Innovation Pathway Study:
Smart Grid Technologies

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Executive Summary

The Smart Grid Technologies Innovation Pathway Study investigates the motivating and influencing factors that have allowed for the commercialization of Smart Grid technologies within the US. In particular, two foundational smart grid technologies are examined: Smart Meters and Synchrophasor Technologies. These are considered to be fundamental because they provide fundamental insights into the behavior and status of the electric grid. On this platform of understanding, additional smart grid technologies are built, including those focused on consumer engagement, renewables integration, automation, and control.

Smart meters were first introduced in the electric utility industry under the name 'automated meter readers' (AMR). These devices allowed utilities to digitally collect monthly usage date from customers, instead of sending personnel into communities to perform readings. This technology had already been widely deployed in the gas and water utility industries. AMR provided clear cost savings for electric utilities. Developers soon realized that greater insights into the grid's operation could be uncovered by recording customer usage information at more frequent intervals. As new features were built into AMR meters, the technology evolved into what is now termed 'Advanced Metering Infrastructure' (AMI). AMR and AMI deployment trends follow the standard s-curve shape, characteristic of technology innovations.

Synchrophasor technology adoption was motivated by large blackouts in the US power grid. Many federally funded studies pointed to a greater need to see into the operational nature of the electric grid. Over a span of decades, mathematical theories, digital relaying technologies, and GPS capabilities merged, to create the first commercial synchrophasor device. Government funding enabled the installation of the first wave of synchrophasor devices. Many US utilities are now purchasing devices without further subsidies.

In 2008, a framework was developed (Stephens, Wilson, & Peterson, 2008) for the strategic evaluation of energy innovation. The socio-political evaluation of energy deployment (SPEED) framework identifies three levels at which innovation processes can be analyzed and affected. These include the strategic, tactical, and operational levels. At the strategic level, aspirational political goals are defined. At the tactical level, state level political processes work to align resources and political constituencies. At the operational level, individual energy projects are executed and supported.

Smart Grid technology developments present a clear example of the SPEED framework fully executed. At the national level, smart grid policy goals were defined in legislation that includes the Energy Policy Act of 2005, and the Energy Independence and Security Act of 2007, among others. These federal policies were supported by initiatives like the American Recovery and Reinvestment Act. Federal policies mandated action at the state level by requiring public utility commissions to perform feasibility studies, quantifying the benefit of adopting smart grid technologies and strategies like AMI, demand response, and net metering. At the local level, the Smart Grid Investment Grant Program and Smart Grid Demonstration Program provided funding and support for the execution of over 120 smart grid projects. This coordinated effort, with three levels of support and intervention, provided the alignment and consistency that enabled smart grid technologies to effectively commercialize.

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Glossary

AEP – American Electric Power

AMI – Advanced Metering Infrastructure

AMR – Automated Meter Reading

ARRA – American Recovery and Reinvestment Act

BPA – Bonneville Power Association

CERTS – Consortium for Electric Reliability Technology Solutions

DOE – U.S. Department of Energy

DP – Dynamic Pricing

DSM – Demand Side Management

EIA – Energy Information Administration

EIPP – Eastern Interconnection Phasor Project

EPAct – Energy Policy Act of 2005

EE – Energy Efficiency

GE – General Electric

GPS – Global Positioning Seattleite

IEEE – Institute of Electrical and Electronics Engineers

IEC – International Electrotechnical Commission

ISO – International Organization for Standardization

LAN – Local Area Network

M&A – Merger and Acquisition

NASPI – North American SynchroPhasor Initiative

NERC – North American Electric Reliability Council

NPCC – Northeast Power Coordinating Council

NYPA – New York Power Authority

PDC – Phasor Data Concentrator

PE – Private Equity

PNNL – Pacific Northwest National Laboratory

PMU – Phasor Measurement Unit

PURPA – Public Utility Regulatory Policies Act

RD&D – Research Development & Deployment

ROCOF – Rate of Change of Frequency

SCADA – Supervisory Control and Data Acquisition

SCDFT – Symmetrical Component Discrete Fourier Transform

SCDR – Symmetrical Component Distance Relay

SGIG – Smart Grid Investment Grant

T&D – Transmission and Distribution

TCP/IP – Transmission Control Protocol/Internet Protocol

TVA – Tennessee Valley Authority

VC – Venture Capital

WAMS – Wide Area Monitoring System

WECC – Western Electricity Coordinating Council

WAPA – Western Area Power Associatio

Introduction

This paper is part of a larger study that seeks to identify shared attributes and common causal factors among the pathways of technology innovation in the energy sector. The purpose of this study is to contribute useful analysis of historical experience to the Department of Energy's ongoing effort in energy technology innovation. This whitepaper provides data research and preliminary analysis of the development of smart grid technologies, including the deployment of advanced electric metering solutions, and the deployment of synchrophasor technologies.

This series of energy technology innovation studies is being conducted in order to distill lessons that can be generalized to other energy technologies, especially those currently in early stages of development or deployment. This paper is not intended to address the challenges and opportunities faced by any technology in particular, except by providing synoptic observations about the interactions of government agencies, academia, and the private sector as they relate to the development and deployment of a new energy technology. Additional papers in this series address technologies including nuclear power plants, renewable energy technologies, and a literature review of innovation studies.

Background

The Smart Grid is a concept, based on the idea of incorporating knowledge into the management of the electric grid. Much of the physical infrastructure that comprises the grid has seen little change in the last 100 years. During this same time period, extraordinary changes have revolutionized the industries of computing and telecommunications. There exists an opportunity to integrate technologies, tools, and techniques, to enhance the US electric grid in the following ways (Litos Strategic Communications, 2008):

- Ensuring its reliability to degrees never before possible.
- Maintaining its affordability.
- Reinforcing our global competitiveness.
- Fully accommodating renewable and traditional energy sources.
- Potentially reducing our carbon footprint.
- Introducing advancements and efficiencies yet to be envisioned.

This is the promise of the smart grid. A host of technologies have been developed to achieve the goals of the Smart Grid. Some of these technologies include:

- Plug-in electric vehicles and intelligent charging control systems
- Zero-net energy commercial buildings
- Superconducting electrical cables
- Energy storage
- Advanced sensors
- Visualization technologies
- Advanced metering infrastructure
- Synchrophasors and phasor measurement units
- Dynamic pricing and demand-side management

Description of Technologies Covered

Smart Grid technologies have been recently introduced to the US electric grid. In recent years, many technological advances have been made, to enhance the planning and operation of the electric grid, through measurement, analytics, and automation. Many of these technologies are in different stages of development and commercial success. This report describes the development and deployment of advanced electrical metering technologies by US electric power utilities, and their adoption of synchrophasor technologies. These two technologies are considered to fundamental to the deployment of other Smart Grid technologies and concepts. For example, the ability to frequently and accurately measure customer electrical usage underpins an electric utility's ability to offer hourly pricing for electrical service. The use of synchrophasor technologies allow utilities to measure the state and health of the grid over vast geographies, in near real-time. This ability to measure is a pre-requisite to creating visualization tools based on measured data.

Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers (DOE, Advanced Metering Infrastructure and Customer Systems, 2015). Customer systems include in-home displays, home area networks, energy management systems, and other customer-side-of-the-meter equipment that enable smart grid functions in residential, commercial, and industrial facilities (DOE, Advanced Metering Infrastructure and Customer Systems, 2015).

A synchrophasor is a sophisticated monitoring device that can measure the instantaneous voltage, current and frequency at specific locations on the grid (DOE, Synchrophasor Applications in Transmission Systems, 2014). Synchrophasors have been commonly given the following definition:

"Synchrophasors are time-synchronized numbers that represent both the magnitude and phase angle of the sine waves found in electricity, and are time-synchronized for accuracy. They are measured by high-speed monitors called Phasor Measurement Units (PMUs) that are 100 times faster than SCADA. PMU measurements record grid conditions with great accuracy and offer insight into grid stability or stress. Synchrophasor technology is used for real-time operations and off-line engineering analyses to improve grid reliability and efficiency and lower operating costs" (DOE, Synchrophasor Applications in Transmission Systems, 2014).

AMI and synchrophasors are two defining members of the Smart Grid technology suite. This paper describes the key historical events, technological milestones, commercial deployments, and financial investments that characterize the growth and success of these two technology areas. The paper concludes by then describing overarching themes and generalizable takeaways learned from investigating the innovation processes underlying the commercial success of these Smart Grid technologies.

Financing Trends Point to Sustained Growth in the Smart Grid Sector

Investments in smart grid technology have seen consistent growth in recent years, indicating a field that is still maturing. Significant investments in the US, including those funded through the DOE Smart Grid Investment Grant and Smart Grid Demonstration Project programs, have built confidence in new technologies. These technologies are starting to see commercial growth in international markets. The two figures that follow display investment information by technology type, and by geographic region. As shown, technologies like smart metering increasingly constitute a smaller percentage of the total market for smart grid products. And the Americas represent a shrinking portion of the smart grid investment footprint.

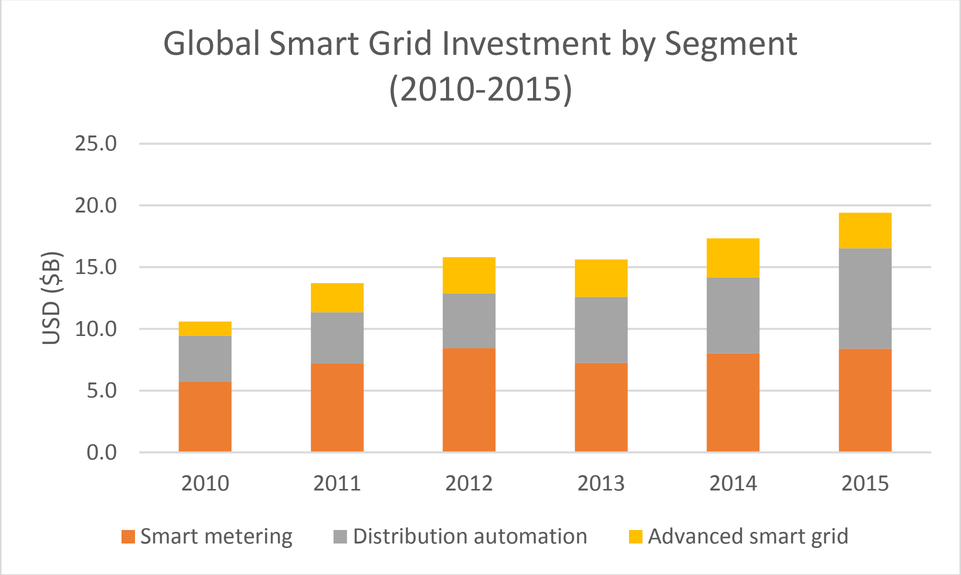


Figure 1: Global Smart Grid Investment by Industry Segment (2010 – 2015)

