilities—is also necessary to further inform policy development.” Elevate Energy has calculated the average annual projected customer savings to be $86. However, hourly pricing, by design, is volatile, especially during extreme temperature periods, and historical market prices are not necessarily predictive of future prices [68].

Hourly pricing is a voluntary opt-in program that has so far attracted participation of approximately 1% of the residential customers [69]. This relatively low participation rate, despite the cost savings that will result for the vast majority of customers, appears to be the result of several factors identified by some of the stakeholders. These concerns include:

- Hourly pricing is not well-understood by customers and it takes time and attention for consumers to appreciate its potential value and understand the actions that can maximize savings
- Opt-in programs generally have far lower participation rates than opt-out default programs
- The effects of hourly pricing on overall electricity costs depend to a great extent on the customer’s load shape. To project the effect on monthly bills requires analysis that many customers may find difficult to undertake by themselves
- Hourly pricing customers are exposed to the occurrences of price spikes. High wholesale prices tend to occur in peak summer periods over brief periods of time, but occasionally can be prolonged, such as during the “polar vortex” winter of 2014 or a sequence of continuing hot days during summer; at times, price spikes occur unexpectedly
• Customers with hourly rates are also exposed to larger seasonal bill variations that may pose difficulties for some to manage, as both usage and prices are generally higher in summer months, unless they also enroll in a budget-billing program.

• Marketing of hourly pricing has been limited to areas with AMI, which will be fully deployed in the ComEd (Ameren Illinois) service territory by the end of 2018 (2019), respectively.

• Utilities were prohibited by the “Integrated Distribution Company (IDC)” rules to promote a supply service, because such service was deemed as interference with the competitive retail supply market. The provision 16-119(e) of FEJA [5] removed this prohibition through the express permission for each utility to market and promote its hourly supply pricing program [71].

The wide-ranging discussions of the WG gave rise to distinct ideas on the design, marketing and customer engagement/education efforts of hourly pricing programs. A considerable portion of the discussion focused on topics of interest that require considerable further analysis to assess their relative merits, pros and cons for Illinois. We collected a set of representative ideas in the discussions to create the list below. The listed ideas do not necessarily reflect agreement by other WG members, and the selection is intended to reflect the broad range of issues discussed. The list is not intended to be exhaustive, is not in any prioritized order and includes the following ideas:

• Shadow billing by the utilities is suggested by some stakeholders to show the effect of hourly pricing on the monthly bill of a customer via a direct comparison to costs under hourly pricing or other optional rate plans. Concerns arose that ARES might object to such a scheme unless they have access to the necessary data to offer such a comparison; such access will raise various data-privacy issues.

• Reduction in Monthly Bill Volatility: The fact that some customers are deterred from selecting the hourly pricing option due to the associated monthly bill variability was cited by some stakeholders as a key issue. Notwithstanding the fact that hourly-pricing customers are eligible for budget billing programs, some stakeholders suggest that utilities need to provide information about potential savings from the hourly programs when marketing budget billing programs.

• Savings Guarantee Pilot: Some stakeholders suggest a focused pilot program to introduce a cluster of selected customers to hourly pricing with guaranteed savings over flat rates and to assess the customer response and results. Such a pilot program may give useful insights into effective ways to encourage customers to select the hourly pricing option.

• Hourly Rates Variability Collar: The implementation of the hourly pricing option can be accompanied by an “insurance” program to mitigate occasional price spikes in hourly rates through the creation of a limited range within which the hourly prices may vary. Any costs incurred to maintain prices within the range will be paid through a small volumetric charge to participating customers.

• AMI Data Provision to ARES: Some stakeholders suggest that customer AMI data need to be shared with competitive suppliers so as to allow ARES to offer innovative hourly-rate programs to customers. However, individual customer data is allowed to be shared with third parties only after authorization by the customer and any data-access initiatives will need to comply with data privacy laws.
Illinois’ unique hourly pricing programs need to be continually reviewed and ideas for expanding and improving them must be carefully evaluated by state regulators and stakeholders.

A less volatile time-varying rate alternative to hourly pricing involves setting fixed daily periods with specified, differentiated prices reflecting the higher market energy costs on-peak and lower costs off-peak. This TOU pricing can reward participating customers who modify their usage behavior to achieve a flatter load shape. TOU rates are predictable, which may be a preferred alternative to hourly rates for many customers. The introduction of utility TOU rates requires regulators to consider their costs and benefits and their impacts on retail markets and electricity consumption, as well as the environmental implications. Moreover, any impediments of the ability of ARES to provide TOU pricing need to be carefully examined. Key factors to be considered in TOU rate design include the following:

- pricing-period definitions, including how many periods, whether fluctuating on an annual or a seasonal basis and their distinctions, which may include peak, off-peak, shoulder-peak, super-peak and weekend
- rate-structure design and price differentiation, with fixed prices or fixed ratios of such prices across the defined periods
- guidelines for price variance across periods to meet consumption, environmental and efficiency objectives
- range of application, inclusion or exclusion of all or a portion of delivery service costs under TOU prices
- cost basis for each service and supply element
- rate design to address potential cross-subsidization within a TOU program
- procurement plan design and frequency to acquire resources to serve TOU customers
- risk management options for TOU service provision

These and other issues will need to be carefully evaluated in the implementation of TOU programs.

The WG4 discussions gave participants the opportunity to air various ideas on TOU pricing matters. We collected a set of representative ideas from participating stakeholders to create the list below. The listed ideas do not necessarily reflect agreement by other WG members and the selection is intended to reflect the broad range of issues discussed. The list is not intended to be exhaustive, is not in any prioritized order and includes the following items:

- Establishment of utility-provided optional TOU rates through ICC proceedings to give customers broader choice: such offerings may require a change or waiver of the IDC rules or may involve legislative action.
- Data issues in TOU design and implementation: analysis of load shapes, demographic and other characteristics of customers who opt for TOU rates and those who do not; performance measurement and evaluation by the utility and independent third parties to assess TOU effects for each utility.
- TOU design proposal: one specific rate structure proposal was an expansion of the hourly pricing program to include a TOU option with fixed-price ratios among the defined periods. A key issue in setting the ratios will be the level of dependence on wholesale market prices, as opposed to setting price ratios at levels intended to modify load shapes.
- Design of pilot programs for customers with diverse behind-the-meter devices to determine which options may benefit consumers: For example, a specific study may investigate both TOU and hourly pricing options for customers with devices such as a simple price display, a disaggregated usage display and a price-responsive thermostat and compare performance against a control group without an in-home device. Similar pilot programs can be launched to study the load shapes and demographic characteristics of customers who are “structural” winners or losers under different TOU rate structures. These pilots can help regulators to formulate policies for risk management in TOU design.
- Shadow-billing provision: Some stakeholders want utilities to provide shadow bills to customers on TOU and on hourly pricing to permit customers to compare the effects on bills of different pricing options.
- Consumer education and training: Some stakeholders advocate that utilities employ tools such as home-energy reports and usage analyses to inform customers about changes in their electricity consumption after they choose a new pricing option. Efforts to improve program design may include research methods such as focus groups.
- TOU participation incentive program: the introduction of TOU options may be accompanied by the provision of guarantees to customers in the first year of a TOU program to incur costs that do not exceed the previous flat rates.

These TOU policy issues are crosscutting with the WG7 discussions and the reader is encouraged to examine their report presented in Chapter 7.

4.6 Market Transformation

Market transformation (MT) efforts entail the formulation of targeted strategies to accelerate the customers’ adoption of new technologies, reduce costs of their acquisition and manage initial market barriers. The goal of MT is to ultimately change consumer transactional behavior so that a market becomes self-sustaining. Examples of MT strategies in the electricity sector include programs and incentives in some states—outside Illinois—to promote electric-vehicle early adoption. In Illinois, peak-time rebate programs that educate customers about the money-saving benefits of peak-energy usage reduction are an initial part of an energy-market transformation effort, as are the various efficiency programs introducing consumers to new products and energy-saving methods.

Once a transformed energy market is established, the market barriers disappear and customer-participation incentives are unnecessary. The ComEd Marketplace, an online store in which customers can purchase discounted energy efficiency and AMI-enabled devices, has received ICC approval for cost recovery in a contested proceeding, in part as a component of the company’s consumer education and market-transformation efforts [72]. This matter is also under litigation in the 2018 rate proceedings. In its first year of operation, the Marketplace had 700,000 visitors and issued $2 million in rebates.

The WG4 discussions gave the participants the opportunity to present various ideas on policy issues on MT matters. We collected a set of representative ideas from the participating stakeholders in these discussions to create the list below. The listed ideas do not necessarily reflect agreement by other WG members and the selection is intended to reflect the broad range of issues aired. The list is not intended to be exhaustive, is not in any prioritized order and includes the following items:
• Learnings from the ComEd Marketplace experience: investigation of the specific customer segments that are accessing the Marketplace and the feasibility of expanding it
• Specific customer segments that are accessing the Marketplace and the feasibility of expanding its educational program offerings to include underserved communities that may lag behind in adopting smart- and energy-efficient products
• Support MT in energy efficiency or EE through the creation of an appropriate EE scoring system: as consumer products have useful multi-year lifetimes—as high as 10 to 20 years for many major domestic appliances, HVAC equipment and LEDs—purchases of inefficient products are costly to customers over their lifetimes, even if the initial investment costs are below EE products. Considerable data and analytics are accessible to make EE issues transparent to inform consumer choices. Some stakeholders articulated the notion that market transparency reduces and potentially eliminates the need for mass market efficiency incentives and can be achieved through a utility information site with a 0 to 100 EE index associated with every marketed electric device from appliances to EVs. Some stakeholders suggest that every marketplace enhancement be compatible with the ICC-approved consumer education and market transformation programs
• Additional EE index score utilization: for example, EE scores may be deployed as part of a PAYS® cost-benefit analysis to identify projects and products that produce a robust payback for consumers.

All these issues require further evaluation, as market transformation is key to long-term achievement of state energy objectives.

4.7 Participation by Customers and Communities in DER Opportunities

As described and discussed in Chapter 1, effective DER deployment has the potential to deliver social, individual, environmental and grid-system benefits. The benefits may be maximized through cooperation among customers, utilities and third-party providers, and facilitated by supportive laws and appropriate regulatory policies. Some stakeholders assert that DER developers need policy certainty to ensure economic value of long-term investments, just as utilities need assurances of full and fair recovery of fixed-grid costs. The ICC has initiated a separate workshop process outside that of the NextGrid study, in which stakeholders are examining DER valuation and related policy [73]. In this section we provide a brief overview of several technology categories available in Illinois and subject to new law and policy. We note that there exist other DER technologies, entailing different challenges and opportunities that may be brought to the Illinois market.

Photovoltaic (PV) installations and solar energy production in Illinois are poised to increase due to the marked reductions in their costs and the significant support provided under FEJA [5.] Specifically, FEJA provisions specify three approaches to transform the Illinois solar market:

• Community solar programs to allow residential and commercial customers to participate in solar energy even without the installation of solar panels at their homes or businesses: Such larger projects can benefit from economies of scale that make them more economic than smaller residential rooftop arrays.
• Adjustable Block Program to provide upfront payments to solar owners for long-term REC contracts: Such a program adds certainty to the amount of benefits and reduces the initial capital investment.

• “Solar for All” to bring distributed generation to low-income communities: With initial funding of approximately $150 million from existing Renewable Energy Resource Funds, this initiative ensures that at least 50% of the solar energy produced is credited to project participants in the form of monthly bill reductions.

These programs are described in detail in the IPA Long-Term Renewable Resources Procurement Plan as approved by the ICC [67]. When fully implemented, solar power capacity in Illinois is projected to grow as much as 50-fold, perhaps to 3,000 MW by 2030. As costs of solar continue to decline, market forces can push the total considerably higher, particularly in projects that combine solar with distributed storage resources that are seeing continued price declines.

While many current utility customers are interested in solar energy, they do not understand its ramifications for both their energy experience and resulting electricity bills. Given that investing in rooftop solar or participation in community solar is an unfamiliar experience, customers and communities need both trustworthy information sources and reasonable consumer protections.

In preparation for the impending solar growth in Illinois, ComEd, Ameren Illinois, solar suppliers and other entities are developing materials and tools for customers to become sufficiently well-informed and aware to allow them to make solar choices with confidence. ComEd’s “Digital Solar Toolkit” is planned to include a calculator for customers to project the financial implications of home solar arrays, educational information about what to expect from the solar developer and the utility during installation and, once operations begin, an online energy dashboard to provide individualized information about outputs, credits and other metrics of interest. Solar developers are to be provided tools for interaction with the utility and management of interconnection requests for their customers. Similarly, Ameren Illinois is adding detailed solar information to its website and is developing customer tools intended to create seamless solar connectivity.

Some stakeholders caution that savings from rooftop solar are not guaranteed by providers and can be lower than projected, while costs may be higher. Installation agreements and contracts may be opaque to many customers and the included financing costs for the installation may not be explicitly disclosed. The Illinois solar market is at present in its infancy and consumers need to become equipped with the tools to understand their options so as to make choices that meet their needs and aspirations.

Many customers cannot have their own solar installation due to a range of barriers, including lack of ownership or access to a rooftop, inability to take on new debt, shade of other buildings or trees, or a structure without a rooftop angled in the correct direction for cost-effective solar power generation. These issues are drivers of community solar developments that provide solar access to all interested parties.

The WG4 discussions gave the participants the opportunity to present various suggestions on solar initiatives. We collected a set of representative ideas from the participating stakeholders in these discussions to create the list below. The listed ideas do not necessarily reflect agreement by other WG members and the selection is intended to reflect the broad range of issues aired. The list is not intended to be exhaustive and is not in any prioritized order. Among the suggestions presented are the following:
• Some stakeholders advocate changes in state solar policies to encourage wider participation by public buildings and not-for-profit institutions. Suggested examples of ways to achieve this include, but are not limited to, technical assistance programs to navigate project planning and budgeting, publicizing annual budgets for solar renewable energy (SREC) certificates categories and publicizing timelines for funding announcements and project submission deadlines as applicable. Additional suggestions focused on creating innovative financing options, such as energy-savings performance contracts as appropriate vehicles for public agencies.

• Numerous large governmental agencies have sizeable rooftop spaces, open areas and electric loads that make them good candidates for solar installations. However, their lack of administrative support, budget and required capital planning flexibility to navigate the development of a successful project forms a barrier not easily overcome. Timely availability of published SREC incentive levels and mechanisms to reduce uncertainty of SREC incentives for such non-profit and public facilities may enable them to install more solar arrays.

• Some stakeholders assert that utility-scale solar will be a more fruitful focus of solar expansion efforts in light of the better returns on investment than those for smaller-scale distributed solar and the avoidance of behind-the-meter operational issues associated with individual customer solar systems.

• Some stakeholders suggest that utility customer-education efforts must be expanded to include training on deploying tools to help customers calculate their solar installations costs and benefits and on key considerations when purchasing solar equipment, as well as provision of correct information to help solar customers understand how to maximize their solar benefits and change their consumption patterns in ways that minimize their net energy costs.

These suggestions raise important issues for state policy makers to consider as they focus on initiatives to push toward deeper penetration of solar resources.

Small-scale solar installations in Illinois are at present eligible for net metering, under which the full retail rate is credited to the customer for each solar kwh generated. Under FEJA, when net-metered enrollment reaches 5% of the utility’s peak demand, net-metering will be phased out for delivery services. Solar producers will then receive market-based payment for solar energy and will be credited for the value of solar to the distribution system as determined by the ICC. While the current solar value is specified by FEJA, future methodology to value solar generation is the subject of some future ICC proceedings. FEJA stipulates that the ICC’s investigation “shall include diverse sets of stakeholders, calculations for valuing distributed energy resource benefits to the grid based on best practices and assessments of present and future technological capabilities of distributed energy resources.” (220 ILCS 5/16-107.6(e)) [71]. Issues related to the value of solar and other distributed energy resource outputs is a subject that received attention in various WG meetings, including WGs 1, 6 and 7.

Consumer-protection measures applicable to solar programs are contained in Part 412 administrative rules and in the ICC-approved IPA Long Term Renewable Resource Plan. Some stakeholders assert that these provisions can be a starting point for similar measures to apply to other DERs marketed to residential customers. The Resource Plan includes provisions for the following matters:

• Approval of vendors and vendor requirements, such as annual reports
• Information about the relationship between the end customer, the installer/developer and the approved vendor
• Contract requirements and standard disclosure forms
• Marketing standards, based on existing Part 412 ARES rules
• Cancellation rights
• Prohibition on any loans being secured by a participant’s home
• Prohibition on prepayment penalties
• Consumer complaint hotline, monitoring and reporting

While some vendors may view these requirements as onerous, many stakeholders believe that experience has demonstrated the necessity of strong consumer-protection measures in retail markets for energy products and services.

4.8 Energy Efficiency

Energy efficiency—driven by improved technology, appliance standards, market demand, regulatory mandates and utility programs—has played a role in keeping overall usage flat or declining in recent years. Illinois has had customer-funded EE programs run by the state of Illinois since 2008, and they have operated with input from the Stakeholder Advisory Group, which was created under statutory authority to provide input into EE program development and operation. Under FEJA, investment in EE increases to more than $400 million and program design is consolidated with utilities’ capital investment and earns a rate of return. Utility EE programs are subject to performance metrics which can increase or decrease the return on equity for these investments [74]. Large industrial customers with peak demand in excess of 10MW were exempted from paying for EE after they successfully argued that they were not adequately served under the statutory EE programs and they have economic incentives and opportunities to make their own cost-effective EE investments.

The WG4 discussions gave the participants the opportunity to present various ideas on policy issues on solar issues. We collected a set of representative ideas from the participating stakeholders in these discussions to create the list below. The listed ideas do not necessarily reflect agreement by other WG members and the selection is intended to reflect the broad range of issues aired. The list is not intended to be exhaustive, is not in any prioritized order, and includes the following items:

• EE/DER Individual and Community Donations: A structured program to allow individual customers to share their kilowatt-hour savings from energy efficiency programs, credits from peak-time rebate programs or generated energy from investments in DER. For example, an individual who saves 10 kWh from an energy efficiency investment may choose to pass such savings along to another customer or community organization or donate to a pool to benefit LMI customers. Members of a community solar program may choose to donate their generation credits to the host site, such as a house of worship, or share those credits with others.

• Peer-to-Peer Exchange: The proposal is to design and implement pilot programs to allow customers to capture additional financial value from their assets via sales of the RECs or the generated kWh to interested third parties such as corporations, local governments, individuals and/or non-profits. An initial pilot program can begin with assets tradeable between peers, such as the RECs associated with EE measures.
• EE Opt-in by Large Customers: FEJA exempted very large customers, whose loads exceed 10 MW, from specific provisions of the Public Utilities Act related to EE (220 ILCS 5/8-103B(l)). Some large hospitals and university campuses and perhaps other public institutions were also covered by the blanket exemption but may wish to participate in EE programs. Some stakeholders suggested that one remedy may be to permit large users to opt into the utility efficiency programs. A change in this policy may require revision of 220 ILCS 5/8-103(B) and possibly other provisions of the PUA, as well as notice for modification of the utilities’ EE program portfolios.

• Program Coordination: The suggestion is to explore opportunities for further collaboration among utility and government hardship and assistance programs and coordinate or integrate them with EE programming to bring efficiency opportunities to those who need them most.

• EE Integration with Basic Utility Service: FEJA makes EE programs and customer operations more integrated segments to a utility, notwithstanding that utilities are generally structured to deliver their outputs as separate products. A stakeholder proposal aims to align the customer-experience expectation with the value proposition to the utility customer, the utility and any third-party service provider. For example, if a customer receives an efficiency benefit through a program, the program provider is compensated to the degree that it reduces ratepayer costs, and doesn’t increase the burden on the customer or the utility.

• Provision of a Uniform Benefit Structure: This idea aims to enable a third party to provide more efficient program delivery that takes advantage of the provider’s ability to offer expanded features. The feasibility of this idea is based on allowing the third party to increase its revenues without duplicating effort or providing a separate customer experience. The value of this idea is under study by the Illinois Energy Efficiency Stakeholder Advisory Group [75].

• Innovative financing: Programs such as PAYS® (Pay As You Save), under which financing is provided to customers and paid on their monthly utility bills for energy improvements that produce net bill savings, can enable customers to benefit from energy improvements with no capital contribution and to overcome any barriers to installing EE measures. The launch of such a program may require legislative authorization.

This list provides a basis for examination in greater depth of next steps for Illinois to take toward maximizing its energy efficiency.

4.9 Electric Energy Storage (Thermal, Battery)

Cost-effective electricity storage can help balance system loads and save energy generated off peak for future use. Storage allows clean power sources with zero fuel costs but variable output—like wind and solar—to generate energy without limitation and for customers to use it whenever needed.

Batteries are a form of distributed energy storage that can be used to support the grid and can defer or avoid infrastructure investment to address congestion. In some locations, grid-scale battery storage is already competing with natural gas plants to serve peak loads under certain conditions [76]. Other technologies such as fuel cells may provide alternative or complementary energy-storage services. Energy storage can also serve as a backup power source to prevent or recover
from outages. Well-integrated energy storage can make the grid more stable, flexible and efficient. Whether it can be deployed cost-effectively as a component of utility operational strategy is the subject of ICC scrutiny in pilot proposals by ComEd.

Storage is a unique DER, because it alternates between being an energy source and a system load, sometimes very quickly. This can entail operational challenges. Because it can support the delivery system in various ways, storage combines characteristics of supply, demand and system-operating technologies, and is not considered simply a form of distributed generation.

Storage, when appropriately paired with renewable generation sources, can be deployed at scale and sited with flexibility. Eventually that may be in a consumer’s basement or closet (and car) if present declining cost trends continue. Forecasters agree that the storage cost will continue to decline as production volume increases and technology improves. Bloomberg New Energy Finance projects battery prices at less than one-third of today’s cost within a decade [15]. As costs come down, storage combined with utility-scale solar will also become increasingly attractive as complementary DER. We note that batteries carry a risk of toxic gas emissions when damaged and that core ingredients such as lithium and cobalt are finite and extraction can lead to water pollution and depletion as associated environmental consequences. Processes for the collection, recycling and disposal of used battery management are critical as battery storage deployment becomes more widespread.

Stakeholders have different views on the appropriate role, if any, for utilities in the owning and operating of storage facilities, an important topic for public policy discussions as the deployment of cost-effective energy storage resources grows. Some stakeholders assert that utility-owned storage can be a customer-beneficial addition to the tools available for grid management. Some argue that it should be a third-party function, with the utility making available location-based grid costs to non-utility storage developers so they can deploy storage systems based on grid needs and thus reduce customer costs.

Cost-effective energy-storage deployment has many potential benefits but also raises new issues for tomorrow’s grid. A customer with on-site self-generation together with a storage resource may use far less grid-provided electricity. In theory, with adequate on-site storage and generation capacity, a customer can entirely disconnect from the grid. This occurs rarely today, because such electricity isolation not only incurs extensive investment costs but is attendant with major risks. However, some stakeholders project that if the savings over grid-provided electricity become sufficiently large, “grid defection” can become a viable customer choice.

There are many reasons why such an outcome is unlikely, including the significant value of a customer to be connected to the grid—not just for service resiliency, backup power and economic efficiency, but also for the critical ability to undertake transactions over the network. A healthy, reliable, accessible and affordable grid will remain essential, and many customers will remain grid-connected, either by choice or necessity. However, the potential for grid defection highlights the need for careful future ratemaking—a topic examined in detail in Chapter 7—and raises questions about whether regulation needs to address the opportunity for customers to transition “off-grid,” the utilities’ response to customers bypassing their delivery grid, and whether non-bypassable stranded-system cost assessments warrant consideration. Some stakeholders believe that a crucial future public goal is to create an environment in which all customers, whether or not they are grid-connected, can thrive.
Jurisdictional and regulatory issues on energy storage are evolving as its deployment becomes more widespread. Some stakeholders assert that all DERs are subject to either ICC or FERC oversight and that batteries must be treated as generation for purposes of interconnection. They recommend that the ICC creates a definition ensuring that lower voltage facilities that qualify under the FERC “seven factors test” are deemed to be transmission. However, as there is better understanding of the unique physical and operational characteristics of storage, there is wider acceptance that storage resources are neither “demand” nor “supply” resources and must be recognized as a distinct resource class. FERC Order 841, issued in February 2018, marks a major milestone in this recognition. Some stakeholders also recommend that the ICC examine issues of tax treatment of revenues from DER interconnection. Some stakeholders further recommend that the ICC consider whether there are circumstances under which customers may be allowed to self-build distribution-system upgrades and interconnection facilities, that comply with the utility’s interconnection requirements.

4.10 Demand Response

We use the term demand response (DR) to refer to load curtailments in response to requests to provide such curtailments, typically driven by pricing, system-loading conditions or some other circumstances. There are various technologies introduced for DR, as discussed in Chapter 1. A DR action results in a load modification on the customer’s side of the meter. Such an action is carried out via centralized direct load control (DLC) by a third party such as the utility or an aggregator, or can be automatically driven by a behind-the-meter device such as a smart thermostat or by a software applet in response to price signals or by manual device disconnection in response to an alert or other message.

DR results in customer benefits through consumption savings, environmental benefits through emission reductions and system benefits through increased efficiency and lower peaks. Various utility DR programs operating in Illinois allow customers to monetize usage reductions during peak events. These include DLC programs under which the utility turns air-conditioning down or off during critical peaks and participating customers receive a flat seasonal fee and peak time rebates under which customers who voluntarily reduce usage during peak events are paid a per/kWh fee. DR can reduce the utilization of gas-peaker plants and competes side-by-side with supply resources in competitive wholesale markets. As every DR load reduction of a specified MW receives compensation at the locational marginal price at the curtailment node, in effect, a DR curtailment receives the same payment as if that specified MW were supplied by a generator during the same period. Such compensation motivates competitive energy providers to offer DR programs, including aggregating participating customer loads.

DR provides system operators with a flexible tool to reduce peak loads and smooth imbalances between supply and demand. DR may be combined with other DERs, including storage resources, to be a component of a “virtual power plant,” that may be dispatched as a large single resource, with considerably faster response times than a conventional plant. However, DR is a voluntary service offered by end-users, and to have capacity value as a resource it must always be available when called upon by system operators.

The WG4 discussions gave participants the opportunity to present various suggestions to enhance and actualize the DR customer and community value. We collected a set of representative ideas to create the list below. The listed ideas do not necessarily reflect agreement by other WG members.
and the selection is intended to present the broad range of issues aired. The list is not intended to be exhaustive, nor in any prioritized order and includes the following ideas:

- **Distribution business model modification to accommodate peer-to-peer transactions among customers:** Customers can maximize their DER value, including energy storage and flexible demand through creating transactive energy markets at the distribution network level. Such a modification may require legislation, in addition to regulatory action and utility investment. This topic was also discussed in the deliberations of WGs 1, 5 and 7 and readers are referred to the respective chapters of those WGs. Some stakeholders assert that, at minimum, large customers need to be allowed to directly access DR markets rather than be required to use other entities for that purpose.

- **Study of peer-to-peer carbon-trading market mechanisms:** Some stakeholders suggest that the ICC and utilities together explore market mechanisms to allow individual customers to trade credits or similar certificates associated with carbon-free generation to bring about reductions in CO₂ emissions in Illinois. These stakeholders advocate pilot programs for Illinois.

- **Investigation of blockchain technology applications:** Blockchain technology used to maintain distributed ledgers of facts and a history of updates and transactions has received considerable attention in many economic sectors. Blockchain can provide near real-time records of transactions among all participants and reduce or eliminate the need for trading intermediaries, which makes possible the effective management of very large volumes of very small transactions. While the deployment of blockchain and associated operating technologies in energy transactions has been demonstrated in some energy areas, some stakeholders think it may have the capability to identify participating DERs on the network, determine those resources’ contributions to energy management activities and establish the value of those contributions. Other stakeholders assert that while blockchain enables data-blocks and information to be stored and used—a potential attribute application in energy transactions—the determination of DERs and their contribution to energy management requires many additional complex applications to function. Given the blockchain potential, it may be an appropriate issue for workshops to explore, examine specific use cases for this technology and, if warranted, formulate pilot programs to test its usefulness in energy transactions.

- **Expansion of utility DR programs:** Some stakeholders suggest that utility DLC air-conditioning programs can be augmented through the performance of pilot programs focused on other appliances, such as water heaters.

- **Some stakeholders suggest that new market structures such as PAYS®—a form of on-bill financing, as discussed above for EE—can also lower barriers to participation by customers in DR.**

- **Pilot DR program for EVs:** Some stakeholders forecast that there will soon be sufficient market penetration by EVs to launch a pilot program to test various managed charging alternatives so as to develop insights into cost-effective strategies in EV charging.
The success to date of DR deployment makes clear that the DR will be an important future resource. As such, these ideas will need to be investigated to determine which are most advantageous to implement in Illinois.

4.11 DER Ownership

DER has significant value, but there are many challenges/barriers to overcome in its acquisition by all customers. Some stakeholders assert that a key barrier for many customers to acquire DER is not just their lack of technology information that can benefit them, but lack of access to capital for these investments. Another challenge is that the payback period for customer-installed DER may be longer than the anticipated residency in the home. A key barrier for renters is the fact that they do not own the premises and landlords may have limited incentives to install DER. Also, customers may not have sufficient disposable income to pay even modest up-front costs, they may not trust vendors’ promises of net savings, and they may not be willing or able to take on debt.

The WG4 discussions gave the participating stakeholders the opportunity to present various options on the topic of DER acquisition. We collected a set of representative ideas to create the list below. These ideas do not necessarily reflect agreement by other WG members and the selection is intended to indicate the broad range of issues aired. The list is not intended to be exhaustive, nor in any prioritized order and includes the following ideas:

- **On-Bill Finance Expansion:** Utility long-term on-bill financing (OBF) programs have effectively helped customers to manage up-front costs of energy efficiency upgrades. But they have been limited to a budget that can serve only a small number of customers. Some stakeholders wish to see OBF expanded to multi-unit buildings. Other stakeholders support expansion of the OBF scale and scope to include DERs, with financing terms explicitly related to the lifetimes of different types of cost-effective DERs, allowing for immediate bill savings. However, other stakeholders oppose the use of utility bills for DER financing because of the potential for higher bills to lead to increased disconnection risk.

- **Broader deployment of OBF:** In addition to the incorporation of DERs, some stakeholders suggest that OBF may be expanded to apply to other services, such as water conservation. In this way, the OBF assistance with water-conservation measures can bring awareness to the energy finance opportunity of those customers who may not otherwise engage with energy utilities and make OBF more cost-effective than offers of separate programs. OBF expansion and the deployment of new financing tools such as PAYS® requires changes to 220 ILCS 5-16/111.7 (electric) and 220 ILCS 5-19/140 (gas).

- **The investigation of long-term financing methods such as PACE:** Where the costs of investment in energy upgrades remain with the building upon an ownership change is warranted to assess how they help address the limited residency challenge [77]. PACE financing on residential buildings, however, is controversial because a lien may be placed on the property when the customer falls behind on payments. Stakeholders noted that DER financing methods may require legislative authorization.

- **Competitive providers are beginning to address DER financing.** For example, there are solar business models based on financing installations and paying for them with revenues from sales of the energy generated and solar RECs produced, in addition to any tax credits or other regional government support/incentives.
• Program integration: Some stakeholders assert that current energy-efficiency programs and renewable-energy programs operate in silos, in order to incentivize specific technology deployment or programs limited in scope, with no overlap in marketing, incentives, or economic impacts. They recommend these programs be integrated by utilities to increase efficiencies and produce larger impacts.

• Community energy planning: one proposal is to develop a new community energy plan (CEP) model to integrate EE, DERs and other energy programs. The intent is to enable communities to organize energy initiatives on a local scale, layering energy efficiency, distributed generation, resiliency, workforce-development programs and associated program incentives. The new CEP model can allow communities to chart energy paths that best meet their specific needs and enable wider participation by residents and small businesses. For example, communities can target shared infrastructure to support transportation electrification and serve other community needs by DER siting at targeted geographic areas, so as to produce complementary benefits, such as a community solar project combined with housing retrofit and workforce development initiatives. However, the costs of CEP and how they are covered remain to be determined.

