RECOVERY ACT – SMARTGRID REGIONAL DEMONSTRATION
TRANSMISSION AND DISTRIBUTION (T&D) INFRASTRUCTURE

KCP&L GREEN IMPACT ZONE SMARTGRID DEMONSTRATION

INTERIM TECHNOLOGY PERFORMANCE REPORT

WORK PERFORMED UNDER AGREEMENT

DE-OE0000221

SUBMITTED BY

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1.1	03/28/2013	Updated with corrected terminology regarding project funding

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FEDERAL DISCLAIMER

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1 Introduction [1]

This document represents the first interim Technology Performance Report for the Kansas City Power & Light Company (KCP&L) Green Impact Zone SmartGrid Demonstration project. The KCP&L project is partially funded by DOE Regional Smart Grid Demonstration Project (SGDP) cooperative agreement DE-OE0000221 in the Transmission and Distribution Infrastructure application area.

This interim Technology Performance Report (TPR) summarizes the KCP&L SmartGrid Demonstration Project as of December 31, 2012 and includes summaries of the project design, implementation, and analysis performed as of that date.

1.1 Project Abstract

Kansas City Power & Light (KCP&L) is known for its commitment to community engagement and its ability to bring together diverse stakeholder groups to develop regional energy solutions. In 2007, KCP&L won the Edison Electric Institute's top award for innovation and contribution to the advancement of the electric industry. In addition, KCP&L is the only utility in the U.S. to reach an agreement with the Sierra Club in pursuing renewable energy and energy efficiency projects while building a high-efficiency coal generating station. Recognizing the need for a new approach to electricity generation, transmission, and distribution, KCP&L was awarded a DOE Regional SGDP cooperative agreement to deploy a fully integrated SmartGrid Demonstration in an economically challenged area of Kansas City, Missouri. The project is investing over $50 million to explore potential benefits to customers, the local grid and provide technology learning and advancement to the entire industry. Of the total investment, the DOE Regional SGDP cooperative agreement is providing approximately $23.9 million.

For the Demonstration, KCP&L is deploying an end-to-end Smart Grid that will include advanced renewable generation; storage resources; leading edge substation and distribution automation, and controls; energy management interfaces; and innovative customer programs and rate structures. The Demonstration is focused on a subset of the area served by KCP&L's Midtown Substation, impacting approximately 14,000 commercial and residential customers across five square miles.

KCP&L's project complies with the DOE's funding guidelines and introduces commercial innovation with a unique approach to SmartGrid development and demonstration:

- First, this project truly creates a complete, end-to-end Smart Grid – from smart generation to smart end-use; it will deliver improved performance focused on a major substation in an urban location.
- Second, it introduces new technologies, applications, protocols, communications, and business models that will be evaluated, demonstrated, and refined to achieve improved operations, increased energy efficiency, reduced energy delivery costs, and improved environmental performance.
- Third, it involves a best-in-class approach to technology integration, application development, and partnership collaboration, allowing KCP&L to advance the

progression of complete smart grid solutions, with interoperability standards, rather than single, packaged applications.

- Finally, KCP&L's demonstration project will provide the critical energy infrastructure required to support a targeted urban revitalization effort—Kansas City's Green Impact Zone.

The project introduces new technologies in the substation and the distribution network as well as advanced renewable resources and large-scale energy storage to supply electricity and offset peak electrical demand. Finally, end users will be provided detailed usage information, digital tools, and innovative programs to empower them to optimize energy consumption and bill savings.

The Green Impact Zone (www.greenimpactzone.org) is the vision of Rep. Emanuel Cleaver II (D-MO) and will be a model for urban renewal and sustainability. The City of Kansas City and the Mid-America Regional Council have also taken lead roles in the effort. Through KCP&L's participation, innovators in today's SmartGrid landscape such as Siemens, OATI, Landis+Gyr, Intergraph, EPRI, Tendril, and Exergonix (formerly Kokam America) have signed-on to provide equipment, technical expertise, and in-kind financial support. A key component of the project is enhancing collaboration between public and private stakeholders. KCP&L believes the SmartGrid project will foster an environment for increased employment opportunities, broad economic development, and reinvestment in the area.

By demonstrating an end-to-end solution, KCP&L will be able to test, evaluate, and report on a complete suite of Smart Grid benefits that include greater energy efficiency, reduced cost, improved reliability, more transparent and interactive information, and an improved environmental footprint. KCP&L believes this project will serve as a blueprint for future Smart Grid implementations and will accelerate the realization of the "utility of the future" that safely delivers reliable electricity with greater efficiency, reduced costs, and improved environmental performance.

1.2 Project Objectives

The primary objective of the SmartGrid Demonstration project is twofold: (a) to demonstrate, test and report on the feasibility of combining, integrating and applying existing and emerging Smart Grid technologies and solutions to build innovative Smart Grid solutions and (b) to demonstrate, measure, and report on the costs, benefits, and business model viability of the demonstrated solutions. The proposed technologies and solutions will be evaluated both individually, and as part of a complete end-to-end integrated Smart Grid system in a defined geographical area. The project will demonstrate certain operational, economic, consumer, and environmental benefits that can be enabled by single Smart Grid technologies and further enhanced by integrated solutions as proposed for this demonstration.

The objectives of individual initiatives are focused on implementing a next-generation, end-to-end Smart Grid that will include Distributed Energy Resources (DER), enhanced customer facing technologies, and a distributed-hierarchical grid control system.

1.2.1 Interoperability

The KCP&L SmartGrid Demonstration Project interoperability objective is to implement an integrated end-to-end solution that demonstrates interoperability of the key Smart Grid components and incorporates elements of seven (7) of the eight (8) priority areas identified by FERC and NIST in the. NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0 (NIST Smart Grid Framework):

- Demand Response and Consumer Energy Efficiency,
- Electric Storage,
- Electric Transportation,
- Advanced Metering Infrastructure,
- Distribution Grid Management,
- Cybersecurity, and
- Network Communications.

This demonstration will implement a distribution network management system, substation and distribution automation systems, distributed resource and demand-side management systems, advanced metering infrastructure and customer-based energy management and behind-the-meter resources and loads. The proposed solution architecture follows the EPRI IntelliGrid Architecture and GridWise Architectural Council recommendations, as well as the NIST Smart Grid Framework.

1.2.2 Cyber Security

One of the objectives of the KCPL&L SmartGrid Demonstration Project (SGDP) is to evaluate and demonstrate end-to-end cyber security and incorporate the appropriate NIST cyber security standards and emerging industry security profiles, namely the NISTIR-7628 and UCAIug Security Profiles for Distribution Management (DM) and Advanced Metering Infrastructure (AMI). Over the course of the project to date, the project team has assessed the applicability of these standards and profiles and has adopted and/or augmented these standards as deemed appropriate.

The project team has taken cyber security considerations into account during each phase of the KCP&L SGDP infrastructure development both from an IT and grid infrastructure perspective. KCP&L has also chosen to implement the SGDP using private communications media wherever practical. By utilizing the Corporate IT Wide Area Network (WAN) and utility-owned Field Area Network (FAN), the communication between KCP&L SmartGrid systems can leverage the vast amount of industry research and development for IP-based technologies. Another benefit of utilizing private networks instead of the public Internet for internal communication minimizes vulnerability to cyber security attacks.

1.2.3 SmartSubstation

The primary objective of the SmartSubstation program is to develop and demonstrate a fully automated; next-generation distribution SmartSubstation with a local distributed control system based on IEC 61850 protocols.

This new SmartSubstation demonstration will enable and quantify the following expected benefits:

- Improved real-time operating data on critical substation equipment
- Reduced O&M costs of relay maintenance
- Improved reliability through automation

By achieving these objectives, we expect to demonstrate Advanced Distribution Automation (ADA) capabilities such as the ability to monitor and capture real-time transformer temperature and gas data; the enablement of real-time equipment ratings; full substation automation with intelligent bus throw-over; and other benefits of integrated intelligent electronic relays such as peer-to-peer communication, fault recording, fault location, circuit breaker monitoring and more efficient maintenance.

1.2.4 SmartDistribution

The primary objective of the SmartDistribution program is to develop and demonstrate a next generation Distribution Management System (DMS) architecture that includes a fully automated, Distributed Control and Data Acquisition (DCADA) SmartSubstation controller that incorporates a Common Information Model (CIM) based model of the local distribution network and performs local grid assessment and control of individual intelligent electronic device (IED) field controls. The DMS and DCADA will provide the operational backbone of the system supporting significant levels of automation on the feeders, complex and automated feeder reconfiguration decisions, and tightly integrated supervision with the Control Centers. The DMS serves as the primary point of integration for the grid facilities and network management functionality including Distributed System Control and Data Acquisition (D-SCADA) systems, Distribution Network Applications (DNA) systems, Outage Management Systems (OMS), Distributed Energy Resource Management (DERM) systems, Geographic Information Systems (GIS) and other supporting systems.

This new SmartDistribution demonstration will enable and quantify the following benefits:

- Improved service reliability by reducing the frequency and duration of outages
- Reduced frequency of momentary outages
- Reduced operational expenses through automation and remote control
- Reduced maintenance expenses through predictive maintenance strategies

In achieving the above objectives, we expect to demonstrate a family of automatic, distributed "first responder" distribution grid monitoring and control functions:

- Substation and feeder load profile metering at 15 minute intervals
- Circuit outage and faulted section identification and isolation switching
- Substation and feeder VAR management
- Substation and feeder voltage management
- Substation and feeder integrated Volt/VAR Management
- Substation and feeder overload management with Dynamic Voltage Control (DVC) and Conservation Voltage Reduction (CVR)

- Distributed DER monitoring and management
- Substation and feeder overload management with Distributed Energy Resources
- Feeder overload management with ambient and duct temperature tracking
- Digital fault recording on breaker relays
- Insipient fault detection and reporting

We also expect to demonstrate time-synchronized voltage and current from strategic points on the circuits, which will improve the accuracy of capacity planning models and will enable better load balancing and improved decision-making for capacity additions.

1.2.5 SmartMetering

The primary objective of the SmartMetering program is to develop and demonstrate state-of-the-art integrated advanced metering infrastructure (AMI) and meter data management (MDM) systems that support two-way communication with 14,000 SmartMeters in the demonstration area and that integrates with other enterprise systems such as CIS, DMS, OMS, and DERM. The SmartMetering infrastructure will provide the technology basis for recording customer and grid data that will be used to measure many SmartGrid benefits.

This new SmartMetering implementation will enable and quantify the following benefits:

- Reduced operating expenses through remote connect/disconnect capabilities
- Improved accuracy and frequency of meter reads
- Improved accuracy of meter inventory and reduction in untracked meters
- Increased success rate of automated reads relative to existing one-way AMR
- Improved outage handling relative to existing AMR technology with increased outage notification success rates and new power restoration messages
- Enables real-time, two-way communication for demand response program control initiation and verification of program participation

The SmartMetering technology will also provide advanced meter-to-HAN communications to facilitate in-home display, home energy management systems, and other consumer facing programs.

1.2.6 SmartDR/DER Management

The primary objective of the Smart DR/DERM program is to develop and demonstrate a next-generation, end-to-end Distributed Energy Resource Management (DERM) system that provides balancing of renewable and variable distributed energy resources (DER) with controllable demand response (DR) as it becomes integrated in the utility grid, coordination with market systems, and provision of pricing signals.

We expect to demonstrate a number of capabilities including:

- The ability to manage and control diverse DERs (e.g. DVC, DG, storage, etc.)
- The ability to manage and control various DR programs effectively
- The ability to manage price-based and voluntary programs with market-based and dynamic tariffs similar to those described under SmartEnd-Use.

- Interoperability with the DMS to monitor distribution grid conditions and leverage DR and DERs to manage distribution grid congestion

By achieving these objectives, KCP&L expects to demonstrate advanced capabilities in demand side resource management, including the ability to leverage those resources for operational efficiencies, reduction of environmental impact, and to support wholesale market operations.

1.2.7 SmartGeneration Resources

KCP&L's primary objective in its SmartGeneration Resources program is the implementation of DR/DER resources and DR programs sufficient in quantity and diversity to support the DERM development and demonstration. To achieve this objective, the demonstration program will include:

- Installation of a variety of roof-top solar system on a mix of residential and commercial buildings, including one larger scale installation (100 kW)
- Installation of a 1MW grid-connected battery
- Implement AMI-based direct load control (DLC) DR program with installation of up to 1600 standalone residential programmable communicating thermostats (PCTs)
- Implement home energy management program with installation of up to 400 Home Area Networks (HAN) that include a PCT, outlet disconnects, and water heater disconnects
- Integrate a large commercial load (UMKC) in the demonstration area by interfacing with their commercial building EMS
- Implement DR-enabled public accessible plug-in hybrid electric vehicle (PHEV) charging stations to demonstrate smart charging strategies

In addition to the primary objective, KCP&L expects to evaluate the feasibility to offset fossil-based generation with renewable sources as well as the potential for flexible, alternative business ownership models. With respect to PHEVs and charging stations, KCP&L expects to demonstrate an intelligent, two-way communication between plug-in vehicles, charging stations and the utility grid while controlling the flow of electricity to plug-in vehicles, balancing real-time grid conditions with the needs of individual drivers.

1.2.8 SmartEnd-Use

The primary objective of the KCP&L SmartEnd-Use pilot program is two-fold. The program will achieve a sufficient number of consumers enrolled in a variety of consumer facing program to 1) support the DERM development and demonstration, and 2) measure, analyze, and evaluate the impact that consumer education, enhanced energy consumption information, energy cost and pricing programs and other consumer based programs have on end-use consumption. We have identified several secondary objectives for the suite of SmartEnd-Use programs expected to be deployed in the Demonstration Area:

- Improve customer satisfaction by increasing awareness and providing cost-saving opportunities
- Improve KCP&L's capacity to serve customers through increased knowledge of customer behavior and usage patterns

- Demonstrate potential to reduce residential peak load profiles to reducing the need for future system capacity expansion by incenting off peak energy usage
- Pilot novel time-of-use (TOU) rate programs designed to provide tangible incentives to reduce energy usage during peak periods

By achieving these objectives, we expect to demonstrate how the integration of a broad suite of efficiency and innovative rate programs into a complete SmartGrid solution can enhance the overall benefits of the solution and optimally leverage the additional technical and operational capabilities that are enabled by the pilot investment.

1.2.9 Education & Outreach

KCP&L's Demonstration Project and associated partnerships in the Green Impact Zone create a tremendous opportunity for customers, the region and the entire country to understand the value of advanced energy distribution and load management while providing reinvestment in Kansas City's urban core. Successful implementation of the KCP&L SmartGrid Demonstration Project will require a steadfast commitment to effective stakeholder-focused communication.

There are three primary communications objectives for KCP&L's SmartGrid Demonstration Project:

- Educate and engage customers in the project area, including the Green Impact Zone, about how SmartGrid investments will ultimately impact and benefit them, and then influence behavior and encourage participation in energy usage management
- Inform the remainder of KCP&L's customer base about how SmartGrid investments could ultimately impact and benefit them
- Share information with the broader utility industry on the progress and outcome of the project

Just as the Demonstration Project is being deployed in a series of phases, so too is the public education and outreach plan. In 2010, the goal was to create general project awareness and understanding through face-to-face interaction, customer engagement and the introduction of new SmartGrid tools. As the project moved into 2011 and beyond, the communications efforts become even more targeted as customer segments emerge and product adoption increases. At this point, KCP&L will begin to analyze and evaluate customer behaviors, attitudes and channel preferences as well as the messaging mix that is most effective. In addition, the grid focused components of the project will be introduced to customers to help them better understanding the complexity and potential value of these investments and transformations.

1.3 Introduction to Kansas City Power & Light Company (KCP&L)

The mission of KCP&L, as a leading and trusted energy partner, is to provide safe, reliable power and customer-focused energy solutions that create stakeholder value through operational excellence, innovation, and a diverse, engaged workforce. Our higher purpose is improving life in the communities that we serve.

Great Plains Energy (GPE), a Missouri corporation incorporated in 2001 and headquartered in Kansas City, Missouri, is the holding company for two vertically integrated electric utilities - KCP&L and KCP&L Greater Missouri Operations Company (KCP&L-GMO). Both utilities operate under the brand name KCP&L. KCP&L's service territory encompasses all or portions of 47 counties over approximately 18,000 square miles in western Missouri and eastern Kansas.

1.3.1 KCP&L Utility Operations

Operating from its headquarters in Kansas City, Missouri, KCP&L has evolved into a full-service energy provider and resource. The company was founded in 1882 and has become one of the Midwest's most affordable energy suppliers because of our leadership in efficient power production and distribution through advanced fuel procurement, power plant technology, and distribution technology.

Our utilities serve over 820,000 customers with approximately 722,000 residential, 96,000 commercial, and 2,800 industrial and bulk power customers. Our utilities, located in Missouri and Kansas, have a combined generation capacity of over 6,100 MWs, 3,000 miles of transmission lines, approximately 17,000 miles of overhead distribution lines and over 7,000 miles of underground distribution lines. Detailed statistics of KCP&L's service territory are shown in Table 1-1.

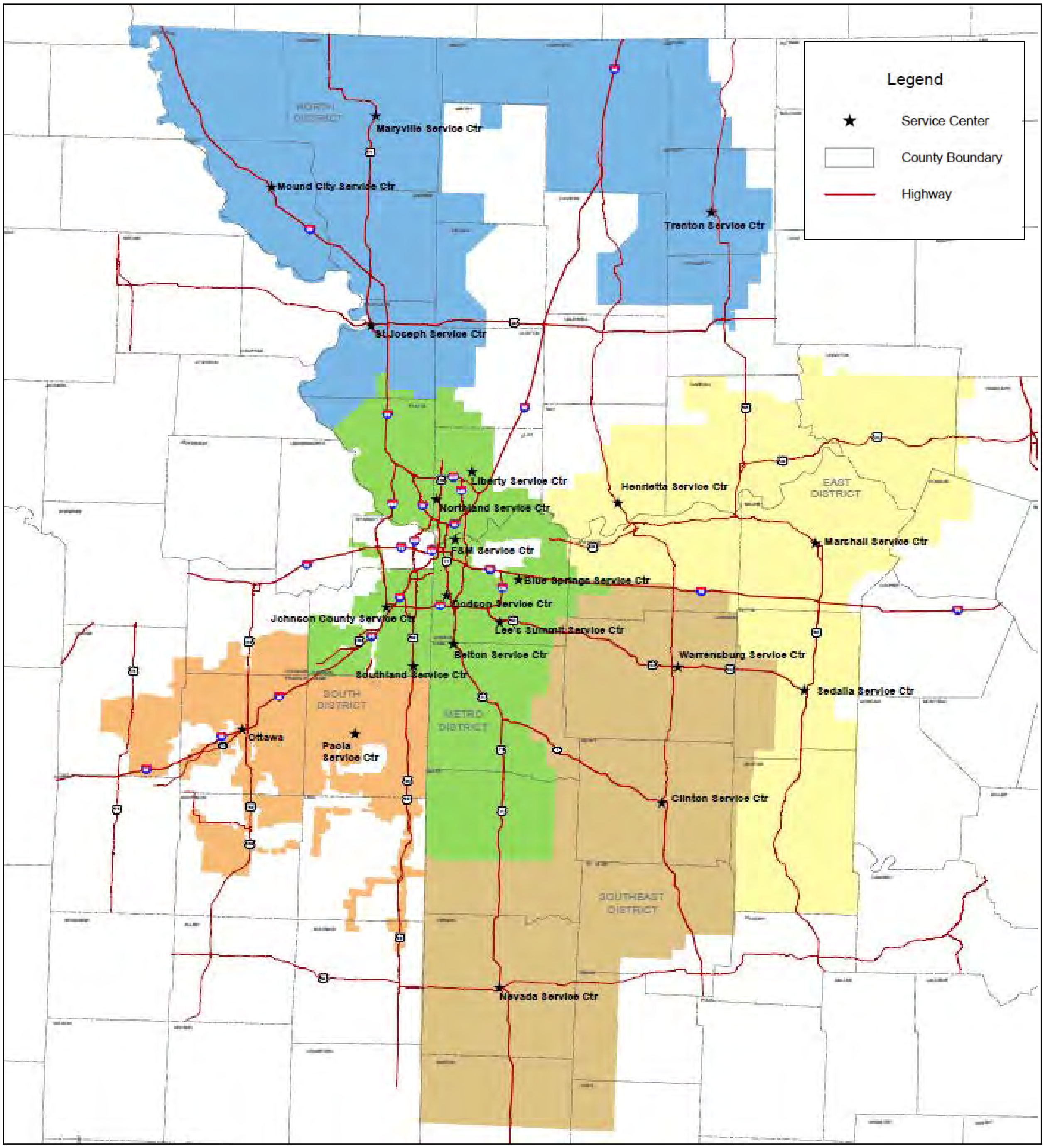
Table 1-1: KCP&L's Service Territory Statistics

KCP&L's Service Territory			
	GPE	**KCP&L**	**KCP&L - GMO**
Total number of customers:			
Residential	723,752	450,359	273,393
Commercial	95,801	57,725	38,076
Industrial & Municipal	2,753	2,393	360
Peak load:			
Summer	5,253 MW	3448 MW	1878 MW
Winter	4,115 MW	2670 MW	1568 MW
Total MWh sales:			
Residential	8,647,450	5,202,904	3,444,546
Commercial	10,636,691	7,506,463	3,130,228
Industrial	3,142,761	1,884,401	1,258,360
Bulk Power	5,492,710	5,280,312	212,398
Distribution Assets:			
Total number of substations	316	91	225
Total number of distribution feeders	1382	767	615
Total miles of overhead distribution line	17,000 mi.	11,768 mi.	5,232 mi.
Total miles of underground distribution lines	7,000 mi.	4,502 mi.	2,498 mi.
Total miles of transmission lines	3,000 mi.	1,765 mi.	1,235 mi.

1.3.2 Service Territory

As shown in Figure 1-1, KCP&L services customers in 47 northwestern Missouri and eastern Kansas counties - a [service territory](#) of approximately 18,000 square miles (www.kcpl.com).

Figure 1-1: KCP&L Service Territory Map



1.3.3 Regulation and Oversight

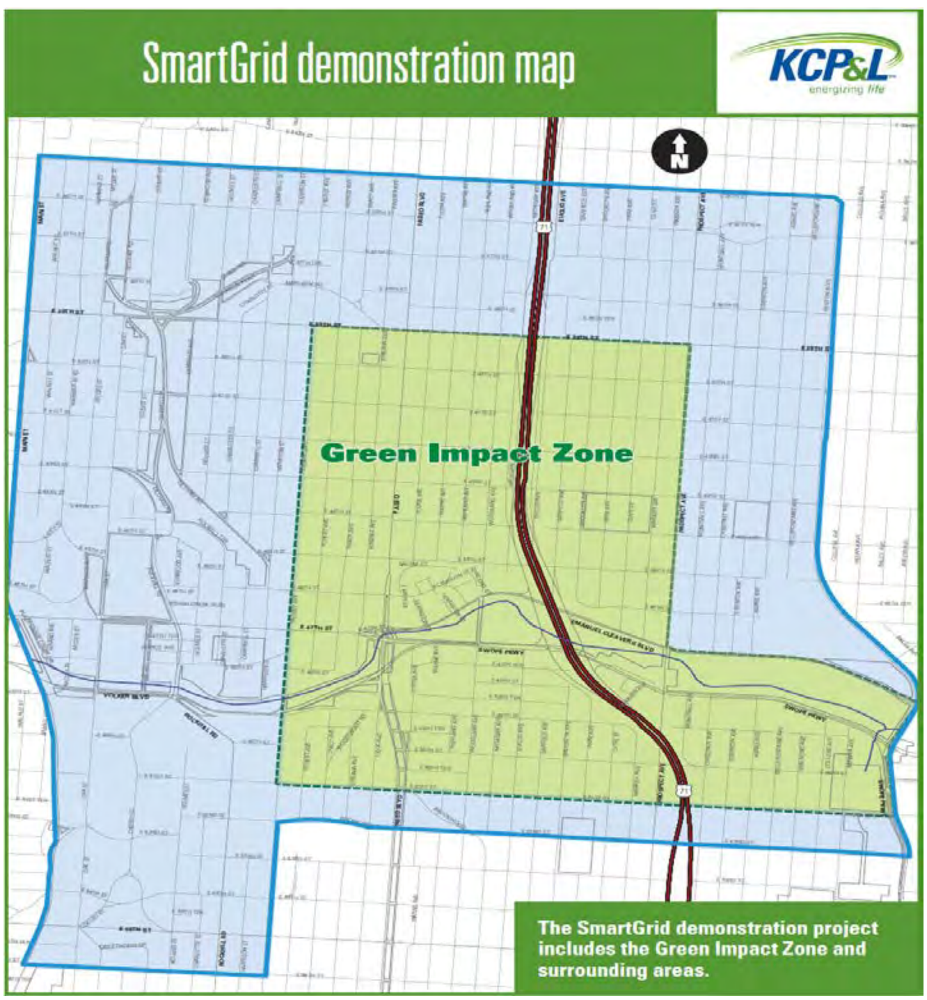
Both utilities are regulated by the Missouri Public Service Commission (MPSC). Kansas City Power & Light is regulated also by the Kansas Corporation Commission (KCC) with respect to retail rates, certain accounting matters, standards of service, and, in certain cases, the issuance of securities, certification of facilities, and service territories.

The utilities are also subject to regulation and oversight by the Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), and Southwest Power Pool, Inc. (SPP). Kansas City Power & Light has a 47% ownership interest in the Wolf Creek Generating Station (Wolf Creek), which is subject to regulation by the Nuclear Regulatory Commission (NRC), with respect to licensing, operations and safety-related requirements.

1.4 Project Location

The Project will deploy Smart Grid technologies on the KCP&L distribution system to the entire Green Impact Zone plus surrounding areas as shown in Figure 1-2. The total Smart Grid demonstration project area is approximately five square miles (www.kcplsmartgrid.com).

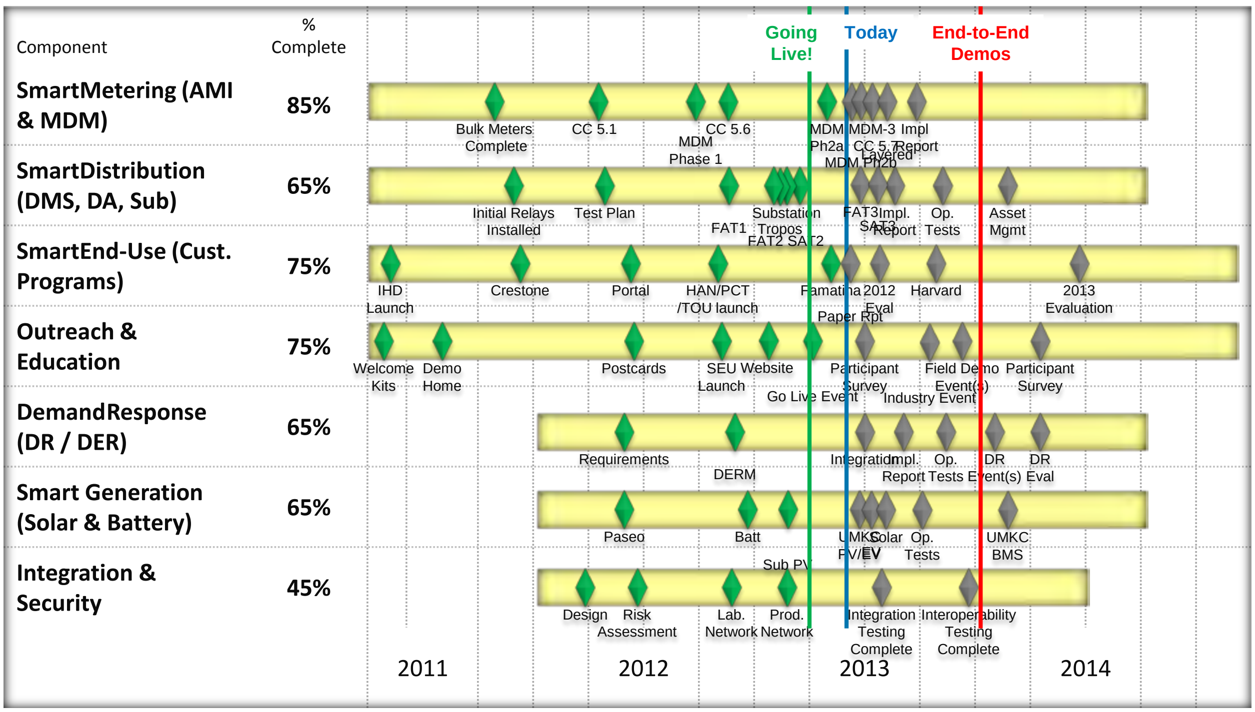
Figure 1-2: KCP&L Green Impact Zone SmartGrid Demonstration Map



1.5 Project Timeline

This section includes a condensed schedule of the KCP&L SmartGrid Demonstration Project. The schedule shown in Figure 1-3 includes main subcomponents of the project and shows their relative start and completion dates. Interdependencies between tasks are not shown on this schedule; however, the information is readily available within the Microsoft Project file that has been created for this project.

Figure 1-3: Project Timeline



1.6 Project Major Milestones

The master project schedule is aligned with the WBS; key project milestones for the project are listed in Table 1-2. During project performance, KCP&L will report the Milestone Status as part of the required monthly Progress Report as prescribed under the Reporting Requirements Checklist. The Milestone Status will present actual performance in comparison with the Milestone Log, and include:

- the actual status and progress of the project;
- specific progress made toward achieving the project's milestones; and
- any proposed changes to the project's schedule required to complete milestones.

The shaded milestones have been published by the DOE as external project milestones.

Table 1-2: Major Project Milestones

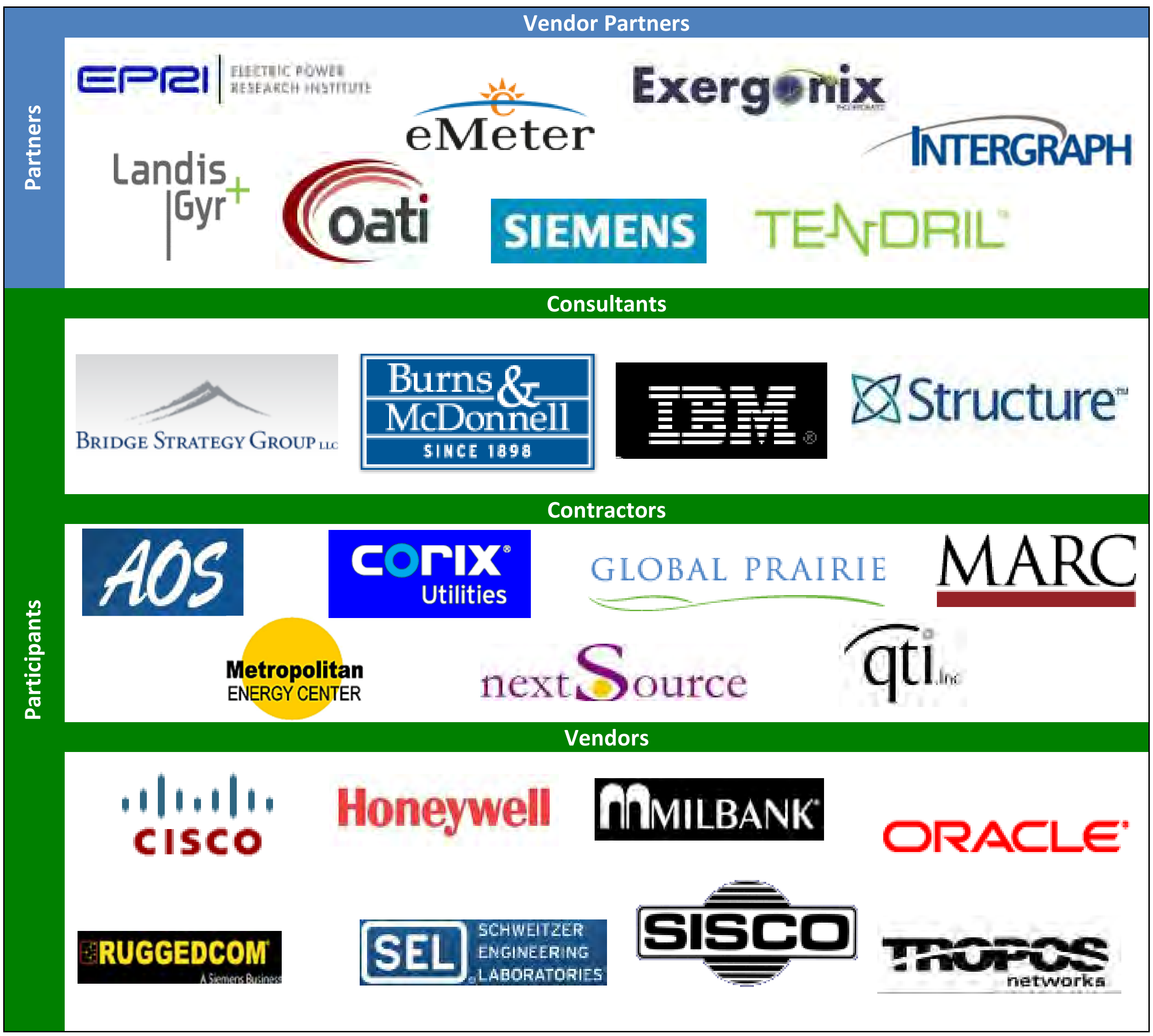
Task	Milestone	Planned Completion Date	Revised Completion Date	Actual Completion Date
1	Revised PMP to DOE for Review	10/29/2010		10/29/2010
2	NEPA Compliance obtained	10/28/2010		10/28/2010
3.2	Develop Initial Cyber Security Plan	10/29/2010		10/29/2010
4.4	Develop Benefits & Metrics Reporting Plan (v1.0 Submitted)	12/30/2010		12/30/2010
5.7.1	First Interim Technology Performance Report	12/31/2012		12/31/2012
5.7.2	Second Interim Technology Performance Report	12/31/2013		[1]
6	Public Outreach and Education	06/30/2014		
	SmartGrid Demonstration Home Grand Opening			01/19/2011
	Innovation Park Grand Opening			10/12/2012
8.4	SmartMetering Deployment	03/18/2011		03/18/2011
8.5	SmartMetering System Acceptance	05/13/2011		05/13/2011
9.4	Collect Consumer 15 min Interval Usage Data	01/03/2012		03/31/2012
10.4	SmartSubstation Protection Network Factory Config.& FAT	12/21/2011		05/04/2012
10.7	SmartSubstation Automation Network Factory Config. & FAT	06/14/2012	08/30/2012	08/30/2012
10.10	Commission SmartSubstation (ready for day-to-day operations)	09/30/2012		09/30/2012
11.4	MDM Phase 1 – Implementation	12/30/2011		03/24/2012
12.10	DMS Factory Configuration and FAT	12/21/2011	08/30/2012	08/30/2012
12.14	Commission DMS System (ready for day-to-day operations)	07/10/2012	09/30/2012	09/30/2012
13.2	Design, Construct, & Test SmartDistribution IP FAN	09/30/2012		09/21/2012
13.6	Commission SmartGrid “First Responder” Subsystem	12/21/2011	01/31/2013	
14	Deploy SmartEnd-Use Implementation (14.2-4 & 14.6-9)	12/31/2012	06/30/2012	06/30/2012
14.3	Implement Home Energy WEB Portal	12/08/2010		10/20/2010
14.4	Implement Home Energy EMS Web Portal	07/06/2011	07/31/2012	06/28/2012
14.5	Implement Home Energy DER Portal	07/06/2011	06/30/2014	
14.6.5	Launch In-Home Display	10/27/2010		10/27/2010
14.7	Demonstration Home Grand Opening	07/13/2011		04/30/2011
14.8	Launch EMS HAN Devices	04/30/2012		04/30/2012
14.9	Launch TOU Tariff	04/30/2012		05/22/2012
15	SmartGeneration Implementation	06/30/2014		
15.1	Deploy Grid Connected Roof-Top Solar	01/11/2012	06/30/2013	
15.2	Deploy DR (AMI) Thermostats (Available to Customers)			04/30/2012
15.5.16	Commission BESS	07/27/2012		06/28/2012
16	Smart DER/DR Management System Implementation	07/03/2014		
16.5	Implement & Unit Test DR Management Sub-system	06/30/2012	07/30/2012	07/27/2012
17.2	Conduct System-System Integration Testing	06/08/2012	02/28/2013	
17.4	Field Demo Integrated SmartGrid Functionality	12/31/2012	06/30/2013	
18.1	Operate System According to Program Plan & Procedures	10/01/2012		10/01/2012
18	Operate Integrated Solution (complete)	10/31/2014		
20.1.4	Submit Draft Report to DOE for Review	12/31/2014		

1.7 SmartGrid Demonstration Technical Project Participants

KCP&L has developed a 'distributed' technical solution model working with a set of best-in-breed vendor participants. The vision for the SmartGrid Demonstration Project is to bring these technical implementation vendors and their capabilities together to develop leading edge, scalable SmartGrid solutions. In selecting participating vendors, KCP&L focused on companies with which we have established relationships, who are leading companies in their respective SmartGrid area, and who share the SmartGrid vision set forth in the demonstration project.

To further the cause of SmartGrid technology development, partners that have agreed to contribute in-kind to the effort have been classified and treated as project partners. In addition to these project partners, KCP&L will work closely with selected vendors to ensure a successful deployment of the demonstration. These strategic partners and vendors are shown in Figure 1-4 and described below.

Figure 1-4: Selected Project Partners



1.7.1 Project Partners

In addition to providing equipment, technical expertise, and in-kind financial support, the project vendor partners will provide leadership on the technical and process aspects of the project, including the selection, implementation, and review of emerging technologies, and ensure that the project's vision is brought to bear through the collaboration of the project's partners and stakeholders.

1.7.1.1 Electric Power Research Institute (EPRI)

EPRI conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. EPRI will provide technical expertise and advice on defined portions of the project. In addition, they are a member of the five-year EPRI Smart Grid Demonstration Initiative, which is focused on Smart Grid projects that integrate distributed energy resources (www.smartgrid.epri.com). One of the main objectives of this initiative is to identify approaches for interoperability and integration that can be used on a system-wide scale to help standardize the use of DER as part of overall system operations and control. As part of this Initiative, EPRI will support this project in several areas including, but not limited, to cost-benefit analysis efforts, use case documentation per the IntelliGrid^{SM} methodology, data analysis and benefits estimation, CO_2 impact assessment and technology transfer.

1.7.1.2 eMeter/Siemens

eMeter's EnergyIP MDM solution is the industry's leading platform for real-time Smart Grid data management. Purpose-built for mass market deployment in heterogeneous and evolving technology environments, EnergyIP brings scalability, adaptability and flexibility to the utility enterprise. eMeter/Siemens will implement the EnergyIP product to provide an enterprise level repository of meter and metering data and support the provision of validated, estimated, and edited (VEE'd) AMI data to the remaining SmartGrid demonstration systems.

1.7.1.3 Exergonix

Exergonix will leverage existing lithium polymer battery technology development and manufacturing expertise to develop and deploy a grid-scale energy storage system to supply peak-shaving, demand-management, and restoration capabilities to the KCP&L grid. The installation will function as part of a larger DERM system, controlled remotely and programmed to function automatically in conjunction with other SmartGrid components.

1.7.1.4 Intergraph

Intergraph is a strategic partner of Siemens Inc., together leading the industry with a number of active Smart Grid projects. Through the partnership, Intergraph and Siemens provide a Smart Grid Operations Command-and-Control Center that integrates an advanced distribution management system (DMS) with SCADA functionality, outage management, mobile workforce management and electric and communications infrastructure management.

Intergraph has also partnered with eMeter to integrate MDM functionality with their Command-and-Control Center platform. The integration will provide grid operators with consolidated end-to-end network visibility and management capabilities to provide utilities with the full operational benefits of their advanced metering infrastructure (AMI) and smart meter deployments for use in outage detection and response. KCP&L will be implementing Intergraph's Smart Grid Operations Command-and-Control Center integrated with Siemens DMS and eMeter's MDM.

1.7.1.5 Landis+Gyr

Landis+Gyr ranks as the worldwide leader in electricity metering with a preeminent position in advanced or "smart metering" systems. In 1994, KCP&L partnered with L+G (then Cellnet) to develop and deploy the first production AMR system in use by a utility. Today, L+G offers the broadest portfolio of products and services in the electricity metering industry including integrated AMM/AMI solutions, communication systems and software, meters, meter data management, services and financing. KCP&L is again partnering with L+G to deploy a state-of-the art Gridstream technology, AMI system and RF mesh AMI field area network.

1.7.1.6 OATI

Open Access Technology International (OATI) Inc. has been serving the energy industry since 1995 and has had steady growth since its inception. As a sub-recipient, OATI will deploy the Distributed Energy Resource Management (DERM) system component of the demonstration project through implementation of its webSmartEnergy application. The webSmartEnergy suites of applications are modular solutions to address the requirements for the emerging SmartGrid. OATI webSmartEnergy products include software and services for Demand Response and Distributed Distribution Resources Management, Renewable Management, and Asset Management.

1.7.1.7 Siemens

Siemens is a world-wide provider of products and services whose experience spans the entire energy network, including generation, transmission, distribution, and the market. They focus on reliable, efficient, and practical innovation and implementation in each segment. As a sub-recipient, they will focus on providing the distribution network "First Responder" functions and the integration of the Distribution Management System (DMS) with SmartSubstation controllers and Distribution SCADA, as well as integration with the existing Geographic Information System (GIS), Advanced Metering Infrastructures (AMI), Meter Data Management (MDM) Systems, and Distributed Energy Resource Management (DERM) Systems.

Siemens plays a dual partner role in that they are both a sub-recipient and a vendor. As a vendor, Siemens will provide the SmartSubstation automation controllers, Distribution SCADA, Distribution Management System (DMS), and a variety of substation and field grid devices and IEDs. Siemens also teamed up with eMeter to provide the MDM.

1.7.1.8 Tendril

Tendril offers solutions to aid customers in understanding, reducing, and managing energy consumption. Tendril will provide a residential Home Energy Management Portal (HEMP) and Home Area Network (HAN) platform which will provide energy consumers and utilities an intelligent network of distributed energy resource management tools that can control load, store energy and produce power. The platform aggregates distributed energy resources and provides consumer and utility control through a single Web-based interface.

1.7.2 Consultants

1.7.2.1 Bridge Strategy Group

Bridge Strategy Group is an elite general management consulting firm used by KCP&L on numerous occasions on key strategic assignments. Bridge was retained to temporarily perform the Director of SmartGrid project functions and provide project level consulting services during the initiation phase in the form of guidance, expertise, and project support to the SmartGrid PMO.

1.7.2.2 Burns & McDonnell Engineering Company

Founded in 1898, Burns & McDonnell is a 100 percent employee-owned, full-service engineering, architecture, construction, environmental and consulting solutions firm with over 3,000 professionals in more than 20 offices. Burns & McDonnell will provide assistance to KCP&L in the form of skilled staff to augment the Project team.

1.7.2.3 IBM

IBM Global Services is the world's largest information technology services provider with professionals servicing customers in 160 countries. They are at the forefront of developing, integrating, and implementing Smart Grid systems. IBM will provide assistance to KCP&L in the development of the project Interoperability and Cyber Security Plan.

1.7.2.4 The Structure Group

The Structure Group is an energy and utility consulting firm specializing in SmartGrid, energy management, risk management and competitive market solutions and will provide assistance to KCP&L in the form of skilled staff to augment the Project team, particularly in the role of IT integration.

1.7.3 Contractors

1.7.3.1 AOS

Alexander Open Systems (AOS) specializes in consulting, designing, implementing and supporting Local, Wide Area and Wireless Networking, Communication and Collaboration, Data Center, Physical and Data Security.

1.7.3.2 Corix Utilities

KCP&L currently contracts with Corix Utilities to provide manual meter reading services for our non-AMR service territory. Corix has performed over 3,000,000 meter changes, AMR/AMI device installations and retrofits for gas, water and electric utilities since 1995, helping utilities make a smooth transition from traditional meter reading to automation. Corix has been retained to perform a pre-deployment audit of all electric meters in the SmartGrid demonstration area.

1.7.3.3 Global Prairie

Global Prairie is an integrated communications and brand management company. Global Prairie will be providing education and outreach enrollment and soliciting volunteers to assist in these efforts.

1.7.3.4 MARC

The Mid-America Regional Council (MARC) provides administrative staff and services for the Green Impact Zone. The Green Impact Zone initiative is an effort to concentrate resources — with funding, coordination, and public and private partnerships — in one specific area to demonstrate that a targeted effort can literally transform a community. Plans are underway to make the Green Impact Zone a model for energy efficiency. Neighborhood leaders, the coordinating council, local utilities and other strategic partners intend to develop and implement a highly coordinated initiative to reduce energy and water usage within the zone — and, in the process, reduce utility bills for residents. The initiative will include individual property strategies as well as neighborhood-wide strategies, such as installation of a smart grid and the expansion of solar and other renewable energy sources within the zone.

1.7.3.5 Metropolitan Energy Center

The Metropolitan Energy Center's mission, when it was founded, was to assist people in the Kansas City region to manage and control their energy use. This nonprofit organization has evolved to become a catalyst for community partnerships focused on energy efficiency, environmental stewardship and economic improvement. KCP&L has partnered with MEC to integrate our SmartGrid Demonstration Home in their "Project Living Proof" demonstration. More information may be found at http://www.kcenergy.org/community.htm.

1.7.3.6 NextSource

NextSource is a global labor resource provider. NextSource will provide assistance to KCP&L in the form of on-site personnel in a variety of roles.

1.7.3.7 QTI, Inc.

QTI, Inc. offers turnkey solutions for general contracting needs. It is a corporation that provides general construction services along with fiber optic network build outs, underground power distribution and warehouse distribution. QTI, Inc. has been selected to manage the AMI meter deployment with a locally hired and trained workforce.

1.7.4 Vendors

1.7.4.1 Cisco

Cisco is the worldwide leader in IP-based networking products and solutions designed to implement truly intelligent information networks. A Cisco® Smart Grid network is a holistic, cross-technology solution that enables utilities and other organizations in the energy industry to build secure, standards-based IP networks to efficiently meet the demands of energy generation, distribution, storage, and consumption. KCP&L will extend our existing Cisco based network to support the SmartGrid demonstration by implementing a new Cisco Smart Grid network as the foundation of the SmartSubstation.

1.7.4.2 Honeywell

Honeywell is providing the interface to the University of Missouri – Kansas City (UMKC) building management system. Part of Honeywell's portfolio of automated demand response (Auto DR) technologies, the Akuacom DRAS is based on OpenADR communication standards. As a result, it provides utilities and independent systems operators (ISOs) with an open, secure path to send price and reliability signals over the Internet, and communicate with building management systems during a demand response event. These signals automatically trigger custom load-shedding measures at each participating facility, such as cycling air conditioners on and off, and turning off banks of lights.

1.7.4.3 Milbank

Milbank, headquartered in Kansas City, is an industry leader in the manufacture of electrical meter sockets and has been servicing the electric utility & wholesale distribution industries for over 75 years with innovative, quality engineered products. Milbank will be providing retrofit A-base meter enclosure covers to accommodate the larger physical dimensions of the AMI meters.

1.7.4.4 Oracle

Oracle is #1 in the worldwide relational database management systems (RDBMS) software market and holds more market share than its four closest competitors combined. The Oracle RDBMS is an integral foundation for many of the SmartGrid demonstration system components to be implemented.

1.7.4.5 Ruggedcom

Ruggedcom designs and manufactures rugged communications equipment for harsh environments such as substations and other outdoor applications. KCP&L will use Ruggedcom network components to implement half of the redundant SmartSubstation IP based protection network.

1.7.4.6 Schweitzer Engineering Laboratories (SEL)

SEL makes electric power safer, more reliable, and more economical. To accomplish this mission, they design, manufacture, and support a complete line of products and services for the protection, monitoring, control, automation, and metering of electric power systems. KCP&L will replace existing electromechanical relays with new SEL feeder relays in transforming the Midtown substation to a next generation SmartSubstation.

1.7.4.7 SISCO

The SISCO ICCP product is being used to integrate the Intergraph and Siemens products. The ICCP-TASE.2 (IEC60870-6) is the internationally accepted standard for the exchange of real-time data in energy utilities for control center integration.

1.7.4.8 Tropos

Tropos provides wireless communications networks for utilities to build and control the Smart Grid. Tropos will provide the wireless, IP-based mesh network for distribution automation.

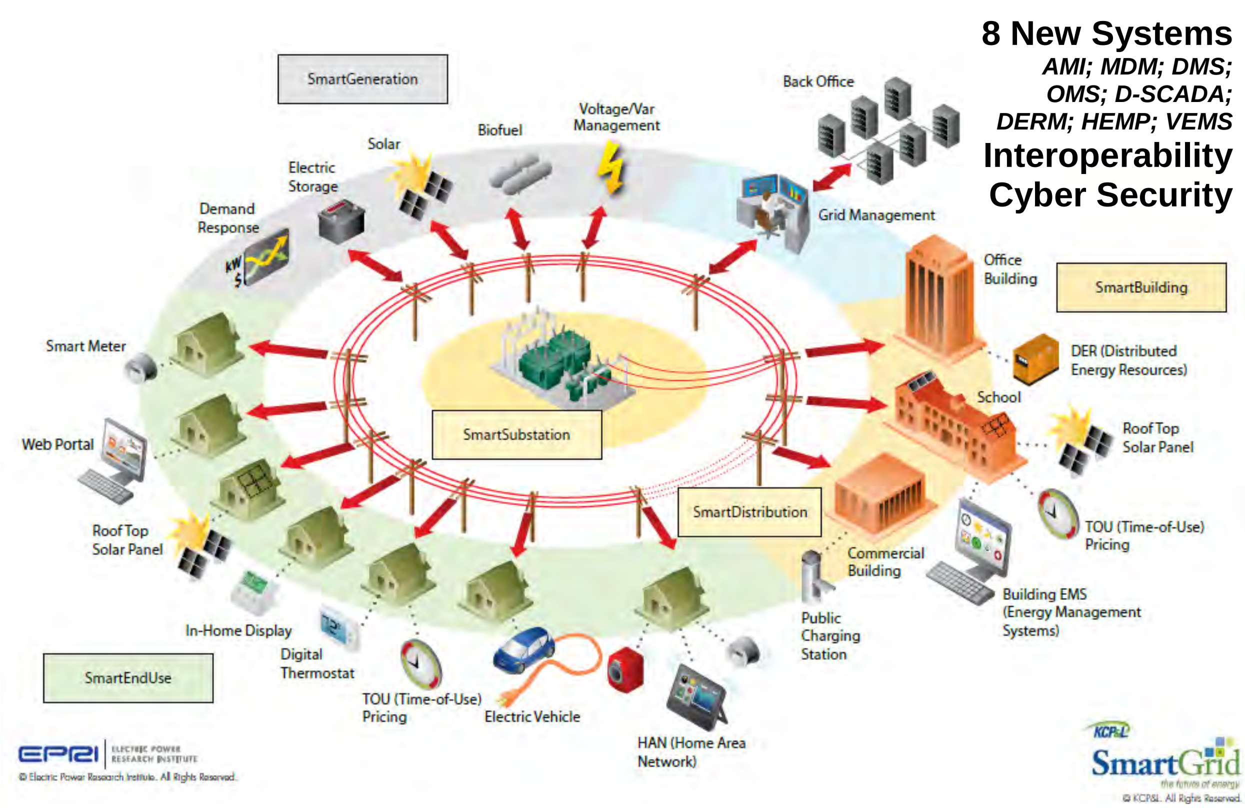
2 Demonstration Systems and Technologies

The KCP&L SmartGrid Demonstration Project will demonstrate the value of integrating SmartGrid technology, communications and control systems to manage the distribution system in cooperation with distributed energy resources within a utility's service territory. In particular, we are targeting distributed, edge-of-grid, resources using a comprehensive next generation SmartGrid infrastructure to integrate and manage the distributed grid assets. Not only will the distributed energy resources be aggregated, visible, and available to the energy traders and bulk grid operators, they will also be available to the DMS and distribution operators as a tool to solve local congestion or power quality issues. Ultimately, individual or circuit aggregated resources can be initiated automatically by the distributed substation controller (DCADA) as one of its "First Responder" functions.