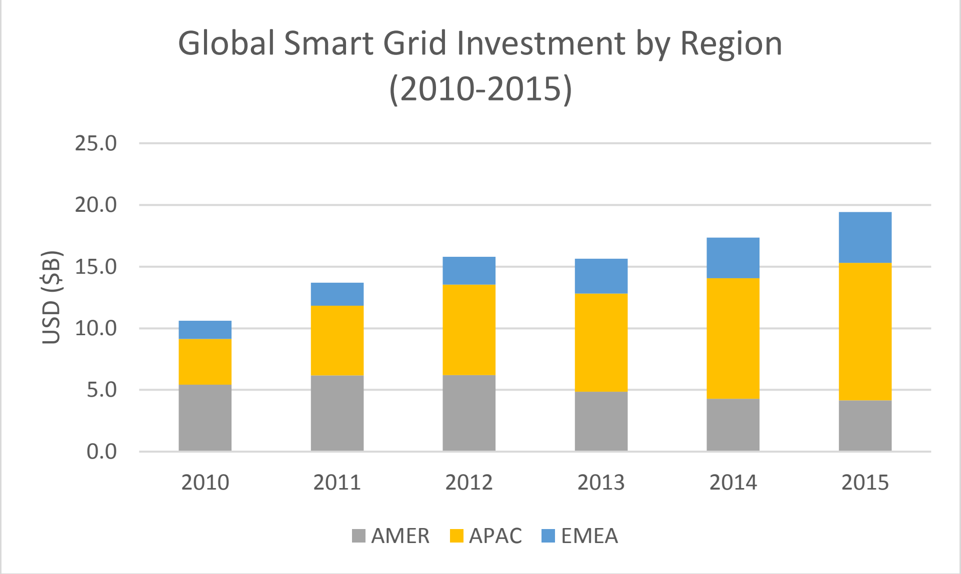


Figure 2: Global Smart Grid Investment by Region (2010 – 2015)

The smart grid landscape has been characterized by large government investments. Between the years of 2007 and 2015, the US Federal Government invested over $9 Billion in smart grid technologies (Office of the Press Secretary, The White House, 2016). Beyond that time frame, the smart grid market (referred to as 'Digital Energy' by many market analysts) has seen sustained interest and activity from public and private investors. The following graphics show investments made by public interests, as well as private equity and venture capitalists. Lastly, the graphic displaying mergers and acquisitions and their value represents another metric by which sustained interest in the Smart Grid sector can be ascertained.

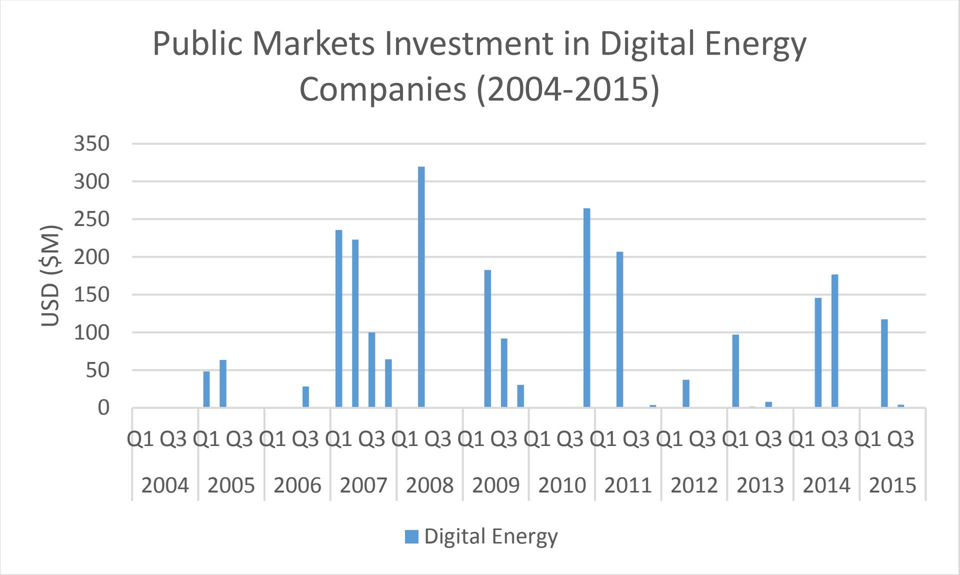


Figure 3: Public Markets Investment in Digital Energy Companies (2004 – 2015)

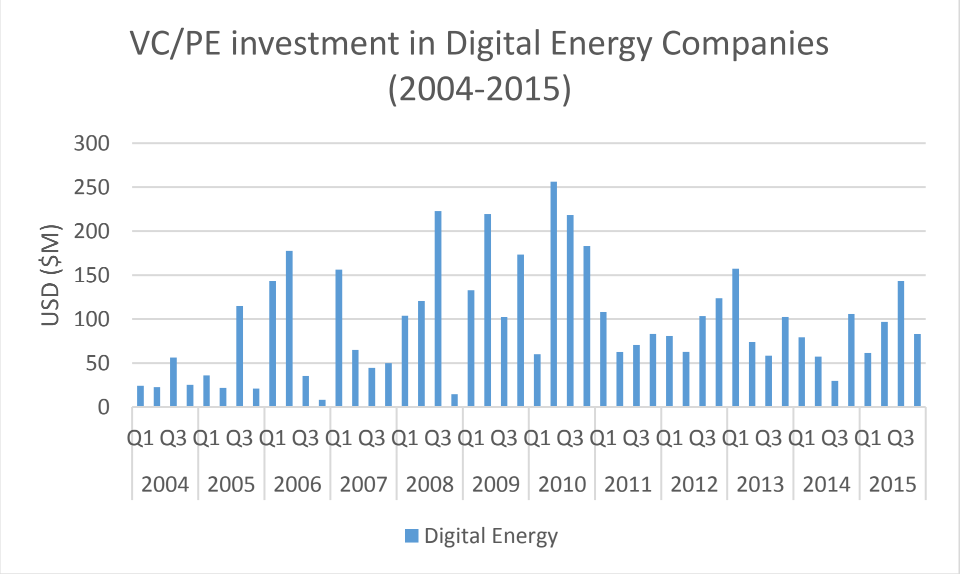


Figure 4: VC/PE Investment in Digital Energy Companies (2004 - 2015)

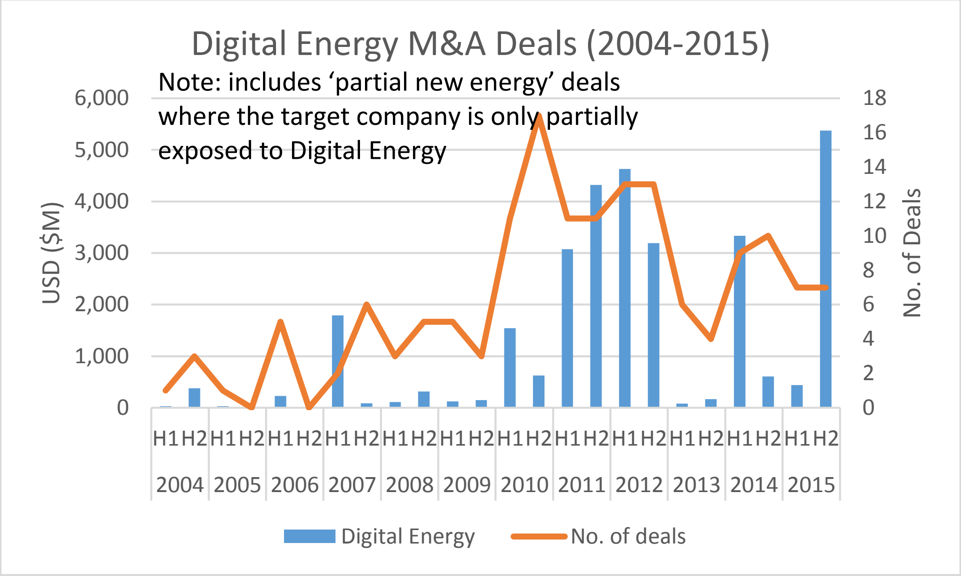
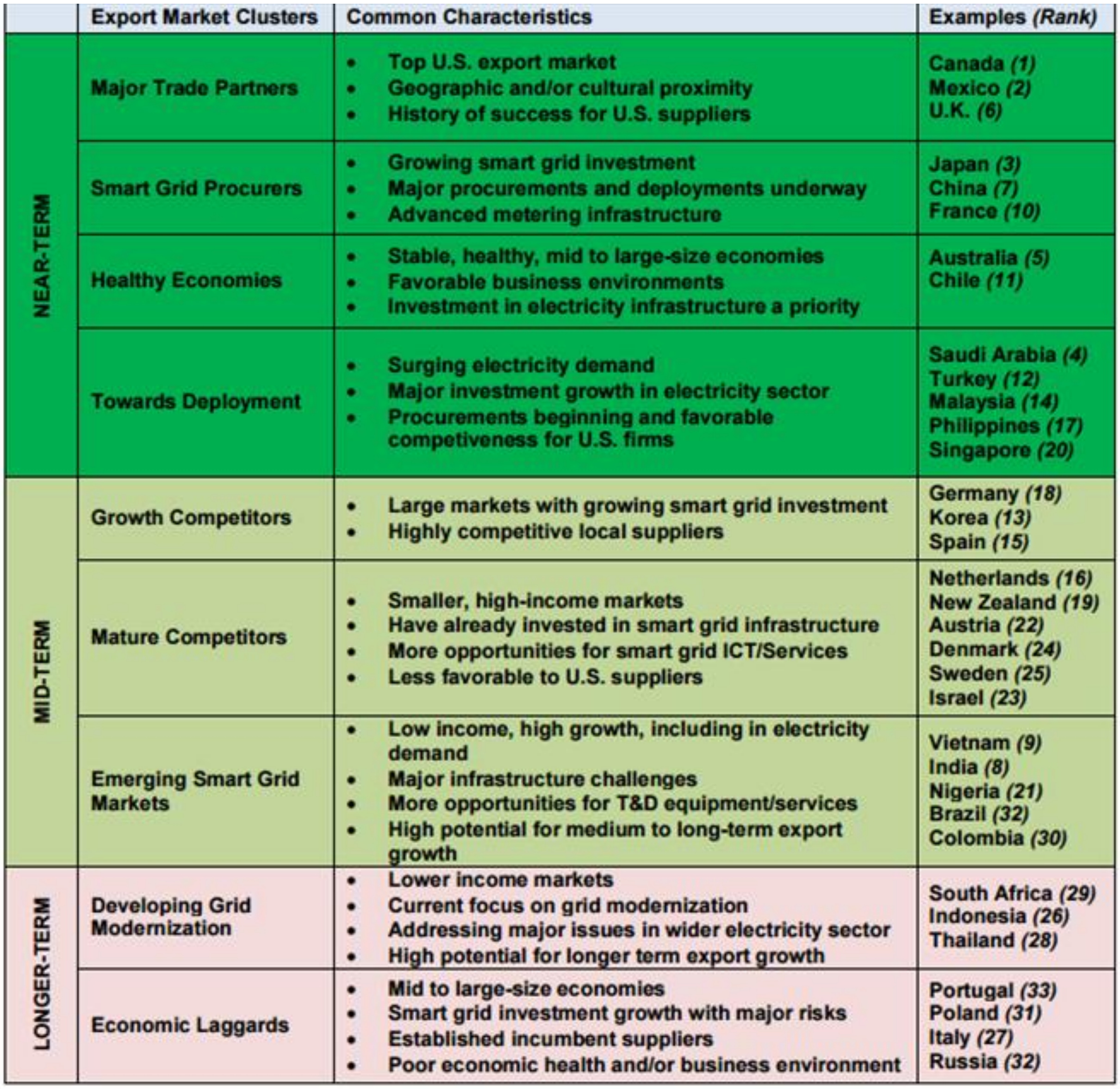


Figure 5: Digital Energy M&A Deals (2004 - 2015)

International Demand for Smart Grid Technologies Will Drive Continued Growth

The increased demand for smart grid technologies in international markets can provide an avenue for sustained sales by domestic corporations who have honed their expertise in supplying smart grid products and services. The following figure from the International Trade Association Smart Grid Export Market Projections report provides extensive detail on near, mid, and long term smart grid market dynamics. The figure below ranks various countries according to their potential for smart grid technology investments.