• Utility planning expansion: Some stakeholders propose that utility system planning be expanded to include coordination with non-utility DER planning activities, through an integrated distribution planning (IDP) process. IDP will broaden system planning to include additional stakeholders in an effort to target DER growth to locations at which it can provide the most value for customers with reduced system costs.

• Resiliency and operational considerations: Explicit reliance on unregulated and uncommitted assets for the distribution grid raises new resiliency and operational challenges. Because utilities have statutory responsibility to ensure safety, resiliency and system security, they require situational awareness of the entire grid, including DERs status and operational data and their system impacts. Utilities assert that they are well-positioned to coordinate planning and operations/dispatch/control of customer and other third-party DERs, as they already accommodate emerging technologies and provide enhanced transparency through hosting capacity analysis and mapping, interconnection processes and other related efforts. From the utility viewpoint, understanding DERs and enhancing their system value is a contribution to system planning that does not require wholesale changes to the planning process. Additional discussion on IDP is found in Chapter 1.

• Creation of distribution network maps: some stakeholders recommend that utilities create maps that show the sites where solar and other DERs of various sizes are best located to benefit the system, based on distribution-grid congestion and system-dynamics considerations. Such maps can help target locations for community solar projects and can be combined with regional incentives.

As the trend continues toward increased deployment of DERs, including energy storage, policy formulation in this area will be of utmost importance. The careful consideration of the issues above and other relevant ideas will be critical to establishing appropriate policy directions to enable DER to flourish in Illinois.
4.12 Transportation Electrification

Many stakeholders assert that transportation electrification (TE)—a topic also discussed in detail by WG1—entails enormous potential benefits for customers and communities and, therefore, needs to be supported through appropriate public policies and initiatives. Undoubtedly, TE and electrification of other sectors are likely to be components of any federal, state or local plans for carbon-emission reduction. Those who favor public policy support of TE argue that, in addition to the high performance, low operating costs, environmental benefits and other characteristics that are gaining electric vehicles (EV) a foothold in the automobile market, EV charging can improve the utility system load shape, bring about more efficient utilization of utility assets, create new sources of flexible resources for supply-demand balance, enhance customer resiliency and utilize renewable energy more effectively. Other stakeholders emphasize that the impacts of deeper EV market penetration on utility systems, customers and communities are by and large not known. They observe that at this early stage of EV market development, the rate at which consumers will embrace EVs in larger numbers and the specific types of EVs they will purchase—battery-only vehicles or plug-in hybrid vehicles, which have auxiliary gasoline engines for extended trips—remains uncertain. Electric vehicles are beginning to make inroads in many sectors including government and private fleets, buses and long-distance trucking. For utilities, TE represents a potential to stop the declines in demand that they have experienced since the onset of the financial crisis in 2008.

The charging of personal EVs may spur substantial growth in residential energy usage. Time-variant rates and managed charging programs can ensure that charging occurs primarily during overnight and off-peak periods, without incurring significant utility investment in new distribution infrastructure. Increased electricity sales during night-time and off-peak hours allow the utility’s fixed costs to be spread over a greater volume of energy, resulting in downward pressure on the rates of all customers, including those who don’t have EVs. However, the lack of existing public-charging infrastructure combined with the “range anxiety” of potential EV buyers is an issue that poses an obstacle to mass-market EV adoption.

Much of the discussion around policy to promote EV growth has centered on the need for public support of electric vehicle supply equipment (EVSE), particularly direct-current fast-charging (DCFC) which is essential to high market penetration of electric-only vehicles. Key issues have emerged about the roles of private market providers and public utilities, criteria for sizing and locating charging stations, regulatory policy and oversight, rate-design options for charging services and many other related matters. Because of the environmental and potential system benefits of EVs, policies and programs to address barriers to EV adoption must be the subject of comprehensive investigation by policy makers. We note that the ICC has held policy sessions and initiated a Notice of Inquiry in 2018 to begin to consider a range of issues associated with EV growth and charging infrastructure.

We also note that the continued developments of fuel cells and hydrogen as a fuel may provide an alternative or complementary technology pathway for transportation in the future, but their adoption has received considerably less attention than TE.

In addition to issues surrounding charging infrastructure, numerous policy matters and stakeholder proposals were discussed in the WG deliberations. We collected a set of representative ideas from the participating stakeholders on other aspects of TE to create the list below. The listed ideas do not necessarily reflect agreement by other WG members and the selection is intended to reflect the
broad range of issues aired. The list is not intended to be exhaustive, is not in any prioritized order and includes the following stakeholder recommendations:

- Targeted marketing of hourly pricing and other TOU rate structures to EV owners accompanied by training of auto dealers with onsite information and enrollment materials.
- Implementation of TOU rates that apply only to the EV-charging portion of household usage: The additional expense of a second meter can be avoided by using the charger itself to measure consumption, or employment of a module, or application of disaggregation software to calculate EV energy usage.
- Smart-charging pilots under which a utility will modulate charging among participating vehicles to optimize loads based on real-time variables to prevent ramping or neighborhood peak issues, coordinate with renewable energy output, optimize local load shape and use aggregated EV loads as DR resources. EV DR may also be done by non-utility aggregators as is being piloted in California, and the added value, if any, of having a third party involved may be examined [78].
- A study of workplace charging is advisable to assess its suitability for combination with solar-energy deployment. While today in Illinois, sunny afternoons are generally peak periods when new loads will not be beneficial, if solar power penetration ever reaches a similar level to that seen in parts of California, support for workplace charging might provide system and public benefits.
- Multi-unit buildings with parking lots pose particular challenges for EV charging because the combined load of many cars charging simultaneously can stress a building’s electricity circuits. There is a need to investigate strategies to deal with the many possible technical solutions and billing alternatives for building owners, property managers, homeowners associations and the utility. All customers have an interest in avoiding costly distribution system upgrades, as those eventually result in higher delivery charges. The discussions raised questions of whether utility support and regulatory involvement in EVSE at large buildings may be beneficial. Some stakeholders project that whether a tenant or owner in a multi-unit building has a right to plug in an electric vehicle or install EVSE, or whether these decisions should be left to private discretion and market forces, is a public policy issue.
- The utilization of street lights as a public charging option may create viable opportunities for the many potential EV owners without a garage or access to electricity in their parking spot. Existing street lights are often adjacent to parked cars, where Level 1 charging may be installed on poles. With the shift to more efficient LED streetlights, there may be adequate existing capacity to accommodate EV charging at low power. A complication arises from the fact that street lights are usually charged on a separate utility rate structure or provided free to a municipality and recovered through a franchise fee. The ICC has the ability to study these rate structures and franchise agreements to determine whether there exists an opportunity for a cost-effective new option to support TE.
- The launch of a training and education program for customers about the benefits of EVs can empower them to make energy-informed purchase decisions with respect to vehicle choice and home charging infrastructure. In this way, utilities can promote market transparency and transformation to enable customers to compare vehicles and other options based on their energy cost merits.
• The need for EVSE coordination was suggested by some stakeholders with a recommendation that utilities create publicly available maps or mapping tools that indicate where grid infrastructure is sufficient for EV-charging facilities. Such information allows EV charging-station hosts to estimate necessary infrastructure upgrade costs by location, to effectively site and plan new station costs. Moreover, such a coordinated effort can track planned installations so that multiple hosts can coordinate their efforts.

• Some stakeholders suggested the modification of class definitions to support TE. They recommend that the ICC define a new class for public-transit electric-bus fleets to create the analogue of the “railroad”-rate class for public-transit electric-rail fleets. The railroad-rate class has historically received a discounted demand charge—the so-called “distribution facilities charge”—in part based on the fact that electric-rail transit service provides public benefits, because it is an affordable, low-emissions transportation mode that encourages compact development. Since public-transit electric-bus fleets provide similar benefits, there is a well-established rationale for this suggestion. This extension can be further broadened to other public fleets, such as school buses or emergency-response vehicles. As in other rate-class considerations, cost causality and allocation are regulatory issues. This matter is further addressed in Chapter 7.

• Deployment of public-bus electrification is one way to bring TE benefits to LMI communities. Such a TE initiative also advances the cause of environmental justice in communities that are adjacent to major sources of pollution. In the same vein, the pursuit of other strategies, such as EV car-sharing programs in LMI neighborhoods, was also suggested.

4.13 Low- and Moderate-Income Customers and Community Issues

Many LMI households struggle to pay their utility bills. LMI utility customers are defined as those households with annual income below 200% of the federal poverty level of $24,300 (in 2014) or 80% of the annual median income, which in Illinois is $60,960, to calculate the LMI ceiling at $48,768. In the ComEd territory, 47% of the population lives on less than 80% of annual median income; in the Ameren Illinois territory the corresponding value is 41%. The stronger economy in recent years has not eased the energy cost burden for many households, as a 2017 survey found a 7% increase in households that reported trouble paying their utility bills [79]. Statistics on this topic abound, as indicated by some recent reports. The annual EIA study of household energy use found that 31% of US households reported a challenge in paying energy bills or sustaining adequate heating and cooling [80]. Another study by the American Council for an Energy Efficient Economy found that 25% of Chicago’s low-income households in multi-family housing experienced an energy burden of 14.6% of income, higher than four times the median [81]. The Center for Financial Services Innovation reported in an earlier investigation that utility bills are the number one use for small-dollar credit products, including payday loans, pawn loans, direct deposit advance loans, auto title loans and non-bank installment loans, which often come with high fees or interest rates and can lead consumers into a cycle of repeat usage and mounting debt [82].

11 ICC Office of Retail Market Development, The IPA uses 80% AMI to define LMI for the purposes of its programs
Some stakeholders view grid modernization as a unique opportunity to drive economic development, including sustainable investment and jobs, at the neighborhood, community, city and state levels, which can benefit disadvantaged communities. In this view, workforce training efforts need to target clean and advanced energy economy job opportunities and Smart Cities programs must be leveraged for community and regional development to enhance economic opportunity in disadvantaged communities.

LMI customers face barriers to participation in emerging DER opportunities that are easily overcome by higher income customers. Such barriers include inability to pay any up-front costs, unwillingness or inability to take on new debt, low rates of home ownership, lack of access to capital even for the most cost-effective energy investments, inefficient housing stock, old and inefficient appliances supplied by landlords, lack of trust in unregulated vendors and the lack of internet service and energy information. Notwithstanding such impediments, LMI customers are engaged in energy savings efforts. More than 80% in a survey with 534 respondents with household incomes below $50,000 report that they are interested in finding ways to save on utility bills and more than half report having taken measures during the past year to do so, such as getting more efficient appliances and bulbs and/or thermostat installation [79].

Access to new technology, particularly in its early stages, is not uniform among customers, as those able to afford initial investment and are well-informed about energy options become early adopters. Therefore, one major social and regulatory issue is to ensure that all customers, including those in low-income, vulnerable and underserved communities, can benefit from advanced technology adoption, market initiatives and options. Other key challenges to address regarding LMI customer needs include ways to:

- engage and inform LMI customers of opportunities to reduce their energy bills
- protect them from abusive practices and marketing fraud; design innovative billing and payment options to make energy more affordable and to allow payments to be coordinated with variations and timing of customer income
- bring the benefits of DER and grid modernization to LMI communities
- implement innovative financing mechanisms along the lines discussed in the EE section
- provide access to independent reviews of vendor competence and successful projects
- provide trustworthy information that LMI customers need to select energy-smart choices
- ensure that utilities have incentives to maintain affordable service and help LMI customers avoid disconnection
- modify credit and collections procedures to account for a customer’s ability to pay for arrearages
- design programs and initiatives based on dwelling type, with potentially different solutions for single-versus multi-family units and for home owners versus tenants

Some stakeholders assert that innovative proposals to empower LMI customers through market-based initiatives must be combined with regulatory and utility efforts to address removing barriers, providing assistance and motivating behavioral change to reduce energy burdens. Analysis of AMI data and plug loads can provide the means for LMI and other customers to gain insights into usage patterns and make appropriate choices that result in lower bills.
Although LMI customers may lack high-speed internet service, they are increasingly connected through smartphones [83]. More than nine out of ten people, with annual incomes below $30 k, have a cellphone and about three out of four have smartphones. Such a pattern is fairly uniform across racial lines, although smartphone ownership falls off sharply among older adults, a situation that is anticipated to change over time [84]. Time spent by consumers on mobile devices has reached a daily average of 3.1 hours and continues to grow [85]. Average daily non-voice time spent on smartphones is anticipated to reach 2 hours 42 minutes by 2019 [86]. Clearly digital engagement through apps, messaging and social media may be an important aspect of new-customer engagement strategies for all customers, including those of low and moderate income.

Illinois does not presently have “lifeline” utility rates, but there are a variety of programs directed at reducing energy burdens for LMI households. State programs include the percent of income payment plan (PIPP) and low-income home energy assistance program (LIHEAP). Funding for these programs is inadequate, as demonstrated by the fact that in 2017 there were 118,235 Illinois households enrolled in LIHEAP out of 1,092,303 households with income below 150% of the federal poverty level [87]. PIPP, under which participants’ gas and electricity costs are limited to 6% of household income, served just 24,940 customers in the most recent program year, spending $23,523,268, or about $943 each [88].

ComEd and Ameren Illinois have their individual customer-assistance programs that address special hardship cases, active military and veterans and low-income customers with critical medical care needs. ComEd assisted 16,000 customers in 2017 with their “ComEd CARE” programs.

The WG4 discussions gave the participating stakeholders the opportunity to present various options on the topic of affordability and other LMI matters. We collected a set of representative ideas to create the list below. These ideas do not necessarily reflect agreement by other WG members and the selection is intended to indicate the broad range of issues aired. The list is not intended to be exhaustive, nor in any prioritized order and includes the following ideas:

- Increase resources available for LIHEAP, PIPP and other programs, which are presently insufficient to meet the need for payment assistance and serve only a fraction of eligible customers.
- Consider changes in policy and practice to provide new options for billing, payment, service deposits and deferred payment arrangements intended to maintain and resume service for customers who cannot afford to pay their entire bills.
- Consider elimination of the customer-deposit requirement, which makes establishing service unaffordable to some customers.
- Protect customers from debt obligations by a redesign of the DER-payment obligations to run with the meter.
- Bundle and coordinate utility programs to streamline program delivery across utility divisions and present a package of options individualized for each customer. To achieve such a goal, utilities need to explore various ways to combine energy efficiency, DR, rate options, payment assistance and other services for LMI customers. In the case of the ComEd territory, it will be ideal to have this goal for ComEd in partnership with Peoples Gas and Nicor. The offer of a “bundle” of options to each LMI customer can result in higher enrollments and can capture additional efficiencies in program delivery. For example, customers who receive LIHEAP assistance or participate in the PIPP program can be provided an energy
consultation that reviews all options and identifies programs that may support the customer in areas of billing and payment assistance, pricing options, community solar, energy audits, EE and other available opportunities. Providing the opportunity for customers to enroll in multiple programs at one time can result in a more efficient and customer-friendly process.

- Customers who apply but are not able to participate in assistance programs may receive priority for outreach and participation in other utility programs that can reduce their energy burdens. Anonymized usage data combined with census data can be used to identify the high-priority areas within a utility service territory for providing consultation events at which combined-program enrollment can be offered.

- Many small-volume customers do not or cannot take advantage of EE and DER incentive programs, notwithstanding the opportunities they provide for savings. A study to gain an understanding of which customers are not participating and the reasons for such non-participation can bring valuable insights and help to improve program designs and implementation strategies so as to achieve higher participation rates and higher bill savings—particularly for LMI customers.

- Add more ways for LMI customers to access information through the formulation of policies and implementation of pilot programs to better equip LMI customers with access to hourly pricing information without the need for WiFi access and in an easily understood and practical format. For example, existing utility paging networks can send hourly pricing signals to display devices provided as needed to the LMI customers whose service is based on hourly pricing.

- Improve metrics and arrange incentives for reducing customer energy burdens in any utility PBR initiatives, such as reductions in terminations, bad debt, consumption reduction and other options. It is important to include in the success measurement of any regulatory program the impacts on vulnerable communities. The incorporation of a bilingual, bicultural approach that addresses both the interests of individuals and the economic welfare and health of the community can help deliver benefits to participants in all programs and initiatives.

- Give customers the tools they need to manage costs, including those without the time or expertise to do it for themselves. The central policy goal should be to reduce household and community energy burdens. Some stakeholders assert that many customers will not engage with the utility about their energy options regardless of efforts in that direction, because they are too busy or overwhelmed with survival issues. Benefits of new technologies—and particularly the more affordable bills they promise—need to be delivered to LMI customers through programs, such as community solar, targeted energy efficiency, PAYS® and other innovative financing options and revised credit and collection procedures.

These suggestions must be taken into consideration in all discussions of the future grid as they address critically important issues in policy formulation that ensure the administration of electricity services on a consistent basis to all customers.
4.14 Grid Modernization and Very Large Commercial and Industrial Customers

Some very large energy-intensive manufacturing facilities need as much electricity as small cities. The set of the 30 largest industrial customers in Illinois—with 90,000 employees—consumes a total of 13 million MWH of electricity per year [89]. Some industrial entities employ energy managers to oversee energy activities, including procurement, usage optimization and demand response participation. The very large commercial and industrial (VLC&I) electricity customers advocate for reliable service at least cost and seek rates they believe accurately reflect the costs to serve them. Some take the position that before any customer-provided funds are expended on grid modernization, new technology, or market changes, they need to be demonstrated in regulatory proceedings to have net customer benefits. Such benefits include lower rates or attainment of other societal goals, such as increased resiliency, enhanced customer convenience, expanded customer choice or expansion of competitive markets.

The VLC&I average delivery service rates per kWh are lower than those of small commercial and residential rates because they generally have flatter load shapes and require less delivery service infrastructure, as service is received at high voltage levels and VLC&I customers use their own equipment to manage energy utilization within their facilities. Delivery service rates of large customers have steadily increased over time but have been offset by lower energy costs and total Illinois C&I unit costs remain below the national averages. According to Energy Information Administration data for July 2018, total average electric costs per kWh in Illinois are 13.21 cents for residential customers, 8.84 cents for commercial and 6.45 cents for industrials [90]. The corresponding national averages are 13.15, 10.51 and 6.82 cents, respectively. Data from the Edison Electric Institute indicate that the ComEd average all-in large industrial rate to be 5.73 cents/kWh and the national average to be 7.00 cents/kWh. Some stakeholders assert that national averages are not a meaningful yardstick for companies that compete in global markets. Moreover, they argue that such companies are unable to raise their prices when electricity costs increase and higher energy costs at Illinois facilities can be a cause to shift production to other locations.

Many VLC&I customers voluntarily participate in energy management efforts that are cost-effective for their own load shapes and consumption volumes. However, these customers assert that such efforts also provide system benefits for which they need to be credited. As discussed above, under FEJA, the General Assembly exempted VLC&I customers from payments into energy efficiency programs administered by the utilities. Some VLC&I customers also object to paying non-bypassable charges to fund renewable energy, zero-emissions credits and other delivery service programs they do not use, as they argue that these charges make their facilities less competitive and increase the costs of the goods they produce, without a commensurate increase in the quality of services they receive. They assert that increased delivery service costs have fully offset the value of lower competitive energy commodity costs.

Some advocates for other customer classes state that regulatory policies and utility services that benefit the community, the environment and smaller volume commercial and residential customers ultimately also benefit VLC&I customers, so it is fair and appropriate that they share in these costs. They assert that VLC&I customers also benefit from RPS and EE requirements because lower usage and growing renewable output, particularly wind power at night, puts downward pressure on market energy prices, particularly at night when many of the largest industrial customers operate loads that benefit from frequent negative prices in wholesale energy markets. More issues on this topic are also discussed in Chapter 7.
5. Electricity Markets

Digitization has transformed the modern economy in many ways including electricity markets. In electricity distribution, smart grid technologies have yielded operational benefits and some consumer-focused benefits (such as residential real-time pricing in Illinois). The growth of consumer-facing digital technologies to automate and manage energy use, as well as the deepening penetration of EVs and DERs such as battery storage and rooftop solar, are bringing the digital economy into electricity and creating the opportunity for customers of all sizes to own DERs, thus becoming “prosumers.” These changes are creating an impetus for grid modernization and for rethinking retail regulation and market design.

An electricity system can strive towards several different objectives e.g., to be reliable, affordable, resilient, secure, clean, etc. One can create a system that is affordable but compromise on resiliency and clean energy. One can design a secure system, but compromise affordability. One can also accommodate clean and variable resources, but compromise reliability and resiliency. It will be quite difficult to meet multiple objectives simultaneously without reliance on efficient competitive markets that provide clear and effective price signals about its needs at various spatial and temporal scales. Creation of decentralized retail markets is an important step in that direction. Such markets offer great promise, but potential operational risks and societal concerns surround them. Retail markets can increase grid efficiency and offer other useful services, over the status quo and even contribute to grid reliability and resiliency. Absent a careful design, these markets can create confusion, undesirable impacts and equity concerns for consumers.

WG5 was charged with this brief:

This WG will consider methods to increase customer access to new technologies and stimulate distribution-level market participation. It will explore market-based platform transactions that the grid can enable and will also study ways to enhance consumer access to Illinois’ competitive retail markets.

The WG identified a process and a path forward for retail markets in Illinois that creates a framework in which DERs are valuable resources and all participants can flourish. The discussion below captures the opinion of one or more of the stakeholders or WG leader and has been ultimately edited and compiled by the leader, with input and review by others. Consensus opinion was not achieved on all aspects this presentation. Thus, though some of the discussion may reflect opinions shared by all stakeholders, this was never confirmed and, accordingly, the information should be read with the understanding that there may have been disagreement on the points raised in discussion.

Our exploration of retail market design starts in a context of distinct wholesale and retail markets. Wholesale markets emerged in the early 1990s out of historical relationships among utilities for providing emergency bulk power sales and implemented market platforms for new generation technologies to enter the market. They are organized at the bulk power level and operated by RTOs. In Illinois, the Midcontinent Independent System Operator (MISO) serves the Ameren territory, while the PJM Interconnection is the RTO for the ComEd territory. In most cases (except for most of Texas), wholesale power market transactions cross state lines and are thus interstate commerce under the jurisdiction of the FERC. Over 75% of the US population lives in an area with organized wholesale markets.
In contrast, retail markets operate within states, at the distribution level and involve transactions between end-use electricity consumers and those who supply them. Conventionally, electricity suppliers were the utility companies. They were vertically integrated and they owned all assets from generation, transmission and distribution to retail. Utilities operated as government-granted and regulated monopolies and were the sole transaction partners for end-use consumers. In 13 states and the District of Columbia, retail supply is largely open to competition. These jurisdictions account for one-third of all electricity produced and consumed in the United States. In seven “hybrid” states small portions of load, mainly confined to large users can access the market. Under open access, the incumbent distribution utility continues to deliver that electricity via the distribution network. Illinois is one of these states; it commenced the process of regulatory restructuring in late 1997 and completed the transition in 2006. In the non-open access and hybrid states, electric service is provided for all or most customers by a vertically-integrated monopoly operating under conventional rate-of-return regulation.

Next Grid was initiated to build on the perceived success Illinois has enjoyed from the development of wholesale and retail markets even though these markets are not perfect (no human-designed institution can be.) Limitations in wholesale and retail market design include RTOs settling demand on a zonal and hourly basis, failing to reflect short term price response in forecasts of peak demand in determinations of capacity requirements and limited or no scarcity pricing in energy and reserve markets and for most customers, non-variable retail rates. The changes brought on by digital and DER innovations create an opportunity to reexamine retail market design in Illinois.

**Figure 17.** From a one-way grid to a grid of things

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12 For a deeper discussion of Illinois’ restructuring experience, see the Introduction to the report.
Figure 17 symbolizes the process of moving from a one-way grid to a more distributed architecture that allows two-way power flows.

These changes have implications for our long-standing understanding of the product in retail electricity. Some believe that what has conventionally been delivered as a bundled commodity and delivery service may evolve into a distributed set of energy services (e.g., transacting over electricity provided by a DER) and grid services (e.g., voltage and frequency regulation activities that maintain real-time balance in the distribution system). For over a century the combination of mechanical technologies and the regulated, vertically-integrated business model meant that the economical approach to energy and grid services was to bundle them into a single transaction. Digital technologies and DER innovations now have the potential to make it possible and possibly more economical, for both energy and grid to be provided in a more distributed way while maintaining the balance of power demand and supply. These physical changes are connected to the system’s ability to evolve from a single vertically-integrated provider of a uniform commodity service to a system in which parties owning resources that are diverse in scale and location can exchange with each other, either mediated through a market platform or in a peer-to-peer fashion.

In this environment, the idea of grid services, with the incumbent distribution company as a grid services coordinator, can help deliver reliable, affordable, clean energy services in a resilient and value-rich network.

This WG focused on identifying the opportunities that digital and DER technologies are creating to have more distributed and technology-enabled retail markets with more widespread consumer-prosumer-producer integrated participation. The stakeholders worked to define terms and understand new retail market approaches and emphasized thinking about retail markets from a functional perspective rather than a role-based or entity-based perspective. The stakeholders discussed transactive energy and the technical and economic implications of moving toward a grid services platform business model. Throughout the process the stakeholders identified and refined a candidate (not exhaustive) list of functionality requirements for retail markets and design principles to use in evaluating design proposals. The WG did not take developing a market design as its objective, rather suggested a process and a path forward for the Commission to follow as it engages in retail market design process. The remainder of the introduction summarizes the “design thinking” approach to market design; the next section examines the reasons to explore distributed, competitive retail markets. We then go over background definitions and discuss transactive energy and the implications of technology and market platforms. Finally, the WG discusses functionality requirements and design principles for retail electricity markets.

Market design has played an important role in the past three decades, particularly in industries undergoing liberalization and regulatory restructuring (e.g., Federal Communications Commission spectrum auctions, wholesale energy markets), industries where different parties are matched with each other (e.g., medical students getting matched with hospitals for their residencies) and newly-created online market platforms arising out of digital innovation. Economist Al Roth, who received a Nobel Prize for his experimental market-design research, defines market design as:

> Market design is both an ancient human activity and the relatively new part of economics that strives to understand how the design of marketplaces influences the functioning of markets. Armed with this understanding, economists can sometimes help build new marketplaces or repair those that are broken [91].
Cramton [92] provides a thorough overview of the application of market design theory, principles and experience to the design of wholesale energy markets.

Throughout human history, the exchange of goods and services has taken place organically from interaction and experimentation and marketplaces have been created to facilitate such exchange. Market rules that better cater to the needs of the participants generally survive longer. In periods of change, especially technological change, market rules that enable people to adapt to changing conditions are important. The rules, or institutional framework, may themselves have to change to enable people to take advantage of these changes. Sometimes these changes emerge, as in the process of evolving legal precedent under English common law. In an administrative legal situation such as public utility regulation, the process of institutional change has to be more deliberate, which is why market-design principles are relevant in evolving regulation to take advantage of opportunities created by digital and DER innovations.

One way to organize and structure a market-design process is by applying design thinking. Design thinking is a general approach to the process of deliberate design in situations as varied as consumer products, software, urban transportation systems, network architecture and markets. The design process starts with a brief, or a problem to solve, a goal to accomplish. The general design thinking model involves five steps, as shown in Figure 18: empathize, define, ideate, prototype and test.

![Stanford d.school Design Thinking Process](https://dschool.stanford.edu)

**Figure 18.** TKTK design thinking model

The crucial conceptual aspect of design thinking is to approach the design question from the point of view of the diverse parties who will be using the item, in this case, customers participating in Illinois’ retail electricity markets. Taking that perspective requires both effort to discover their preferences and empathy, or the ability to see the design from their viewpoint.
From the brief and the empathize-define-ideate process, designers then assemble a set of functionality requirements—what the design should enable users to accomplish—and from that, a set of design principles used to evaluate design choices. Design principles define how to measure whether the design meets the brief and accomplishes the goals of the design process.

Testing of the proposed market design is therefore crucial and is a fundamental aspect of design thinking. In digital market design, testing takes several forms because markets are technology-mediated interactions to engage in exchange. Computer simulation of the design based on historical data is a good place to start, but simulation cannot be the only testing tool when creating markets that have never existed before because historical data may not reflect how people will actually behave in a new institutional framework. Experimental economics, using laboratory testing with profit-motivated human subjects, is a method for testing market designs to see how people will actually behave. Agent-based simulation that combines the simulation and experimental methodologies and results enables one to see how such a complex system is likely to behave, as well as the patterns of participant behaviors and outcomes that are likely to emerge. These forms of testing are crucial steps in market design before the implementation of new market rules. Such testing will help identify rules that can lead to bad market outcomes or enable participants to manipulate the rules to gain market power and modify those rules before implementation.

5.1 Why Retail Markets?

As discussed in the introduction to this study, Restructuring 1.0 in Illinois created substantial value and benefits. We want to continue that trend in light of subsequent changes in digital technologies and DERs. Technological change is inevitable and can be quick and unexpected; retail markets can enable consumer and producer adaptation to unknown and changing conditions while retaining the resiliency and access requirements that have historically been paramount in electricity distribution. Retail markets can embrace a consumer-driven ideology, enabling equal access and opportunity as well as empowering customer-driven environmental choices. Flourishing retail markets may have beneficial implications for economic growth in Illinois—a modern, efficient electricity industry with choice, opportunities, experimentation and dynamism would contribute to a more dynamic state economy and encourage well-being and economic growth. However, the benefits of implementing retail markets must be weighed against the cost of implementation. This section discusses the reasons to pursue retail market design in three categories that reflect the underlying economic principles: resource allocation and static efficiency, innovation and dynamic efficiency and coordination in complex systems.

Static efficiency is the property of a market outcome that is the welfare-maximizing allocation of a given amount of resources to a given set of uses, for a given set of preferences and costs. This efficiency criterion is relevant for short-run allocation and dispatch. Markets lead to outcomes that have static efficiency when prices effectively coordinate production and consumption, reflecting the underlying costs (including opportunity costs) and benefits of producing and consuming energy. Using prices to coordinate production and consumption more productively increases capacity utilization, reducing the idle capacity in non-peak periods and reducing the peak sizes.

Different institutional frameworks (i.e., different market rules) may yield outcomes that perform better or worse on this measure.

There may be potential benefits of retail markets and widespread DER deployment to the electrical grid that can implement voltage support, enhanced reserves and defer future investments in grid
infrastructure. Any benefits that DERs can provide to the distribution grid, however, are dependent on what, when and where they contribute output to the distribution system: what product (real power, reactive power, or reserves) is being delivered or consumed from the network, where the product is transacted and when the product is transacted. Accurate estimation of DER benefits to the distribution system begins with a rigorous engineering grid analysis. For example, with the advent of smart inverters, a solar installation can give VAr s at a specific location; energy storage can contribute additional capacity; both can respond to over—or under—generation circumstances at a specific point. These services are mostly uncompensated by current utility tariffs. It is possible that utilities can utilize these locally-dispatched resources for a set of needed services rather than relying for the same services on resources at the transmission-system level. This may result in more efficient distribution system operation and enhance the value of these customer-sited resources. These services can be procured via utility programs or acquisitions or even priced at a local node when a utility is capable of operating such distributed or transactive energy markets [93].

If policymakers advocate for changes to the statute and utilities are deemed responsible for administration of other non-grid DER value streams, utilities should be adequately compensated for administering those value streams. Otherwise, to the extent non-grid DER value streams are conflated with grid-value streams, distribution customers may not benefit from the all the values they are compensating for (through their utility bill) or may pay twice for value they are recognizing through other mechanisms. Further, DER valuation may be different, or require a different methodology, depending on the DER type (i.e., solar vs. storage, EVs, EE, DR, etc.) Such DER valuation must be grounded on sound distribution-engineering principles and economic foundations and be equitable.