2.1 Demonstration Systems Overview

The KCP&L SmartGrid Demonstration focuses on the Company's Midtown Substation and multiple distribution circuits serving approximately 14,000 customers across 3.75 square miles with total demand of up to approximately 69.5 MVA. Our scope of work, illustrated in Figure 2-1, touches every functional area of the electricity distribution network.

Figure 2-1: KCP&L Demonstration, a True End-to-End SmartGrid

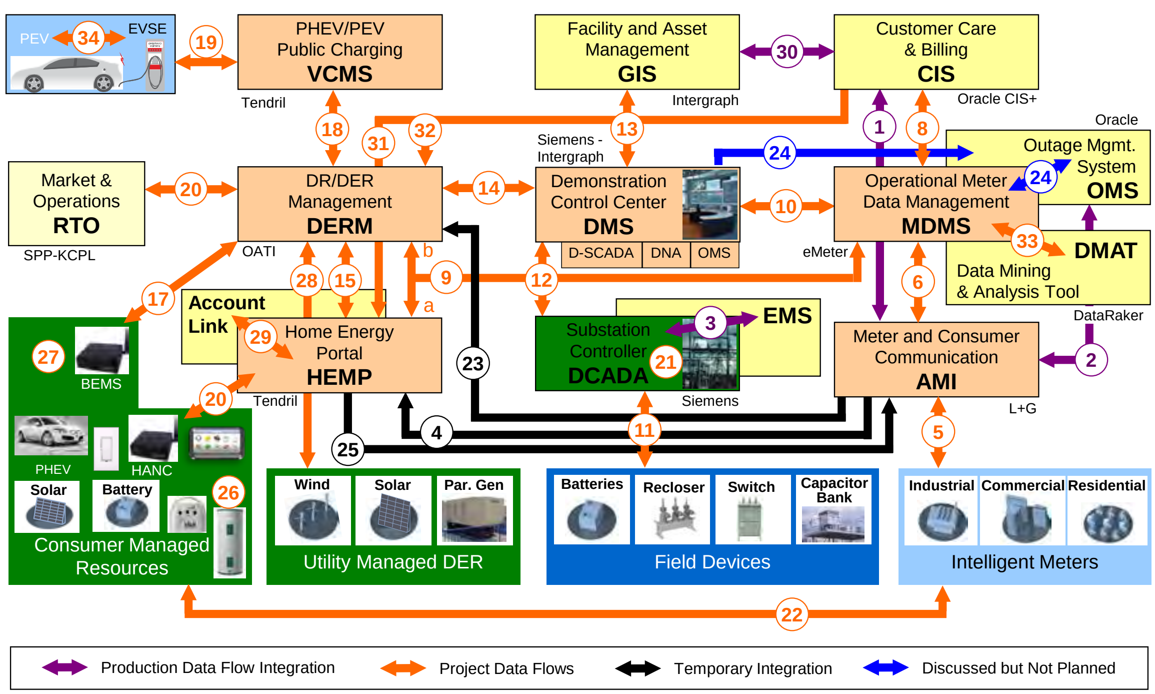


The SmartGrid pilot infrastructure includes a distribution grid control system that consists of five major components as shown in Figure 2-2 below. The grid control infrastructure is a "standalone" system for the demonstration project, but it is used to control the grid as part of normal day-to-day operations within the demonstration area.

The pilot infrastructure components include:

- **Distribution Management System.** This provides all the necessary systems and applications for the KCP&L Control Center Operators to manage the distribution network reliability, quality of supply, coordinate with substation controllers and field automation, and enhance efficiency of the operations, crew and maintenance staff.
- **Distributed Control and Data Acquisition.** This DCADA includes the SmartSubstation control functions and the automation of reclosers, switches, and capacitor banks to support communication with Smart-Substation[TM] Controllers for automated feeder reconfiguration.
- **Advanced Metering Infrastructure and Meter Data Management.** This supports two-way communication with electronic meters for consumer billing information, verification of electrical service status, and remote service on-off capabilities.
- **Distributed Energy Resource Management.** This provides balancing of renewable and variable energy sources with controllable demand as it becomes integrated in the utility grid, coordination with market systems, and provision of pricing signals to consumers.
- **Home and Vehicle Energy Management.** This enables customers to make informed consumption decisions and to allow consumer managed resources to participate in proactive utility grid management programs.

Figure 2-2: KCP&L Demonstration, T&D Control Systems Infrastructure



As depicted in Figure 2-2, there are four (4) integration points with existing systems; GIS, CIS, OMS, and EMS/SCADA.

- **GIS** – will continue to be the source of facility and network connectivity information.
- **CIS** – will continue to be the source of customer information and will continue to provide billing functions for customers on existing rate structures.
- **OMS** – will continue to be the production system for analysis of customer outage information for manual dispatch. The DMS will process outage calls for automated restoration and demonstration purposes.
- **EMS/SCADA** - will continue to have control authority over the distribution functions for which it currently controls, primarily distribution feeder breakers. DMS will have control authority over all new control functions

This pilot infrastructure creates the next-generation grid monitoring and control platform that is being used to manage the KCP&L Green Impact Zone Demonstration grid for project duration.

The DMS and DCADA provide the operational backbone of the system supporting significant levels of automation on the feeders, complex and automated feeder reconfiguration decisions, and tightly integrated supervision with the Control Centers. The DMS serves as the primary point of integration for the grid facilities, electrical system load, and real-time substation and feeder information. It includes Distribution Supervisory Control and Data Acquisition (D-SCADA), Distribution Network Analysis (DNA), Outage Management (OMS) and integration with KCP&L's existing Mobile Work Force Management system, Geographic Information System (GIS), and other supporting systems.

The Smart-Substation™ controller establishes an intelligent substation IT infrastructure with the ability to make feeder and substation reconfiguration decisions, control field equipment, verify operations, track local grid capacity, and coordinate with the DMS. This "proactive" management of the distribution grid is a necessary step in preparing for the integration of significant levels of renewable and variable energy resources, controllable demand, and demand response. With the addition of distributed energy resources, the DMS and Smart-SubstationTM become essential to managing Volt/VAr conditions, adaptively modifying protection equipment settings, and managing crew safety.

The AMI/MDM provides access, collection, and management of meter asset information and the consumer metering information for billing, consumer awareness and consumer participation in demand management/response programs or the market. It will be deployed to all customers in the KCP&L Green Impact Zone SmartGrid Demonstration area, including residential, commercial and industrial consumers. It will collect the customer's 15 minute interval consumption data required to support many of the SmartGrid analysis to be performed and for the experimental TOU rates and other EE/DR incentives to be evaluated. Additionally, the MDM will manage the flow events and other data flows between the legacy CIS and OMS and the demonstration DMS/OMS, DERM system and provides an avenue for integration with selected Home Area Network (HAN) management systems.

The DERM system provides all the necessary functions to balance distributed energy resources with available dispatchable ("controllable") demand to make most efficient use of existing energy options while optimizing economic value for consumers in the market. It aggregates distributed energy resources and controllable load groups for dispatch and market participation with group and, potentially, demographic leverage. It assesses balancing within a defined future time period (i.e. 5 minutes) and issues commands to participating resources to adjust their output and/or demand where appropriate. Excess resource can be bid into the market. The system tracks aggregate and individual resource commitments and settles accounts. It uses available load models and network conditions from the DMS as constraints to ensure reliable network operation, request network control changes and verify resource participation. It accepts requests from the DMS to suspend dispatch of energy resources in areas where operational safety conditions are at risk. It will use consumption information from the AMI/MDM system to verify demand management/response participation. It will track, retain, and report all information necessary to quantify resource and related economic participation.

All these systems assume an underlying standards-based infrastructure of communications, field automation, and end-to-end cyber-security. The demonstration systems are fully integrated using the standards defined by the NIST SmartGrid Interoperability Framework, where applicable, and interface with existing production systems at KCP&L at clearly defined and controlled integration points to maintain the security and integrity of KCP&L enterprise systems. As a whole, the program is verifying a full range of NIST and other standard modeling and information exchange protocols necessary to implement a functional, cost-effective, secure intelligent grid. The project has helped define, validate, and verify the necessary parameters and potential solution adjustments for KCP&L, and the industry, to plan and implement a system wide roll-out of the successful SmartGrid technologies and processes.

Several fundamental aspects of next generation SmartGrid T&D Infrastructure are being demonstrated and verified in this project, including:

- State-of-the-art multi-transformer, multi-bus distribution substation upgrade
- SmartSubstation with IEC61850 communication protocols over a secure IP Ethernet substation LAN
- Highly-integrated, distributed hierarchal control solution between a centralized DERM system, DMS/SCADA system, a distributed DCADA controller within the SmartSubstation, and individual IED field controls
- Automated “first responder” distributed decision making through intelligent substation controllers and enabled feeder devices
- Dynamic equipment ratings based on field conditions
- Integrated supervision of automation and filtering of field information to improve distribution operations situational awareness
- Integration of distributed and renewable energy resources and controllable demand
- Availability of customer demand response, price signals, and market participation
- Two-way accessibility of the customer meter, availability of current energy usage information, and customer participation in energy programs
- A comprehensive SmartGrid communications infrastructure
- End-to-end cyber security provisions

The following subsections describe the various components of the project.

2.2 Interoperability Strategy & Plan [2]

The KCP&L project team developed and published a “SmartGrid Interoperability Plan” that detailed a strategy and approach for system interoperability for the KCP&L SmartGrid Demonstration Project. The following subsections provide an overview of the significant element of the Interoperability plan developed for the project.

2.2.1 Interoperability Vision

Federal and industry requirements for interoperability and security are critical to a successful integrated Smart Grid solution and they are a key focal point for this project. Inherent in any approach to integration and interoperability are the challenges posed by the heterogeneous nature of the grid components; as each component varies in ability to securely and accurately communicate in the overall Smart Grid solution.

KCP&L’s vision calls for many emerging technologies to be integrated into the Transmission and Distribution networks, ultimately, achieving interoperability with and between legacy environments. The planned demonstration project poses challenges due to immature and emerging Smart Grid standards, the high level of interoperability involved across distributed platforms, and the need to carefully protect customer and system control information across a highly distributed network reaching outside of utility boundaries and onto customer premises. Given the heterogeneous nature of combining legacy components and products of numerous vendors, the project must anticipate and mitigate several challenges. These challenges include:

- Communicating with legacy systems and devices
- Communication between open standard and proprietary components
- Identifying failure and upgrading and maintaining components so that overall system operation is highly reliable
- Supporting interacting parties’ anticipated response to failure scenarios, particularly loss of communications

2.2.2 Interoperability Strategy

To make effective progress for this project and deliver customer and operational benefits, KCP&L envisions an approach to maximizing interoperability that takes aggressive action despite market and standards uncertainties, and that provides a measured means to carefully protect operational reliability, cyber security, and long-term investments. The structured, evolutionary approach described in this document preserves investments, yet provides the flexibility needed for orderly integration of emerging frameworks, methods and standards. Key aspects of KCP&L’s strategy for managing interoperability risks include:

- Product selection with consideration of emerging standards for distribution grid management (e.g., IEC 61968 and IEC 61850)
- Open and modular architectural approaches that emphasize vendor-independent integration mechanisms (e.g., Service-Oriented Architecture)
- Investment in ongoing integration test-bed capability to provide for agile component integration, interoperability testing and means for managing technical and security risks through hands-on application and integration of new technologies

- Continued collaboration with public/private industry consortia and special interest groups (such as SGIP, EPRI, IEC, IEEE, UCAIug and the GridWise Alliance) toward the refinement of interoperability standards
- Ongoing and regular review of current implementation and architecture versus current industry standards and emerging integration models

However, using a standard, even an open standard, is not a panacea. As technology changes over time, standards go through life cycle phases, both in commercial adoption and technical maturity. Today's new standard is tomorrow's legacy specification. Also, there is no shortage of standards within the complicated landscape of interface specifications in electric power, manufacturing, buildings automation, and information technology in general.

Throughout the project development life cycle, KCP&L will identify, analyze, and develop mitigation approaches to the various risks encountered in the project. This will be accomplished through periodic reviews, implemented to ensure the successful completion of one stage of the project's life cycle prior to progressing to a subsequent stage. During these reviews, adherence to standards, buy-in from stakeholders and resolution of issues will be accomplished. Evidence of completion will be accomplished through documentation of required artifacts for each life cycle stage.

2.2.2.1 Strategic Interoperability Directions

This section describes important strategic directions of KCP&L that are intended to enable increased interoperability. These technologies and the accompanying business processes will be implemented as needed for the demonstration project; however, they represent important steps towards a broader integration of the demonstration systems.

2.2.2.1.1 Application Interface Interoperability

Initially, integration with legacy production systems will be achieved primarily through file transfers. However, ultimately, web services deployed in a Service-Oriented Architecture will be used to achieve interoperability between proprietary protocols and will be used to create open interfaces between legacy and new systems and applications. Through the use of open standards, such as web services and the protocols and standards defined by W3C and OASIS consortia, along with mechanisms for guaranteed delivery of transactions and resilient network architecture, KCP&L will deploy a Smart Grid ecosystem (system of systems) that is highly available, easily upgraded, interoperable, and that is capable of maintaining transactional integrity despite losses of communication between system components.

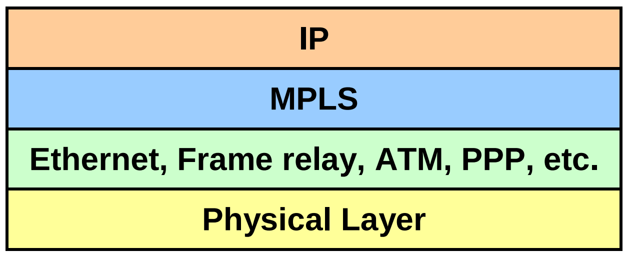
Web services are a set of emerging standards that enable interoperable integration between heterogeneous IT processes and systems. Web services provide a common standard mechanism for interoperable integration among disparate systems, and the key to their utility is their standardization. This common mechanism for delivering a "service" makes them ideal for implementing a Service-Oriented Architecture (SOA).

Besides using the common Web transports, Web services also require a common language for the data exchanged – Extensible Markup Language (XML). XML is simply the "scaffolding" for the actual exchange. For the Web services protocols to be interoperable across diverse systems and suitable for Smart Grid applications, standards bodies, such as W3C, OASIS, and WS-I, must formally standardize these protocols. KCP&L continues to implement these standards and contribute to the SOA standards adoption process with other utilities through participation in user groups and standards bodies.

2.2.2.1.2 Interoperability of Communications Networks

With respect to the underlying communications network, KCP&L is implementing increasingly meshed approaches with redundant communications paths and traffic prioritization features (Figure 2-3). In part, this is being accomplished through adoption of Multi-Protocol Label Switching (MPLS) as specified by the Internet Engineering Task Force (IETF).

Figure 2-3: KCP&L MPLS-based IP Communication



MPLS is a highly scalable and protocol agnostic data-carrying mechanism that can encapsulate legacy routing protocols. MPLS offers enhanced security and robust communication failover capabilities. In addition, the protocol allows segmentation, prioritization and optimization of specific traffic, such as control and market information. The adoption of IPv6 is another important direction in this area, offering enhanced security and traffic segmentation.

2.2.3 SmartGrid Demonstration Communication Networks

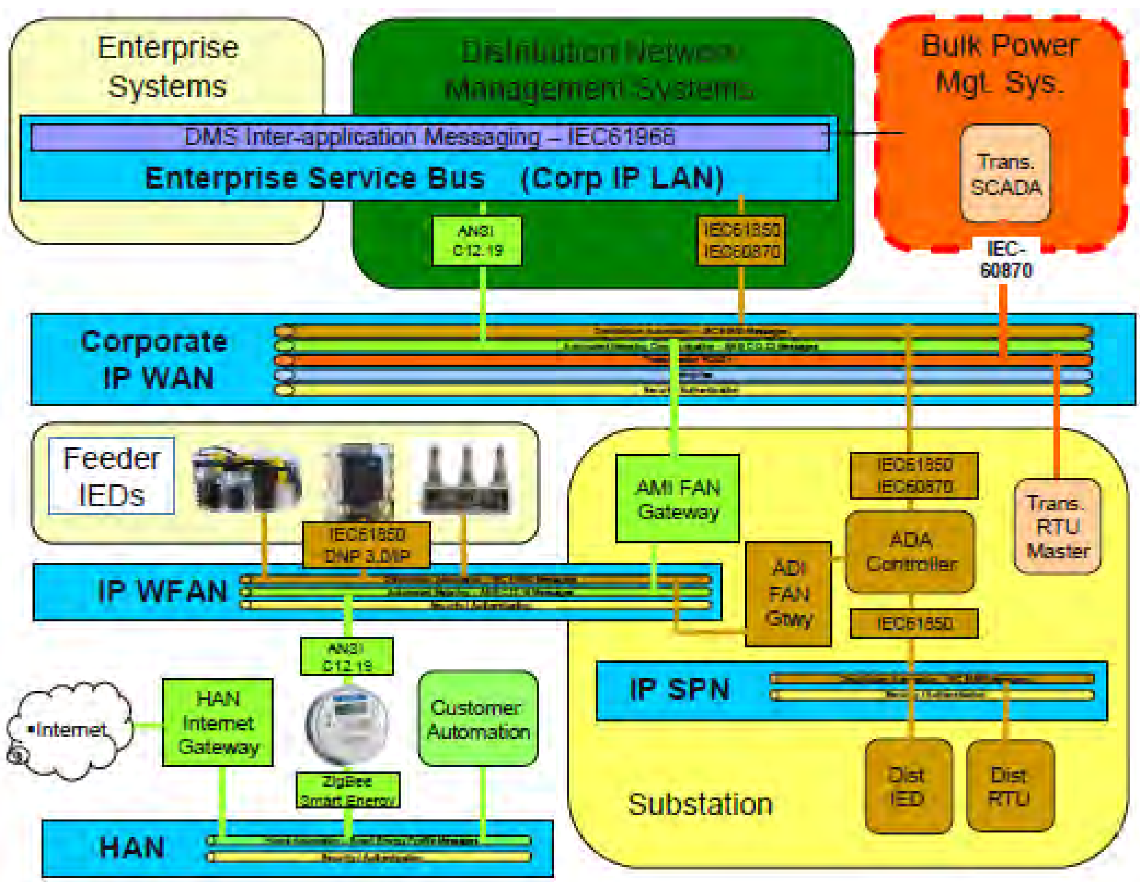
The public Internet is a very powerful, all-pervasive medium. It can provide very inexpensive means to exchange information with a variety of other entities. The Internet is being used by some utilities for exchanging sensitive market information, retrieving power system data, and even issuing some control commands to generators. Despite standard security measures, such as security certificates, a number of vulnerabilities still exist.

KCP&L has chosen to implement its SmartGrid Demonstration Project using private communications media wherever practical. By using the Corporate IT WAN and a utility-owned FAN, the KCP&L SmartGrid pilot solution can still leverage the vast amount of research and development into Internet Protocols (IP) and technologies. They will just be implemented over a private Intranet instead of the public Internet to minimize the exposure to cyber security risks. The communications and information networks proposed to support the deployment of the SmartGrid demonstration project is depicted in Figure 2-4.

The far reaching and complex nature of the SmartGrid dictates that no-single communications technology or security policy can be developed to implement and properly secure the SmartGrid. The hierarchical nature of the technologies that will be implemented to create the SmartGrid Communication Network provides for security "check-points" between control and network layers that may have different security requirements. Therefore, it is a natural extension for the Security Architecture to be constructed around Security Domains.

A Security Domain represents a set of resources (e.g. network, computational, and physical) that share a common security requirements and risk assessment. For example; within the 'bulk power system' there are two distinct Security Domains: NERC-CIP and NERC-nonCIP. While having different security requirements, all Security Domains will be secured and managed through a consistent set of security policies and processes. Secure connectivity, data encryption, firewall protection, intrusion detection, access logging, change control and the audit reports associated with these applications will likely be required for all SmartGrid security domains.

Figure 2-4: KCP&L SmartGrid Demonstration Project Communication Network



2.2.4 Interoperability Plan and Approach

To meet the interoperability challenges associated with ensuring interoperability across the SmartGrid Demonstration Project, KCP&L will use a structured approach as outlined in Figure 2-5. This involves adoption of industry frameworks for interoperability from the GridWise Alliance, the National Institute of Standards and Technology (NIST) and the International Electrotechnical Commission (IEC).

The frameworks, and their associated models and methods will be used to derive architectures that satisfy requirements for interoperability. The architectures will be implemented as blueprints for designs. These components together comprise the KCP&L solution for Smart Grid and, when applied throughout the system life-cycle will ensure that the solution meets KCP&L's business requirements, achieves intended legal and regulatory objectives, operates securely and efficiently, enables reliability and agility, and can be easily integrated within the larger electric grid.

Figure 2-5: KCP&L SmartGrid Interoperability Approach

Frameworks	**Broad Conceptual Structured Approaches** • NIST Framework and Roadmap for Smart Grid Interoperability • GridWise Architectural Council Interoperability Context-Setting Framework
Models & Methods	**Means to Achieve Intended Results and Develop Requirements** • NIST Smart Grid Cyber Security Strategy and Requirements • EPRI IntelliGrid^{SM} Methodology (Business Use Cases)
Requirements	**Drive Architecture and Establish Functionality** • NIST Smart Grid Cyber Security Strategy and Requirements • AMI-SEC AMI Security Profile & Distribution Security Profile
Architecture	**Satisfies Requirements and Provides Blueprint for Designs** • NIST Smart Grid Cyber Security Strategy and Requirements • Customized to Fit KCP&L Requirements
Standards	**Support Architecture and Provide Design Foundation** • NIST Framework and Roadmap for Smart Grid Interoperability Standards • NIST Guidelines for Smart Grid Cyber Security
Designs	**Implement Architecture in Compliance with Standards** **Developed to meet Requirements and Functionality**
Solutions	**Implement Designs to meet Requirements and Provide desired Functionality**

2.2.4.1 Frameworks

A solution framework captures key domains and their interactions in order to enable discussions between partners as to how their contributions address the overall solution. It is used to communicate within the electricity system to compare, align, and harmonize solutions and processes as well as with the management of other critical infrastructure. With the support of the context-setting framework, opportunities and hindrances to interoperability can be debated and prioritized for resolution. Cross-cutting issues, such a cyber security and privacy are areas that need to be addressed in all aspects of the model and agreed upon to achieve interoperation. They usually are relevant to more than one interoperability category of the framework. The framework makes no architectural or technical recommendations. However, architectures will be derived from the framework and designs developed based on the architectural blueprints.

2.2.4.1.1 NIST SmartGrid Framework [3]

This KCP&L solution framework will be aligned with the NIST Special Publication 1108R2 - NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2. This document identifies guiding principles for the adoption of standards for the Smart Grid and the Smart Grid domains to which interfaces and standards apply. It also identifies standards for consideration and incorporation into Smart Grid architectures and solution designs. Applicable standards will be incorporated into the KCP&L demonstration project.

The Smart Grid is a complex system of systems for which a common understanding of its major building blocks and how they interrelate must be broadly shared. NIST has developed a conceptual model to facilitate this shared view. This model provides a means to analyze Use Cases, identify interfaces for which interoperability standards are needed, and facilitate development of a cyber security strategy. For this purpose, NIST adopted a model that divides the Smart Grid into seven domains (described in Table 2-1 and shown in Figure 2-6).

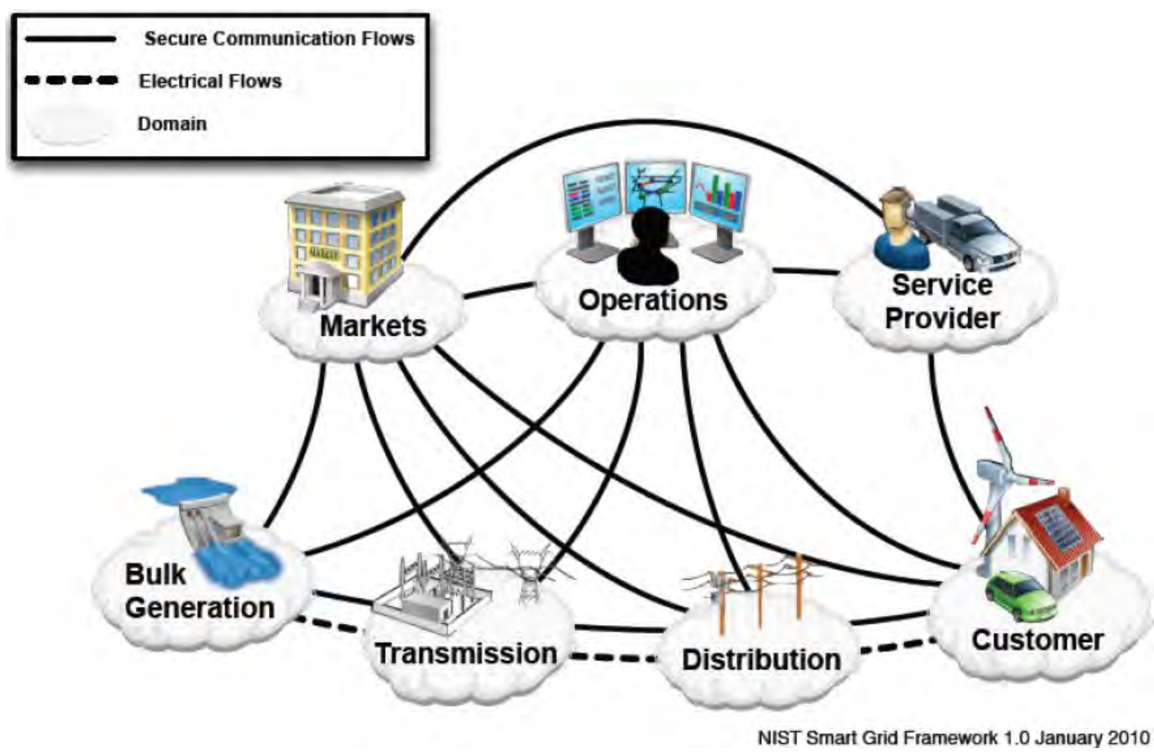
Each domain—and its sub-domains—encompass Smart Grid actors and applications. Actors include devices, systems, or programs that make decisions and exchange information necessary for performing applications: smart meters, solar generators, and control systems represent examples of devices and systems. Applications, on the other hand, are tasks performed by one or more actors within a domain. For example, corresponding applications may be home automation, solar energy generation and energy storage, and energy management. The *NIST Framework and Roadmap for Smart Grid Interoperability Standards* describes the seven Smart Grid domains in more detail.

Table 2-1: Domains & Actors in the Smart Grid Conceptual Model

Domain	Actors in the Domain
Customers	The end users of electricity. May also generate, store, and manage the use of energy. Traditionally, three customer types are discussed, each with its own domain: residential, commercial, and industrial.
Markets	The operators and participants in electricity markets.
Service Providers	The organizations providing services to electrical customers and utilities.
Operations	The managers of the movement of electricity.
Bulk Generation	The generators of electricity in bulk quantities. May also store energy for later distribution.
Transmission	The carriers of bulk electricity over long distances. May also store and generate electricity.
Distribution	The distributors of electricity to and from customers. May also store and generate electricity.

In general, actors in the same domain have similar objectives. In order to enable Smart Grid functionality, the actors in a particular domain often interact with actors in other domains, as shown in Figure 2-6. However, communications within the same domain may not necessarily have similar characteristics and requirements. Moreover, particular domains also may contain components of other domains. For instance, the ten Independent System Operators and Regional Transmission Organizations (ISOs/RTOs) in North America have actors in both the Markets and Operations domains. Similarly, a distribution utility is not entirely contained within the Distribution domain—it is likely to contain actors in the Operations domain, such as a distribution management system, and in the Customer domain, such as meters.

Figure 2-6: Interaction of Actors in Different Smart Grid Domains



Underlying the conceptual model is a legal and regulatory framework that includes policies and requirements that apply to various actors and applications and to their interactions. Regulations, adopted by the Federal Energy Regulatory Commission at the federal level and by public utility commissions at the state and local levels, govern many aspects of the Smart Grid.

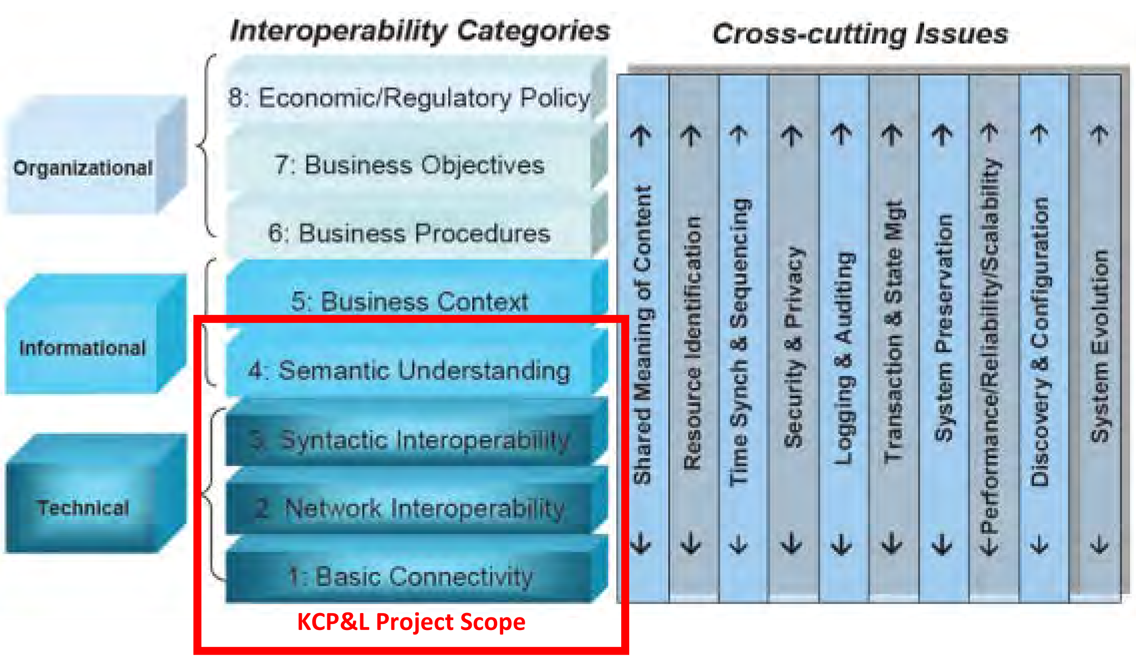
2.2.4.1.2 <u>GridWise Architecture Council Interoperability Framework [4]</u>

KCP&L will utilize the GridWise Architecture Council's (GWAC) Interoperability Context-Setting Framework to align the solution, make appropriate interoperability decisions, and deliver the anticipated results to the stakeholder community.

The GridWise interoperability context-setting framework identifies eight interoperability categories that are relevant to the mission of systems integration and interoperation in the electrical end-use, generation, transmission, and distribution industries. The major aspects for discussing interoperability fall into three categories: technical, informational, and organizational. The organizational categories emphasize the pragmatic aspects of interoperation. They represent the policy and business drivers for interactions. The informational categories emphasize the semantic aspects of interoperation. They focus on what information is being exchanged and its meaning. The technical categories emphasize the syntax or format of the information. They focus on how information is represented within a message exchange and on the communication medium.

Figure 2-7 depicts these categories of interoperability. The framework pertains to an electricity plus information infrastructure. At the organizational layers, the pragmatic drivers revolve around the management of electricity. At the technical layers, the communications network and syntax issues are information technology oriented. In the middle, we transform information technology into knowledge that supports the organization aspects of the electricity-related business. The material in the *GridWise Interoperability Context-Setting Framework* describes each subcategory. Each layer typically depends upon, and is enabled by, the layer below it. The KCP&L SmartGrid Demonstration Project will focus on the four (4) lower layers of the GWAC Stack as anchor points for the interoperability testing and demonstration.

Figure 2-7: GridWise Interoperability Framework



2.2.4.2 Methods and Models

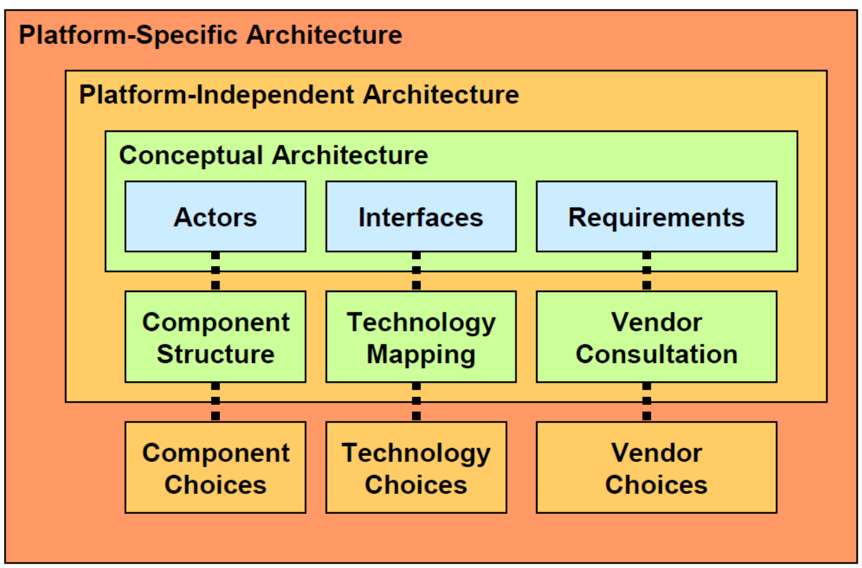
As a member of EPRI's five-year Smart Grid demonstration project, our system integration and interoperability requirements definition and design will also be coordinated through EPRI's formalized smart grid demonstration project. We will leverage EPRI's IntelliGridSM methodology to support the technical foundation for a smart power grid that links electricity with communications and computer control. The IntelliGridSM Architecture is an open-standard, requirements-based approach for integrating data networks and equipment that enables interoperability between products and systems.

2.2.4.2.1 EPRI Intelligrid Methodology [5]

EPRI's IntelliGrid^{SM} methodology provides tools and recommendations for standards and technologies when implementing systems such as advanced metering, distribution automation, and demand response and also provides an independent, unbiased approach for testing technologies and vendor products. The IntelliGrid^{SM} methodology was developed at EPRI over a six year period and turned over to the International Electrotechnical Commission (IEC). EPRI has applied this methodology to help a number of utilities (FirstEnergy, Salt River Project, Alliant Energy, Duke Energy, Southern Company, and TVA) with specific roadmaps for smart grid development and deployment in addition to working with industry members of the IntelliGrid^{SM} research program to continually advance the interoperability standards and methods for the industry.

The IntelliGrid^{SM} methodology starts with a conceptual architecture and then moves to development of a platform-independent architecture that provides a basis for integrating actual applications. The ultimate goal is architecture with vendor specific aspects with the ability to plug-in many different vendor applications as a result of industry standard interfaces. Legacy systems and technology is integrated via appropriate gateways and translators. Figure 2-8 illustrates the concept of designing an architecture that starts with a conceptual architecture and then moves to development of a platform-independent architecture that provides a basis for integrating actual applications. The requirements developed in this project help provide the basis for the architecture design. For instance, the architecture should support new technologies like substation video and infrared camera data.

Figure 2-8: IntelliGrid^{SM} Architecture Definition Evolution



IntelliGrid^{SM} methodology defines an Environment as a logical grouping of power system requirements that could be addressed by a similar set of distributed computing technologies. Within a particular environment, the information exchanges used to perform power system operational functions have very similar architectural requirements, including their:

- Configuration requirements
- Quality of service requirements
- Security requirements

- Data management requirements

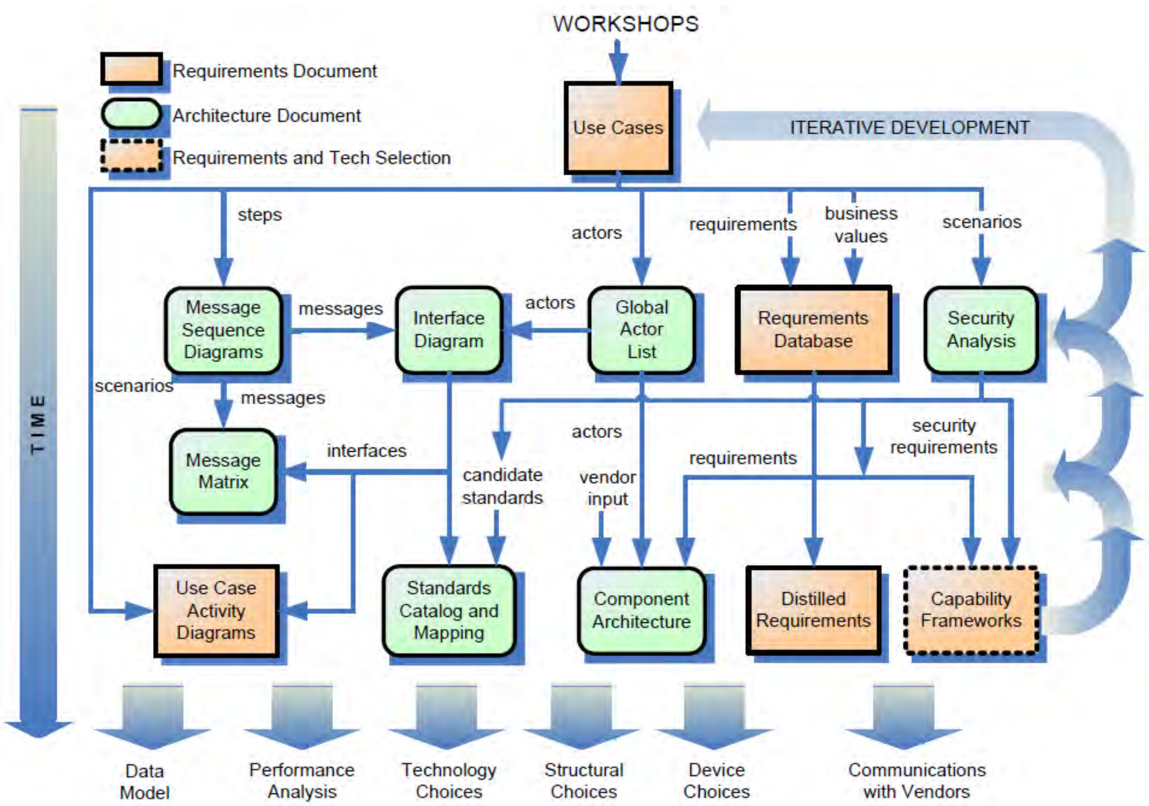
The IntelliGrid^{SM} methodology results in both a plan for the integrated information infrastructure and a study of the requirements and principles required to make particular automation projects work. In basic terms, the IntelliGrid^{SM} architecture is a set of high level concepts that are used to design a technology independent architecture as well as identify and recommend standard technologies, and best practices. These high level concepts include:

- The use of object models and modeling services to give standardized names to data, and to describe their relationships, formats, and interactions in standardized ways
- The development of security policies and the implementation of security technologies where needed, not only to prevent security attacks and inadvertent mistakes, but also to handle recovery from inevitable failures
- The inclusion of network and system management to monitor and control the information infrastructure in a manner similar to the monitoring and control of the power system
- Reduction in stranded assets from systems that can integrate
- Ability to incrementally build upon first steps; and then scale up massively
- Reduced development costs by building on components of IntelliGrid^{SM} architecture systems engineering
- Robustness achieved from structured approaches to systems management
- Architecture is necessary to consistently and adequately secure the energy industry

The Smart Grid infrastructure is defined by the applications and technologies that are built on it. This is at the heart of the “Use Case process” that is used to define the requirements for the Smart Grid. Use Cases define the applications in a way that can be used to determine the specific requirements for communications infrastructure, new technologies, and information integration. From the Use Cases, thorough and effective test plans may be developed as described in Figure 2-9.

The results of the Use Case analysis will be compared against the existing and emerging technologies, standards and best practices of the industry. The focus will be on what technologies best enable building the new architecture on top of what exists now and what will emerge in the future. The recommended technologies, standards and best practices pertaining to the creation, storage, exchange and usage of various forms of power system information will be evaluated and rated.

Figure 2-9: IntelliGrid[SM] Use Case Driven Interoperability Test Plan Development Process



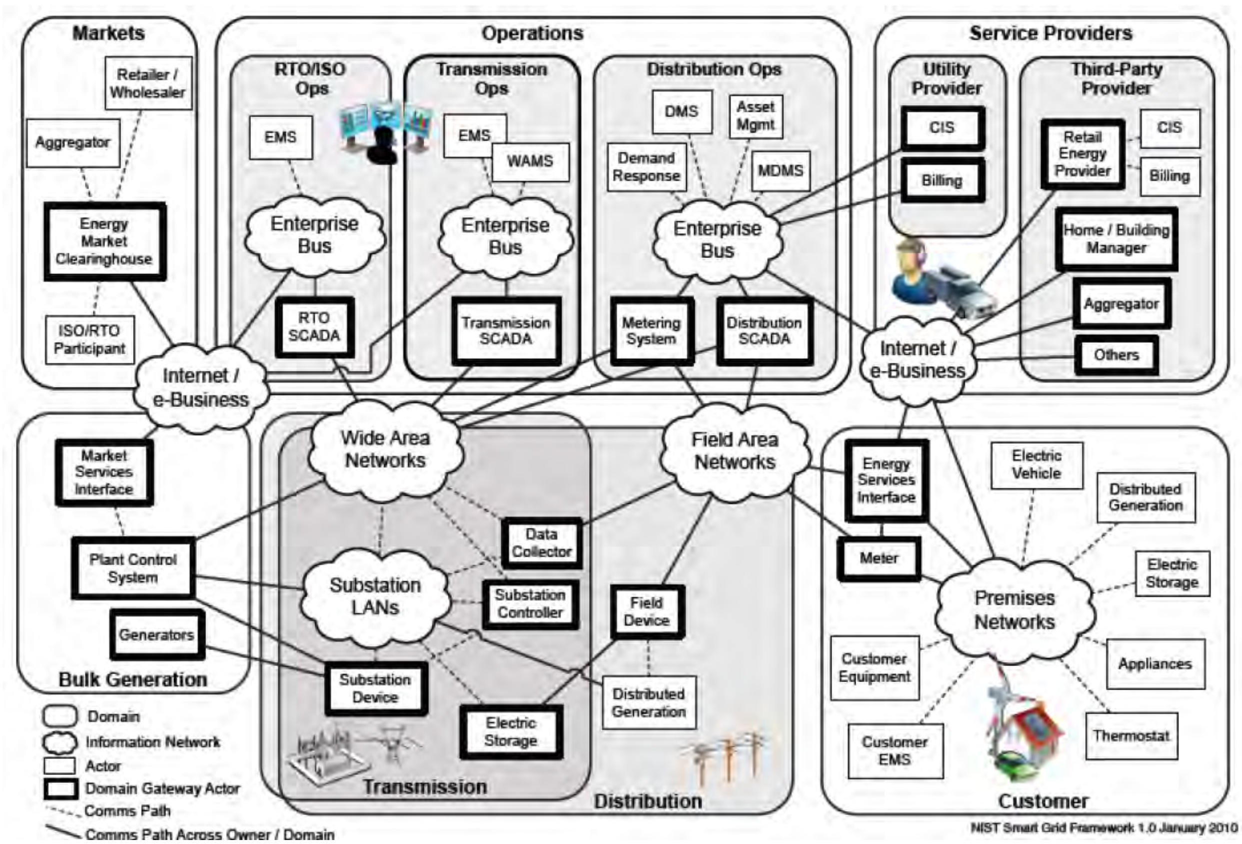
2.2.4.2.2 NIST SmartGrid Interface Reference Model [3]

The Smart Grid is a complex system of systems for which a common understanding of its major building blocks and how they interrelate must be broadly shared. The Smart Grid will ultimately require hundreds of standards, specifications, and requirements. Some are needed more urgently than others. To prioritize its work, NIST chose to focus initially on standards needed to address the priorities identified in the Federal Energy Regulatory Commission (FERC) Policy Statement, plus additional areas identified by NIST. The eight priority areas were:

- Demand Response and Consumer Energy Efficiency
- Wide-Area Situational Awareness
- Energy Storage
- Electric Transportation
- Advanced Metering Infrastructure
- Distribution Grid Management
- Cyber Security
- Network Communications

NIST, with the assistance of EPRI and using the IntelliGrid[SM] methodology, developed a conceptual architectural reference model illustrated in Figure 2-10 to facilitate this shared view. This model identifies interfaces among domains and actors. The model provides a means to analyze Use Cases, identify interfaces for which interoperability standards are needed, and facilitate development of a cyber security strategy.

Figure 2-10: NIST Smart Grid Logical Interface Reference Model



2.2.4.2.3 NIST/SGIP Smart Grid Cyber Security Logical Reference Model [6]

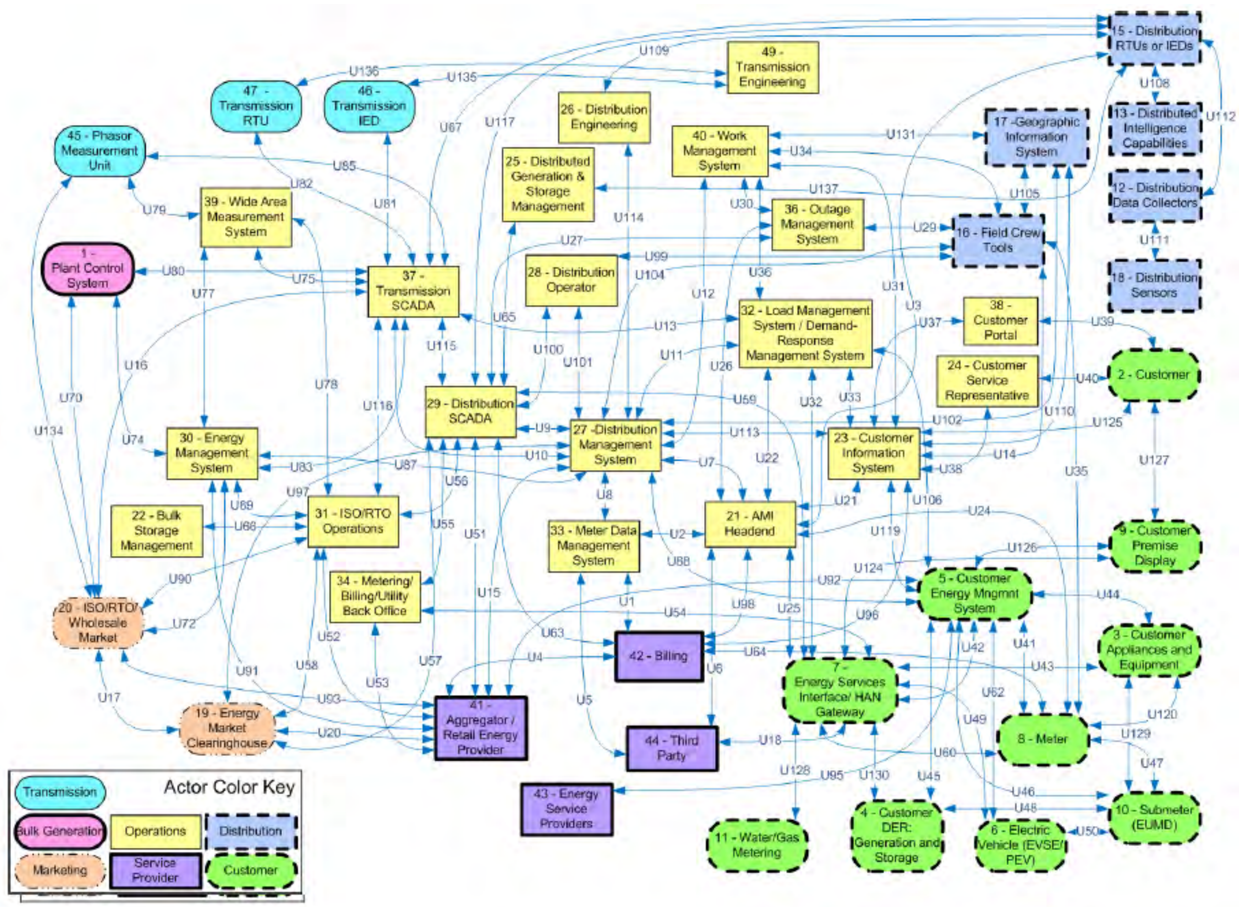
The SGIP Cyber Security Working group developed a logical reference model of the Smart Grid, including all the major domains—service providers, customer, transmission, distribution, bulk generation, markets, and operations—that are part of the NIST conceptual model. In the future, the NIST conceptual model and the logical reference model included in this report will be used by the SGIP Architecture Committee (SGAC) to develop a single Smart Grid architecture that will be used by the CSWG to revise the logical security architecture included in this report.

Communications among actors in the same domain may have similar characteristics and requirements. Domains may contain subdomains. An actor is a device, computer system, software program, or the individual or organization that participates in the Smart Grid. Actors have the capability to make decisions and to exchange information with other actors. Organizations may have actors in more than one domain. The actors illustrated in this case are representative examples and do not encompass all the actors in the Smart Grid. Each of the actors may exist in several different varieties and may contain many other actors within them.

The logical reference model represents a blending of the initial set of Use Cases, requirements that were developed at the NIST Smart Grid workshops, the initial NIST Smart Grid Interoperability Roadmap, and the logical interface diagrams for the six FERC and NIST priority areas: electric transportation, electric storage, advanced metering infrastructure (AMI), wide area situational awareness (WASA), distribution grid management, and customer premises.

The logical reference model is a work in progress and will be subject to revision and further development. Additional underlying detail as well as additional Smart Grid functions will be needed to enable more detailed analysis of required security functions. Figure 2-11 illustrates, at a high level, the diversity of systems as well as a first representation of associations between systems and components of the Smart Grid.

Figure 2-11: NIST Smart Grid Cyber Security Logical Reference Model



2.2.4.3 Requirements

Requirements define what the Smart Grid is and does. Requirements that drive and specify the functions and how they are applied are foundational to the realization of the Smart Grid. The following are some of the key characteristics of effective requirements:

- Industry policies and rules of governance are well developed, mature, and can be consistently applied
- Requirements are well-developed by domain experts and well documented following mature systems-engineering principles
- Requirements define support for applications and are well developed enough to support their management and cyber security as well

2.2.4.3.1 KCP&L Application Use Cases

The Use Case process is a mature, industry-accepted practice for describing system behavior as requests are made from it. Use Cases provide a "who does what in what order" analysis. Use Cases are a means to an end, in that they drive requirements which are rational, comprehensive, and defensible.

The IntelliGrid℠ methodology assists in developing Use Cases in a systematic manner, all with the goal of identifying and documenting all significant requirements.

The steps to define a Use Case include:

1. **Review the Scope of the Use Case.** Identify known assumptions, constraints, and business rules for the Use Case.
2. **List the Actors.** What goals do they want to accomplish? What information will they generate/consume?
3. **Identify the Scenario Pre-Conditions and Assumptions.** What must happen before the scenario can start? What conditions can we assume to exist, or be true, at the start of the scenario?
4. **Identify the Scenario Post-Conditions.** What must happen after the scenario is complete? What is the observable state or status after the implementation of the Use Case?
5. **Identify the Steps for the Scenario.** As each step is defined, identify requirements for that step to occur.
6. **Define Information Exchanged and Requirements for the Steps.** What information is exchanged and between who? What is required for the step to occur (Functional)? What type of targets, behavior, performance measures must be reached for that requirement (Nonfunctional)?
7. **Identify Alternate Scenarios.** What happens when things go wrong?
8. **Check if We're Done.** Did the primary actor reach its goal?

The KCP&L SmartGrid Demonstration Project team has identified more than 90 use cases to cover the breadth of the KCP&L SmartGrid demonstration project. The use cases have been organized into the following groupings:

- Network Communications
- Automated Meter Information
- Meter Data Management
- Home Area Network Administration
- SmartEnd-Use
- Demand Response Management (DRM)
- Distribution Substation Automation
- First Responder
- DMS—SmartDistribution
- Pluggable Electric Vehicle Charging

The identified Use Cases are by no means a comprehensive listing of Smart Grid Use Cases. As the Smart Grid develops, additional Use Cases will be needed to support new and evolving functions and technologies. KCP&L fully expects that this listing of Use Cases will change slightly through the detailed project design process.

The KCP&L project team acknowledges the prior works of many individuals that form the basis of the Use Cases developed specifically for our project. Prior works by EPRI, SCE, AEP, and the OpenHAN organization provided a foundation for the majority of this work product.