Table 1: Understanding Different Types of Smart Grid Markets



	Export Market Clusters	Common Characteristics	Examples *(Rank)*
NEAR-TERM	Major Trade Partners	• Top U.S. export market • Geographic and/or cultural proximity • History of success for U.S. suppliers	Canada *(1)* Mexico *(2)* U.K. *(6)*
	Smart Grid Procurers	• Growing smart grid investment • Major procurements and deployments underway • Advanced metering infrastructure	Japan *(3)* China *(7)* France *(10)*
	Healthy Economies	• Stable, healthy, mid to large-size economies • Favorable business environments • Investment in electricity infrastructure a priority	Australia *(5)* Chile *(11)*
	Towards Deployment	• Surging electricity demand • Major investment growth in electricity sector • Procurements beginning and favorable competeviness for U.S. firms	Saudi Arabia *(4)* Turkey *(12)* Malaysia *(14)* Philippines *(17)* Singapore *(20)*
MID-TERM	Growth Competitors	• Large markets with growing smart grid investment • Highly competitive local suppliers	Germany *(18)* Korea *(13)* Spain *(15)*
	Mature Competitors	• Smaller, high-income markets • Have already invested in smart grid infrastructure • More opportunities for smart grid ICT/Services • Less favorable to U.S. suppliers	Netherlands *(16)* New Zealand *(19)* Austria *(22)* Denmark *(24)* Sweden *(25)* Israel *(23)*
	Emerging Smart Grid Markets	• Low income, high growth, including in electricity demand • Major infrastructure challenges • More opportunities for T&D equipment/services • High potential for medium to long-term export growth	Vietnam *(9)* India *(8)* Nigeria *(21)* Brazil *(32)* Colombia *(30)*
LONGER-TERM	Developing Grid Modernization	• Lower income markets • Current focus on grid modernization • Addressing major issues in wider electricity sector • High potential for longer term export growth	South Africa *(29)* Indonesia *(26)* Thailand *(28)*
	Economic Laggards	• Mid to large-size economies • Smart grid investment growth with major risks • Established incumbent suppliers • Poor economic health and/or business environment	Portugal *(33)* Poland *(31)* Italy *(27)* Russia *(32)*

The following figure displays the countries mentioned above, listed by their rank.

1. Canada
2. Mexico
3. Japan
4. Saudi Arabia
5. Australia
6. United Kingdom
7. China
8. India
9. Vietnam
10. France
11. Chile
12. Turkey
13. Korea
14. Malaysia
15. Spain
16. Netherlands
17. Philippines
18. Germany
19. New Zealand
20. Singapore
21. Nigeria
22. Austria
23. Israel
24. Denmark
25. Sweden
26. Indonesia
27. Italy
28. Thailand
29. South Africa
30. Colombia
31. Poland
32. Brazil
33. Portugal
34. Russia

2016 ITA Smart Grid Top Markets Report

Figure 6: Smart Grid Export Market, Countries by Rank

Larger macroeconomic trends influence a country's suitability for smart grid investments. The following figure arranges countries based on risk and reward.

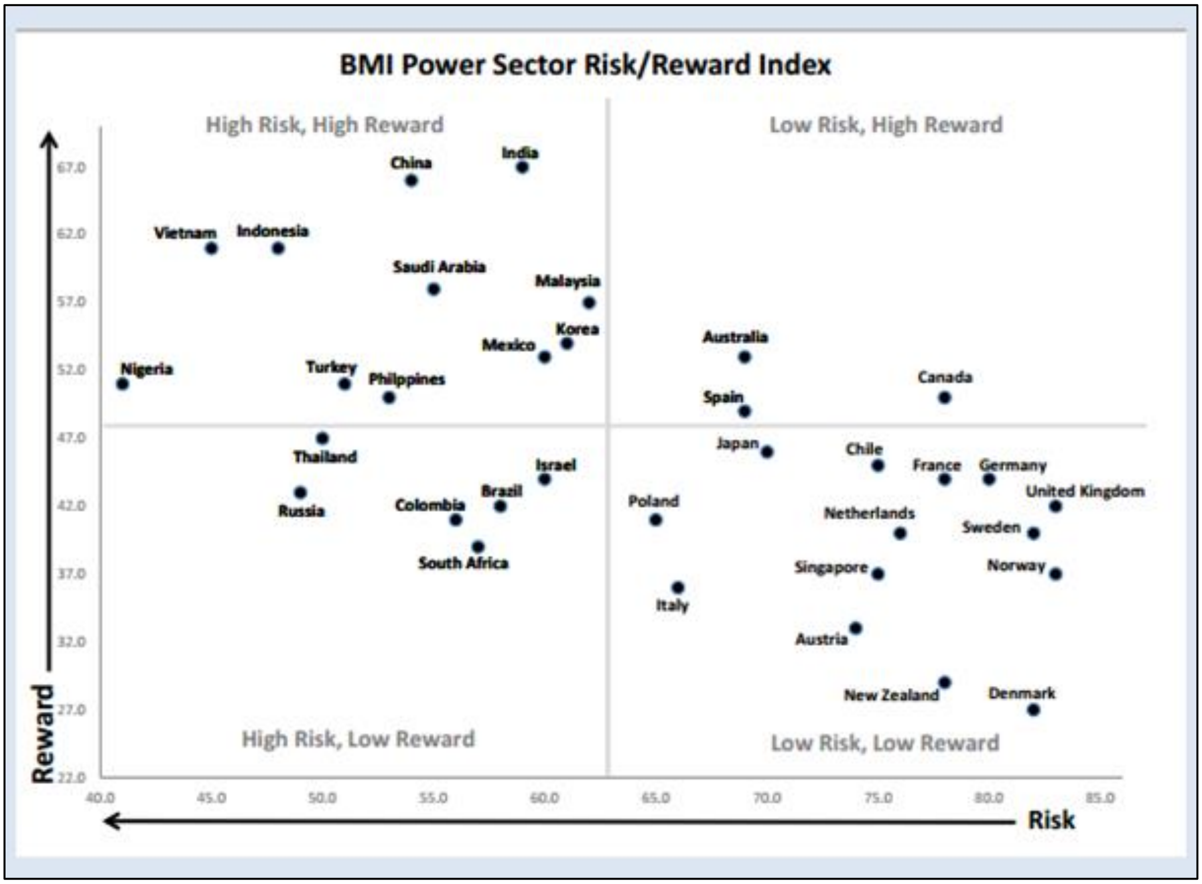
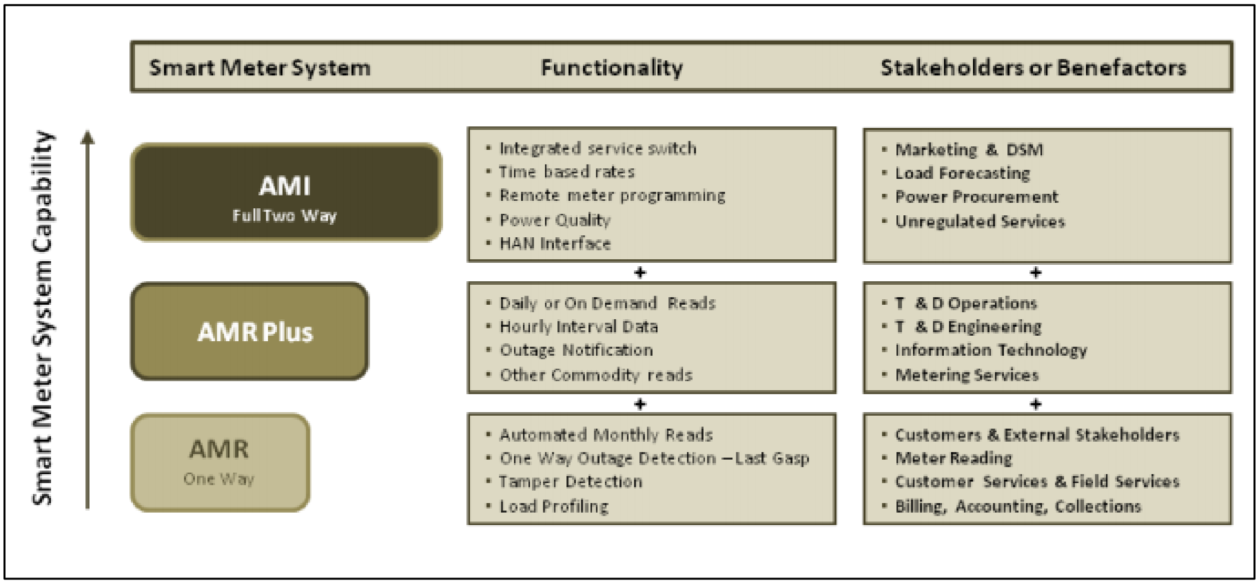


Figure 7: BMI Power SEctor Risk/Reward Index

Analysis of Technology Maturation Trends – Smart Meters

Deployments of advanced metering systems by US electric utilities were first recorded by EIA in 2007. Automated meter reading (AMR) technology helped utilities to reduce costs by eliminating the need to have a technician physically visit and take readings from every customer meter. Automated meter reading opened the door for the communication of in-field, digital information back to the utility.

The first generation of AMR technology performed measurements and communicated back to the utility on a monthly basis. New features were soon added to AMR technology, including more frequent communications with the utility, and the measurement and reporting of new types of information. As the benefits of the technology extended beyond meter reading, AMI morphed into Advanced Metering Infrastructure (AMI). The following figure describes the changes in features and benefits that occurred in the transition from AMR to AMI.



Smart Meter System	Functionality	Stakeholders or Benefactors
AMI Full Two Way	Integrated service switch Time based rates Remote meter programming Power Quality HAN Interface	Marketing & DSM Load Forecasting Power Procurement Unregulated Services
AMR Plus	Daily or On Demand Reads Hourly Interval Data Outage Notification Other Commodity reads	T & D Operations T & D Engineering Information Technology Metering Services
AMR One Way	Automated Monthly Reads One Way Outage Detection – Last Gasp Tamper Detection Load Profiling	Customers & External Stakeholders Meter Reading Customer Services & Field Services Billing, Accounting, Collections