Existing retail markets already perform well in certain respects for some customers on the static efficiency measure. Industrial customers in Illinois currently have access to many innovative electricity products, being discussed as part of NextGrid at least in some form. Many industrial customers own on-site, highly efficient cogeneration facilities that already operate as a DER on the grid. Industrial customers overwhelmingly take advantage of electricity supply choice and can structure their power contracts so that the price is tied directly to the locational marginal price for power. Industrial customers also participate in utility-sponsored and RTO/ISO-sponsored demand-response and other emergency or economic curtailment programs, providing benefits to the entire grid through peak-demand reductions.

Dynamic efficiency evaluates market performance over time, to see whether the market design yields investment opportunities that are welfare-enhancing and the extent to which the market institutions enable innovation in new products and services, the creation of new markets, the application of new production methods, or the implementation of new ways of organizing production [94]. The signals that market prices and market profits provide can induce investment to expand existing infrastructure, products and services; they can also induce innovation. Without those price and profit signals from market processes and without an institutional framework that enables risk-taking entrepreneurs to innovate, industries and economic well-being can stagnate. Dynamic efficiency is one of the most important hallmarks of thriving markets and is one of the fundamental principles underlying the innovation and dynamism that we experience in the modern economy.

Modern societies are complex adaptive systems and our increasing use of digital technology harnesses that complexity to enable people to accomplish more and to have higher well-being than
they may have enjoyed otherwise. In such complex systems, how are our actions and plans coordinated when we engage in so much commerce and exchange with strangers? Every person in society, whether producer or consumer, has different preferences and different perceptions of costs and benefits and no one person or group has access to the perceptions and beliefs of others. Without having the same knowledge as others, how can coordination across these different interests and perceptions occur? Prices and market processes provide signals that indicate relative value and by responding (or not responding) to price signals, people communicate something about their perception of values and costs. Markets are thus powerful processes of social learning.

One of the most important reasons to explore retail electricity market design is to generate the benefits that arise from a closer relationship between prices for consumption and costs of production. Costs and benefits of electricity production and consumption vary across time and place in ways that a fixed-price administratively-determined retail rate cannot reflect. DERs and digital smart grid technologies reduce the costs of achieving a closer relationship between prices and costs. The extensive literature on dynamic pricing over the past 15 years has documented the effects of pricing that changes over time to reflect changes in underlying costs [95]. A few of the papers in this literature illustrate the potential arising from more distributed retail markets.

Allcott [96, p.824] analyzed the Energy Smart Pricing Plan (ESPP), a collaborative project between ComEd and the Center for Neighborhood Technology “to test whether real-time pricing may incentivize significant reductions in peak electricity demand.” The ESPP started in 2003 with 693 households participating that were socio-economically diverse and lived in a variety of types of dwellings that represented the Chicago area. A pre-program survey indicated that saving money and environmental benefits were the two main drivers of interest in participation. ESPP participants (other than the randomly-chosen control group) received notification if the price 24 hours ahead was forecast to be above 10 cents/kWh and they also received programmable thermostats they may use to set the times when the thermostat would change settings. They were thus able to respond to day-ahead price signals, which track actual real-time prices very closely. Among the results of his analysis, Allcott finds that households reaped an average of $10 of consumer surplus per household per year in return for little effort and by using increasingly inexpensive digital technology. All income and housing categories experienced reduced electricity bills, including low-income households in multi-unit dwellings. He also finds that “energy management and information technology can significantly increase households’ price elasticity” [96, p.835] meaning that in-home digital energy management technologies that automate responses to price signals make households more likely to respond to such signals. Using digital automation to respond to prices in peak periods is a way to flatten load duration and to improve capacity utilization.

Jessoe & Rapson [97] used data from July-August 2011 in Connecticut to test the effects of informative digital in-home technology on the extent to which residential customers responded to price changes. Their study included a control group, a group that received price signals and a group that received price signals and had in-home displays they may use to monitor those changes. They found that the technology-enabled group was much more likely to respond to price changes and that those behaviors persisted (leading to conservation) even after the high-price market period had passed. They concluded that in-home digital technology facilitated demand response and learning.
EDF-CUB [69] examined the results of residential real-time pricing in Illinois, in the ComEd service territory. This study analyzed 2017 usage data from 1.3 million residential smart-meters to compare what customers would have paid under ComEd's basic flat rate offer versus real-time pricing and a time-of-use rate design. Using a conservative estimate for individual peak-load variation, the analysis estimates that 60% of customers would have saved an average $0.26 a month from real-time pricing and that 59% of customers would have saved an average $0.53 a month from our TOU design. These results show lower and less widespread savings for real-time pricing than our previous analysis of 2016 data, likely due in part to a lower difference between wholesale energy prices and the contracted price of ComEd's flat-rate energy. The study also used census block-level income data to estimate the savings of LIHEAP-eligible customers under these rate designs to non-eligible customers. Customers in locations where the majority of households would be eligible for LIHEAP were 6% more likely to see savings from real-time pricing, for an average $0.33 per month and 1.2% more likely to save with a TOU rate, for an average $1.66 per month.

Customer preferences are resulting in demand for access to a wide variety of energy-related products and services that will, in turn, require an evolution toward a multi-sided mesh of interactions between the utility, producers of value-added products and services and their consumers/prosumers. Market design will continue to evolve to accommodate these interactions and will likely require many incremental steps toward a fully realized distribution market that provides price signals reflective of system costs and enables customer response. In this continuously developing market, there needs to be consideration of and adherence to, the engineering realities of the grid, fair and proportionate attribution of transaction benefits/costs in the appropriate market (wholesale or retail) and assurances that all customers and communities benefit from and have the opportunity to participate within the market.

5.2 Background, Definitions and Relevant Literature

Within this context and given WG5’s exploratory market-design brief, in our first meeting the WG gathered information on several relevant topics. The stakeholders started by defining terms that are novel or are often misunderstood (decentralized and distributed network architecture, reliability and resiliency and transactive energy). The WG then proceeded to learn about transactive energy, the implications of retail market platforms, the infrastructure underlying distribution in a high-DER environment and the implications of distributed retail markets for the operation of wholesale power markets.

**Network Architecture**

Networks of all types (e.g., electricity distribution, communications, water, rail, highways) have architectures. A network’s architecture is its physical design, the arrangement of how the components connect to and relate to each other. Network architecture specifies the functional organization of the physical components, the operating procedures and rules and (if relevant) data formats and standards. A network’s physical configuration can fit in one of three categories [98]:

- **Centralized:** All users connect to a single node and only that node
- **Decentralized:** Multiple nodes exist as hubs and users connect to one of those nodes, but not to other hubs and not to each other
- **Distributed:** All users can connect to any adjacent nodes, creating a peer-to-peer network
Figure 19 provides a visual example of each of the three types of network configurations. The current configuration of the electricity distribution network is decentralized.

![Network Configurations](image)

**Figure 19. Differences in physical network configurations**

**Transactive energy**

One framework for designing technology-enabled retail electricity markets is transactive energy (TE). One stakeholder presented background on transactive energy and some of the open research questions in TE. Transactive systems “… use an automated distributed negotiation methodology to coordinate energy devices using economic signals at various time scales so as to maximize the beneficial allocation of available resources in electric power systems” [99]. In a TE system, electricity end-use digital devices are programmed to set the prices they are willing to pay to operate at their current settings, to submit those prices as bids into a digital market and to change their settings if the market-clearing price is higher than the device is programmed for. For example, a homeowner can program a two-way communicating thermostat with a price that represents how much the homeowner is willing to pay per kilowatt-hour to keep the temperature in the home at its current level. The thermostat bids that price into a digital retail market and if the market-clearing price is lower than the set price, the thermostat is unchanged; if the market-clearing price is higher than the set price, then the thermostat is programmed to change its settings by, say, increasing its temperature by four degrees so the air conditioning does not operate as often.

**Transactive Energy Market Design**

TE field projects have demonstrated some of the capabilities and challenges of such distributed coordination. The GridWise Olympic Peninsula project had 130 households with two-way communicating thermostats and four different contract pricing groups—fixed price, time-of-use with critical-peak pricing, real-time pricing and a control group with only the thermostat [100]. Homeowners may automate their response to price signals, a capability that was most relevant to
those on the real-time price contract. The retail market design in this experiment was a digital double auction, with thermostats submitting bids to purchase electricity and suppliers submitting offers. The bids and offers were organized into demand curves and supply curves, respectively, yielding a market-clearing price in every market period. Thermostats with set prices below the market clearing price were programmed to change their settings autonomously. This digital double-auction retail market ran every five minutes. On average the participants saved 10% compared to their usual utility bill and the real-time price group saved 20%. Electricity consumption across the entire group fell and distribution feeder-capacity utilization increased.

In a second TE project in northeast central Ohio, 100,000 residential and 10,000 commercial and industrial customers with heterogeneous demographic and energy-profile characteristics participated in a field experiment with digital meters and communication-enhanced consumer programs [101]. As in the Olympic Peninsula project, the GridSmart participants had two-way programmable in-home technologies and the real-time retail market was structured as a double auction that reflected real-time prices in the PJM wholesale market. Customers expressed a preference between comfort (or a comparable service metric) and savings, which in turn set a range of allowable temperature (quality) outcomes and looking forward at anticipated prices. Given that information, customer devices derived bids using automation to deliver comfort (service) within the desired range. There may be a maximum price at which the customer would prefer a service interrupted, which is not as dynamic as a fully transactive system. Real-time market participants saved approximately 20% compared to their regular bill and AEP Ohio estimated significant operational savings from the technology implementation.

A transactive energy system requires two elements: digital technology and market institutions. A digital communications network connects participants and their devices and digital devices enable participants to automate responses to price signals and other data signals and also mediate the interconnection of devices to the electricity distribution network. Market institutions provide the framework in which participants interact and thus govern the algorithms they employ to automate device communication, market participation and changes in device settings. Transactive energy systems can be implemented in conventional vertically-integrated utility settings as well as restructured settings with competitive retail markets.

TE market designs in the field experiments summarized above have generated beneficial consequences for individuals and for system operation. Individual participants saved both money and energy because the market design aligned economic and environmental incentives and reduced the transaction costs associated with implementing demand response. As a result, demand patterns changed over time and peak demand fell, leading to more uniform capacity utilization and thus accommodation of future demand growth. This more-level capacity utilization enables distribution utilities to optimize their infrastructure spending and use while still delivering system coordination and resiliency. Pratt et. al [102] provide a useful case study of how a TE system with home energy management systems can aid coordination and deployment in a high-DER environment.

TE is simultaneously a framework for thinking about high-DER retail electricity markets, a method for system control that uses economic value as the primary control variable and an abstract model of human and physical interactions and their implications for distribution system infrastructure. Transactive energy systems need further testing and research to deepen our understanding of the physical feedback effects in such a complex system.

**Technology and Market Platforms**
The WG also discussed the implications of platforms. A platform is “a business based on enabling value-creating interactions between external producers and consumers. The platform provides an open, participative infrastructure for those interactions and sets governance conditions for them. The platform's overarching purpose: to consummate matches among users and facilitate the exchange of goods, services, or social currency, thereby enabling value creation for all participants” [103].

ComEd discussed their vision of high-DER market platforms in the Illinois context in the WG’s fourth meeting. As of April 2018, 1.3 million ComEd customers were receiving supply from an ARES; this amounts to 33.9% of ComEd’s customer base and accounts for 70% of total load. Customer preferences and technologies are changing, however and will result in demand for access to a wide variety of services beyond those currently provided by utilities and ARESs.

These changes are likely to prompt an evolution toward multi-sided meshed interactions among the utility, producers of value-added products/services and their consumers/prosumers. A distribution market platform may serve as a framework to accommodate these evolving preferences and the increasing complexity of the power distribution system. This platform would provide for real-time exchanges of value between diverse market participants, with varying combinations of real power, reactive power and reserve power serving as the basis of this value.

Conceptually, value in this market structure will need to be created and captured in dynamic and personalized ways without compromising the security, reliability and resiliency of Illinois’ electricity supply. The value created will be determined by key design criteria including investment efficiency, dynamic efficiency, participant equity, price stability, customer choice, simplicity and feasibility, utility return stability and impact to grid integrity and operations. Advancement toward this future market structure can also provide a host of new economic development opportunities for Illinois, its consumers, communities and businesses and it will be important to endeavor to ensure that market benefits extend to all members of our communities, regardless of background or socioeconomic status.

The market’s design and functions will evolve as DER penetration deepens and will necessitate incremental steps between today and a fully realized distribution market. It will be important, therefore, to have policies that do not preclude the development of such a market and, as an initial step, this chapter will help stakeholders develop better understanding of objectives, organization, costs, etc. of a distribution market.

A WG member from Open Access Technology discussed the technology aspects and requirements of platforms that enable DER interconnection and market transactions. The electric industry landscape is undergoing fundamental changes due to a combination of factors including the proliferation of DERs, new digital technologies, transportation electrification and the emergence of increasingly savvy prosumers (consumers with DG sources such as rooftop solar and energy storage) demanding the choice to purchase or sell electric energy with other prosumers or the utility as they please, based on price and other value preferences. These changes have fundamental impacts on the utility operation and business models and their interactions with consumers/prosumers.

In the face of the challenges of a highly distributed environment, potential solutions are emerging with market-based transactive exchanges involving grid-edge peer-to-peer transactions as well as end-to-end market-based transactions up and down the electric power system operational layers. Two main constructs are notable in this context, namely Transactive Energy systems (as discussed
above) and Distributed System Platforms. Together these two constructs lead to the extension of the two-decade old centralized energy markets to decentralized grid-edge bilateral exchanges, while providing necessary coordination between wholesale power markets and distribution system operators, paving the way for prosumers to also engage in voluntarily offering grid services to grid operators and getting compensated for the associated value. Incentive-compatible design of the emerging decentralized transactive-market model is key to its success to ensure there are no free riders and costs and benefits are allocated based on cost causation and benefit creation.

The technology platform supporting the decentralized peer-to-peer transactions and providing a clearing house for grid services based on voluntary prosumer participation needs a number of new functions to ensure an open and level playing field while guarding against data privacy breaches and malicious cyber-physical threats. Figure 20 represents a possible set of DSP platform functions:

A consultant followed the discussion of platform technologies with a presentation on the economics of electricity market platforms. He described the evolution of power markets to efficiently meet modern grid challenges and integrate distributed technology \cite{104}. To remain simultaneously affordable, reliable and environmentally sustainable, a modern grid would rely on dynamic competitive markets to communicate price signals to demand and distributed energy resources DERs. The rapid expansion of smart-network connected devices and EVs (EVs), DER growth and advances in power electronics will create challenges for existing practices:

- Centralized dispatch may become computationally intractable for utilities with millions of smart end-use devices, hundreds of thousands of EVs and thousands of MW of distributed resources

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure20}
\caption{A possible set of DSP platform functions}
\end{figure}
• Smart devices will be able to anticipate demand response (DR) events and modify their baseline usage to earn program incentives, making conventional DR programs less effective
• Current zonal and hourly RTO settlements, fixed rates and administrative determinations of DER value may conceal variations in time-, location- and product-specific value

The ability of dynamic, competitive markets to communicate prices, which reflect marginal costs and thereby the value of the next best alternative use of scarce resources, will be able to improve asset utilization, lower costs and provide consumers greater choice and control, if customers understand the information they are receiving and choices they are able to make.

Grid and networking assets, together with system planning and operations, provide the physical platform for grid services. Efficient coordination of demand and DER may require the integration of two market functions:

• Transactional Markets: These include forward commodity markets and real-time markets to price incremental differences between actual usage and supply and previous purchases and sales. The forward market would enable competitive suppliers and consumers to hedge risk and lock in prices as their schedules are set. The real-time market would reflect actual power flows and ensure that participant incentives are aligned with grid operations. RTO energy and ancillary service markets are examples of transactional markets. With the growth of distributed resources, markets may become increasingly granular and settle at points within the distribution system at distribution locational marginal prices (DLMPs). Illustrative modeling suggests that in high DER cases DLMP markets may reduce system and consumer costs.

• Service Marketplaces: Service markets may integrate supply with access to smart technology and value-added utility and third-party services. Early examples of such markets can be found in the online consumer marketplaces for Commonwealth Edison, Ameren and many other electric distribution utilities in the US and Europe.

These markets would necessarily exchange information with distribution system operations to ensure that the market outcomes respect the grid engineering constraints. Both the transactional and service markets may be platform markets. Platform markets are multi-sided, in that they provide the infrastructure components and rules to facilitate transactions among multiple producers and consumers. Platform markets can lower transaction costs, enable easy access to goods and services, engage unused capacity and accelerate innovation [103]. Many of the most valuable companies—e.g., Apple, Alphabet, Amazon, Facebook, Alibaba and Tencent—rely on platform market business models.

The combination of emerging technology and increasingly granular markets may enable grid services to become progressively dynamic and efficient. For example:

• Advances in power electronics can provide Volt-VAR control, power-flow control and fault isolation and restoration on a sub-cycle basis
• Intelligent devices and smart inverters can optimize demand and help stabilize the grid on a sub-dispatch interval time scale
- Flexible demand, DER, dynamic ratings and grid topology control can improve the efficiency of system dispatch

The integration of efficient markets and dynamic grid services offers opportunities to create a more affordable, resilient and environmentally sustainable power system. Regardless of the extent to which decentralized retail electricity markets are developed, the incumbent distribution utilities will still be responsible for maintaining the safety, security and resiliency of the distribution system in an affordable and efficient manner, while continuing to provide customer service and access to electricity markets.

ComEd and Ameren gave presentations to the WG on infrastructure requirements to enable distributed markets. As the distribution system is significantly more complex than the transmission system, implementation of a retail market characterized by greater decentralization will require significant investment in the grid from a physical and communications standpoint, to enable the reliable, resilient and secure operation of an interactive and market-based distribution system.

As the grid continues to evolve and the possibility of distributed retail electricity markets and transactive energy platforms emerge, several practical technology considerations must be addressed (Ameren 2018). Among these considerations are the capabilities of existing AMI systems, communication systems, system monitoring and control systems, system models and financial engines and rate structures available today. Indeed, consideration of many of these factors will be required, regardless of adoption of retail markets or other functions to support deeper levels of DER penetration.

AMI Systems: By the end of 2019, both ComEd and AIC will have deployed AMI to all of their customers, reading data in intervals as frequent as 15 minutes depending on utility and rate class and collecting that data multiple times throughout the day. To support a potential future-electricity markets scenario, data in smaller intervals (perhaps 5 minute) may need to be read by the meters, collected and made available to customers in real time. This would potentially change the way network is operated and may result in increased investment costs.

Communications Systems: Today the Illinois grid operates with thousands of sensors and grid devices and millions of meters. Utility communication networks in place to support communication to these devices leverage AMI mesh, public wireless and wired and utility wireless and fiber. To support a future scenario, a much more robust, resilient, high bandwidth and low latency communication system will be needed to accommodate the anticipated volume and timeliness of data to support the tens of thousands of digital sensors, grid devices and millions of meters and potentially tens of millions of smart customer devices. The communication system will need to leverage AMI mesh and utility wireless and fiber networks.

Monitoring and Control Systems: Advanced distribution management systems (ADMS) with functions such as supervisory control and data acquisition (SCADA), outage analysis and switching, are used to manage and control devices on the grid today. To support a future scenario that includes tens of thousands of varying grid related devices, the system may require a fundamentally different operational paradigm (e.g., a distributed energy-resources management systems or DERMS) with a broad set of capabilities that are yet to be defined. New computing capability and algorithms will also be needed to balance the millions of devices across the grid in real time.
One point of discussion in other WGs that this group did not address is the extent to which the communications, monitoring and control systems can use communication infrastructures such as the Internet and customer networks in addition to the distribution utility’s communication network.

System Models: Existing models of the transmission, sub-transmission and distribution systems may not be fully integrated today and may not fully model distributed energy resources in all cases. In addition, when physical changes occur in the system, they are typically not updated in all systems in real time because such functionality is not necessary to support existing operations. To accommodate future requirements, it may be necessary to maintain and require online updates of detailed models of DERs and other system components to reflect system needs in real time.

Financial Engine & Rate Structure: Market platforms that manage a few thousand nodes exist only at the transmission RTO level. The majority of residential and small commercial customers are still on a flat kWh rate structure. Soon, the financial engine will need to operate at the distribution level with millions of nodes included in the analysis (if each device is a node in the network). One may need to adopt time-based rates more widely to support such a market.

Note that because Ameren and ComEd operate as regulated monopolies, they have the right to recover all reasonable expenditures, even expenditures made in pursuit of the development of “the utility of the future” that may or may not yield the expected results. It is imperative that a cost/benefit analysis accompany each step in the formation of the new market platform, particularly in the case of large capital-investment projects undertaken by rate-regulated utilities.

More distributed retail markets and retail market platforms will change the interaction between wholesale markets and retail markets (and may even blur the distinction between them because of the diversity of new technologies and their capabilities). Different models for such an interaction have been envisioned, e.g., one where the RTO meets minimal operational requirements and merely schedules based on the RTO/DSO interfaces [105], or a much more expansive model where the RTO’s have better visibility into the operations of the distribution system and retail markets.

A WG member from Rakon Energy presented an approach towards price transparency between existing wholesale and new retail markets, to enable wholesale markets to evolve and adapt to high-DER retail markets. Today’s wholesale energy markets provide price visibility via locational marginal price (LMPs) at commercial pricing nodes for resources, load, external asynchronous resource and hubs. By focusing one level below commercial pricing nodes, on elemental pricing nodes, wholesale markets may better integrate with such retail markets. Visibility into elemental pricing nodes, which are sometimes connected at the distribution level, is necessary for retail electricity-market participants to gain insights into wholesale market opportunities. Wholesale markets currently have constraints on transactions that cross the boundaries of local balancing authorities. MISO has a market roadmap item to remove such impediments. Pricing at elemental pricing nodes is possible, as demonstrated using examples from MISO Business Practices Manual. Currently, there is no DER aggregation order from FERC. However, grid operators such as MISO and PJM must comply with FERC order 841 on electric storage resources. This discusses related aspects of distribution connected resources at the wholesale grid.

5.3 Market Functionality Requirements and Design Principles

Throughout the WG’s meetings the stakeholders focused on consumer-centered market design, connecting every discussion to what retail markets should enable consumers to accomplish and ways to evaluate the design elements.
In an ideation exercise the stakeholders created illustrative stories about six different types of actors in a highly distributed retail-market context. How can retail markets benefit these diverse users and enable them to flourish? What might these users want to accomplish using market processes?

- Residential: single-family homeowner or family: considering the installation of PV and/or the purchase of an EV
- Renter in a multi-unit building, low-income family or a senior resident: seeking to reduce their energy bill
- High-rise building owner: utilizing building-controls system as a grid resource
- Manufacturer of large equipment: maintaining power quality and possibly reducing energy expenditure that usually is a significant portion of the operation costs
- Microgrid operator, property developer builds new homes: operating the neighborhood’s grid as a microgrid at the edge of the distribution grid
- City mayor: seeking plans for development of smart cities (e.g., Pittsburgh) and other infrastructure

The following are stories for illustrative purposes only and are not necessarily representative of the population that would fall into each category. They synthesize the results of stakeholder discussions and do not represent the views of any individual stakeholder or of all of the stakeholders in the WG. The discussion below is not exhaustive, but merely suggestive.

Residential single-family homeowner: This homeowner is financially comfortable, owning their own single-family home and their household income makes consideration of PV and EV purchases feasible. Such thinking suggests environmental awareness and possibly an interest in being perceived as environmentally sensitive as motivations and they may have the twin motivations of a desire to go green and reduce energy costs. The existence of a solar or EV rebate may influence their decision, as well as the length of time to recover initial costs. The income profile and examination of visibly green purchases suggests they may be part of a family that includes 2 working parents and school-age children. The parents may have a desire to transmit concern for the environment to a younger generation. If one accepts a premise of a two-income household with children, time to deal with energy issues will, perhaps, be limited.

Markets would enable this homeowner to enjoy limited hassle and both the reality and appearance of environmental contributions. Market access may enable them to earn revenue from the excess capacity in their DERs, which may defray a portion of the up-front purchase and installation costs. This is a household that may consider rooftop PV and less costly and hassle-free ownership of a share in community solar to be competitive options (in the absence of rate design incentives for selecting rooftop solar). Improved rate-design and community solar tokenization might be a preferable option, particularly if it comes with some visible sign of participation in the community solar project, e.g. a community-solar member decal to place on their EV or in a window at home.

This customer would benefit from and may be willing to let their EV participate in an ancillary-services market provided it is entirely automated and does not interfere with their use of the car. Connected home automation to enable market participation may be attractive.

Retail markets should include the following features to enable this person to realize their goals:

- A broad policy foundation for sustainable growth of DERs, which ensures that some customers do not have to pay more as a result of other customers’ choices
- Access to EV-charging away from home
• Retail market design that yields clear and actionable retail prices and has low entry barriers
• A platform to transact grid and energy services
• Ability to use and communicate customer data in a secure, privacy-oriented fashion to connect customer with valuable service offerings

Changes to markets and regulation that may enable consumers to realize these values may include nodal and interval RTO settlements in the wholesale market, block and index retail prices offered by the retail service provider, a service platform to purchase smart devices, energy management and other services for the home and a comprehensive EV service platform market for supporting various EV-related services.

Renter in a multi-unit building and/or a low-income family or a senior resident: Consider a working family or a senior who are looking for opportunities to save money where possible, making better use of information to make informed energy choices. Comfort, autonomy and a desire to protect the environment may be motivations, but they require simplicity and easy transaction capability. They may be limited in their ability to make energy-efficient appliance and device choices because, as renters, they may not be able to (or have the financial means to) replace existing inefficient equipment.

Markets would enable such renters to choose contracts that match their preferences for flexibility and affordability through features such as dynamic pricing with automation (transactive energy) that gives them access to low overnight prices, financing options, online bill comparison tools and user-friendly data analysis. Digital technology may also improve the user experience and reduce transaction costs for low-income and other customer assistance programs.

Product or service innovations that enhance value for such customers will likely bundle energy services with other in-home information services, such as home communications, home security, or in-home health-care monitoring. General-purpose digital devices, such as smart speakers and apps on smart phones, enable both transactive energy and other forms of action and communication. Low-income and senior customers who are renters tend to be more difficult to reach with conventional marketing, so retailers may find value in partnering with community organizations for marketing, outreach and education and to build a trust-based relationship with these customers. Retail markets should include the following features to enable these persons to realize their goals:

• Retail market design that yields clear and actionable retail prices and offers low entry barriers
• Platform structure for grid and energy services
• Ability to use and communicate customer data in a secure, privacy-oriented fashion to connect customer with valuable service offerings
• Delivery via a well-functioning, reliable, resilient, safe and secure distribution system

Technology, together with a regulatory framework that facilitates peer-to-peer and other types of transactions and an accompanying retail market design that encourages voluntary participation and customer choice can enable such customers to realize these values and goals. Novel market architectures may require reduction of regulatory constraints on customer choices that have been
typically viewed as instruments of consumer protection. Such protection schemes may no longer be relevant, given that customers have access to data and technology. Further mechanisms and opportunities to finance device purchases and pay for them out of energy savings would put technology in the reach of cash-constrained customers.

High-rise building owner: Building owners and managers are motivated by the potential for energy savings using advanced control systems. They recognize the need for cost-effective innovation and affordable infrastructure. Their incentives include tenant needs/wants/desires, such as managing usage and pricing, reliability and resiliency, a more fine-grained control by making use of sub-metering or other forms of consumption monitoring, etc. Both owners and tenants have uses for data and information about energy consumption, potential revenue from DER installation and use and the portfolio of available digital and DER technologies. A high-rise building may not have a large enough roof surface area to take advantage of solar generation but can form a partnership with community solar in the neighborhood. A distinctive feature of large buildings is that they have large thermal mass. Active management of a building’s energy consumption can allow it to offer its demand reduction in a market. That management might involve cooperation from the tenants, or it may be done independently from the actions of the tenants in a way that does not compromise their comfort or productivity.

Markets may enable this building owner to invest in behind-the-meter technology installations for tenants that increase property value, integrate their assets into existing or new markets (e.g., through demand response participation) and enter service-based relationships with market participants as either a consumer or a producer. Building owners have the potential to become large-scale prosumers, to their own benefit and to the benefit of the distribution system, particularly contributing to its resiliency. Innovations that may impact such building owners and their ability to participate in emerging market include:

- Energy efficiency audits and services
- Energy management solutions
- Market access intermediary options, or the potential to bypass an intermediary
- Development of reliability and resiliency products and services
- Energy transaction via blockchain or smart contracts

Retail markets should include the following features to enable building owners to realize their goals:

- Retail market design that yields clear and actionable retail prices and offers low entry barriers
- A grid-services platform structure
- Providing value for increased asset utilization through a transparent cost/benefit approach
- Access to markets for DR, aggregation and other services
- Coordinated interaction with the grid to deploy new technologies
- More geographically granular pricing and settlements by the RTO in the wholesale market
- Block and index retail prices offered by the retail service provider
Manufacturer of large equipment: Large manufacturers are sophisticated energy users who actively manage consumption to minimize energy costs and demand charges. This entity needs reliable service at the lowest cost. Manufacturers typically compete in a global marketplace and all procurements and investments, including energy, compete internally for limited, carefully managed resources. As technology has advanced over the past decades, power quality has become increasingly important. Many companies have also adopted corporate commitments to environmental sustainability, including increased use of renewable energy.

Retail markets may enable large manufacturers to continue to reduce costs through scheduling flexibility and demand response and automating that process where possible, to take advantage of low prices. Market opportunities may induce them to invest in on-site generation, including DERs such as solar and storage. They may also increase revenue by providing local reserves and/or reactive power when prices are high enough.

Retail markets should include the following features to enable building owners to realize their goals. Retail market design that yields clear and actionable retail prices, including bases for determining locational prices that are transparent, credible and understandable and have:

- Low entry barriers and open access, encouraging the use of DERs
- Measurable and verifiable customer-provided grid services
- A grid-services platform structure
- Ways to both monitor and perhaps monetize power quality
- Reliability and resiliency in power delivery
- Standard contract forms for customer provision of grid services that would reduce possible transaction costs

Microgrid operator: Microgrids are self-contained distribution networks that can operate independently from the distribution grid. In many ways, a microgrid operator is similar to the large building owner in terms of characteristics, incentives and opportunities. Microgrid operators can offer and bid into markets and profit from their ability to adjust consumption and production flexibly within their network. Microgrids may be one way to facilitate DER integration for consumers. Microgrids primarily serve to promote resiliency by providing power to areas when they are isolated from the main grid. The extent to which they enable doing so using DERs and renewable energy aligns that resiliency with carbon reduction and other environmental goals. Microgrid operators can utilize markets to incentivize deployment and coordination of DERs within their network. Retail markets should include the following features to enable building owners to realize their goals:

- Retail market design that yields clear and actionable retail prices, including bases for determining locational prices that are transparent, credible and understandable and have low entry barriers and open access, encouraging the use of DERs
- A grid services platform structure
- Providing value for increased asset utilization through a transparent cost/benefit approach
- Access to markets for DR, aggregation and other services
- Coordinated interaction with the grid to deploy new technologies
- A policy framework that includes support for microgrid pilot and demonstration projects and reduction in regulatory barriers to non-utility microgrid construction (e.g., the prohibition of delivery wires crossing public rights-of-way)
- A policy framework that incentivizes actions towards carbon reduction and other environmental goals

City mayor: City mayors are motivated to ensure that infrastructure is built, planned and operated with maximum functionality and always operates to facilitate economic development and increase social welfare of their residents. They must also focus on the needs/wants/desires of their residents and how those are evolving in the direction of sustainability, consumer choice and convenience. With respect to energy infrastructure, they prioritize affordability, reliability, resiliency and security and are increasingly prioritizing green branding as a mechanism for economic development as well as aligning economic and environmental incentives. As mayors, they take a “bird’s eye” view and are thinking more in terms of “smart cities” and how energy infrastructure interacts with and has interdependencies with other types of infrastructure. In many ways, city mayors will see retail markets as enablers of resiliency through promotion of DERs, such markets will allow the distribution system to operate even when faced with unanticipated outages in the transmission grid. Some value propositions of markets for city mayors include automation and customer choice platforms that enhance the environmental and resiliency aspects of smart cities. Data availability to consumers and to city planners is important, as is the establishment of consumer protection and privacy rules that ensure that customers own their data and can grant access rights to third parties. Retail markets should include the following features to enable city mayors to realize their goals:

- A reliable, resilient and secure distribution grid over which the retail market runs
- Opportunities for meaningful participation by all consumers and communities, including development of microgrids and community solar projects
- Retail market design with low entry barriers and ease of access to energy, reactive power and reserves markets to enable DER and community solar participation
- A grid services platform structure to inform residents about product and service options and enable them to transact
- Coordinated interaction with the grid to deploy new technologies
- A policy framework that includes support for microgrid pilot and demonstration projects and reduces regulatory barriers to non-utility microgrid construction (e.g., the prohibition of delivery wires crossing public rights-of-way)
- A policy framework that includes carbon reduction and other environmental goals
- New policy and regulatory approaches ensure continued confidence in the integrity of the markets
- Encouraging cost-effective innovation through pilots or demonstration projects
- Revising regulatory institutions to fit better with a performance-oriented, value-enhancing, distributed environment where distribution utilities coordinate grid services

The stakeholders used these scenarios and the ideas generated in the presentations to define preliminary lists of functionality requirements and design principles and to identify which functionality requirements and design principles were more or less important to each individual stakeholder. They had an opportunity to participate in a survey to prioritize and rank both the functionality requirements and the design principles that had emerged over the course of the previous meetings. This survey does not yield statistically significant results (n=11) and thus
provides only suggestive guidance on the design path that the Commission should pursue. To the extent that the results show variance in responses, that variance indicates the extent to which the stakeholders prioritized items differently in their responses.