2.2.4.3.2 Industry Requirement Profiles

Detailed requirements will be determined by using the method and models mentioned in the preceding section, analyzing KCP&L's business objectives for the demonstration, and using the following industry reference documents:

- NIST NISTR 7628 – Smart Grid Cyber Security Strategy and Requirements
- UtilityAMI AMI Enterprise System Requirements Specification v1.0
- UCAIug (ASAP-SG) Security Profile for Distribution Management (draft)
- UCAIug (ASAP-SG) Security Profile for Third Party Data Access (draft)
- UCAIug (ASAP-SG) Security Profile for Advanced Metering Infrastructure v2.0
- UCAIug (OpenHAN) Home Area Network System Requirements Specification v2.0

2.2.4.4 Architecture and Design [7]

It is difficult for organizations and industries to change. Many strategic initiatives end in failure because the required changes are viewed in isolation rather than in relation to the complete infrastructure. When building reference model architectures, there are three key architecture types:

- Conceptual – Services (e.g. Outage Detection Service)
- Logical – Components (e.g. Outage Management System)
- Physical – Implementations (e.g. CES OMS)

Developing a conceptual SmartGrid architecture model based on goals and requirements will further enhance an organization's ability to be effective in the implementation of core strategy and vision.

The National Institute of Standards and Technology (NIST) Smart Grid Interoperability Panel (SGIP) Smart Grid Architecture Committee (SGAC) is responsible for creating and refining a Smart Grid conceptual architecture reference model. On July 16, 2010, the SGAC approved a plan to develop a generic Smart Grid conceptual architecture by January 2011. The process for developing a generic Smart Grid conceptual architecture will be based on three key process tasks:

- Developing grid architecture goals from national energy goals and national policy documents
- Developing a formalized list of requirements relating to and mapped to each of the accepted grid architecture goals

- Developing a list of energy services based on the list of accepted requirements

The final deliverable of a generic Smart Grid conceptual architecture will allow grid participants to develop their own internal logical and physical architectures.

The systems architecture and designs developed for the KCP&L SmartGrid Demonstration Project will satisfy the requirements developed through the processes outlined in the preceding section. It will leverage existing industry reference architectures and architectural artifacts, such as those developed by GWAC, NIST, and UCAIug.

The demonstration project architecture and systems design will also leverage the IEC 61968 series for Application Integration at Electric Utilities, the IEC 61850 series for Communication Networks and Systems in Substations, and other emerging standards discussed in the next section.

The KCP&L project team is participating in the NIST/SGIP sponsored SmartGrid Conceptual Architecture Model development effort and as this architectural reference emerges, it will be considered for adoption into the KCP&L SmartGrid Demonstration Project system architecture.

2.2.4.5 Standards

This SmartGrid Demonstration Project architecture and standards to be implemented are closely aligned with the *NIST Special Publication 1108 - NIST Framework and Roadmap for Smart Grid Interoperability Standards*. This document identifies guiding principles for the adoption of standards for the Smart Grid and the Smart Grid domains to which interfaces and standards apply. It also identifies standards for consideration and incorporation into Smart Grid architectures and solution designs.

Additionally, in the NIST Framework, NIST recommends some criteria for adoption of standards. Generally, these involve openness and accessibility. NIST believes that Smart Grid interoperability standards should be open. The term “open” standard as used by NIST means that a standard is “developed and maintained through a collaborative, consensus-driven process that is open to participation by all relevant and materially affected parties and not dominated or under the control of a single organization or group of organizations, and readily and reasonably available to all for Smart Grid applications”. In addition, NIST states that Smart Grid interoperability standards should be developed and implemented internationally, wherever practical. Figure 2-12 summarizes the NIST criteria for standards adoption to achieve interoperability which have been adopted by KCP&L.

Figure 2-12: NIST Guiding Principles for Identifying Standards for Implementation

For *Release 2.0*, a standard, specification, or guideline is evaluated on whether it:

- Is well-established and widely acknowledged as important to the Smart Grid.
- Is an open, stable, and mature industry-level standard developed in a consensus process from a standards development organization (SDO).
- Enables the transition of the legacy power grid to the Smart Grid.
- Has, or is expected to have, significant implementations, adoption, and use.
- Is supported by an SDO or standards- or specification-setting organization (SSO) such as a users group to ensure that it is regularly revised and improved to meet changing requirements and that there is a strategy for continued relevance.
- Is developed and adopted internationally, wherever practical.
- Is integrated and harmonized, or there is a plan to integrate and harmonize it with complementing standards across the utility enterprise through the use of an industry architecture that documents key points of interoperability and interfaces.
- Enables one or more of the framework characteristics as defined by EISA[*] or enables one or more of the six chief characteristics of the envisioned Smart Grid.[†]
- Addresses, or is likely to address, anticipated Smart Grid requirements identified through the NIST workshops and other stakeholder engagement.
- Is applicable to one of the priority areas identified by FERC[‡] and NIST:
  - Demand Response and Consumer Energy Efficiency;
  - Wide Area Situational Awareness;
  - Electric Storage;
  - Electric Transportation;
  - Advanced Metering Infrastructure;
  - Distribution Grid Management;
  - Cybersecurity; and
  - Network Communications.
- Focuses on the semantic understanding layer of the GWAC stack,[*] which has been identified as most critical to Smart Grid interoperability.
- Is openly available under fair, reasonable, and non-discriminatory terms.
- Has associated conformance tests or a strategy for achieving them.
- Accommodates legacy implementations.
- Allows for additional functionality and innovation through:
  - *Symmetry* – facilitates bidirectional flows of energy and information.
  - *Transparency* – supports a transparent and auditable chain of transactions.
  - *Composition* – facilitates building of complex interfaces from simpler ones.
  - *Extensibility* – enables adding new functions or modifying existing ones.
  - *Loose coupling* – helps to create a flexible platform that can support valid bilateral and multilateral transactions without elaborate prearrangement.**
  - *Layered systems* – separates functions, with each layer providing services to the layer above and receiving services from the layer below.
  - *Shallow integration* – does not require detailed mutual information to interact with other managed or configured components.

* GridWise Architecture Council, GridWise Interoperability Context-Setting Framework, March 2008.

** While loose coupling is desirable for general applications, tight coupling often will be required for critical infrastructure controls.

2.2.5 Summary

This section presents a strategy, approach, models and methods for achieving interoperability between components of the KCP&L SmartGrid Demonstration Project. Although the focus of this document has been on technical aspects of interoperability, the organizational and informational aspects of the model are also being addressed both in the context of the demonstration and the future integration with business processes and objectives.

Adoption of the applicable standards, and the other aspects of the frameworks described in this document will ensure that interoperability is appropriately aligned with business objectives including integration with other market participants.

Additionally, not all standards considered may ultimately be adopted. However, each will be considered for adoption along with other emerging standards and guidelines using the structured approach outlined in this document and incorporated into vendor agreements and procurement language as appropriate. Adopting the NIST and GWAC Interoperability frameworks, along with the EPRI methods, will ensure that interoperability is a primary consideration throughout the lifecycle of the KCP&L SmartGrid solution, and that the appropriate artifacts are documented.

2.3 Cyber Security Strategy & Plan [8]

The KCP&L project team developed and published a "SmartGrid Cyber Security Plan" that detailed a strategy and approach for implementing cyber security in the KCP&L SmartGrid Demonstration Project (SGDP). The following subsections provide an overview of the significant elements of the cyber security plan developed for the project.

The cyber security strategy and approach is intended to have broad applicability beyond the SGDP including future development of the portions of the SGDP that ultimately extend into production systems.

The terms 'cyber security' and 'cyber infrastructure' are used throughout this document. The following definitions are used in the U.S. National Infrastructure Protection Plan (NIPP) and are included to ensure a common understanding:

- **Cyber Security:** The protection required to ensure confidentiality, integrity and availability of the electronic information communication system
- **Cyber Infrastructure:** Includes electronic information and communications systems and services and the information contained in these systems and services. Information and communications systems and services are composed of all hardware and software that process, store, and communicate information, or any combination of all of these elements. Processing includes the creation, access, modification, and destruction of information. Storage includes paper, magnetic, electronic, and all other media types. Communications include sharing and distribution of information. For example, computer systems, control systems (e.g., SCADA), networks, including the Internet and cyber services (e.g., managed security services), are all part of cyber infrastructure.

2.3.1 Smart Grid Cyber Security Trends & Challenges

Cyber security for the electric grid is evolving in response to several accelerating trends:

- Increasing scrutiny of regulators, customers, shareholders and external entities due to a heightened awareness of the potential for a catastrophic failure or attack on the nation's critical infrastructure
- Emerging threats to the security of the grid by terrorist nation-states, countries and criminal organizations who may target the electric grid with increasingly sophisticated methods of attack
- Increasing dependence on "smart" networked, IP-enabled devices to monitor and control the grid and decreasing reliance on serial devices communicating over closed networks
- Moving from proprietary systems requiring special expertise known only to a few individuals with specialized skills towards cost and efficiency advantages gained through the use of open operating systems, application platforms and communications protocols

- Increasing use of efficiencies to be gained through using wireless communication and public communications networks, often using non-proprietary technologies and protocols
- Increasing the degree of the distributed electric grid within generation and markets, and the evolution of domains such as distributed generation assets that are not under the direct ownership and control of the utility

The factors noted above contribute to several challenges when considering an approach to securing the grid:

- Cyber security mechanisms must be employed throughout the system life cycle and end-to-end to secure all of the potential attack points in the grid. These attack points are increasing in number. Also, the risk of compromise has increased due to both intentional and unintentional traditional IT-oriented threats, which increasingly have the potential to affect control systems within the grid.
- Reliability and availability of the grid remain primary considerations, and security controls must not degrade grid reliability and availability.
- Utilities, vendors and standards bodies have been slow to respond to security challenges and incorporate cyber security mechanisms into their products, partially because of these challenges, shifting business requirements and changing regulatory landscapes.
- Mechanisms to detect anomalous behavior within the grid indicating that a cyber attack on control systems is underway are immature, and some standard operating procedures and disaster scenarios do not adequately account for responses to cyber events.

2.3.2 Cyber Security Strategy & Approach

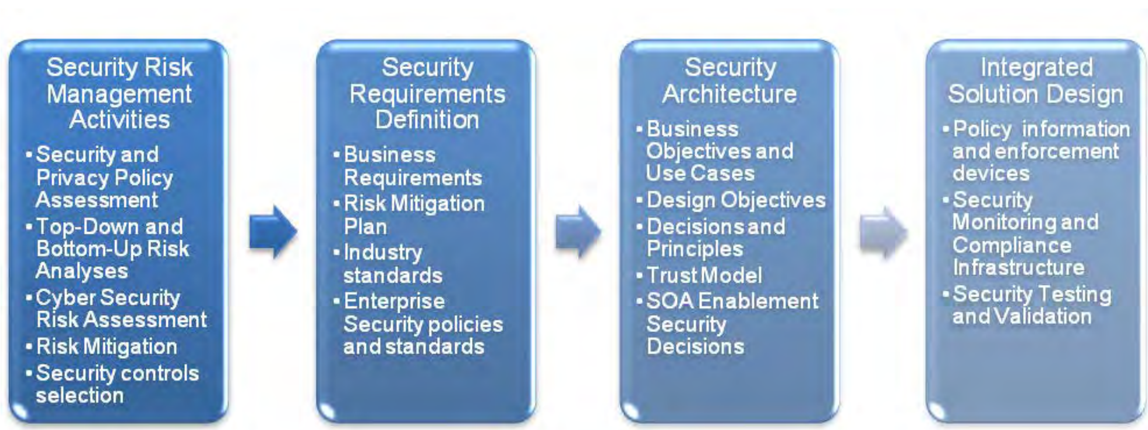
The challenges outlined in the preceding section will be met through the development of a cyber security controls framework, design, architecture, and infrastructure that ensures that technologies, polices, processes and procedures result in adherence to existing cyber security regulations, evolving Smart Grid security requirements and KCP&L's business requirements. This will be accomplished by adoption of the NIST/EPRI security framework (NIST SP 1108R2: NIST Framework and Roadmap for Smart Grid Interoperability Standards Release 2.0 February 2012 and NISTIR-7628: Guidelines for Smart Grid Cyber Security – August 2010) and other frameworks, subject to KCP&L's business requirements and SGDP budget considerations. Implementing the controls identified in the framework consists of the following activities to provide end-to-end security:

- Perform a comprehensive risk assessment [9] and adopt a risk management strategy to ensure risk-based decision making throughout the system's life cycle
  - Categorize the interfaces according to the framework (i.e., the types of domains that are involved in particular use cases)
  - Identify and analyze all logical interfaces to determine the risks to confidentiality, integrity and availability exposed through them

- Determine cyber security requirements
- Select appropriate controls and technical countermeasures to mitigate the risks and rationalize these in a cyber security architecture
- Develop and deploy a cyber security governance, risk management and compliance process and tools tailored for the KCP&L operations environment and project budget
- Implement the countermeasures and controls, leveraging existing cyber security infrastructure capabilities to the extent possible according to an integrated secure systems design
- Test and validate whether the deployed cyber security infrastructure is providing the expected security assurance
- Develop plans to remediate cyber security gaps and address residual risks
- Develop and implement cyber security criteria in procurement language and device vendor selection in accordance with best practices
- Monitor the ongoing development of Smart Grid cyber security standards and requirements for incorporation into KCP&L's strategic plans

The overall cyber security strategy examines both domain-specific and common requirements when developing a mitigation strategy to ensure interoperability of solutions across different parts of the infrastructure. Implementation of a cyber security strategy requires the development of an overall cyber security risk management framework for the Smart Grid. This framework is based on existing risk management approaches developed by KCP&L and other best practice organizations.

Figure 2-13: KCP&L SmartGrid Security Strategy and Approach

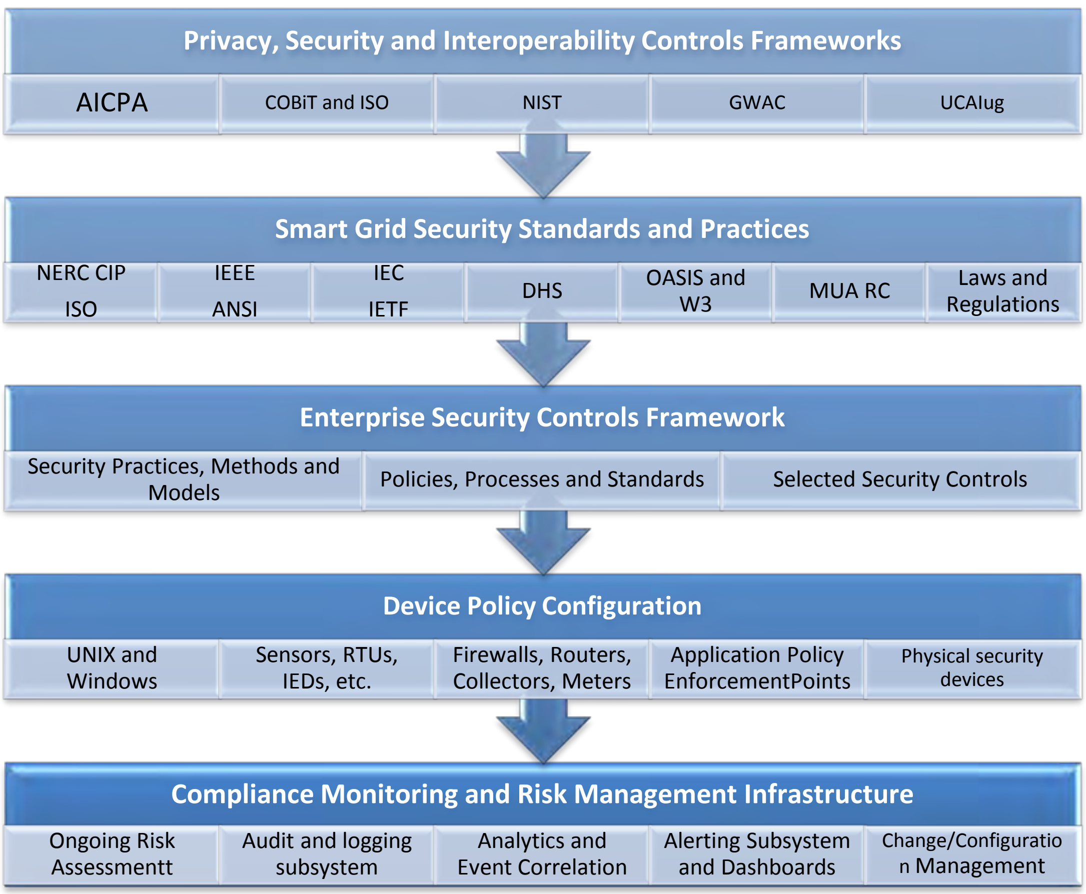


This risk-driven approach to cyber security, depicted in Figure 2-13 above, along with architectural discipline imposed through governance and compliance assessment frameworks will ensure that security expenditures are aligned with business objectives and project budgets. In conjunction with the cyber security architecture, security design objectives will be identified for authentication, access control, logging and auditing, data confidentiality, data integrity and non-repudiation, Service-Oriented Architecture (SOA) and messaging security.

Once the conceptual architecture is completed, high-level and detailed designs will be completed for the cyber security infrastructure. The designs will be documented, refined and validated against the architecture through use cases and scenarios. The risk assessment will be updated if new risks are discovered and additional controls and countermeasures will be deployed using risk mitigation methods within the risk management process.

Well-defined processes, methods, and software solutions are designed to assist and automate the implementation of risk and compliance management processes. Therefore, the solution involves identifying and customizing tools to meet the specific requirements of KCP&L and integrating these tools and methods into a comprehensive solution applicable to the operations environment. The infrastructure will be deployed in a manner consistent with the Government, Risk, and Compliance (GRC) framework shown in Figure 2-14.

Figure 2-14: KCP&L GRC Management Framework



2.3.3 Smart Grid Cyber Security Design Considerations

2.3.3.1 Cyber Security Standards

In addition to being required by regulatory and compliance audit agencies, security policies, procedures and guidelines form the basis of a risk management program. They express management's intent with regard to the cyber security program and compliance with applicable laws and regulations, assign roles and responsibilities and define who is accountable for cyber security activities. The increasing interoperability of traditional IT systems and control systems, along with increased scrutiny of security controls by external agencies, makes the establishment and maintenance of a standards-based cyber security policy framework an essential component of the security program.

KCP&L has a policy framework that aligns security policies to IT and business policies. These policies will be analyzed for their relevance to the Smart Grid. Cyber security policies applicable to the operations environment will be reviewed and updated to reflect the requirements of Smart Grid operations and compliance with emerging standards. Gaps in the policy framework will be identified and policies that are consistent with enterprise policies will be created to address those gaps when appropriate.

The standards and frameworks listed in Table 2-2 and Table 2-3 are relevant to Smart Grid cyber security best practices with particular emphasis on:

- NERC - Critical Infrastructure Protection (CIP) Version 3.0
- NISTIR-7628 Guidelines for Smart Grid Cyber Security – August 2010

Controls implementing these standards where required or where warranted based on best practices from other evolving Smart Grid standards will be expressed in cyber security policies, procedures and guidelines as appropriate. Compliance will be assessed through use of the GRC framework. The framework will ensure that:

- policies, procedures and guidelines will be documented in a central repository
- the policy maintenance life cycle will include regular review and incorporation of relevant standards
- compliance is assessed periodically
- exceptions will be documented and associated workflows created
- audit readiness is maintained

Table 2-2: Summary of Applicable Cyber Security Standards

Standards	Description	Date
NISTIR-7628	Guidelines for Smart Grid Cyber Security	August 2010
NERC - CIP	Critical Infrastructure Protection (CIP) v3.0	Various
NIST SP 800-30	Risk Management Guide for Information Technology Systems v1.0	September 2012
NIST SP 800-53	Recommended Security Controls for Federal Information Systems and Organizations v3.0	May 2010

Table 2-3: Summary of Applicable Cyber Security Frameworks

Frameworks	Description	Date
NIST SP 1108R2	NIST Framework and Roadmap for Smart Grid Interoperability Standards Release 2.0	February 2012
UCAIug	Security Profile for AMI v2.1	October 2012
UCAIug	Security Profile for DMS v1.0	February 2012
UCAIug	Security Profile for OpenADR v0.03	March 2012
UCAIug	Security Profile for Substation Automation v0.15	September 2012

2.3.3.2 Risk Management

The KCP&L risk management framework defines the processes for combining impact, vulnerability, and threat information to produce an assessment of risk to the KCP&L SmartGrid and to its domains and sub-domains, such as businesses and customer premises. Risk is the potential for an unwanted outcome resulting from an incident, event, or occurrence, as determined by its likelihood and the associated impacts. Because the Smart Grid includes systems and components from the IT, telecommunications, and energy sectors, the risk management framework will be applied on an asset, system, and network basis, as applicable. The goal is to ensure that a comprehensive assessment of the systems and components of the KCP&L SGDP is completed. The framework will make use of the NIST/EPRI cyber security framework as a reference construct to ensure that applicable requirements are incorporated.

The risks of operating a system cannot be completely eliminated. After the implementation of controls, residual risks will be tracked and subject to the further assessment activities to determine methods of reducing the residual risk to acceptable levels. The risk assessment is used as input into the KCP&L Risk Management Process, which includes methods and activities that result in risk mitigation or acceptance. The Risk Management Process is depicted in Figure 2-15 below.

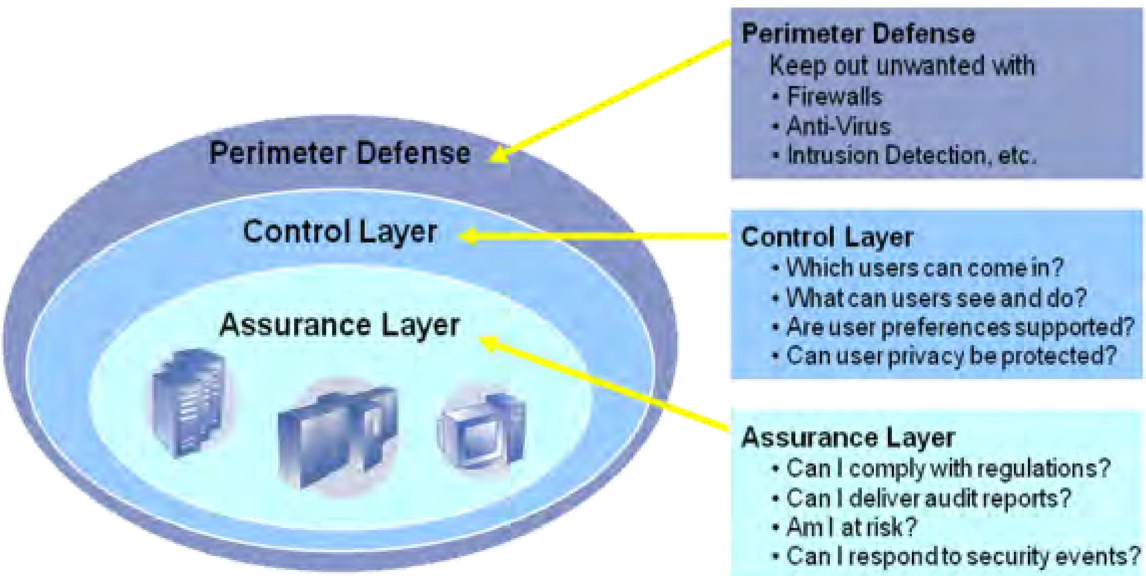
Figure 2-15: KCP&L Risk Management Process

Following the risk assessment, the next step is to select and tailor the cyber security and business requirements. These requirements will drive a security architecture, which will be integrated with the systems architecture, NIST and other industry reference architectures. Integration with the NIST/EPRI reference architecture [3] [10] and other security standards will help ensure interoperability of components.

2.3.3.3 Defense in Depth

Defense in depth is the layering of security controls in such a way that the damage of an exploit is minimized. An attacker must circumvent multiple controls to exploit vulnerabilities or gain unauthorized access. Security mechanisms are also layered in such a way as to limit the damage resulting from a compromise. A medieval castle with its moats, walls and other defenses is an example of a defense in depth security stance. A well-defended castle does not rely on a single defense to protect the most valuable assets, but on multiple layers. The security architecture, as illustrated in Figure 2-16 below provides for layers of security to form a defense in depth cyber security posture.

Figure 2-16: KCP&L *Defense in Depth* Security Posture



The architecture may include the following components to achieve a layered defense that complies with laws and regulations and meets KCP&L's business and budget requirements:

Perimeter Security:

- Protocol-level firewalls
- Intrusion detection (network and host-based)
- Application-level firewalls
- Wireless and endpoint security
- Physical security of cyber assets

Control Layer:

- Identity and access management
- Application security
- Compliance monitoring

Assurance Layer:

- Cyber security governance, risk and compliance management
- Cyber security policy development
- Cyber security testing
- Cyber security incident response

2.3.3.4 Trust Model

One important aspect of the Smart Grid that has not been sufficiently addressed by the industry is the development of a trust model for the Smart Grid. This section describes the method that KCP&L will use to develop a solution architecture that implements a trustworthy design.

Trust is defined as the measure of confidence that can be placed in the predictable occurrence of an anticipated event or an expected outcome of a process or activity. For business activities that rely on IT, trust is dependent on both the nature of the agreement between the participants and the correct and reliable operation of the IT solution.

An objective of a trust model for the KCP&L SGDP is to implement mechanisms and strategies for trustworthiness of systems protecting the confidentiality, integrity and availability of information between actors (requesters and consumers of information) and domains by ensuring accountability for actions. In a distributed information system, the ultimate concern of a trust model should be the information itself, rather than the sources that supply the information. A good trust model facilitates this type of interaction without hindering the more traditional approach to trustworthiness – i.e., interacting only with trusted sources of information.

The implementation of a trust model for the Smart Grid has many complex dimensions:

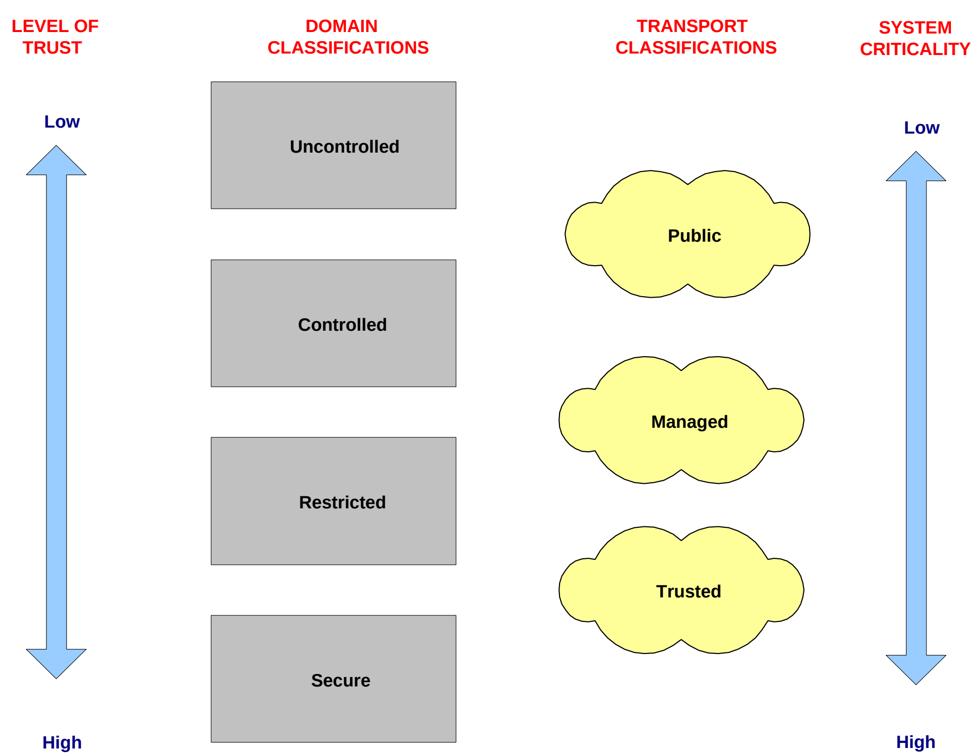
- Control systems with interfaces between them are often in different organizations, and therefore, the chain of trust between them is more important
- By definition, market operations are across organizational boundaries, thus posing trust issues
- The implementation of a model that enables network and systems architecture and facilitates effective communication among the various business entities without inadvertent or unauthorized sharing of trade secrets, business strategies or operational data and activities, while enabling sharing of fine-grained energy data and other information between organizations (and units within organizations) to realize the advantages of Smart Grid technology

- The management of large amounts of privacy-sensitive data in an efficient and responsible manner while complying with regulations regardless of the current state and location of data
- Trust of event or systems data
- Trust relationships between field devices and security policy enforcement points
- Trust within mesh networks, between leaf mesh nodes and gateways, and between mesh and non-mesh networks and interconnected mesh networks having different trust models
- The establishment of a user trust model for administration of keys, passwords and other sensitive data that does not create an undesirable amount of dependence on IT personnel and avoids an actor becoming a single point of failure

The activities undertaken using the secure architecture method will result in development of a conceptual trust model for the KCP&L SGDP.

Once the KCP&L solution architecture has been defined and mapped to the NIST framework, the architecture will be decomposed into its component domains. Figure 2-17 provides an example of semantics associated with varying trust levels of different domains and includes the security zones and the interfaces between them.

Figure 2-17: KCP&L Trust Model



Different semantics than those shown above may be used in the KCP&L SmartGrid trust model, however the process of applying the trust model will be the same. Different security levels that depend on the design of the network and systems architecture, security infrastructure and how trusted the overall system and its elements are will be assigned. This model will help put the choice of technologies and architectural decisions within a security context and guide the choice of security solutions.

One realistic expectation of the usefulness of the trust model, assured by application of this method, is that designers and integrators of IT solutions will enlist all reasonable measures to achieve the correct and reliable operation of IT solutions throughout the design, development, and deployment phases of the solution life cycle.

2.4 SmartSubstation

The Midtown SmartSubstation implementation will consist of new microprocessor based protective relays, a new substation protection and control network, Human Machine Interfaces (HMIs), substation data concentrators, substation controllers, and applications. The SmartSubstation will operate KCP&L's substation with advanced functionality to provide more reliability, efficiency, and security.

Upon completion of the SmartSubstation implementation, KCP&L will be able to demonstrate the following functions:

- Peer-to-peer communication between IEDs via IEC 61850 GOOSE messages
- Controlling the tap changer of the transformers and the smart grid feeder breakers via IEC 61850 MMS messages
- Protection of substation devices, assets and feeders
- Redundant data collection concentration in the substation
- Redundant local HMI
- Cyber security though use of firewall rules and VLANs
- Physical security through electronic access control and NERC-compliant logging tools
- Redundant TCP/IP communication between substation and DMS SCADA system
- Smart applications in the substation that operate in closed-loop mode
- Volt/Var management using tap changers and capacitor controllers
- Feeder overload management via Dynamic Voltage Control
- Fault management applications performed in conjunction with devices on the feeders (via the substation controller)
- Automated switching procedures to isolate faults on the feeders and provide service restoration
- Real-time transformer rating with oil temperature by using the transformer relay for the measurements, or an additional small I/O device built into the control cabinet of the transformer. Logic in the I/O device or the relay (PLC) will provide for the fan controls
- Relay metering including calculations for real power, reactive power, apparent power, etc.

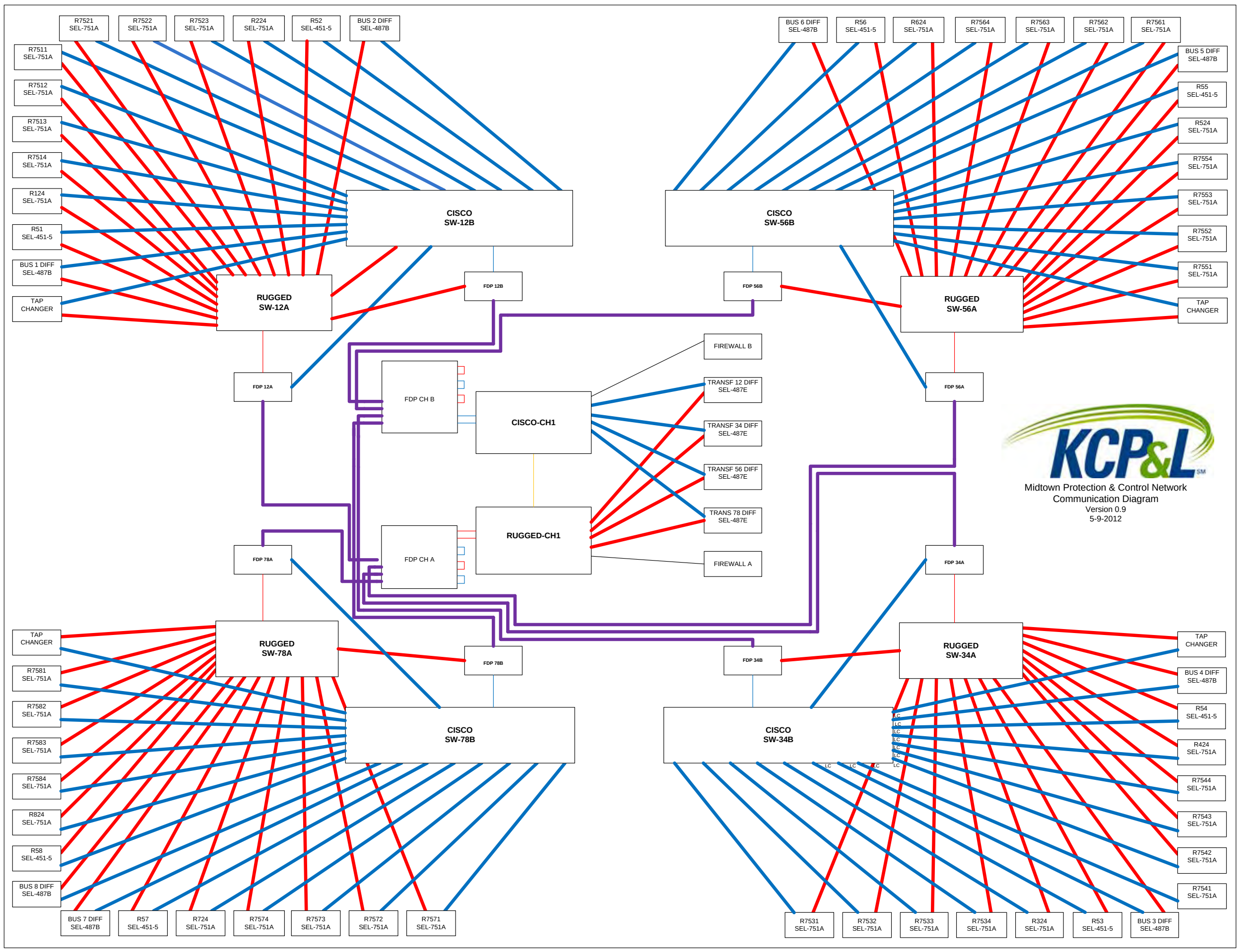
2.4.1 Substation Protection Network Upgrade

2.4.1.1 SPN Upgrade Overview

This project includes upgrades to protection and control equipment and the deployment of an Ethernet-based substation control network utilizing the IEC 61850 network architecture. This effort requires the Network Services, Substation Protection, and Relay System Protection departments of KCP&L to work together to design, provision, and operate this joint network. The IEC 61850 network should be treated like any other protection and control system, and should only be used for protection and control purposes.

The existing electromechanical relays at Midtown Substation will be replaced with new microprocessor relays (Intellegent Electronic Devices). These IEDs will have communication capabilities utilizing IEC 61850 in the protection and automation system. The IEC 61850 implementation will allow KCP&L to minimize wiring in the substation and provide automation such as interlocks through this digital system. Figure 2-18 provides an overview of the substation protection and control network that will be implemented.

Figure 2-18: SmartSubstation Protection and Control Infrastructure



2.4.1.2 SPN Upgrade Characteristics

2.4.1.2.1 Network Design [11]

Substation protection and control networks are deployed in harsh environments and transport critical data. As such, the network and its components have demanding requirements. The network must have high availability and low latency, providing fast, reliable communication between networked devices. Networking equipment deployed in these networks must be environmentally hardened, as it may be deployed in enclosures with limited climate control, requiring the equipment to operate across extreme humidity and temperature ranges. Therefore, a reliable physical architecture for the network is needed along with ruggedized, highly reliable network components.

The IEC 61850 Midtown substation control network configuration consists of redundant 1 Gbps Ethernet backbones routed throughout the substation. These backbones will interconnect remote primary and backup Ethernet switches installed in various switchgear enclosures to main Ethernet switches located in the main control enclosure. Protective relays, equipped with redundant Ethernet ports, will connect to the appropriate primary and backup remote switches using 100 Mbps Ethernet.

The Midtown Substation control network topology was chosen to achieve the following:

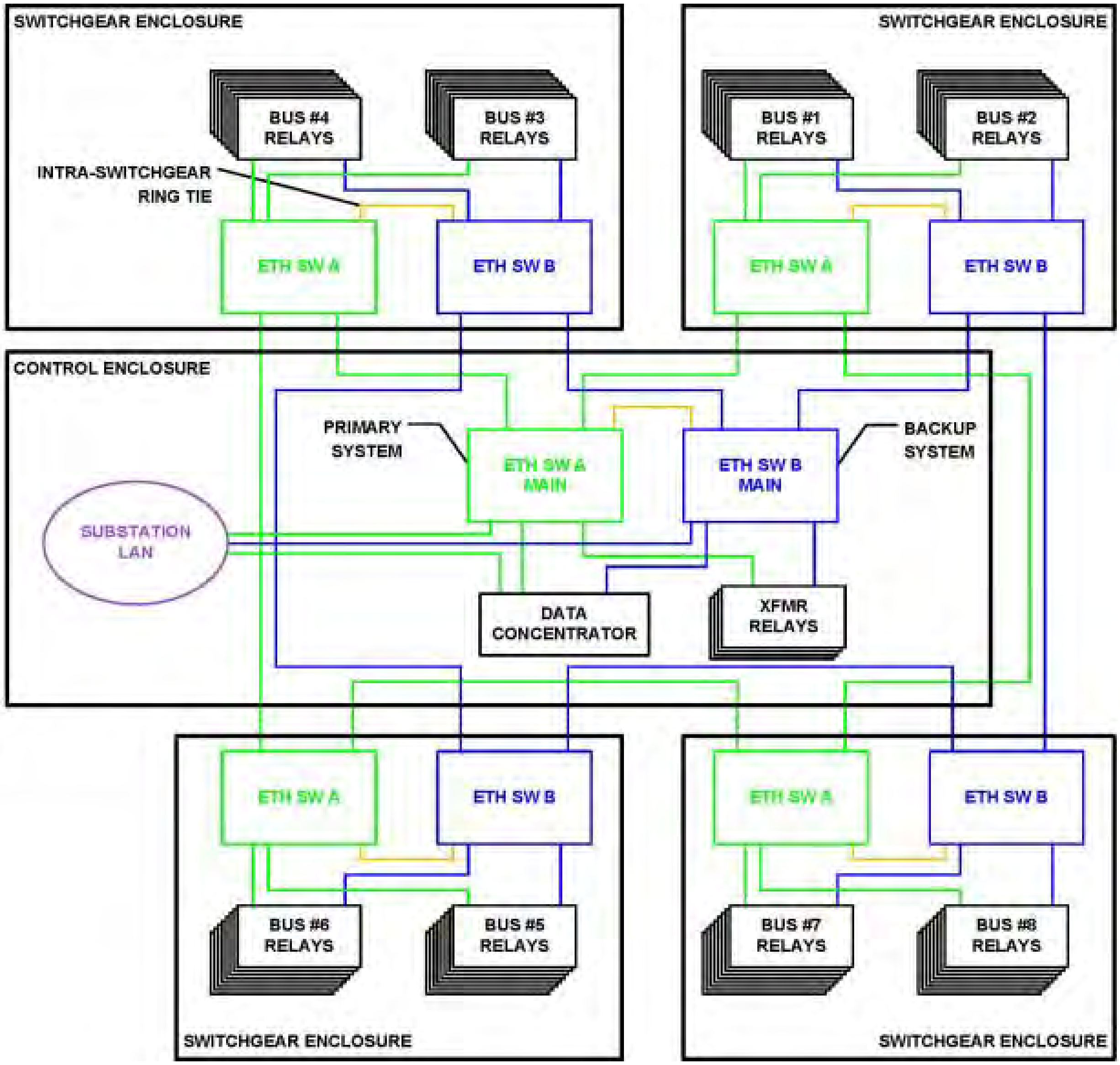
- Provide high-bandwidth, low-latency communications
- Minimize or eliminate single points of failure for cabling and equipment
- Minimize infrastructure costs

The IEC 61850 network was designed as a redundant Ethernet ring architecture. Ring architectures allow for self-healing networks, increasing availability and reliability. The Ethernet switches comprising the network are arranged in rings, providing redundant pathways between two points in the network via the Ethernet backbone. This configuration protects against loss of communication between devices due to failure of a communication link or loss of an intermediate switch. Loss of communication only occurs when there is a failure in the edge switch to which one of the two communicating devices is connected. To further increase reliability, redundant rings can be deployed. This allows devices with redundant Ethernet interfaces to take advantage of a standby Ethernet network, reducing the probability of a loss of station control due to failure of any single piece of network equipment. This redundant ring configuration eliminates single points of failure for all Ethernet hardware when the communication devices are configured in fail-over mode.

Aside from enhanced fault recovery, the additional redundancy can significantly ease maintenance of the network, as any single network device can be completely removed from service without network disruption or loss of station control. Direct connections should be made between primary and backup switches in each control enclosure, providing a local link for traffic in the event any enclosure is isolated from the rest of the network.

The Midtown substation protection and control network architecture is shown in Figure 2-19.

Figure 2-19: Midtown Substation Protection and Control Network Architecture



2.4.1.2.2 61850 MMS Report by Exception

The Distribution Data Concentrator (DDC) will communicate with the substation devices using the IEC 61850 manufacturing messaging specification (MMS). The devices will send the DDC annunciators and metering values. The DDC will send the devices control messages. Rather than implementing a typical SCADA poll, the devices will be configured to have unsolicited reporting enabled. When one point's instantaneous magnitude crosses a pre-defined deadband threshold, the device will send the DDC the magnitude of all the points in its 61850 report.

During the pilot, serial communications will be maintained to each relay from the substation remote terminal unit to support dual communications with the relays from the existing energy management system (EMS).

2.4.1.2.3 61850 GOOSE for Advance Response [12]

The substation IEDs will utilize 61850 Generic Object-Oriented Substation Event (GOOSE) messaging for peer-to-peer communications. For the demonstration project, KCP&L will be using GOOSE messaging to implement four functionalities:

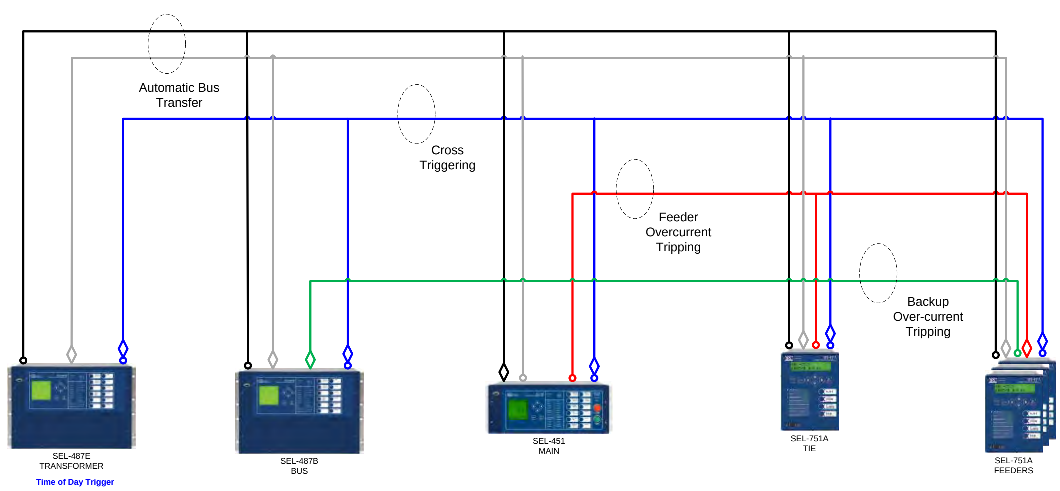
- **Load Transfer** - The load-transfer scheme restores service to customers by automatically closing the tie breaker upon lockout of the transformer. The Midtown Substation design consists of two four-position buses fed from a dual-wound distribution transformer. Tie buses are used for maintenance and emergency backup of station operations when the transformer is removed from operation. The combined load of the two buses can be above the two-hour power rating for the transformer on many of the buses. In the past, a dedicated programmable logic controller (PLC) was used at these locations to calculate the optimal feeder configuration to transfer to the tie bus before the tie breaker was closed. As part of the upgrade, KCP&L wanted this logic to be moved into the relay logic, eliminating the need for the PLC and additional wiring. This objective was achieved through the use of automation logic in a SEL-451 relay, with the real-time event notification capabilities of IEC 61850 GOOSE messaging for inter-relay communications. The feeder relays (SEL-751) were used to publish the individual feeder loads and the total tie-bus transformer load (SEL-487) using IEC 61850 GOOSE messages. The main relay (SEL-451) subscribes to these analog values along with status messages for bus lockout, which triggers the scheme. The main breaker relay continually computes and publishes the optimal feeder configuration to transfer if a fault occurs, based on each feeder's load and available capacity. When each feeder relay sees the scheme-enabled GOOSE message sent, it opens if it is to be shed before the bus tie breaker is closed. This scheme uses the two-hour overload power rating for the tie bus transformer, which gives the distribution operator two hours to reconfigure distribution feeders, thereby relieving the overload condition while continuing to provide service to customers on the affected bus.
- **Faster Overcurrent Tripping** - Implementing a communications-based breaker failure scheme instead of relying on time overcurrent values resulted in the faster overcurrent tripping of main and tie breakers upon feeder breaker failure. When a feeder breaker trips, it sends a GOOSE message to the main and tie breakers indicating an operation where a stuck breaker timer is initiated. If a follow-up breaker-open message is not received within this time, the main and tie breakers trip, thereby clearing the fault. This faster overcurrent tripping scheme and subsequent schemes reduce wear on equipment, decreasing the likelihood of equipment failure and improving customer reliability.
- **Backup Overcurrent Tripping Scheme** - Backup overcurrent protection in the bus differential relay provides redundancy to the logic, sensors and wiring in the feeder relays, allowing them to trip a feeder with a reclosing function if the feeder relay fails to detect or clear a fault. The bus differential relay uses its current circuit and sensor to monitor the feeder, and it is programmed to send a GOOSE-based trip message to the feeder relay, clearing the fault if the feeder relay has not already done so. This scheme and the previous scheme could have been implemented using pre-IEC 61850 protection and control designs and techniques, but they were not

cost effective to implement. Using the common communications bus reduces the cost of implementing these additional schemes to programming and testing. Once the schemes are initially developed as part of this pilot, they can be used for future projects at a marginal cost.

- **Cross Triggering** - Cross triggering of all devices for every distribution system event and at a specific time each day provides the engineering department with detailed oscillography and event information. This information explains how the protection and control functions performed under fault conditions. Previously, event information was only available from fault recorders, which were not cost-effective for distribution substations. KCP&L's design leverages the power of relays for recording waveforms and IEC 61850 GOOSE messages to cross trigger devices, enabling station-wide awarenesss that had been impossible in the past. Analyzing this information allows schemes and settings to be optimized, providing customers with more reliable service.

The four GOOSE functionalities implemented for this project are shown in the GOOSE logic diagram, Figure 2-20.

Figure 2-20: GOOSE Logic Diagram



2.4.1.3 SPN Implementation

KCP&L began replacing the Midtown IEDs in February 2011. The devices were replaced in a systematic manner, one switchgear or transformer at a time. Devices associated with five switchgear were replaced in 2011, three switchgear were replaced in 2012, and all four transformers were replaced in 2012. Sixty three total IEDs were installed in the Midtown Substation, as described in Table 2-4.

Table 2-4: Substation IEDs Installed

IED	Model	Monitor/Control	Quantity
Bus Main Breakers	SEL-451-5	Monitor Only	8
Tie Breakers	SEL-751A	Monitor Only	8
Transformer Differential Relays	SEL-487E	Monitor Only	4
Bus Differential Relays	SEL-487B	Monitor Only	8
Feeder Breakers*	SEL-751A	Monitor Only	20
Feeder Breakers*	SEL-751A	Control	11
Load Tap Changers	Eberle REG-DA	Control	4
**11 of the 31 circuits in Midtown Substation feed the Green Impact Zone, or the project area. The feeder breakers for these circuits have monitor and control capabilities, whereas the non-smart grid feeders can only be monitored.*			

The point of demarcation between KCP&L's existing transmission EMS and the demonstration project DMS is the substation feeder breaker. Both systems have monitor and control capabilities of these devices. The feeder breakers will continue to send data to the existing Midtown RTU, but the 11 smart grid feeder breakers will also send information to the new substation data concentrator, the SICAM. In order to avoid having controls come from both the EMS and the DMS, a control authority selector has been added to the EMS so that the distribution operators can toggle control between the two systems.

Although the Midtown substation devices have the necessary IEC 61850 Configured IED Description (CID) files loaded, the IEC 61850 GOOSE messaging hasn't been activated as of yet. Currently, the devices are communicating via 61850 MMS messaging to the SICAM, but they won't perform the peer-to-peer GOOSE communications until a multi-bus test can be conducted.

The fiber installation occurred during April and May of 2012. The Midtown Substation physical infrastructure is laid out in a star configuration with one cable trench for each bay in the ring bus. These trenches extend from the control enclosure, which is in the center of the substation, out to each switchgear enclosure. Two twelve-fiber, single-mode fiber optic cables were installed between each switchgear enclosure and the main control enclosure. Fiber distribution panels (FDPs) were installed in each switch location, as well as within the control enclosure. At Midtown Substation, it was impractical to install new conduit directly between each switchgear enclosure to create a truly physical ring, so the Ethernet switches were connected in a ring by patching in the FDPs located in the control enclosure. These new fiber optic cables were installed in the existing cable trench with other control cable.

The network switches were also installed in April-May 2012. As part of the pilot, the Midtown Substation was retrofitted with a redundant Ethernet communications network with hardware from two switch vendors (RuggedCom and Cisco) for protection operation. Using two vendors allowed KCP&L to evaluate the products simultaneously to determine which was best suited for substation protection and control networks. Each vendor's equipment was used to build a ring in the substation, and each relay has an interface connected to both rings. The rings are interconnected at two points for redundancy. The core ring was built using gigabit fiber connections. The relays each have two 100-Mbps Ethernet interfaces used in a hot standby configuration. Each vendor has its own proprietary protocol for blocking loops from forming in the Ethernet network while recovering from a link failure in less than 50 msec. In between the rings, rapid spanning tree protocol was used to provide failover in less than 250 msec.

2.4.2 Substation Distributed Control & Data Acquisition (DCADA) System

2.4.2.1 Substation DCADA Overview

The Substation Distribution Control And Data Acquisition (DCADA) system consists of redundant Distribution Data Concentrators (DDCs), redundant Human Machine Interfaces (HMIs), and redundant Distribution Automation Controllers (DACs). The DDC acts as a communications gateway between the substation and field Intelligent Electronic Devices (IEDs). The DAC is the substation controller, and it runs in closed loop mode to perform “first responder” applications on the substation and field IEDs. The HMI acts as the local view of all substation activity.

2.4.2.2 Substation DCADA Characteristics

2.4.2.2.1 Distribution Data Concentrator

The Midtown Substation SICAM PAS (Siemens Integrated Control And Monitoring Power Automation System) acts as the Distribution Data Concentrator (DDC) for the substation and field devices reporting to Midtown. The SICAM PAS controls and registers the process data for all the devices in a substation. It is essentially a communication gateway, so that only one data connection to a higher-level system control center is required.

The SICAM’s networking and IT capabilities, interoperable system structure, and integration with existing systems are designed to simplify configuration and commissioning and help to increase the efficiency of operations management. The SICAM is capable of polling for data collection, power monitoring, control automation and system-wide visualization. The over-arching goals of the SICAM are to increase the reliability and availability of KCP&L’s systems, leading to a stable power supply.

The SICAM PAS is capable of communicating via the following:

- IEC 61850
- DNP3
- Modbus
- OPC
- Profibus
- TG8979

For KCP&L’s demonstration project, the SICAM will utilize IEC 61850 to communicate with the substation devices and DNP3 to communicate with the field devices.