Figure 8: Evolution of Smart Meter Capabilities

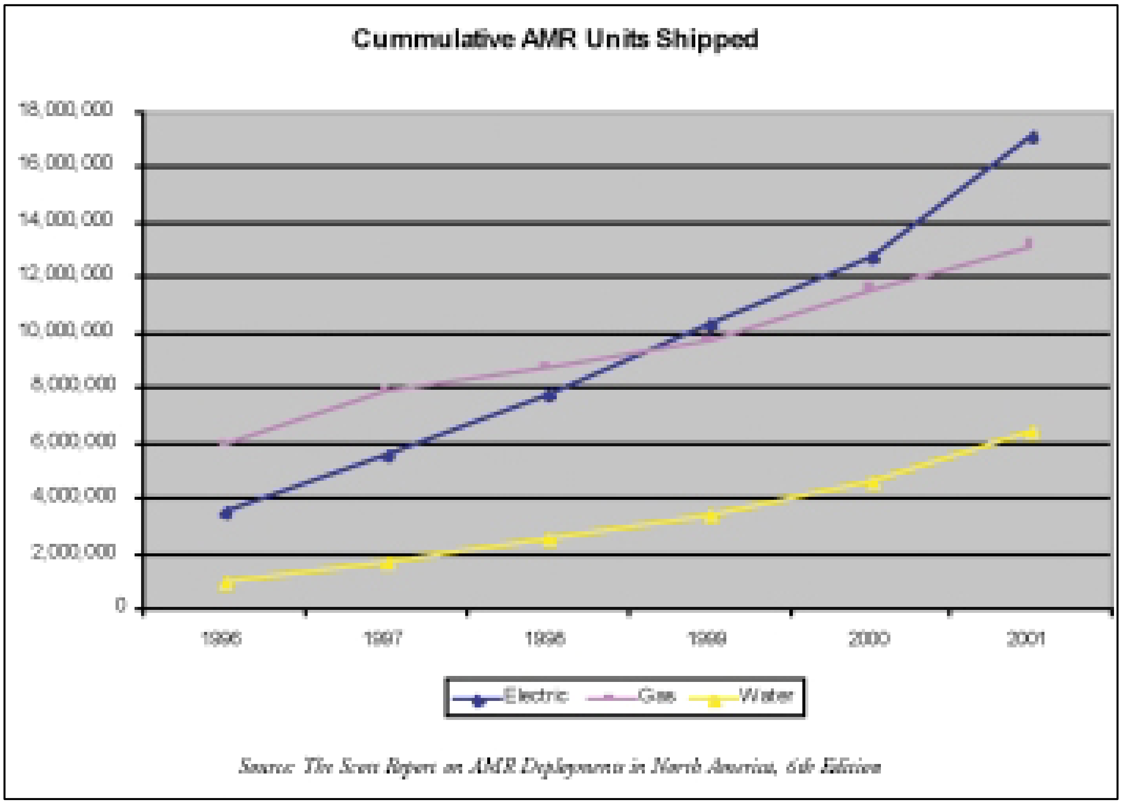
Note: Functionality and Stakeholders/Benefits are additive, progressing from AMR to AMI

Automated meter reading systems were first developed by water utilities in the US, and were also deployed in large numbers by gas utilities, before finding popularity in the electric utility industry (Chebra, 2016). Automated metering technologies had been deployed for more than 20 years before becoming popular in the electric industry. Unlike the water and gas industries, unique characteristics of the electric industry allowed automated metering to become a defining technology that underpinned the development of new services and business models.

Deployment Figures for Smart Meter Networks

The following figures show the total number of smart meters deployed in the US. As shown, the smart meter market has seen tremendous growth in the last eight years, when reliable deployment figures were first collected by the US EIA. It is noted that smart meters deployed through federal government assistance represent less than a third of the installed base.

Prior to 2007, US utilities had installed approximately 27 million AMR devices (Gabriel, 2007). The following graphic shows the early deployment of AMR devices in the US (Chebra, 2016). Reliable, publically available deployment data is not available between 2001 and 2007. It is known that during that time, the installed base of AMR grew from nearly 17 million devices, to approximately 27 million. Commercial reports containing more data are available from fee-based services (Cognyst Advisors, 2014).



Source: The Scott Report on AMR Deployments in North America, 6th Edition

Figure 9: Cumulative AMR Units Shipped (1995 - 2001)

The following figure shows the relative deployments of AMR versus AMI. AMI products began to dominate the market in 2013. The market for AMR products saturated around 2010, while AMI sales were growing rapidly.

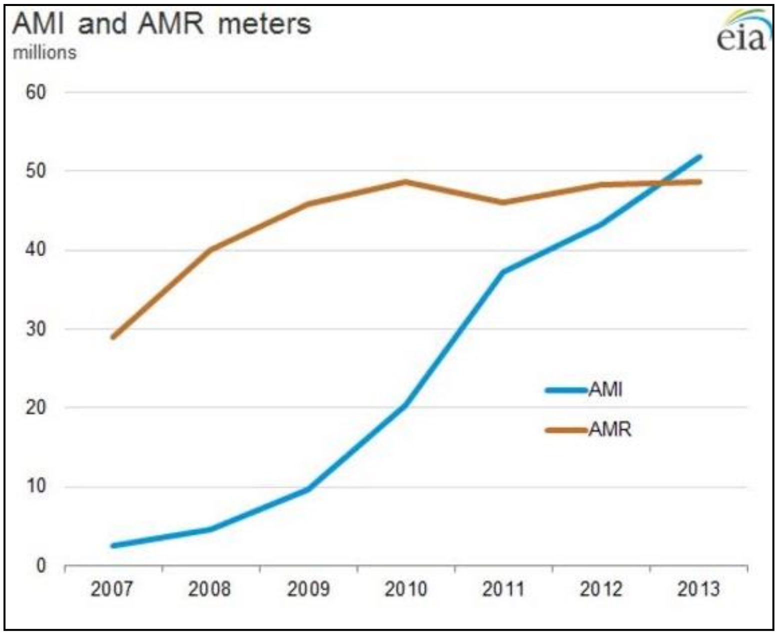


Figure 10: Installed Base of Smart Meters (2007 - 2013)

When one compares the AMI/AMR curve above to the standard innovation s-curve below, one can clearly see the trend of diminished returns for AMR, as AMI grew in popularity. The APPA noted in their 2007 publication that utility metering was following an s-curve pattern (Gabriel, 2007). Their reference was related to the displacement of traditional, electromechanical meters with solid-state AMR devices. Not long after, another s-curve can be seen, as AMR is displaced by AMI.

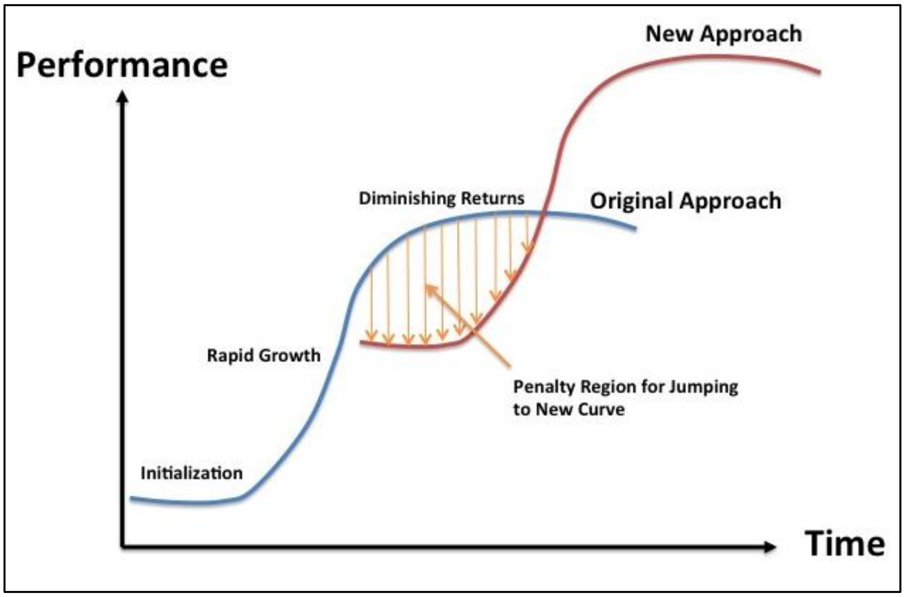


Figure 11: An Example of Successive Innovation S-Curves

Primary Factors Influencing Smart Meter Deployments

Smart Meters Offered Significant Cost Savings Over Traditional Utility Metering Strategies

The advent of automated meter reading technology prevented utilities from sending service personnel to every metered customer location on a monthly basis. This alone provided utilities with significant savings. In addition, many utilities have integrated their smart meter data into outage management systems, allowing utilities to identify power outages on distribution networks, without sending crews to search physical areas. Utilities can utilize smart meters to perform trouble shooting remotely, allowing repairs to be conducted more efficiently. In addition, utilities can use smart meters to remotely connect and disconnect customer service, eliminating fees for customers and expediting service requests.

State and Federal Policies Encouraged Utilities to Investigate the Benefits of Smart Meters

The Energy Policy Act of 2005 required all state commissions to analyze the feasibility of deploying smart meters within their jurisdiction, and provide a report of their findings within 18 months (Gabriel, 2007). PURPA Standard 14, enacted in the 2005 Energy Policy Act (EPACT), consists of the "Time-Based Metering and Communications" standards (EIA, 2011). This standard requires an electric utility provide a time-based rate schedule to consumers and enable the electric consumer to manage energy use and costs through smart meters. The passing of EPACT and PURPA Standard 14 did not include penalties for states or utilities that chose not to comply. Although some states chose not to enact policies, every state underwent an investigation of the benefits of smart meters. The following figure shows the status of statewide metering policies by 2011, following the passing of EPACT. States with 'Adopted' policies include those in which public utility commissions have directed utilities to file deployment plans. Those labeled 'Pending Studies' include states in which the legislature or public utility commission is studying the effects of pilot programs and large scale deployments.

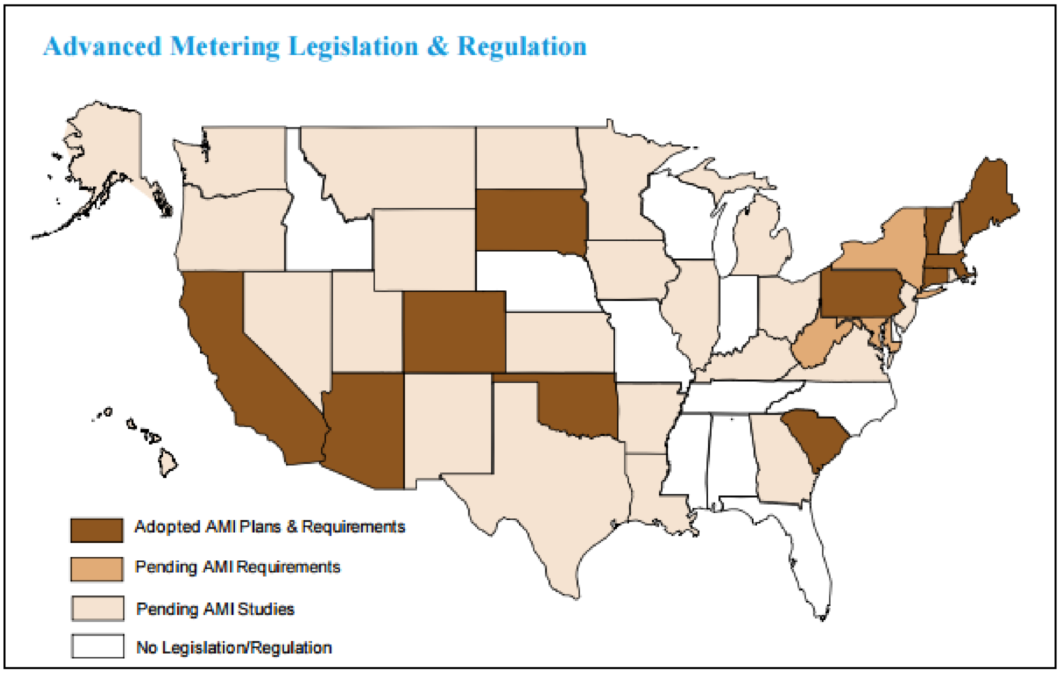


Figure 12: Advanced Metering Legislation by State (EIA, 2011)

Smart Meters Were a Necessary Pre-requisite to Offering New Services to Customers

In efforts to increase operational effectiveness, decrease peak demand, and integrate renewable resources, utilities have introduced special programs that involve consumer participation. Some of these programs include demand response, time-of-day pricing, and net metering. Given the past paradigm of manually metering customer usage on a monthly basis, all of the special programs mentioned would have been impossible to implement. High accuracy and high resolution customer consumption data are needed for implementation. Therefore, smart meters were seen as a prerequisite to initiating additional programs, which each provided unique incentives for rate payers and asset owners.