A functionality requirement is an action or capability that a system must have to meet user needs. In our context, a functionality requirement for retail market design is an action or capability that users/actors (diverse consumers, prosumers, micrograms, etc.) may value and that the market design should enable to occur. Below is a list of functionality requirements that emerged out of WG discussions. Some of them are from the perspective of the individual actor (i.e., what functions should retail markets enable them to accomplish?), while others are at the next level down in the system (i.e., what does the market system’s technology have to do to enable beneficial market functioning?). All are as general as possible to encompass as many diverse ways of engaging in retail markets as possible. The survey asked the stakeholders: From your perspective and/or the perspective of the stakeholders you represent, rank each one as essential (1), important (2), less important (3), not important (4). See the NextGrid website [15] for survey.

- Transact in an energy market
- Automate participation in energy market
- Transact to provide grid services (e.g., voltage or frequency regulation)
- Ability to choose to contract with an independent retailer for energy services
- Ability to choose bill stabilization or a fixed-price contract
- Invest in DERs
- Interconnect (either individuals or commercial microgrids) with distribution grid using interoperable standards and rules without additional gatekeeping (i.e., how the internet works)
- Expect customer data protection and privacy
- Expect reliable delivery services
- Provide data access with customer consent
- Market participation that is technology neutral
- Market operator and grid operator can manage large numbers of transactions
- Flexible and transparent wholesale market integration (e.g., industrial direct access, communication of price signals between retail and wholesale)
- Provide a platform for customers to discover and transact for energy services
The results are shown in Figure 21. It presents the functionality requirements in decreasing order of importance based on the survey results. Resiliency, grid operation and wholesale market integration were essential functionality requirements, with the remaining being important but to a lesser extent. Higher-variance items, such as technology neutrality, bill stabilization, or interoperable interconnection, reflect the fact that different stakeholders prioritized those items differently.

The design of retail markets encourages competition in retail supply and open access to all customers. Along with deepening penetration of digital technologies and distributed energy resources, the retail market may potentially evolve to facilitate future peer-to-peer (P2P) energy trading. P2P energy trading in a retail market offers options for an end-use consumer to exchange excess self-generated electricity directly to other consumers or aggregators through a market-based platform. It will further increase competition in the retail market and reduce dependence on the central transmission and electric supply systems, which can also increase system resiliency. Enabling efficient P2P energy trading requires a retail market with a platform that addresses challenges of real-time communication, trust and security in energy transactions. It also requires novel distribution grid operations to ensure the quality and resiliency of electricity delivery with power flow from consumers to consumers, consumers to grid and grid to consumers.

The survey asked the stakeholders: From your perspective rearrange the list in order from most important (1) to least important (18). This exercise is difficult, because these principles were all identified in discussion as being important, although the degree of importance and the order of importance are likely to vary across stakeholders.
- Ease of use
- Transparency and verifiability
- Equity across consumers
- Reliability
- Resiliency
- Consumer protection
- Data privacy
- Cyber security
- Static economic efficiency: enable coordination and resource allocation through price discovery
- Dynamic economic efficiency: enable coordination and innovation in products and services
- Technology-neutral
- Utility’s role is market-agnostic
- Ease of automation
- Rules are flexible and extensible to enable adaptation
- Technologies are flexible, extensible and interoperable to enable adaptation
- Low market-entry barriers
- Market liquidity
- Contribute to greenhouse gas reduction

Figure 21 presents the functionality requirements in decreasing order of importance based on the survey results. Three design principles were consistently ranked highly: transparency and verifiability, reliability and reliability. Again, higher variance reflects the fact that different stakeholders prioritized those items differently.

<table>
<thead>
<tr>
<th>Design principle</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Mean</th>
<th>Std Deviation</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transparency and verifiability</td>
<td>1</td>
<td>12</td>
<td>4.64</td>
<td>3.26</td>
<td>10.60</td>
</tr>
<tr>
<td>Reliability</td>
<td>1</td>
<td>11</td>
<td>4.82</td>
<td>2.92</td>
<td>8.51</td>
</tr>
<tr>
<td>Resilience</td>
<td>1</td>
<td>15</td>
<td>5.45</td>
<td>3.55</td>
<td>12.61</td>
</tr>
<tr>
<td>Dynamic economic efficiency: enable coordination and innovation in products and services</td>
<td>1</td>
<td>14</td>
<td>7.00</td>
<td>3.91</td>
<td>15.27</td>
</tr>
<tr>
<td>Static economic efficiency: enable coordination and resource allocation through price discovery</td>
<td>1</td>
<td>11</td>
<td>7.09</td>
<td>2.81</td>
<td>7.90</td>
</tr>
<tr>
<td>Ease of use</td>
<td>1</td>
<td>15</td>
<td>7.55</td>
<td>5.47</td>
<td>29.88</td>
</tr>
<tr>
<td>Equity across consumers</td>
<td>2</td>
<td>18</td>
<td>8.00</td>
<td>5.72</td>
<td>32.73</td>
</tr>
<tr>
<td>Consumer protection</td>
<td>1</td>
<td>14</td>
<td>8.36</td>
<td>3.91</td>
<td>15.32</td>
</tr>
<tr>
<td>Cyber security</td>
<td>3</td>
<td>14</td>
<td>8.43</td>
<td>3.09</td>
<td>9.52</td>
</tr>
<tr>
<td>Data privacy</td>
<td>2</td>
<td>15</td>
<td>9.36</td>
<td>3.62</td>
<td>13.14</td>
</tr>
<tr>
<td>Rules are flexible and extensible to enable adaptation</td>
<td>1</td>
<td>15</td>
<td>10.00</td>
<td>4.67</td>
<td>21.82</td>
</tr>
<tr>
<td>Utility’s role is market-agnostic</td>
<td>2</td>
<td>18</td>
<td>11.00</td>
<td>4.79</td>
<td>22.91</td>
</tr>
<tr>
<td>Technology-neutral</td>
<td>3</td>
<td>18</td>
<td>11.82</td>
<td>4.43</td>
<td>19.60</td>
</tr>
<tr>
<td>Technologies are flexible, extensible, and interoperable to enable adaptation</td>
<td>3</td>
<td>16</td>
<td>12.09</td>
<td>3.70</td>
<td>13.72</td>
</tr>
<tr>
<td>Low market-entry barriers</td>
<td>2</td>
<td>17</td>
<td>12.18</td>
<td>5.06</td>
<td>25.60</td>
</tr>
<tr>
<td>Ease of automation</td>
<td>4</td>
<td>17</td>
<td>12.91</td>
<td>3.63</td>
<td>13.17</td>
</tr>
<tr>
<td>Contribute to greenhouse gas reduction</td>
<td>5</td>
<td>18</td>
<td>15.09</td>
<td>4.94</td>
<td>24.45</td>
</tr>
<tr>
<td>Market liquidity</td>
<td>8</td>
<td>17</td>
<td>15.18</td>
<td>2.89</td>
<td>8.33</td>
</tr>
</tbody>
</table>
Figure 21. Preliminary ranking of design principles

The survey also asked: Are there design principles not on the list that you think should be? List up to three. Various stakeholders responded and their responses are reported below; these statements should not be attributed to the WG as a whole and are included here to communicate ideas of some of the stakeholders.

Incentive compatibility is one of the foundational economic principles in market design – rules and frameworks should enable individuals to make choices that benefit them and align individual values with the value to the network. Transactive/transactional markets should be incentive-compatible with efficient operation of the power system, implying:

- Market design can be layered and decentralized, but distributed markets that don’t account for constraints and the lack of switching, storage and latency may be infeasible
- Markets will require an exchange of information with system operations. Imbalances—differences between forward contracts and actual demand and supply—need to be priced based on actual power flows in after-the-fact real-time markets to maintain incentive compatibility
- There are on-going research questions about how to integrate transactive markets and grid operations that will need to be further explored

A functional model of a modern grid should account for activities operating on multiple time scales including sub-cycle, semi-autonomous power electronics, rapid sub-dispatch interval controls, conventional dispatch and dynamic system configurations. The power industry is beginning to understand the best ways to integrate markets and new technologies. A careful combination of novel technology and market design offers the promise of higher system efficiency.

Consumer protection, particularly for residential customers, is an important design principle. Some stakeholders suggest that methods for implementing consumer protection in retail markets may include:

- Require disclosure on all marketing materials and bills of the utility price to compare
- Prevent automatic contract renewal
- Increase fees on door-to-door marketing to cover public interest risk of that sales channel
- Prohibition on selling to LIHEAP and PIPP customers
- Automatic penalties, including three-strikes-and-you’re out provisions for companies that violate ICC rules

Accommodating and not erecting barriers to participation of new and diverse resources and market participants at different scales. This principle has implications for investment and for innovation in new products and services:

- Capital is available and seeking investment opportunities. However, investors need a stable market structure in which returns can be predicted with a good degree of resiliency
Create a regulatory framework and tariffs that allow assets to participate in wholesale and distribution-level markets for various products (energy, capacity, reserves, other ancillaries)

Investors in T or D grid-connected and consumer/prosumer assets get access to new revenue schemes to earn a return on their investments

Consumers/prosumers in the future have opportunities to opt out of certain distribution grid services

Utilities receive the opportunities for additional revenue streams (new business models) to replace (if appropriate) revenue lost as consumers choose not to pay for certain services. This must be done thoughtfully so as not to overburden the emerging DER market with costs

Must be done in a way that does not strand low-income people and burden them with the stranded cost of the legacy utility network and operations

Allow for future flexibility—do not codify specific technologies or service providers. Allow for consumers to choose their optimal product, price and provider, thereby allowing the free market to determine what offerings are successful

If the market is going to be competitive for DERs, the utility cannot be permitted to rate-base generation (solar of any scale, wind, batteries, or other future technologies) through this process, nor can they be allowed to favor certain market participants, especially their own affiliates.

Finally, the survey also asked stakeholders how they define equity in the context of retail electricity markets. A common element emerged in response to this question: equal access to products and services, to data and to retail pricing options.

The WG5 discussions suggest that the process for the Commission to explore retail market design should start with a vision, an idealized proposition of desired outcomes, one of which is an expanded domain of value creation for and by customers via retail markets. From that vision, develop a roadmap, which will happen incrementally, with specified high-level endpoints that correspond to the vision. Using the roadmap, develop functionality requirements and design principles based on the work done in this WG and the preliminary functionality requirements and design principles explored here. Some of the stakeholders suggest the importance of evaluating those functionality requirements and design principles with a view toward optionality—do not settle on “the answer” too early in the roadmap process.

Based on these inputs, the next step would be to develop a draft market-design proposal. The market-design proposal should then be tested in two different ways: evaluated in comparison to market designs in other states and countries to learn from their successes and mistakes and testing using computer simulation, economic laboratory experiments and agent-based models to evaluate and refine the draft market design.
6. Regulatory and Environmental Policy Issues

Environmental concerns often raise tension with the needs of the state’s electrical grid and the outcomes of its electricity production and delivery practices. As Illinois considers the NextGrid future, the state may seize the opportunity to bring those two policy positions closer into alignment, so that the future of the grid serves not only to provide reliable, affordable electricity to all communities in Illinois, but also to achieve the state’s environmental and climate goals. The WG6 stakeholder participants set out to tackle policy questions related to environmental impacts of distributed energy resources (DERs), climate consequences, adaptation and mitigation together with carbon regulation and the beneficial electrification of transportation and other new loads. The WG explored opportunities and challenges relating to technological advances and environmental impacts and identified regulatory and policy approaches to the modernization of Illinois’ grid with the desired environmental objectives attained. To this end, the WG6 deliberations focused its work on four specific aspects of environmental and regulatory issues: the environmental impacts of the broader deployment of DERs, climate and grid resiliency, beneficial electrification and pathways to decarbonization.

In this chapter, we report on the nature and scope of the discussions and summarize the broad range of viewpoints from the diverse group of participating stakeholders. The viewpoints expressed are those of one or more participants and do not imply agreement by any other stakeholders. In addition to the discussion of the main thrusts of the various deliberations, this chapter also includes a summary of the responses received from the WG members to a survey prior to the WG meetings.

6.1 Environmental Impacts of Distributed Energy Resources

A preliminary step prior to any WG6 meetings, the WG6 leader surveyed the participating members on possible outcomes of increased DER adoption and deployment. The survey included the following questions:

- What environmental outcomes can be served by distributed energy resources?
- What functions of the electric grid can be served by the different types of distributed energy resources?
- What are different outcomes and benefits that distributed energy resources can bring to the electric grid?

The returned survey responses identified the following potential environmental benefits:

- Offsets in the need for electricity generated by fossil fuels
- Contributions from DERs to the decarbonization of the electricity system
- Mitigation of the impacts of climate change and severe weather events
- Reductions in the peak load and offsets in the need for polluting peaker plants
- Reductions in air, land and water pollution such as particulate matter, sulfur dioxide (SO₂), nitrogen oxides (NOx), mercury and other pollutants, including in but not limited to, low-income neighborhoods

In addition to potential environmental gains, survey responses identified distinct advantages for the electricity grid that can emanate from the widespread DER deployment, including voltage support, enhanced reserves and deferred future costly investments in grid infrastructure. These survey results served well the discussions that ensued in the meetings of WG6.
The starting point of the discussions was facilitated by a broad presentation on the environmental impacts of DERs. In the presentation, DERs were defined broadly to include “demand- and supply-side resources that can be deployed throughout an electric distribution system to meet the energy and resiliency needs of the loads served by that system. Moreover, DERs can be “owned by the user, a third party, or the utility and can be used for a wide variety of applications” [106]. The three broad DER categories are DG, distributed energy storage and demand-side management. Distributed generation includes systems such as solar photovoltaics, combined heat and power, i.e., cogeneration, systems, diesel generators, gas-fired turbines and fuel cells. Distributed energy storage includes batteries, thermal storage and flywheels. Demand-side management includes energy efficiency, demand response and EVs.

The identified grid benefits of DERs include:

- Reduced peak kW demand with the associated lower utility demand charges
- Reduced requirements for capacity infrastructure additions (e.g., substation transformers) as a result of reductions in peak demand
- Reduced need for dedicated infrastructure improvements (e.g., capacitors) from enhancements in power quality
- Reduced generation capacity required to supply the reduced demand and lower peak
- Reduced requirements for backup generators

Moreover, DERs can have environmental benefits whenever they displace other forms of electrical generation that would otherwise contribute to negative health and environmental impacts, as in the case of coal-fired generation and can help support resiliency in the face of climate-related environmental challenges. The identified environmental benefits of DERs are:

- Reduced carbon emissions
- Reduced criteria air pollutants
- Reduced water consumption for steam generation for electricity
- Smaller geographic footprint for energy generation infrastructure

The outcomes and benefits that some forms of DER can bring include consumer, system and regional grid benefits. Consumers benefit from reduced energy costs, cleaner environment and, under certain conditions, increased resiliency. Furthermore, DERs may create customer choice and control over the type of electricity generation technology. Growth in DER deployments can spur economic development and create jobs in regions with deeper DER penetrations. The displacement of fossil fueled generation by the clean DER electricity can help create cleaner and healthier air for customers and help address equity concerns.

The stakeholder discussion focused on three key questions that were considered in the breakout sessions held by the three subgroups created by the partition of the participating WG6 members. The appropriate responses to the following questions were discussed by the three subgroups:

- How can distributed solar, energy storage, EVs, energy efficiency, demand response and other appropriate technologies be used to reduce air and water pollution and bring about substantive environmental and grid benefits?
- What are the regulatory obstacles to capturing those benefits?
- What are alternatives to overcome those regulatory obstacles?
In the paragraphs below, we report on the subgroup perspectives reported to the entire WG. Widespread DER deployments can significantly impact conventional generation source utilization and their associated environmental impacts. Given that a large portion of DERs are renewable or derived from renewable energy sources, deeper DER penetrations can reduce the need for electrical generation from conventional, carbon-intensive sources so as to thereby reduce emissions and surface and water pollution. To that end, DERs help to facilitate retail market decisions and policy constructs that result in cleaner, carbon-free generation portfolios. Replacement of fossil-fired generation in this way can bring about reductions in coal mining activities, coal generation and natural gas production and consumption for electricity generation. In turn, discussion participants suggested these changes can result in reductions in emissions associated with fossil fuel transportation and in water consumption used for steam generation. However, the manufacturing life cycle of DERs must also be carefully considered as it may be water and, to some extent, carbon intensive. The environmental impacts of retired DER resources are unclear. The same is true of batteries once they reach a threshold reduction in their state of charge.

An additional benefit of DER deployment is a reduced dependence on the bulk grid as the generated electricity is near the consumption point. As a result, there are reductions in the peak and total demand for electricity in the bulk grid and corresponding reductions in emissions and pollution under conditions that the renewable energy generated by DERs displace polluting energy sources and do not simply offset other sources of low- or no-carbon energy – both renewables and nuclear - in the grid. A flatter grid-wide consumption profile can also reduce peak capacity needs on the grid and avoid inefficiencies in the distribution of electricity and line losses that entail unnecessary additional emissions.

Other benefits resulting from DER technologies include:

- Greater energy independence perceived by customers
- Additional, more flexible energy storage systems that reduce excess generation capacity requirements
- Greater customer empowerment, engagement and buy-in, leading to behavioral changes that increase energy savings
- Benefits associated with the electrification of the transportation sector through synergies with DER adoption
- Innovation spurring additional innovation as technologies continue to develop and be beneficial to society

In the discussions on the DERs’ potential environmental and grid benefits, the WG also identified important caveats in and hindrances to the attainment of such benefits. For example, the formulation of appropriate incentives for DER deployment, requires the explicit consideration of the answers to the questions—who pays, how much and what are the returns. A major obstacle is the lack of an existing mechanism for the valuation of certain DER benefits. Some WG stakeholders, however, noted that the FEJA [5] defined the "value of DER"—at least for the distribution system—and that other value streams are compensated—or can be compensated—through other mechanisms such as sales of renewable energy credits, participation in PJM markets and state government payments. The discussers indicated that the lack of a policy mechanism that recognizes these value streams and rewards reductions in emissions and other pollutants slows significantly the pace of DER developments, particularly when compared to the treatment of conventional generation resources. Furthermore, policymakers need to determine whether such
value would be decided through a command-and-control regulatory approach or a market-driven approach. Additional regulatory obstacles are also discussed below.

The discussions on the question on regulatory obstacles identified friction in the regulatory structure, the lack of policy regarding a carbon price or tax, opposition from existing institutions and the lack of information as the principal causal factors for such obstacles. At the outset, the subgroup participants acknowledged that lack of a carbon policy, both in Illinois and at the federal level, was identified as an impediment to wider DER adoption. Without a dollar value associated with carbon emissions, electricity generators, distribution utilities and customers lack incentives to reduce carbon production or chose a supplier simply based on reduced carbon levels via deployment of cleaner technologies and implementation of additional efficiency or supply strategies. A carbon price can remove the incentive to externalize emission costs. Similarly, whenever other attributes of clean electricity generation are inadequately valued, customers and utilities lack sufficient and correct information to appropriately value DER investments and therefore underinvest in such ventures. The valuation of DER can be approached via different strategies.

An aspect of the current regulatory structure that participants identified as an obstacle is the friction among various agencies and jurisdictions, such as the federal government, state agencies and the two RTOs that serve Illinois—MISO and PJM Interconnection. Participants described this system of fragmented, overlapping interests and regulatory goals as a “Tower of Babel” situation, which frustrates the ability to craft a unified and workable policy to establish consistent and appropriate values for clean and conventional electricity resources. Furthermore, although the deployment of new technologies continues to occur within the existing utility and RTO framework, some of these institutions can hinder the adoption/deployment of new technologies in a timely manner. The conventional model for electricity delivery under a “hub and spokes” structure, with distinct responsibilities with respect to generation, transmission and distribution delineated to the utilities, RTOs and other entities, can present challenges to a transition towards a “web-based” distribution system, where electricity can be generated at many different locations and supplied to other customers on the grid on a more local and individualized basis.

The set of obstacles related to the lack of timely and appropriate information elicited considerable discussion. For example, do existing incentives for DER technology deployment represent appropriate market signals with fidelity, or do they distort the true costs of such technologies? Furthermore, are those incentives effective to attain their specified policy goals? Do consumers have the information that they need to make informed choices? Are there additional barriers to overcome? The answers to these questions are crucial to the formulation of policies that are effective and economically efficient to incentivize the appropriate investments.

WG discussion participants offered a wide range of alternatives to overcome the identified barriers. For example, some participants suggested the use of rigorous cost-benefit analyses to evaluate potential policy solutions and educate consumers and policymakers on energy solutions and challenges, so they can make better informed decisions. However, without a complete understanding of the potential value of DER and awareness of the total costs of conventional, more polluting sources of electricity, customers and policymakers may be unable to make decisions that properly value DERs and their environmental benefits. The participating stakeholders also discussed more specific policy actions that may be taken, such as the specification of a price on carbon at either the regional or the federal level, adoption by Illinois of a clean-energy standard or participation by Illinois in an existing sub-national carbon market or the establishment of a state
zero-emission vehicle goal. Other possible solutions cited include the encouragement of targeted investments in DER and clean-energy technology in low-income communities and the alignment of incentives and provision of more choices to customers in order to encourage development and adoption of non-wires alternatives in the solution of electricity generation and delivery issues.

The deliberations in the breakout subgroups indicate that the availability of mechanisms for the valuation of DERs, the availability of timely and detailed information, the formulation of needed policies and the removal of identified barriers are key requirements to move effectively on the more rapid deployment of DERs to bring about the societal and environmental benefits that DERs create.

6.2 Climate and Grid Resiliency

FERC defines “Grid Resiliency of Bulk Power System” as:

The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to and/or rapidly recover from such an event ... Resiliency can encompass a wide range of attributes, characteristics and services that allow the grid to withstand, adapt to and recover from both naturally occurring and man-made disruptive events [107].

To set this definition within the context of the WG6 activities, two presentations—one on the effects of climate change by a meteorologist and another on insurance considerations by an insurance outfit expert—were instrumental to provide a meaningful basis. For Illinois, the anticipated impact of climate change requires a power grid that ensures equitable and reliable access to power in times of extreme weather events to all communities and individuals across the state. According to the insurance professional, Illinois is already experiencing disruptions caused by a changing climate. For instance, heavy rains and floods have increased in recent years and the state experienced its hottest May on record in 2018, immediately after its coldest April in over a century. As extreme weather events become more common and frequent, disasters such as floods will take a toll on the state’s infrastructure and its people. As observed in other US venues, large storms can cause massive disruptions, destroy communities and claim thousands of lives, as they did in Puerto Rico, Florida and Texas in 2017. Due to climate change, the likelihood of such an event in Illinois continues to increase.

According to the meteorologist, extreme weather phenomena directly impact the state’s economy. Power outages, such as the ones caused by severe storms, represent losses that cost the average business over $1,000 per hour for the loss of electricity. Even non-weather-related natural events can incapacitate terrestrial electrical infrastructure, as he demonstrated with the example of coronal mass ejections [108]. Given the state’s aging infrastructure, the need for new and continued investment is clear to ensure grid resiliency, even without the expected effects of climate change and extreme weather phenomena.

With these impacts in mind, investments in the grid and policies relating to the grid must take into consideration the twin principles of climate adaptation—the dispatch of actions to prepare for and adapt to new conditions, in order to reduce harm or take advantage of new opportunities—and climate mitigation—the implementation of appropriate measures to reduce the amount and speed of future climate change via reductions in emissions of heat-trapping gases or removal of carbon dioxide from the atmosphere by needed shifts in the state’s resource mix to include more carbon-
free resources. When surveyed on the specific risks and considerations for energy demand, generation, distribution and transmission, given anticipated climate impacts on Illinois’s power grid, WG 6 survey respondents provided the following responses:

- Rises in temperature, hotter summers, more heat waves and creation of urban heat islands
- More extreme weather, including extreme cold/polar vortices, greater weather event intensity/frequency and damaging winds
- More precipitation
- More peak air conditioning
- Annual gross/peak energy increases
- More intense use of water resources
- Risks for essential services customers, such as first responders, water and communications
- Risks for vulnerable communities
- Heat stress on equipment
- Freezing coal piles
- Natural gas supply constraints
- Cooling water and thermal discharge challenges
- Threats to transmission and distribution infrastructure from wind and possibly ice loads

The respondents also proposed the following potential solutions to these identified risks:

- Implementation of appropriate grid management practices
- Increased grid flexibility and capacity to adapt to new challenges
- Development of demand-response capabilities under a wide range of conditions
- Differentiated standards of service for essential services
- Design of transmission projects to withstand extreme weather, including ice loads
- Reduced reliance on large centralized, fossil-fuel powered generation stations
- More extensive burial of distribution grid lines underground
- Built-in redundancy of power service via different schemes, including the implementation of microgrids
- Integration of deeper penetrations of DERs, particularly of those that harness wind and solar energy
- Avoidance of overdependence on natural gas generation sources
- Continued investment in energy efficiency
- Encouragement and incentivization of innovation to meet grid needs under climate change conditions
- Investment in R&D technologies to conserve energy and water resources
- Education and training of customers on global impacts of climate change

In addition, the survey respondents suggested the following steps policymakers can take to facilitate and implement the proposed solutions to the climate change challenges:

- Decomposition of large future projects into smaller, manageable subprojects
- Mandate for explicit requirements to perform integrated community and regional planning and to prepare responses
Incorporation of climate-change considerations into all decision-making on grid planning and operations issues
Focus on grid modernization, reliability and resiliency in all planning matters
Implementation of requirements to ensure the effective implementation of energy efficiency and demand response programs
Implementation of workable schemes to ease policy barriers among interconnected grid ISO/RTOs and between an ISO and interconnected DSOs
Adherence to a policy to urge grid operators to properly value DERs and low-carbon resources
Advocacy of infrastructure changes to support further integration of wind and solar resources into the grids with avoidance of subsidies of coal-fired resources
Imposition of requirements for the preparation of equitable transition plans for fence-line communities and workers prior to the approval of new generation

The survey results are valuable as they provide a good representative cross section of the views held by the participating stakeholders.

For the discussion of the climate and grid resiliency issues that followed the two presentations, WG6 was partitioned into three subgroups to consider the appropriate responses to the following three questions:

- Given the climate impacts that Illinois can reasonably expect, what specific risks and factors must be considered with respect to demand, energy generation and grid infrastructure?
- What are the possible economic, social and environmental impacts on the grid that can emanate as a result of Illinois climate changes?
- How can all of these risks and impacts be mitigated, addressed or managed? And, what can policy makers and other players in the electric power industry do to formulate and implement the appropriate solutions to these challenges?

In the paragraphs below, we report on the subgroup perspectives reported to the entire WG6. Participants in the lengthy discussions identified a wide range of outcomes that can be expected from Illinois’s climate impacts. Many of these outcomes, if realized, can entail cascading effects, which result in increased intensity and complexity phenomena. For a scenario, under which climate changes result in extreme weather events at an increased frequency, the grid must adapt to events such as hotter and longer-lasting heat waves, more intense storms, increased flooding and extreme cold-snap events during winter months. These climate impacts will directly impact customers and their energy demands. More intense storms result in more damage to the physical transmission and distribution infrastructure, which can cause more frequent, sustained power outages. The costs associated with the maintenance, repair and reconstruction of the grid infrastructure due to storm damage can lead to rate increases for customers. Frequent storms can also impact the resiliency of every energy generation source and that of the electricity network.

Temperature extremes are accompanied by higher energy consumption for heating or cooling. For example, customers who increase the air conditioning utilization intensity during heat waves can, in turn, increase the peak load of a system. Moreover, longer duration of peak demand may lead to more intense generation asset utilization and, eventually requires additions of supply capacity and delivery capability. Such additions increase costs and necessitate, in turn, rate hikes. Higher peaks can force existing power plants to run more intensely for longer periods to supply the
additional demand, which leads to additional pollution and associated health impacts. This sequence of consequential outcomes can have an outsized impact on a grid with severely constrained resources. Temperature extremes can also raise concerns about the fuel supply security of existing power plants, with cold temperatures resulting in damaged pipelines, frozen coal piles or iced waterways on which barges cannot navigate while longer duration heat waves lead to warped roads and rail lines.

Renewable generation sources are not immune from the effects of climate change or concerns about safety: for example, the installation of new solar arrays must be carried out with the understanding of the potential risks of snow and wind loading on existing buildings whose rooftop design did not consider the requirements to accommodate photovoltaic cells nor the fire risks associated with solar arrays.

The outcomes of changes to Illinois’s climate need not be entirely negative. The desire to reduce dependence on a centralized electricity supply system pushes customers to embrace opportunities to install DERs and to supply electricity on a more local basis. However, a realistic assessment of the current situation leads to the conclusion that for the foreseeable future, the bulk grid will continue to play a predominant role to ensure the reliability, security resiliency and other socio-economic benefits of deeper penetrations of DERs.

In the discussions on the economic impacts of climate change, the participating stakeholders identified several costs that can arise. They include the following cost elements associated with:

- Repairs of infrastructure damaged by severe weather events as a result of sustained climate change
- Resiliency investments to improve transmission and distribution infrastructure assets
- Lost business due to inadequate generation supply and/or constrained deliverability situations
- Ripple effects emanating from outages
- Greater impacts experienced by vulnerable communities

These additional cost elements can lead to higher rates for customers. However, as investments in the grid are made to improve resiliency using the slogan “Build Back Better,” service quality can improve to provide some benefits from the rate increases. Additional positive impacts include new jobs and economic development associated with investments in renewable energy, energy efficiency and grid resiliency.

The ramifications of more frequent or sustained grid outages due to climate change can impact society in general, as lack of reliable power can result in food and water shortages, hinder access to health care, cut off communication means and limit the ability of essential services to operate effectively. Changes in climate and the livability of certain areas in and outside of Illinois can potentially result in “climate refugees” as populations migrate away from regions that can no longer sustain today’s population levels. Examples such as Puerto Rico indicate the undesired impacts of extreme weather events on the grid; climate change can make such weather events a reality in Illinois. Social impacts can also include increases in inequity to the extent that the costs associated with climate change affect more severely already vulnerable populations in terms of their housing, transportation, employment aspects and/or in the manner that investments in adaptation and resiliency are allocated.
Environmental impacts of climate change can consist of additional pollution from existing fossil-fueled plants that may be operated more intensely to meet the increased energy demand. On the positive side, climate changes may drive more customers to adopt energy conservation measures and to show preference in their consumption for more renewable resource outputs. Such outcomes can lead to increased reliance on cleaner resources and more efficient energy utilization.