2.4.2.2.2 Human Machine Interface

The substation Human Machine Interface (HMI) provides a local view of all of the equipment located inside the fence of the substation. The purpose of the HMI is to give substation personnel a tool for viewing the current status of the equipment within the substation, as well as giving them the potential to operate the smart grid devices from within the substation control house.

For this project, the Distribution Management System (DMS) only contains information for one substation, but for a system-wide DMS implementation, the DMS would likely provide a higher level of information about devices at all of the substations, and the Distribution Automation Controller (DAC) would just be a black box with no graphical user interface. Thus, the HMI would provide this look inside the black box.

Unlike the DMS and the DAC, the HMI does not contain any information about the field devices. The HMI does, however, provide information about the substation network equipment, which is not displayed in the DMS. Through the HMI, the user will be able to verify whether any substation issues are related to network communications. Each substation device will be connected to a particular network switch and mapped to a specific port. Although the user can't modify any network configurations from the HMI, he will be able to easily determine whether any problems exist on the network prior to engaging the IT personnel at KCP&L.

2.4.2.2.3 Distribution Automation Controller

The Distribution Automation Controller (DAC) is the brains of the substation. It receives device status updates from the SICAM, and it determines how to respond to activity occurring on the distribution system.

The DAC can perform many of the same applications as the Distribution Management System, but it does so in a closed loop method, and it can only control devices within its area of control. The DCADA can control any devices within Midtown substation or any field devices on Midtown feeders.

The Distribution Network Applications that can be performed by the DAC include:

- Distribution System Power Flow
- Distribution System State Estimation
- Feeder Load Transfer
- Volt/Var
- Fault Management

To learn more about the applications above, refer to section 2.5.2.

If the substation is running in closed loop mode, then the DAC makes decisions and sends controls to IEDs without the interaction of an operator. In this mode, the DAC attempts to resolve any issues that arise using its "First Responder" functionalities. If the DAC isn't able to solve the problem with its available tools and applications, then the DAC transfers control to the DMS, where the operator is alerted of the issue and asked for input to solve the problem.

2.4.2.3 Substation DCADA Implementation

At this point in the project, KCP&L has done a majority of the work on the DDC and HMI implementations, but there is still work and testing to do with the DAC functionalities.

KCP&L chose to implement redundancy for most of the critical systems in this project. The Distribution Data Concentrator is certainly considered a critical piece of hardware, so two SICAMs were rack-mounted in the Battery Control Enclosure, right next to Midtown Substation.

Other than the physical installation, the first big task in the Distribution Data Concentrator (or SICAM) implementation was to determine the points that KCP&L wanted to send back to the DDC from the substation devices. From the DDC, the data flows up to the DAC (the substation brain) and the DMS for use by the system applications and for display on the DMS graphical user interface.

KCP&L wanted to create a profile for each device type so that when a new device is added to the system at a later date, a template can be used to facilitate this process. KCP&L held some healthy debates regarding the signal list strategy. Some personnel wanted to bring back only the data that is currently going to the substation RTU, while others wanted to bring back lots of additional data so that the operator would have a plethora of information displayed at the Distribution Management System. KCP&L decided to go with a robust signal list. This led to some issues as KCP&L learned that there were point limitations with our system.

Although the SICAM is capable of performing arithmetic functions, it wasn't configured as such for the KCP&L project. If KCP&L was to use the SICAM in the future, they would likely reconsider the implementation of this system. Since it is capable of performing calculations, KCP&L would probably limit the number of points reported back from each device. A smaller number of points would be sent to the SICAM, and then the SICAM could calculate the remaining points with that information. For example, instead of bringing back all the points associated with voltage, current, and power, the device would just send the voltage and current data and the SICAM would calculate the power values.

Another learning opportunity with the Distribution Data Concentrator pertained to deadbands. For the demonstration project, KCP&L wanted to utilize report-by-exception instead of the polling that's traditionally done in the substation. Report-by-exception could potentially limit the amount of unnecessary data that flows into the SICAM, as data is only sent when an event occurs. For status points, the device simply reports when its status changes state. For analogs, however, the reporting frequency is not so obvious. KCP&L had to determine and configure deadbands so that the device knew when it needed to send the SICAM updated information. When one analog reached a deadband, the device would send all the data points within that 61850 report. With KCP&L's initial deadbands, the devices were sending 61850 reports many times each second, and the SICAM became overloaded. As a result, KCP&L had to reconsider the deadband settings and carefully monitor the impact of these changes. Eventually KCP&L was able to settle on deadbands that didn't overload the system, but still updated the data at a reasonable rate.

If KCP&L implemented 61850 in other substations at some point in the future, they would likely consider setting a deadband on only one type of analog in the 61850 report dataset. For example, they might set deadbands on all of the current values, so that only changes to the system current would trigger data transfer. Understanding 61850 reporting was critical to this realization.

An additional take away from the 61850 signal list exercise had to do with manufacturer specific implementations within 61850. The 61850 standard is loose enough to allow vendors to make modifications that may make some attributes of their devices vendor specific. One of the lessons learned in regards to vendor implementation of 61850 was that the controls may have to be modified in a relay's CID file in order to be interoperable with other devices. For example, the SEL 751A's CID file had to be manually modified in order to be controlled via pulse by the Siemens SICAM.

KCP&L deployed two HMIs for this project – the first is located inside the Midtown Substation Control House, and it is intended for substation personnel. The second is located inside the Battery Control Enclosure, just north of the Midtown Substation. It is intended for educational purposes for the demonstration project, as well as to provide a side-by-side comparison of an HMI view to a DMS view of the system.

Once the HMIs were installed and the signal lists were completed, KCP&L did a point-by-point checkout of the substation devices using the HMI. Outages were scheduled so that each device could be taken offline and tested in a controlled environment. Any issues or unexpected results were carefully analyzed and resolved until all the points from the devices to the SICAM and the controls from the SICAM to the devices worked properly.

The outstanding HMI tasks include training and some networking remapping. Although Siemens did all of the initial HMI design and configuration, KCP&L will be responsible for any modifications or updates to this system in the future. As such, KCP&L needs to understand how to make changes to properly map the SICAM data to the HMI, as well as how to make graphical modifications that are desired. Additionally, in order for the SICAM to display the networking information, it needs to have a correct mapping of the substation devices to the ports on the various switches. Some of this mapping was modified during installation, so the port mapping needs to be updated to reflect the current configuration.

The Distribution Automation Controller implementation is not as far along as the DDC or HMI implementations. One server is currently installed in the Battery Control Enclosure, and the other is planned for installation at the same location in February 2013. This set of servers will ensure system redundancy of the substation analytics engine.

Initially, the DAC will receive substation and field data updates from the SICAM, but it will not be used for analytics. KCP&L is planning to gain confidence in the systems using a crawl, walk, run philosophy. So even though the DAC hardware is deployed, KCP&L won't be testing in closed loop at the substation for a while. Currently, KCP&L is testing out the DNA applications in the open loop mode at the DMS. Upon completion of this, KCP&L will move to closed loop testing of the DMS, and then finally KCP&L will move to closed loop testing at the DCADA.

2.4.3 Substation Asset Management

KCP&L plans to implement substation asset management technologies at the Midtown Substation. At this time, these components of the project are still under development with no information to report.

2.4.3.1 Substation Asset Management Overview

To be completed in future releases of this report…

2.4.3.2 Substation Asset Management Characteristics

To be completed in future releases of this report…

2.4.3.3 Substation Asset Management Implementation

To be completed in future releases of this report…

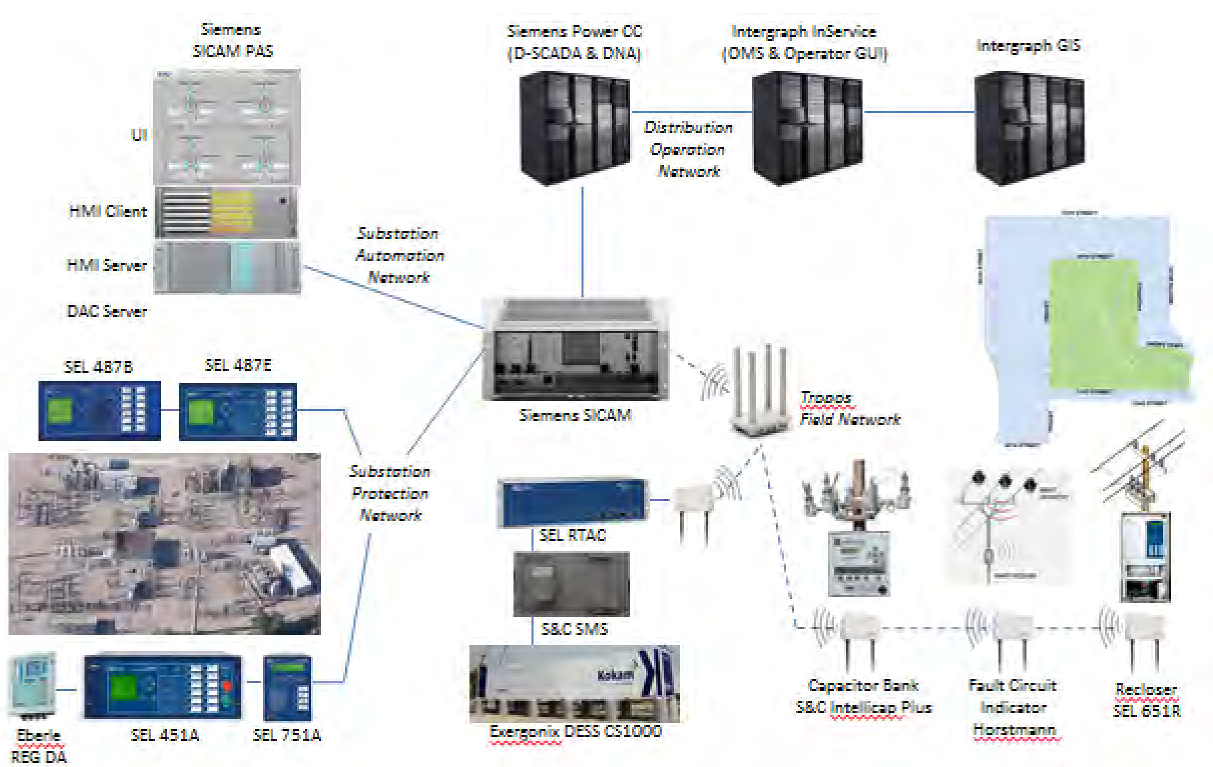
2.5 SmartDistribution

The SmartDistribution sub-project deployed a state-of-the-art Distribution Management System (DMS) and Advanced Distribution Automation (ADA) network. The DMS for this project will only be used for Midtown Substation, but for an enterprise-wide deployment, this DMS would be Central Control for *all* of the distributed intelligent substations and field networks. The DMS monitors and controls the state of distribution network at all times, and it solves reliability issues through its Distribution Network Analyses (DNA) applications.

The ADA network consists of a Tropos 2.4/5.8 MHz mesh network, capacitor banks, fault circuit interrupters, and reclosers. The field devices will communicate back to the substation controller and the DMS. The DNA applications will run in open or closed loop at the DMS, and in closed loop at the substation. These applications will respond to any potential network overloads, and will automatically reconfigure the network as needed.

Figure 2-21 shows the components of KCP&L's SmartDistribution implementation.

Figure 2-21: SmartDistribution Components



2.5.1 DMS

The DMS serves as the primary point of integration for the facilities, consumer, electrical system, load, distributed energy resource, and real-time substation and feeder information. It includes Distribution Supervisory Control and Data Acquisition (D-SCADA), Distribution Network Analysis (DNA), Outage Management System (OMS), and a common user environment for operations. The DMS integrates with the Geographic Information System (GIS) and other supporting systems.

2.5.1.1 DMS Solution Overview

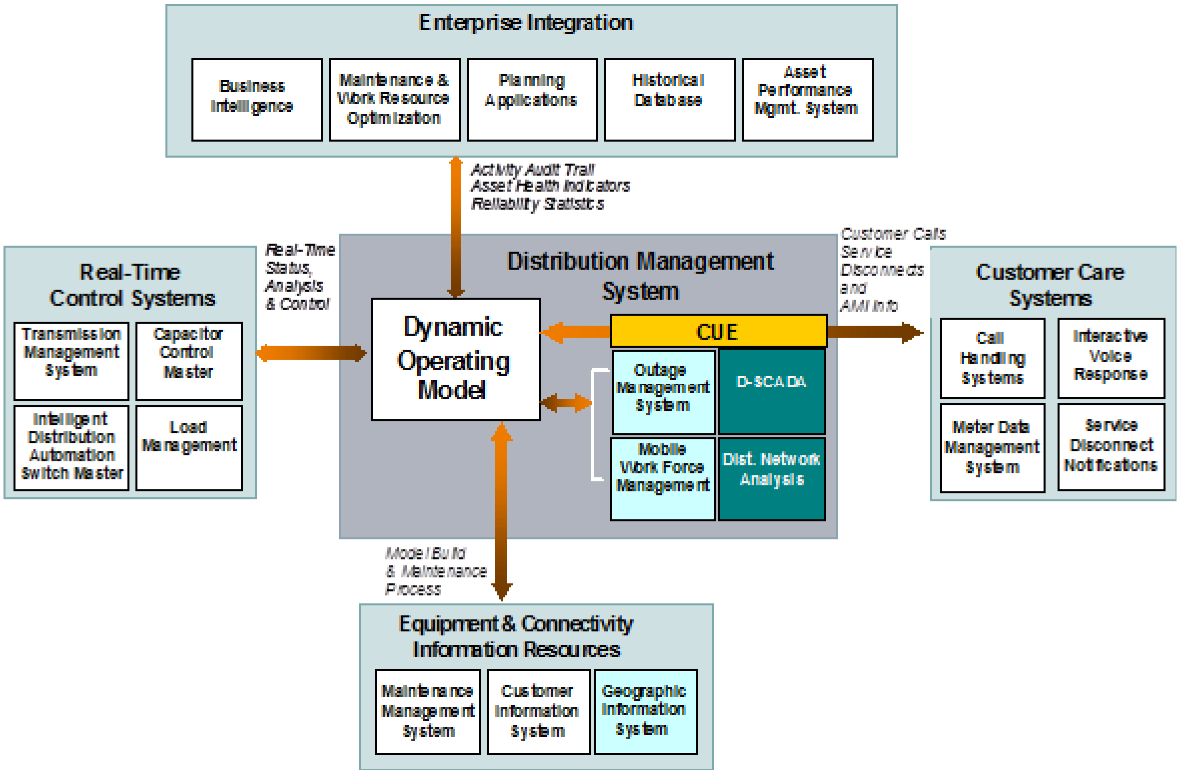
Siemens Distribution Management Systems (DMS) enable the user to evaluate the state of the electrical distribution system, efficiently manage day-to-day construction and maintenance efforts, and proactively guide operators when the system is needed most; during storms and related restoration activities. As utilities come under greater pressure to more fully utilize existing equipment, a DMS is an essential element in maintaining and improving delivery reliability while reducing complexity and automating related work processes. The recent acceleration in Distribution Automation, Substation Automation and AMI in the industry has created additional impetus to establish DMS as a solid foundation to leverage these aspects of the emerging "SmartGrid".

For KCP&L, the demonstration DMS will be composed of a number of tightly integrated tools and systems addressing different aspects of the Distribution Operator's work tasks, including:

- **Distribution SCADA (D-SCADA)** – provides real-time device and automation information to keep the operating model as close as possible to the real conditions in the field. D-SCADA provides all real-time data services and control agent capabilities for the combined solution.
- **Distribution Network Analysis (DNA)** – provides equipment loading and complex voltage calculations to help the operators understand the voltage and loading of the distribution feeders and individual equipment at any point in time. It also provides a variety of Fault Management and Operations Optimization tools to offload the operations staff and improve efficiency.
- **Outage Management System (OMS)** – provides the ability to view the current connectivity of the distribution feeders and safely manage day-to-day and emergency restoration work. The Siemens offering includes the Intergraph InService product as an integral component in the total DMS solution. The OMS provides the basis for all outage information and is uniquely suited for KCP&L's needs, minimizing the integration costs with the existing GIS and Mobile Work Force Management systems. The OMS is integrated at a product level with the Siemens DNA and D-SCADA products to provide a complete solution with "best of breed" product functionality.

These systems are tightly integrated to automate the user's workflow as much as possible and enable efficient transition between major functions. Siemens' DNA and D-SCADA components of a DMS System are integrated with Outage Management and Mobile Work Force Management systems. The interfaces enable lower implementation and maintenance costs for its customers and directly support cost-effective rollout of the demonstration project. Figure 2-22 outlines a general DMS solution.

Figure 2-22: Full Generalized DMS Solution



2.5.1.2 DMS System Characteristics

Some of the key features of KCP&L's demonstration project DMS include:

- Provides a single highly efficient user interface for all DMS functions
- Visually correlates and integrates large amounts of field information
- Supports management of outage restoration and mobile work crews
- Utilizes available information from Distribution Automation (DA) and Automated Metering Infrastructure (AMI) sources
- Provides modeling and simulation of Distributed Energy Resources
- Provides modeling and simulation of intelligent field devices and the supporting protection and control schemes
- Incorporates all available feeder and substation measurements and fault indicators
- Establishes a time-smoothed granular feeder load model for more accurate solutions
- Rapidly and accurately determines fault locations and automatically provides isolation and restoration plan options
- Tracks system/feeder load reduction capacity on an on-going basis
- Supports various optimization objectives, including voltage, VAr, loss, and load capacity management
- Establishes a generalized model-based integration platform for simplified integration with other enterprise systems

For the demonstration project, Siemens and Intergraph will provide a packaged solution that satisfies all the components of a Distribution Management System. Siemens will be responsible for the D-SCADA and DNA pieces, and Intergraph will provide the OMS and user interface.

2.5.1.2.1 D-SCADA

The D-SCADA component of the DMS is provided by Siemens for the demonstration project. D-SCADA provides interaction capabilities with automated and intelligent distribution system field devices. D-SCADA includes the following:

- Data Acquisition – provides the interface to the system field devices, facilitates the scanning of telemetered data periodically and by exception, transmits control commands, and ensures data integrity
- Network Control Executive – handles switching commands from the OMS and manages their execution
- ICCP Interface – provides the interface that connects D-SCADA to the OMS. It facilitates real-time data transmission and reception, as well as required data point identifier mapping and conversion
- Data Archiving Interface – directs scanned and derived system data to an independent long term archiving system (not implemented on project)
- Communications Management Display – enables the user to view and change the status of the data acquisition equipment and also displays communications equipment errors and allow the user to view and reset communication error counts
- Configuration Management Tool – monitors the status of key components of the D-SCADA network servers, printers, network interfaces, true time devices, database domains, etc; it also allows the user to start and stop D-SCADA on individual servers

2.5.1.2.2 DNA

The DNA component of the DMS is provided by Siemens for the demonstration project. DNA provides the underlying analysis platform to support decisions at either the DMS (Control Center) or at the substation controller. The applications are configurable to their deployment location and the utility's needs.

DNA provides tools to simplify and improve the analysis of situations, providing more reliable network status information and supporting the network operation for both unplanned situations and planned activities. DNA uses the CIM-based logical and topological data model of the distribution network of the real-time database. This data model will be synchronized between the central DMS SCADA system and the substation DCADA system.

For this project, Distribution Network Analyses include the following:

- Distribution System Power Flow
- Distribution System State Estimator
- Feeder Load Transfer
- Volt/VAR
- Fault Management

These functions are described in greater detail in section 2.5.2.2.

2.5.1.2.3 OMS

The OMS component of the DMS is provided by Intergraph for the demonstration project.

Intergraph's InService model is built upon KCP&L's existing Geographic Information System (GIS) with links to KCP&L's Customer Information System (CIS). Intergraph's base OMS product is capable of analyzing outage notifications from CIS, integrated voice response (IVR), and the automated metering infrastructure (AMI). Using a configurable rules engine, these "calls" are grouped together to predict the correct protection device. Input from SCADA systems and manual input from an operator or dispatcher supplement these predictions.

The major benefits of Intergraph's OMS for KCP&L's implementation include:

- **Increased network reliability** by proactively monitoring the grid for potential problems using distribution analytics and alarming for notification.
- **Reduced time to restore power** by using the trouble analysis engine to pinpoint the most probable outage location

InService's trouble analysis uses the GIS network connectivity model as the baseline configuration, and then processes all transactions to maintain the real-time state of the distribution system. Trouble analysis handles the meter notifications to predict the extent of an outage and the most likely point of failure.

InService's switching procedure management (SPM) works with Siemens' DNA to handle emergency or planned switching orders. SPM will allow KCP&L dispatchers to create, review, and execute switch plans with multiple levels of approval.

2.5.1.2.4 Consolidated UI

The graphical user interface component, InService, is provided by Intergraph for the demonstration project. InService's geospatial displays of the distribution system consolidate information from various systems into one comprehensive graphical user interface (GUI). From the base map, users will be able to view device statuses, operate switches, turn on and off layers, and view configurable attributes of the facilities. The network map features dynamic colorization and attribute-based symbology that changes with the state of the device. The display can be filtered based on network components or devices related to a particular event.

2.5.1.3 DMS Implementation

The DMS implementation kicked off in 2010 and really gathered momentum in 2011. Initial tasks included hardware, software, and license procurement, and determining the configuration for the test, production, and support systems. Other initial tasks included design document review and interface design. The DMS/DCADA interface is a Siemens to Siemens interface, so KCP&L didn't have much involvement in this; rather KCP&L reviewed and signed off on this pre-made interface with minor changes. The DMS/DERM interface, however, is a custom interface between Siemens and OATI for this demonstration project. In order to design the message exchanges for this interface, KCP&L, Siemens, and OATI met for several days to create use cases for the possible scenarios. The main scenarios that were detailed included:

- Initialization between DMS and DERM – used the first time a new database is applied or after one of the systems has been restarted
- Feeder load management – also called “studycase,” this is an exchange between the DMS and the DERM done in a planning mode
- Feeder load shed – also called “emergency,” this is an exchange between the DMS and the DERM done in real time when an overload has occurred

Upon completion of the DMS/DERM use cases, all parties worked on technical specifications for these interfaces to develop the standards-based messages that would be used to exchange the agreed upon information.

Another task that required lots of coordination in 2011 was the creation of the substation and field device signal lists. Siemens provided KCP&L a spreadsheet with the required points for each device type that would be necessary for the DNA applications to run. There are hundreds of additional data points that can be brought back from the devices to the data concentrator, however, so KCP&L had to agree on the set of points that might be useful to the dispatcher moving forward. The first version of the signal list was completed in October of 2011. Much iteration has occurred since then, as KCP&L learned more about system limitations, how the Siemens applications use the points, and how and when the points are sent back to the data concentrator.

As part of the DMS implementation, KCP&L participated in several workshops to expedite the process of obtaining the necessary configuration data for Siemens and Intergraph. The DNA workshop was held in September 2011, and the SCADA workshop was held in January 2012. Although these sessions were critical to Siemens and Intergraph in order to continue with their DMS configuration, they would have been more effective if they had been broken up over time. Conducting the workshops before KCP&L knew much about the system and how it works meant that all parties had to revisit the information several times throughout the implementation as KCP&L learned more about the DMS. A follow up DNA workshop was held in May 2012, and a follow up SCADA workshop was held in July 2012 to address some of these issues.

Another major task in the DMS implementation has been the database migration process. In production, KCP&L plans to conduct this process on a monthly basis, so it is important that it is somewhat automated and that KCP&L fully understands what needs to occur between the Siemens and Intergraph components of the DMS. In order to start the migration process, KCP&L’s existing GIS model is sent to the DMS. Over the past year and a half, KCP&L’s GIS experts have worked closely with the Siemens and Intergraph engineers to make sure that the KCP&L model can be fully ingested into the DMS. The project team has also worked to understand the behind-the-scenes interactions between the Siemens and the Intergraph portions of the DMS. While all of this is still in progress, KCP&L has a much better understanding of the data migration process now.

Since the initiation of the DMS portion of the demonstration project, KCP&L personnel have taken part in a number of training courses to prepare them for operation of the DMS. Courses taken to date are listed in Table 2-5.

Table 2-5: DMS Training Courses Completed

Training Course	Dates
System Administrator Training (Intergraph)	02/14/2012 through 02/17/2012
Configuration Training (Intergraph)	05/29/2012 through 05/31/2012
iDispatcher Training (Intergraph)	07/31/2012 through 08/02/2012
Tester Training (Siemens)	08/13/2012 through 08/14/2012
HMI/SICAM Training (Siemens)	08/14/2012 through 08/17/2012
System Installation Training (Siemens)	10/01/2012 through 10/05/2012
Switch Plan and Switch Simulator Training (Intergraph)	10/10/2012
Distribution Network Analyses (Siemens)	10/29/2012 through 11/01/2012

In terms of formal DMS testing and acceptance, the original intent was to conduct one comprehensive Factory Acceptance Test (FAT) and then follow up with one comprehensive Site Acceptance Test (SAT). Because of the huge DMS scope, KCP&L, Siemens, and Intergraph decided to break up these activities into three more manageable pieces of work. The phased work efforts are outlined below:

- **Phase I – substation device monitoring.** For this phase, a point-to-point check out of all the substation devices was conducted to ensure that the DMS could monitor the status of all the substation devices. The Phase I FAT was conducted from 4/23/2012 through 5/3/2012, and the SAT was conducted from 5/24/2012 through 6/4/2012.
- **Phase II – substation device control and field device monitoring/control.** For this phase, the DMS control capabilities were verified for all of the substation devices. Additionally, the monitoring and control capabilities were tested for the capacitor bank controllers and the fault circuit indicators. The Phase II FAT was conducted from 8/20/2012 through 8/31/2012, and the SAT was conducted from 9/17/2012 through 9/28/2012.
- **Phase III – recloser and battery monitoring/control, DNA functionality, and DERM integration.** For this phase, the final two devices will be verified. Since the recloser controller wasn't available from the manufacturer at the time when the rest of the field devices were checked out (in Phase II), it was combined with the Phase III scope of work. Additionally, the battery controller (the SEL RTAC) will be tested as part of Phase III. The DNA applications will be tested in Phase III, which will incorporate monitoring and control of the substation and field devices, as well as logic of each of the DNA applications. The last component of the Phase III work is the DMS/DERM interface testing. Siemens and OATI will need to demonstrate not only the message exchanges, but also the comprehensive interaction between the two systems as outlined in the DMS/DERM use cases. The Phase III FAT is scheduled for January 2013, and the SAT is planned for February 2013.

2.5.2 Distribution 1st Responder Functions

One of the main objectives of the SmartDistribution portion of the project is to implement a family of automatic, distributed "first responder" functionalities. These functionalities will be performed centrally by the DMS and locally by the DCADA system in the Midtown Substation. These applications, running on redundant systems, are enhancements to the basic substation automation system.

2.5.2.1 1st Responder Function Overview

As part of the project, KCP&L will implement distribution First Responder applications that greatly improve the control of the distribution network, increase supply quality and reliability, ensure optimal use of network equipment, and minimize losses and detection and elimination of overloads at particular points in time.

Siemens' Distribution Network Analyses (DNA) provide tools to simplify and improve the analysis of situations, providing more reliable network status information and supporting the network operation for both unplanned situations and planned activities. DNA uses the CIM-based logical and topological data model of the distribution network of the real-time database. This data model will be synchronized between the central DMS SCADA system into the substation DCADA system.

For this project, Distribution Network Analyses are composed of the following capabilities:

- Distribution System Power Flow
- Distribution System State Estimator
- Feeder Load Transfer
- Volt/VAR Control
- Fault Management

2.5.2.2 1st Responder Function Characteristics

Each DMS and substation controller vendor has its own set of distribution applications, but for this project, KCP&L is utilizing Siemens' Distribution Network Analyses. The DNA applications that are being configured for this demonstration project are detailed below.

2.5.2.2.1 Distribution System Power Flow

Distribution System Power Flow (DSPF) calculates voltage magnitude and phase angle for all electrical nodes, active and reactive powers for slack nodes, and reactive power and voltage angles for nodes with PQ/PV generators. It calculates network status (voltage magnitudes and phase angles, line flows, and network losses) under different load conditions and configurations to detect any potential limit violations. The results of DSPF are used for further operational analysis and optimization processes. DSPF is capable of handling both symmetrical balanced and unsymmetrical unbalanced distribution systems. In the real-time context the DSPF can be executed based on a periodic, manual or event triggered conditions.

In DCADA substation operation, the DSPF combines the results of the Distribution System State Estimator (DSSE) and calculates the load flows and voltage conditions during the solution search. It operates in a closed loop mode in the substation.

2.5.2.2.2 Distribution System State Estimator

Distribution System State Estimator (DSSE) provides a complete network solution for real-time network conditions for real-time monitoring and further analysis of the network. This solution is based on real-time measured values, scheduled loads, and generations. It provides the statistical estimates of the most probable active and reactive power values of the loads using existing measured values, switching device statuses and initial information on active and reactive customer loads. DSSE results are used to monitor the real-time network operating state. In the real-time mode the DSSE can be executed periodically, manually or triggered by an event.

DSSE application provides the real time status of the electric node voltage vectors as a basis for power flow calculations and the starting point for other subsequent analysis functions (Volt Var Control (VVC), Feeder Load Transfer (FLT), and Fault Detection, Isolation and Restoration (FDIR)). DSSE is a closed loop function processing initial load values and minimizing the differences between the measured and calculated values. Upon obtaining the voltage vector solutions, it calculates the flows of active and reactive power on all lines as well as power losses.

2.5.2.2.3 Feeder Load Transfer

Feeder Load Transfer (FLT) determines the optimal radial distribution network configuration to mitigate or remove feeder overloads. It removes the feeder overloads by transferring load from overloaded feeders to the feeders with spare capacity. FLT determines switching plans that ensure continuous supply of power to the consumers, and voltage and current levels within technical limits. FLT can be triggered manually to transfer the load from one feeder to another or it can be triggered by Distribution System State Estimator (DSSE).

FLT can be executed in closed loop, open loop or study mode in the DMS Control Center level and in closed loop mode in the substation level. The result of closed loop execution in both DMS and DCADA level is a set of the switching steps that will be performed on remotely controlled “normally open switches” as well as closed switches. The result of executing FLT in open loop mode in DMS level is a list of suggested switch operations that includes both remotely as well as manually controlled switching devices. The solutions presented by FLT will be verified by the Distribution System Power Flow (DSPF) to assure there are no remaining overloads or voltage violations. In the latter case, the FLT will trigger VVC functionality to try to find an optimal solution. In case a solution is not found or any of the switching steps is unsuccessful, a warning will be sent to the dispatcher in the DMS Control Center and the DCADA application part of functions will be disabled.

2.5.2.2.4 Volt/VAR Control

A Volt/Var Control (VVC) function deals with the complexity of the voltage and reactive power control in a modern distribution system. The primary objective of VVC is to satisfy voltage and loading constraints. It is able to work with both balanced and unbalanced distribution systems. It supports the control of transformer on-load tap positions (LTC, voltage controllers) and switchable shunt reactive devices (typically capacitors) to meet the objectives. VVC can be executed to satisfy any of the following 4 objective functions:

- Minimize the sum of power losses
- Minimize the power demand
- Maximize the substation transformer reactive power
- Maximize the difference between energy sales and energy prime cost

2.5.2.2.5 Fault Management

Fault Management is a set of DNA applications used for locating distribution network faults and providing fault (or planned outage) isolation and service restoration. Fault Management can be executed in real-time or study context. Fault Management is capable of localizing the faulty area as closely as possible, based on available real-time data from SCADA. The Fault Management set of applications includes Fault Location, Fault Isolation and Service Restoration, Fault Isolation and Immediate Restoration, and Fault Detection and Immediate Restoration.

Fault Location (FLOC) determines the locations of permanent faults through the telemetered information protection devices and fault indicators as well as manually updated information. FLOC is triggered by change in the switch status. It can be operated in open and closed loop mode. Fault Location can be configured to handle either outage and/or non-outage faults. If different faults (independent from each other) trigger different fault detectors, FLOC detects and processes multiple faults in parallel.

Fault Isolation and Service Restoration (FISR) can be used for section isolation due to maintenance work or fault in the system. The isolation function determines a set of switching operations to isolate an area of the network. It can be initiated by the location of the faulty segment or area, or by manual selection for planned outage. Service restoration provides a possible choice of switching procedures to restore service. FISR can be executed in open loop or closed loop mode. In open loop mode, FISR presents the advisory solutions to the dispatcher and the dispatcher will make a final decision to execute the optimal solution. In closed loop mode, FISR executes the solution calculated. Only if the control step is not successful or not executable, further steps are stopped and a dispatcher is informed.

Fault Isolation and Immediate Restoration is performed to isolate equipment from the rest of the network and immediately restore unaffected and non-faulty de-energized equipment. In addition to switching operations required to isolate the specified equipment, additional switching operations required to energize (from alternate sources) equipment that is de-energized but not outaged are determined. If the selected equipment is energized, fault isolation and immediate restoration can be configured to generate restoration steps before isolation steps.

Fault Detection and Immediate Restoration (FDIR) is a combination of the FLOC and FISR features to locate the fault and isolate the faulted area and immediately restore power to unfaulted but out-of-service customers. FDIR is triggered by FLOC function. FDIR can be executed only in closed loop mode at both substation and DMS Control Center levels. It will select the most feasible isolation and restoration procedure and execute it by sending a control command to the field. This assures minimal outage time. In the event that it cannot find a local solution within its means, it will notify the dispatcher for higher level analysis and supervision.

2.5.2.3 1st Responder Function Implementation Process

Implementing the First Responder functionalities will occur through a long, systematic approach. The first steps in this process were to configure the Siemens and Intergraph databases for this functionality. KCP&L participated in a DNA workshop in 2011, where the initial database setup occurred. As the process advanced and KCP&L learned more about how the data is used by the applications, KCP&L has made tweaks to the database configuration.

The most critical DNA functionality to implement first is DSPF. This application is used by many other applications, so it's important that it can run properly and generate correct results. Siemens, Intergraph, and the KCP&L GIS team have worked diligently to make modifications and corrections to the KCP&L GIS data in order to generate good DSPF output.

To test out the other DNA capabilities, KCP&L plans to use a crawl, walk, run approach. Early in 2013, KCP&L will be testing out the DNA applications in the open loop mode at the DMS. Upon completion of this, KCP&L will move to closed loop testing of the DMS, and then finally KCP&L will move to closed loop testing at the DCADA.

2.5.3 Advanced Distribution Automation Network

The Advanced Distribution Automation (ADA) network exists to provide monitoring and control capabilities to devices in the field. These devices communicate with both the substation controller and the distribution management system. The substation controller uses the field device information to perform First Responder functionalities in closed-loop mode, and the DMS uses the field device information to perform First Responder functionalities in either open or closed loop. The distribution operator will have access to all of the information about these field devices to assist in planning decisions and resolve network issues.

2.5.3.1 ADA Network Overview

Originally, KCP&L planned to use the AMI network for both metering and distribution automation purposes. This would have reduced equipment, installation, and network management requirements. One of KCP&L's main project goals, however, was to utilize NIST's emerging standards for the smart grid and test out the interoperability between system vendors. For ADA, this meant using Internet Protocol (IP) to communicate to the field devices on the feeders. As a result, KCP&L opted to implement a separate field network for DA.

2.5.3.2 ADA Network Characteristics

The KCP&L Advanced Distribution Automation network will consist of a number of field devices that communicate to the substation controller and to the DMS via an RF mesh network.

2.5.3.2.1 Tropos Network

Tropos' GridCom® wireless IP mesh network will extend the KCP&L SmartGrid IP network to reclosers, capacitors and fault indicators in the field, providing direct monitoring and control communications with substation-based distribution automation controllers and the centralized distribution management system. It will help KCP&L optimize energy delivery through active Volt/VAR optimization and feeder load transfers.

The Tropos GridCom® network also paves the way for enhancing power reliability by centrally monitoring fault indicators and automatically configuring around faults, reducing the impact and duration of outages, which is a cause of increasing concern for customers. The network provides the high-capacity, low-latency and security required to support the applications KCP&L plans to deploy to implement their advanced distribution automation vision for the demonstration project.

The Tropos GridCom® network provides high resiliency with multiple redundant communications pathways to ensure that there is no single point of failure. It leverages the 2.4 GHz and 5.8 GHz frequency bands simultaneously and dynamically manages airtime, helping to avoid localized interference on any one frequency band. Dynamic channel selection, adaptive noise immunity and other advanced RF resource management techniques provide added resiliency.

GridCom® is based on a fully distributed architecture. It does not rely on a centralized controller for its operation, removing potential single-points-of-failure and eliminating unnecessary network traffic. GridCom's distributed intelligence performs functions such as network optimization, path selection and routing, and enforcing security and QoS policies.

GridCom® supports centralized management using Tropos Control, a comprehensive and scalable network management system. Tropos Control supports network implementation and optimization plus ongoing management of Key Performance Indicators. Although the network itself operates independently of Tropos Control, Tropos Control is used for alarm management, configuration, provisioning, and performance management.

2.5.3.2.2 Automated Field Devices

KCP&L is utilizing a combination of existing and new devices for this distribution automation deployment. The following devices are planned for installation in the demonstration project area:

- **Capacitor bank controllers -** KCP&L already has a number of capacitor banks installed in the demonstration project area, so these will be used on the new Tropos network. The old controllers will be replaced with new S&C IntelliCAP PLUS controllers, and a Tropos 1310 router will be connected to the controller. The capacitor bank controllers will communicate with the Tropos router via serial DNP3. Although KCP&L wanted IP communications to all of the controllers, this was not an option from most capacitor bank controller manufacturers. As a result, the communications from the SICAM to the router will be IP based, but the communications from the router to the controller itself will be serial. The capacitor banks used for this project are a combination of standard and VAR controls.
- **Faulted circuit indicators –** KCP&L will be installing Horstmann Fault Circuit Indicators (FCIs) for the demonstration project. Each FCI receiver can communicate with up to twelve FCIs, or four sets of three devices (one device per phase). The quantity of FCIs associated with a particular receiver is based on the number of devices desired in a certain geographic area – the range of the receivers is the limiting factor. KCP&L will only be able to get information *from* these devices; FCIs are not capable of responding to any controls.
- **Recloser controllers -** KCP&L plans to use two different types of reclosers for this distribution automation implementation – the G&W Viper-ST solid dielectric and the Siemens SDR 3212 vacuum reclosers. The recloser controllers are SEL 651R. All of the reclosers and their associated controls are new for this project. The reclosers are being used for three different purposes:

- Isolation switch – used where the feeder transitions from underground to overhead
- Mid-circuit recloser – used to segment the feeder into multiple pieces to limit the affected customers in the event of a fault
- Tie recloser – used to feed a portion or all of a circuit from an adjacent circuit

2.5.3.3 ADA Network Implementation Process

The first step in the ADA network implementation was to set up a lab instance of the Tropos mesh network. KCP&L wanted to test out the capabilities of the network in a controlled environment, so routers, gateways, and field devices were set up in the IPNEO lab at KCP&L.

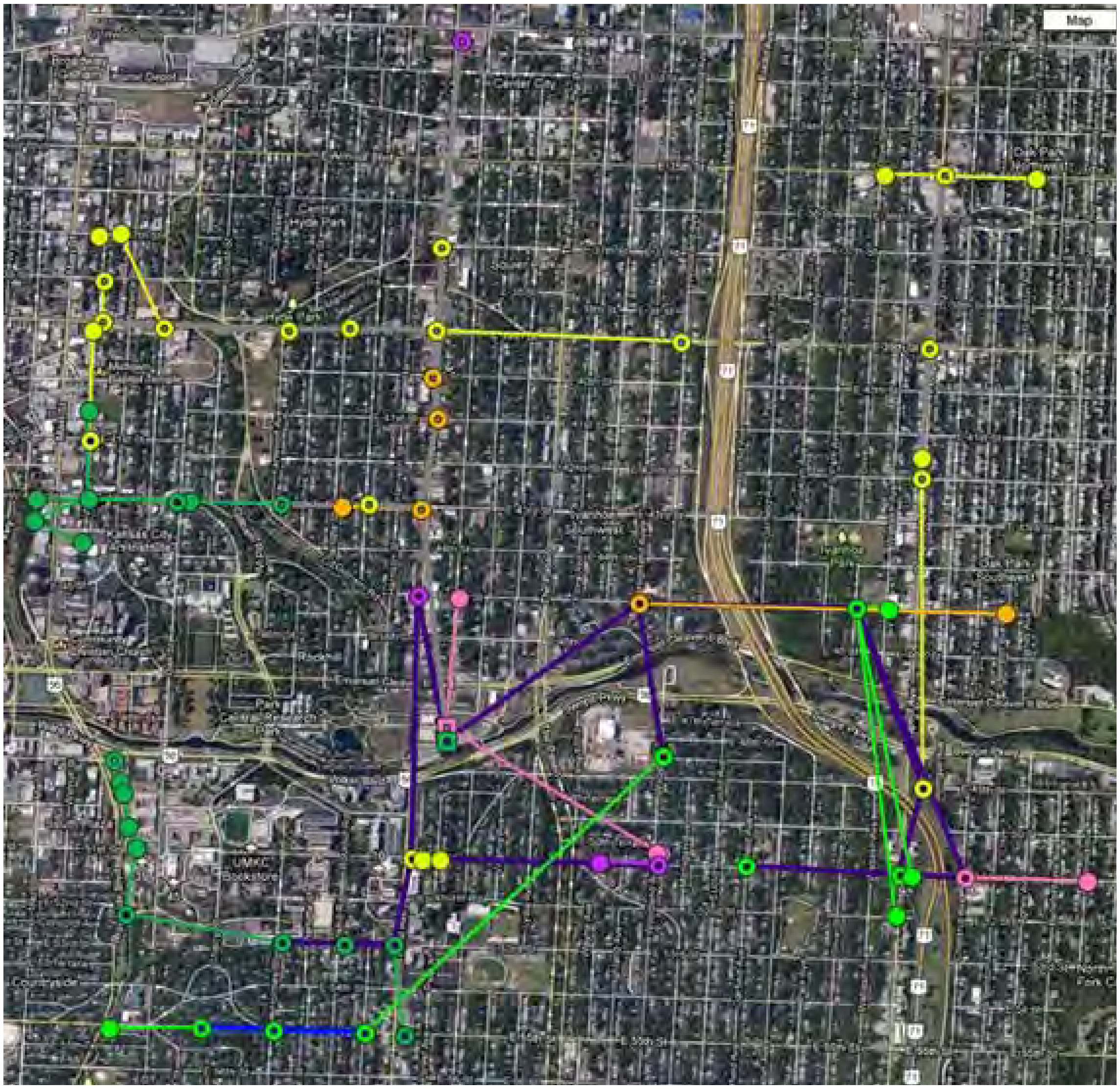
At the same time, Tropos engineers performed a field survey of the project territory. They determined the mounting assets for the network gateways and the base mesh nodes, and they trained the KCP&L field crews on the mounting and installation process.

After getting comfortable with the lab network, KCP&L field crews began deploying the 6320 and 1310 devices in the field. The key elements of the base mesh include:

- Tropos Infrastructure Gateways (6320s) - two at 801 Charlotte and two at Midtown Substation
- Tropos Infrastructure Nodes (6320s)
- Tropos Edge Routers (1310s)

After completing a first pass at the base mesh, Tropos and KCP&L worked together to optimize the network. As a result, several nodes were relocated, and several were added to the network. These changes greatly improved network performance, and all nodes currently have at least a 92% ping success rate. The current base mesh network is shown below, in Figure 2-23.

Figure 2-23: KCP&L Base Mesh Network



Now that the Tropos base mesh is performing as desired, the remainder of the field devices will be installed. KCP&L is prioritizing the field devices on feeders 7551 and 7561, as those are the feeders that are being utilized for testing. At this point, capacitor bank controllers and one FCI have been installed in production. Point-by-point checkouts of these devices have already occurred.

Because the SEL 651R is a new device, it wasn't readily available for installation in the production environment. Point-by-point checkout is planned for January 2013, and production deployment will follow.

In previous implementations, KCP&L wouldn't have utilized reclosers to perform all of these functions; rather, they would have used a combination of switches and reclosers. For this project, however, they decided to use reclosers for isolation, mid-circuit, and tie functions. This decision was made for two reasons. First, the cost difference between reclosers and switches is decreasing dramatically. There isn't as much incentive to utilize switches even when full recloser functionality isn't required. Second, KCP&L wanted to experiment with field device profiles. The same device will be used to perform three separate functions, and this will be implemented through the use of DNP profiles.

Upon completion of the ADA deployment, the field devices described in Table 2-6 will be installed for the demonstration project.

Table 2-6: Field Devices

Field Device	Vendor/Model	Quantity
Capacitor bank controllers	S&C IntelliCAP PLUS	36
Fault circuit indicator receivers	Horstmann	12
Recloser controllers	SEL 651R	20

The remaining field devices and their associated Tropos routers will be deployed in early 2013.

2.6 SmartMetering

The SmartMetering sub-project deployed a state-of-the-art integrated advanced metering infrastructure (AMI) and meter data management (MDM) system. AMI deployment consisted of replacing all customer meters within the Demonstration Project area (approximately 14,000 meters) with communicating SmartMeters and installing an accompanying wireless two-way communication network to enable real-time communications between the meters and the MDM. The MDM stores and manages all meter data reported by the SmartMeters and is integrated with KCP&L's other systems such as the Customer Information System (CIS), DMS, Outage Management System (OMS), and the DERM.

The SmartMeters lower operating costs, increase the frequency of meter reads, increase the accuracy of meter reads, and facilitate utility-controlled demand response messaging. Customer satisfaction has also been improved through remote service connect/disconnect, on-demand meter reading, and increased customer access to usage information. Furthermore, overall system reliability has been increased through enhanced outage/restoration notification.

2.6.1 Advanced Metering Infrastructure (AMI)

2.6.1.1 AMI Overview

The Landis+Gyr Gridstream SmartGrid communication system and SmartMeters provide the capability for AMI and Home Area Networks (HAN) via a common two-way communication infrastructure. The system supports the acquisition of load profile, time-of-use and demand meter data, and meter and site diagnostic information from the electric meters that perform these measurements. Using meters equipped with these capabilities, the system also supports "under-glass" remote physical disconnect and Home Area Network communication via the ZigBee- standard Smart Energy Profile. SmartMeters also support outage and restoration reporting and real-time on-demand reads.

2.6.1.2 AMI Characteristics

The AMI is composed of two main components: Command Center – the AMI Head-End System (AHE) and the Gridstream Wireless Field Area Network (FAN). The AHE is the software and hardware that allows the utility to interact with the AMI and integrate the AMI with other systems within the utility. The FAN is the hardware (collectors, routers, and meters) that enables the utility to receive meter data and send commands to meters.

2.6.1.2.1 Command Center – The AMI Head-End System

The AHE is the advanced metering software and hardware platform that enables data reporting and system control between itself and the FAN. The scalable system enables KCP&L to remotely program meters, manage remote connects/disconnects, analyze critical peak usage, view load control indices, and perform other critical, day-to-day functional operations. The AHE simultaneously manages the meter data collected from all SmartMeters within the Demonstration Project area, validating each data element, and integrates the data with the MDM. The AHE is compliant with the Multispeak, CIM, and IEC CIM 61968 standards. The AHE utilizes Web Service APIs to interface with other systems and can deliver specific scheduled data extracts to these sytems.

2.6.1.2.2 Gridstream Wireless Field Area Network

The Landis+Gyr Gridstream SmartGrid communication system provides full two-way wireless mesh communication and functionality to electric meters, direct load control devices, advanced distribution automation (ADA) devices and Home Area Network devices enabled with a ZigBee communication module.

Advanced metering and diagnostic information that electric meter provides can be communicated over the network to the Command Center head-end operating system and displayed, reported and interfaced to a utility's Meter Data Management (MDM) system, Customer Information System (CIS), Outage Management System (OMS) and other enterprise applications. Figure 2-24 shows a schematic of the Gridstream System for AMI, ADA and Meter to HAN Gateway.

Figure 2-24: AMI RF Mesh FAN

2.6.1.2.3 Smart Meters

Features of the SmartMeters within the AMI include:

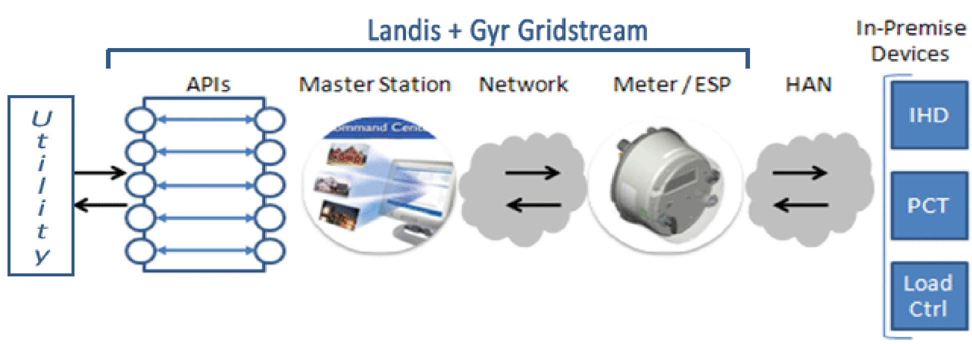
- Full Two-way Mesh Radio AMI Communications
- Variable Output Power 100 to 425 milliwatts
- Auto-registration
- ANSI C12.19 Tables support
- Forward, Reverse, Net, Total Energy
- Voltage/Power Quality Information

- Downloadable Firmware
- Advanced Metering: Demand/TOU/Load Profile
- 5/15/30/60-minute Interval Data Recording
- Data Storage
- Outage and Restoration Notification
- Integrated Service Connect/Disconnect
- Load limiting
- ZigBee Smart Energy Profile HAN Interface
- Reactive Energy & Power Factor (commercial meter only)

2.6.1.2.4 HAN Communications via the AMI

The AMI supports HAN applications via the ZigBee-standard Smart Energy Profile using the SmartMeter to manage the HAN. This allows KCP&L to communicate usage information, pricing information, and text messages with ZigBee compliant in-home devices, such as In-Home Displays (IHDs), Programmable Communicating Thermostats (PCTs) and HAN Gateways.

Figure 2-25: Communication Flow from the AHE to the HAN via the FAN



2.6.1.3 AMI Implementation

The KCP&L AMI, also referred to as SmartMetering in customer communications, was implemented to support the Demonstration Project area over an approximately nine month period beginning in October, 2010 and ending in June, 2011. The implementation consisted of the deployment of SmartMeters to all customers within the Demonstration Project area, the installation of the AHE to manage SmartMeter information, the deployment of the wireless FAN to connect SmartMeters to the AHE, and the integration of the AHE to KCP&L back-office systems.

SmartMeter installers for the project were hired through a third party from the Demonstration Project area. This was in line with KCP&L's commitment to hire and train local labor as the overarching theme of the Green Impact Zone. These employees were given training on basic electricity, proper residential metering configuration, meter exchange procedures, workplace safety, and customer service. KCP&L journeymen meter technicians deployed all 3-phase meters in the Demonstration Project area due to their expertise and high level of safety awareness.

Meter reading routes were selected for the determined project geographic area. Prior to implementation, KCP&L conducted a route audit to check for safety concerns, determine accessibility issues, identify non-standard and A-base meter enclosures, and identify potential customer concerns. During KCP&L's previous Automated Meter Reading (AMR) deployment, A-base meter sockets were used to retrofit many legacy meter types housed within meter enclosures. Minor safety issues (e.g. meter seals missing, diversion issues, etc.) were identified and corrected prior to beginning the installation of SmartMeters.

Through pre-deployment testing, KCP&L meter technology staff determined that the greater physical depth of the SmartMeter would not allow the meter enclosure cover to close properly on many of these installations. KCP&L contracted with Milbank, a local Kansas City meter socket manufacturer, to design and construct modified covers for those legacy meter enclosures.

Meters were installed according to sequential routes established by KCP&L. Installers used hand held computer devices to record old meter numbers and readings, latitude/longitude of each smart meter service point, and a picture of both the old and new meters. All new meter identification information was captured and data was uploaded and sent to KCP&L electronically at the end of each day of installation. This helped ensure data transfer was accurate and the pictures assisted in investigations and resolutions of issues that arose.