A 2014 Edison foundation report highlighted the growing prevalence of smart pricing programs in the US (Institute for Electric Innovation, 2014). The report noted that over 8 million smart metered customers in California, Delaware, the District of Columbia, Maryland, and Oklahoma, were eligible to participate in programs which incentivized reductions in electrical demand during peak hours. Smart pricing programs include Baltimore Gas & Electric's Smart Energy Rewards, Oklahoma Gas & Electric's SmartHours, Pepco and Delmarva Power's Peak Energy Savings Credit, San Diego Gas & Electric's Reduce Your Use, and Southern California Edison's Save Power Day (Institute for Electric Innovation, 2014).

The graphs below, compiled in 2011, illustrate state commitments to passing demand response and net metering legislation. Though many states did not pass firm legislation mandating smart meters, policies concerning demand response and net metering will require AMI to be implemented. These indirect policies promote the adoption of smart meters.

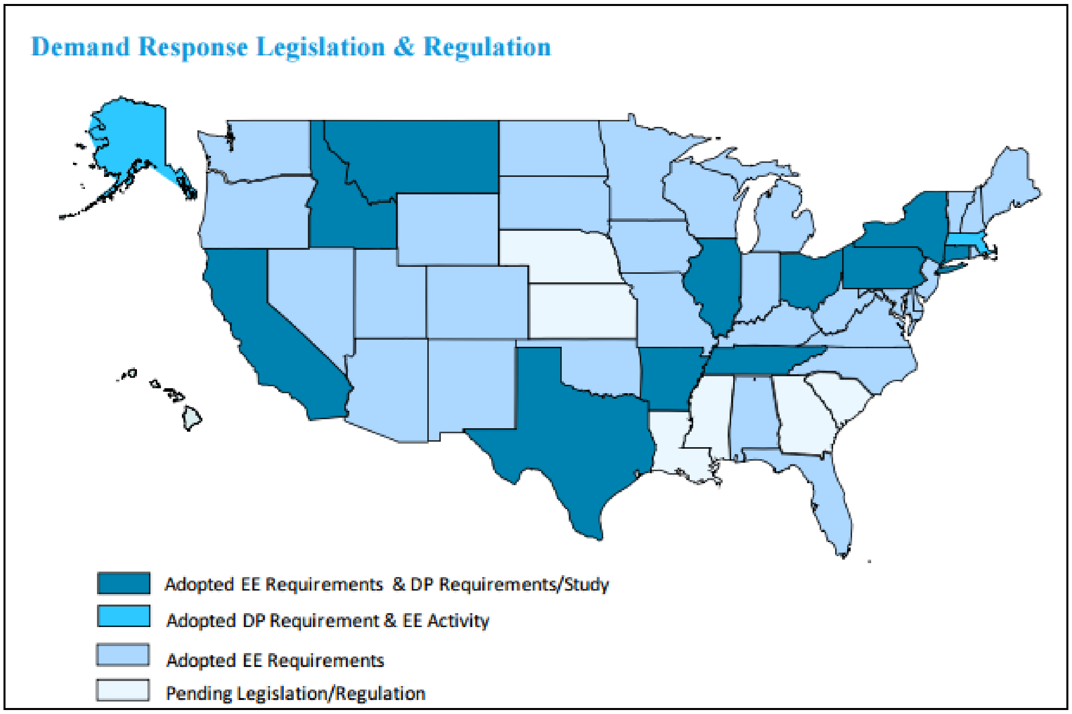


Figure 13: Demand Response Legislation by State (EIA, 2011)

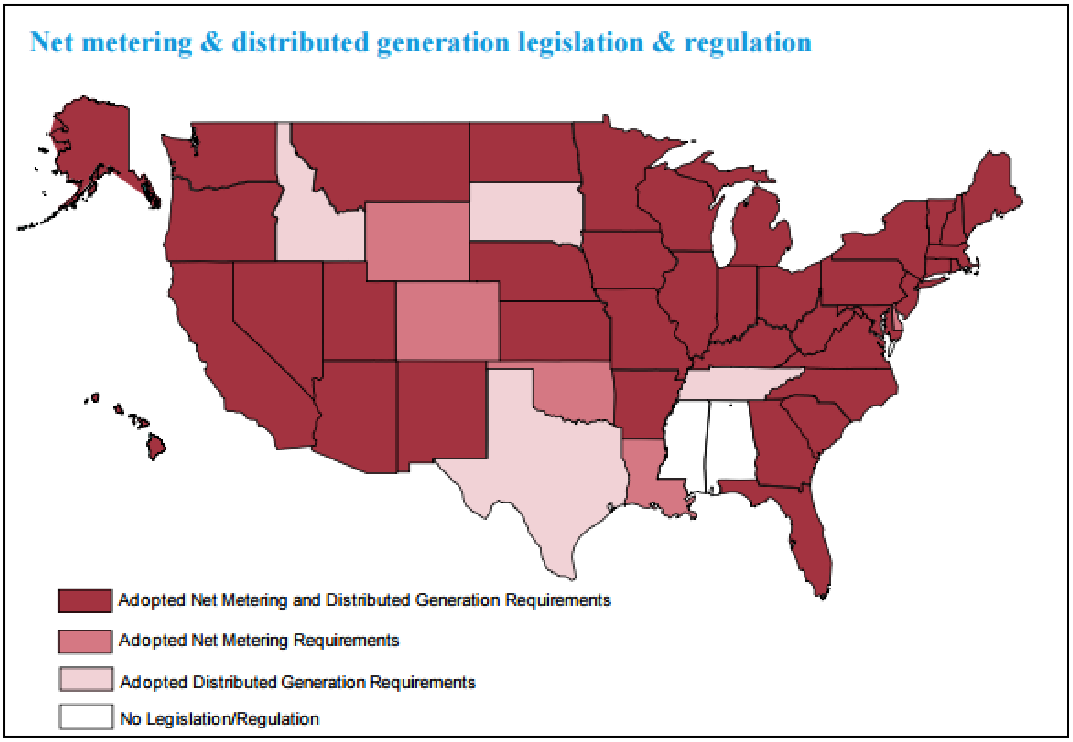


Figure 14: Net Metering Legislation by State (EIA, 2011)

Following the legislative actions described above, the graph below shows actual statewide smart meter deployments by 2013.

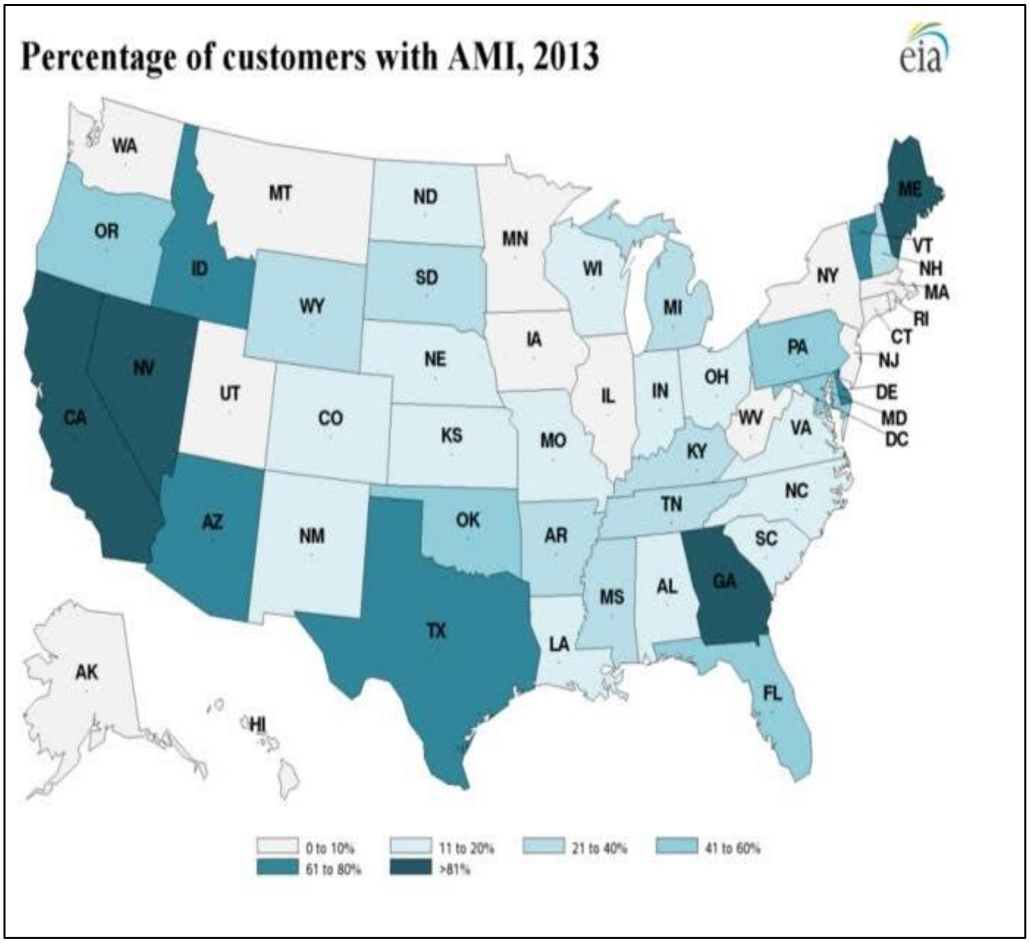


Figure 15: AMI Customer Density by State (2013)

<u>Federal Programs Encouraged Smart Meter Deployments</u>

In 2009, Congress passed the American Recovery and Reinvestment Act (ARRA or Stimulus Package) which allocated over $3B in federal funding from the Department of Energy (DOE) for Smart Grid Investment Grants (SGIG). Within the SGIG program, 30 projects were funded within the Advanced Metering Infrastructure category. These projects accounted for over $800 Million in federal funding, and supported the installation of over 15 million meters (DOE, 2015).

The following figure shows the SGIG funded meter deployments in the context of the installed base in the US. As shown, the SGIG funded meters account for less than a third of the current installed base.