The discussions on mitigation of climate change impacts indicated explicit acknowledgment that mitigation at the global level is needed to address climate considerations. The participants suggested several approaches to mitigate climate-related risks and impacts in Illinois. In line with the lengthy time horizon over which climate impacts endure, several suggested solutions take on a long-term perspective. Among these are the education and training programs of customers and policymakers about the range of climate change impacts on the grid and the adoption of planning methodologies for future infrastructure investments that emphasize the need to include mitigation of still unknown but with possibly more severe and serious impacts in the future. Such approaches abandon the implementation of short-term “Band-Aid” strategies. Other suggested approaches include the formulation of effective incentives for wider DER deployment and the push to seize on opportunities for additional electrification. In addition, the expansion of the renewable portfolio standard, adoption of a clean energy standard and the establishment of a fuel economy standard were other approaches that were proposed.

While the proposed approaches can help to create a cleaner, more efficient grid over time, some solutions can also help to mitigate climate impacts on the grid. Utility-rate design mechanisms and communication technologies can be configured to provide more real-time information to customers to signal changes in consumption and to possibly help to manage situations that entail increases in peak demand periods. The incorporation of factors such as environmental issues, equity and resiliency into the wholesale market prices can be instrumental to provide quantification of the value of avoidance of further climate impacts.

WG6 discussion participants expressed that, in general, future grid investments need to promote resiliency, particularly for critical service providers, such as police, fire and hospitals, whenever feasible. Public-private partnerships can be effective mechanisms, under certain scenarios, to encourage investments that otherwise are not undertaken. Participants in the WG6 discussions also stressed that future investments in the grid need to be made with a focus on equity across communities. The discussions stressed that Illinois needs to continue to use state policies to overcome gaps in federal climate policy through steps such as formulation of emission reduction targets and the specification of carbon pricing.

The deliberations on the impacts of climate change and the proposed mitigation measures provide a useful basis for the future work on policy formulation and implementation strategies.

6.3 Beneficial Electrification

Electrification occurs when a device or service that had been powered by a primary energy source shifts to electricity to provide the required energy. A good example is a vehicle owner who replaces an internal combustion engine car by an electric battery vehicle. The “beneficial” characterization of electrification refers to those switches that provide benefits to customers, the environment and the grid, without any associated adverse impacts. For example, consider the substitution of a petroleum-burning heater by an electric heat-pump water heater that provides the switching customer benefits in the form of lower costs over the equipment lifecycle, together with emission
reductions, as long as the electric-generation mix on the grid is cleaner than petroleum utilization for electricity—as is the case, in general in the US

Also, such a switch provides grid flexibility through energy storage deployment and demand shift to off-peak periods, and so is considered beneficial electrification. On the other hand, if that electric heat-pump water heater raises new environmental concerns, incurs increased yearly maintenance costs or simply fails to provide the same quality of service, then it cannot be considered “beneficial.” As long as the costs of low- and zero-carbon sources of energy continue to decline and advances in technology and efficiency in fossil-fueled generation plants continue to develop, the further electrification of the energy sector can yield significant benefits to customers, the environment and the grid simultaneously, if such electrification is properly managed and deployed.

The discussions on this topic followed a presentation on electrification, in which six key principles were specified to which state policy makers need to adhere in order to operationalize beneficial electrification. They are:

- Emphasis on efficiency: the maximization of energy efficiency implies the maximization of the electrification benefits, in general
- Recognition of the value of flexible load for grid operations: more extensive electrification can be instrumental in the reduction of peak demand on the grid
- Understanding of the emissions effects of load changes: the avoidance of marginal emissions from fossil-fuel sources yields environmental benefits under replacement by renewables
- Usage of emissions efficiency to measure the air impacts of beneficial electrification: electrification can lead to larger emission reductions whenever the marginal generation is less carbon intensive than the existing fuel source
- Measurement of lifecycle matters: the lifecycle of a particular piece of equipment or technology matters in the evaluation of the overall benefits of electrification of that equipment or technology
- Design of rates to encourage beneficial electrification: flexibility in rate design allows consumers to make choices to minimize their electric bill that are consistent with choices they would make to minimize system costs

Moreover, the presentation also identified the following steps to create a policy framework to encourage beneficial electrification:

- Set goals
- Identify barriers
- Adopt metrics
- Recognize timing
- Include affected participants
- Develop an all-inclusive process

The policy principles and process recommendations serve to provide insights into the nature and scope of beneficial electrification to Illinois policymakers and stakeholders as they assess ways to ensure that electrification is, in fact, beneficial and to maximize those benefits, with the various constraints explicitly considered.

After the presentation, WG6 was partitioned into three subgroups to consider the appropriate responses to the following three questions:
• **What are the benefits to Illinois from the pursuit of a strategy of beneficial electrification?**
• **What are the key challenges to Illinois in the adoption of such an approach?**
• **How to effectively address the identified challenges?**

In the paragraphs below, we describe the subgroup perspectives reported to the entire WG6. In terms of environmental benefits that Illinois can expect, some participating stakeholders asserted that more widespread electrification can reduce emissions and improve local air quality, in general, under the assumption that the emissions produced by the Illinois’ electricity generation mix continues to decline. For example, replacement of conventional combustion-engine cars by EVs reduces the gasoline or diesel consumption and, consequently, reduces air pollution impact, so long as those EVs are charged using lower-emission electricity generation and provided such charging is optimized to avoid increases in capacity additions of new generation or the use of higher-emission electricity generation on the margin. As such, electrification of the transportation and other sectors represents a significant opportunity for reduction of greenhouse gas emissions. We note that due to its large nuclear power plant fleet as well as its growing wind resource utilization, Illinois produces considerable amount of zero emissions electricity.

In addition, beneficial electrification can reduce financial as well as environmental costs for Illinois customers. As the total cost of ownership of an electric appliance is, typically, below that of a functionally-equivalent non-electric appliance, electrification of that appliance reduces a consumer’s energy costs, particularly, when its operation is scheduled during off-peak electricity demand periods. Virtually all Illinois customers currently are offered RTP electricity, but only a small fraction of residential customers currently use RTPs. The considerable potential to reap increased benefits from beneficial electrification requires more education and training of customers. Additional opportunities for increased benefits are possible from TOU rates.

Beneficial electrification can also impact positively on the grid. While electrification enhances consumer and commercial productivity, comfort and security at costs below those of current non-electric alternatives are also possible. Electrification represents, as such, new, additional electricity demand that effectively increases the utilization of installed assets. The provision of more electricity supply without additional capacity investment translates into stable customer rates. Indeed, the better utilization of the existing assets can lower system costs in per kilowatt hour terms, provided that such utilization of the system is during those hours when the system resources are not stressed. Opportunities for load shape modifications and peak reductions can also be exploited to contribute to lower generation and delivery costs. Moreover, the grid can also benefit from a reduction in line losses and possibly improved resiliency whenever DERs are sited near the new electrification loads. Investment in grid infrastructure improvements can help utilities facilitate electrification to realize the cost benefits more rapidly although the potential rate increases to recover the investment costs can reduce or, in some cases, eliminate such benefits.

Overall, the investment to accommodate added electrification loads can drive Illinois to emerge as a leader in technology and a role model for other states to emulate. Electrification is not just a goal for its own sake in light of the fact that it supports the important goals of decarbonization, productivity and efficiency improvements and effective grid-modernization. The expansion of the EV charging-infrastructure provides well-paying jobs, numerous economic benefits and efficient technological development to act as a stimulus for economic development in Illinois.
The WG6 subgroup deliberations identified several obstacles to beneficial electrification. In some cases, it may be difficult for a change to meet all the requirements of the definition of beneficial electrification given in the presentation at the initial session on this topic in terms that a change must provide benefits to customers, the environment or the grid without any adverse associated impacts. One set of issues concerns the costs involved. The total costs of ownership of a new appliance that operates on electricity instead of some other raw energy source ideally need to be more economic for a consumer to purchase and use than non-electrified options. In other words, a consumer needs to receive additional benefits above the individual contribution to environmental benefits to justify a switch to that new appliance. Moreover, the consumer must have sufficient capital or access to financing in order to effectuate the switch. Also, as many appliances/products have long lifecycles a switch to the electrical option may not be cost effective, given the remaining life to the current appliance/product. Such a consideration weighs heavily, particularly for low- and moderate-income customers.

The capital costs for the newly added infrastructure required to upgrade the existing transmission and distribution grids may be considerable for utilities. Furthermore, electrification projects may entail additional operational impacts and costs. Under the assumption that all these costs are recovered through rates, customers may react negatively if they fail to perceive or experience immediate benefits. The question of who pays for infrastructure upgrades is particularly relevant when viewed through an equity lens, particularly in cases in which electrified appliances or products are adopted broadly by more affluent communities while low-income consumers are left to shoulder a disproportionate share of the burden. In general, the cost impacts of enhanced electrification merit careful consideration to ensure that the associated infrastructure costs are cost effective from an end-use customer perspective and that such costs do not impose excessive burdens on end-use customers or on industry in Illinois, or do not entail unfair cost shifts.

The lack of flexibility in existing rate structures in Illinois, as evidenced by the challenge to create an equitable TOU rate option other than RTP, may be viewed as an obstacle once electrified appliances and products become more widespread. While utilities do offer an hourly price as well as a critical peak rebate options, enrollment in the specific programs remains low. Customers who are on the traditional, flat average price rates have no economic incentive to not use their additional electrical appliances at times of peak demand. In other words, absent an increase in enrollment in existing TVR programs or the introduction of new options such as TOU rates, new electrification can imply higher demands for electricity at peak periods, that entail higher generation costs and emissions and added strain on the grid.

The absence of a price on carbon is also a serious deterrent to further beneficial electrification. Such an absence exacerbates the difficulty to explicitly reflect the costs society must bear due to the deleterious greenhouse gas emission impacts that are not at present internalized either in the fossil fuel “market” prices or the price of electricity from carbon-emitting sources. The lack of signal on the harmful effects of carbon-intensive generation may inadvertently encourage electrification that would not occur were such costs included in the electricity price. We note, however, that other energy sources receive federal or state subsidies that result in lower their prices. Clearly, the environmental benefits of electrification depend on the environmental profiles of the generation resources and the fuels from which the appliance/product switch is done, which are both time and location specific. The FEJA provisions attempt to include a carbon price by the requirement that the electricity price from zero-carbon resources reflect the value of avoided CO₂ emissions.
Under the assumption that grid resiliency and reliability, as discussed in Section 6.2, are critical considerations in policy formulation, the electrification of more appliances/products and the resultant increases in electricity demand can strain the capabilities of the current infrastructure. On the one hand, in cases of natural disaster caused or man-made outages, electrification without additional grid investment can strain backup energy sources so as to reduce resiliency and hinder timely recovery from service disruptions. On the other hand, for those electrified appliances/products with storage capabilities, as in the case of EVs and water heaters, such electrified loads are able to support localized electricity supply even in cases that the grid itself cannot meet demand due to lack of resiliency.

In light of future benefits that can emanate from beneficial electrification, the WG6 subgroup discourse identified specific strategies that can be deployed to overcome the various obstacles. In order to provide maximum flexibility and customers control over their energy use, Illinois can explore rate design options that are more closely aligned with the actual electricity costs to provide stable and predictable pricing blocks. In addition, additional investments in energy controls and energy efficiency can make flexible rate design more feasible and customer friendly. Indeed, the specification of a price on carbon to indicate the actual price of electricity compared to that of fossil fuels, can encourage additional deployment of renewable and zero emission resources, energy efficiency and demand response, and can serve to show that electrification is beneficial to the environment. Some or all of the revenues from the collected additional carbon price can be re-invested in efficiency programs and the infrastructure required to support additional electrification.

Stakeholders also proposed incentives to encourage customers to adopt technologies and approaches that favor efficient electrification over less-efficient, conventional technologies, such as the replacement of gas-powered water heaters and internal combustion engine vehicles. Illinois can identify the best targets for initial electrification so as to maximize the “bang for the buck”. Also, low- and medium-income communities may be prioritized to ensure that all consumers receive their proportionate shares of the electrification benefits and to avoid subsidies by certain customers of the benefits of others. The discussions emphasized the importance that Illinois become aware of possible conflicts between different policy goals, such as those of energy-efficiency requirements that aim to reduce overall demand versus the aims of beneficial electrification that are likely to increase the total load served.

Furthermore, the participating stakeholders strongly suggested that Illinois needs to encourage utilities, businesses and public institutions to invest in technologies and pursue policies that can accelerate electrification to facilitate widespread adoption of measures to develop electric vehicle fleets, rural electric-vehicle corridors, community solar, building technology and electrified autonomous/ride-share transportation options and other appropriate non-transportation utilization of fossil fuels. To the extent electrification is beneficial, such policies can help Illinois realize additional benefits.

The results of the wide-ranging discourse on beneficial electrification pinpoint important considerations to include in the formulation of new policies and strategies to enable Illinois to garner the additional benefits that electrification can provide.

**6.4 Pathways to Decarbonization**

Decarbonization programs established in various jurisdictions come in several forms, including market-based trading mechanisms, e.g., a public or private trading market and registry or a regulatory cap-and-trade program, a direct price on carbon emissions, e.g., an upstream or retail-
level carbon tax, and non-price-based policies, e.g., efficiency standards or specified levels of renewably energy resource deployment. A well-known market-based decarbonization program is the Regional Greenhouse Gas Initiative (RGGI), which covers the states in the northeastern and mid-Atlantic regions. The RGGI states have participated in over 40 allowance auctions during the past ten plus years to reduce CO2 emissions in the power sector by more than 50 percent and to raise $2.9 billion from the program to reinvest in their economies, all the while the states’ GDPs grew during the same period. RGGI has accelerated the transition to cleaner energy sources, with half the current power generation in RGGI states produced by low or no-carbon sources. Also, the investments in energy-efficiency programs funded by RGGI proceeds reduced electricity consumption and helped to further reduce fossil fuel consumption. The RGGI efforts are estimated to have created $4 billion in net economic benefits and tens of thousands of new jobs. Other notable decarbonization regimes include the California-Quebec cap-and-trade system and British Columbia’s carbon tax. These and other decarbonization programs in various venues are worthwhile to study and assess for Illinois in its consideration of a particular regime for the state to adopt to further decarbonize.

The first item in the session devoted to the decarbonization pathways topic, participants in WG6 were surveyed on the following two questions:

- If Illinois were to put a price on carbon and other greenhouse gases through either the imposition of a tax or the establishment of a cap-and-trade system, what information is required by Illinois policy makers and what factors they need to take into consideration prior to the development and implementation of such a system?
- If there are pollution issues that need to be addressed in addition to carbon and other greenhouse gases, what are those pollution issues and how should they be addressed?

The responses to the first question of the survey were classified into five categories: the types of required information; the regulatory structure issues; the economic aspects; the environmental aspects; and the disbursement and allocation of collected revenues. The survey responses included the following examples of information that Illinois needs to collect prior to specification of the decarbonization policies:

- Target levels for the optimum emissions and reductions within specified time points
- Information on the availability of emission inventory data and effective monitoring systems
- A comprehensive understanding of the social, economic, public health and environmental costs and benefits of a state carbon price
- A measure of the damages caused by emissions and the costs of abatement
- A definition of “environmental justice communities”
- The extent to which an Illinois program would have jurisdiction over, or have impacts on, emissions from generation assets located in other states
- All applicable lessons from California’s cap-and-trade system and from RGGI
- General information on the emission legislative and regulatory regimes of other states

This list provides a good starting point on information requirements and additional items can be added once Illinois starts on its initiative on decarbonization policy and regulation. The regulatory structure issues proposed by the survey respondents include:
• Specification of the tax terms or the carbon price at a level adequate to obtain the desired reductions or targeted revenues
• Determination of the desired level of emission reductions that can be obtained by harnessing of market forces
• Specification of all activities in the designated geographical regions of the states whose emissions must fall below the cap, price or tax, with explicit consideration given to the appropriate integration of the Illinois program into the PJM and MISO wholesale electricity markets
• Program design without loopholes to ensure that leakages are prevented
• Comparison of the relative merits of a tax imposition vis-a-vis a cap and trade mechanism
• Given the relatively low carbon cost established under FEJA and the similarly low prices experienced in the California and RGGI carbon markets, the recognition of the appropriate value for the social cost of carbon or the carbon price specification is of critical importance
• Determination of effective interactions and appropriate alignment of the Illinois program with those of other states, with the recognition of the state boundaries, the generation out of state sites and the option to join existing programs instead of the creation of a brand new program
• Decision on the entity that implements and administers the Illinois program
• Decision on the entity that collects the program revenues, collection mechanism and the allocation/disbursement of the collected funds

The decision making on these issues is of paramount importance to ensure that the program meets its intended goals. The economic issues proposed by the survey respondents include:

• The specification and determination of the appropriate carbon price
• The allocation of the payments among customer groups and their levels
• The impacts of a carbon-price program on Illinois’s economy and its competitiveness
• The impacts on energy-intensive industries
• The impacts on Illinois’s coal production sector
• The burden on public-sector entities of a carbon cap, price, or tax
• The burden on disadvantaged populations of a carbon cap, price or tax, bearing in mind considerations of equity and environmental justice
• The disbursement of the collected revenues to ensure the program objectives are met

The decision making on these economic issues is of critical importance to ensure the success of the implemented Illinois program. The environmental issues proposed by the survey respondents include:

• The impacts of a carbon price or tax on the existing zero emissions credits program and the Illinois RPS
• The impacts of a carbon price or tax on the transportation sector carbon emissions
• The trades-offs between a carbon price or tax and the direct encouragement of zero-carbon generation
• The need for the electrification of transportation, heating and other sectors to achieve deep decarbonization
• Legacy issues associated with coal in Illinois

The resolution of these environmental issues is key to the ability of the Illinois program on decarbonization to meet its goals. The responses to the question on the disbursement of the collected revenues include the following suggestions:

• Refunds to consumers to offset the possibly higher payments for electricity consumption
• Investments in energy efficiency and clean-energy technologies
• Targeted funds for environmental justice communities
• General revenues to the state

In response to the second survey question regarding other, non-greenhouse gas-pollution issues that need to be addressed, the responses identified pollutants in water and other solid wastes, hazardous air pollutants (such as mercury), criteria air pollutants (particulates, ozone, SO₂, NOx, etc.), impacts from the entire lifecycle of renewable and storage technologies, carbon embedded in products brought into Illinois and air pollution from trucks in low-income neighborhoods. As possible mechanisms to address these additional pollutants, the responses suggested the following measures: market-based programs, prioritization by the utilities of clean generation deployment, creation of recycling and disposal policies, phase out of diesel generation at backup plants and replacement by storage resources and a focus on the reduction of other emissions with the reduction in CO₂ as a side benefit.

The WG6 participating stakeholders benefitted from a detailed presentation on market and regulatory pathways to decarbonization, which was followed by the partition of the WG6 members into three subgroups to consider the appropriate responses to the following three questions:

• Given the considerations required to establish a system to price carbon emissions, what are the expected benefits for Illinois from such a system?
• What are the key challenges in the adoption of such a system by Illinois?
• How to address those challenges?

In the paragraphs below, we describe the subgroup perspectives reported to the entire WG6. Participating stakeholders identified various benefits that can emanate from Illinois’ establishment of a carbon price or tax. The reductions in carbon emissions through a pricing mechanism likely lead to cleaner air for Illinois, as well as cleaner water, healthier communities and healthier individual Illinois residents because incentives for reductions in greenhouse-gas emissions are also expected to produce reductions in co-pollutants. A price on carbon can result in additional investments in renewable energy and energy efficiency.

A carbon price or tax can also bring significant economic impacts. The drive to lower emissions can spur technological innovations in energy efficiency, electric vehicle technology and other cost-effective and scalable technologies. Moreover, such developments create new jobs and increase investments in the state. Communities are likely to benefit from a healthier environment and from investments that result from the disbursements from the new revenue streams from a carbon price or tax. Also, an Illinois carbon price policy heightens public awareness of the effects of carbon emissions. Overall, the introduction of a carbon price or tax can result in decisions by Illinois residents in their homes and communities to better protect the environment from carbon impacts. An added outcome of a state carbon price is the opportunity for Illinois to assume a leadership role.
in this policy arena either as a collaborator with other jurisdictions already on the path to introduce similar policies, or as a role model for other states with interest to pursue such a policy.

While the impacts on a particular participant in the state’s economy can be positive, negative, or neutral, the overall economic impacts of a prospective carbon-price policy in Illinois are unknown. Although evidence in other jurisdictions indicates the potential for economic growth for the state, the uncertainty surrounding possible negative economic outcomes, such as increased energy costs and customer rates, worker dislocation, or other negative impacts on the state’s economic competitiveness, may pose an obstacle to Illinois policymakers to establish such a system or a reason not to pursue such a course of action. Whether or not such negative impacts would actually occur is an unknown due to the many sources of uncertainty.

Political resistance may also arise from disagreements over how to spend any new revenues collected from the carbon price or tax and concerns around the uncertainties whether those revenues would be applied to the intended purposes. Similarly, doubts over the ability of a state-level program to ensure both system-wide and local public-health benefits can generate political reticence towards the creation of a new program.

Concerns about effects on low-income and environmental justice communities also need to be carefully addressed. For example, without other limitations or enforcement efforts, a market-based approach can increase emissions—or not decrease them—in environmental justice communities. Increased electricity prices can also negatively affect low-income communities and other Illinois ratepayers if there is not a corresponding rebate of carbon fees to consumers. Higher prices can also cause energy-intensive businesses to move jobs and tax dollars out of state.

Policy and market integration and coordination with other regional entities may create obstacles for an Illinois-specific carbon-pricing policy. The required coordination with MISO and PJM may also create additional costs for such a program, while a lack of consistent policy with that of the other states and of the federal government can diminish the effectiveness of the program’s carbon reductions and hinder the state’s economic competitiveness, vis-à-vis that to its neighboring states, if not appropriately addressed. Certainly, there is no shortage of challenges associated with the introduction of a carbon program.

WG participants discussion examined a range of strategies to address these challenges that can arise were Illinois to implement a carbon-price policy. Illinois may draw from the experiences of the RGGI states and California to avoid potential pitfalls in the design of its own program. Furthermore, Illinois in its pursuit of a carbon-price policy has the choice to become part of an existing program or to establish its own venture. In the case of the latter choice Illinois can attempt to enlist its neighboring states to construct a regional, broad-based approach, which can help the state avoid certain economic and administrative challenges, such as industry migration from Illinois to other states. In order to avoid problems and mitigate potential negative impacts of a carbon price, the state must consult early and often with affected stakeholders, including but not limited to all relevant state, federal and regional regulators, utilities, industry groups, ratepayer advocates, municipalities, environmental organizations and environmental justice communities, to ensure a new policy choice does not disproportionately negatively impact certain segments of the state’s population, business community or any other group of utility customers. The engagement of various stakeholder groups early in a dynamic, inclusive policymaking process, the state has better chances to craft a sustainable, successful program. There are opportunities to use revenues
from the program in targeted ways to mitigate any predictable negative impacts of the program, in the form of either customer rebates or appropriate transition planning for affected communities.

The specification of clear policy goals for a new program initiative can also help Illinois navigate challenges that arise in its subsequent implementation. A potential carbon cap or tax can initially cover a single, specific sector of the carbon emitter economy to give program administrators an opportunity to evaluate how its effectiveness and efficacy so as to make needed modifications before its expansion to other emitters and to reconcile its effects with those of other environmental initiatives, including beneficial electrification. An independent entity can be engaged or established to monitor the program with relevant, meaningful metrics to measure its efficacy to achieve its goals and to make well-justified recommendations for its enhancement. The program can continually be steered to ensure its effective and efficient integration with the state’s RPS, energy efficiency and REC and ZEC markets so as to maximize the aggregated net benefits.

Some participating stakeholders cautioned that prior to Illinois’s commitment to the implementation of new environmental policies on carbon price or tax and grid modernization investments, the economic impacts of such policies must be carefully vetted to identify undesired ramifications such as higher end-use customer electricity costs, cost-shifting among customer classes and harm to the state’s industry competitive position, particularly relative to that in neighboring states. Such an assessment must include detailed cost-benefit analyses, using an accepted methodology that does not predetermine the outcomes and considers the need for cost caps, to ensure that these policies produce benefits for Illinois end-use customers in excess of their costs. In this way, Illinois can ensure that before policymakers proceed on any grid modernization or environmental initiatives, unintended ramifications, such as the imposition of substantial additional cost burdens on end-use electricity customers and unfair cost burden shifts to large industrial customers, resulting in cross subsidization—a violation of the cos-causation principle in ratemaking, are avoided.

Throughout the discussions, the participating stakeholders emphasized the importance and necessity of a public educational/training campaign to clearly articulate the rationale for the implementation of a carbon price program, its impacts on individuals and communities and the disbursement of the revenues collected from the program. An effective campaign provides assurance to the public of the goals of the program and also safeguards its long-term viability.

6.5 Concluding Remarks

As this summary of the discussions and deliberations of the WG6 stakeholders indicates, the transformation of the electric grid currently underway creates countless new opportunities to innovate in the protection and the utilization of Illinois’s environment as the energy needs of all of its citizens are met safely, reliably, resiliently and cost-effectively. The various views expressed also underline the critical need that this ongoing transformation carefully consider new, detrimental environmental impacts on the grid from the rapid changes in Illinois’ climate that are currently underway. Such care is needed in the continuing integration of deeper penetrations of DERs in their various technology forms, the movement toward electrification supplied by low-carbon resources such as wind, solar and nuclear energy and the development of sustainable pathways to decarbonization. All Illinois players—consumers, electric power industry entities and regulators—need to effectively balance the environmental, public health and economically beneficial and disadvantageous outcomes from existing and future policies, regulations and
statutes—to ensure an economically efficient, reliable, resilient and clean electricity supply and delivery system for Illinois in the coming years.

The broad range of diverse views espoused by the WG6 participating stakeholders gave rise to many thoughtful ideas, questions and candidate solution approaches that provide a good starting point in future deliberations about the opportunities and the challenges that must be addressed as Illinois transitions to the NextGrid environment. Clearly, there are many issues and concerns that require further study and investigation, thoughtful analysis and large volumes of data as Illinois maps the steps needed to realize the full potential of the NextGrid transformation. What also undeniably became clear throughout the NextGrid study process for WG6 matters is that the participation of all parties with a keen interest in the changes brought on by the NextGrid concepts is the best way to ensure that Illinois' future grid works for everyone.
7. Ratemaking

This chapter provides a summary of the numerous presentations, lengthy discussions and the feedback sessions held WG7. The intent of the presentations was to provide a platform for the discussions of rate alternatives to support the future electricity grid. The individual participating stakeholders introduced their own assumptions to advocate their specific proposals. There was no independent verification of data used in the presentations. No effort was made to forge consensus and, similarly, there was no effort to catalog points of disagreement. That was not the intent of the WG. While the depth of discussion on various topics was limited by time, the interchanges serve to lay the foundation of a framework for continuing dialog. The representations and some of the discussion below may reflect opinions shared by all WG members, other parts of the discussion may not. The WG Leaders tried to leverage points of disagreement to stimulate discussion.

Ratemaking has always been a principal part of public utility regulation. It consists of three distinct phases: determination of the revenue requirements, allocation of costs, and design of the charges to provide the utility the ability to recover those costs. Ratemaking therefore determines how much revenue that utilities are allowed to collect from customers and what they will supply in exchange. Each of these decisions requires good information to support the regulatory pursuit of the public interest. Ratemaking has far-reaching effects. The prices that result from the ratemaking process play important functions affecting customer behavior, e.g., how much electricity to consume and whether or not to self-generate, and utility incentives, e.g., performance metrics, decoupling, and energy-efficiency cost recovery. They also directly affect the ability of a utility to recover its costs and maintain financial health.

The objectives of the ratemaking process are framed by constitutional and legislative mandates, judicial and regulatory decisions, and various policy objectives. These objectives include establishing of just and reasonable rates for customers and utilities, support of fair treatment of utility customers, utilities’ financial health via reasonable returns and accurate revenue requirements, reliable service, promotion of the efficient electricity use, and acceleration of customer-driven decarbonization and new and emerging customer-oriented technologies. Ratemaking can also help address many of the challenges facing the electric utility industry. While stakeholders may disagree about certain goals and the best way to achieve them, ratemaking can help to make the industry more efficient, more responsive to customers, and advance other public-policy goals.

Throughout its history, state utility regulation has searched for that particular rate design or cost allocation methodology most compatible with the evolving concept of the public good. In the late 1960’s and 1970’s, stakeholders’ pressures on regulators, supported by economic theory—largely championed by Professor Alfred Kahn—led to new rate mechanisms, such as future test years, fuel-adjustment mechanisms, special rates to certain industrial customers, seasonal rates, construction work in progress in rate base and phase-ins of new expensive power plants. Utilities and others have also proposed various rate mechanisms over the past several decades. These mechanisms, typically, reflect a departure—sometimes incremental, other times more radical—from conventional ratemaking practices. In certain cases, stakeholders promoted these alternative rate mechanisms because of technological developments, changing market and operating environments. In some instances, requirements to evaluate alternative ratemaking forms were mandated by legislation, such as the Public Utility Regulatory Policies Act of 1978 [8]. In others, for example, decoupling, parties or regulators saw environmental and financial stability benefits.
Alternative ratemaking mechanisms, considered in the past, encompassed a wider range of options. Stakeholders in the regulatory process in recent years, for example, have expanded their interest in nonconventional rate mechanisms to include different cost and capital investment trackers for an increasing number of utility activities, time varying rates (TVR), performance-based ratemaking, revenue decoupling, formula rates, new rate designs and surcharges for new investments. At the same time some customer groups have opposed such mechanisms, believing that they resulted in higher costs for customers and diminished regulatory oversight.

All regulation is, in part, incentive regulation. Given the practical limitations on the regulator’s access to information and capacity for oversight, utility regulation inevitably relies, implicitly and/or transparently, on the incentives created by the regulator’s chosen method of ratemaking. Alignment of regulatory incentives with attainment of the goals assigned to utilities has always challenged regulators. Examples of rates to create new incentives, under discussion in a number of states, currently include straight fixed-variable-type rates, including rates with higher customer charges and three-part tariffs that include a demand charge for residential customers, real-time pricing, multi-year rate plans, price caps, surcharges for innovations and creation of a separate rate class for distributed energy resource (DER)13 customers, cost-based standby rates14, and performance-based rates for utilities15. Some argue that these structures do not represent improvements, as they have shifted risk on revenue recovery and increased prices to customers.

As DER penetrations deepen, some observers have asserted that regulators may need to address how utilities can recover their costs to maintain resource adequacy (when provided by the utility) and delivery service16 (offset by grid benefits provided by DER). In Illinois utilities do not recover energy costs because they are no longer vertically integrated. Continued reliance on the volumetric component of utility rates to recover costs that do not directly vary with delivered power will

13 DER includes technologies, such as rooftop solar, energy storage, energy efficiency and demand response that provide generation or allow a customer to reduce or manage its demand.

14 Most DER systems require backup, supplemental or maintenance service from a utility. The rates charged for these services can affect the economics of a DER project. A desirable outcome of appropriate standby rates is to not discourage economic combined heat and power (CHP) and avoid a subsidy from full-requirements customers. Less-than-full cost recovery by the utility shifts costs to other customers; more-than-full cost recovery results in excessive payment by DER customers making DER less economic. Overall, a good standby rate results in no subsidy, is fair to DER customers and full-requirements utility customers and does not discourage good DER projects nor encourage bad DER projects.