KCP&L used internal construction crews, assisted by L+G personnel, to deploy the communications network. Collectors were installed at the substation in the Demonstration Project area and on a transmission pole near the future site of a new substation just north of the area. One collector communicates via a fiber-based network and the other via a wireless network. Landis+Gyr provided an optimized network installation guide for the routers within the FAN. Routers were installed on distribution feeder poles where possible.

2.6.2 Meter Data Management (MDM)

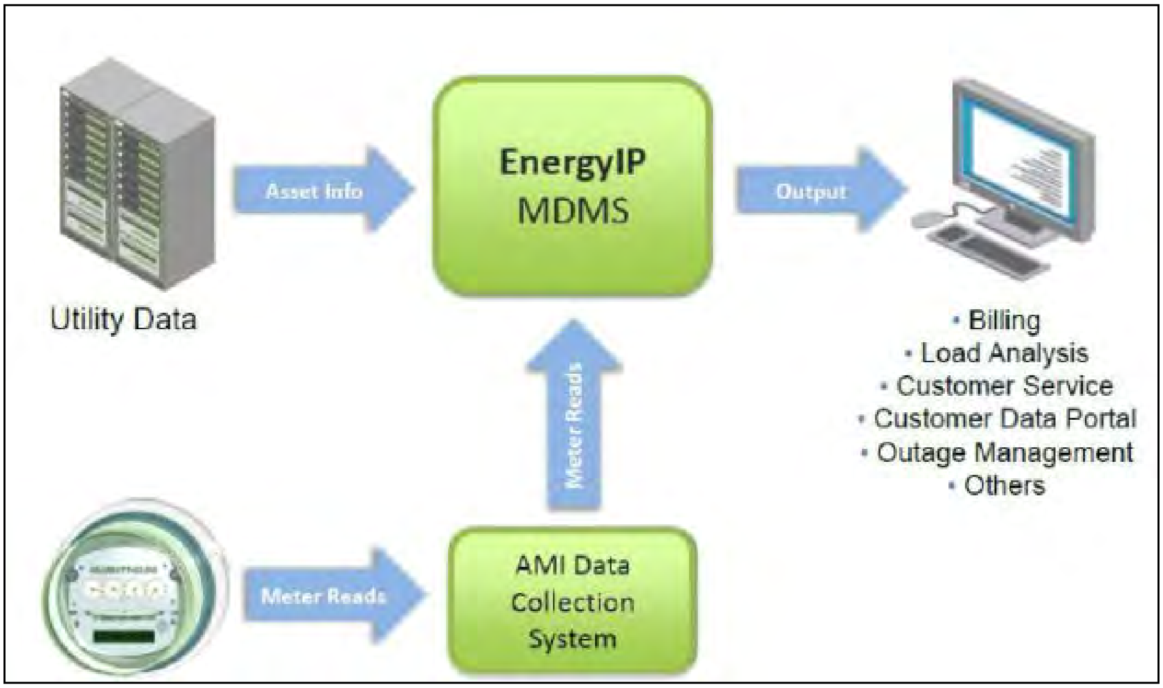
The Meter Data Management System (MDM) provides access, collection, and management capabilities for the consumer metering information for all customers in the KCP&L Green Impact Zone SmartGrid Demonstration area, including residential, commercial and industrial consumers. It stores the customers' 15-minute interval consumption data and daily register read data which is then available to support SmartGrid data analytics and for billing the TOU Billing Pilot Program rates launched in 2012. Other EE/DR incentives may be evaluated using this data in the future. Additionally, the MDM manages the work flow of events and other requests between the legacy CIS and AMI infrastructure for Remote Service Order handling as well as integration between the AMI infrastructure and the demonstration OMS for outage analysis. Future avenues for integration may include the demonstration DMS/OMS systems, DERM system and selected Home Area Network (HAN) management systems.

2.6.2.1 MDM Overview

The eMeter EnergyIP MDM system provides the capability for receiving and storing meter interval and register data from the AMI system. Services such as Validation, Estimation and Editing (VEE) are provided as part of the data storage process to ensure a high level of data completeness and data quality. The EnergyIP platform supports integration with Customer Information Systems (CIS) for data synchronization, remote service order processing (i.e.

Connects, Disconnects, and On-Demand Reads) and calculation of billing determinants from interval data for use in Time-of-Use (TOU) billing and other advanced billing programs. Additional integration is provided with the AMI infrastructure to capture and manage meter events including Outages and Restorations generated from the AMI which are then sent downstream to systems such as the Outage Management System for further processing.

Figure 2-26: MDM Integration Overview



2.6.2.2 <u>MDM Characteristics</u>

This section describes the major characteristics of the MDM system which are being leveraged by KCP&L as part of the SmartGrid Demonstration project.

2.6.2.2.1 <u>Meter Usage Data Repository</u>

At the core of the MDM's capabilities is the ability to store large amounts of meter generated data. For KCP&L, this includes daily register reads and 15-minute interval reads for the 14,000 AMI meters deployed to the Demonstration Zone, or roughly 1.3M interval reads per day to go with 14,000 register reads. Once in the MDM repository, the MDM can provide aggregations of data across various levels including circuit, feeder, substation and transformer. It can also export this VEE'd data for use in downstream systems such as the Data Mining and Analysis Tool (DMAT), Distributed Energy Resource Manager (DERM) and Home Energy Management Platform (HEMP).

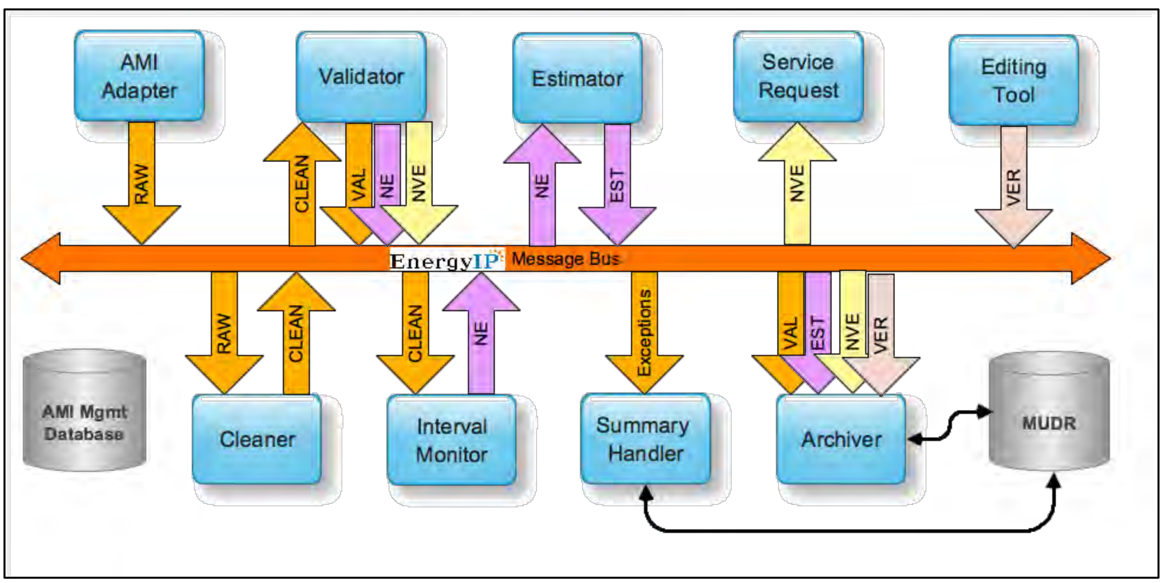
The MDM also provides storage for all historical meter read data from the beginning of the SmartGrid Demonstration project AMI rollout in October 2010; full history will be retained for the duration of the Demonstration project for each meter. This is a significant improvement over what would otherwise be available from the AHE or meters themselves.

In addition to meter readings, the MDM also is a repository for events generated within the AMI meters such as Outages, Restorations, alarms (i.e. tampering) and operational activities (i.e. Demand Reset). Service orders are also tracked and stored in the MDM system for activities including remote connects, remote disconnects and on-demand reads.

2.6.2.2.2 Validation, Estimation & Editing

The MDM delivers Validation, Estimation, and Editing (VEE) capabilities that provide estimations for missing intervals, and ensure more reliable, accurate interval data is posted to the Meter Usage Data Repository. The Validation module performs validation according to user configurable rules associated with each data stream; these validations include checks for usage spikes, reverse rotation, etc. Where possible, the Estimation module will follow a defined set of rules to extrapolate and interpolate interval data as well as to estimate register read data when the data is not received from the AMI infrastructure. There are times when the Validator determines that the interval data needs manual verification and editing and/or when the Estimator is unable to provide a valid estimate. For these instances, manual editing via a tabular or graphical view is available within the MDM. In all cases, the MDM also tracks versioning of data when estimation and editing are taking place and it provides audit trails for data manipulations.

Figure 2-27: MDM Interval Handling Workflow



Transient Message Types
RAW = Raw Interval Message
CLEAN = Clean Interval Message
NE = Needs Estimation

Persistent Record Values
VAL = Validated (incl Verified)
EST = Estimated (incl Edited)
NV = Not Validated
NVE = Needs Verification/Edit

2.6.2.2.3 Usage Framing

The MDM can support multiple usage framing configurations based on a utility's needs. This "framing" sums up a customer's interval data over a specified period of time into a total usage amount for that period and stores it in the appropriate "bin". For example, KCP&L's Time-of-

Use (TOU) billing program has established a framing schedule that, on non-holiday weekdays, sums all 16 of a customer's 15 minute interval values between 3PM-7PM to create a "peak" usage bin and the remaining 80 daily interval values between 12AM-3PM and 7PM-12AM to provide an "off-peak" usage bin. For weekends and holidays, all 96 daily intervals are added to the "off-peak" total. The schedule is further split into summer vs. winter seasons – during the winter, all usage is added to the "off-peak" bin. As the MDM can support multiple framing configurations, when KCP&L considers additional custom programs in the future such as critical peak pricing, EV charging (aka super-off-peak pricing), or simply different TOU schedules, these can all be set up in the MDM for framing into the appropriate usage bins. Each of these framing programs can also be configured to be setup on specific subsets of customers which further enables the utility to deliver advanced billing solutions to its customers.

Figure 2-28: Usage Framing for TOU

Season	ProfileID	Weekday	TOU BIN	Season	ProfileID	Weekend	TOU BIN	Season	ProfileID	Holiday	TOU BIN
Winter	1	00:00-08:00	1	Winter	1	00:00-00:00	1	Winter	1	00:00-00:00	1
		08:00-21:00	3								
		21:00-00:00	1								
Summer		00:00-08:00	1	Summer		00:00-00:00	1	Summer		00:00-00:00	1
		08:00-12:00	3								
		12:00-18:00	2								
		18:00-23:00	3								
		23:00-00:00	1								

2.6.2.2.4 Billing Determinants

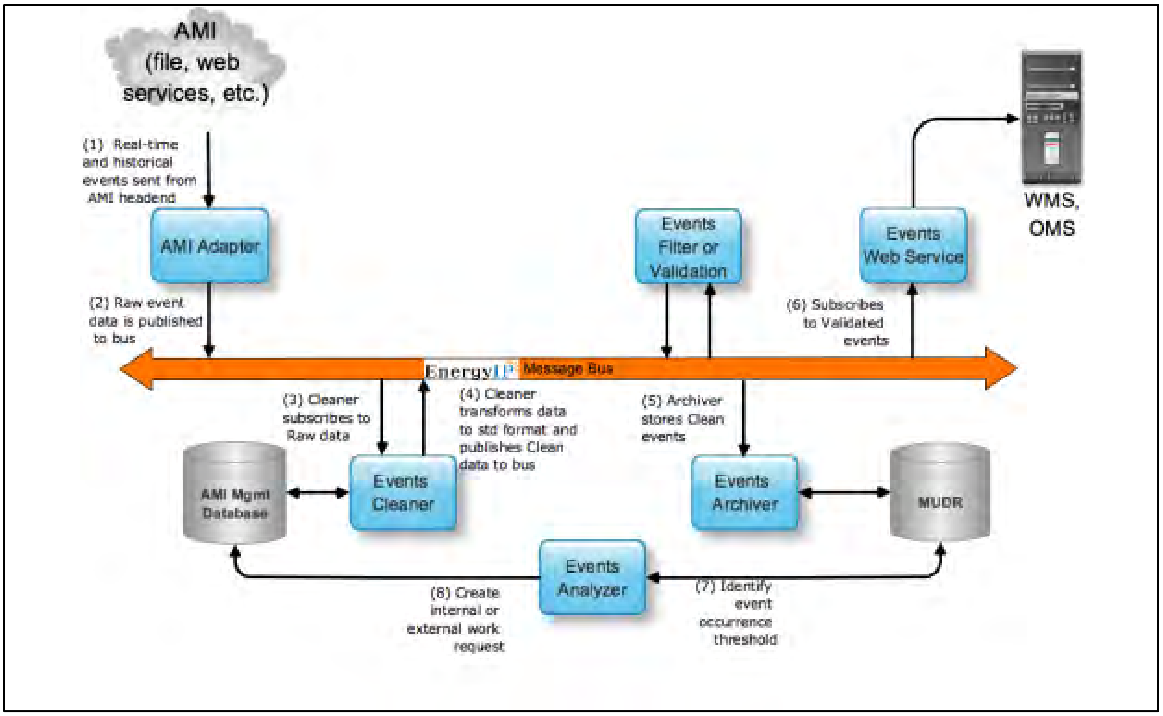
The MDM provides a variety of methods to calculate and deliver billing determinant information to a utility's CIS system. This can be done in a batch format that matches bill cycles / billing routes and delivers a customer's total usage for the month or at various other more customizable levels. The billing determinants can be delivered in both a "Push" method where the MDM produces and delivers a file on a set schedule or in a "Pull" method where the CIS system makes the request for data to the MDM and receives the necessary response back. In addition to traditional billing, MDM can support various advanced billing programs such as Time-of-Use (TOU) billing, critical peak pricing, EV charging rates, etc. as desired by the utility.

KCP&L is currently using a modified version of the Pull Billing process to support its TOU billing pilot program. The TOU rate schedule (summer/winter seasons and peak/off-peak times) and rate programs (1TOUA for standard customers and 1TOAA for all-electric customers) are set up in the MDM system to drive usage framing as noted above. This framed usage is then retrieved via an "off-cycle", "informational" request to the MDM Pull Billing interface. This type of request supports KCP&L's daily retrieval of the peak/off-peak bin values for TOU customers. These daily usage values are then processed through KCP&L's SmartGrid middleware which converts them to virtual daily dial values for each TOU bin. These values are then fed into the CIS system when needed for monthly bill cycle processing.

2.6.2.2.5 Meter Event Management

MDM provides the capability to interface with the AMI infrastructure to collect event flags for outage, tamper and diagnostic issues. It can store and manage defined business processes including the creation of service orders and/or transmission of event logs to the relevant utility system for further action. MDM has the ability to generate reporting on these events as well.

Figure 2-29: MDM Event Handling Overview



With the exception of the Outage / Restoration Events which are described in more detail below, KCP&L is currently capturing and storing event messages in the MDM; future projects may build additional interfaces and reports to utilize this information. Events being tracked in the MDM are listed in Table 2-7.

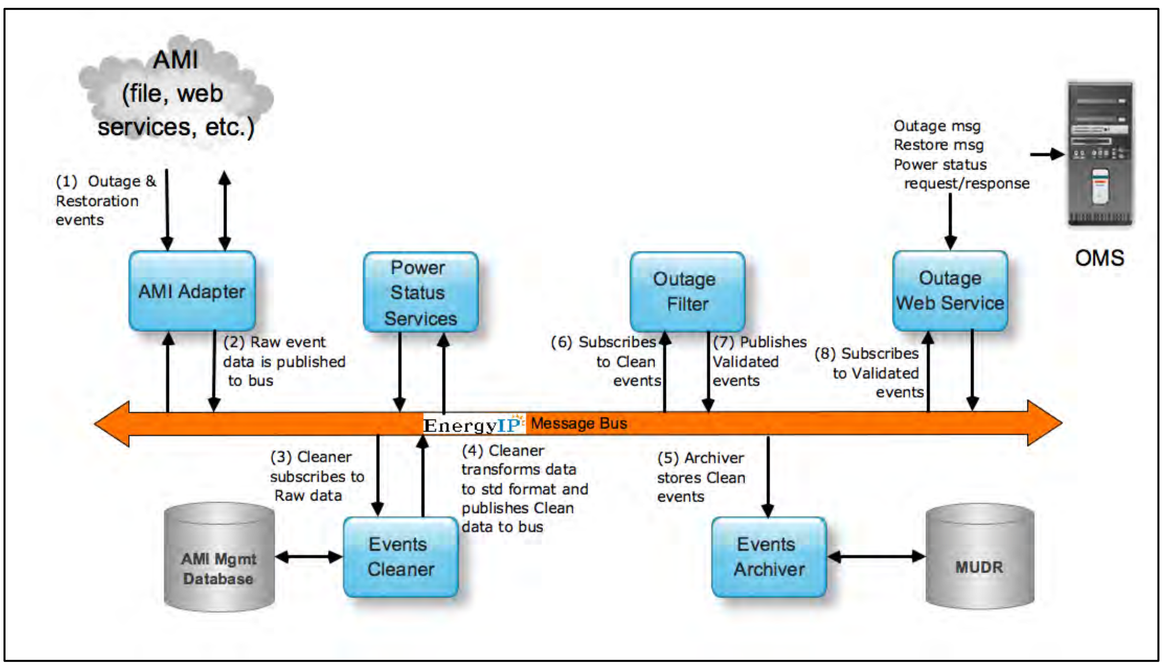
Table 2-7: MDM Events Tracked

Event Number	Event Description
3.18.1.199	RAM Failure Detected event mapping
3.18.1.220	ROM Failure Detected event mapping
3.2.1.149	Meter Battery Low event mapping
3.21.1.173	Non-volatile Memory Failure Detected event mapping
3.21.1.213	Meter Reprogrammed event mapping
3.21.1.52	Fatal Error
3.21.1.79	Measurement Error Detected event mapping
3.21.1.81	Event Log Cleared event mapping
3.21.1.95	History Log Cleared event mapping
3.21.18.79	Self-Check Error Detected event mapping
3.21.7.79	Meter Configuration Error event mapping
3.33.1.219	Reverse Rotation Detected event mapping
3.33.1.257	Tamper Attempted Suspected event mapping
3.8.1.61	Meter Demand Reset Occurred event mapping

2.6.2.2.6 Outage Event Management

As noted above, the MDM captures and stores Outage and Restoration events generated from the AMI metering system.

Figure 2-30: MDM Outage/Restoration Event Handling



Once in the MDM, configurable business rules can be applied to filter the raw outage information prior to transmitting it along to the OMS system. These filtering rules include managing the time stamps on events that may be transmitted multiple times to prevent the repetitive messages from having to go downstream to the OMS as well as monitoring for de-bouncing scenarios where the outage and restoration come into the MDM in a very short time span. The MDM also provides a bellwether capability as well as critical infrastructure monitoring capability for designated meters; neither of these functions is being used currently by KCP&L in the MDM. The MDM workflow can also provide integration support for Power Status Verification requests made by the OMS system and transmitted down to the AMI infrastructure through the MDM.

The Outage and Restoration Events configured in the KCP&L MDM are listed in Table 2-8.

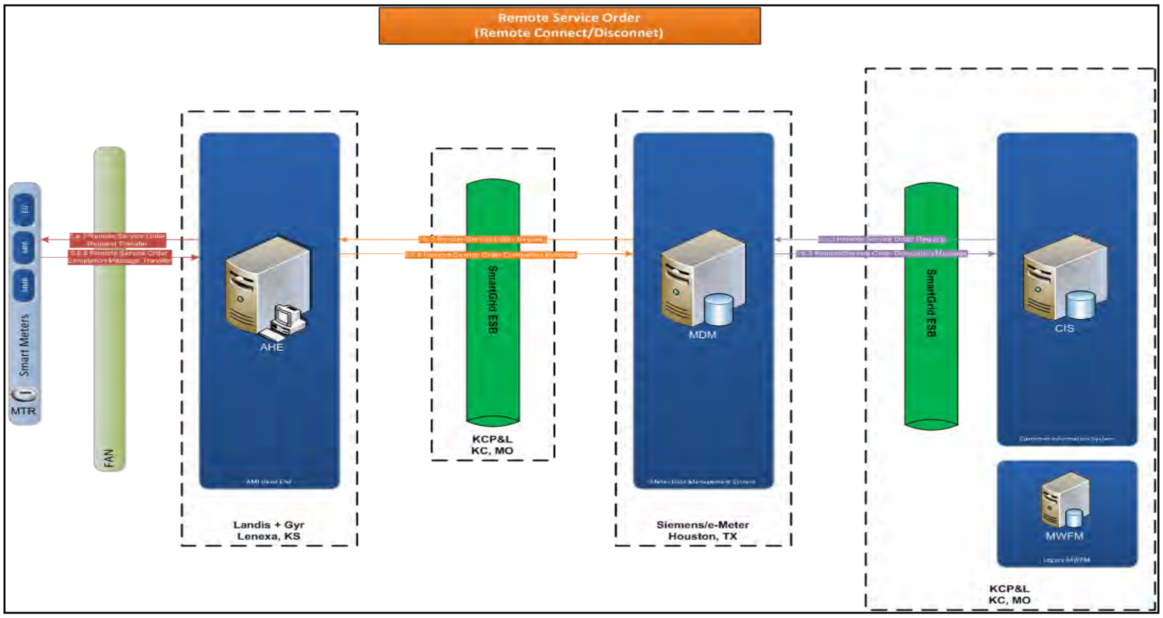
Table 2-8: Outage Restoration Events

Event Number	Event Description
3.26.9.185	Endpoint Power Outage
3.26.9.216	Endpoint Power Restore
3.26.17.185	Primary Power Down
3.26.17.216	Primary Power Restore

2.6.2.2.7 Remote Service Orders

The MDM provides the capability for integration with CIS and AHE systems to provide workflow management for various service orders, including remote connects, remote disconnects and on-demand reads (ODR). As part of this integration, MDM receives a single order from CIS and breaks it down into the appropriate components – i.e. disconnect and ODR or reconnect and ODR – to be sent down to the AHE in the appropriate order. As part of the workflow, the MDM will send the initial request (i.e. ODR) to the AHE and then wait for the response prior to sending the second part of the service order (i.e. Disconnect) down to the AHE. Once the necessary responses for all messages in the workflow are received from the AHE, the MDM then packages them into a single response that is then sent back to CIS for processing. In addition to supporting integration with CIS for these order types, the MDM also supports manual entry (if needed) of these service requests directly in the MDM.

Figure 2-31: MDM Remote Service Order Handling Overview



KCP&L has implemented Remote Service Order capability for voluntary customer-requested On-Demand Reads, Remote Disconnects and Remote Reconnects as of the conclusion of 2012. Additional work to handle remote service orders for non-payment by customers is targeted for early 2013.

2.6.2.3 MDM Implementation

The KCP&L Meter Data Management (MDM) System was deployed during 1Q2012 using the eMeter EnergyIP 7.2 software platform hosted by Siemens at their Customer Pilot Hosting Environment (CPHE) in Houston, TX. Initial interfaces were built between the MDM system and KCP&L's internal CIS system and SmartGrid Middleware to deliver service point information and meter read data to the MDM. Additional interfaces were added following the initial launch to provide interactive two-way capabilities for Time-of-Use billing, remote service order processing, outage/restoration events and other meter events involving MDM, CIS, the AHE and Enterprise Service Bus (ESB). All meter read data (15 minute intervals and daily register reads) from the beginning of the AMI rollout in October 2010 is stored in the MDM system.

2.6.2.3.1 Phase 1 – Initial Launch

The MDM was implemented jointly by KCP&L and Siemens in three major phases, each comprised of several sub-projects. Phase 1 consisted of the initial launch of the system and key interfaces as well as the load of all historical meter read data from October 2010 through March 2012; this phase completed in March 2012. The MDM work necessary to support TOU billing was completed as part of this phase also.

Preliminary scoping workshops were conducted in mid-2011 with development and configuration beginning in earnest in September. A key element was the stand-up of Siemens Customer Pilot Hosting Environment in Houston; this was the first time that eMeter or Siemens had implemented an eMeter installation in a Software-As-A-Service (SaaS) model. This included an internal Siemens-only Development environment as well as Test and Production environments that are connected to the corresponding KCP&L systems.

Basic configuration of the MDM included Validation, Estimation and Editing (VEE) settings, the various meter data services that process information within the MDM, all of the field values necessary to operate, configuration of the system calendar (bill cycles, holidays, etc.), user setup and security configuration. The TOU rates, calendar and usage framing setup work was also performed during this initial round of configuration activity.

KCP&L and Siemens implemented a number of core interfaces during this initial phase. They included the “FlexSync” interface to transmit incremental changes in service point information from CIS to MDM to keep the two systems in synch with CIS acting as the system of record. KCP&L was the first customer to implement the “FlexSync” method instead of the traditional “batch” synchronization method that would send a full set of service point information for all customers on a regularly scheduled basis. Meter reads are being sent to the MDM from KCP&L’s AHE via a secure file transfer process that transmits the register read file once daily with all 14,000 reads; the 15-minute interval reads are sent on an hourly basis to the MDM with approximately ¼ of the meters sending four hour blocks of intervals every hour which results in roughly 56,000 reads being sent every hour from AHE to MDM in the SmartGrid Demonstration Zone. The final interface delivered during this phase was the “Pull Billing” interface that KCP&L is using to retrieve daily framed usage totals to be used in billing TOU customers. The “Pull Billing” interface uses the standard MDM interface in a non-traditional manner by pulling daily “Off-Cycle, Informational” reads instead of the standard monthly billing determinants; these daily totals are then fed through KCP&L’s SmartGrid middleware where they are converted into virtual daily dial reads that can be used by the legacy CIS system for billing the TOU customers.

The final component of Phase 1 involved loading both service delivery point information and meter read data to the MDM system. Using the FlexSync process, KCP&L loaded ~14,000 records that included customer, account, service delivery point, premise and meter data to establish the appropriate and corresponding information within the MDM. All relationships between these various data sets was loaded as of January 2012 and did not include any historical changes – i.e. move-ins/outs, meter exchanges, etc. that may have occurred from the beginning of the Demonstration project and AMI rollout in October 2010. Once these service delivery points’ records were fully loaded, KCP&L and Siemens then loaded the set of historical AMI from October 2010 onward. By the time this load was completed in March 2012, we had loaded approximately 5.8M historical daily register reads and ~550M historical 15 Minute Interval reads. Our ability to load this was aided by Landis+Gyr’s willingness to retain the data longer than would typically be held and by Siemens flexibility in developing a load process; per the vendors, an MDM is typically implemented at the start of an AMI rollout so that the data can begin loading from the onset.

2.6.2.3.2 Phase 2 – ESB Integration

The second phase of the MDM implementation took place over the middle and latter part of 2012. This phase focused on improving the security of the end-to-end system by moving the MDM and its interfaces into a VPN tunnel, as well as integration of the MDM with an Enterprise Service Bus (ESB) to allow KCP&L to take advantage of the various workflows, service order and event management capabilities provided by the MDM system. This phase completed in November 2012.

While preliminary workshops occurred in February 2012, work began in earnest in the April/May timeframe with a preliminary security assessment as well as a set of detailed Joint Design Sessions (JDS) that were hosted by KCP&L and included participation from the Siemens delivery team and Siemens/eMeter architects, as well as technical and project management support from Landis+Gyr (AMI vendor) and Intergraph (Outage Management System vendor).

Integration with the KCP&L SmartGrid Enterprise Service Bus (ESB) was one of the main development activities for both KCP&L and Siemens during Phase 2 of the MDM Implementation. The KCP&L ESB development provided an interface between the MDM and CIS as well as the MDM and OMS as well as an interface between the MDM and the AHE; collectively, these interfaces support three different business processes. Siemens supported this integration work by implementing the eMeter L+G 5.1 Adapter (IEC61968-9 Version 1 compliant) which faces the AHE and supports receipt of general meter event messages, outage/restoration event messages and the handling of remote connect/disconnect/on-demand read commands. Between CIS and MDM, to support the transmission of Remote Disconnect, Remote Connect and Remote On-Demand Reads from CIS to the AHE, Siemens developed the “CIM2AG” adapter (IEC61968-9 Version 2 compliant) for transmitting messages between the EnergyIP Activity Gateway and KCP&L’s ESB. Between OMS and MDM, Siemens developed the “OMS2CIM” adapter (IEC61968-9 Version 2 compliant) which currently supports transmission of Outage/Restoration events via the ESB to OMS; eventually, this is expected to support Power Status Verification requests from the OMS back to the AHE as part of Phase 3. Configuration of the MDM was also performed by Siemens to support the necessary workflow for translation and management of the remote service orders as well as the Outage/Restoration events. General meter events (non-outage, non-restoration) are simply logged in the MDM for future analysis.

2.6.2.3.3 Phase 3 – Wrap-Up

The final phase of the MDM Implementation is underway as of November 2012 and is expected to complete in the March/April 2013 time frame depending on the final scope and delivery schedules for the component projects. Scoping, schedule and cost discussions are currently underway between KCP&L and Siemens for the delivery of this work. Major elements targeted for this phase can be broadly grouped into two categories: Functionality and Operational Support.

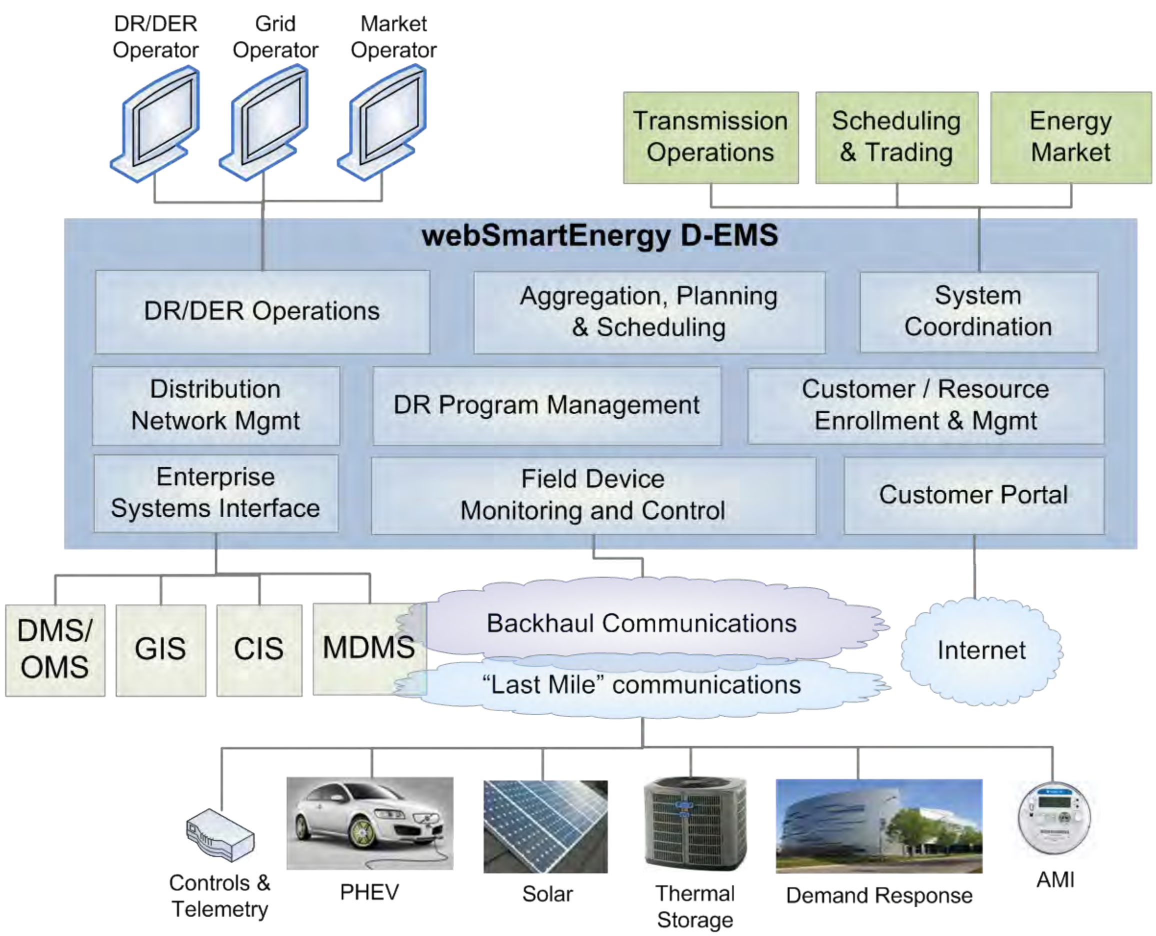
The category of “Functionality” includes both internal MDM configuration as well as some additional interface work between the MDM, ESB and other KCP&L SmartGrid Systems. KCP&L is targeted to upgrade the eMeter L+G Adapter from the currently implemented 5.1 Adapter to use the 5.7 Adapter; this will support the Power Status Verification (PSV) interface between the OMS system and AMI infrastructure as well as resolving some outstanding defects in the current adapter that KCP&L has identified. The Power Status Verification project will enable the OMS system to send a PSV message via the ESB to MDM where it will be translated to the appropriate message type and then sent on to the AMI system for response. MDM will be providing workflow management for this process. Interval data is at the core of two additional work packages – the aggregation of interval data for load research by KCP&L as well as the delivery of post-VEE'd interval data from MDM to downstream systems such as the HEMP, DMAT and DERM. Configuration to deliver both of these outputs will be performed in the MDM and KCP&L will provide the necessary interfaces to retrieve the output and deliver it to the appropriate location for processing. A final set of functionality is expected to expand the remote service order capability delivered in phase 2 to include remote disconnects and reconnects related to non-payment by customers; the majority of this work will be performed in the CIS system to identify these customers whereas MDM is expected to re-use the existing workflow and support testing.

2.7 SmartDR/DER Management (DERM)

The SmartDR/DER Management sub-project is deploying a state-of-the-art distributed energy resources management (DERM) system. This DERM stores and manages all information pertaining to demand response (DR) and distributed energy resources (DER) programs and assets. The DERM must integrate with a number of other KCP&L systems, including the Customer Information System (CIS), Meter Data Management (MDM) system, Distribution Management System (DMS), and Customer Relationship Management (CRM) system. In addition to interfacing with these back-end systems, the DERM will communicate with various "control authorities" that oversee particular types of resources.

For this project, the DERM will be used to respond to overload conditions for system reliability purposes. The DERM will help to prevent overloads from occurring, and it will shorten the duration of outages that do occur. The DERM is also capable of being used for economic purposes, but this will not be the focus during the demonstration project.

Figure 2-32: Distributed Energy Management Solution Functional Overview



2.7.1 DERM Overview

For the demonstration project, KCP&L will be implementing a DERM system from Open Access Technology International, Inc. (OATI). Their product, called the webSmartEnergy Distributed Energy Management Solution (DEMS) provides full visibility into demand side capabilities, the ability to leverage those capabilities for operational and economic efficiencies, and the ability to aggregate and use those capabilities in support of wholesale market operations. A diagram of the webSmartEnergy DEMS solution appears in Figure 2-32.

2.7.2 DERM Characteristics

The OATI webSmartEnergy DEMS is the industry's most comprehensive software solution for demand-side resource management and control. webSmartEnergy DEMS provides the bridge between advanced metering, DR/DER, variable generation, distribution grid, transmission grid, and wholesale markets. In addition to a full complement of conventional Demand Response capability, webSmartEnergy DEMS provides the capabilities needed to optimally manage distributed energy resources for the support of distribution system load relief, and for the transmission and market operations, (e.g., providing ancillary services and balancing energy to support variable generation). By mapping DR/DER to distribution grid locations, and tracking circuit, feeder, and equipment conditions, webSmartEnergy DEMS provides a unique combination of capabilities for integrated Smart Grid operation while considering limitations imposed by transmission and distribution grids.

The webSmartEnergy DEMS solution provides the following capabilities:

- Managing and controlling diverse types of demand-side resources:
  - Demand response resources including commercial and industrial (C&I) energy management systems, home automation equipment, home area network devices, concentrated energy efficiency programs
  - Feeder and substation-level generation and storage resources including PV roof-top assets and the Green Impact Zone 1MW battery
  - Customer stand-by/parallel on-site dispatchable and non-dispatchable generation
  - Plug-in electric vehicle charging stations

- Creating and managing various DR programs:
  - Dispatchable/direct load control (DLC) programs as well as price-based and voluntary programs, including market-based and dynamic tariffs
  - A variety of traditional utility DR programs including time of use (TOU), critical peak pricing (CPP), AC cycling, and emergency curtailment

- Managing various market and transmission operation support products:
  - Mapping DR/DER capabilities to wholesale energy products
  - Energy, ancillary services (non-spinning reserve, spinning reserve, and regulation from eligible resources), capacity (for resource adequacy, where allowed by market)

  - Aggregation at feeder and substation levels, as well as by device type, DR program, market product, zone, pricing node, etc.

- Tracking and managing renewable portfolio standards (RPS) and greenhouse gas (GHG) contributions of distributed and demand-side resources
- Interfaces and secure integration with AMI/, field devices, customers, system operations, enterprise, and other external MDM system interfaces including:

  - Interfaces with wholesale scheduling and trading functions – independent system operator (ISO) operations
  - Integration with systems, operations, and customer service systems including MDM, CIS, SCADA/EMS/DMS
  - Interfaces with field equipment including HAN based devices

- User interface and operational support for different user classes/roles including:

  - Demand response manager, curtailment service provider, aggregator
  - Customer services for customer enrollment and customer interactions
  - Merchant operator for wholesale aggregation and scheduling
  - Customer portal

- Scalable design with high-performance work flow for DR program execution management. It is designed to support a large number of customers, a large volume of transactions (DR functions), and a large number of simultaneous users (customer portal access)
- Stringent cyber security measures and adherence to NERC CIP and other cyber security standards
- Data privacy and stringent cyber security measures and access authorization/control by user classes and functional roles
- Web service interfaces for integration and interoperability with utility's system operations and wholesale scheduling systems

For the demonstration project, the DERM will be called upon when the DMS needs assistance with a current or projected future overload. The DMS will try to solve the issue using its own resources first, through feeder load transfer or conservation voltage reduction. If these methods do not completely address the overload, then the DMS will call upon the DERM for demand response.

The DERM will store and manage all the information about the various demand response programs and assets for the demonstration project. It will keep track of tariff limitations (for example, KCP&L might only be able to call upon a particular program four times in one month) and any costs associated with calling on each program. It will suggest DR options that address the overloaded feeders and it will prioritize based on these limitations and associated costs.

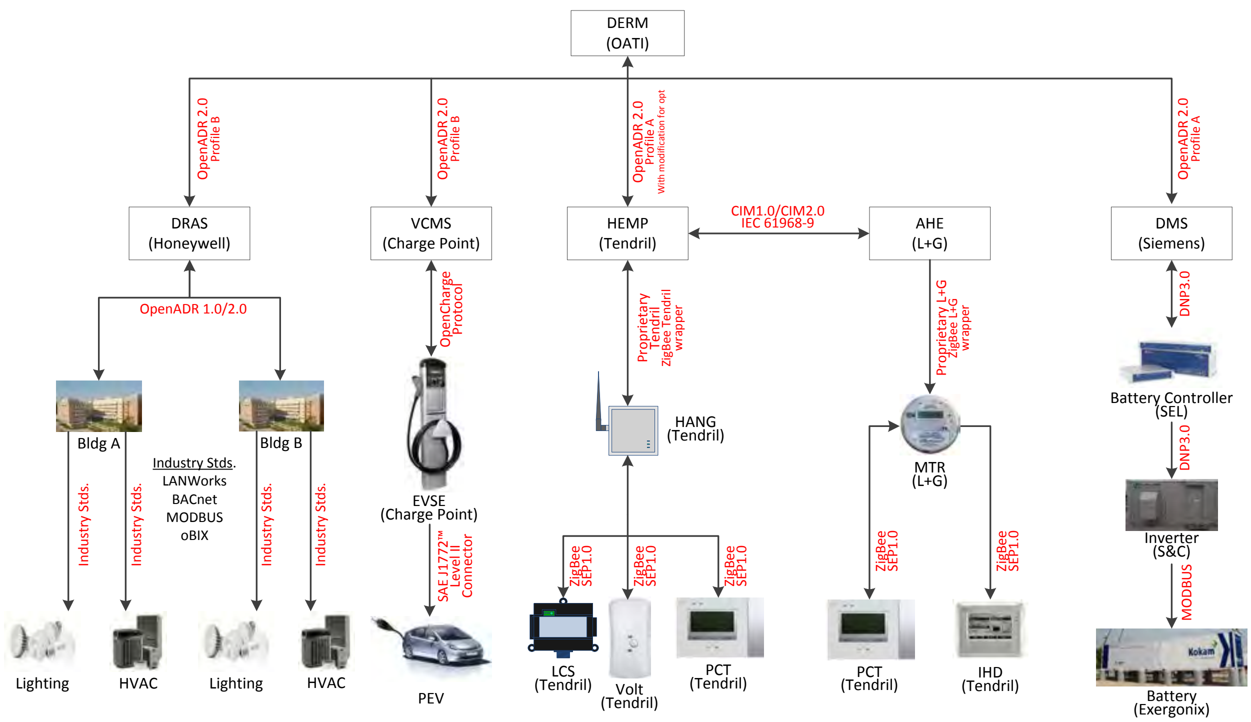
Once the operator selects the DR to apply to the situation (either using the DERM's recommendation or selecting other options), the DERM schedules the DR event. The DERM won't communicate directly to the end devices participating in the event, however. Instead, the

DERM sends DR messages to the "control authorities." For the demonstration project, the DERM will dispatch DR events to the following control authorities:

- Home Energy Management Platform (HEMP) for residential DR
- Vehicle Charge Management System (VCMS) for EV charging stations
- Distribution Management System (DMS) for grid-connected assets, such as the 1MW battery
- Demand Response Automation Server (DRAS) for Commercial Building Management (BMS) systems

These control authorities will then send the appropriate DR messages down to the end devices to direct their participation in the scheduled event. Figure 2-33 shows the various systems that the DERM can call upon, along with the message types used for each of the associated interfaces.

Figure 2-33: DERM Demand Response Architecture



2.7.3 DERM Implementation

The DERM implementation began in 2011. The first step in this process was to familiarize KCP&L personnel with the capabilities of the system. OATI project members came to KCP&L for a workshop where they demonstrated the overall system, and then they walked through the components planned for the KCP&L project.

The next big task was to design the interface between the DMS and the DERM. Since this was a completely new, custom interface, it required lots of face-to-face time between Siemens, OATI, and KCP&L. In order to design the message exchanges for this interface, KCP&L, Siemens, and

OATI met for several days to create use cases for the possible scenarios. The main scenarios that were detailed included:

- Initialization between DMS and DERM – used the first time a new database is applied or after one of the systems has been restarted
- Feeder load management – also called "studycase," this is an exchange between the DMS and the DERM done in a planning mode
- Feeder load shed – also called "emergency," this is an exchange between the DMS and the DERM done in real time when an overload has occurred

Upon completion of the DMS/DERM use cases, all parties worked on technical specifications for these interfaces to develop the standards-based messages that would be used to exchange the agreed upon information.

In order for the DERM to function, it needs to get input from several other KCP&L back-end systems. KCP&L has worked to provide the required information to OATI to get the DERM up and running. The data requirements are outlined below:

- **AMI interval data** – the DERM needs this information to create customer baselines. It is currently getting this 15-minute interval data on a daily basis from the AMI Head-End (AHE), but eventually the data will come from the Meter Data Management (MDM) system after it has gone through the Validation, Estimation, and Editing (VEE) process.
- **Customer enrollment data** – the DERM needs this information to map DR capabilities with distribution transformers. It is currently using a list of Green Zone customers enrolled in the Optimizer program, along with some artificially-generated enrollment information for testing purposes. Eventually, this data will come from a combination of HEMP, AHE, and CRM data.
- **Network connectivity model** – the DERM needs an up-to-date model of the distribution model so that when DMS asked for reduction on a particular feeder, the DERM is looking at the same section of the distribution system. This model is currently being sent from Siemens and loaded manually by OATI personnel. Eventually, this process needs to become more automated since it is planned for monthly data model updates.

Even though all of the interfaces with other systems are not complete, KCP&L and OATI conducted a Factory Acceptance Test covering the base functionality of the DERM. This test occurred 5/22/2012 through 5/25/2012. The major variances discovered during the FAT were all resolved the month following the testing.

Another major work effort for this component of the project was the DERM/HEMP interface design. KCP&L asked OATI and Tendril (the HEMP vendor) to utilize OpenADR 2.0, profile A, for this interface. Since the A profile was still be developed when the design of the interface was underway, KCP&L agreed to have the two vendors designed around a particular working draft. Additionally, KCP&L allowed several modifications to the A profile implementation to facilitate the opt-out functionality that was desired for the project. Upon completion of the interface, OATI and Tendril conducted point to point testing of the planned DR messages.

Currently, OATI and Siemens are conducting testing of the DMS/DERM interface. They started by doing simple message exchange testing, and they are now moving towards testing the full-fledged use cases. This advanced testing requires that the messages are sent and received as expected, and that any internal DMS or DERM applications are triggered as designed. This complex testing will continue into 2013.

Additional DERM work efforts planned for 2013 include:

- Automated daily meter interval data push from MDM, after it has gone through the VEE process
- Automated weekly push of customer enrollment data from CRM/HEMP/AHE
- End-to-end testing of residential DR for the following flows:

    - DERM -> ESB -> HEMP -> ESB -> AHE -> meter -> end device
    - DERM -> ESB -> HEMP -> HAN Gateway -> end device

- Design, development, and testing of DERM/BMS interface
- Design, development, and testing of DERM/DMS interface for battery control
- Design, development, and testing of DERM/EVSE interface

2.8 SmartGeneration Resources

KCP&L will make use of a variety of distributed energy resources in the project area, including:

- Grid-scale energy storage
- Distributed renewable generation
- Direct load control demand response (DR) programs

Working in concert with other SmartGrid technologies, these resources will serve to demonstrate a "virtual power plant" which can dynamically respond to changing system conditions. The net effect of this virtual power plant is to defer the need to build additional fossil-fuel generating resources as well as helping to defer distribution and transmission system upgrades. Benefits of such deferrals flow through to customers in the form of lower costs, increased reliability and reduced environmental impact.

2.8.1 Battery Energy Storage System (BESS)

2.8.1.1 BESS Overview

One SmartGeneration component of the KCP&L demonstration is the evaluation of a 1.0 MW / 1.0 MWh Exergonix lithium polymer battery energy storage system (BESS). This system will be interconnected to the head of a single urban circuit just downstream of the substation bus. It will be integrated with demonstration control systems and will be exercised to demonstrate its capability to offer direct grid support via the following applications:

- Energy time shifting
- Net circuit load peak shaving
- Volt/Var support
- Circuit Islanding

In addition to demonstrating these applications, KCP&L aims to appraise the battery system's technical performance with regards to roundtrip AC efficiency.

2.8.1.2 BESS Characteristics

KCP&L partnered with Exergonix (www.exergonix.com) to provide and install the BESS. The Exergonix BESS consists of over 5,000 Kokam Superior Lithium Polymer Battery (SLPB) pouch cells that are coordinated by a unique battery management system. The battery system is driven by a PureWave Storage Management System (SMS) from S&C Electric (this may also be referred to as the Power Conditioning System or PCS).

2.8.1.2.1 Battery Technology

The patented SLPB technology is proven, is already in production in the U.S., and is being used in numerous applications around the world. The SLPB cell design increases energy density to as high as 200 Wh/Kg in high energy cell configurations and power densities as high as 2400 W/Kg can be achieved with minimum optimization on a high power cell design. The Kokam SLPB meets all performance standards of the U.S. Advanced Battery Consortium (USABC). The SLPB cells are expected to provide extended run time, 10+ years of operational life (up to 10,000 cycles), reduced need for complex cooling systems, and safe operation over a wide range of temperatures.

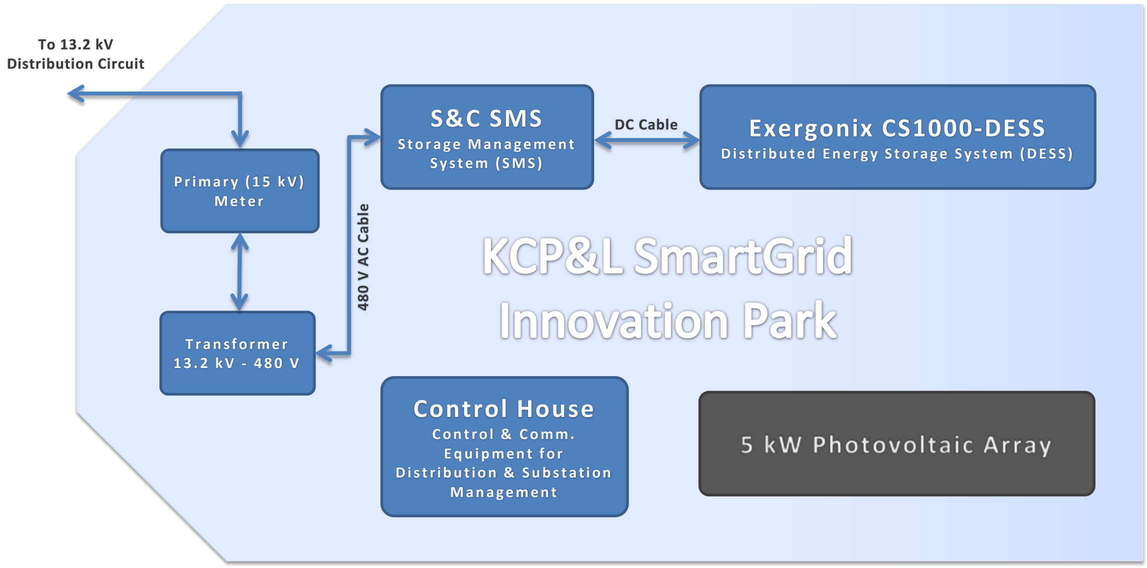
2.8.1.2.2 *Power Conditioning System (PCS)*

The S&C Electric PureWave SMS manages charge and discharge of the battery subsystem and converts AC grid power to DC battery power. It consists of a control system and a four quadrant bi-directional inverter, rated at ±1.0 MW / 1.25 MVA. The SMS converts nominal battery voltages (460 V_{DC} – 800 V_{DC}) into 3-phase 60 Hz, 480 V_{AC}, ±10%. It can operate at temperatures between -40°C and +40°C and altitudes up to 1,000 meters without de-rating. It is connected to a 480 V_{AC} transformer via a wye-delta configuration to step-up voltage to a 13.2-kV MV distribution circuit (See Figure 2-34). This PureWave SMS is specially equipped with remote control protocols for islanding purposes, a feature that is not included in the standard commercial product offering. The 800 V DC-to-DC converter can step down voltage and utilize a UPS to provide 30-minutes of backup auxiliary power to all internal controls needed during islanding events. At the conclusion of islanding events, the SMS can sync the battery with a recloser to automate seamless grid reconnect.

2.8.1.3 BESS Implementation

Figure 2-34 provides a schematic of the energy storage project's layout at KCP&L's SmartGrid Innovation Park. The site includes the BESS, smart grid pilot control house equipment, step-up transformer, and associated metering and monitoring equipment. It also includes a 5.0 kW ground-mounted PV array that is connected directly to the same circuit as the battery through a separate transformer.

Figure 2-34: BESS Implementation Site Overview



KCP&L broke ground on the project site in early February 2012 and the BESS arrived in March after successful factory testing. The battery was tested by Exergonix in Korea, while the SMS and a scaled-down version of the battery were factory tested together in Wisconsin at an S&C facility. Interconnection of the SMS and production battery unit occurred on-site in June 2012.

The site was completed and unveiled at the opening of the SmartGrid Innovation Park in October 2012. The completed battery system installation is shown in Figure 2-35. The battery enclosure is wrapped in educational content to facilitate community awareness and engagement.

Figure 2-35: BESS Installation

Remote and advanced operation of the BESS through integration with a pilot distribution management system is under development and is expected to be tested in 2013.

2.8.2 Distributed Renewable Generation: Solar Photovoltaic

2.8.2.1 Solar PV Overview

KCP&L will install approximately 180 kW of diverse solar photovoltaic (PV) systems on both residential and commercial properties throughout the pilot project area.