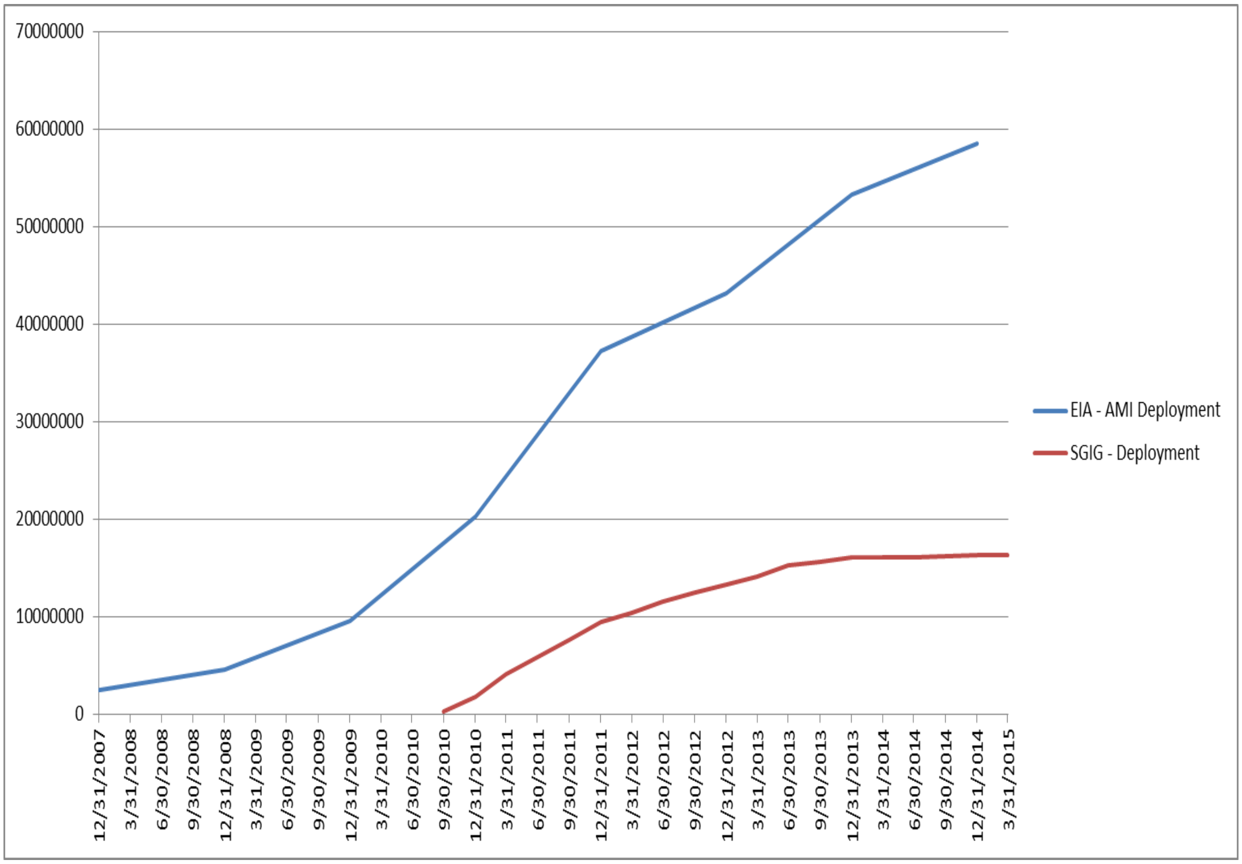


Figure 16: Cumulative Smart Meter Deployments and SGIG Contribution

Smart Meter Suppliers and Market Dynamics

The following figure lists the major smart meter suppliers for the US market, describing their percent market share, as well as their contribution to the installed base.

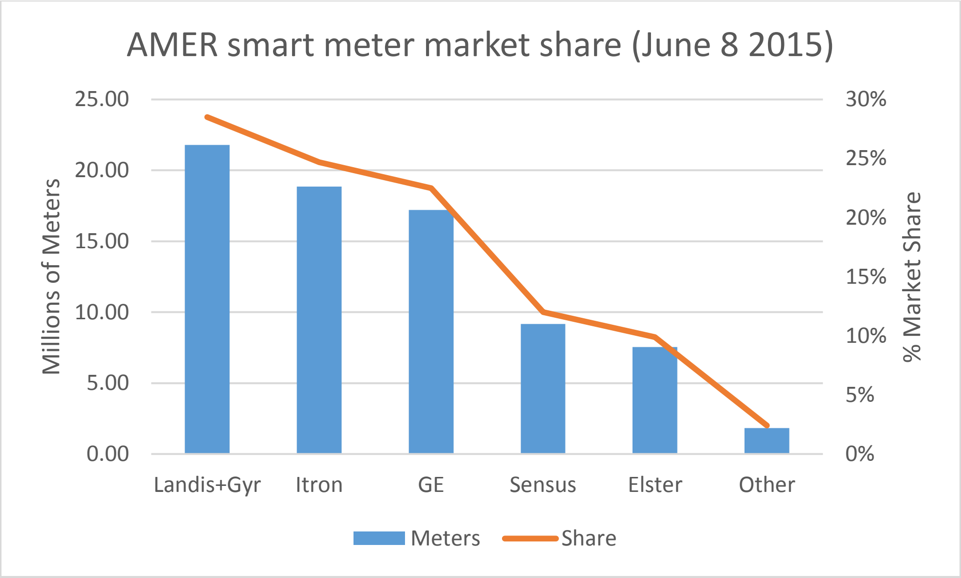


Figure 17: Market Share for US Smart Meter Suppliers

Smart meters are a single component within AMI systems. Advanced metering infrastructure links automated metering a communication network and computational power. AMI is fundamentally composed of three components (Gabriel, 2007):

- an advanced meter capable of communicating remotely
- a communications network
- a system capable of managing information—often known as “meter data management”

The following figure shows the market share for companies supplying broader AMI equipment, as opposed to smart meters.

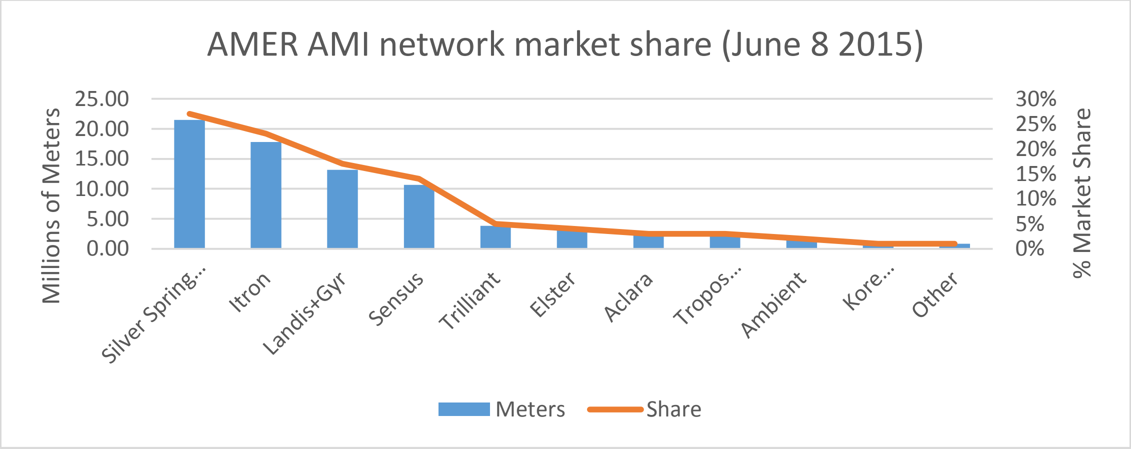
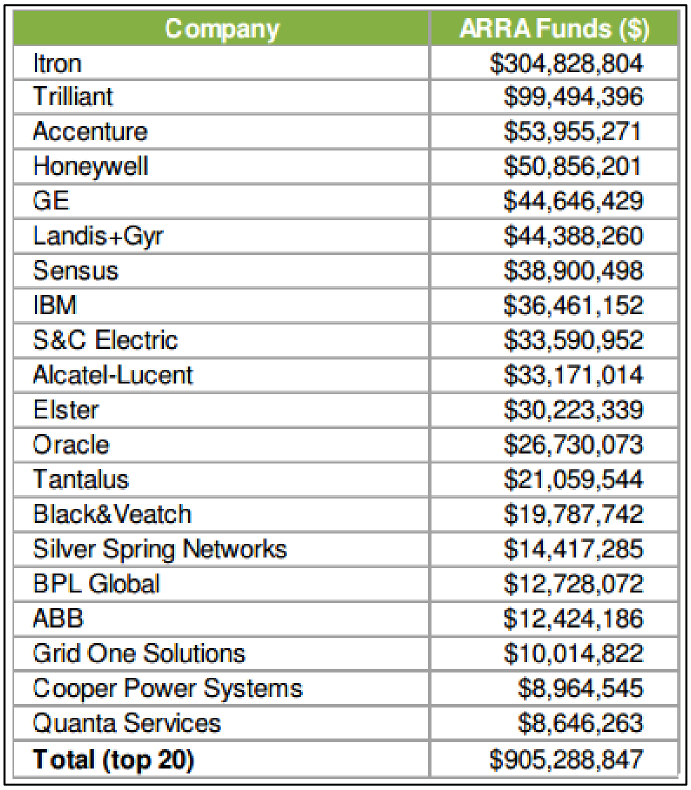


Figure 18: Market Share for US AMI Product Suppliers

__Top 20 Smart Grid Companies Receiving Smart Grid ARRA and Matching Funds__

As a point of comparison to the market leaders listed above, the graphic below shows top 20 matching fund recipients from the SGIG program (DOE, 2013). Though many of the companies listed are identical to the ones above, the SGIG listing contains a greater diversity of actors. The SGIG program encouraged participation from a number of different companies, though it seems that the program itself was not a major determining factor in which companies became market leaders in the US.

Table 2: Top 20 ARRA Matching Fund Recipients for Smart Meter Projects (DOE, 2013)



Company	ARRA Funds ($)
Itron	$304,828,804
Trilliant	$99,494,396
Accenture	$53,955,271
Honeywell	$50,856,201
GE	$44,646,429
Landis+Gyr	$44,388,260
Sensus	$38,900,498
IBM	$36,461,152
S&C Electric	$33,590,952
Alcatel-Lucent	$33,171,014
Elster	$30,223,339
Oracle	$26,730,073
Tantalus	$21,059,544
Black&Veatch	$19,787,742
Silver Spring Networks	$14,417,285
BPL Global	$12,728,072
ABB	$12,424,186
Grid One Solutions	$10,014,822
Cooper Power Systems	$8,964,545
Quanta Services	$8,646,263
Total (top 20)	$905,288,847

Mergers and Acquisitions Involving Major Suppliers to the U.S. Market, 2003-2013

In the smart meters market, leaders rose to prominence through the acquisition of smaller metering companies, and through strategic mergers. The chart below details the most significant M&A activity that impacted the smart meter market (Alejandro, et al., 2014). As shown, GE, Itron, and Landis+Gyr were all active in building through metering businesses through strategic M&A activities.

Table 3: Mergers and Acquisitions Impacting Smart Meter Market Leaders (Alejandro, et al., 2014)

Company	Date	Merger/Acquisition
Sensus	2003	Spun off as wholly owned subsidiary through acquisition of Invensys Plc, a metering systems company
Itron	2004	Itron enters the electric meter manufacturing business through acquisition of Schlumberger Electricity Metering
	2007	Itron expands presence in smart meters through acquisition of Actaris Metering Systems S.A.