15 Illinois has statutory provisions for performance-based utility rates (220 ILCS 5/9-244). In a general context, appropriate performance-based rates provide an affirmative response to the question whether customers get value for their money. Evaluation of utility revenues considers various metrics – reliability, service quality, DER penetrations, energy-efficiency savings—that benefit customers and society as a whole. The question then becomes, based on utility metrics, what revenues regulators allow utilities to earn. In this aspect, performance-based rates are similar to the U.K. RIIO mechanism. Performance-based rates can involve formal incentive mechanisms or simply rate adjustments by regulators based on their judgment of whether a utility performed exceptionally well or below par. The latter approach is problematic if the regulators’ decision is done after-the-fact in an ad hoc fashion, rather than by the upfront application of rules and criteria to the utility.

16 The Public Utilities Act defines delivery service (220 ILCS 5/16-102) as “those services provided by the electric utility that are necessary in order for the transmission and distribution systems to function so that retail customers located in the electric utility’s service area can receive electric power and energy from suppliers other than the electric utility, and shall include, without limitation, standard metering and billing services.”
present challenges\textsuperscript{17}. As some WG members noted, the Illinois policy innovations are designed to ensure that all customers have opportunities to reduce their bills through DER and energy efficiency, with broader value to the grid and the electric utilities ensured. Others have noted that currently, the Illinois electric utilities face nearly zero risk in the cost recovery, due to the formula rates and the various rider surcharges that permit the utilities to recover discrete costs, including, inter alia, uncollectibles and energy-efficiency riders which provide a return on the investment along with an additional incentive payment for extraordinary performance. Risk reduction for ComEd’s corporate parent was also engrained in the Future Energy Jobs Act (FEJA) \cite{5} with the inclusion of the so-called zero emissions credit (ZEC) customer surcharges. As such, with the enactment of the Energy Infrastructure Modernization Act (EIMA) \cite{4} and FEJA, the utilities enjoy virtually risk-free cost recovery.

Concerns have been raised by utilities, stakeholders, and analysts about the ability of current ratemaking practices to support or adapt to the industry’s ongoing transformations. Some concerns arise from the interest to protect particular parties or stakeholders, while others from a more general, public-interest perspective. Even in those jurisdictions without anticipated radical industry reform, utilities and other stakeholders and their regulators are contemplating changes to long-standing ratemaking practices that may become necessary in the future. Comments from some parties contend that current ratemaking practices are adequate to induce innovation by utilities and market participants, with the financial incentives already built into the regulatory and ratemaking processes. No presentations, however, were offered to further develop such a position.

Illinois is in a rather unique situation, because the state already has set up formula rates that make adjustments to utility revenues on an annual basis. The WG explored some current ratemaking practices, which have become the source of contentious debates in several states—both in terms of the seriousness of the concerns and the potential remedies proposed. These include:

- Financial effects on utilities from reduced sales, given the typical rate design that recovers most fixed costs through volumetric charges; however, one stakeholder noted that despite declining revenues over the last several years, electric utility earnings have grown.
- Rates and rate design for both DER and full-requirements customers that, for example, may reduce the share of fixed costs recovered from DER customers or may include volumetric rates that lead to charges above societal marginal costs.
- Potential inability for customers to appropriately manage their energy usage or receive incentives to invest in DER, including energy-efficiency and demand-response programs, higher than the resulting system benefits.
- Imbalance of risk allocation between utilities and their customers.
- Undue economic damage to third parties who compete with the utilities to provide specific services.
- Inappropriate pricing—over- or under-pricing—of surplus power generated by DER-owning customers.
- Insufficient compensation to DER-owning customers for the value contributed to the utility grid by their DER.
- Deficient DER-customer payment to the utility for standby and other grid services.

\textsuperscript{17} One reason is that utility rates to core or full-requirements customers may rise faster as more customers migrate to DER.
- Excessive rates for standby service from the utility.
- Inadequate price signals for customers to correctly reflect market prices and environmental impacts of their usage.
- Uniform prices across all time periods and at all locations in a utility service territory.
- Underdeployment of smart technologies to provide more efficient pricing and enhanced customer energy-management options.
- Subsidies vs. cost shifting due to inefficient rate design between DER adopters and customers without DER ownership.

The report summarizes these concerns and the deliberations of the WG7 that have addressed them with broad strokes. We note that the ICC will be involved in other regulatory forums, such as future rate cases that will discuss issues under [8]. We refer the reader to Appendix F for the definitions of the terminology used in this section and the rest of the chapter.

Today, regulators face several challenges in ratemaking. They include the following:

- The limits of authority under the law within which to decide how utilities are provided the opportunity to recover their authorized costs.
- Regulators and stakeholders are being confronted with additional public policy objectives, such as environmental considerations and customer interest in the adoption of new technologies, such as DER. The ability to reach compromise solutions has become more challenging, given the growing array of interests in the regulatory process. In the public interest theory of regulation, the regulatory body has an active role that “does not permit it to act as an umpire blandly calling balls and strikes for adversaries appearing before it” [109]. Indeed, it has an affirmative obligation to advance the public interest. In a dynamic environment, the continuation of existing rates and policies may not constitute the best or, in some cases, even a reasonable response to emerging challenges. As a result, regulators may need to consider whether to adjust ratemaking to enhance net value for consumers and society and, within this context, how to provide an appropriate return to the utility and balance equity considerations affecting different stakeholders.
- As interest in clean energy sources grows, regulators need to explore and refine new concepts of cost and grapple with issues of revenue shifting.

Overall, good ratemaking demands both good analytics and sound judgment by utilities in rate proposals and, similarly, by regulators and stakeholders in their assessments. Good ratemaking, as well as any regulatory action, requires well-informed decisions driven toward the public good.

The major challenges in future ratemaking for electric utilities in Illinois include the following:

- A reasonable opportunity for utilities to recover prudently incurred cost
- Balanced cost allocation across different customers and balanced risk allocation—upside and downside—between the utility and the customers
- Benefit maximization from smart meters, new technology and data deployment
- Service affordability for low-income customers
- Resolution of conflicting objectives for ratemaking with the implication that satisfaction of a specific objective at the cost of one or more other objectives not being met
• Concerns that cost socialization and subsidies to encourage distributed generation and new clean energy technologies—including the appropriate definition and measurement of costs—may require utility customers to pay for infrastructure without any direct or little no benefits to them
• Fair and efficient rate design and efficient pricing for both the output and utility services to support DER deployments
• Definition and scope of the “public interest”
• Resolution of the management of volumetric pricing or fixed rates in the new environment

Although ratemaking is both an art and a science, it requires a strong foundation consisting of specified objectives and tacit recognition of underlying economic principles, such as cost recovery and causation. Regulators must then supplement these factors with good judgment based on evidence and information that reaches beyond unduly favoring special interest groups. At its core, regulators must translate private interests into the public interest.

In Illinois, rates must be “just and reasonable,” and any rate that is not just and reasonable is unlawful [2]. As a general practice, regulators set rates so that utilities have the opportunity to recover their authorized costs. The regulators determine the new rates to be sufficient to allow utilities to attract capital necessary to finance their operations to provide the services consumers demand, while at the same time charging consumers a fair price for the services purchased. These requirements imply that customers are charged no more than necessary to give a utility an opportunity to recover prudently-incurred costs, including depreciation, and a reasonable return on their investment. Many decades of ICC and court decisions in Illinois have established a body of law defining what it means for a rate to be “just and reasonable” 18. At the conclusion of each rate case, for example, the regulators consider the utility’s new rates to be “just and reasonable” on a forward-going basis.

The WG members identified several topics and questions that need to be addressed. They include:

• What outcomes are desirable in the NextGrid environment?
• What are the rate design objectives?
• How appropriate are current rate mechanisms for achieving these outcomes?
• Which pricing option—real-time, time-of-use or critical peak—is preferable, if any?
• Do advanced rate mechanisms require more granular data than presently available?
• How can ratemaking stimulate the development and deployment of innovative technologies?
• Is there a need to apply performance-based regulation more extensively or differently?
• What is the appropriate cost basis for ratemaking?
• Are formula rates performing in the interest of utility customers and the public good?
• Can present data be better exploited for ratemaking?

18 If a utility constantly earns below its authorized rate of return (i.e., its cost of capital), it may discourage utility investments that jeopardizes the quality of utility service or, in the worst case, cause severe financial problems that may lead to bankruptcy. The fact that the history of state utility regulation has seem few bankruptcies shows that one of its long-term objectives is to avoid utilities from experiencing severe financial problems.
• Is there a need to revisit pricing for partial-requirements customers?
• Which current ratemaking mechanisms require further consideration?
• Which specific “new” ratemaking mechanisms should be considered?
• How will new ratepayer mechanisms help to achieve the desired outcomes in the NextGrid era?
• Is there empirical evidence that new ratemaking mechanisms can benefit customers and advance the regulatory/policy goals underlying NextGrid?
• How can regulators and policymakers weigh the pluses and minuses of ratemaking mechanisms to select the appropriate ones to advance the NextGrid goals?
• Is there agreement among WG members about specific ratemaking mechanisms that they would adopt, reject or consider further? If so, what are they?
• What are the primary ratemaking objectives and do such objectives include provisions to allow a prudent utility a reasonable opportunity to receive sufficient revenues to attract new capital without encountering serious financial difficulties?
• What are additional objectives and do they include the following: public acceptability causing severe political backlash; rate stability and gradualism without rate shock; affordable utility service to low-income households; price signals based on marginal-costing principles; efficient competition on a level playing field; moderate regulatory burden with streamlined rate cases; and promotion of specified social goals to clean up the environment?
• What is the best path forward for ratemaking in Illinois?

These topics and questions are detailed in the remaining chapter sections, as are the many issues that came up during the lengthy deliberations. The premise underlying WG7’s efforts is that the preparation for the NextGrid world warrants an examination of current rate mechanisms that can effectively accommodate the major changes in the electric industry, including digitization, the transformation of consumers into prosumers and the movement toward decarbonization.

The WG7 presentations served to educate all WG7 members and stimulate the ensuing discussions. This chapter is to some extent investigative, as it identifies major ratemaking topics and the related issues and then explores a representative range of viewpoints on those issues. The chapter first reviews the current ratemaking structure for ComEd and Ameren in Illinois. There follows a discussion on time-varying rates (TVR), performance-based regulation and DER valuation.

### 7.1 Current Ratemaking in Illinois

For many decades, Illinois utility rates have been set by the ICC using the conventional cost-of-service approach favored by most state regulatory agencies. Rate cases are held periodically, when either the ICC or, more commonly, the affected utility, determines that a rate adjustment is warranted. In those cases, which are governed by Section 9 of the PUA [8] and the Commission’s associated rules, evidence is adduced from all interested parties and the decisions rendered. Once rates are set, they remain in place until the next rate case, with provisions for some cost elements that were substantial, volatile and beyond the utility’s control, e.g., fuel costs, to be adjusted in between rate cases. The Electric Service Customer Choice and Rate Relief Law of 1997 [2] significantly affected the ratemaking process, causing the electric utilities to unbundle their formerly bundled rates, in order to price delivery service separately from generation and transmission service. Delivery service rates were first established in 1999 and are adjusted thereafter using the conventional rate-case approach.
The Energy Infrastructure Modernization Act of 2011 (EIMA) [4] radically changed ratemaking for ComEd and Ameren. EIMA gives the two utilities the opportunity to use formula ratemaking in return for a commitment to infrastructure investments that strengthen and modernize the grid, including investment in smart grid technology [8]. Also, as originally enacted, EIMA included sunset provisions which terminated the formula ratemaking process at the end of 2017; this provision has since been modified twice, once to move the sunset date to the end of 2019 and the second time to move it to the end of 2022. Under formula ratemaking, (1) ComEd and Ameren committed to $3.2 billion investment over 10 years for upgrades, distributed automation, smart meter implementation; (2) the regulatory process was streamlined to allow more rapid adjudication and inclusion of costs into rates; (3) there is increased certainty and timely recovery of utilities’ prudent and allowed investments and expenses; (4) the utilities invested in AMI after ICC approval of an implementation plan; and (5) prescribed treatment is applied to, among other things, the rate of return on equity (ROE), return on pension assets, incentive compensation, rate-case expense and amortization of costs such as storm damage over a threshold. Utilities, in addition, must meet several performance targets, which if not met, result in ROE reductions19.

Some contend that utility customers have benefited from formula rates through improved resiliency and stable rates. In addition, the streamlined regulatory process has resulted in a proceeding to adjudicate contested issues, eliminate regulatory lag and maintain the ICC’s ability to review the prudence of all costs included in customer rates. Other stakeholders have noted that legislative action taken subsequent to the EIMA’s enactment limited contested issues, and that the utilities’ investment plans were reviewed differently outside of the formula rate cases themselves. Further, there is a contention by others that rate stability has been due primarily to wholesale power costs, not delivery-service rates, which are the only component covered by formula rates.

In addition, the regulatory process has been streamlined with infrequent contested issues during formula-rate proceedings, leaving ICC’s ability to review the prudence of all investments recovered in customer rates unchanged. Some stakeholders expressed concerns that formula rates have allowed utilities to pass through costs without adequate review, and that utilities are effectively guaranteed their authorized rate of return. In effect, they argue that formula rates have shifted risks from utility shareholders to customers. This was an issue over which different WG members strongly disagreed, some pointing out that the formula-rate process provides ample opportunity for stakeholders to review and contest debatable utility costs. They argued that the risk of disallowance still exists, and all utility investments must be deemed prudent by the ICC. Some believe that certain attributes of the current model, including decoupling and the so-called Uncollectible Rider, distribute risk equally between customers and utilities by correcting for over/under recovery; others, such as the current performance metrics, are one-sided and unsymmetrical, exposing utilities to the risk of reduced ROE if they fail to meet targets without the additional earning opportunity if targets are met or exceeded.

19 Targets are specified in terms of values of performance metrics to measure improvements over baseline values: frequency and duration of customer interruptions, overall improvement in exceeding service-reliability targets, reduction in the number of estimated bills, opportunities for minority-owned and female-owned businesses to participate as utility contractors, and additional performance improvement measures. If the utility does not achieve the incremental annual performance goals over a given period, it must reduce its return on equity by as much as 38 basis points.
The WG7 deliberations discussed at length numerous issues. Some of the major policy questions that arose:

- Are current ratemaking practices in Illinois suitable to achieve the objectives of the NextGrid world?
- Are formula rates to continue indefinitely?
- What problems, if any, arise in the absence of additional performance-based ratemaking for those functions presently subject to cost of service principles?
- Which specific aspects of current ratemaking warrant a revisit?
- Are current ratemaking practices adequate to support the balancing act that regulators perform in the ratemaking process?

In addition, participating stakeholders made presentations and discussed topics that include formula rates, cost of service principles, ratemaking for electric service, risk shift and affordability, and standby rates. The key take-aways of these presentations:

- Until recently, it was difficult to encourage residential customers to go to competitive suppliers; the two developments that changed this situation are the ability to purchase receivables and consolidated billing (PRCB) and the advent of municipal aggregation to allow communities to determine the default retail supplier for all residents in their community.
- Formula ratemaking has changed the regulatory process for ratemaking to a yearly event: by May 1st of every year, utilities must provide accounting information that will affect the rate change beginning the subsequent year; the ICC makes decisions about rates that are effective the following January. The formula rates process separates rate design from revenue requirements.
- Formula rates provide a fixed method for ratemaking compared setting the ROE and removing cost of service and rate design from the annual process to one that occurs once every three years. The formula rates are both backward and forward looking, as they include prior year actual financial impacts and forecasts for the subsequent year. A salient feature is the incentive/penalty that may ensue based on the tracked performance metrics, and is included in a tariff.
- The Future Energy Jobs Act (FEJA) allows utilities to treat energy-efficiency program costs as a rate-base item on which they earn a return through a separate recovery mechanism.
- Changes made to the formula in the most recent statutes extend formula rates to 2022 and allow energy-efficiency costs to be rate-based, provide incentives and penalties related to attainment of energy efficiency objectives, and (3) tighten the ROE collar specification.

Overall, the lengthy discussions provided a valuable assessment on the various viewpoints on some key ratemaking issues. Here are highlights:

- Each ratemaking component—the revenue requirements and the rate design—is critical for the future; participants expressed different perspectives on the relative importance of each.

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20 There is a separate formula and docketed proceeding for the EE costs (different incentives, different ROE, etc.), and also a different "sunset" period.
• The separation of revenue requirements from rate design under formula rates allows for additional time to review rate design, which some stakeholders viewed as under-emphasized in the past.
• FEJA can bolster both energy efficiency and distributed generation with new incentives in place. Some stakeholders argued these incentives already exist or are being accounted for under the new FEJA provisions. FEJA allows electric utilities to earn additional profits for annual energy savings that exceed the ICC-set energy savings goal. The energy efficiency program has an independent, third-party evaluator responsible for reports on savings, which in turn affects ROE, without any chance for “abuse.”
• Marginal cost of service, accepted in most states, is not used in Illinois for actual cost allocation. The utilities have not done a marginal cost of service study since the 1990’s.
• Some stakeholders asserted that formula rates have increased resiliency, stimulated “smart” investments and made rates more predictable for customers. But other stakeholders claimed that formula rates shifted more risks to customers and resulted in significant increases in electric utility service costs.
• Formula rates have helped to stimulate investments in resiliency improvements and AMI.
• An unresolved issue is whether cost of service studies need to be based on embedded costs or marginal costs.
• As a default option, TVR can be more prominent but may have an adverse effect on some customers whose ability to shift usage, either by volume or time of day, is limited, especially vulnerable customers. For this reason, these stakeholders believe that TVR needs to be opt-in only.
• While there has been concern that such rates may have a negative impact on vulnerable customers, other parties asserted that available studies indicate that low-income and other at risk customers tend to respond to price differences and generally benefit from TVR.
• In the area of equitable cost recovery, the marginal-costing-based rates came under close scrutiny. If rates are partly based on correctly calculated marginal costs to reflect efficient cost causation, some residual costs remain that cannot be recovered through marginal cost-based rates alone. For example, a CHP customer who can avoid payment for these residual costs results in other customers paying for the utilities’ recovery of costs. Analogously, any value the CHP provides to the electric system needs to be compensated.
• There was disagreement on whether a least-cost objective is the most desirable from a societal and customer perspective. As argued by some stakeholders, net value may be a better criterion when there are other objectives.
• There are questions as to the extent new data are needed for setting rates in the future, the granularity of such data and whether new data may be unnecessary.
• There was an exchange of ideas on standby rates with questions on whether such rates should be mandated, specific costs to include in such rates, and whether utilities need to undertake a cost-of-service study to determine what portion of distribution costs should be allocated to partial-requirements customers. The discussion also touched on the most appropriate setting to address this matter—
either as part of the rate design proceedings, which occur every three years, or in a special proceeding at the discretion of the Commission.

- Some believe ratemaking that shifts more risks to customers may not be antithetical to their interests, as long as such a shift reduces utility investment costs so that customers may benefit in the long run.
- There are potentially large benefits from smart meters, of which customers have yet to avail themselves.
- Over the past several years there has been less financial assistance available for energy expenses to low-income households at state and federal levels, and available funds fail to meet Illinois’ needs for financial assistance.

These viewpoints are important considerations in future work to create a more efficient and effective rate structure in Illinois for the NextGrid environment.

7.2 Time-Varying Rates

The discussion in this section focuses on time-varying rates—TVR—and so relates primarily to the energy-supply portion of customers’ rates rather than the delivery service portion. Thus, it applies principally to residential customers. Generally, non-residential customers, whose load is above 100 kW, do not take supply service from the utility, and when they do, it is at hourly index prices based on the hourly wholesale rates. Pricing structures for competitive retail supply are generally not under the ICC’s purview. Time-of-use (TOU) pricing differentiates prices by time periods, with fixed predetermined prices between two consecutive general-rate cases. Prices are typically higher during peak periods and lower at off-peak periods. The prices also serve to promote certain technologies, such as distributed energy storage, plug-in electric vehicles, and rooftop solar PV systems. For example, a cost-based, off-peak rate can improve the competitiveness of electric vehicles so as to induce more consumers to switch to electric from gasoline vehicles or to not switch to natural gas vehicles. TOU rates need to be sufficiently flexible to accommodate changing characteristics of supply and demand over time.

Under critical peak pricing (CPP), the utility raises substantially its prices during “critical peak periods,” or for certain specified hours during so-called event days. The goal is to reduce load during those few hours within which the utility has exceptionally high generation or power-purchasing costs. The benefit to customers is that they receive lower prices during non-critical periods relative to those under the standard tariff. A major benefit to the utility is capacity deferral and the reduced probability of shortfalls. In the absence of time-based price signals, such as critical peak pricing or its cousin’s peak time rebate and real-time pricing, customers use electricity without regard to scarcity. Such a situation exacerbates the ramifications of the coincident peak problem and leads to higher costs and, eventually, rates for everyone. Typically, the utility notifies customers in advance of a critical peak event and, under CPP, the number of events per year is capped. CPP is simple to implement, and customers pay truly high prices during only a small number of hours. Its biggest drawback lies with resistance to the utility setting extremely high prices during “stress” periods. This can seriously burden some customers.

Under EIMA [4], both ComEd and Ameren have in place programs which reward customers for reduced consumption during grid stress times. Payments are made to customers using funds received from capacity markets, and customers are not penalized if they fail to achieve a load reduction in response to a request. Real-time pricing (RTP) sets rates at short intervals (e.g., hour-to-hour) in line with a utility’s marginal energy costs—often defined by the market prices during
those times\textsuperscript{21}. A major consideration in RTP design is the five-minute or hourly changes in wholesale prices. RTP links wholesale prices to the retail electricity price, thus giving utility customers more appropriate price signals. The consequence is a more efficient level of total demand and more efficient allocation of electric power across hourly periods. Customers may benefit from lower energy and capacity costs. RTP can also help with the effective integration of renewable energy resources into an electric grid by using load flexibility during all hours of the day. Notwithstanding its strong theoretical appeal, backed by empirical evidence across numerous studies showing net benefits, we have seen relatively little use of this pricing method at the state level, especially for residential customers\textsuperscript{22}. Evidence also indicates that automated tools to monitor and act upon price changes are required. Until the wide implementation of such tools becomes reality, the monetary benefits ostensibly do not justify customers’ time and attention.

A perceived barrier to RTP is the widespread acceptance of average-cost pricing in public utility regulation, i.e., the setting of uniform prices across different periods based on embedded historical accounting costs. Such pricing limits customers risk exposure and the need to pay fluctuating prices—for example, higher prices during peak periods and other periods of high demand. There is concern that some consumers are unable to shift load either by usage reductions or time-of-day shifts, because of their particular circumstances, such as work schedules, lack of efficient equipment, age or medical conditions, and thereby face higher utility bills. Even if consumers do shift their loads, regulators may conclude that the benefits would still fall short of metering and other costs. Peak-time rebate is perhaps the most palatable type of critical peak/real-time TOU rate program to consumer advocates. It requires the automatic enrollment of all customers. This addresses the participation issue that has particularly plagued opt-in TVR.

The WG7 meetings had presentations on modern rate design and TVR. The discussions were long, at various points heated, and led to the following policy questions:

- Which program among TOU pricing, RTP, critical peak pricing (CPP), or peak-time rebates is most useful to attain a specific objective? What are the additional economic-efficiency gains from RTP relative to TOU pricing? Can two or more of these programs serve complementary purposes?
- Are TVR or dynamic rates good candidates for mandatory, opt-in, or a default/opt-out options? What are the advantages and disadvantages of each with reference to current rates? Is it possible in Illinois to have RTP as a mandatory rate, as customers are free to switch from the incumbent utility to an ARES?
- There is empirical evidence from the CUB study that RTP benefits residential customers in Illinois. Yet, participation rates are very low—below 2%. What accounts for such low participation and is it due to inadequate customer education or the shallow penetration by technologies, such as programmable thermostats, or both?

\textsuperscript{21} Real-time pricing is sometimes referred to as dynamic pricing.

\textsuperscript{22} Pilot programs for RTP have shown that customers do respond to price signals and that the benefits generally exceed metering and other incremental costs associated with RTP. For example, RTP requires electricity smart meters that can send and receive information about electricity costs and give consumers more timely information about their own consumption.
• Is it appropriate for vulnerable customers to receive special treatment if they experience higher utility bills than under standard rates?
• If RTP becomes widely used by customers, can customers receive net savings comparable to the smart meter costs?
• Can RTP be the key contributor to the benefit maximization from new technologies in a NextGrid world?

The formulation of the responses to these questions requires considerable further work to ensure that the specifics of the Illinois situation are appropriately considered ahead of the adoption of a specific strategy.

Multiple challenges in the TVR arena indicate the many intricacies involved in balancing the interests of all the stakeholders. Presentations and discussions stressed the importance of engaging price-responsive demand and DER to simultaneously keep electricity affordable and ensure reliability, resiliency and environmental sustainability. A key challenge is to effectively separate efficient price signals from the intra-class allocation of embedded costs. One of the views presented stressed the complementarity of TVR and RTP. TVR electing behavioral responses to a limited number of events, while RTP is deploying smart technology to respond to price signals serve complementary purposes. The engagement of flexible demand and DER can combine notice of high-price periods to bring about behavioral responses, access to smart technology and the ability to respond to rates with a dynamic RTP component to gain the full benefits of smart technology.

The challenges of specifying details to recover costs and their allocation across customer classes were alluded to in the vast majority of comments. Written comments submitted to the NextGrid process were added to the WG7 record in order to urge Illinois to encourage more TVR offerings and consumer outreach efforts to expand adoption. The comments include description of successes in terms of savings under current RTP rates in other states and references to the lessons from the ICC’s Blue Ribbon Telecommunications Task Force in the 1990s. The following bullets summarize the highlights of TVR discussions:

• The response to TVR and dynamic pricing may be considerably enhanced by the effective deployment of smart technologies. For example, home-display monitors or smart thermostats can increase the average peak reductions associated with TVR by more than 70% [110]. Indeed, smart thermostats and intelligent systems can automate responses to dynamic rates or RTP so that customers need not have to keep abreast of possibly rapid price changes.
• Protecting vulnerable customers under TVR is an important consideration.
• TVR bring the benefits of decreased electricity usage when economically efficient so as to encourage customers to shift their usage away from peak or high-cost periods to periods of considerably lower prices.
• The allocation of residual costs that arise, typically, from fixed costs requires careful judgement so as to ensure just and reasonable rates.
• Whenever volumetric rates fail to reflect marginal societal costs, they can lead to economically inefficient outcomes.
• While there is no doubt that marginal cost pricing can advance economic efficiency, its deployment in rates must be combined with an equitable mechanism to recover residual revenue requirements to ensure utility financial stability.
• An important issue is whether TVR are opt-in or opt-out rates. While most TVR around the country are offered on an opt-in basis, opt-out TVR implementations result in much higher participation rates by customers. These opt-out TVR lead to lower utility marketing costs but have undesirable impacts on those customers unwilling or unable to adjust their usage, making them worse off.
• Given the absence of an agreed upon single definition of affordability, this issue is more appropriately addressed outside TVR consideration and any other rate designs with the primary objective of advancing economic efficiency. Any improvement in economic efficiency reduces investments and expenditures required to provide reliable, resilient, and environmentally sustainable electric service, so as to make electricity more affordable.
• There are questions as to how much more economically efficient are RTP relative to TOU rates, and whether TOU rates can achieve most of the economic-efficiency gains that RTP brings about.

Clearly, the effective implementation of TVR is fraught with challenges but also provides opportunities to bring about efficiencies when effectively implemented. The perspectives of the WG7 participating stakeholders on the TVR issues are summarized in the table in Appendix G.

7.3 Performance Regulation

There are two major performance regulation mechanisms—performance incentive mechanisms (PIMs), which tie utility revenue to specific performance metrics and targets, such as resiliency, and multi-year rate or revenue plans which typically include PIMs and allow the utility to benefit from cost savings by retaining a portion of any cost reduction below the allowed rate or revenue levels achieved during the multi-year rate or revenue cap. The EIMA introduced performance-based ratemaking (PBR) to Illinois by linking the utility’s return on equity to the utility’s performance to be dependent on the satisfaction of certain resiliency and customer metric targets. FEJA includes symmetrical return on equity incentive/penalties based on the utility’s performance in the delivery of energy-efficiency savings to customers. Some believe that this is already, in essence, a provision that established performance-based rates in Illinois. Other WG7 participants contend that a results-based regulatory model can shift the regulation emphasis from the reasonableness of historically-incurred costs to the pursuit of long-term customer value. Regulatory incentive plans, according to some, allow shifting the focus from inputs to outputs. Especially appealing to many industry observers is the notion that a primary criterion for utility revenues is its relationship to the value that customers receive from utility service. Others believe that utilities need to be allowed to pursue innovation and investment in facilities, under the guidance of the ICC, and to recover the prudent costs of such investments. Implementing such regulation to produce desirable outcomes can pose serious challenges for regulators, especially under the current environment, which limits their authority to play a lesser role. Thus, attaining PBR is not as easy as what appears at first sight.

In general, performance-based rates may be viewed as addressing whether or not customers are getting compensatory value for their money. The key motivation stems from attempts to directly address the concerns with cost-of-service regulation, due to its salient feature that the base rates between general rate cases remain fixed in spite of changes in conditions over that period. There are various side effects with fixed rates and the accompanying economic inefficiencies and disincentives.
The price-cap concept in regulation was introduced in the telephone sector in England and Wales and played a prominent role in the regulatory framework that accompanied the privatization of the British electricity industry. Its application to electric-industry restructuring in a number of states, such as New York and California, in the 1990’s was short lived and it was subsequently abandoned without a detailed assessment of the rationale for its abandonment. PBR may require lesser regulatory resources than current US regulatory systems do. Also, the nature of required regulatory resources differs from conventional state regulatory regimes. Evaluation of utility revenues considers the performance level in the outputs, such as, resiliency, service quality, DER penetrations and energy-efficiency savings that benefit customers and society as a whole.

Performance-based rates can involve formal incentive mechanisms or simply rate adjustments by regulators based on their judgment of whether a utility performed exceptionally well or subpar. The latter approach is problematic if the regulators’ decision is done after-the-fact in an ad hoc fashion, rather than applying upfront rules and criteria to each utility. Some stakeholders recommend that any future regulatory model augment the existing formula rate and sustain the benefits and improvements realized through EIMA and FEJA.

There may be an opportunity to augment the formula rate to incentivize the utility to achieve specific outcomes, but appropriately designed incentives need to be limited to outcomes that are within the utility’s control and not be tied to factors such as customer behavior. From a public-interest perspective, a key objective of ratemaking is to improve a utility’s performance of a utility. Better performance increases the chances that utilities charge just and reasonable rates, in addition to the rates aligning appropriately with long-term customer and societal interests. In other words, an essential ratemaking role is to protect customers from excessive rates, balanced with the ability of a prudent utility to obtain adequate revenues to ensure its financial health. For the record, PBR is allowed in Illinois under section 9-244 of the Public Utilities Act. However, it has not been used much, if at all, particularly since the enactment of EIMA.

In the area of performance regulation, the major policy questions that arose are:

- Is PBR a concept that warrants further consideration in Illinois?
- What forms are most promising and which ones can be ignored?
- How can PBR concepts be incorporated in the rate design to enhance utility service provision, manage costs and improve customer affordability?
- Are there additional metrics, such as disconnection rates, deferred-payment arrangement success rates, reconnection rates and other collection/affordability criteria that need to be included in the formula rate structure?
- Do utilities have a capital bias under cost-of-service regulation?
- How can regulators best exploit deploying benchmarking and performance metrics in the rate design? How strong a reliance on benchmarking and performance metrics is needed?
- Which is the preferable path to attain the NextGrid objectives—to tweak the conventional ratemaking model or to drastically revamp the existing model—in order to provide the appropriate utility incentives to achieve the desired objectives?

These questions are representative of the thrusts of the lengthy WG7 discussions. The presentations on the topics of PBR and PIMs, performance measurement and benchmarking and capital bias and incentives provided a good starting point for WG7 deliberations and made clear the complexities that arise in the selection of metrics and targets. A peer comparison may provide
a better performance metric than an individual utility’s historical performance. As an example, a target to have a utility maintain its SAIDI in the top-specified quantile in a group of similar utilities may be more meaningful or relevant than an individual utility’s historical performance. For incentives to be effective, they must provide net savings to customers, in addition to creating opportunities for a utility to receive additional revenue streams. While the economics literature clearly shows the effectiveness of incentives, some stakeholders stated that the idea that incentives provide the correct answer need not go uncontested.