The implementation of these PV systems within the pilot project area will enable KCP&L to assess:

- The impacts of intermittent distributed generation on circuit voltage and power quality
- Monitoring of renewable generation and tracking against RPS requirements
- Building a database of PV type/installation generation performance in the KC metro area
- The potential for reverse power flows due to distributed generation
- The feasibility of aggregating, managing and potentially dispatching a high penetration of utility owned distributed PV systems and capacity
- The feasibility of owning and operating numerous distributed generation on the system

2.8.2.2 Solar PV Characteristics

The PV systems, with the exception of those installed on utility property, will be established through a lease agreement in which KCP&L will lease roof-top space but will own and maintain the PV system for a multi-year contract period.

Each system will be designed and specified independently based on available southern facing roof space. A variety of PV technologies and installation methods will be sought. Each system will be directly grid connected and metered independently for tracking purposes.

2.8.2.3 Solar PV Implementation

KCP&L has completed the installation of three separate PV systems with a total nameplate capacity of 107.35 kW. Installed systems are summarized in Table 2-9.

Table 2-9: Smart Grid PV Systems Installed

System Location	Technology	Capacity (kW)	In-Service Date
Project Living Proof (demonstration home)	Polycrystalline	3.15	01/19/2011
Paseo High School Gymnasium Roof-top	Thin film	99.20	04/19/2012
Innovation Park (Midtown Substation)	Monocrystalline	5.00	10/17/2012
		107.35	

Approximately 72 kW of additional PV capacity is currently under development with numerous customers within the pilot project area and those systems will be installed in 2013.

2.8.3 DR Load Curtailment Programs

2.8.3.1 DR Load Curtailment Program Overview

As part of the demonstration project, KCP&L will deploy direct load control devices to customers and businesses within the project area and integrate them with back office applications to manage and execute in accordance with market-driven or reliability-driven demand response events. Direct load control devices will include:

- Residential standalone programmable communicating thermostats (PCT)
- Residential home are network (HAN) based PCTs
- Commercial BMS integration

All project demand response resources will be engaged through 2-way communication between the customer premise and the back office DERM webSmartEnergy application, DEMS and DMS, and other grid management systems. The DR thermostats may be aggregated and operated based on grid connectivity (small or wide scale) as needed to provide desired locational load relief.

The project will assess these DR resources capabilities for providing “fast DR” emergency and ancillary service products, e.g., non-spin and balancing energy.

2.8.3.2 DR Load Curtailment Characteristics

2.8.3.2.1 Residential Standalone Programmable Communicating Thermostat

The Standalone Programmable Communicating Thermostat (PCT) provides customers a means to better manage their heating and cooling costs by enabling them to program a weekly heating/cooling schedule, participate in demand response events, and receive real-time pricing signals and text messages from KCP&L.

Similar to an existing enterprise-wide program called EnergyOptimizer, KCP&L will deploy advanced PCTs to customers in the project zone with smart meters. These ZigBee-based PCTs, Tendril Set Point, will be paired with a customer's smart meter to enable utility-controlled demand response events. Events will be initiated by the project DERM and events messages will be delivered to the devices via the AMI network (through the meter). The PCT model utilized for this project is shown in Figure 2-36.

Figure 2-36: Standalone Programmable Communicating Thermostat

The Standalone PCT is an electronic device that receives information directly from a customer SmartMeter wirelessly via an IEEE 802.15.4 network running the ZigBee Smart Energy Profile (SEP) 1.0 specification to receive pricing signals, demand response events, and text messages.

When a demand response event occurs, customers are notified ahead of time with information about event start time and duration. By default, customers are opted into each event. However, once customers receive the event, they can opt-out or back in at any time before the event concludes. Customers can make this opt-in/out decision at either the thermostat or the web portal. Event participation is recorded for post-event evaluation and analytics.

The Standalone PCT also provides customers with the ability to:

- Receive real-time pricing information
- Receive demand response event information from KCP&L

- Opt-in/out of demand response events at the thermostat
- Receive important text messages from KCP&L

2.8.3.2.2 Residential HAN DR

Similar to the standalone PCT, KCP&L will deploy HAN PCTs as a part of a larger HAN package that includes a HAN gateway, PCT, and two 120 volt control switches. The PCT is identical, the Tendril Set Point, however, the HAN gateway facilitates two-way communications with utility back office systems over broadband internet connection rather than the AMI network.

2.8.3.2.3 Commercial BMS DR Overview

KCP&L will extend its existing commercial curtailment program, MPower to the project area. MPower is a load curtailment program designed to help manage system, or circuit-level peak demands. Program participants are paid up to $45 per kW of curtailable load just for agreeing to be "on call" to reduce load to a predetermined level at KCP&L's request. They are paid an additional payment of $.35 per kW when they are called upon to reduce load and successfully do so. This program serves to defer the need to build additional fossil-fuel-fired generating resources while contributing to grid stability and reliability.

Also, capabilities for supply of "fast DR", i.e., ancillary services, from demand-side resources will be provided. DR load curtailment programs will be evaluated to specifically demonstrate the aggregated ability of demand-side resources to supply ancillary services such as spin and non-spin energy in support of grid operations, e.g., balancing variable generation from solar and wind resources. Similar to the DR Thermostats programs, by mapping and tracking the DR load curtailment capabilities against circuit, feeder and substation connectivity, locational energy products can be made to support grid operation and variable generation balancing.

2.8.3.3 DR Load Curtailment Implementation

To be completed in future releases of this report…

2.9 SmartEnd-Use

The SmartEnd-Use sub-project deployed a Home Energy Management Platform (HEMP), Time-of-Use (TOU) rate plan, and Vehicle Charge Management System (VCMS) to increase customer adoption of consumption awareness and management techniques, as well as expand KCP&L's demand management capabilities. Together, the HEMP and TOU rate enable customers to directly manage their energy consumption and associated costs. Furthermore, the HEMP and VCMS provide KCP&L with demand response assets that can be called on during peak demand times to help increase distribution grid stability and decrease operating costs.

2.9.1 Home Energy Management Platform (HEMP)

A smart grid contains advanced technology that enables enhanced, two-way communication between a utility and its customers. The HEMP provides KCP&L a means to monitor customer involvement, communicate billing and consumption information to customers, and manage demand response assets. In turn, the HEMP provides customers with information to understand their energy consumption and costs and tools to help manage both.

The HEMP enables KCP&L to implement and evaluate several technologies that facilitates both indirect and direct load control by providing customers with energy education tools and in-premise Home Area Network (HAN) devices, thus empowering customers to better manage energy consumption and costs. These tools also serve the added benefit of preparing customers for dynamic pricing as well as a means for utilities to communicate pricing signals and billing information.

KCP&L believes this project will serve as a blueprint for future smart grid implementations, help evaluate the effect these advancements have on delivering reliable electricity with greater efficiency and improved environmental performance, and accelerate realization of the values and benefits a "utility of the future" may represent.

2.9.1.1 HEMP Overview

The HEMP is a system that interfaces with other back-office systems to exchange various data, including energy consumption, billing plans, demand response events and information about various in-premise Home Area Network (HAN) devices. The HEMP consists of a Utility Administrative Web Portal, a Customer Web Portal, and HAN devices that communicate with the portals to enable the customer to monitor and control their energy consumption and costs. KCP&L uses the Administrative Portal to monitor and manage Customer Portal accounts and HAN devices. The Customer uses the Customer Portal to view their energy consumption, billing plans, and demand response events, and manage their in-premise HAN devices.

2.9.1.2 HEMP Characteristics

The HEMP is composed of two main components: 1) a web-based portal that provides customers with access to their historic energy usage information and tips for managing energy usage, and 2) the ability to manage the in-premise HAN devices, monitor real-time usage, and set preferences for responses to demand response and pricing programs.

2.9.1.2.1 *Customer Web Portal*

The Customer Web Portal, as shown in Figure 2-37, is a full featured informational web portal that is designed to give customers access to their detailed energy usage and help them better understand the impact of their electricity usage on their bills. It also provides additional recommendations and information to encourage them to make decisions that conserve energy, help the environment, and save money.

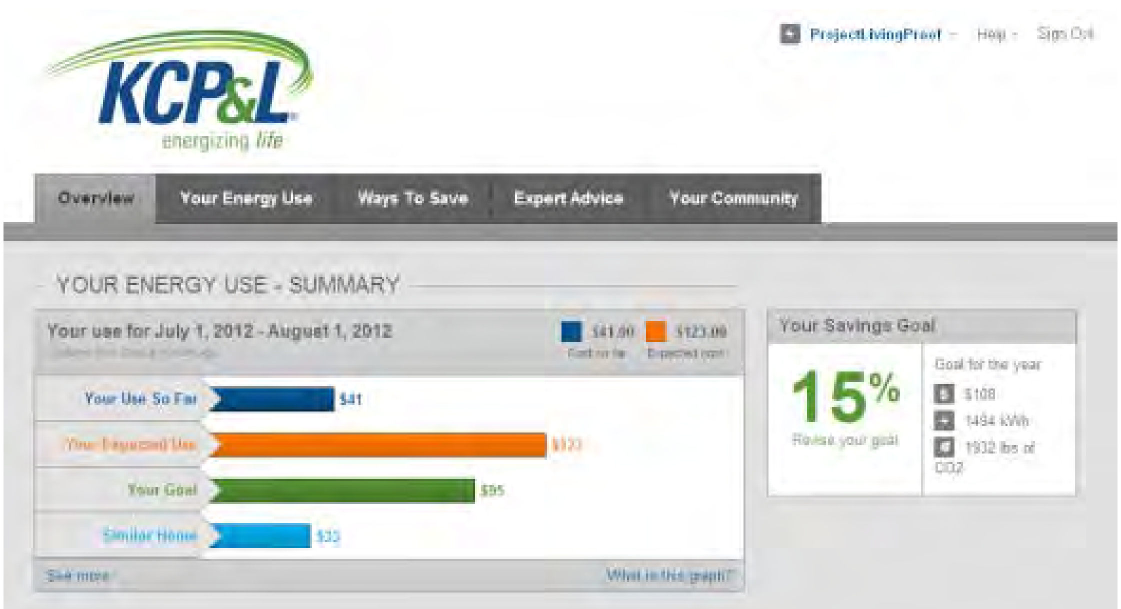
KCP&L's Customer Web Portal is designed to show a customer how much and when they use electricity each day and help them estimate their bill, including taxes and charges, before they receive it.

Traditionally, electricity customers have used energy without knowing how much money they were spending and when. Now, for example, on a hot summer day customers will be able to see exactly when usage goes up. This information may influence customers to use electricity differently at those times and receiving it in near real-time through in-premise HAN devices facilitates immediate action to manage energy consumption and costs instead of waiting for a monthly bill to see this information.

The Customer Web Portal allows customers to:

- See energy usage information in easy-to-understand charts
- Estimate their current monthly bill
- Compare this month's bill against last month's bill
- Evaluate hourly, daily, and monthly electricity usage amounts
- Review yearly billing history
- Compare their usage against other homes in their community
- Receive messages from KCP&L about their usage

Figure 2-37: Customer Web Portal



2.9.1.2.2 In-Home Display

The In-Home Display (IHD) provides real-time energy usage information to customers directly from their meter to increase awareness of electricity usage and help identify opportunities to reduce consumption and save money.

The IHD is a portable electronic device that receives information directly from a customer SmartMeter and presents it to them in easy-to-understand screens. The IHD communicates with the meter wirelessly via an IEEE 802.15.4 network running the ZigBee Smart Energy Profile (SEP) 1.0 specification to receive real-time energy consumption data, pricing signals, text messages, and estimated billing information. The IHD does not require an Internet connection.

The IHD provides customers with:

- Current electricity usage information
- Current electricity costs
- Important text messages from KCP&L
- Up-to-date current month usage and estimated billing information

The IHD allows a customer to set a price limit on how much electricity they want to use for the month. It will then visually notify customers with green, yellow, and red backlighting indicating whether they are meeting, nearing, or exceeding that limit. The IHD only receives and displays energy usage information and does not directly affect customer energy consumption; it simply sends warning signals to influence energy consumption in order to meet the customer-imposed limits, thus enabling customers to manage their consumption and costs.

Figure 2-38: In-Home Display

2.9.1.2.3 Home Area Network

The Home Area Network (HAN) provides customers a means to better manage their heating, cooling, and simple load consumption costs by enabling them to program a weekly heating/cooling schedule, program pricing schedules for each device, participate in demand response events, and receive real-time pricing signals and text messages from KCP&L.

The HAN is a suite of electronic devices that receive information directly from a customer SmartMeter, as illustrated in Figure 2-39, to increase customer awareness of electricity usage and help identify opportunities to reduce consumption and save money. The HAN communicates with the SmartMeter wirelessly via an IEEE 802.15.4 network running the ZigBee Smart Energy Profile (SEP) 1.0 specification to receive pricing signals, demand response events, and text messages. Included in the suite is a gateway device, a PCT and a pair of 120V Load Control Switches (LCSs). An optional 240V LCS may be included for customers with a larger controllable electric load, such as a water heater or pool pump.

Figure 2-39: Home Area Network Devices

The HAN provides customers with the ability to:

- Receive real-time pricing information
- Receive demand response event information from KCP&L
- Opt-in/out of demand response events at the thermostat and load control switches
- Remotely monitor and control the devices via the Customer Web Portal
- Program temperature set points and pricing rules for the thermostat
- Program pricing rules for the load control switches
- Receive important text messages from KCP&L

The gateway within the HAN establishes an IP connection between the Customer Web Portal via the customer supplied internet connection, enabling customers to manage energy consumption in their home using the functionality provided by the HEMP. The gateway device receives real-time usage information directly from customer SmartMeters. This usage information is passed to the Customer Web Portal to be displayed to customers. The gateway also transfers control commands from the Customer Web Portal to the PCT and LCSs. This enables customers to remotely manage device schedules and rules, control devices, and manage demand response event participation.

The PCT within the HAN allows customers to set schedules for their heating and cooling needs throughout the week. Customers can set four different temperature set points for both heating and cooling throughout each day of the week. This helps customers better manage their heating/cooling loads when they are away from their homes. The PCT also includes different temperature modes, such as “Hold” and “Vacation”, which offer customers more flexibility in managing their consumption.

The LCSs within the HAN allow customers to set pricing rule for the simple loads attached to the LCSs. This enables the device to respond and operate to changes in electricity rates automatically, thus giving the customers added flexibility to help manage energy consumption and costs. The LCSs also report individual consumption to the Customer Web Portal to be displayed to customers. This feature enables customers to better understand the energy consumption and operating costs of the individual appliances within their homes.

Program participants will have their PCT and LCSs enrolled in the SmartGrid demand response program. When a demand response event occurs, customers are notified ahead of time with information about event start time and duration. By default, customers are opted into each event. However, once customers receive the event, they can opt-out or back in at any time before the event concludes. Customers can make this opt-in/out decision at the PCT, the LCSs, or the Customer Web Portal. Event participation is recorded for post-event evaluation and analytics.

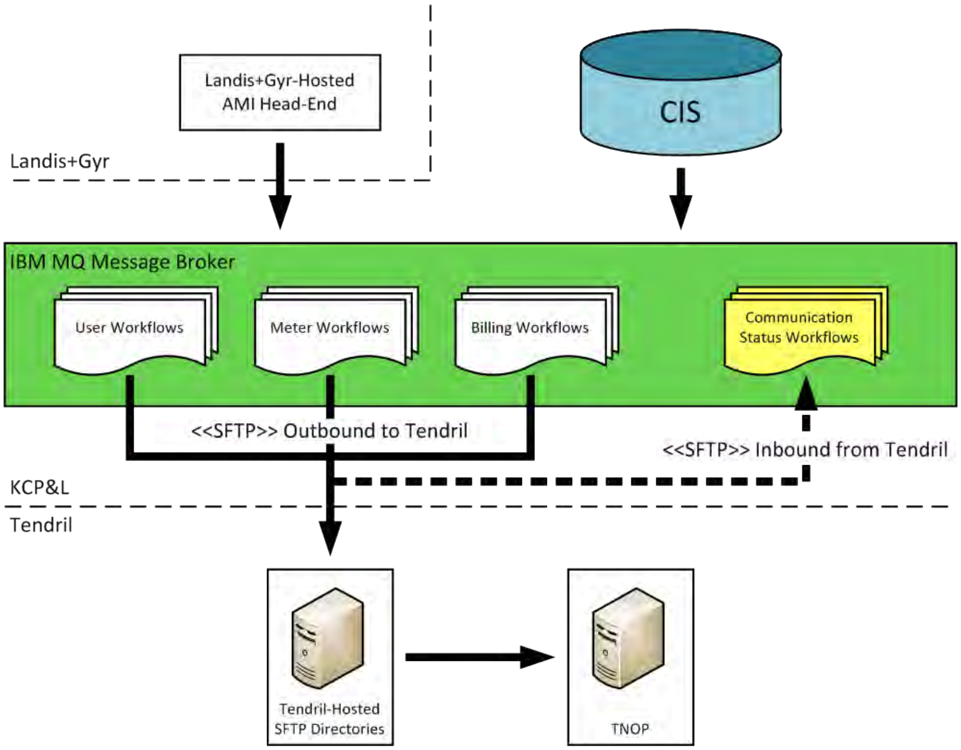
In conjunction with new voluntary TOU rate options and the energy management capabilities that the HAN provides, it is expected that the HAN users will reduce their overall kWh usage, shift load to off peak times, and voluntarily allow HAN-connected devices to participate in demand response events.

2.9.1.3 <u>HEMP Implementation</u>

2.9.1.3.1 <u>Customer Web Portal</u>

The Customer Web Portal was rolled-out to KCP&L customers in October 2010, coinciding with the AMI and IHD deployments. Integration was completed with the AHE, CIS, and customer AccountLink to populate the portal with accurate customer usage and billing information and enable Single Sign-On (SSO) access for customers. Meter reads are passed from the AHE through MQ Broker interfaces to the HEMP. Historical billing information and daily bill true-ups (including taxes and fees) are created by the CIS and passed through an MQ Broker interface as well. Secure account sign-on is managed by an interface between HEMP and AccountLink that utilizes SAML.

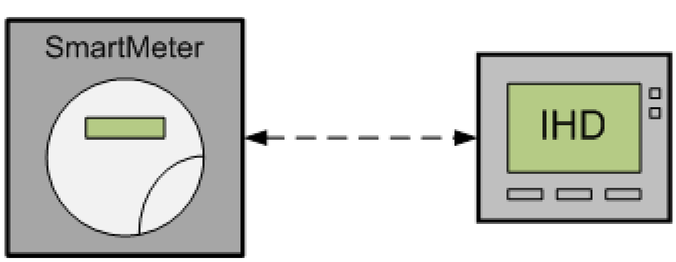
Figure 2-40: Customer Web Portal Data Flows



2.9.1.3.2 In-Home Display

The IHD was rolled-out to KCP&L customers in October 2010, coinciding with the AMI and Customer Web Portal deployments. Integration was completed with the AHE, CIS, and SmartMeters to populate the IHDs with accurate real-time usage information, real-time pricing information, day-behind customer usage information and estimated billing information. CIS was configured to send pricing signals to the AHE based on the customers' rate codes. These pricing signals are then sent down to the IHDs via the SmartMeters (Figure 2-41). Customers can then see their real-time energy price and accumulated daily costs. Estimated billing information is created by the CIS in the form of daily bill true-ups (including taxes and fees). These daily bill true-ups are then passed through an MQ Broker interface to the AHE, which in turn passes the information to the IHDs in the form of "tunnel" text messages.

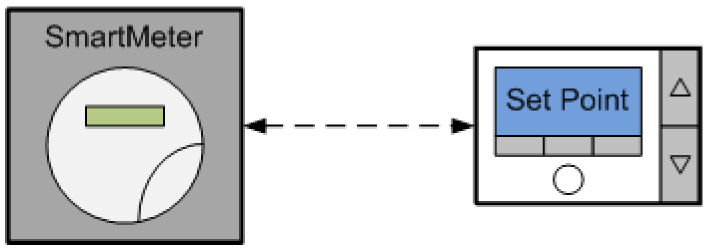
Figure 2-41: In-Home Display Communication



2.9.1.3.3 Standalone Programmable Communicating Thermostat (PCT)

The PCT was rolled-out to KCP&L customers in June 2012. Along with a built-in programmable schedule, the PCT supports pricing signals and demand response events via communications with SmartMeters. As with the IHD customers, CIS was configured to send pricing signals to the AHE based on the PCT customers' rate codes. These pricing signals are then sent down from the AHE to the PCTs via the SmartMeters (Figure 2-42). Customers are able to see real-time pricing information on the screen of the PCT to make energy conserving decisions when programming the temperature set point and schedule.

Figure 2-42: Standalone PCT Communication



Prior to provisioning the PCT to the customer's SmartMeter, the customer's Customer Web Portal account is configured to support the PCT.

As noted above, the PCT also supports demand response functionality. Through integration between the DERM, HEMP, and AHE, the PCTs can receive demand response events to help reduce, level, or shift load during peak demand periods. The DERM can forecast demand on the distribution grid and call on the PCTs for load reduction, if necessary. A message is sent from the DERM to the HEMP to identify the PCT customers needed to meet the load reduction requirements. The HEMP then routes the demand response messages to the AHE. The AHE passes the demand response events to the PCTs via the SmartMeters prior to or at the start time of the event, depending on the event parameters. Once received at the PCT, the customer is automatically opted into event participation with the option to opt out of the event at any time prior to the end of the event. This opt-out/in decision can be made directly at the device. Customer event participation information is then passed to the DERM via the AHE and HEMP to be used for future demand response forecasting.

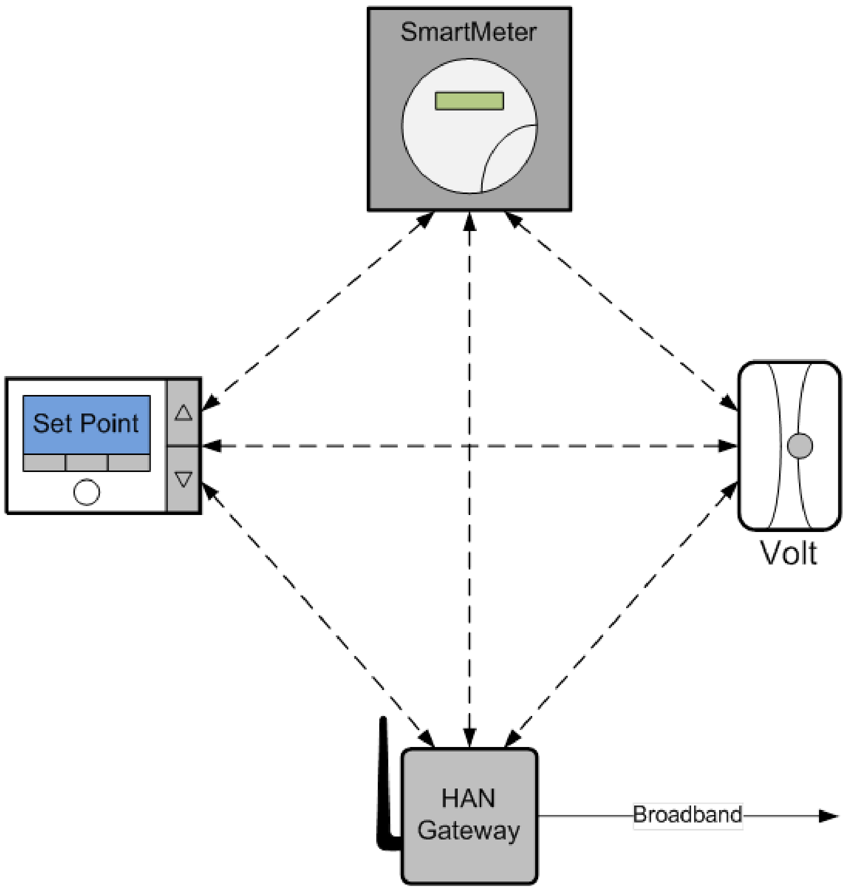
2.9.1.3.4 Home Area Network (HAN)

The HAN was rolled-out to KCP&L customers in February 2012. The HAN was initially available to a small set of "friends and family" to verify functionality. Once these "friends and family" HANs were installed and verified, customers within the demonstration project were then able to enroll in the HAN program based on a set of prequalification criteria (broadband internet connectivity, HVAC type, presence of a 240V load, etc.).

Prior to provisioning the devices to the customer's SmartMeter, the customer's Customer Web Portal account is configured to support the HAN devices. Once the devices are provisioned to the SmartMeter, they are registered within the Customer Web Portal using the device MAC Address. Once registered within the Customer Web Portal, the customer can then access and control the devices, including changing temperature set point, PCT schedule, and pricing rules for the PCT and LCSs within the HAN.

CIS was configured to send pricing signals to the HEMP based on the customers' rate codes. These pricing signals are pulled from the HEMP via the HAN gateway rather than through the metering network and are displayed on the PCT (Figure 2-43). Customers are able to see real-time pricing information on the screen of the PCT to make energy conserving decisions when programming the temperature set point and schedule.

Figure 2-43: Home Area Network Communication



As noted above, the HAN also supports demand response functionality. Through integration between the DERM and HEMP, the HANs can receive demand response events to help reduce, level, or shift load during peak demand periods in the same manner of the PCTs. Once the DERM forecasts demand on the distribution grid, it can call on the HANs for load reduction, if necessary. A message is sent from the DERM to the HEMP to identify the HAN customers needed to meet the load reduction requirements. The HEMP then routes the demand response messages to the HANs via a broadband internet connection prior to or at the start time of the event, depending on the event parameters. Once received by the HAN, the customer is automatically opted into event participation with the option to opt out of the event at any time prior to the end of the event. This opt-out/in decision can be made at either the devices (PCT or

LCSs) or within the Customer Web Portal. Customer event participation information is then passed to the DERM via the HEMP to be used for future demand response forecasting.

2.9.2 Residential Time-of-Use (TOU) Program

In response to a request from the Missouri PSC and in conjunction with the KCP&L Smart Grid Demonstration Project that included AMI metering, KCP&L implemented a process by which KCP&L is able to bill a new Missouri time-of-use (TOU) pilot tariff through the CIS system based on usage information collected from AMI meters and stored in the Meter Data Management (MDM) System.

The initial pilot tariff went into effect on January 1, 2012 and consists of two daily periods in the summer months: an on-peak period and an off-peak period. Summer on-peak periods will occur over a defined hourly range (four hour period that will start and end on the hour from 3pm-7pm) on summer weekdays and non-holidays. The summer season runs from May 16th to September 15th, inclusive. The tariff expires at the end of the SmartGrid Demonstration Project pilot on December 31, 2014.

Participating customers receive monthly bills that include usage information grouped into the three TOU period categories of peak summer, off-peak summer, and winter usage. They are also able to view TOU cues in the Home Energy Management Portal (HEMP) and on In Home Displays (IHDs) if they are participating in those programs.

2.9.2.1 TOU Overview

While designed to be revenue neutral for KCP&L average residential customers, the pilot TOU tariff provides greater incentive for customers to shift load from peak periods to off-peak periods due to the significant difference between peak and off-peak prices during summer months. Off-peak prices of these tariffs represent a tangible opportunity for customers to shift load and save money on their annual electricity expenses without reducing overall usage.

Successful peak load shifting benefits KCP&L by reducing burdens on inefficient generators and limiting strain on various components of the distribution system resulting in more efficient and more economical delivery of electricity to customers. This project will also provide key inputs to the overall DOE SmartGrid Demonstration project analysis and reporting. Additionally, it satisfies the IRP request for Missouri Public Service Condition (MPSC).

2.9.2.2 TOU Characteristics

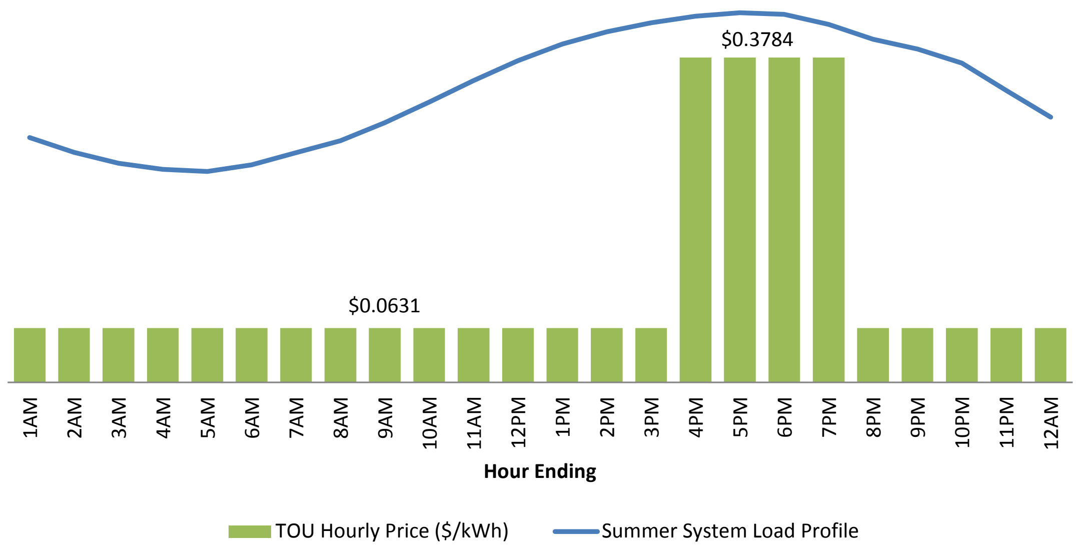
2.9.2.2.1 TOU Tariff Details

Two pilot TOU tariffs offer one summer rate structure: peak period of 3-7pm. Peak periods for both tariffs will occur on summer weekdays, excluding holidays. Summer is defined as May 16th through September 15th, inclusive. During the summer season, a flat peak price is applied to all energy used during defined peak hours and a flat off-peak price is applied to energy used at all other times. The customer’s standard rate would apply to all energy used in the remainder of the year, considered the winter season. Table 2-10 summarizes tariff details.

Table 2-10: Pilot TOU Tariff Details

Rate Codes	
1TOUA – TOU Rate for Residential Standard Customers currently on 1RS1A rates	
1TOAA – TOU Rate for Residential All-Electric Customers currently on 1RS6A rates	
Schedule	
Peak Rates are charged from 3PM – 7PM Central on non-holiday weekdays (Monday-Friday) during Summer Season; weekends (Saturday-Sunday) and holidays are billed at discounted off-peak rates	
Summer Season: May 16th through September 15th (inclusive)	
Winter Season: September 16th through May 15th (inclusive)	
Holidays observed during Summer Season include Memorial Day, Independence Day and Labor Day	
Pricing	
TOU Summer Peak Price:	$0.3784/kWh
TOU Summer Off-Peak Price:	$0.0631/kWh
TOU Winter Price:	Declining Block; same as standard rates
Excluded Customers	
Dual meter customers	
Net metering customers	
Customers w/ Current Transformer greater than 1.0	
Business Rules	
Customer can sign-up anytime during the year; however, the rates will not be affected until the first day of their next billing cycle	
Customer may exit the program anytime; however, they cannot join again during the remainder of the pilot period, which ends on December 31, 2014	
Other Considerations	
Upon request, customer will be made “whole” for the current and previous billing cycles; the current approach would not include making them whole for an entire summer season or to retroactively go back to prior years	
Enrollment occurs at the start of a billing period and customers who elect to exit the program may have their exit backdated to the start of the previous billing period	

Figure 2-44: KCP&L System Load Profile and TOU Rates



2.9.2.2.2 AMI Capture of Meter Read Interval Data

A foundational element of KCP&L's Time-of-Use program is the ability of the Landis+Gyr AMI meters to collect and transmit 15-minute interval data that include date and timestamp information. On a typical day, the meter will capture 96 15-minute intervals with the initial interval running from 12:00:01AM – 12:15:00AM and the final daily interval running from 11:45:01PM – 12:00:00AM. These intervals are transmitted on a regular basis to downstream systems including the MDM for further processing. The AMI meters are all set up generically to collect this 15-minute interval data along with the regular daily register read value; a custom metrology solution was not required for TOU due to KCP&L's leveraging the capabilities of the MDM and SmartGrid Middleware as outlined below.

2.9.2.2.3 MDM Usage of Meter Read Interval Data

The 15-minute interval data collected by the AMI system is stored in the eMeter EnergyIP Meter Data Management (MDM) System hosted by Siemens. The MDM system provides two major capabilities that are critical for TOU: usage framing and billing determinant generation.

Usage framing sums up a customer's interval data over a specified period of time into a total usage amount for that period and stores it in the appropriate "bin". During the Summer Season, on non-holiday weekdays, the MDM sums all 16 of a customer's 15 minute interval values between 3PM-7PM to create a "peak" usage bin and the remaining 80 daily interval values between 12AM-3PM and 7PM-12AM to provide an "off-peak" usage bin. For weekends and holidays, all 96 daily intervals are added to the "off-peak" total. During the winter, all usage is added to the "off-peak" bin.

KCP&L also uses the MDM to deliver billing determinant information to its CIS system using a modified version of the MDM's "Pull Billing" method where the CIS system makes the request for data to the MDM and receives the necessary response back. Framed usage is retrieved on a daily basis via an "off-cycle", "informational" request to the MDM Pull Billing interface and is returned in "peak" and "off-peak" bin values.

2.9.2.2.4 KCP&L SmartGrid Middleware (incl. TOU Register Read Calculator)

KCP&L's legacy CIS system currently receives register read values from a variety of metering systems including both AMR and AMI to bill customers. To support integration of these multiple systems, KCP&L has deployed a custom, in-house middleware solution that collects and stores daily register read values from all meters across the territory and normalizes the data to feed to CIS. For integration of the SmartGrid AMI meters, KCP&L added a SmartGrid specific component to the middleware which in turn required an additional enhancement to support TOU billing: the TOU Register Read Calculator.

The TOU Register Read Calculator translates the daily peak and off-peak usage values retrieved from the MDM into a daily dial read, effectively creating a virtual dial for each of the TOU bins: summer peak, summer off-peak and winter off-peak. These register read values are then fed into the CIS system following the normal meter billing process when needed for monthly bill cycle processing. In addition to the translation from usage values to register values, the Calculator provides some additional important capabilities. It provides error tracking and reporting capabilities for use by the IT team and AMI Analyst. It converts AMI/MDM provided decimal values to integer values for the CIS system; the AMI/MDM system provides values with up to four decimal places – i.e. 12345.1234. It also supports the accounting requirement that the sum of the TOU KWH bin values match the billed KWH value; this true-up capability is critical due to the decimal/integer translation necessary as well as decimal/integer gap that may occur on a customer's initial enrollment.

2.9.2.2.5 CIS/Billing Updates

CIS coding was not required. Existing system capabilities were leveraged to enable the setup of the virtual register dials noted above in CIS for billing without requiring a physical meter exchange. During the enrollment process, the meter is temporarily deactivated from the customer account during which time it has the three TOU measuring components for summer peak (SKP), summer off-peak (SKO) and winter off-peak (WKH) added and activated on the customer's meter. Once these measuring components are added, the meter is reactivated on the customer account and once the customer is moved to the 1TOUA/1TOAA rate, including an initial install read, they are then active on the TOU program.

2.9.2.2.6 TOU Tendril

To aid customers in more effectively participating in the TOU program, various cues are provided to participants who are users of the Home Energy Management Platform (HEMP) and/or KCP&L provided In Home Displays (IHDs). Upon enrollment, KCP&L pushes a rate change via the existing MQ interface to the Tendril back-office system that supports the HEMP which causes the Portal to display their 1TOUA/1TOAA rate instead of the previous 1RS1A/1RS6A rate. It also changes the pricing information to reflect the TOU prices (outlined in the Tariff section above) in the Portal. The rate change on the customer record also triggers the Portal to display the appropriate TOU pricing based on the season and time of day.

A similar solution was implemented to ensure that the correct pricing amount was pushed out to the AMI meters for display on the IHD. The existing TTM (Tunnel Text Message) interface that pushes customer pricing details out to the meters was updated to send the TOU Summer Peak pricing as an "Event" to the meter so that the peak rate will display on the IHD from 3PM-7PM and then revert back to the off-peak price once the TOU period ends each day.

2.9.2.2.7 Customer Print Bill

The final visual cue provided to the customer is the billing detail received on their monthly printed (or PDF) bill. At the present time, this is being added manually by the Billing Services team through use of Adobe Writer to edit each monthly customer bill and to add the three lines displaying their register dial values and usage totals for each of the three TOU bins. This is expected to be automated as part of KCP&L's upcoming OneBillPrint Project.

2.9.2.3 TOU Implementation

Following regulatory approval in December 2011, KCP&L's TOU Pilot tariff went into effect on January 1, 2012. The systems interfaces and configurations were deployed during May/June 2012 and the first customers were enrolled effective with their bills at the beginning of June 2012. Over the course of this initial Summer Season, a total of 68 customers enrolled. Four of the customers have since exited the program with two customers moving out and two customers withdrawing as they had determined it wasn't the right fit for them.

System implementation included the following components:

- CIS - Rate and measuring component setup in CIS
- MDM - Configuration of the TOU calendar and rates
- SmartGrid Middleware - Deployment of the Pull Billing Interface and the TOU Register Read Calculator.
- HEMP – interface and rate changes to transmit TOU data to the Tendril back-office systems as well as the price push to the meter

The project also developed an enrollment/cancellation process jointly with the SmartGrid Support Team and Billing Services. Several training sessions were held with these teams to introduce the overall TOU program including the rate structure, customer benefits and business support processes. Ongoing customer support is provided on a day-to-day basis by the SmartGrid Support Team. The IT team is engaged in production operational support of the various system interfaces to ensure that they are transferring and processing the necessary meter read and billing data correctly. The Billing Services team has roughly a five to seven day window of time each month when the SmartGrid Bill Cycles (3-7) are billed; during this timeframe, they review the bills for errors and also manually add the TOU bin detail to the bills for printing.

2.9.3 Vehicle Charge Management System (VCMS)

2.9.3.1 VCMS Overview

The Vehicle Charge Management System (VCMS) is deploying an integrated network of electric vehicle charging stations for the SmartGrid Demonstration Project. A total of ten Electric Vehicle Supply Equipment Stations (EVSEs) will be deployed within the Demonstration Project area. The VCMS and EVSE will provide customers the convenience of public charging, and the will simultaneously provide KCP&L with further demand response resources and capabilities. The VCMS will be integrated with the DERM and will serve as the “control authority” for each EVSE during demand response events.

2.9.3.2 VCMS Characteristics

The VCMS and EVSEs for the SmartGrid project are being supplied by LilyPad EV, a Kansas City-based licensed ChargePoint supplier. Each EVSE consists of a dual port, level 2 (240V) Coulomb CT2021 Charging Station with SAE J1772 standard connectors (Figure 2-45). Each EVSE is equipped with a cellular modem enabling two-way communications with the ChargePoint web platform. This will allow customers to locate and reserve individual EVSEs using web mapping applications. Also, KCP&L will be able to monitor and manage each EVSE via the ChargePoint web platform.

Figure 2-45: Coulomb CT2021 Charging Station

KCP&L will be able to monitor and manage each EVSE via the ChargePoint web platform. Station summaries, including usage and inventory reports, reservation schedules, and audit reports, will be readily available through the platform. KCP&L will also be able to manage access control, station provisioning, station alarms, and peak load configurations.

As part of the SmartGrid Demonstration Project interoperability efforts, KCP&L is implementing demand response integration between the VCMS and the DERM using APIs developed by ChargePoint. To help meet the SmartGrid Demonstration Project cyber security goals, HTTPS and SSL protocols will be utilized for all API transactions between the VCMS and DERM. These APIs support the project goals of implementing cutting-edge industry interoperability standards. These APIs are capable of providing DERM (or other systems) with EVSE Information, scheduling and reservation capabilities, demand management, and usage analysis. Utilizng this integration, the DERM will be able to execute demand response events on the VCMS and EVSEs. Events can be performed on the entire population of EVSEs on an emergency or scheduled basis.

2.9.3.3 VCMS Implementation

A total of ten EVSEs are being deployed during this implementation, six of which have already been installed. Supply and installation of the EVSEs is being managed by LilyPad EV.

The EVSE locations are:

- Demonstration House (installed)
- Midtown Substation (installed)
- Midwest Research Institute (installed)
- Nelson-Atkins Museum of Art (installed)
- UMKC – University Center (installed)
- UMKC – Chemical Lab (installed)
- City of KCMO – Swope Pkwy
- Blue Hills Community Center (2x)
- Undetermined Location

2.10 Education & Outreach Strategy & Plan [13]

The KCP&L project team developed and published a "SmartGrid Education & Outreach Plan" that detailed a strategy and approach for conducting SmartGrid Education and Outreach elements for the KCP&L SmartGrid Demonstration Project. The following subsections provide an overview of the significant elements of the education and outreach plan developed for the project.

2.10.1 Introduction

There are numerous examples from other utilities around the country that demonstrate that the overall success of a Smart Grid project is closely tied to the overall success of the utility's public education and outreach plan. In the case of the Kansas City Power & Light Company (KCP&L) Green Impact Zone SmartGrid Demonstration Project (Demonstration Project), the geographic boundaries and demographic mix of the customer base present a unique set of communications challenges and opportunities. In response, KCP&L has developed a highly targeted, multi-phased public education and outreach effort that will drive awareness and understanding of SmartGrid as well as encourage product acceptance and adoption. KCP&L is working in close collaboration with its vendor partners and a wide range of community groups, most notably, Kansas City's Green Impact Zone, an initiative led by U.S. Rep. Emanuel Cleaver II to focus federal stimulus dollars on a 150-square block geographic area in Kansas City's urban core. In addition, although the current SmartGrid pilot project is limited to only 14,000 KCP&L customers, there is the much broader audience of approximately 800,000 customers across the company's service territory. The success and lessons learned over the next five years will help determine the likelihood and plan for future deployment.

2.10.2 Education & Outreach Messaging

2.10.2.1 <u>SmartGrid Demonstration Project Messages</u>

The key Demonstration Project messages that support KCP&L's SmartGrid communications objectives include:

- SmartGrid will provide customers with enhanced energy information and tools, helping them manage usage and control costs.
- SmartGrid will improve system reliability, increase energy efficiency and improve air quality.
- The SmartGrid Demonstration Project will allow KCP&L to obtain valuable customer feedback, leading to system-wide improvements for the entire customer base.
- Through KCP&L's testing, evaluating and reporting, the SmartGrid Demonstration Project will serve as a blueprint for future Smart Grid implementations, and it will accelerate the realization of the "utility of the future."
- SmartGrid will utilize advanced technology, including renewable generation, storage resources, cutting-edge substation and distribution automation and control, energy management interfaces, and innovative customer programs and rate structures.

2.10.2.2 Industry-wide Smart Grid Messages

The overarching messages above were crafted to support and enhance these broader Smart Grid objectives, as articulated by "Seven Principal Characteristics of the Modern Grid," outlined in The NETL Modern Grid Initiative:

- **Self-heals**: The modern grid will perform continuous self-assessments to detect, analyze, respond to, and as needed, restore grid components or network sections.
- **Motivates and includes the consumer**: The active participation of consumers in electricity markets brings tangible benefits to both the grid and the environment, while reducing the cost of delivered electricity.
- **Resists attack**: Security requires a system-wide solution that will reduce physical and cyber vulnerabilities and recover rapidly from disruptions.
- **Provides power quality for 21st century needs**: The modern grid will provide the quality of power desired by today's users, as reflected in emerging industry standards. These demands and standards will drive the grid.
- **Accommodates all generation and storage options**: The modern grid will seamlessly integrate many types of electrical generation and storage systems with a simplified interconnection process analogous to "plug-and-play."
- **Enables markets**: This characteristic is particularly important because open-access markets expose and shed inefficiencies. The modern grid will enable more market participation through increased generation paths, more efficient aggregated demand response initiatives and the placement of energy storage and resources within a more reliable distribution system.
- **Optimizes assets and operates efficiently**: The modern grid's assets and its maintenance will be managed in concert with one goal: to deliver desired functionality at minimum cost.

2.10.3 Education & Outreach Audiences

Throughout the duration of this project, KCP&L needs to communicate its key messages to a number of audiences, including:

- SmartGrid Demonstration Area Customers (14,000)
- All KCP&L Customers (800,000)
- KCP&L Employees (3,600)
- State Agencies, Legislators and Regulators
- Utilities and Smart Grid Industry

Within each key audience group, KCP&L has identified a number of key stakeholder groups that are also targets for education and outreach. In some cases, these groups and organizations are the vehicle to reach the target audiences, and in other cases they are intended to serve as advocates and supporters for the SmartGrid project.

2.10.3.1 SmartGrid Demonstration Area Customers

KCP&L's SmartGrid Demonstration Project has unique customer demographics and geographic area – in and around the Green Impact Zone. This may be one of the only projects of its kind to be focused on the urban core with such a high percentage of low-to-moderate income residents. This presents a number of unique communications and education challenges that KCP&L will address over the course of the project.

Table 2-11: Green Impact Zone Demographic Chart

Metric	SmartGrid Demonstration Area	Green Impact Zone
Population	19,960	8,374
Population in Poverty	23%	31%
KCP&L Customer Accounts	11,265	2,897
Median Household Income	$28,000	$22,000
Ethnicity: White, non-Hispanic	38%	7%
Ethnicity: Black, non-Hispanic	52%	89%
Ethnicity: Hispanic	5%	2%
Age: < 25 years	37%	43%
Age: 25-39 years	25%	20%
Age: 40-59 years	24%	22%
Age: > 60 years	14%	15%
Average Monthly Electric Bill	$85.10	$87.01

Within this audience group, the key stakeholders include:

- Individual Customers
- Neighborhood Groups
- Schools
- Community Leaders
- Elected Officials
- Green Impact Zone Partners

2.10.3.2 All KCP&L Customers

While customers living within the Demonstration Project area will be the first affected by SmartGrid initiatives, what KCP&L learns from the project will eventually impact all KCP&L customers. As such, outreach to the entirety of KCP&L's customer base will be an important part of SmartGrid communications.

Within this audience group, the key stakeholders include:

- Residential Customers
- Commercial Customers
- Industrial Customers

2.10.3.3 KCP&L Employees

As media coverage of and interest in the project in the broader service territory increases, KCP&L employees will be asked by friends, family and neighbors about SmartGrid. The 3,600 KCP&L employees can be utilized as SmartGrid ambassadors, but KCP&L will need to provide them with ongoing communications in order to make them effective.

Within this audience group, the key stakeholders include:

- Customer Care Departments
- Engineering and Operating Departments
- KCP&L Employees Living in the Project Demonstration Area

2.10.3.4 State Agencies, Legislators and Regulators

The individuals in this audience are charged with representing the community. They include elected or appointed individuals, who are especially sensitive to activities that may affect their constituents. Educating this audience is critical to ensuring continued support for SmartGrid, as these individuals will want to be informed so that they can answer any questions raised.

Within this audience group, the key stakeholders include:

- Missouri Public Service Commission & Staff
- Kansas Corporation Commission & Staff
- Missouri Office of Public Counsel
- Elected Officials

2.10.3.5 Utilities and Smart Grid Industry

One of the main goals of this project is to serve as a blueprint for future integrated Smart Grid demonstrations and implementations throughout the country. The project seeks to define, validate and verify the necessary parameters and potential solution adjustments for KCP&L, and the industry, to plan and implement a system-wide roll-out of the successful Smart Grid technologies and processes. In order to do this, KCP&L will need to effectively communicate and share knowledge with other utilities and the Smart Grid industry as a whole.

Within this audience group, the key stakeholders include:

- Department of Energy
- National Energy Technology Laboratory
- National Institute of Standards & Technology
- Smart Grid Interoperability Panel
- Professional Associations (IEEE, NSPE, etc.)
- Labor Organizations (IBEW)

2.10.4 Value Proposition Groups

The key, high-level messages outlined above will be tailored for each of the audience groups outlined above and focused on the appropriate value proposition area.

2.10.4.1 The Consumer

Individual residential consumers are primarily interested in what the Smart Grid will do for them as individuals. The consumer value proposition answers the question, "What's in it for me?" Some of the consumer benefits include the following:

- **Information:** Smart Grid products will provide customers more information about their energy usage and help them learn which end-use devices and behaviors influence their consumption pattern the most.

- **Choice:** Customers will be offered products and services not previously available to them, and they will be able to decide which they want to use. Some of the new opportunities include consumer-owned generation and storage resources.
- **Control:** New Smart Grid products and tools will give customers the ability to manage their electricity use, which can help them save money on their monthly electric bills.
- **Convenience:** The new technologies will enable KCP&L to provide faster customer service: meter alerts of outages, remote service connect/reconnection and 15 minute interval data to help respond to customer inquiries.
- **Reliability:** The updated system will manage the grid to prevent outages and restore service more quickly when outages do occur.

2.10.4.2 The Utility

The utility value proposition answers the question, "What's in it for KCP&L?" It must be noted that direct utility benefits are also indirect consumer benefits, as utility savings are used to reduce the upward pressure on rates. The Smart Grid is expected to provide benefits in a number of utility operational areas, some of which include:

- Improved reliability by enabling distribution automation as well as access to real-time operating data on critical substation equipment
- Reduced energy delivery cost through increased automation and ability to predict and proactively address maintenance strategies
- Improved customer satisfaction
- Improved carbon footprint

2.10.4.3 Society

The societal value proposition answers the question, "What's in it for us?" The Smart Grid is expected to provide benefits in a number of societal areas, some of which include:

- Downward pressure on electricity prices
- Improved reliability, reducing losses that impact consumers and society
- Increased grid robustness, improving grid security
- Reduced emissions
- New jobs and growth in our gross domestic product
- Transformation of the transportation sector leading to a reduction in the U.S. dependence on foreign oil

2.10.5 Communications Approach

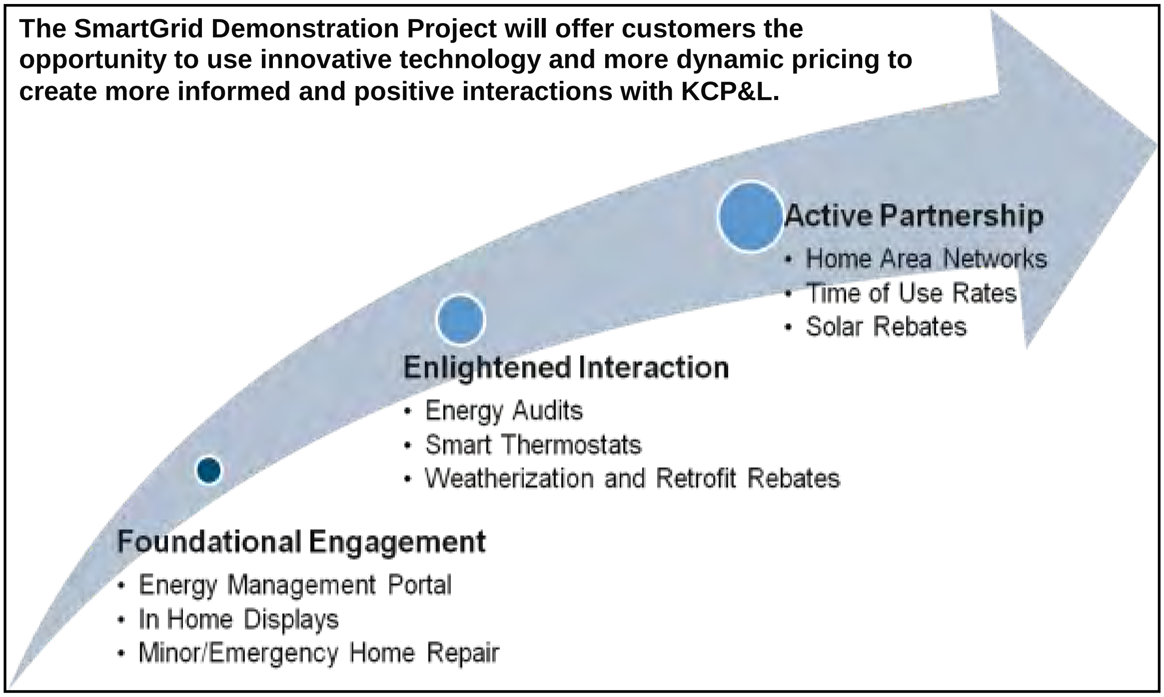
KCP&L intends to educate and engage consumers through a highly targeted, integrated marketing campaign consisting of a variety of tactics across a range of channels for optimal impact. Strategic considerations include:

- Frequent and proactive customer communication, well ahead of customer impacts
- Engagement of key leaders and company ambassadors
- Regular face-to-face communication with customers
- Opportunities for customers to "touch and feel" improvements and products

- Pairing of KCP&L representatives with neighborhood groups and other key organizations
- Cultivation of third-party key leader support

As KCP&L progresses with its Demonstration Project, customers are given the opportunity to move along a continuum tied to value proposition (Figure 2-46). SmartGrid gives them the opportunity to use innovative technology to create a more informed and effective interaction with KCP&L.