Elster	2002	Elster Electricity LLC, formerly known as ABB Electricity Metering, acquired Ruhrgas industries, an electricity and water meter producer.
	2010	Elester Integrated Solutions merges with Elster Electricity LLC – Elster Electricity surviving entity.
	2012	Elster Group acquired by Minford AG (Germany), a wholly owned subsidiary of Melrose PLC (United Kingdom), for $2.3 billion and became privately held company.
Landis+Gyr	2004	Landis+Gyr was acquired by Australia-based Bayard Capital, owner of British meter manufacturer Ampy Automation-Dialog. Bayard Capital continued to acquire metering firms, extending the Landis+Gyr name to all metering products by 2008.
	2006	Landis+Gyr acquired Enermet Group (Finland), Hunt Technologies (United States) and Cellnet Technologies (United States)
	2011	Toshiba Corporation (Japan) acquired Landis+Gyr for $2.3B
Echelon	2010	Echelon acquired Xtensible Solutions, Inc. (US), and it subsidiary, Aclara (US), a smart meter producer.
	2013	Echelon announced its intention to sell Aclara due to lackluster meter sales.
GE Energy	2011	GE acquired UK-based start-up Remote Energy Monitoring, Ltd., with operations in the United Kingdom and Australia.
	2011	GE acquired France-based electricity and automation equipment company Converteam for $3.2 billion, changing the company name to GE Power Conversion in 2012.
	2015	GE sells metering division to Aclara

Analysis of Technology Maturation Trends – Synchrophasors

PMU Deployment Curves, Deployment Locations and Data Flows

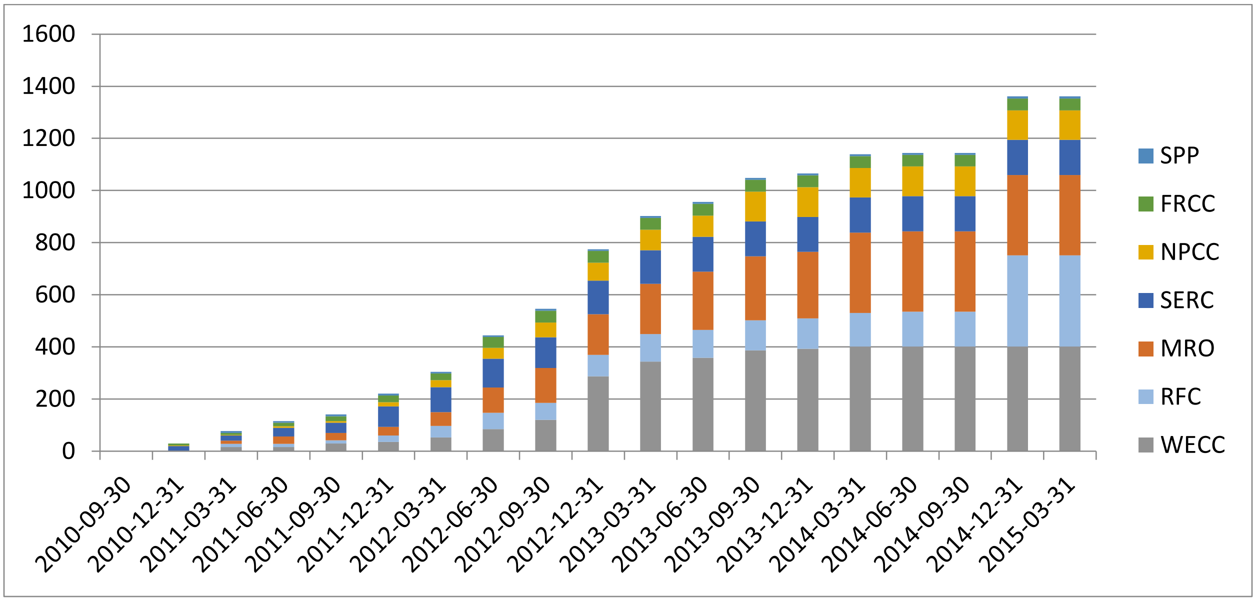


Figure 19: Total SGIG Synchrophasor Deployments, and NERC regions

Total SGIG - Synchrophasor Deployments by NERC Region

Note: NASPI estimates that there are approximately 2,000 PMUs on the North American transmission system. To date there have not been efforts to collect the number of PMUs installed outside of the SGIG program. Of the approximately 600 synchrophasors that are not accounted for though SGIG deployments, roughly half were installed concurrently with the ARRA projects, using private funding, with the remainder installed after 3/31/2015. See NASPI map of PMU installations and Network Connections below.

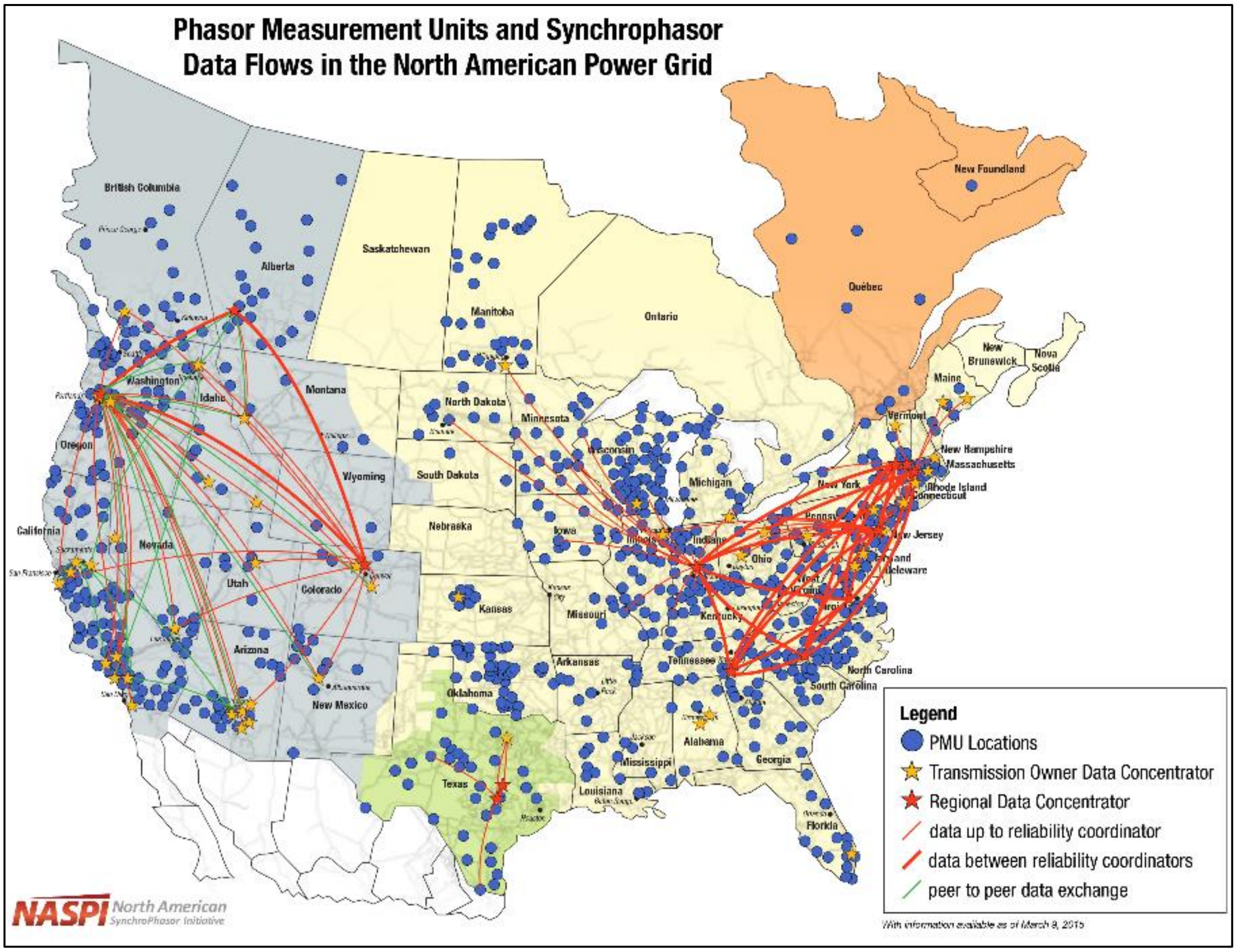


Figure 20: Location of PMUs and the Flow of Related Information

Prior to the deployment of synchrophasors, supervisory control and data acquisition systems (SCADA) were used to monitor and control power systems. SCADA systems measure grid conditions every 2 to 4 seconds. Synchrophasor technology provides time-synchronized data at a rate of more than 30 times per second to detect disturbances that often cannot be observed with SCADA systems. For example, network oscillations that could destabilize the power grid are readily detected by synchrophasor technology. Today's networked PMU networks located strategically across the power grid with high-speed communications networks provide grid operators with wide-area visibility to better detect system disturbances, improve the grid's efficiency, and prevent or more quickly recover from outages.

Analysis of significant Trends and Events

In 1893, Charles Steinmetz presented a paper to the IEEE power and energy society that provided a simplified mathematical description of a waveform of alternating current (Olken, 2015). He called his representation a phasor. Over 100 years later, the first field installations of commercially manufactured synchrophasor measurement units (PMUs) would take place on both the eastern and western transmission networks as part of the American Recovery and Investment Act funded, Smart Grid

Investment Grant Program. The next section of the paper will cover the efforts and events that drove the RD&D culminating with the commercialization and deployment of networked synchrophasors across North America.

Primary Factors and Contributors Impacting Synchrophasor Deployment

Developments in Computer Relaying and Release of Global Positioning Satellite (GPS) System Lead to Development and Initial Deployments of Synchrophasors

On November 9, 1965 at approximately 5:16 PM, approximately 30 million people living in 80,000 square miles in the North Eastern United States experienced what at that time was the largest blackout in the history of the power grid (Swidler, 1965). That day President Lyndon B. Johnson issued a Memorandum directing the Federal Power Commission to launch a thorough study of the cause of the failure and to deliver a report identifying the causes and recommended steps to prevent a recurrence of the event. On December 6th the Commission delivered a report which amongst the findings noted that control centers should be equipped with display and recording equipment which provides operators with as clear a picture of system conditions as possible (Grigsby, 2012).

The blackout in 1965 led to significant research in power system operations (Phadke A. G., 2002). Power systems introduced wide area measurements as inputs for static state estimators. The new estimators were designed to provide a real time estimate of the current state of the power system to allow operators to judge the security of the power system from the point of view of the next contingency. However, the technology available during the mid-60's did not allow for simultaneous measurements with high data rates, thus the wide area measurements and estimators could only provide a "quasi-steady state approximation to the state of the power system" (Phadke A. G., 2002).

An additional takeaway form the 1965 blackout report was the need for increased coordination between transmission system operators. In the three years following the 1965 blackout both the Northeast Power Coordinating Council (NPCC) and Nation Electric Reliability Council, now the North American Electric Reliability Council (NERC), were founded. NERC, along with the Department of Energy helped stand up and finance the North American SynchroPhasor Iniative (NASPI), which provides a forum to promote synchrophasor development and use to improve power system reliability and viability.

During the 1970's and 1980's significant progress was made in developing algorithms for computer relaying for power equipment and systems. This was a significant breakthrough at the time, when the available computers were not fast or inexpensive enough to warrant a fully computerized protective relay. In 1977, Arun G. Phadke, Mohammed Ibrahim and Ted Hibka, working in the Computer Application Department of American Electic Power (AEP), published the paper, "Fundamental Basis for Distance Relaying using Symmetrical Components". The paper was a culmination of their efforts to create a Symmetrical Component Distance Relay to protect high voltage transmission lines. The relaying algorithm required the processing of only one equation to determine the fault location for all fault types that occur on the system, and could be calculated with the microcomputers available at that time.

At this time Jim Thorpe, a professor from Cornell, joined Phadke and the Computer Applications Department at AEP to assist them in their research. Phadke, Thorpe and Adamiak, building on the relaying work at AEP, published the first phasor measurement paper, "A New Measurement Technique for Tracking Voltage Phasors, Local System Frequency and Rate of Change Frequency" (Phadke, Thorp, & Adamiak, May 1983). This was the first time that phasor measurement techniques were separated from the relaying work. The Symmetrical Component Discrete Fourier Transform (SCDFT) technique outlined in this paper proved that it was possible to measure voltages and currents with precise accuracy and with results that are noise free. The SCDFT required the synchronized measurement of phasors across a power grid and spurred the next stage in the development of synchrophasors, the synchronization of the clocks used to sample the voltage and current signals (Phadke A. G., 2002).