Some comments also touched on the fact that, at certain times incentives can lead to counterproductive results, that is, become perverse incentives. Similar disagreements arose in the area of capital bias and the creation of effective countermeasures. Some stakeholders pointed out that performance incentives can help to offset capital bias and that regulators can mitigate capital bias in various ways. Such disagreements are not unexpected, given the diverse group of stakeholders who participated in the deliberations. The discussions produced several highlights that are listed below:

- The principal motivators for PBR and PIMs stem from concerns about the tenets and underlying assumptions of conventional ratemaking to serve the public interest.
- Regulators can apply benchmarking in various ways, ranging from “red flagging” abnormal utility performance to modifications of a utility’s rate of return.
- The deployment of performance metrics to evaluate and take appropriate action can provide utilities with stronger incentives to improve their performance in both cost and non-cost areas. The key factors are setting an appropriate standard or benchmark and determining a penalty or reward, or both, that is, (a) fair to the utility and (b) effective in changing utility behavior to improve its performance and benefit both customers and society as a whole.
- Incentives directed to improve utility performance require special care, as perverse outcomes may occur with poorly-structured incentives. Although desirable, win-win incentives are tough to design, implement and execute.
- Peer-based benchmarking has distinct advantages over history-based benchmarking in a dynamically changing environment.
- A tough task for regulators is to separate the effect of utility management from factors outside its control in the evaluation of a utility’s performance.
- Selection of the appropriate benchmark and the specification of the targeted level are crucially important in designing any effective PIM.
- While new incentives can mitigate “capital bias,” they can also create perverse incentives if not structured appropriately.

This list of issues indicates key challenges and opportunities that regulators need to confront in the PBR and PIMs areas. In light of the complexities of the issues, it is clear that to attain palpable progress on the path to implement added PBR concepts in Illinois, the ICC must proceed deliberately but with the appropriate level of caution. The perspectives of the WG7 participating stakeholders on the TVR issues are summarized in the table of Appendix G.

7.4 Valuation of DER

The North American Electric Reliability Corporation (NERC) defines DER as “any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System [111]”. DERs include distributed generation, loads and
energy-storage resources, both behind and in front of the meter. The generation sources include all types of resources including renewables, microturbines, cogeneration, emergency and stand-by or back-up. In addition, we include aggregated DERs and microgrids under the DER umbrella. DERs provide benefits to the electricity system and its customers in addition to those to the customer who directly benefits from lower electricity bills. The utility can increase these benefits by sound integrated distribution planning and efficient operations. As the grid changes, planning and operations processes, as well as assets and infrastructure, adapt to support effective integration of emerging technologies. Grid functions also evolve to support these technologies, and utilities are already adapting to anticipate the advancement of technology to take advantage of cost declines and to put increased control capabilities, convenience, and choice into customers’ hands. Other potential benefits include increases in diversity of the fuel and generation-technology mix and, whenever renewable DERs are deployed, reduction in carbon emissions.

Although the DER-value discussion is often focused on environmental and direct economic benefits, DERs can also benefit the distribution grid by providing real power, reserves and reactive power support to address such needs, to maintain desired voltage profiles and avoid distribution-system investments. This focus is entirely consistent with the FEJA language that requires that the distributed generation-rebate valuation formula in Illinois, yet to be approved by the Commission, “reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs.”

A key issue is how the different DER categories connect to the power grid. The interconnection for DER integration into the distribution grid poses technical and cost challenges as the distribution system was not designed to host DERs. The determination of both the value that DER provides, as well as the net value, with the explicit consideration of mitigating costs to address the associated challenges is therefore highly important. The value that a DER provides, however, depends on its location and timing in terms of the real and reactive power services provided to the distribution grid. Indeed, much of the value a DER provides is a function of its connection to a particular substation, feeder and possibly within a given individual feeder. The reason for this variation is that whenever additional supply is needed to meet peak demand, such supply must be injected at a specific location. A DER interconnected on a feeder upstream of the grid constraint has little value, whereas, at an interconnection downstream of a constraint, or multiple constraints, the value may be considerable.

Moreover, timing of the provision of DER services must coincide with that of the grid needs to allow its value to be truly leveraged. These statements make evidently clear that the rationale for the DER valuation cannot be based simply on system or feeder average values to ensure that appropriate stakeholders incentives to install DER at sites will be where they can provide value to the distribution grid. Otherwise, either inadequate compensation or excess returns result and unnecessarily increase the distribution system operations costs the without fair value provided to the customers that rely on it. A framework to assess the value to the distribution system needs to focus on the value that DERs provide to the distribution grid, and to do so in a way that is analytically sound and based on actual conditions. Such a framework must be based on temporal and locational considerations with all physical, economic and technical considerations taken into account to ensure that the DER values correctly reflect the specific situations in the assessment of the investment requirements. Such an analytic approach determines the actual DER value and, for
completeness, the process needs to compare the DER value to the annualized costs of the conventional distribution investment to ascertain the contribution or DER “value.”

A fundamental issue is the nature of costs included in the DER analysis. Some stakeholders assert that considering embedded costs in evaluating incremental costs that a DER imposes on a distribution circuit is inappropriate, since marginal distribution costs provide the correct measure. As such, marginal-cost studies are required and such studies have not been performed by Illinois electric utilities since the 1990s. We note that the proposed approach provides an additional benefit, since consideration of the DER contributions to the distribution system is independent of the technology, as the focus is on what, where, and when DER provides value. In this way, both under- and over-compensation of DER are avoided, as the consideration of the appropriate integration costs ensures that the market for DER develops correctly.

As the DER penetrations deepen, their impacts on the distribution system operations become more pronounced. Thus, a better understanding of the appropriate DER value ensures that the future distribution-system planning can leverage all the DER benefits without incurring unnecessary risks. How to determine this value is rightly a matter of serious debate, with many states involved in developing methodologies to do so efficiently and fairly. Under FEJA, Illinois has assumed a leading position to establish the foundation for such a methodology with a recognition of the DER value to the distribution grid and the emphasis on the need for a data-driven process to assess the actual DER contributions to the distribution system. The development of a distribution system-focused valuation methodology is associated with numerous major policy questions. The following list is a collection of representative questions and issues raised in the WG deliberations:

- What is the DER value to the distribution system, as a component of the total DER value?
- Does net metering reflect undue bias toward renewable DER value relative to that of other generation sources, such as cogeneration and other clean energy sources, and energy efficiency? Does this question need a response, given that Illinois has a mandate to move away from full net metering and to set a DER rebate value that utilities are required to compensate each DER for its value to the distribution grid?
- Do the valuation of these benefits to utilities in dollar terms require the deployment of a combination of sound analytics and empirical evidence? Do they require technical/fact-based valuation grounded on sound distribution engineering and economic foundations?
- Are the benefits of a specific DER installation to full-requirements utility customers commensurate with the increased electricity prices that result from the compensation to that DER project? Is the issue here one of “fairness” in which utility customers additional payments for their share of DER project exceed the benefits they obtain?
- How should regulators treat measurable benefits in dollars versus difficult-to-measure-and-quantify benefits to determine utility compensation to DER customers?
- Does DER compensation need to be DER-technology-type specific with a different scheme for each technology?
- How should regulators allocate the benefits from a solar DER installation among the utility, the full-requirements customers, and the DER installation?
• What prices does a DER-installation owner need to pay for grid services and receive for the value the project provides to the grid? Are these prices fair?
• While COS studies often demonstrate that customers with behind-the-meter generation—so-called DG customers—are less costly to serve than other customers, the analysis of such studies indicate that many DG customers in a given territory are larger consumers, and therefore both, on the whole and on average, contribute more to system costs than average residential customers. Are there cost-shifting issues that need to be studied?
• As neither Ameren nor Com Ed has performed a marginal cost-of-service study since the late 1990s and embedded distribution cost studies are performed every three years, is it time to prepare a new marginal cost-of-service study? If utilities adopt dynamic rates more closely reflecting short-run marginal costs, what types of analysis are needed in the rate design to recover residual costs?
• The load reduction by DG customers reduces the utility costs. Can these avoided costs constitute a form of energy efficiency?

As the list clearly indicates, there are many areas that require further study. A major question is whether DER valuation should be based on embedded cost or marginal cost. As advanced technology becomes more pervasive on the grid and the needs and expectations of customers evolve, a reassessment and evolution of the rate-design cost basis becomes necessary. Such an evaluation needs to assess compatibility with existing rate-design principles to ensure just, reasonable and affordable rates that continue to allow regulated utilities the opportunity to recover their reasonable and prudent cost of providing utility services to the public. There is an issue of whether there is a need for more granular data to appropriately reflect the time- and location-specific characteristics of the DER-provided services.

The value placed on the surplus power sold by a DER to the utility is a separate matter distinct from the price the DER pays the utility for grid services. However, the consideration of the trade-offs between higher DER payments for surplus power and continued low rates to full-requirements customers is important. These issues and the many questions associated with them indicate the broad range of challenges in the DER-valuation topic. Their full consideration in future studies is important in the formulation of policies to effectively support the NextGrid plans and the associated developments for their implementation. The perspectives of the WG7 participating stakeholders on the TVR issues are summarized in the table of Appendix G

7.5 Additional Ratemaking Issues

There was considerable discussion among the WG7 participating stakeholders on issues that do not fall neatly into any specific category described thus far. The reader may find it useful to gain additional information from such discussions. We collected the issues and questions that arose in these discussions and present them in the bullets below:

• Several WG7 stakeholders stated that there is value to the information on what have been the customer experiences around the country with different rates so as to gain some insights for Illinois.
• How do value propositions change actions, e.g., for electric vehicles?
• There is a substantial need to support customers by providing actionable options to manage risks so as to align with their objectives.
• The explicit incorporation of zero emissions credit (ZECs) is critical in ratemaking policy formulation as a host of additional regulatory costs associated with ZECs are imputed on customers. While programmatic costs have increased dramatically, electricity costs have decreased in Illinois. As such the question as to how externalities impact customer behavior arises and must be addressed.
• Unbundled rates can provide various price signals. However, when customers are faced with a collection of price signals, it can be difficult to correctly parse them.
• Rate options for customers are a great way to provide choices, so they can optimize their benefits for the risks they are willing to accept.
• An important issue to consider in ratemaking is incorporating impacts and costs of future, technologies, in general, and information technologies, in particular.
• The tendency is to use rate design to compensate people for avoiding certain costs and charging consumers for causing them. Emphasis should shift toward having customers pay for services provided.

All these issues and questions require considerable study ahead of the formulation of new policy. This list of issues provides an appropriate starting point for designing studies on topics that can help create an adequate background to develop appropriate regulatory policy strategies.

7.6 The Path Forward and Survey Responses

A survey was sent out to the WG7 participants [15] and received 18 responses. The respondents provided a ranking of their preference on a scale of 1—5 for a ratemaking mechanism or issue. Based on the response means for each question, the top four issues of interest are: pricing new unbundled services, the role of TVR in a NextGrid world, the changing nature of utility rate structures, and the valuation of distributed energy resources and its relationship to costs. The respondents were split equally on whether or not utilities need to have a separate rate for EV charging. There was a wide array of responses to the question, “How do we get from here to the future?” with the highest support given for the option to continue a collaborative process rather than to turn to litigation. The median view was to move ahead cautiously, but to address the ratemaking issues that confront the ICC and the different stakeholders in the years ahead.

The opinions expressed fell between two extremes. At one end are those who espouse the view that new technologies, public policies and market conditions necessitate new rate mechanisms to maximize the welfare of Illinois citizens and the state as a whole. These respondents believe that retention of the current ratemaking structure in Illinois assumes a world that no longer exists. Moreover, under this view, Illinois will fail to exploit the full benefits that these changes, some of which are transformative, offer to its citizens. At the other end, are those who argue that the status quo is working well and, at most, policymakers need only to fine tune the present rate mechanisms. These stakeholders have the perspective that any major ratemaking reforms constitute, essentially, a zero-sum game, where some interests will benefit at the expense of others.

Overall, some respondents indicate mistrust of the utilities and others have the view that certain stakeholders simply attempt to advance their own agendas at the expense of the public good. The latter express their intent to move ahead slowly or not at all. The thrusts of the responses on the diverse views expressed are listed below.

• Go slow, so customers and stakeholders have time to adjust to modifications that are introduced
• We must proceed with care
• Continued collaboration is preferred to litigation
• Changes need to be gradual and introduced over a reasonable timetable. As the grid of the future becomes increasingly distributed, there needs to be a corresponding focus on the design, planning, maintenance and operations of the grid to ensure safety, reliability and resiliency. Pilot programs serve as a useful tool to test the functionality and integration of innovative technologies. A transparent, ICC-governed process to set the prices paid for/by DERs allows an orderly integration of new technologies and provides all parties with the opportunity to explore future ratemaking models
• Conduct pilots for various ratemaking alternatives
• Go forward with a combination of workshops focused on specific issues, identification of needs to be addressed in upcoming rate design proceedings and a follow-on effort on the NextGrid WGs work
• Stakeholder workshops facilitated by ICC staff and/or ICC investigatory dockets may be helpful to advance consideration of ratemaking issues in Illinois
• Continue to move forward through workshops, discussions and ICC-directed proceedings
• The focus should be on unbundled services and implementation of new technologies that provide such services to ensure balanced grid operations
• In the path towards the NextGrid environment, recognition of the shift of utilities as commodity providers to that of services providers is required. The appropriate trajectory on that path requires the identification of the goals and objectives and the accompanying design of ratemaking to ensure that prices help to reach these goals. The engagement of consumers through ongoing education can be fruitful to gain their support with demonstrations of the benefits attainable with the implementation of grid modernization. Such demonstrated proofs of the value of grid modernization efforts enable the recognition that the grid as the backbone of the electric system is reality, as DERs depend extensively on the provision of their services to willing buyers
• Develop efficient and increasingly granular rate designs that are based explicitly on nodal pricing to develop platforms for regional markets. Such designs should address resiliency by measures that ensure grid-flexibility enhancements and investments into assets that provide value for reliable service to different customers. The design must explicitly place a high priority to support innovation and price carbon to address environmental sustainability [112]
• Keep grid investments as low as possible, as its days may be numbered, with the explicit objective to maximize “bang for buck” for each investment deemed to be cost effective
• It is essential to return to the basics of a monopoly structure and ensure such a structure is not a barrier to effective competition. For example, Honda—an auto manufacturer, is a new player in the electricity sector as a provider of an EV-charging option, which explicitly offers off-peak options so as to consider electricity pricing and grid impacts. Under the monopoly structure, a utility may erect barriers to such newcomers. As a result, customers may be required to pay for utility investments from which they obtain no benefits
Continue to engage stakeholders with various interests and embrace new technologies and advancements.

These various perspectives revealed in the responses to the survey may provide guidance to the ICC, the Illinois General Assembly and other interested policymakers on future ratemaking actions for ComEd and Ameren.

After all is said and done, four major questions face regulators in their decisions of the merits of different rate mechanisms:

- What are the objectives of ratemaking?
- What trade-offs do regulators have to make among the different objectives, some of which may conflict with one another?
- What rate mechanisms and which cost perspective—embedded vs. marginal—are most effective to achieve those objectives and serve the public interest?
- What is the appropriate basis for rate design: besides costs, which other relevant factors such as market structure and prices, contemporaneous access to technology and information, equity, income and price elasticity are explicitly considered?

The diverse opinions of the various stakeholders who participated in the WG7 deliberations on ratemaking issues arise from differences in their answers to one or more of the questions above. The third question is compatible with the “balancing act,” wherein any regulatory action, including ratemaking, needs to result in a non-zero-sum game. As such, disagreements among the participating stakeholders are understandable. From an economics standpoint, the solution to the question is attained via a two-step procedure: identification of the optimal tradeoff frontier, followed by the balancing of competing objectives to select a point on that frontier. Some of the WG7 stakeholders argue that new or modified conventional rate mechanisms cannot lead to such a solution due to the non-inclusion of utility customers as beneficiaries.

Such rate mechanisms either shift risk to customers or fail to provide any direct benefits to them. Some of the alternative rate mechanisms, as argued by others, are more transparent in the provision of benefits to certain stakeholders, such as utility shareholders and environmentalists, but provide no direct benefits to the consumers. In the past, regulators emphasized the longer-term consequences of their actions rather than attempt to meet the short-term demands of stakeholders. Continuation of such past actions has become more complicated, as the number and interests of stakeholders have grown and diversified, respectively, making the task to satisfy their demands considerably more difficult.

In the NextGrid environment, the balancing act will become increasingly more complex with many additional complications and so full consideration of the often-conflicting objectives of all the players need to be carefully assessed and effectively addressed. Indeed, the objectives and desires of the diverse stakeholders and players are clear:

- utility competitors wish to ensure a “level playing field” for all market players to allow utilities/electric service providers and third-party providers to provide services on a competitive basis with practical and workable protocols that can be created under appropriate regulatory reforms to help achieve this objective
- customers desire lower prices for reliable, safe services
- utilities need rates that allow them to be financially healthy
- environmentalists and customers want clean energy and energy efficiency
• some customers want more control over their electricity usage and the price they pay for services provided

For the NextGrid developments to be successful, changes to the electric system need to be supported by the development of appropriate business models, rate structure, and regulatory reforms to enable utilities/electric service providers to own assets and provide services and also allow third-party providers to offer services and compete to ensure safe, reliable, resilient and secure grid that meet consumer demands at just and reasonable prices.

The attempts to accommodate these diverse and, in some instances, inherently conflicting objectives pose tough challenges for regulators. The observed postures of the WG7 participating stakeholders and the tone of the discussion best illustrate the complexities that must be confronted in future utility ratemaking in Illinois. Certainly, these challenges should be addressed in a systematic manner to allow utilities to harness effectively the potential of NextGrid and for customers to obtain the potential benefits at just and reasonable rates.
8. Concluding Remarks

The NextGrid Study definitively demonstrated that grid modernization is of huge interest in Illinois in light of the critical importance of energy, in general, and electricity, in particular, in the continued economic wellbeing and competitiveness of the state. Indeed, the extensive participation by the large and diverse groups of stakeholders at the numerous meetings of the seven WGs held during the study indicates that there is no doubt that the future grid is a matter of utmost importance. Given the wide array of participating stakeholders in the seven WGs, it is not surprising that so many perspectives were expressed during the lengthy deliberations. As such, the apparent lack of agreement among the participants is expected. However, there is little doubt, notwithstanding the large number of views—some of which, at times, rather polarized, that the participating stakeholders have much in common. There is very broad interest in active participation to mitigate climate change impacts in every possible way. Virtually, all participants share the goal to make the grids greener through the continued integration of deeper penetrations of renewable energy resources (RERs) so as to reduce emissions. Stakeholders share the desire to pursue sustainable ways to meet energy needs. There is broad interest in adopting advances in technology to make the grids smarter, to deploy more sensors to improve visibility and situational awareness, to deploy analytics and data with finer granularity to provide enhanced information and to extend the benefits of cleaner and environmentally sensitive electricity by various electrification targets. Many stakeholders are clamoring for more customer education and training to take advantage of what the modernized grid offers. Indeed, it is clear that many stakeholders are keenly interested in the provision of help to customers to use technology to transform energy into creation of new opportunities. The affordability of electricity was also emphasized throughout all the deliberations.

Illinois is in a highly fortuitous situation as it embarks on further grid modernization from a very strong initial position. Year after year, Illinois is ranked as the second leading state in grid modernization. This high ranking provides a clear recognition of the many accomplishments by legislators, regulators, utilities and their customers, market players, stakeholders and various entities in the electricity sector, to spearhead the formulation and adoption of appropriate policies, plans, rate structures and mechanisms, and adopt technology and innovative schemes to plan, operate and manage grids to supply and deliver safe, reliable and cost-effective electricity. Moreover, Illinois with the largest nuclear fleet in the nation generates considerable portion of carbon-free electricity, in addition to that generated by green RERs.

The previous seven chapters make amply clear that there is considerable disagreement on nearly every aspect of grid modernization among the participating stakeholders. As such, there is no shortage of challenges in the push to pursue advancements on the grid modernization front. Certainly, regulators and policy makers, utilities, vendors, electricity sector entities, customers, public interest groups, consultants, academics and other interested stakeholders have widely different goals and objectives, some of which may conflict with one another, as they consider their expectations from the modernized grid. The NextGrid Study was effective in bringing forth the many perspectives and objectives of the diverse stakeholders through the WG discussions. This is due to the fact that the Study was not designed to be a consensus building exercise but more of an information gathering process so as to become better acquainted with the desires and viewpoints of all the stakeholders. As such, the tenor of the discussions and the high-level of participation by the various stakeholders indicate that there exists genuine interest to move forward collaboratively in order to harness the benefits of wider deployment of grid-integrated DERs, including ESRs, and adoption of new technologies and analytics under appropriately formulated policies and rate structures/mechanisms. The challenge is to create a collaborative framework under which all the diverse stakeholders can participate in a meaningful way. This may not be an easy process but is doable and so
must be done. In this way it is possible to continue to make progress on the grid modernization front. As the beneficial outcomes of the modernized grid impact every stakeholder, there is every reason to pursue a joint collaborative process to ensure the achievement of a modernized and decarbonized grid to supply safe, reliable, resilient, cost-effective, sustainable and secure electricity services.

The discussions held by every WG made clear that there are many known unknowns in addition to the unknown unknowns. In virtually every topic area, further studies and investigations need to be undertaken before Illinois is ready to embark on a specific course of action. Indeed, for each issue there is a need for careful and detailed planning of a systematic effort to perform the associated work after the necessary steps are taken to gather the needed knowledge and Illinois-centric information ahead of the selection of a specific approach.

The NextGrid Study was not intended to develop a specific roadmap for Illinois to pursue. Rather, the intent was to gather a body of appropriate knowledge, information and awareness to get as comprehensive a picture as possible of the challenges and opportunities of the future grid and potential practical approaches, on which to embark. This goal has been successfully met, as evidenced by the large numbers of knowledgeable, innovative and creative ideas described in each WG report. The various thrusts that cut across two or more WGs’ scopes of activities made clear that there are some low-lying fruits that are ripe for picking as they provide excellent opportunities that are important to seize and pursue deliberately and without much delay. In this way, the benefits that accrue to society, customers, the grid and Illinois can be effectively captured.

We include three specific recommendations as part of the NextGrid Study based on the reports of the WGs. The first is in the area of EV-charging infrastructure. The second focuses on the deployment of ESRs grid enhanced ability to provide the required flexibility in the further integration of RERs at deeper penetrations into the d-grids. The third is centered on the need to act proactively on the privacy front to ensure that the growing digitalization in the grid is carried out in a way that effectively protects the privacy of the customers. The rationale for and scope of each recommendation are discussed in the paragraphs below.

The establishment of an EV-charging infrastructure is of critical importance to maintain Illinois’s leading position in grid modernization. For many years now, a major causal factor of the slow growth in EV sales has been tied to the lack of an adequate EV-charging infrastructure. There is a need to put an end to this chicken-and-egg syndrome so that the rapid adoption of EVs can proceed in order to remove the millions of polluting fossil-fueled internal combustion engine vehicles from the roads. Given the fact that since 2017, the CO₂ emissions from transportation sector exceed those from the stationary electricity generation system, the imperative for the reduction of the population of polluting fossil-fueled vehicles is clear. Not only is the displacement of such vehicles through the growth in the number of EVs an excellent example of beneficial electrification, the establishment of an EV-charging infrastructure creates many new jobs, brings about a cleaner environment and provides a role model for the electrification of other transportation sectors, such as trucks, buses and company fleets, as well as that of other sectors. Clearly, there are many questions to be answered as to the mechanism under which the infrastructure is to be created, impacts on electric rates and the role of utilities. The ICC can initiate docketed proceedings in this matter so as to determine the most expeditious modality to deal with those questions. The key point is that the EVs represent an unparalleled opportunity to substitute electricity for less efficient and less productive energy forms and reduce emission. The EV-charging infrastructure can be an important element in the continuing modernization of the grid and can create with the more intensive harvesting of distribution grid integrated RERs.
The slow pace of ESR development in Illinois fails to provide Illinois grids with the opportunity to benefit from the multiple services that ESRs can provide. Moreover, as the penetrations of integrated RERs into the distribution networks deepen, the need for ESRs becomes more intense. The growth of demand for ESRs has resulted in rapid price declines that are expected to become more substantive as the economies of scale can be more effectively exploited. The California mandate on ESR demonstrated that a sharp increase in demand can reduce the price of storage through a sharp increase in demand. Illinois is in an excellent position to exert a big push on storage to create sizeable reductions in the price of technology. The enactment of a mandate for the installation of ESRs requires considerable efforts to appraise legislators of the significance of such a legislative initiative and of its ramifications. Alternatively, there is the opportunity to formulate meaningful incentives for utilities or other entities to install ESRs. There are other possibilities to increase the presence of ESRs in Illinois grids. The ICC can play a leadership role to bring about the deployment of ESRs in Illinois, be it on the bulk grid, d-grid or behind the meter, as important elements of the grid modernization and an opportunity to create new jobs. Such a deployment will bring measurable improvements in reliability, resiliency and flexibility of the grid, as well as emission reductions.

As the AMI efforts near completion in Illinois and the grids continue to become more digital, the protection of customer privacy becomes more difficult and the risks of a loss of privacy increase. Moreover, the security of the data collected by smart meters in the AMI can become a new problem that may pose a safety issue for a residential customer in case a hacker is able to monitor the residential customer meter data. In recent years, there have been massive attacks on many large corporations. Such threats are also faced by utilities that collect huge amounts of consumption and other data from their grid-connected customers. To date very little has been done to protect customer privacy in the electricity sector. As Illinois continues its efforts to modernize the grid, the privacy protection looms as a major issue that needs to be addressed. Illinois can seize the opportunity to contribute significantly to this issue through the enactment of rules and regulations for customer data protection. Such an effort has the potential to set the framework to effectively manage the privacy protection of customer information.
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**Appendix A: Glossary of Acronyms**

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>ABAC</td>
<td>attribute-based access control</td>
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<tr>
<td>ABP</td>
<td>adjustable block program</td>
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<tr>
<td>ADMS</td>
<td>advanced distribution management system</td>
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<tr>
<td>ADN</td>
<td>active distribution network</td>
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<tr>
<td>AI</td>
<td>artificial intelligence</td>
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<tr>
<td>AMI</td>
<td>advanced metering infrastructure</td>
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<td>AMR</td>
<td>automatic meter reading</td>
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<tr>
<td>ARES</td>
<td>alternative retail electric supplier</td>
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<tr>
<td>CAIDI</td>
<td>customer average interruption duration index</td>
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<tr>
<td>CAISO</td>
<td>California Independent System Operator</td>
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<tr>
<td>CEP</td>
<td>community energy plan</td>
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<tr>
<td>CESER</td>
<td>cybersecurity, energy security, and emergency response</td>
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<tr>
<td>CHP</td>
<td>combined heat and power</td>
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<tr>
<td>CPP</td>
<td>critical peak pricing</td>
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<tr>
<td>CPUC</td>
<td>California Public Utilities Commission</td>
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<tr>
<td>CSP</td>
<td>curtailment service provider</td>
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<tr>
<td>CSV</td>
<td>comma-separated values</td>
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<tr>
<td>CTA</td>
<td>Chicago Transit Authority</td>
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<tr>
<td>DA</td>
<td>distribution automation</td>
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<tr>
<td>DCFC</td>
<td>direct-current fast-charging</td>
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<tr>
<td>DER</td>
<td>distributed energy resource</td>
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<tr>
<td>DERMS</td>
<td>distributed energy resource management system</td>
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<tr>
<td>DG</td>
<td>distributed generation</td>
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<td>DHS</td>
<td>Department of Human Services</td>
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<tr>
<td>DLC</td>
<td>direct load control</td>
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<tr>
<td>DLMP</td>
<td>distributed locational marginal price</td>
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<tr>
<td>DMS</td>
<td>distribution management system</td>
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<tr>
<td>DNP</td>
<td>distributed network protocol</td>
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<tr>
<td>DOE</td>
<td>Department of Energy</td>
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<tr>
<td>Acronym</td>
<td>Description</td>
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<tr>
<td>DR</td>
<td>demand response</td>
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<td>DSO</td>
<td>distribution system operator</td>
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<td>DSP</td>
<td>distribution system platform</td>
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<tr>
<td>DSS</td>
<td>digital self-service</td>
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<tr>
<td>EDF</td>
<td>Environmental Defense Fund</td>
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<tr>
<td>EE</td>
<td>energy efficiency</td>
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<tr>
<td>EEI</td>
<td>Edison Electric Institute</td>
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<tr>
<td>EIA</td>
<td>Energy Information Administration</td>
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<tr>
<td>EIMA</td>
<td>Energy Infrastructure Modernization Act</td>
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<tr>
<td>EPRI</td>
<td>Electric Power Research Institute</td>
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<tr>
<td>ES-C2M2</td>
<td>electricity sector cybersecurity capability maturity model</td>
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<tr>
<td>ESCC</td>
<td>Electricity Subsector Coordinating Council</td>
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<tr>
<td>ESPP</td>
<td>energy smart pricing plan</td>
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<tr>
<td>ESR</td>
<td>energy storage resource</td>
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<tr>
<td>ESS</td>
<td>energy storage system</td>
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<td>EV</td>
<td>electric vehicle</td>
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<tr>
<td>EVSE</td>
<td>electric vehicle charging station</td>
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<tr>
<td>FAN</td>
<td>field area network</td>
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<tr>
<td>FEJA</td>
<td>Future Energy Jobs Act</td>
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<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<tr>
<td>FLISR</td>
<td>fault location isolation and service restoration</td>
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<tr>
<td>GIS</td>
<td>geographic information system</td>
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<tr>
<td>GME</td>
<td>geomagnetic disturbance event</td>
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<tr>
<td>GUID</td>
<td>globally unique identifier</td>
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<tr>
<td>HAN</td>
<td>home area network</td>
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<tr>
<td>HILF</td>
<td>high-impact, low frequency</td>
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<tr>
<td>HIU</td>
<td>historical interval usage</td>
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<tr>
<td>HVAC</td>
<td>heating ventilation and air conditioning</td>
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<tr>
<td>ICC</td>
<td>Illinois Commerce Commission</td>
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<tr>
<td>ICE</td>
<td>internal combustion engine</td>
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<tr>
<td>IDC</td>
<td>integrated distribution company</td>
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<tr>
<td>IDP</td>
<td>integrated distribution planning</td>
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<tr>
<td>Acronym</td>
<td>Description</td>
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<tr>
<td>IEC</td>
<td>International Electrotechnical Commission</td>
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<tr>
<td>IEEE</td>
<td>Institute of Electrical and Electronics Engineers</td>
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<tr>
<td>IoT</td>
<td>internet of things</td>
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<tr>
<td>IPA</td>
<td>Illinois Power Act</td>
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<tr>
<td>ISEIF</td>
<td>Illinois Science and Energy Innovation Foundation</td>
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<tr>
<td>ITC</td>
<td>independent transmission company</td>
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<tr>
<td>KPI</td>
<td>key performance indicator</td>
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<tr>
<td>KRI</td>
<td>key risk indicator</td>
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<tr>
<td>LIHEAP</td>
<td>low-income home energy assistance program</td>
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<tr>
<td>LMI</td>
<td>low and moderate income</td>
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<tr>
<td>LMP</td>
<td>locational marginal price</td>
</tr>
<tr>
<td>LMV</td>
<td>locational marginal value</td>
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<tr>
<td>LTE</td>
<td>long-term evolution</td>
</tr>
<tr>
<td>MISO</td>
<td>Midcontinent Independent System Operator</td>
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<tr>
<td>MPLS</td>
<td>multiprotocol label switching</td>
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<tr>
<td>MSP</td>
<td>metering service provider</td>
</tr>
<tr>
<td>MT</td>
<td>market transformation</td>
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<tr>
<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
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<tr>
<td>NIST</td>
<td>National Institute of Technology</td>
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<tr>
<td>NPP</td>
<td>nuclear power plant</td>
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<tr>
<td>NREL</td>
<td>National Renewable Energy Laboratory</td>
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<tr>
<td>NWA</td>
<td>non-wires alternative</td>
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<tr>
<td>OATT</td>
<td>open access transmission tariffs</td>
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<tr>
<td>OBF</td>
<td>on-bill finance</td>
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<tr>
<td>OEM</td>
<td>original equipment manufacturer</td>
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<tr>
<td>OPGW</td>
<td>optical ground wire</td>
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<tr>
<td>ORMD</td>
<td>Office of Retail Market Development</td>
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<tr>
<td>OT</td>
<td>operational technology</td>
</tr>
<tr>
<td>PBR</td>
<td>performance-based ratemaking</td>
</tr>
<tr>
<td>PCC</td>
<td>point of connection</td>
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<tr>
<td>PEV</td>
<td>plug-in vehicle</td>
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<tr>
<td>PG&amp;E</td>
<td>Pacific Gas &amp; Electric</td>
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</table>
PIM  performance incentive mechanism  
PIPP  percent of income payment plan  
PLC  peak load contribution  
PMU  phasor measurement unit  
PSC  public service commission  
PTC  production tax credit  
PUA  Public Utility Act  
PUC  public utility commission  
PV  photovoltaics  
RAP  regulatory assistance project  
RBAC  role-based access control  
REC  renewable energy credit  
RER  renewable energy resource  
RES  retail electric supplier  
RGGI  greenhouse gas initiative  
RMI  Rocky Mountain Institute  
RPM  risk management plan  
ROE  return on equity  
RPS  renewable portfolio standard  
RR&S  reliability, resiliency, and security  
RTO  regional transmission organization  
RTP  real-time pricing  
SAIDI  system average interruption duration index  
SAIFI  system average interruption frequency index  
SCADA  supervisory control and data acquisition  
SDN  software defined networking  
SMCD  smart meter connected device  
SONET  synchronous optical networking  
SREC  solar renewable energy certificate  
SSO  single sign-on  
TE  transportation electrification  
TLS  transport layer security
<table>
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<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>TOU</td>
<td>time of use</td>
</tr>
<tr>
<td>TVR</td>
<td>time-varying rate</td>
</tr>
<tr>
<td>UCB/POR</td>
<td>Utility Consolidated Billing and Purchase of Receivables</td>
</tr>
<tr>
<td>UCS</td>
<td>Union of Concerned Scientists</td>
</tr>
<tr>
<td>UIUC</td>
<td>University of Illinois at Urbana-Champaign</td>
</tr>
<tr>
<td>UPS</td>
<td>uninterruptable power supplies</td>
</tr>
<tr>
<td>VAr</td>
<td>Volt-ampere reactive, a unit of power</td>
</tr>
<tr>
<td>VLC&amp;I</td>
<td>very large commercial and industrial</td>
</tr>
<tr>
<td>VPP</td>
<td>virtual power plant</td>
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<tr>
<td>WG</td>
<td>working group</td>
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<tr>
<td>XML</td>
<td>extensible markup language</td>
</tr>
<tr>
<td>ZEC</td>
<td>zero emissions credit</td>
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Appendix B: Cook County Energy Efficiency Case Study

Cook County just completed a $112M capital improvement project focused on energy efficiency that impacted 75% of the County’s building portfolio and focused on the “low hanging fruit,” such as lighting upgrades, BAS upgrades, boiler and chiller replacement, etc. The 19% reduction includes the carbon emission reductions from the $112MM capital improvement projects. The County is now focused on the remaining 60% reduction needed to meet the 2050 goal.