Figure 2-46: Customer Value Proposition



3 Methodology [14]

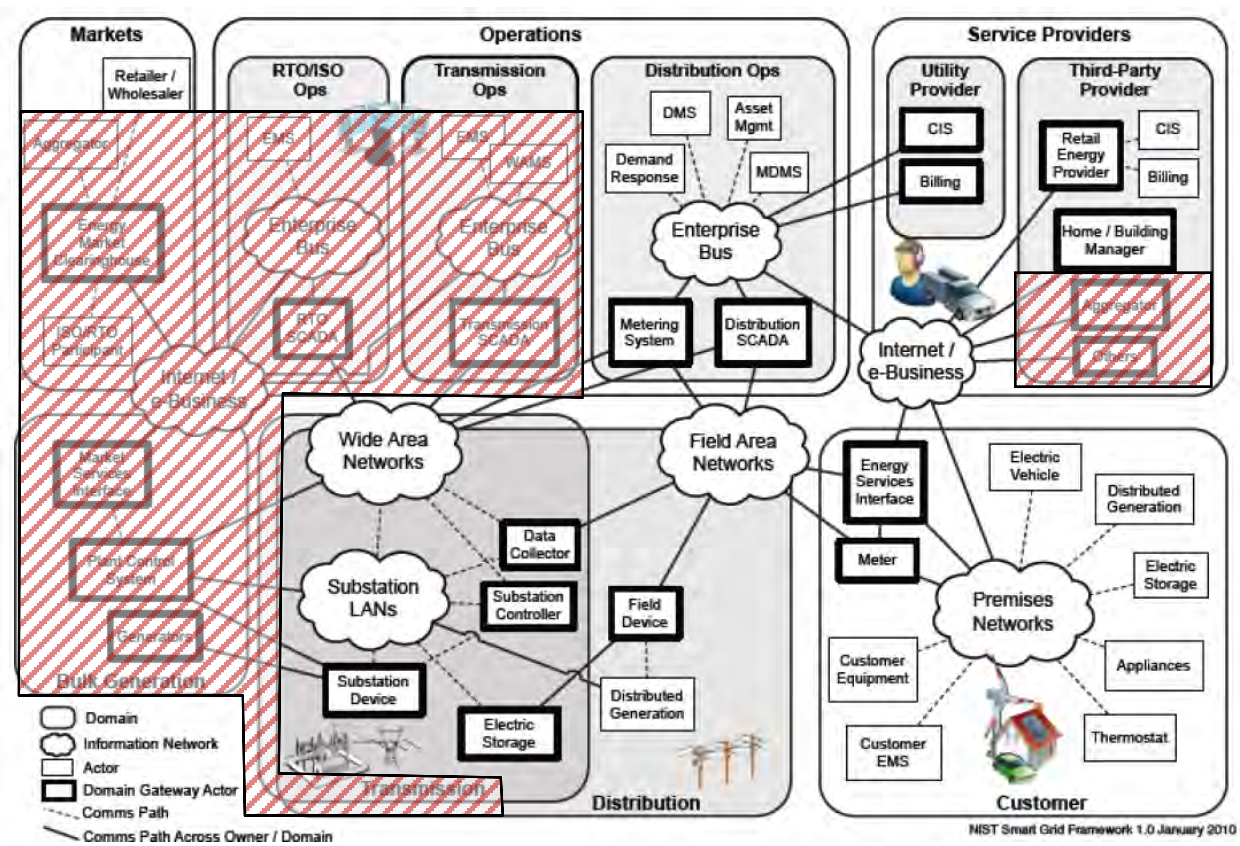
The KCP&L SmartGrid Demonstration has been explicitly designed to be a complete end-to-end SmartGrid demonstration program in a geographically defined area of Kansas City. By focusing on the circuits and distribution feeders surrounding its Midtown Substation, the Company will be able to assess the potential benefits of a SmartGrid solution from SmartGeneration through to SmartEnd-Use in a regionally unique, controlled "laboratory" environment. The goals of this demonstration are in sync with those of the DOE SmartGrid Demonstration Initiative – to quantify SmartGrid costs, benefits and cost-effectiveness as well as verify SmartGrid technology viability, and validate new SmartGrid business models, at a scale that can be readily adapted and replicated around the country.

A key objective in our SmartGrid Demonstration will be to quantify the costs and benefits of each of our solutions separately and as a complete solution. The Demonstration is designed as a regionally unique effort to display the benefits of single initiatives and the overall synergies and interrelations that can occur as a result of building complete programs. In our budgeting process, we have defined the operating and capital costs of each of the initiatives along with an estimate of potential benefits. These benefits include operational, economic, customer and environmental improvements. Where possible, specific, quantifiable methodologies were developed to translate benefit metrics into potential monetary value. For the overall solution, additional program management costs were included and synergistic benefits were estimated. These costs and benefits will be periodically evaluated during the Demonstration as part of the required DOE reporting process. Additionally, where possible, we will quantify the cost-effectiveness of the technology solutions developed for the demonstration vs. existing and / or alternative technologies and solutions to determine the cost effectiveness of our demonstration vs. existing and emerging alternatives.

3.1 Interoperability [2]

The KCP&L SmartGrid Demonstration Project main objective is to demonstrate an end-to-end grid management system that involves the integration of ten (10) new systems/sub-systems, from six (6) project vendor partners, and seven (7) legacy KCP&L systems. Figure 3-6 illustrates the scope of the project demonstration integration relative to the NIST Logical Interface Reference Mode. To meet the integration challenges associated with ensuring interoperability across the SmartGrid Demonstration Project KCP&L used a structured methodology highlighted in Section 2.2. The following sections provide the integration and interoperability design results from the application of this methodology.

Figure 3-1: KCP&L Project vs NIST SmartGrid Logical Interface Reference Model



3.1.1 Integration Requirement Planning

The KCP&L SmartGrid Demonstration Project demonstrates an end-to-end grid management system that involves the integration of ten (10) new systems/sub-systems and seven (7) legacy KCP&L systems. With this large of an integration project the development of a common project understanding between all project participants was essential to project success.

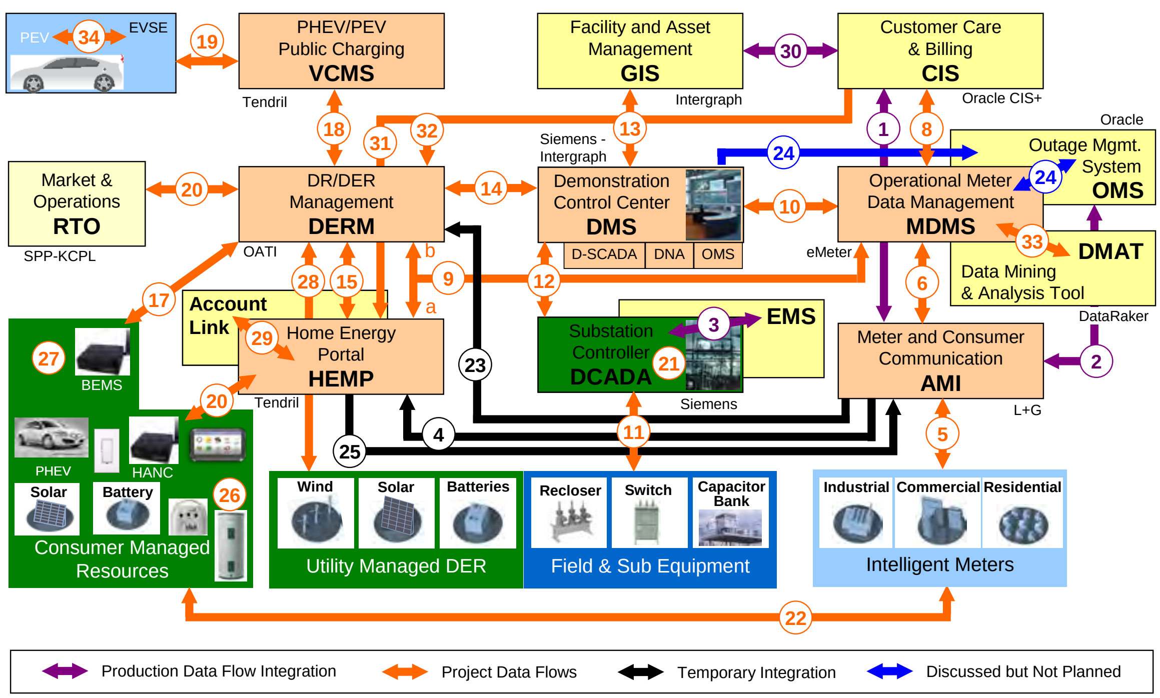
To reach this common understanding KCP&L initiated a series of conceptual design workshops and work efforts beginning in November 2009. Each workshop was facilitated by KCP&L and was attended by subject matter experts from each vendor partner, KCP&L enterprise architects, KCP&L SmartGrid project resources, and KCP&L subject matter experts. Approximately thirty

(30) KCP&L employees and twenty (20) vendor partner participants were involved in the workshops. The objectives of these initial efforts were to:

- Gain a high level understanding of role and functions of each of the new systems/sub-systems
- Establish an understanding of the functionality that the integrated solution is to demonstrate
- Identify and resolve any functionality gaps and overlaps in vendor products and the proposed integration
- Identify and characterize the nature of each of the major project integration points

Through these initial project scoping efforts, thirty-three (33) potentially significant integration points were identified and characterized. These interfaces are illustrated in Figure 3-7.

Figure 3-2: KCP&L SmartGrid Demonstration Systems Interfaces



3.1.2 Integration and Interoperability Requirement Definition

Use cases identify detailed workflows and the corresponding functional requirements for the KCP&L SmartGrid Demonstration Project implementation. Additionally, these use cases identify the data exchange points between the SmartGrid systems and devices using a Common Information Model (CIM) design, which allows the systems to exchange information independent of the manufacturer or vendor. This is important as utilities seek to actively deploy systems and devices from multiple manufacturers.

3.1.2.1 EPRI-Assisted Use Cases

As a member of EPRI's five-year smart grid demonstration project, our demonstration system integration and interoperability requirements definition and design were supported through

EPRI's formalized smart grid demonstration project. We leveraged EPRI's IntelliGrid^{SM} [1] methodology to define the technical foundation for the project that links electricity with communications and computer control systems to achieve gains in reliability, capacity, and customer services.

The IntelliGrid process is a structured methodology for identifying requirements based on business use cases. The Intelligrid methodology is an open-standards, requirements-based approach for integrating data networks and equipment that enables interoperability between products and systems. This methodology provides tools and recommendations for standards and technologies when implementing systems such as advanced metering, distribution automation, and demand response and also provides an independent, unbiased approach for testing technologies and vendor products.

KCP&L and EPRI launched the formal Intelligrid^{SM} methodology Use Case process for the project on August 12, 2010. EPRI assisted the KCP&L project team in applying the IntelliGridSM methodology to develop an initial set of four use cases:

1. First-Responder Applications—Distributed Control and Data Acquisition (DCADA) identifies feeder overload conditions and responds accordingly
2. Distributed Hierarchical Monitoring and Control—Interface between the Distribution Management System (DMS) and DCADA Integration
3. Distributed Energy Resource Management System (DERMS)—DMS to DERMS Integration
4. Customer Demand Response

3.1.2.2 KCP&L-Developed Use Cases

The KCP&L SmartGrid Demonstration Project has continued to develop use cases to define the integration requirements for the entire project. In total, more than 90 use cases have been developed to cover the entire breadth of the KCSG demonstration project. The use cases have been organized into the following groupings:

- Network Communications
- Automated Meter Information
- Meter Data Management
- Home Area Network Administration
- SmartEnd-Use
- Demand Response Management (DRM)
- Distribution Substation Automation
- First Responder
- DMS—SmartDistribution
- Pluggable Electric Vehicle Charging

The KCP&L SmartGrid Demonstration Project team has identified the Use Cases listed in Table 3-1 as the basis for defining project interoperability requirements and test plans. A summary description of each Use Cases is presented in Appendix B. As the Use Cases are fully developed and documented, they will be revised in future updates to this Technology Performance Report.

Table 3-1: SmartGrid Demonstration Project Use Cases

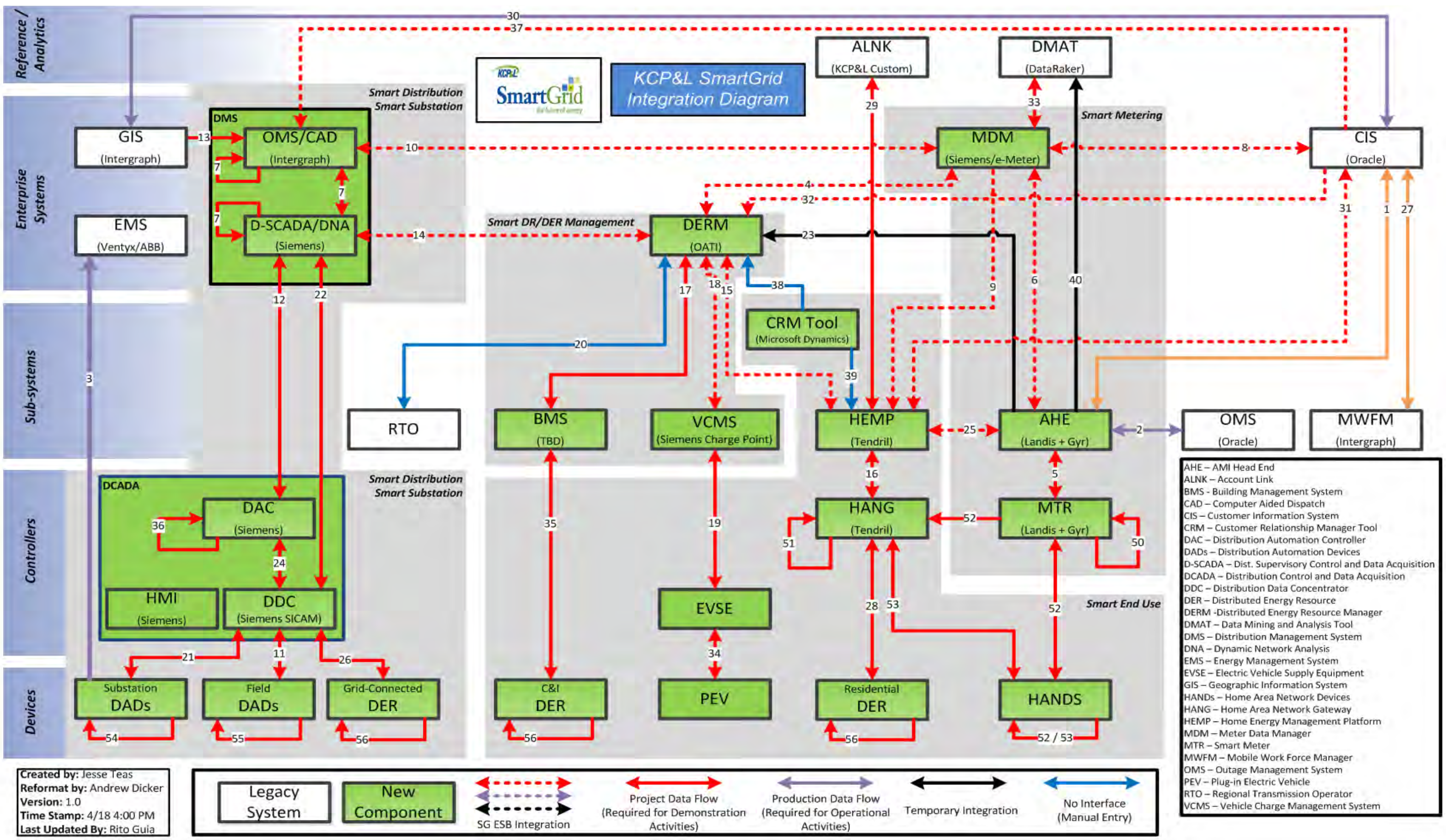
ID	Use Case Title
AMI-01	Customer Requested Remote Service Order Completion
AMI-02	On Demand Meter Read
AMI-03	On-Demand Meter Status Check
AMI-04	Automated Daily Meter Read
AMI-05	SmartMeter Alarm Events
AMI-06	SmartMeter Advisory Events
AMI-07	SmartMeter Log Only Events
AMI-08	SmartMeter Source Power Events
AMI-09	FAN Device Alarm Events
AMI-10	FAN Device Advisory Events
AMI-11	FAN Device Log Only Events
AMI-12	Remote SmartMeter Update
AMI-13	Field SmartMeter Update
AMI-14	Remote FAN Device Update
AMI-15	Field FAN Device Update
AMI-16	Remote Service Order Completion
AMI-17	SmartMeter Replaced by Field Crew
SUB-01	DCADA Monitors and Controls Substation Devices
SUB-02	DCADA Monitors and Controls Field Devices
SUB-03	Substation Transformer Dissolved Gas Analysis and Thermal Monitoring
SUB-04	Substation Transformer Dynamic Ratings
SUB-05	Feeder Cable Dynamic Ratings
1ST-01	DCADA Performs Fault Detection, Location, Isolation, and Restoration
1ST-02	DCADA Performs Volt-Var Management
1ST-03	DCADA Performs Dynamic Voltage Reduction for Demand Response
1ST-04	DCADA Performs Localized Load Transfer due to Overload
1ST-05	DCADA Initiates Relay Protection Re-coordination (RPR)
DMS-01	DMS Network Model Maintenance
DMS-02	DMS Monitors and Controls Substation Devices
DMS-03	DMS Monitors and Controls Field Devices
DMS-04	DMS Processes Protective Device Alarms
DMS-05	DMS Performs Emergency Load Transfer
DMS-06	DMS Schedules Required Load Transfer
DMS-07	DMS Manages Scheduled Events for Grid-Connected DER
DMS-08	DMS Operator Returns Grid to NORMAL Configuration
DMS-09	DMS Performs Fault Detection, Location, Isolation, and Restoration
DMS-10	DMS Performs Volt-Var Management
DMS-11	DMS Performs Dynamic Voltage Reduction for Demand Response
DMS-12	DMS Initiates Relay Protection Re-coordination
DRM-01	DR/DER Resource/Asset is Registered in DERM
DRM-02	DERM Manages DR/DER Resource Availability
DRM-03	DERM Distributes DR/DER Event Schedule to Resource/Asset to Control Authority
DRM-04	DMS Manages Grid-Connected DER Event Messages
DRM-05	Home Energy Management Portal Manages DR Event Messages
DRM-06	VCMS Manages DR Event Messages
DRM-07	Customer Opts Out of DR Events
DRM-08	Verification of DR/DER Event Participation

ID	Use Case Title
DRM-09	DERM Creates DR/DER Event for Bulk Power Systems
DRM-10	DERM Generates Retail Pricing Signals
DRM-11	DERM Distributes Demand Response Information Messages
SEU-01	Customer Views Historical Energy Information via Home Energy Management Platform
SEU-02	Customer In-Home Display – Basic Functions
SEU-03	Customer In-Home Display – Daily Bill True-Up
SEU-04	Customer Registers HAN Gateway to Home Energy Management Platform
SEU-05	Customer Uses HEMP to Provision HAN Device to HAN Gateway
SEU-06	Customer Programmable Communicating Thermostat Management
SEU-07	Customer Load Control Switch Management
SEU-08	Customer Initiates De-Provisioning of Customer HAN Device
SEU-09	Customer In-Home Display – Prepayment
SEU-10	Customer Registers for DSM Rates and Programs
SEU-11	Customer Configures HAN Device Settings via HEMP
SEU-12	Customer Configures HEMP with Energy Usage Preferences
SEU-13	HEMP Responds to Energy Signals
SEU-14	HEMP Manages Customer PEV Charging
HAN-01	Utility Commissions Home Area Network
HAN-02	Utility Provisions HAN Device to SmartMeter
HAN-03	Utility Sends Text Message to HAN Device
HAN-04	Utility Cancels Text Message
HAN-05	Utility Sends Pricing Signals to SmartMeter and HAN Devices
HAN-06	Utility Home Area Network Device Information
HAN-07	Utility De-Provisions HAN Device on Utility Home Area Network
HAN-08	Utility De-Commissions Utility Home Area Network
HAN-09	HAN Device Vendor Change Control
HAN-10	HAN Device Status Check
PEV-01	PEV Charging at a Public Charge Station
PEV-02	Customer Enrolls in Utility PEV Program
PEV-03	Customer Registers PEV to Home Premise
PEV-04	Customer PEV Charging at Home Premise
PEV-05	Un-Registered PEV Charging at Premise EVSI
PEV-06	Charge Validation and Settlement via Clearinghouse
PEV-07	Utility Controls PEV Charging at Public Charge Station
PEV-08	Utility Controls Customer On-Premise PEV Charging
MDM-01	MDM Distributes Daily Customer Updates
MDM-02	MDM Distributes Daily Meter Data
MDM-03	MDM Creates Billing Determinants
MDM-04	SmartMeter Inventory Management
NWK-01	Field Automation Network for Advanced Metering Infrastructure
NWK-02	Field Automation Network for Distribution Automation
NWK-03	Utility Home Area Network
NWK-04	Customer Home Area Network
NWK-05	PEV Charge Network
NWK-06	Substation Distribution Automation Network
NWK-07	Substation Distribution Protection Network

3.1.2.3 Project Integration/Interface Points

Through the use case requirement definition efforts, the SmartGrid Project Team identified additional integration/Interface points. These interfaces are illustrated graphically in Figure 3-8. Appendix C provides initial design characterizations for each of the identified interfaces.

Figure 3-3: KCP&L SmartGrid Systems Integration



3.1.3 Smartgrid Application Integration Architecture Design

One of the objectives of the project is to demonstrate end-to-end interoperability using the NIST SmartGrid Framework architecture. As Illustrated in Figure 3-1 and Figure 3-3, the KCP&L SmartGrid Demonstration Project integration architecture design is closely aligned with the NIST Framework and Roadmap for Smart Grid Interoperability Standards. The following subsections provide an overview of the integration architecture being implemented.

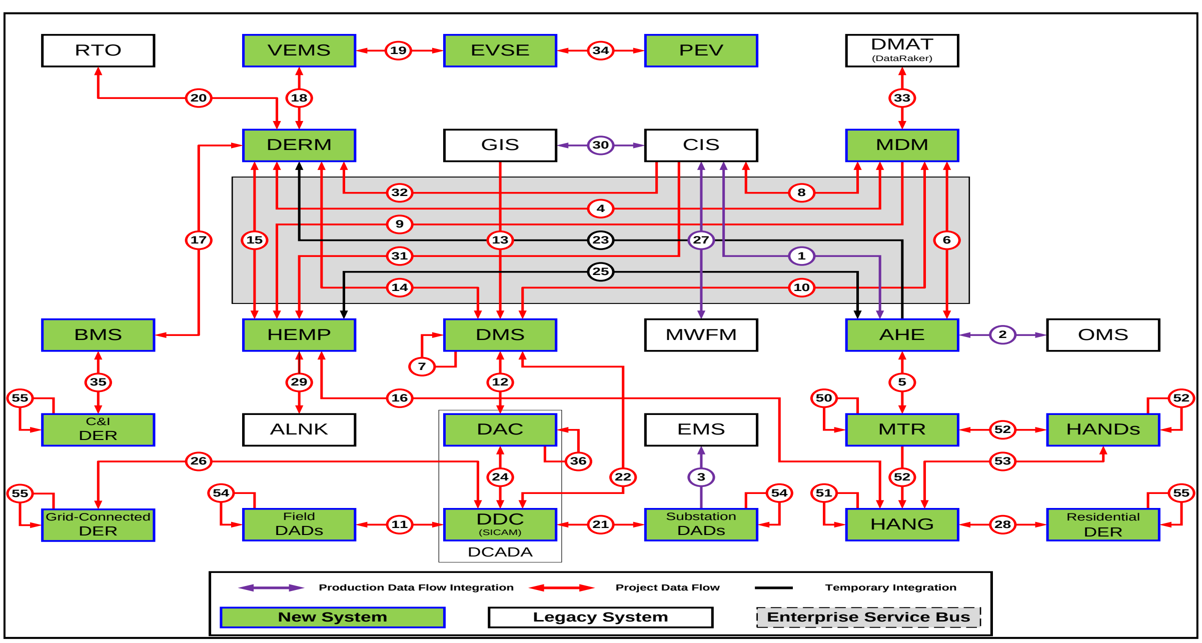
3.1.3.1 <u>SmartGrid Enterprise Service Bus Framework</u>

An Enterprise Service Bus (ESB) refers to a software architecture construct. This construct is typically implemented by technologies found in a category of middleware infrastructure products, usually based on recognized standards, which provide foundational services for more complex architectures via an event-driven and standards-based messaging engine (the bus).

The IEC 61968 series of standards is intended to support the inter-application integration of a utility enterprise that needs to connect disparate applications that are already built or new (legacy or purchased applications), each supported by dissimilar runtime environments. Therefore, these interface standards are relevant to loosely coupled applications with more heterogeneity in languages, operating systems, protocols, and management tools. This series of standards – which are intended to be implemented with middleware services that exchange messages among applications – support applications that need to exchange data every few seconds, minutes, or hours rather than waiting for a nightly batch run. They will complement—not replace—utility data warehouses, database gateways, and operational stores.

Figure 3-4, the KCP&L SmartGrid Master Interface Diagram, introduces the Enterprise Service Bus (ESB) and identifies the interfaces that should be considered for implementation with the ESB instead of point-to-point interfaces.

Figure 3-4: KCP&L SmartGrid Master Interface Diagram

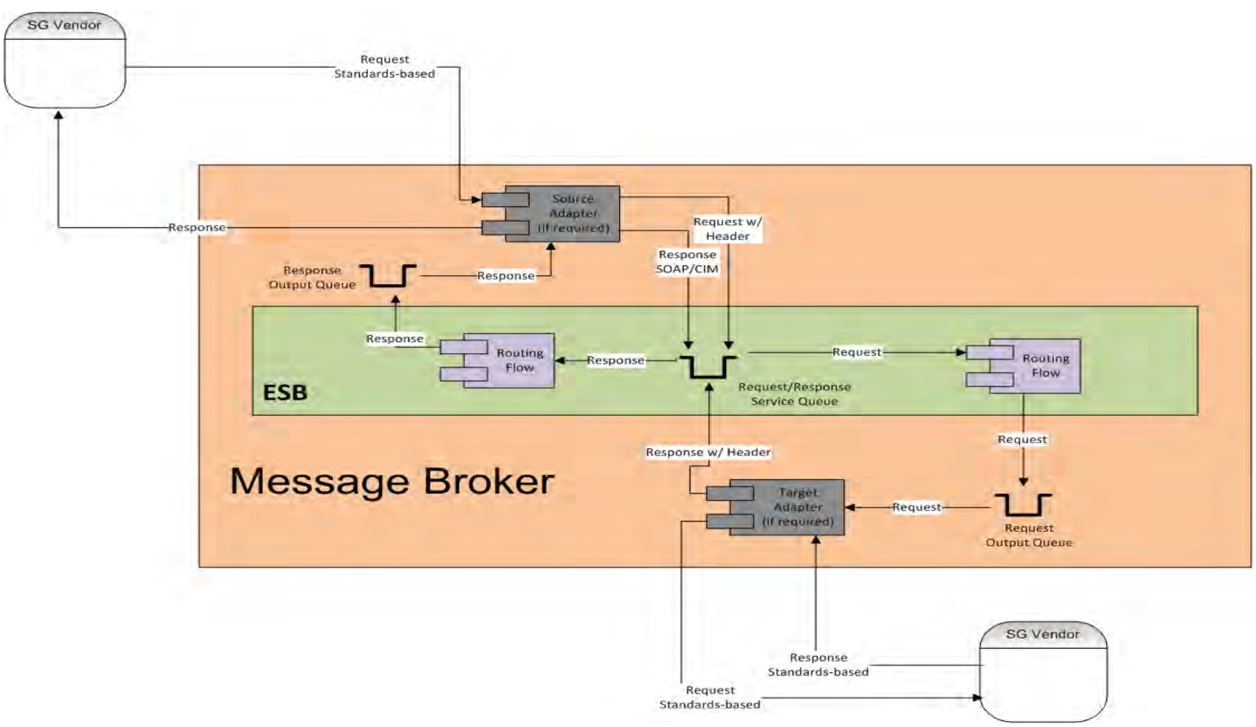


As KCP&L does not currently utilize an enterprise service bus (ESB) in its legacy architecture, the project is leveraging prior EPRI work [15] in developing the project's ESB framework to implement the SmartGrid system to system integration depicted in Figure 3-3 and Figure 3-4. The ESB framework will define how the message payloads will be conveyed using Web Services and the Java Message Service (JMS).

The Enterprise Service Bus (ESB) implemented for the SmartGrid Demonstration Project as illustrated in Figure 3-5 has been based on the following constructs:

- The SmartGrid ESB will utilize the existing KCP&L IBM Websphere MQ and IBM Websphere Message Broker as messaging platform and communication backbone
- The SmartGrid ESB will manage all routing flows and transport requirements using IBM Websphere MQ
- The SmartGrid ESB will implement a series of application adapters using IBM Websphere Message Broker
- The application adapters will manage any message translation, transformation, and/or any mediation required
- Any/all exchange of information between SmartGrid vendor partners must be routed and transported through KCP&L's network and SmartGrid ESB, where appropriate
- All SmartGrid vendor application must communicate to the SmartGrid ESB application adapters using Web Services, JMS, or MQ messaging
- Auditing capabilities will be implemented to log the state of the message as it flows through the ESB

Figure 3-5: KCP&L SmartGrid ESB Framework Example



3.1.4 Interoperability Standards

The development of the SmartGrid Demonstration Project Transmission & Distribution infrastructure involves many standards and numerous levels of integration. One of the objectives of the project is to demonstrate end-to-end interoperability using the following NIST SmartGrid Framework identified interoperability standards. The following subsections list the standards that have been incorporated into the project.

3.1.4.1 Back-Office Systems Integration Standards

- International Electrotechnical Commission (IEC) 61968-1 for general systems- and application-level interface architecture
- IEC 61968-3/61970 for application-level interfaces between the DERMS and DMS
- IEC 60870-6/TASE.2 (Inter-Control Center Communications Protocol, ICCP) for real-time internal DMS communications
- IEC 61968-9 for application-level interfaces with the AMI, Meter Data Management System (MDMS), Customer Information System (CIS), and DMS
- OpenADR 2.0 for demand response (DR) interfaces between DERMS and DR control authorities: Home Energy Management Portal (HEMP), DMS, Building Energy Management System (B-EMS) and Vehicle Control Management System (VCMS)

3.1.4.2 Field Device Communication Standards

- IEC 61850 for substation automation and communication with distributed resources
- IEC 61850 for communication to distributed automation (DA) devices over the Field Area Network (FAN) (when available)
- Distributed Network Protocol (DNP) 3.0/Internet Protocol (IP) for communication to DA devices over the FAN

3.1.4.3 In-Home Communication Standards

- OpenHAN for Home Area Network (HAN) device communication, measurement, and control architecture
- ZigBee for meter-based utility-managed HAN (UHAN) devices
- ZigBee and WIFI for customer-managed HAN (CHAN) devices
- Smart Energy Profile 1.x for UHAN communications
- Smart Energy Profile 2.x for CHAN communications

3.2 Cyber Security Implementation

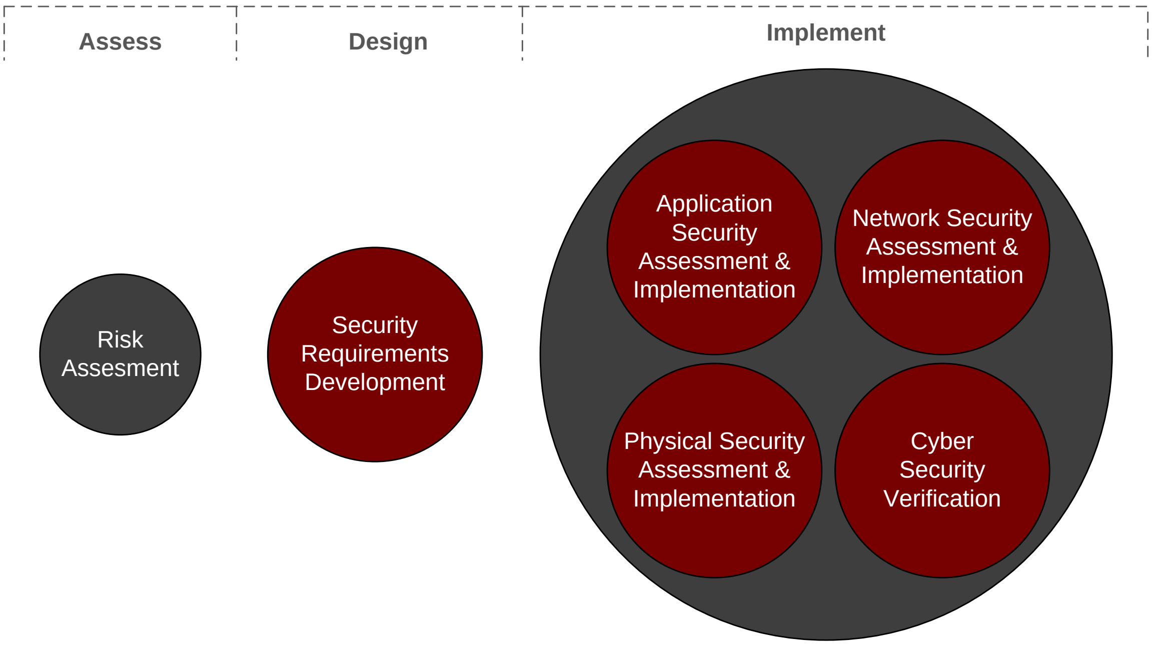
KCP&L chose to conduct a comprehensive risk assessment of all the systems within their Smart Grid Demonstration Project (SGDP). KCP&L made this decision to meet the requirements set forth in both their SmartGrid Cyber Security Plan [8] and the U.S. Department of Energy (DOE) Smart Grid Demonstration funding announcement [16] that states implementing sound cyber security controls for all Smart Grid systems.

To follow the KCP&L SmartGrid Cyber Security Plan, the risk assessment performed for the project was primarily based on the guidelines provided in the National Institute of Standards and Technology (NIST) in their Special Publication 800-30 – Risk Management Guide for Information Technology Systems (NIST SP 800-30) [9]. The NIST Interagency Report 7628 Volumes I-III (NISTIR-7628) [10] and the UCA [17] International Users Group's Advanced Metering Infrastructure and Distribution Management (UCAIug AMI and UCAIug DM) Security Profiles were also used to conduct the analysis and provide cyber security suggestions for the KCP&L project.

KCP&L chose to focus on and address several areas of cyber security threats in the implementation of its SGDP. The focused cyber security threat areas included (but were not limited to): autonomous systems and malicious code, external attack, insider abuse and unauthorized acts, insider attack, legal and administrative actions, physical intrusion and/or theft and violent acts of man.

KCP&L developed and is in process of executing an effective cyber security plan tailored to identify, assess, and mitigate threats, risks, and vulnerabilities related to KCP&L's SmartGrid implementation. The cyber security plan focused on three execution areas (see Figure 3-6). The first execution focus area (Assess) comprised of conducting a risk assessment of the KCP&L SGDP applications. The second focus area (Design) included creation and distribution of security requirements based on the risk assessment results to both KCP&L and vendor application developers. The third focus area (Implement), which is in progress, includes four parallel sub-focus areas (Application Security Assessment & Implementation, Physical Security Assessment & Implementation, Network Security Assessment & Implementation, and Cyber Security Verification).

Figure 3-6: Cyber Security Plan Execution Focus Areas



3.2.1 Risk Assessment [18]

A complete risk assessment based on the NIST SP 800-30 was performed for twenty-one Smart Grid applications. The risk assessment results provided:

- Impact-based classification for all Smart Grid applications
- Risk rating for all Smart Grid applications
- Approaches for developing security requirements

Separate methodologies were developed to calculate the values of the risk rating model components: threat, vulnerability, likelihood, impact, and mitigation. Each methodology was applied uniformly to all systems to determine values of the components.

3.2.1.1 Scope of Assessment

As a prerequisite to the risk assessment, all systems within the KCP&L SmartGrid portfolio were identified along with their respective interfaces. This step formed the boundaries of the scope and created a foundation for the assessment. The resultant scope of the risk assessment was identified to include the Smart Grid systems listed in Table 3-2.

For the systems that were included in the scope, several methods were used to develop a deeper understanding of KCP&L's implementation of Smart Grid technologies. These methods included the review of system documents such as use cases, interface diagrams, and vendor software specifications. In addition, focus group interviews with the Subject Matter Experts (SMEs) were performed using a set of targeted questions. The result was a grouping of Smart Grid systems into several business function domains that were later used as one of the criteria to recommend the creation of security zones. The collaborative work with the SMEs also resulted in the classification of all system interfaces into one of the NIST-specified logical interface categories. This classification was later used to determine the security controls that will be required to secure the systems.

Table 3-2: Smart Grid Systems Included in the KCP&L Risk Assessment

Smart Grid Systems included in the Risk Assessment	Commonly Referred as:
Advanced Metering Infrastructure Head-End	AHE
AccountLink	ALNK
Building Management System	BMS
Customer Information System	CIS
Distributed Control and Data Acquisition	DCADA
Distributed Energy Resources – Commercial & Industrial	DER – C&I
Distributed Energy Resources – Grid-Connected	DER – Grid-Connected
Distributed Energy Resources Management System	DERM
Distributed Energy Resources – Residential	DER – Residential
Data Mining and Analysis Tool	DMAT
Distribution Management System	DMS
Energy Management System	EMS
Field Distribution Automation Devices	Field DADs
Geographic Information System	GIS
Home Area Network Devices	HANDs
Home Area Network Gateway	HANG
Home Energy Management Platform	HEMP
Meter Data Management System	MDM
SmartMeter	MTR
Mobile Workforce Management System	MWFM
Substation Distribution Automation Devices	Substation DADs

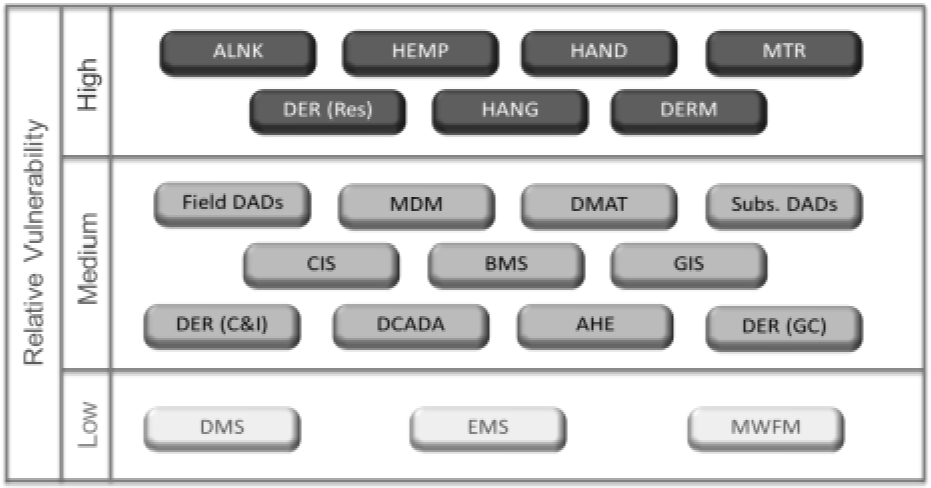
3.2.1.1 Risk Quantification

In order to assess the value of the threat component in the risk model, several internal and external threat sources were identified. The assessment not only included threat sources with an intention to harm the organization but also those resulting from unintentional acts and natural occurrences. Once the threat sources were identified, a list of motivations and possible threat actions taken by each threat source was produced. The value of the threat component for each system was determined by evaluating whether each threat source could impact the system. This value for each system thus equated to the number of threat sources identified to pose a risk to that system.

Vulnerability is defined as the susceptibility of a system to attacks. In the risk assessment, systems were evaluated for the broad categories of system vulnerabilities and operational vulnerabilities. System vulnerabilities directly affect one of the three cyber security goals of confidentiality, integrity, and availability. Operational vulnerabilities are further categorized into people, policy and procedural vulnerabilities. To provide a numerical value to the vulnerability of a system, an approach was used to quantify two of the fundamental reasons that make a system vulnerable. The resulting two variables were the relative technical ease of coordinating an attack and the relative ease of access to parts of the system.

A summary of the relative vulnerability ratings of the Smart Grid systems is graphically represented in Figure 3-7, where each system is placed in either the Low, Medium, or High region.

Figure 3-7: Graphical Representation of Relative Vulnerability Ratings

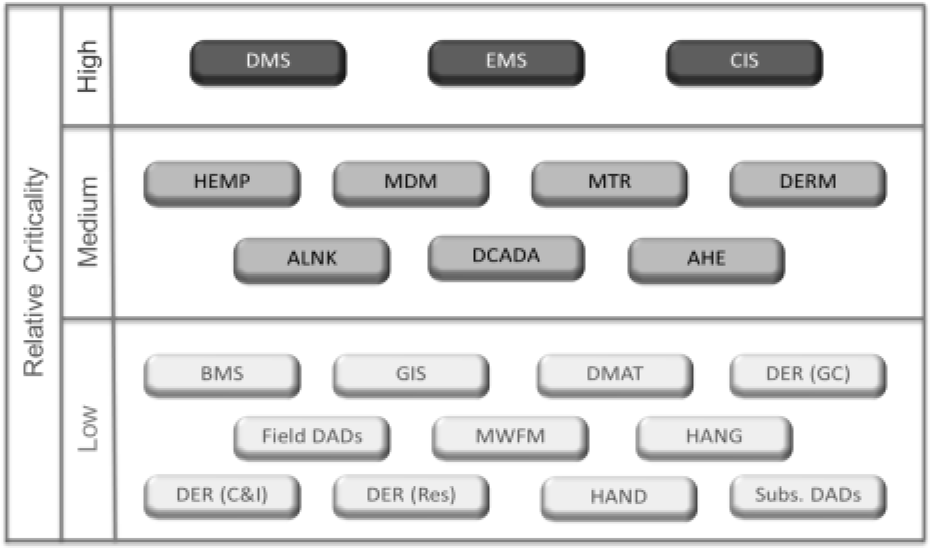


Several measurement criteria were used to assess the likelihood of an attack. These criteria included the evaluation of a potential threat source's motivation and capabilities as well as the nature and frequency of existing vulnerabilities. In the risk assessment, this component did not represent the likelihood of a successful attack, but merely the likelihood of an attack. Similar to the other risk model components, a rating methodology was developed to assign a value for likelihood to all systems. Each threat source was applied to each system and its likelihood of an attack was given a rating. The highest assigned likelihood rating of among the threat sources for a system was then used as that system's overall likelihood rating.

Impact (also referred to as criticality) can be defined as the effect or influence a successful attack may have on a system and/or the organization. Examples of impact include significant monetary damage, compromised consumer privacy, loss of important business operations for long periods of time, national-level damage to company reputation, and years of litigation. For the risk rating model, a quantifying approach was developed to estimate the effects that a cyber-compromise of confidentiality, integrity, and/or availability would have on the system and the organization. The confidentiality impact was judged based on the qualitative assessment of the sensitivity of the system's data and the effects of a data leak event. The integrity impact was assessed in terms of the cost of fixing a data integrity issue. Lastly, the availability impact was evaluated by considering the cost of lost productivity, lost opportunity, lost business image, or increased business cost caused if each system became unavailable for a certain length of time.

A summary of the relative criticality ratings of the Smart Grid systems is graphically represented in Figure 3-8, where each system is placed in the Low, Medium, or High region.

Figure 3-8: Graphical Representation of Relative Criticality Results



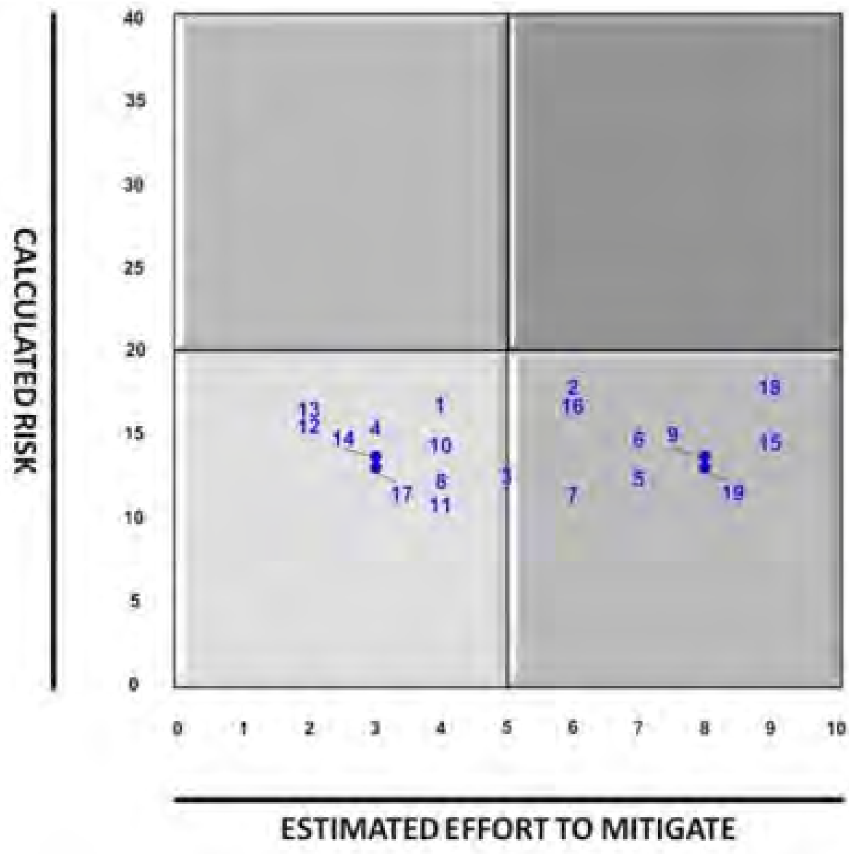
Mitigations are defined as risk reducing efforts or controls commissioned to protect a system's vulnerabilities or diminish the impact or likelihood of an attack on a system. To assess the value of the mitigation component, first the cyber controls suggested in the NISTIR-7628 and the UCAIug AMI and DM Security Profiles were studied for their applicability to the KCP&L SmartGrid systems. Once the applicable sets of controls were identified, they were matched with the security controls mandated in KCP&L policies, standards, and processes. A methodology was created to quantify the existing mitigations so that it can be used in the risk rating model. The methodology was based on the assumption that all requirements stated in KCP&L policies, standards, and processes are enforced on all existing and new systems at KCP&L.

The primary purpose for the risk assessment was to identify the risk level of each Smart Grid system so that KCP&L can strategize its efforts towards securing the project as a whole. The prioritization task becomes less complex with a risk rating available for each system. The final risk rating for each system was calculated using the model:

$$Risk = Threat + Vulnerability + \ Likelihood + \ Impact - Mitigation$$

Once the risk ratings were calculated, the systems were plotted against an estimate of the effort required to further mitigate the systems' vulnerabilities, likelihoods, and impacts. Figure 3-9 shows the systems plotted against the calculated overall risk rating and estimated effort to mitigate.

Figure 3-9: Risk Rating Categories



System ID	System
1	AHE
2	ALNK
3	BMS
4	CIS
5	DADs (Field & Substation)
6	DCADA
7	DER - C&I
8	DER – Grid-Connected
9	DER - Residential
10	DERM
11	DMAT
12	DMS
13	EMS
14	GIS
15	HAND/HANG
16	HEMP
17	MDM
18	MTR
19	MWFM

There is not, nor should there be, an "ideal" level of risk or a static "target" level of risk at which to aim. These calculated risk ratings should be used to prioritize efforts to reduce overall system risk. Risk may be reduced by mitigations and controls applied at the policy, network, or system level.

3.2.1.2 Risk Assessment Recommendations

There were ten major recommendations given in the risk assessment report. Some were technical in nature, such as assessing and implementing recommended security controls, or designing and implementing recommended network security zones. Others were more policy- and process-based, such as updating policies and documenting mitigation activities. The following list is an overview of the ten major recommendations:

- Implement the provided sets of security controls in a phased approach
- Implement the recommended conceptual security zones using network design techniques
- Create an implementation plan that covers the recommended security controls and security zones
- Update the KCP&L SmartGrid Cyber Security Plan to maintain focus on security and to meet DOE expectations

- Create security requirements for all systems to convert the security controls from concept to implementation
- Develop minimum security requirements for any Smart Grid system externally hosted by a third-party
- Update KCP&L policies, standards, and/or processes to include protection of Smart Grid systems based upon the provided set of procedural controls
- Create and execute test cases to verify the placement and functionality of the security controls
- Perform periodic security assessments to identify and mitigate new risks
- Participate in working groups to learn and create best practices and standards for securing the grid

3.2.2 Risk Mitigation

The completion of the risk assessment resulted in a set of actionable mitigation steps that can be taken by KCP&L to make its Smart Grid systems secure. The KCP&L SmartGrid Trust Model [8] was also used as an important reference while creating these mitigation recommendations. The KCP&L Trust Model domains (Secured, Restricted, Controlled, and Uncontrolled) were used to develop recommended security zones for KCP&L SmartGrid systems and to determine the security controls for data stored and/or generated by the systems. The trust model transport classes (Trusted, Managed, and Public) were used to determine the security controls for data transmitted between systems.

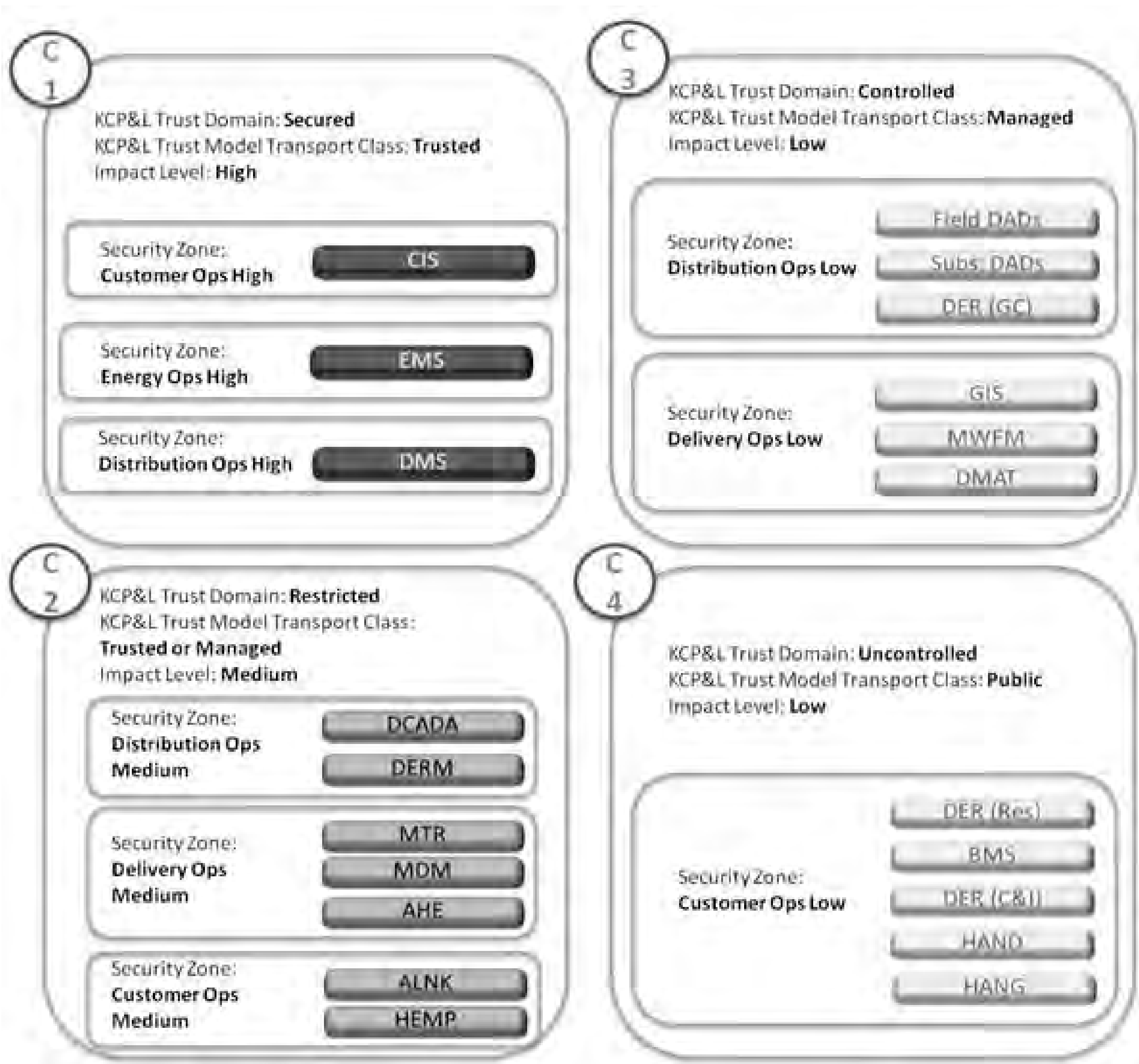
The mitigation recommendations resulting from the risk assessment fell into one of the following two types of security control implementations: creation of security zones and implementation of tailored control sets or implementation of industry-suggested control sets. Detailed descriptions of both security control implementations are covered in the following subsections.