A parallel technical development that was critical to the commercialized synchrophasor was the creation and release of GPS technology to the public. GPS technology allowed for the precise synchronization of voltage and current measurements taken at various measuring nodes along the power grid. Synchronization of is achieved by using timing signals from GPS to time stamp the phasor measurements which are aligned by the time stamp to obtain simultaneous measurements (Mauryan & Ramkumar, 2014). Advancements in GPS technology eventually allow measurements to be time-synchronized to within a hundred nanoseconds (Barker, 2001). This precision is necessary for a sampling rate of 30 times a second, whereas SCADA technology was only able to take measurements every 2 to 4 seconds. The inclusion of GPS technology in synchrophasors also allowed measurements to be time-synchronized at the sending end, in comparison to SCADA systems which time aligned data at the receiving end, allowing the collection and transmission of data to be much more reliable and accurate. Continued advancement of GPS technology has reduced the cost of the receiver needed to time align the data from $20,000 in 1988 to just under $100 in 2015 (Phadke A. , PMU Memories, Looking Back Over 40 Years, 2015).

Phadke transitioned from AEP to Virginia Tech in the mid-80s and continued his work on PMUs with funding from the Department of Energy, AEP, the New York Power Authority, the Tennessee Valley Authority and the Bonneville Power Administation. In 1988 the Virginia Tech research team developed the first prototype PMU. The initial field installations of synchrophasors by the Virginia Tech team took place at the Bonneville Power Administration, American Electric Power and the New York Power Authority (Phadke A. G., 2002). Later field tests would install the first commercialized synchrophasor, created by Macrodyne in 1991. The design of the Macrodyne unit was based off of the prototype developed by the Virginia Tech team (Huang, PMU Testing and Evaluation).

In 1993, DOE, EPRI, BPA and WAPA funded and deployed the first synchrophasor network, designed to provide a wide-area measurement and monitoring system to enhance real time situational analysis (Overholt, Ortiz, & Silverstein, 2015). These initial units were installed as part of WECC's Wide Area Measurement System (WAMS) project. The WAMS PMU unites were initially installed in California, Arizona and Colorado. Experiencing significant equipment issues and communications breakdowns, field upgrades were recommended to resolve the equipment trouble. In 1998 BPA developed a new Phasor Data Concentrator, which collects and time aligns the data from the PMU, and resolved the communications problems between the PMU and the PDC (Madani, 2006).

<u>Major North American Blackouts Create Demand Side pull for Synchrophasor Measurement Units</u>

Two major power outages occurred in Western North America in 1996 due to congestion on transmission networks during hot summer days. Wide-area synchronized time recordings of the disturbance event collected by PMUs installed by BPA replicated system conditions and were used to determine the sequence of events, and to understand why the initiating events cascaded into large scale blackouts (Venkatasubramanian, 2003). The post event analysis showed that operators had "about five minutes to react before the second [transmission] line tripped, at which point the western grid came apart quickly" (Barker, 2001). A real-time monitoring system could have provided operators with the necessary information in time to prevent the cascading outage.

The 2003 US-Canada blackout led to a surge in support for CERTS and the EIPP. 50 million power users were affected by the blackout, with many of the affected living and working in large urban centers with both large industrial and financial sectors. Estimates on the cost of the 2003 blackout range from $4.5 to $10 B. The Department of Energy frequently cites the total cost of this blackout at $6B (ELCOM, 2004). The final report on the 2003 blackout notes that the need for improved wide area visualization capabilities had been a reoccurring theme in blackout investigations. The significant economic damages sustained as a result of the blackout contributed to the demand for technology able to prevent cascading outages.

At this time real-time PMU systems had been tested in both the eastern and western interconnections, but as the report identifies, the needed improvements in the quality of these systems would require "significant new investments in existing or emerging technologies". The report identifies the "development of practical real-time applications for wide-area system monitoring using phasor measurement and other synchronized measuring devices, including post-disturbance applications" as an important area for reliability research. It further recommends that NERC work with the public and private sector research organizations to "assess the applicability of existing and new technology to make the interconnections less susceptible to cascading outages" (FERC).

In 2002, the Department of Energy launched the Eastern Interconnection Phasor Project (EIPP), executed by the Consortium for Electric Reliability Technology Solutions (CERTS). CERTS was established to create a coordinated response to transitions occurring in the US electric power system and to "monitor research on reliability technologies and assure that gaps to not emerge" (certs, 2016). CERTS is comprised of research entities from industry, academia and the national labs. By 2006 the EIPP work group was comprised of over 220 stakeholders, broken up into six task teams. Each task team is led by an industry member with support from a DOE-funded CERTS team member. The task team leads, along with NERC, CERTS and DOE representation form the Leadership Committee that facilitates communication and coordination amongst the project team members (Donnelly, Ingram, & Carrol, 2006).

One of the key takeaways from the experience deploying PMUs on the western interconnection was that the value of synchrophasor technology increases as data is shared by multiple utilities operating within an interconnection. As part of the EIPP, the Tennessee Valley Authority (TVA) installed a (PDC) to aggregate the data collected by PMUs installed by utilities on the eastern interconnection. TVA developed the openPDC software program to organize incoming data. This open source program is available on the web at www.openpdc.codeplex.com. As of 2011, the TVA PDC was the collection point for 120 PMUs in the eastern interconnection (Donnelly, Ingram, & Carrol, 2006). Former TVA employees also went on to form the Grid Protection Alliance, a non-profit corporation which now manages the openPDC software (Alliance, 2015). Utilities in the Eastern Interconnection are currently in the process of transitioning to the Eastern Interconnection Data Sharing Network – a new network for sharing operating reliability data, including both SCADA and synchrophasor data.

In 2006, DOE partnered with NERC to incorporate synchrophasors into NERC committee structure. DOE's mandate was focused on research, and at this time it was generally accepted that synchrophasor technology needed to begin the transition into an operating framework. The two organizations assisted in combining the western interconnection synchrophasor users with the EIPP to form the North American Synchrophasor Initiative (NASPI). NASPI is made up of five committees covering operations, planning, data network management, performance standards and research. Committees are composed of vendors, academics and utilities, with vendors leading activity in the data network management committee, academics in the research committee and utilities in the operations, planning and performance standards committees (Donnelly, Ingram, & Carrol, 2006). The planning and coordination facilitated by NASPI allowed utilities to maximize the funding available through the ARRA funded SGIG program.

Large Scale Deployment of Commercialized Synchrophasor's Due to American Recovery and Reinvestment Act Funded Smart Grid Investment Grants

In 2009 DOE selected 13 entities and invested $155 million in ARRA funding along with $203 million in participant cost-share funding to deploy synchrophasor networks. Prior to the SGIG program there were approximately 166 research-grade, networked PMUs, most installed as part of the WAMs and EIPP efforts. The SGIG program provided funding for the installation of 1,380 networked PMUs and 226 PDCs (DOE, Advancement of Synchrophasor Technology, 2016). The efforts also led to the installation of approximately 600 additional PMUs (NASPI estimates that there are currently more than 2,000 networked PMUs on the North American transmission grid). NASPI is currently working on creating a PMU registry to identify the exact number and location of PMUs installed.

Aside from the significant penetration of synchrophasor networks, the SGIG program drove significant advancements in technology performance, technology use, communication network design, and the development of cybersecurity requirements. The scale of the deployment effort, along with the coordination amongst participants and other industry players through NASPI, facilitated these major advancements.

Equipment Testing and Standards For Synchrophasors

Developments to synchrophasor hardware were driven by PMU testing and standards creation. Testing of PMUs between 1995 and 2005 was led by PNNL. In 2005, PNNL leveraged DOE funds and set up a PMU testing facility with help and support from BPA (Novosel, Snyder, & Vu, 2007). The testing and certification of devices to meet industry standards increased user acceptance of the technology.

The use of synchrophasor devices is governed by a variety of codes, standards, and regulations; to ensure their safe operation, to ensure that common test procedures are used amongst manufacturers, and to ensure that the resulting products are interoperable. The development of IEEE standards for synchrophasors facilitated the growth and adoption of the technology. In 1995, IEEE introduced the first synchrophasor specific standard. However, as synchrophasors were integrated into existing substation and power system control and communication systems, their use became subject to a host of relevant standards. The most recent update to the standard regulating Synchrophasor measurements, which occurred in 2011, requires compliance in both steady state and dynamic conditions, and was a significant development for the technolog. The following chart describes the standards relevant to the use and integration of synchrophasors.

Table 4: Standards Relevant to Synchrophasor Deployments

Standard	Description	Applicability	Timeframe
ISO 8601	Date and time format	Synchrophasors use precise timing and synchronization methods for reporting power system measurements. This standard provides guidance on the proper format used by PMUs when communicating synchrophasor-related timing information.	First created in 1988. Pre-dates synchrophasor standards, but is applicable to their use.
IEC 61850 Sections: 6, 7-2, 7-3, 7-4, 8-1, 8-2, 80-1, 9-2, 90-1, 90-2, 90-3, 90-4, 90-5	Communication networks and systems for power utility automation	IEC 61850 is a communication standard for electrical substation automation systems. The abstract data models defined in the standard can be mapped to various protocols, run over TCP/IP or substation LANs using high speed Ethernet.	Standard development began in 1995. Pre-dates widespread synchrophasor use, but still applies to the technology.
IEC 60870 Sections: 5-101, 5-103, 5-104, 5-5	Telecontrol equipment and systems	This standard is generally applicable to SCADA systems, commonly used in power systems substations and other facilities. Synchrophasor data is often combined with SCADA measurements to achieve situational awareness.	Released in 2000.
IEC 61588 (IEEE 1588)	Precision clock synchronization protocol for networked measurement and control systems	Allows for networked devices, each with their own clock, having its own inherent resolution, precision, and accuracy, to be synchronized to a master clock.	Published in 2004, updated in 2008.
IEC 61869	Instrument transformers	This is a general standard governing newly manufactured instrument transformers. This standard is generally applicable to grid measurement devices.	Introduced in 2007, with updates in 2012 and 2013.
IEC 62351	Power systems management and associated information exchange – Data and communications security	Defines physical security parameters and electronic security parameters that govern the exchange of synchrophasor data. This standard covers a broad range of technologies, synchrophasors being a subset.	Published in April, 2008.

IEEE C37.118.1-2011	IEEE Standard for Synchrophasor Measurements for Power Systems	Synchronized phasor (synchrophasor) measurements for power systems are presented. This standard defines synchrophasors, frequency, and rate of change of frequency (ROCOF) measurement under all operating conditions. It specifies methods for evaluating these measurements and requirements for compliance with the standard under both steady-state and dynamic conditions. Time tag and synchronization requirements are included. Performance requirements are confirmed with a reference model, provided in detail. This document defines a phasor measurement unit (PMU), which can be a stand-alone physical unit or a functional unit within another physical unit. This standard does not specify hardware, software, or a method for computing phasors, frequency, or ROCOF.	Created in 2011.
IEEE C37.118.1a-2014	Amendment 1: Modification of Selected Performance Requirements	Modifications in this amendment include some performance requirements with related text updates to correct inconsistencies and remove limitations introduced by IEEE Std C37.118.1(TM)-2011. It was discovered that a few requirements were not achievable with the published models as was intended and others were extremely difficult to meet with available hardware. This amendment modifies requirements in Table 4 through Table 10. Text was modified to support the requirement modification. Testing described in 5.5.9 was clarified, and Table 11 (formerly Table 12) was	Updated in 2014.

		modified to match. Annex C was modified to keep it consistent with the rest of the document.	

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