In order to do this, Cook County will have to focus on high performance and zero energy building design and operation and deployment of renewable energy and microgrid technology. There are many benefits from this effort:

- Resiliency
  - **Energy:** outages are expensive for customers and utilities. Multiple resources of a microgrid can prevent them.
  - **Security:** In times of crisis, microgrids operate separately from the grid and can keep campuses and communities running.
  - **Community:** A microgrid can connect to other microgrids and provide power to surrounding communities.

- Cost Savings
  - Efficient equipment of zero-energy-ready design can last longer and reduce operating costs.
  - Electricity costs are partially based on peak demand. Operating off-grid for portions of the day can reduce the peak and rate class that of a campus.
  - Microgrid technologies can support other ancillary services which can create additional revenue streams.

- Meet carbon reduction goals
  - Microgrids and zero energy design both support diversity in renewable energy technologies including solar, wind, geothermal, combined heat and power, biomass energy, battery storage, which reduce carbon emissions.

- Meet water savings goals
  - Water and energy are closely related. Some of the old boilers at the Department of Corrections (DOC) are losing 60-70% of the water they use; that means significant water and energy may be saved by improving these power systems.

- Technological Advancement
  - Selecting more efficient technologies can reduce the need for frequent replacements by making the whole system function more efficiently and effectively.
  - Incorporating technology at the outset of a master plan can help establish baseline information and create the goals and metrics for success.

- First mover
- Being at the forefront of newer technology pilots can provide more resources such as national lab research, academic support, financial grant opportunities, DOE resources and awareness to garner political, economic, utility and community support.
- It’s a good time for clean energy investments, with the Future Energy Jobs Act providing incentives for community solar and energy efficiency incentives.

- Energy Efficiency
  - Zero energy design can reduce equipment replacement costs, lower energy and water usage and reduce carbon emissions.
  - Including Zero Energy Design from the outset can promote a low EUI as has been evidenced in K-12 School Design projects highlighted in the ASHRAE Advanced Energy Design Guidelines.

If the County is going to meet its aggressive emissions reduction goal, it likely will have to completely change how, when and where, it uses energy.
Appendix C: CTA’s Electric Bus Program

Of CTA’s fleet of over 1,880 transit buses, two are all-electric. CTA’s two e-buses entered service in October 2014 and have demonstrated reliable, efficient performance under all Chicago weather and road conditions. While these buses have stated battery range up to 100 miles, CTA operates them only up to about 80 miles per charge. The buses “slow-charge” in CTA’s indoor bus garages on 100 kW chargers with plug-in cords.

CTA’s two e-buses operate on the following daily service and charging schedule:

- Charge three to five hours overnight in the garages
- Perform morning rush period transit service for 50 to 60 miles (about six hours)
- Return to the garages during the mid-day lull and charge for three to five hours
- Perform evening rush period transit service for 70 to 80 miles (about eight hours)
- Return to the garages for overnight charging again

CTA is currently conducting a procurement process for an additional 20 to 30 e-buses and associated charging infrastructure. The e-buses in this upcoming purchase will charge en-route at the two end-point terminals. The en-route chargers will be DC “fast-chargers,” specified to be the highest power available on the market today, which CTA anticipates to be in the 400-600 kW range. When the e-bus is correctly positioned under the mast-mounted charger, a pantograph arm descends down from the charger to contact the roof of the bus and convey the charge. CTA anticipates charging e-buses for five to ten minutes during their normally scheduled layover times, enabling e-buses to run in continuous service throughout the day and night without returning to the garage.
The long-range e-buses that are available today typically require overnight, garage-based, slow charging. They have the advantage of being able to provide service on any bus route (because they don’t rely on en-route charging infrastructure), but today’s e-bus battery technology is not sufficient to meet CTA’s longest bus service “blocks” of about 300 miles. In addition, the larger battery packs on these e-buses add weight and cost to the bus. To charge a large fleet of long-range e-buses overnight, CTA would need to install slow chargers in the garages on essentially a one-to-one basis with the number of e-buses.

In comparison, shorter-range e-buses that charge en-route can operate nearly continuously by “topping off” their batteries at fast-chargers during terminal layover times. Their battery packs are less expensive and lighter and therefore require less propulsion power to transport. Installing fast-charging infrastructure in a decentralized manner (distributed throughout the transit service area) is much more expensive than installing slow-charging infrastructure at existing bus garages, but the decentralized plan is less subject to the risks of power outages. Both en-route charging and garage charging may result in high demand fees and capacity costs. In both scenarios, mitigating these expenses will depend on the degree of flexibility to shift charging times and the ability to manage charging schedules.

CTA is eager to work with its utilities, energy suppliers, policymakers and other partners to continue exploring opportunities to achieve energy efficiencies and cost savings and to deploy new clean energy technologies. Below are listed several areas for potential collaboration that would support CTA’s initiatives on both the rail and bus systems.
Appendix D: Load Forecasting

Forecasting today is driven by the peak hour and day, factoring in weather adjustments. Load growth projections are driven by new construction/redevelopment. For individual customers, growth is often assumed to be zero. Longer-term econometric load growth (land use, economic growth) are not factors in short term distribution planning but are factored into longer term substation construction plans.

Load forecast horizons should be consistent with the lead-time to complete projects. Emerging challenges in load forecasting include:

- Shifting from focus on peak to all hours
- Forecasting DER adoption
- Forecasting DER behavior
- Allowing for uncertainty in DER time series forecasting
- Understanding and incorporating DER scheduling and dispatch, market forces and market operations
- Projection of climate change and weather trends
- Consideration of potential changes in public policy

Forecasting DER adoption and behavior may become a significant factor in future planning. Issues associated with transportation electrification and its impact on the grid are one example:

- The location of EV-charging facilities, especially for DCFC and public transit, may drive significant locational load growth. A single fast charger may have a demand of 500kW, so a station with ten of them would need 5 MW delivery capacity
Individual EV-charging schedules may depend upon what purpose the vehicle is used for (commuting, ride sharing, intercity travel, local errands, etc.). Charging loads may be affected by availability of charging stations at workplaces, shopping malls and other locations, electricity pricing options such as TOU, development of smart charging programs and traffic conditions will affect EV loads at any given time. DCFC loads at highway locations may peak during holiday driving weekends.

Forecasting the rate of EV adoption is necessary for planning but is difficult. Reaching a “tipping point” may mean very rapid market penetration; however, slow growth may mean underutilization of EV infrastructure. The pace of transportation electrification depends upon the complex interaction of public policy, customer choice, cost (of EVs themselves as well as the relative prices of electricity and gasoline), market forces, adoption by transit agencies, technology/performance development, availability of charging infrastructure and economic conditions. There may also be dramatically different adoption rates in different locations. The “neighbor” effect has already been shown to cause clusters of consumer EV adoption and initial adoption is in higher income areas. All of these factors have implications for system planning and load forecasting.

Other DER technologies may contribute similar new kinds of forecasting challenges. For example, widespread adoption of heat pumps (an alternative to fossil fuel for heating) would affect load forecasting. The emergence of a cost-effective combination of rooftop solar and energy storage may have a dramatic impact on system planning, operation and forecasting.
Utilities would have to integrate many sources of “big data” and sophisticated analytics in order to handle the load forecasting challenge posed by high DER integration.

Typical capacity relief projects may include a wide range of (conventional) solutions:

- Switching (shifting load to other feeders)
- Phase balancing
- Voltage correction (cap banks)
- Reconductoring
- Line extensions
- Substation transformer additions or upgrades
- New substations

If forecasting becomes more complex, planning also becomes correspondingly challenging, as illustrated in the chart above.
Appendix E: BOMA/Chicago Stakeholder Perspective

BOMA/Chicago is a trade association that has represented the interests of the Chicago office building industry since 1902. Membership includes 239 commercial office, institutional and public buildings and 169 companies that provide commercial building services to support operational excellence. BOMA/Chicago members constitute approximately 80% of all rentable office space and more than 98% of rentable space in Class A buildings in downtown Chicago.

New technology available to the energy sector may provide opportunities for innovation to better serve customers, lower rates and improve grid reliability and resiliency. Given the success of competitive energy markets in Illinois and nationally, BOMA/Chicago believes that market mechanisms should continue to be a key guidepost to empower customers.

BOMA/Chicago believes that decisions about what technologies and innovations best serve customers should be made, first and foremost, by customers themselves, through transparent market mechanisms. Regulation or policy preferences should be predicated upon transparent information and process, cost benefit analysis from the customer perspective and openness to examining both monopoly utility and non-monopoly utility models as the means to best serve customers.

Commercial and residential buildings use 40% of all the energy in the US and consumer 75% of the electricity. Building owners—both commercial and residential—have economic incentives to reduce energy use with advanced technologies. These technologies can also provide added benefits for owners and occupants including reduced maintenance, self-diagnosis of faults and better indoor environmental quality. But, installing advanced systems in new construction has a cost and retrofitting existing buildings is often a challenge. New opportunities are emerging for buildings to provide services to the grid such as demand response, DG and ancillary services. Becoming grid interactive means that owners can access additional revenue streams to help recoup the costs of energy technology, reducing the cost recovery time and creating incentives for alternative financing.

Argonne Lab is studying how advanced building systems can help provide those services including the use of variable speed fans and pumps that can be controlled from the grid, advanced HVAC controls including adaptive control, predictive control and adaptive scheduling that can respond to grid signals. Thermal storage within the building structure or systems (such as hot water tanks) is a promising technology for providing load shifting and demand response. How to size and integrate electric storage in the form of batteries or fuel cell systems is also under study by Argonne, as is how to integrate building-related DERs such as solar panels and other generators. Argonne is also developing new metering technologies for monitoring building electric usage and generation.

The Department of Energy (DOE) is researching other energy efficient technology for buildings including advanced HVAC equipment like heat pumps, energy efficient appliances and lighting and supply technologies like geothermal and combined heat and power.
**Building Integration into Energy Market and New Technology Deployment Goals**

All BOMA/Chicago buildings have participated in competitive supply since the inception of Illinois choice in the late 1990’s. Since that time, sophistication has grown and buildings have been aggregating supply options as well as blending demand response and energy efficiency projects into their portfolios.

Participation in competitive markets has been highly beneficial for BOMA/Chicago members, as the opportunity to take advantage of innovative service offerings from Alternative Retail Electric Suppliers (ARES) and competitive energy service providers has resulted in more efficient energy use, lower environmental impacts, substantial cost savings and new revenue streams. Those benefits have not been limited to the building owners alone; building tenants and their employees have benefited by extension through lower lease costs, energy efficiency, increased opportunities for procurement of clean energy and other similar market-driven positive developments.

BOMA/Chicago’s members have substantial experience participating in complex competitive wholesale markets in PJM and elsewhere. With the implementation of more advanced Building Automation Systems (BAS), buildings continue to be some of the most sophisticated consumers in the energy markets. As a result of their ability to control and automate certain systems of a building (such as heating, ventilation and air conditioning), as well as to respond to price signals (from capacity calls to frequency regulation signals with storage or variable frequency drives), large buildings, particularly in aggregate, should be seen as a resource for providing grid stability and improved grid operations.

Additional current and future projects involving BOMA/Chicago buildings include efforts to demonstrate that buildings can integrate into all supply-side and demand-side market including frequency regulation and spinning reserve. Buildings will soon be able to monetize their operational flexibility and automation and deploy new technologies and infrastructure to enable smarter investment decisions for owners, managers and tenants as part of the cost benefit analyses of integrating energy efficiency and new technologies into building operations and energy planning and procurement.

In order to accomplish these goals, building owners, managers, engineers and tenants will need to be able to reliably measure and verify improvements and efficiencies. This means that there is a pressing need for real-time data access and control capabilities in order to meet the market requirements of regional transmission organizations.

**BOMA/Chicago’s Key Guiding Principles of New Technology Deployment**

BOMA/Chicago suggests that the investigation of new technology should not simply be about how to integrate new technologies and innovation into the existing monopoly utility model. Rather, new technology and innovation should be evaluated first in the context of whether and how any new technology or innovation can help customers. Assuming a technology or innovation can deliver a benefit to customers, the next question is, at what cost? No technology should be mandated through law or policy without a rigorous cost benefit analysis, that focuses on empowering customers and delivering benefits through a process that enables consumers to control their own destiny and achieve their own energy-related goals.
Assuming a particular technology or innovation is seen by building owners as cost-effective, the next question is how to deploy that technology or innovation most efficiently for the customer. The assumption should not be that the monopoly utility model will be the default “right answer” to that question. Market mechanisms or alternative regulated methods should also be explored. Indeed, given the success of competitive energy markets in Illinois, the default assumption should be that markets can most efficiently deploy the technology or innovation.

In order to proceed in that manner, it is critical that all regulatory, policy and legislative proposals be entirely transparent and issues be open to debate. Before any conclusions or recommendations are reached there should be a methodical approach to evaluating technologies, to ensure that any “solution” is designed to address a real “problem.” Accordingly, BOMA/Chicago suggested the following key principles:

- Ensure that any “Solution” is Designed to Address a Real “Problem”
- Use a Cost Benefit Analysis to Evaluate Each Potential Technology
- Advance Competitive Markets including DR and DERs
- Encourage Full Disclosure of Cost Components and Accurate Cost Allocation
- Use a Cost Benefit Approach to Benefit all Stakeholders

**Cost Benefit Approach**

BOMA/Chicago believes that the integration of new technology should always be the outcome of an acceptable cost benefit analysis.

**BOMA/Chicago’s View of Competitive Markets**

Understanding the historic benefits of the competitive energy markets in Illinois is a key consideration in determining future methods to incentivize new technology deployment and integration. Given past market-driven successes, BOMA/Chicago believes that serious consideration must be given to facilitating a competitive market model as the primary deployment methodology for NextGrid solutions.

**Distributed Generation Drivers**
The main drivers of DG for buildings (as well as other consumers) include: environmental benefits such as greenhouse gas (GHG) reduction; promoting the use of local energy sources such as wind, solar, hydro, biomass, biogas and others; creating local revenue streams (electricity sales, lower costs, DR); and, creating employment opportunities (manufacturing, erection, maintenance, operation). BOMA/Chicago buildings operate in a competitive environment that motivates them to reduce energy bills, secure new revenue streams and advance environmental goals.

**BOMA/Chicago’s Identified Following New Technology Deployment Barriers**

- Inadequate information about available technologies
- Limited understanding of life-cycle costs & benefits
- Limited available investment capital
- Increased transactions costs
- Distorted investment priorities
- The Energy Efficiency “Gap”
- Consumers’ Actual Investments
- Investments Made in Consumers’ Interests

BOMA/Chicago believes that competitive energy markets in Illinois and nationally have been an enormous success, both in creating cost savings for customers and incentivizing innovation and new technology. Illinois should build upon those market-driven successes. Choices about what grid technologies and innovations best serve customers should be made by customers, through transparent market mechanisms. Regulation and policy decisions will be appropriate in certain instances, but any regulation or policy preferences should be predicated upon transparent information and process, cost benefit analysis from the customer perspective and openness to the idea that non-monopoly utility models best serve the needs of some customers.
Appendix F: Ratemaking Terms

- **Customer Charge**: A customer or basic service charge is a fixed fee charged in each billing period that is independent of the customer’s energy consumption.

- **Demand Charge**: A demand charge is based on the customer’s highest load measured in kW during either a billing period or a specified subset of hours – e.g., during hours when a system or circuit peak load is forecast to occur or a specified time interval, such as the highest 15 minutes or hour. Some demand charges include a “ratchet” clause that entails the application over the course of the subsequent year of the highest demand registered in a billing period.

- **Distributed Energy Resource (DER)**: DER refers to any generator or storage resource, demand control or energy efficiency technology program located either “behind-the-meter” on a customer’s premises or interconnected directly into the local distribution system.

- **Distribution Locational Marginal Price (DLMP)**: Time- and site-specific locational marginal pricing at elemental or commercial billing locations on a utility distribution system that reflect congestion and marginal distribution losses in the distribution grid, and the impacts on equipment service life. DLMPs typically refer to real power but analogous prices may be computed for reactive power.

- **Fixed Costs**: Embedded Costs that do not vary with short-run changes in output.

- **Locational Marginal Pricing**: Prices at a specified time that reflect the market clearing prices at specific locations within the bulk power grid, with the congestion and losses explicitly considered.

- **Market Based Rates**: TVR that pass through changes in market clearing prices applied to time periods corresponding to the periods covered by wholesale markets, typically on an hourly or real-time market subperiod.

- **Marginal Cost**: The change in cost of an infinitesimally small incremental or decremental unit of short-run supply or consumption at a specified time and location for a specific product.

- **Minimum Bill**: A minimum bill sets a threshold limit on what a customer pays in a given billing period even if the customer has zero consumption or zero net usage under a net metering tariff during that period.

- **Multi-year Rate/Revenue Plan (MRP)**: In MRPs, either price caps on rates or revenue caps on allowed revenues are specified or adjusted in accordance with a given formula.
or attrition mechanism over the multi-year period (e.g., 3 to 8 years) of the plan. Such multi-year plans are a principal form of performance based ratemaking (PBR) that are often used in setting electric utility rates in various jurisdictions outside the United States. The RIIO plan formulated by the United Kingdom Office of Gas and Electric Markets is frequently cited as an example of a MRP that applies PBR.

- **Performance Based Ratemaking (PBR):** PBR aims to approximate the incentives used in efficient markets by the alignment of the utility’s compensation with its actual performance in provision of cost savings, customer value and/or innovation. PBR may be included in some forms of MRPs where the utility may have incentives to constrain costs to provide desired levels of service and/or policy outputs. In addition, the term PBR is also used to describe the application of specific PIMs within the context of conventional cost of service regulation. A specific example is a utility that may receive either an incentive or be imputed a penalty depending on how well it meets a given resiliency target or some other performance metric.

- **Performance Incentive Mechanism (PIM):** PIMs provide incentives or disincentives, (i.e., penalties) that target specific elements or outcomes of utility performance. PIMs are based on a specified performance metric target or standard and the associated formula that determines the amount of rewards/penalties, such as the share of “gains”/“losses” allocated to utility shareholders and customers. The reward/penalty component may be symmetric or asymmetric, include limits on rewards/penalties and a “dead band” in recognition of the inherent uncertainty associated with the specified target. PIMs can also include waivers or exceptions for certain events beyond the utility’s control.

- **Real-Time Pricing (RTP):** Prices that can vary continually, from one to another interval, be it at a typical interval of 5 minutes, 15 minutes or one-hour to reflect the wholesale electricity market prices and the utility’s short-run variable costs that may explicitly include resource scarcity. Examples of RTP programs include RTP, RTP plus a capacity adder referred to as RTP+ and block and index pricing known as hedged RTP.

- **Residual Costs:** Residual costs are the utility revenue requirements that are above what can be recovered in rates based on short-run marginal costs. To the extent that transmission and distribution services are natural monopolies, the utilities that provide these delivery services often are unable to recover their average costs from rates set based on marginal costs.

- **Social or Societal Marginal Costs:** The change in cost of an infinitesimally small incremental/decremental unit of short-run supply or consumption including associated
externalities, such as the environmental impacts whose cost changes are explicitly incorporated.

- **Time Varying Rates**: Administratively specified rates that can vary by hour, day or season that may or may not be based on market outcomes. Examples of such rates include time-of-use, critical peak pricing and critical peak rebates.

- **Variable Costs**: Costs that depend explicitly on the changes in demand and, consequently, directly on the short-run changes in the costs and delivery of services.

- **Volumetric Rates**: Rates that are based on consumption within a defined period, typically, expressed on a per kWh basis.
WG7 participating stakeholders came with distinct perspectives on each of the rate mechanisms discussed. Such a situation is not surprising as it mirrors the positions of different stakeholders articulated in various regulatory proceedings and other forums, both in Illinois and around the country. This table summarizes those perspectives, as well as the general sentiments of the discussion.

<table>
<thead>
<tr>
<th>Rate Mechanism</th>
<th>Perspective A</th>
<th>Perspective B</th>
<th>Perspective C</th>
<th>The WG participants’ General Sentiment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formula Rates</td>
<td>stabilized Illinois formula rates, with incentives for smart-grid investments, resiliency improvements, reduced regulatory costs due to streamlined process and performance targets for specific non-cost functional areas</td>
<td>reduced regulatory lag; questionable whether harmful or helpful to customers in the long run</td>
<td>greater emphasis on rate design when separated from the revenue requirements</td>
<td>generally beneficial to customers and good for Illinois; dispute over whether or not shift of risk harms customers</td>
</tr>
<tr>
<td>Cost of Service (COS) Ratemaking</td>
<td>from an economic perspective, the superiority of marginal cost studies over embedded cost studies is indisputable</td>
<td>data used in COS studies need to be more granular</td>
<td>may bias utilities toward capital expenditures that may be inferior to other types of expenditures</td>
<td>reassessment of COS ratemaking warranted in view of improved data and changing market and public-policy environment</td>
</tr>
<tr>
<td>Standby/Partial Requirements Rates</td>
<td>Present rates are reasonable; they were approved by the ICC</td>
<td>Excessive largely because of misallocation of distribution cost to partial requirements service</td>
<td>Alleged problems addressable in rate design proceedings or designated ICC proceeding</td>
<td>Parties can request ICC to rule on reasonableness of present rates; biggest dispute is whether distribution costs allocate</td>
</tr>
<tr>
<td>Rate Mechanism</td>
<td>Perspective A</td>
<td>Perspective B</td>
<td>Perspective C</td>
<td>The WG participants’ General Sentiment</td>
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<td>-------------------------------------------------------------------------------</td>
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</tr>
<tr>
<td>TVR</td>
<td>different forms of TVR in TOU rates, RTP rates, critical peak rebates and CPP rates can reduce peak demand, without agreement on which form is preferable; rate simplicity is crucial to gain customer acceptance</td>
<td>low participation likely to continue with opt-in and the continued absence to enable technology; opt-in also imposes higher marketing costs for utilities</td>
<td>any implementation needs to address the potential harm on vulnerable customers; the opt-out alternative may result in lower customer satisfaction and more complaints</td>
<td>to partial requirements customers are excessive</td>
</tr>
<tr>
<td>Efficient and Equitable Rates</td>
<td>full benefits of smart meters yet to be exploited by the customers; full customer access to the latest technologies and engagement of all customers yet to occur</td>
<td>critical issues on affordability and allocation of “residual costs” yet to be addressed</td>
<td>need to investigate the outcomes of new rate designs, including block and index rates in various jurisdictions</td>
<td>several issues need to be addressed before new rate design implementation</td>
</tr>
<tr>
<td>PBR</td>
<td>ability to overcome or mitigate some of the problems of COS ratemaking, such as capital bias; ability to allow certain expenditures to be rate based, as in the case of third-party</td>
<td>ability to provide appropriate incentives for utility performance aligned to meet public-policy goals and long-term customer welfare at targeted levels; in contrast to COS ratemaking,</td>
<td>increasingly considered or applied by both utilities and regulators across the country; PBR concept not new; the reason for the abandonment of the initial adoption by US utilities needs to be investigated</td>
<td>applicable to wide range of utility activities with potentially large benefits for correct design and implementation; ability to provide appropriate incentives to steer utilities’ activities to meet public-</td>
</tr>
<tr>
<td>Rate Mechanism</td>
<td>Perspective A</td>
<td>Perspective B</td>
<td>Perspective C</td>
<td>The WG participants’ General Sentiment</td>
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<td>-------------------------------------------------------------------------------</td>
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<td>-------------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td>services deemed more beneficial to customers than other alternatives</td>
<td>avoidance of prudence reviews as long as PBR correctly applied</td>
<td></td>
<td>policy goals and to maximize customer welfare</td>
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<tr>
<td>Performance</td>
<td>ability to induce better utility performance, especially to perform comparative studies of peer utilities</td>
<td>questionable as to the effectiveness of the deployment of measurement data by the ICC: e.g., monitoring requirement incorporated into a PBR plan, “red flagging”</td>
<td>proper use depends on the ability to separate the effect of utility management from factors outside its control in a utility’s performance assessment</td>
<td>Current uses may be restricted to “red flagging” utilities with seemingly subpar performance; the crucial step is to set a benchmark or target</td>
</tr>
<tr>
<td>Measurement</td>
<td>key issue of whether valuation of DER based on embedded costs or marginal costs</td>
<td>trade-offs between additional DER payments for provision of surplus power and lower rates to full-requirements customers</td>
<td>question whether solar and other DER owner customers constitute a separate rate class requires the explicit consideration of their load factors relative to full-requirements customers</td>
<td>question of the need for finer granularity data to accurately valuate DER</td>
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<tr>
<td>Valuation of DERs</td>
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243
Appendix H: NextGrid Calendar of Meetings

Table H1: WG1 Meetings

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<thead>
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<th>meeting number</th>
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<th>time</th>
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<tr>
<td>1</td>
<td>December 5, 2017</td>
<td>10 am—12:15 pm</td>
</tr>
<tr>
<td>2</td>
<td>January 16, 2018</td>
<td>10 am—12:15 pm</td>
</tr>
<tr>
<td>3</td>
<td>January 30, 2018</td>
<td>10 am—12:15 pm</td>
</tr>
<tr>
<td>4</td>
<td>February 14, 2018</td>
<td>10 am—12:15 pm</td>
</tr>
<tr>
<td>5</td>
<td>February 28, 2018</td>
<td>1—5 pm</td>
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<tr>
<td>6</td>
<td>March 13, 2018</td>
<td>10 am—12:15 pm</td>
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Table H2: WG2 Meetings

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<tr>
<td>1</td>
<td>March 15, 2018</td>
<td>1—3 pm</td>
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<tr>
<td>2</td>
<td>March 26, 2018</td>
<td>1—4 pm</td>
</tr>
<tr>
<td>3</td>
<td>April 13, 2018</td>
<td>11 am—1:50 pm</td>
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<tr>
<td>4</td>
<td>April 27, 2018</td>
<td>11 am—1:30 pm</td>
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Table H3: WG3 Meetings

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<tr>
<td>1</td>
<td>April 11, 2018</td>
<td>12—3:30 pm</td>
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<tr>
<td>2</td>
<td>April 27, 2018</td>
<td>9 am—12 pm</td>
</tr>
<tr>
<td>3</td>
<td>May 11, 2018</td>
<td>9 am—12 pm</td>
</tr>
<tr>
<td>4</td>
<td>May 22, 2018</td>
<td>9 am—12 pm</td>
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<tr>
<td>5</td>
<td>June 14, 2018</td>
<td>10 am—12 pm</td>
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Table H4: WG4 Meetings

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<td>1</td>
<td>April 18, 2018</td>
<td>1—3 pm</td>
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<td>2</td>
<td>May 2, 2018</td>
<td>1—3:30 pm</td>
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<tr>
<td>3</td>
<td>May 15, 2018</td>
<td>1—3:30 pm</td>
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<tr>
<td>4</td>
<td>June 5, 2018</td>
<td>1—3:30 pm</td>
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<tr>
<td>5</td>
<td>August 6, 2018</td>
<td>1—3:30 pm</td>
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### Table H5: WG5 Meetings

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<td>1</td>
<td>May 14, 2018</td>
<td>1—3:15 pm</td>
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<td>2</td>
<td>June 4, 2018</td>
<td>1—4 pm</td>
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<td>3</td>
<td>June 25, 2018</td>
<td>9am—12 pm</td>
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<td>4</td>
<td>July 30, 2018</td>
<td>2—5 pm</td>
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### Table H6: Working Group 6 Meetings

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<td>June 6, 2018</td>
<td>1—3:30 pm</td>
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<td>2</td>
<td>June 20, 2018</td>
<td>1—3:30 pm</td>
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<tr>
<td>3</td>
<td>July 25, 2018</td>
<td>1—4 pm</td>
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### Table H7: Working Group 7 Meetings

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<td>1</td>
<td>June 8, 2018</td>
<td>9am—12 pm</td>
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<tr>
<td>2</td>
<td>June 19, 2018</td>
<td>10am—1 pm</td>
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<tr>
<td>3</td>
<td>July 30, 2018</td>
<td>9am—1:30 pm</td>
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<tr>
<td>4</td>
<td>September 13, 2018</td>
<td>1—5 pm</td>
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### Table H8: Stakeholder Advisory Council (SAC) Meetings

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### Table H9: Technical Advisory Group (TAG) Meetings

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## Appendix I: List of Participating Stakeholders

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