3.2.2.1 Creation of Security Zones and Implementation of Tailored Control Sets

This type of security control implementation includes a collection of security controls specifically tailored for the Smart Grid project based upon security zones and interfaces between security zones. Each security zone includes Smart Grid systems that have the same criticality level and perform similar business functions. The goal of this implementation is to incorporate controls that will bring high risk systems down to a medium risk level and adequately protect the systems based on their impact levels. As such, the selection of controls in this type of implementation is also based on the risk and impact ratings calculated for each system as part of the end-to-end risk assessment.

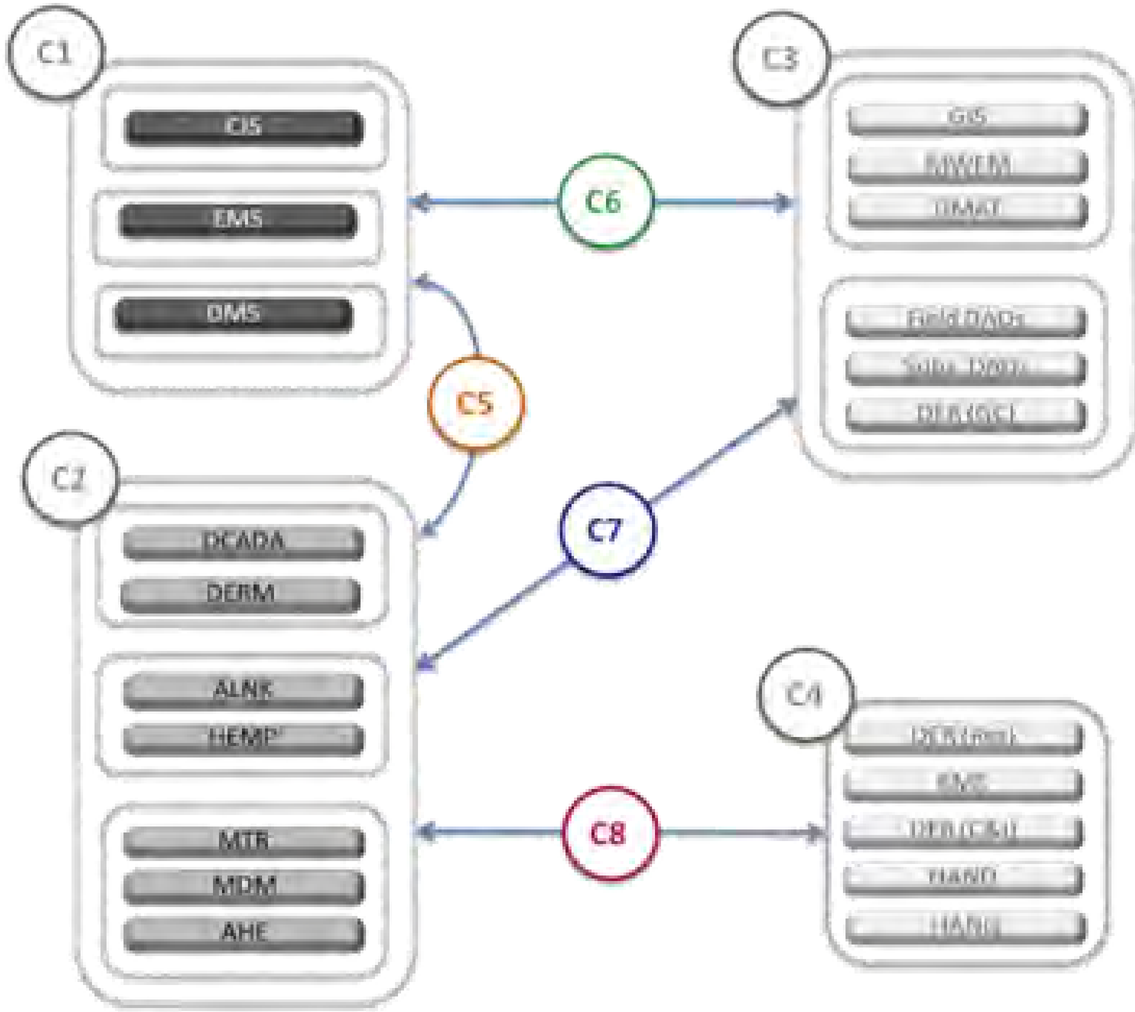
Figure 3-10 provides a graphical view of the recommended security zones for the KCP&L SGDP.

Figure 3-10: Representation of Smart Grid Applications in Respective Security Zones



Second, security control sets are created that tailor to the security zones and interfaces between them. Each control set is a collection of security requirements from the NISTIR-7628 Volume-I as well as many of the ones included in the UCAIug [17] AMI and DM Security Profiles. Figure 3-11 provides a visual representation of the control sets applicable to each security zone and its interfaces.

Figure 3-11: Representation of Control Sets for Inter-Security Zone Communication



3.2.2.2 Industry-Suggested Controls

The second type of security control implementation is a collection of controls based on industry best practices and guidelines. This type lists all the controls suggested in the NISTIR-7628 Volume-I [10] based strictly on the applicable logical interface categories and their recommended controls. These security requirements, if implemented to their fullest, should adequately secure the Smart Grid systems. It is worth noting that the controls recommended in the implementation type discussed in Section 3.2.2.1 are a subset of the controls recommended in this type.

Table 3-3 provides a summarized listing of the KCP&L SmartGrid systems along with their applicable NISTIR-7628 Logical Interface Categories. The table indicates that a majority of the NISTIR-7628 security requirements were found to be applicable to all the Smart Grid systems. To improve readability and act as a quick reference, the table lists requirements in the format "All Except… the requirements found *not* to be applicable."

Table 3-3: NISTIR-7628 Security Requirements Applicability by System

SmartGrid System	Applicable NISTIR-7628 Logical Interface Categories	Applicable NISTIR-7628 Security Controls
AHE	5, 13, 14	**All** Except: SG.AC-12, SG.IA-5, SG.SC-4, SG.SC-17
BMS	15	**All** Except: SG.AC-11, SG.AC-12, SG.AU-16, SG.IA-5, SG.SC-4, SG.SC-6, SG.SC-9, SG.SC-17, SG.SC-26, SG.SC-29
CIS	7, 8, 10	**All** Except: SG.SC-6, SG.SC-9, SG.SC-17
DCADA	1, 2, 3, 5	**All** Except: SG.AC-12, SG.AU-16, SG.SC-4, SG.SC-9, SG.SC-17, SG.SC-26
DER - C&I, **DER - Grid-Connected,** **DER - Residential**	11	**All** Except: SG.AC-11, SG.AC-12, SG.AC-14, SG.AU-16, SG.IA-4, SG.IA-5, SG.IA-6, SG.SC-3, SG.SC-4, SG.SC-5, SG.SC-6, SG.SC-7, SG.SC-9, SG.SC-17, SG.SC-26, SG.SC-29, SG.SI-7
DERM	8, 9, 16	**All** Except: SG.SC-6, SG.SC-17, SG.SC-29
DMS	5, 10	**All** Except: SG.AC-12, SG.AU-16, SG.IA-5, SG.SC-3, SG.SC-9, SG.SC-26
EMS	1	**All** Except: SG.AC-12, SG.AU-16, SG.SC-4, SG.SC-6, SG.SC-9, SG.SC-26
Field DADs, Substation DADs	11	**All** Except: SG.AC-11, SG.AC-12, SG.AC-14, SG.AU-16, SG.IA-4, SG.IA-5, SG.IA-6, SG.SC-3, SG.SC-4, SG.SC-5, SG.SC-6, SG.SC-7, SG.SC-9, SG.SC-26, SG.SC-29, SG.SI-7
GIS	10	**All** Except: SG.AC-12, SG.AU-16, SG.IA-5, SG.SC-3, SG.SC-6, SG.SC-9, SG.SC-26
HAND, HANG	15	**All** Except: SG.AC-11, SG.AC-12, SG.AU-16, SG.IA-5, SG.SC-6, SG.SC-4, SG.SC-9, SG.SC-26, SG.SC-29
HEMP	8, 16	**All** Except: SG.SC-5, SG.SC-6, SG.SC-29
MDM	7, 8, 10	**All** Except: SG.SC-6, SG.SC-9
MTR	15	**All** Except: SG.AC-11, SG.AC-12, SG.AU-16, SG.IA-5, SG.SC-4, SG.SC-6, SG.SC-9, SG.SC-26, SG.SC-29

3.2.3 Security Requirements Development

Using the tailored control sets from the risk assessment as a basis, KCP&L evaluated the security controls provided in the NISTIR-7628 to determine which controls were applicable to each system in the project for the following areas:

- Application Security
- Physical Security
- Network Security
- Policy/Procedural Controls

As part of this evaluation, KCP&L determined whose responsibility it would be to implement each control for each system: KCP&L, the vendor(s), or a combination of KCP&L and the vendor(s). For the scope of the SGDP, KCP&L determined that a large subset of the security controls recommended in the tailored control sets were appropriate. To show what controls were applicable for each system, KCP&L developed a master spreadsheet. An excerpt of this spreadsheet is shown below in Figure 3-12.

Figure 3-12: Excerpt from Master Security Controls Spreadsheet

NISTIR-7628 Smart Grid Requirement Number	NISTIR-7268 Smart Grid Requirement Name	Technical or Administrative Requirement	Network	MDM	AHE	DERM	HEMP	DMS	DCADA & SICAM	Battery & Inverter
SG.AC-1	Access Control Policy and Procedures	Administrative								
SG.AC-2	Remote Access Policy and Procedures	Administrative								
SG.AC-3	Account Management	Administrative								

3.2.4 Application Security Assessment & Implementation

After determining what controls were applicable for each system, KCP&L developed and provided security requirements for each SGDP system to the original equipment manufacturers (OEMs) via questionnaires. A sample of a questionnaire sent to the OEMs is provided in Figure 3-13 below.

Figure 3-13: Excerpt from Vendor Cyber Security Questionnaire

NISTIR 7628 Smart Grid Requirement Number	NISTIR 7268 Smart Grid Requirement Name	Is Requirement Implemented? (Yes/No/Planned)	If **Yes**: Provide technical details of implementation. If **No**: Provide a reason why. If **Planned**: Provide planned date of implementation and technical details of implementation.	If requirement has been implemented, please list the tests performed that validate the requirement being met.	Please list the supporting test documentation (cases/procedures, results) that is supplied to KCP&L as part of this questionnaire.
SG.AC-1	Access Control Policy and Procedures				
SG.AC-2	Remote Access Policy and Procedures				
SG.AC-3	Account Management				
SG.AC-4	Access Enforcement				

As part of the Implement focus area, KCP&L is currently assessing responses to the security questionnaires to evaluate the cyber security readiness for both KCP&L and OEM-hosted systems as follows:

- If security requirements are met
- How security requirements are met
- If any third-party assessment (NISTIR-7628, NERC CIP, SSAE 16, etc.) has been performed
- What organizational controls will be implemented by KCP&L and the OEMs
- What shared organizational controls will be implemented by KCP&L and the OEMs
- What technical controls will be developed by KCP&L and the OEMs

3.2.5 Physical Security Assessment & Implementation

As part of the Implement focus area, KCP&L is in the process of evaluating physical security controls both for KCP&L-hosted systems and OEM-hosted systems. To establish a high level of physical access control and monitoring, the project team:

- Assessed the existing controls at the KCP&L corporate data center and found them to be appropriate for the SGDP

- Assessed the existing controls in the KCP&L operations control room and found them to be appropriate for the SGDP
- Designed and is in the process of implementing physical security zones and requirements for the SGDP substation and SmartGrid Innovation Park
- Is in the process of evaluating the controls that each OEM has in place within their hosted facilities

Within KCP&L's SmartGrid Innovation Park, KCP&L is in the process of implementing an industry-recommended physical security architecture consisting of the following:

- Keycard access for the main gate
- Keycard access for the pedestrian gate
- Keycard access for the battery control house
- Motion detectors
- Video cameras

3.2.6 Network Security Assessment & Implementation

As part of the Implement focus area, KCP&L assessed the Smart Grid network architecture and related security requirements. Based upon the results of the risk assessment, the project team:

- Created KCP&L network segregation requirements
- Created KCP&L high-level network architecture both for the overall SGDP and within the SGDP substation
- Is in the process of implementing a Smart Grid network isolated from the KCP&L corporate network
- Is in the process of implementing point-to-point virtual private network (VPN) connections to OEMs hosting Smart Grid applications
- Is in the process of evaluating the network security architecture of the OEM's hosting facilities

Within the SGDP substation network architecture, KCP&L implemented the following secure enclaves (graphically depicted in Figure 3-14):

- **Substation Corporate User Network** – This network provides KCP&L personnel in either the existing SGDP control house or battery control house access to applications on the corporate network and a connection to the Internet.
- **Substation Distribution Protection & Control Network** – This network consists of redundant fiber optic ring networks that connect all of the substation distribution automation devices that are designed for protection and control (relays and tap changers). The communication within this network is high-speed IEC 61850 compliant.
- **Substation DMS Operator Network** – This network allows KCP&L personnel to access information displayed to DMS operators in the control center via a DMS workstation installed in the battery control house. Role-based access control (RBAC) determines the privileges of each user.

- **Substation Distribution Automation Network** – This network contains the systems that make the SGDP substation a “SmartSubstation”. This is comprised of DCADA and the substation HMI.
- **Substation Physical Security Network** – This network consists of the security host devices installed in the new battery control house. Each host device collects information from the security devices installed throughout the SmartGrid Innovation Park (video cameras, electronic badge readers, and motion detectors). The hosts send this information to Corporate Security via the KCP&L WAN.
- **Distribution Automation Network** – This wireless field area network provides a communication path for the DMS and DCADA to monitor and control the grid-connected battery and field distribution automation devices (capacitor banks, FCIs, and reclosers).
- **Field AMI Network** – This is the wireless mesh network used for communication between the SmartMeters installed throughout the project area. It also includes the AMI collectors, which are used to transmit messages in and out of the AMI network.

3.2.7 Cyber Security Verification

The final sub-area within the Implement focus area is performing cyber security controls verifications for the vendor-hosted SGDP applications to ensure that guidelines in the NISTIR-7628 have been met. This verification process will consist of four phases:

1. Pre verification data collection and review
2. Onsite verification
3. Analysis
4. Report generation

Pre verification data collection and review will consist of sending a data request to each vendor to furnish the following documentation:

- A detailed list of servers and work stations that will be used for hosting the KCP&L application(s).
- A diagram detailing the network topology of the hosted applications.
- Final responses to previously sent security questionnaire.
- Copy of internal or third party audit reports (general IT or cyber security specific) performed for hosted site.
- The reports, findings, and action plans of any vulnerability assessment performed within the last twelve calendar months.
- A detailed description of implemented physical security controls to secure the hosted site.

Once the documentation is received, KCP&L will review and prioritize focus areas for the onsite verification visit. The onsite verification visit will consist of interviewing vendor personnel, observing hosted environment, reviewing documentation, and reviewing evidence for twenty-two areas of cyber security and information technology controls:

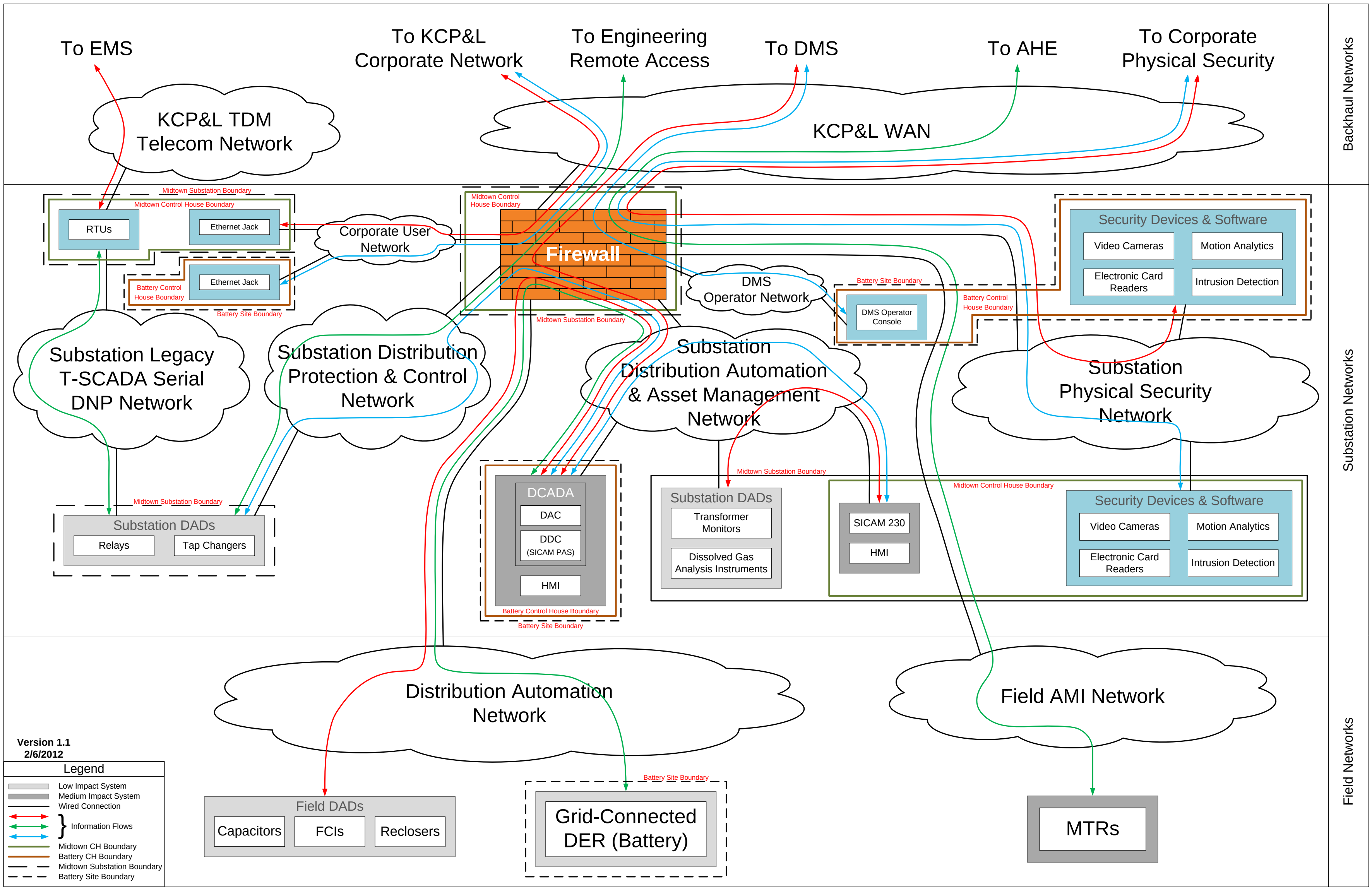
1. Hosting services applicable to KCP&L
2. Secure Software Development Life Cycle (SDLC)
3. Security configuration management
   - Ports and services
   - Patch management
   - Malicious software prevention
   - Logging, auditing and monitoring
4. Access/account management
5. Change management
6. Network security architecture
7. Code management
8. Vulnerability and security assessments
9. Electronic access controls and monitoring
10. Physical access controls and monitoring
11. Cyber security incident response process and procedures
12. Data backup and restoration
13. Disaster recovery/continuity of operations
14. Data center operations
15. Information protection
16. Test environment
17. Testing methodology
18. Personnel security and training
19. Cyber security team
20. Leadership commitment/support
21. Internal/third-party audits
22. Industry participation

In the analysis phase, KCP&L will analyze the information collected before and during the onsite visit. The analysis will focus on determining whether the vendors' application(s) and practices adhere to the guidelines set forth in the NISTIR-7628. For each of the twenty-two areas identified above, KCP&L will assess if the vendor:

1. Completely adheres to the guidelines
2. Partially adheres to the guidelines (including identification of gaps)
3. Does not adhere to the guidelines

After analyzing, KCP&L will generate a report regarding each vendor that details the project team's analysis and identifies any gaps that the vendor would need to fill in order for KCP&L to move forward with them after the SGDP ends, depending on whether KCP&L decides to expand enterprise-wide at that point.

Figure 3-14: Midtown Substation Network Architecture



3.3 SmartSubstation

3.3.1 Substation Protection Automation

An IEC-61850 compliant substation controller (DCADA) and substation network will be installed in the Midtown Substation along with various other component upgrades to enable substation protection automation. Component upgrades will include the replacement of electromechanical relays with intelligent electronic relays and intelligent bus throwover relays. All new relays will communicate directly with the substation controller. The substation controller will provide distributed intelligence at the substation that will enable execution of automated protection operations based on feedback from real-time monitoring of transformers, relays, cables, cap banks, and other field equipment installed throughout the circuits.

Substation Protection Automation will reduce operation and maintenance costs as manual or remote operations will be executed automatically. Automated actions based on real-time feedback will also help prevent component failures or route power around component failures within the substation, thus improving reliability and further reducing operation and maintenance costs. Implementation in accordance with IEC-61850 will provide experience and learning for the industry. Monitoring of all substation equipment will provide better operating data for utility decision making.

3.3.1.1 Baseline Data:

- No baselines will be used for this methodology

3.3.1.2 Measurement Method/Methodology:

- Automated operational activities will be tracked by the project DMS/DCADA systems. Manual operational activities at the midtown substation will be tracked by the KCP&L legacy MWMS.
- Reliability indices and failure events will be calculated from data tracked by the project OMS and DMS.

3.3.1.3 Analytical Method/Methodology:

- Automated operational activities performed by these devices will be recorded and compiled to summarize and assess the overall impact these device and network upgrades have on the operations and maintenance of this substation.
- All failure/outage events experienced within the project boundaries will be recorded and analyzed. One event, if available, will be compared to a hypothetical legacy substation response to the same situation to assess and quantify the improvement in overall response time and limitation of impact.

3.3.2 Real-Time Transformer Monitoring & Rating

An IEC-61850 compliant substation controller and substation network will be installed in the Midtown Substation along with real-time monitoring and rating of each transformer serving the twelve Smart Grid circuits. Transformer monitors will measure and communicate temperature readings and dissolved gas analysis readings directly to the substation controller. The substation controller will provide distributed intelligence at the substation that will enable execution of automated operations based on real-time monitoring feedback and will also capture transformer operating data.

Transformer monitoring will reduce operation and maintenance costs as transformer performance issues may be rectified before leading to an operating failure and outage. Avoided failures will improve reliability on the equipped circuits. Additionally, transformers will be able to be operated closer to rated capacity as accurate and real-time information will be available regarding their operational health and status. They will no longer be constrained to theoretical limits. Implementation in accordance with IEC-61850 will provide experience and learning for the industry. Monitoring of all substation equipment will provide better operating data for utility decision making.

3.3.2.1 Baseline Data:

- Baseline data for reduced operations and maintenance costs from Transformer Monitoring will consist of maintenance events forecasted for the affected components based on historical maintenance data.
- Baseline data for increased reliability and failure prevention will consist of forecasted indices and failure events based on historical reliability indices (SAIDI/SAIFI) and historical failure events for the affected feeders/circuits.
- Baseline data for transformer utilization will be based on theoretical load factors for each transformer that will be monitored in the project.

3.3.2.2 Measurement Method/Methodology:

- Automated failure prevention activities will be tracked by the DMS/DCADA systems, recording actions executed and devices involved.
- Reliability indices and failure events will be calculated from data tracked by the project OMS/DMS.
- Transformer utilization (percentage) will be calculated from actual load data recorded versus rated capacity.

3.3.2.3 Analytical Method/Methodology:

- Actual maintenance and failure prevention activities on these circuits will be compared directly to baseline forecasts on a monthly and annual basis.
- Actual failure events and reliability indices on these circuits will be tracked and evaluated on a monthly and annual basis.

3.4 SmartDistribution

3.4.1 Fault Detection, Isolation, & Reconfiguration

Fault isolation, fault location, circuit monitoring devices, and automatic circuit reconfiguration equipment will be deployed on 4-6 of the SmartGrid distribution circuits. This will include two-way communications to enable system operators to continuously monitor and operate this equipment remotely. The systems will also automatically identify circuit faults and isolate them to smaller sections of the circuit when possible. Remaining sections of the circuit will be restored automatically without human intervention. Additionally, system operators will receive alerts regarding the faulted section and deploy field crews directly to the failed equipment, avoiding timely fault searching.

This will improve reliability, resulting in significant reductions in SAIFI and SAIDI. Operational costs will be reduced as manual switching will be executed remotely and fault locations will reduce fault searching time. It is estimated that SAIFI could reduce 20%, SAIDI 30%, and manual switching decreased by 3-6 truck rolls per circuit per year.

3.4.1.1 Baseline Data

- Baseline data for reduced operations and maintenance costs for FLCR will consist of manual operational events forecasted for the affected circuits based on historical operational data.
- Baseline data for increased reliability and failure prevention will consist of forecasted indices and failure events based on historical reliability indices (SAIDI/SAIFI) and historical failure events for the affected feeders/circuits.

3.4.1.2 Measurement Methodology

- Automated operations will be tracked by the DMS and manual operations will be tracked by the KCP&L MWFS.
- Reliability indices and failure events will be calculated from data tracked by the KCP&L project OMS/DMS.

3.4.1.3 Analytical Methodology

- Automated and manual operational activities on these circuits will be compared directly to baseline forecasts on a monthly and annual basis.
- Actual failure events and reliability indices on these circuits will be tracked and evaluated on a monthly and annual basis.

3.4.2 Integrated Volt/VAR Management

The implementation of a Distributed Control And Data Acquisition (DCADA) system in conjunction with real-time monitoring of field devices such as capacitor bank controllers, voltage monitors, and voltage regulators will enable advanced Volt/VAR management, demand response, and energy conservation on distribution circuits within the SmartGrid Demonstration Project. DCADA (substation controller) will communicate with field devices on the circuits via the KCP&L Field Area Network (FAN) and will communicate with the Distribution Management System (DMS) via the KCP&L WAN. DCADA will monitor and adjust voltage settings at tap changers and field devices in order to:

- Optimize voltage across the entire circuit
- Optimize voltage and VAR to minimize energy losses on each circuit
- Temporarily reduce voltage on the circuit in order to execute Demand Response (Dynamic Voltage Control-DVC)
- Continuously reduce voltage on the circuit in order to reduce energy consumption (Conservation Voltage Reduction-CVR)

The capability will be operated to demonstrate optimizations under various load conditions, DVC under peak load conditions and other system or circuit constraining conditions, and CVR under sustained operational conditions.

Volt/VAR Management will enable automated and decentralized volt/VAR control on equipped circuits to either optimize voltage along the circuit, reduce VAR on the circuit, reduce energy losses on the circuit, execute Demand Response (DVC), and improve energy overall energy efficiency (CVR). KCP&L expects DVC, VAR reduction, and reduction of losses to be of the most value on the selected circuits as they are urban circuits with stable voltage anticipated.

3.4.2.1 Baseline Data

- Baseline data for voltage optimization demonstration will consist of mapping hourly average voltage deviations from target voltage at all measurable points along the circuit over 5 non-event/holiday weekdays.
- Baseline data for DVC events will consist of an adjusted previous day average (High 4 of 5) hourly load profile for each circuits involved in the DR events.
- Baseline data for loss reduction demonstration will consist of adjusted previous day average (High 4 of 5) hourly loss profile for those circuits involved.
- Baseline data for CVR demonstration will consist of weather-adjusted cumulative energy consumption for each circuit over 5 non-event/holiday weekdays.
- All baseline data will be sourced from KCP&L's AMI system which will include circuit metering at the bus for each SG circuit in addition to all customers.

3.4.2.2 Measurement Methodology

- Circuit interval load and VAR data for circuits will be measured through KCP&L's AMI metering deployed as part of the Project.
- AMI metering will be deployed on all circuits at the bus and at each customer in the project area and all data will be stored in KCP&L's Meter Data Management (MDM) System.
- Volt/VAR demonstration events will be tracked by the DMS/DCADA operational data store.

3.4.2.3 Analytical Methodology

- At each reporting milestone, event/demonstration period data will be compared to baseline data to determine a quantified impact (reduction in voltage deviation, peak load reduction, loss reduction, etc.). Quantified impacts measured will be described and reported in semi-annual impact metrics and TPRs.

3.5 SmartMetering

3.5.1 AMI

AMI will be deployed to the entire KCP&L SmartGrid Demonstration area. Deployment will include the installation of smart meters (capable of two-way communications, interval metering, and remote connect/disconnect) at approximately 14,000 residential, commercial, and industrial customers. Meters will measure, store, and wirelessly transmit 15-minute interval energy usage data to a central Meter Data Management (MDM) system where it will be available to other KCP&L systems. Communications between meters and the MDM will be accomplished through a dedicated RF-mesh Field Area Network (FAN) and KCP&L's private Wide Area Network (WAN).

AMI will capture meter reading at 15-minute intervals as opposed to the daily reads currently accomplished by KCP&L's Automated Meter Reading (AMR) system, will enable two-way communications between KCP&L and customers' premises, and will enable KCP&L to remotely connect or disconnect customers from the KCP&L service center.

3.5.1.1 Baseline Data:

- Baseline data for AMI impact to operational costs will be based on per customer estimated costs to operate KCP&L's current AMR system.

3.5.1.2 Measurement Method/Methodology:

- AMI performance tracking will be captured by the AMI Head-End.

3.5.1.3 Analytical Method/Methodology:

- Observed operational costs of the AMI system will be compared to estimated operational costs of the AMR system on a per customer basis.
- AMI system health and interval read performance will be tracked for comparison and benchmarking analysis.

3.6 SmartGeneration Resources

3.6.1 Grid-Connected Battery

A 1.0 MWh, 1.0 MW-capable Grid-Connected Battery has been installed adjacent to the Midtown Substation with direct interconnect to a single 13.2 kV circuit, immediately downstream of the substation transformer. The battery consists of Superior Lithium Polymer Battery (SLPB) technology and is capable of high-rate charging and discharging of energy. The system is expected to operate at greater than 70% efficient with respect to net energy output versus input.

The Grid-Connected Battery System will be capable of providing peak reduction on the circuit, load following, shift energy consumption from peak to off-peak, and may improve reliability on the circuit. KCP&L may also explore using the battery system for voltage and VAR control on the circuit.

3.6.1.1 Baseline Data

Baseline data for the DERM system will consist of interval and daily load profile data (kWh) for the circuit with the Battery. Baseline profiles for this circuit for each battery charge/discharge event will be based on weather-adjusted previous or proxy day load profiles (demand response events) as measured through interval metering. The following data will be available:

- Interval load data for this and other relevant circuits through KCP&L's project AMI.
- Voltage measurements from relays, reclosers, and cap banks.

3.6.1.2 Measurement Methodology

- Circuit interval load data for the circuit with BESS will be measured through KCP&L's AMI system deployed as part of the Project. AMI metering will be deployed on all circuits in the Project area and all data will be stored in KCP&L's Meter Data Management (MDM) System.
- BESS charge and discharge events will be tracked by the DMS, Storage Management System (SMS), Battery Management System (BMS) and the DERM.
- Battery performance metrics will be calculated based on monitoring data from metering on the high side of the BESS transformer, the SMS, and the BMS.
- Voltage measurements and violations will be tracked at circuit breaker relay and at the battery interconnect recloser and potentially at cap bank(s) downstream.

3.6.1.3 Analytical Methodology

The BESS will be evaluated based on demonstrating its ability to charge and discharge on demand and according to scheduling. This will be verified through circuit/feeder load analysis and AMI metering on the high side of the BESS transformer. At each reporting milestone, circuit interval load data for the circuit with the BESS will be extracted from the MDM System through KCP&L's Data Mining and Analysis Tool (DMAT) (DataRaker). The DMAT has built in functionality that will build hourly load profiles for each circuit for comparison with previous or proxy day profiles of the same circuits.

Voltage measurements at select devices will be recorded and extracted by the DMS/DCADA system for comparison and analysis during charge/discharge and var compensation events.

3.6.2 Distributed Solar Generation

Approximately 180 kW of distributed solar photovoltaic (PV) capacity will be installed within the SmartGrid Demonstration Project area by KCP&L. These systems will consist of one large commercial-scale system to be installed on a local school rooftop and various smaller distributed systems on homes and businesses throughout the project area. All solar systems will be directly connected to the local grid and independently metered.

Distributed PV systems within the project area will reduce energy consumption (kWh) on the SmartGrid circuits and may also reduce average summer demand (kW) for those circuits affected as PV generation generally peaks during electrical demand peak in summer months.

3.6.2.1 Baseline Data

Baseline data for Distributed PV Generation will consist of interval and daily load profile data (kWh) for all circuits with solar generation. Since each PV system will be metered independently, circuit baseline load profiles will be constructed by adding observed PV generation to observed net circuit load plus losses, if able to estimate. The following data will be available:

- Interval load data for all circuits and PV meters through KCP&L's AMI.

3.6.2.2 Measurement Methodology

Circuit interval load data and each PV generation system will be measured through KCP&L's AMI system deployed as part of the Project. AMI metering will be deployed on all circuits in the Project area and all data will be stored in KCP&L's Meter Data Management (MDM) System. For select PV systems, generation output may be metered separately at the PV system inverter to verify KCP&L's baseline and analytical methodologies.

3.6.2.3 Analytical Methodology

The Distributed PV Systems will be evaluated based on generation performance and impacts to net circuit load profiles. This will be verified through circuit load and PV generation profile analysis. At each reporting milestone, circuit interval load data for all circuit and PV meters will be extracted from the MDM System through KCP&L's Data Mining and Analysis Tool (DMAT) (DataRaker).

3.6.3 DERM/Programmable Control Thermostats

The implementation of a Distributed Energy Resource Management (DERM) System in conjunction with Programmable Control Thermostats (PCTs) will enable advanced utility utilization of demand response on the distribution system. The DERM will maintain a sophisticated distributed energy resource (DER) inventory and will be capable of forecasting, scheduling, selecting, and executing load control programs for all or select devices/resources. Demand response events then may be scheduled and executed system-wide (as is common practice now) or may now be isolated or grouped to only impact targeted circuits or alternatively defined sections of the distribution system to support reliability needs.

DERM/PCTs will enable utility-controlled reduction in kW on the entire system or on select groups of DERs with advanced scheduling and execution for both system demand reduction or for reliability purposes.

3.6.3.1 Baseline Data

Baseline data for the DERM/PCT system will consist of hourly load profile data for circuits within the project area that have PCT customers. Since the PCT program will be event-based, baseline profiles for each circuit and each event will be based on weather-adjusted previous or proxy day load profiles for the same circuit (to compare event day hourly load profile against). These baseline profiles will be constructed from available interval metering data measured on each circuit through dedicated AMI meters located on the high side of the transformer.

3.6.3.2 Measurement Methodology

Circuit interval load data for circuits with DERM/PCT will be measured through KCP&L's AMI system deployed as part of the Project. AMI metering will be deployed on all circuits in the Project area and all data will be stored in KCP&L's Meter Data Management (MDM) System. DERM/PCT scheduled and executed events will be tracked by the DERM system and participant compliance will be tracked by the HEMP system.

3.6.3.3 Analytical Methodology

The DERM will be evaluated based on demonstrating its ability to schedule and execute demand response programs for a select group of customers at a specified time. This will be verified through circuit/feeder load analysis and device compliance data. For each demand response event, circuit load profile data will be captured for all circuits within the project area with PCTs (both those that were scheduled in the event and those that were not) to verify that demand reduction occurred when and where it was intended. Metering data will be retrieved from the MDM System through KCP&L's Data Mining and Analysis Tool (DMAT), DataRaker.

In addition to verifying the ability of the DERM system to schedule and execute demand response on select groups of participants (circuits), KCP&L intends to utilize this event and baseline load profile data to assess the accuracy of DERM demand reduction forecasts. This will be accomplished by directly comparing event day load profiles for each participating circuit to baseline load profiles. The difference at each daily time point should closely reflect DERM forecasted demand reduction potential throughout the event.

3.6.4 DERM/C&I Load Curtailment Programs

The implementation of a Distributed Energy Resource Management (DERM) System in conjunction with Commercial and Industrial Load Curtailment (C&I-LC) will enable advanced utility utilization of demand response on the distribution system. The DERM will maintain a sophisticated distributed energy resource (DER) inventory and will be capable of forecasting, scheduling, selecting, and executing load control programs for all or select devices/resources. Demand response events then may be scheduled and executed system-wide (as is common practice now) or may now be isolated or grouped to only impact targeted circuits or alternatively defined sections of the distribution system to support local reliability needs.

DERM/C&I-LC will enable utility-controlled reduction in kW on the entire system or on select groups of DERs with advanced scheduling and execution for both system demand reduction or for reliability purposes.

3.6.4.1 Baseline Data

Baseline data for the DERM/C&I-LC system will consist of hourly load profile data for circuits within the project area that have C&I-LC customers. Since the C&I-LC program will be event-based, baseline profiles for each circuit and each event will be based on weather-adjusted previous or proxy day load profiles for the same circuit (to compare event day hourly load profile against). These baseline profiles will be constructed from available interval metering data measured on each circuit through dedicated AMI meters located on the high side of the transformer.

3.6.4.2 Measurement Methodology

Circuit interval load data for circuits with DERM/C&I-LC will be measured through KCP&L's AMI system deployed as part of the Project. AMI metering will be deployed on all circuits in the Project area and all data will be stored in KCP&L's Meter Data Management (MDM) System. DERM/ C&I-LC scheduled and executed events will be tracked by the DERM system and participant compliance will be tracked by the HEMP system.

3.6.4.3 Analytical Methodology

The DERM will be evaluated based on demonstrating its ability to schedule and execute demand response programs for a select group of participating customers at a specified time. This will be verified through circuit/feeder load analysis. For each demand response event, circuit load profile data will be captured for all circuits within the project area with C&I-LC customers (both those circuits that were scheduled in the event and those that were not) to verify that demand reduction occurred when and where it was intended. Metering data will be retrieved from the MDM System through KCP&L's Data Mining and Analysis Tool (DMAT), DataRaker.

In addition to verifying the ability of the DERM system to schedule and execute demand response on select groups of participants (circuits), KCP&L intends to utilize this event and baseline load profile data to assess the accuracy of DERM demand reduction forecasts. This will be accomplished by directly comparing event day load profiles for each participating circuit to baseline load profiles. The difference at each daily time point should closely reflect DERM forecasted demand reduction potential throughout the event.

3.7 SmartEnd-Use

3.7.1 Historical Interval Usage Access (Portal)

The utility-hosted Home Energy Management Portal (HEMP) is a network system that provides customers with website access to various tools by which customers may visualize and analyze their detailed energy usage history. The HEMP visualization and tools will be accessible through a personalized and secure internet website. For AMI customers, the HEMP website will be an extension of KCP&L's AccountLink customer account access that will present customers with interval energy usage data from smart meters as well as information about their account such as enrollment in energy programs and scheduled DR events. Through the HEMP portal, customers will have access to previously unavailable interval usage information from their smart meter within user-friendly visualizations that will allow them to determine how their energy decisions affect their energy costs and provide them with tools, advice, and programs to manage and reduce those costs. Customers with Home Area Networks will also be able to manage various aspects of their network devices through the HEMP interface, including enrolling devices in DR programs/events.

It is estimated that HEMP users will gain increased knowledge of their energy usage patterns and reduce their monthly and annual kWh usage by 1-5%.

3.7.1.1 Baseline Data

Baseline data for HEMP users will consist of interval and daily load profile data (kWh) for a control group consisting of those customers within the project area that choose not to access their HEMP account online. It is expected that a significant number of customers who receive smart meters will choose not to manage or view their accounts online due to a lack of internet service or interest in doing so. Control group load profiles will be captured for each customer class and sub-class through AMI interval metering that will be deployed for all customers within the Demonstration Project area. Interval load data of all customers within the Project area through KCP&L's AMI will be available for all baselines.

3.7.1.2 Measurement Methodology

Customer 15 minute interval load data for HEMP participants and during HEMP utilization will be measured through KCP&L's AMI system deployed as part of the Project. AMI metering will be deployed to all customers in the Project area by early 2011 and all data will be stored in KCP&L's Meter Data Management (MDM) System. In addition to measuring usage of HEMP participants, customer actions within the HEMP will be tracked to examine how often customers are using the various capabilities and accessing the available information within their online account.

3.7.1.3 Analytical Methodology

At each reporting milestone, customer interval load data for all participants within the Project area will be extracted from the MDM System through KCP&L's Data Mining and Analysis Tool (DMAT) (DataRaker). The DMAT has built in functionality that will enable the aggregation and calculation of hourly load profiles grouped by customer type and program cohort. Load profiles of HEMP participants will be compared to other groups on an hourly, daily, and monthly basis.

KCP&L will compare load profiles and monthly kWh usage of HEMP users to those of non-HEMP users.

3.7.2 In-Home Display

In-Home Displays (IHD) (also referred to as In-Premise Displays (IPD)) will provide KCP&L's customers with real-time energy usage monitoring that enables them to better manage their personal energy usage and costs. The device is a small, portable digital display that receives usage and price signals directly from the meter and displays the information for the customer. The IHD essentially provides customers with a real-time "speedometer" and "odometer" for electric use – giving them both current consumption rate information as well as access to visualize historical usage information. In addition to usage and price information, IHDs can display demand response (DR) messages to customers asking them to reduce load during peak events. IHDs will be provided free to participating residential and small commercial customers.

With the additional information that the IHD provides the consumer, it is expected that the IHD users will reduce their overall energy consumption and voluntarily participate in DR events. Other studies have shown that IHD users may reduce their overall energy consumption by as much as 5-7%.

3.7.2.1 Baseline Data

Baseline data for IHD users with regards to overall energy usage will consist of interval and daily load profile data (kWh) for a control group consisting of those customers within the project area that choose not to utilize an IHD. Baseline data for IHD users with regards to demand response events will consist of weather-adjusted previous or proxy day load profiles. Control group load profiles and previous day load profiles will be captured for each customer class and sub-class through AMI interval metering that will be deployed for all customers within the Demonstration Project area. The following data will be available for baselines:

- Interval load data of all customers within the Project area through KCP&L's AMI.

3.7.2.2 Measurement Methodology

Customer 15 minute interval load data for IHD participants and during IHD utilization will be measured through KCP&L's AMI system deployed as part of the Project. AMI metering will be deployed to all customers in the Project area by early 2011 and all data will be stored in KCP&L's Meter Data Management (MDM) System.

3.7.2.3 Analytical Methodology

At each reporting milestone, customer interval load data for all participants within the Project area will be extracted from the MDM System through KCP&L's Data Mining and Analysis Tool (DMAT) (DataRaker). The DMAT has built in functionality that will enable the aggregation and calculation of hourly load profiles grouped by customer type and program cohort. Load profiles of IHD participants will be compared to control group(s) on an hourly, daily, and monthly basis to assess differences in kWh usage and assess load shape changes, if present. Additionally, load profiles of IHD participants during demand response events will be analyzed and compared to previous or proxy day load profiles for the same customer (days without demand response events).

3.7.3 Home Area Network (HAN)

Home Area Networks (HAN) will consist of a gateway device communicating to the KCP&L meter and to numerous energy devices in customer home. The gateway device will get real-time usage information directly from the customer's smart meter. The gateway device will also establish communications between the utility Home Energy Management Portal (HEMP) via the customer supplied internet connection, enabling customers to manage energy consumption in their home using the functionality provided by the HEMP. Program participants will have their programmable control thermostats and a second significant controllable load (water heater, auxiliary AC, etc.) enrolled in the utility DR program. The HEMP will also allow customers to control these and other energy consuming appliances to manage their daily energy consumption. These devices may include any plug loads and smart appliances such as refrigerators. The gateway device will also get real-time usage information directly from the customer's smart meter. HAN provides customers and the utility with enhanced control of energy usage.

In conjunction with new voluntary TOU rate options and customer energy management that the HAN provides, it is expected that the HAN users will reduce their overall kWh usage, shift load to off peak times, and voluntarily allow HAN-connected devices to participate in DR events.

3.7.3.1 <u>Baseline Data</u>

Baseline data for HAN users with regards to overall energy usage will consist of interval and daily load profile data (kWh) for a control group consisting of those customers within the project area that choose not to utilize an HAN. Baseline data for HAN users with regards to demand response events will consist of weather-adjusted previous or proxy day load profiles. Control group load profiles and previous day load profiles will be captured for each customer class and sub-class through AMI interval metering that will be deployed for all customers within the Demonstration Project area. The following data will be available for baselines:

- Interval load data of all customers within the Project area through KCP&L's AMI.

3.7.3.1.1 <u>Measurement Methodology</u>

Customer interval load data for HAN participants and during HAN utilization will be measured through KCP&L's AMI system deployed as part of the Project. AMI metering will be deployed to all customers in the Project area by early 2011 and all data will be stored in KCP&L's Meter Data Management (MDM) System. Participation in DR events will be tracked through the HEMP. In addition to measuring usage of HAN participants, customer actions within the HEMP will be tracked to examine how often customers are logging in to online accounts to access available information or manage their HAN.

3.7.3.2 <u>Analytical Methodology</u>

At each reporting milestone, customer interval load data for all participants within the Project area will be extracted from the MDM System through KCP&L's Data Mining and Analysis Tool (DMAT) (DataRaker). The DMAT has built in functionality that will enable the aggregation and calculation of hourly load profiles grouped by customer type and program cohort. Load profiles of HAN participants will be compared to control group(s) on an hourly, daily, and monthly basis to assess differences in kWh usage and assess load shape changes, if present. Additionally, load profiles of HAN participants during demand response events will be analyzed and compared to previous or proxy day load profiles for the same customer (days without demand response events).

3.8 Education and Outreach

3.8.1 Communication Methods

As mentioned previously, KCP&L's approach to public education and outreach for its SmartGrid Demonstration Project takes a highly targeted multiple-channel approach to reach customers and other key stakeholders. For each audience, Table 3-4 below identifies audience key stakeholders and communication methods that will be utilized for this audience. Descriptions of the communication methods identified in Table 3-4 are grouped in the following subsections:

- Consumer Communications
- Civic Outreach
- Consumer Advocate Interaction
- Technology Education and Knowledge Transfer
- Project Tours and Field Demonstrations

Table 3-4: SmartGrid Audience Communication Methods

Audiences	Audience Description	Communication Methods
SmartGrid Demonstration Project Area Customers	Customers living within the SmartGrid Demonstration Project Area. Key Stakeholders: • Individual Customers • Neighborhood Groups • Schools • Community Leaders • Elected Officials • Green Impact Zone Partners	1. SmartGrid website 2. Direct mail 3. SmartGrid welcome kit 4. SmartGrid DVD 5. E-mail outreach 6. Radio advertising 7. Print advertising 8. Outdoor advertising 9. Automated customer notification 10. Energy fairs 11. SmartGrid Demonstration House 12. Social media 13. KC media coverage 14. Key leader briefings and mailings 15. Community organization meetings and newsletters 16. Neighborhood association meetings and newsletters 17. Church group meetings, displays and bulletins 18. SmartGrid education module for schools 19. KCP&L employee advocates 20. Green Impact Zone staff 21. Ambassadors 22. SmartGrid customer service representatives 23. SmartGrid office

Audiences	Audience Description	Communication Methods
All KCP&L Customers	While customers living within the Demonstration Project area will be the first affected by SmartGrid initiatives, what KCP&L learns from the project will eventually impact all KCP&L customers. As such, outreach to the entirety of KCP&L's customer base will be an important part of SmartGrid communications. Key Stakeholders: • Residential Customers • Commercial Customers • Industrial Customers	1. SmartGrid website 2. Radio advertising 3. Print advertising 4. Outdoor advertising 5. Energy fairs 6. SmartGrid Demonstration House 7. Social media 8. KC media coverage 9. SmartGrid education module for schools 10. KCP&L employee advocates 11. SmartGrid customer service representatives 12. SmartGrid office
KCP&L Employees	As media coverage and interest of the project in the broader service territory increases, KCP&L employees will be asked by friends, family and neighbors about SmartGrid. The 3,600 KCP&L employees can be utilized as SmartGrid ambassadors, but KCP&L will need to provide them with ongoing communications in order to make them effective. Key Stakeholders: • Customer Care Departments • Engineering and Operating Departments • KCP&L Employees Living in the Project Demonstration Area	1. The Source (employee newsletter) 2. Daily e-Source updates 3. TV monitors 4. Leadership Link videos 5. Managers Leadership Forum updates
State Agencies, Legislators, and Regulators	The individuals in this audience are charged with representing the community. They include elected or appointed individuals, who are especially sensitive to activities that may affect their constituents. Key Stakeholders: • Missouri Public Service Commission & Staff • Kansas Corporation Commission & Staff • Missouri Office of Public Counsel • Elected officials	1. SmartGrid educational workshops 2. MO & KS Commission Smart Grid staff participation in project workshops 3. MO SmartGrid stakeholder group meetings 4. Project technical reports 5. Project technical website

Audiences	Audience Description	Communication Methods
Electric Utilities and Smart Grid Industry	One of the main goals of this project is to serve as a blueprint for future integrated Smart Grid demonstrations and implementations throughout the country. In order to do this, KCP&L will need to effectively communicate and share knowledge with other utilities and the Smart Grid industry as a whole. Key Stakeholders: • Department of Energy • National Energy Technology Laboratory • National Institute of Standards & Technology • Smart Grid Interoperability Panel • Professional Associations • Labor Organizations	1. Project technical reports 2. Project technical website 3. EPRI's Smart Grid resource center *(www.smartgrid.epri.com)* 4. Workshops 5. Webcasts 6. Periodic publications 7. White papers/articles 8. SmartGrid Demonstration House 9. SmartSubstation Tour

3.8.2 Consumer Communications

Communicating with KCP&L's end users, both those located in the Demonstration Project area and those in the greater service area, is extremely important. By reaching out to the consumer, KCP&L will drive awareness and understanding of SmartGrid as well as encourage product acceptance and adoption.

3.8.2.1 Customer Focused SmartGrid Website

Although internet access is low in some parts of the SmartGrid Demonstration Project area, the KCP&L SmartGrid website is an important customer communication vehicle, both for KCP&L customers within the project area and in the broader service territory. The website provides key information about the Demonstration Project, including facts sheets, meter installation maps, timelines, upcoming events, news and FAQs. The MySmart Portal and MySmart Display instructional videos are also hosted on the website. The site is part of KCPL.com, but is also accessible via www.kcplsmartgrid.com (Figure 3-15). Over the course of the Demonstration Project, KCP&L will continue to add to and enhance the site with user functionality, Flash-enabled graphics, video clips, testimonials and a series of short "How To" videos.

Figure 3-15: *www.kcplsmartgrid.com* Home Page Screenshot

3.8.2.2 <u>Direct Mail</u>

One of the challenges of the Demonstration Project area is the high percentage of renters, making it a highly transient area, with residents constantly moving in and out. In addition to the broader mix of marketing and education efforts, KCP&L intends to reach residents through a series of direct mail letters and postcards. These consistent and regular updates will be particularly useful to new residents within the Demonstration Project area, especially those not already familiar with the project.

In early September 2010, all 14,000 KCP&L customers were sent a letter from Mike Deggendorf, KCP&L's Senior Vice President for Delivery. The letter welcomed them to the SmartGrid Demonstration Project and broadly explained both the customer benefits and next steps as the project gets underway.

KCP&L has also distributed a series of SmartGrid postcards to customers, staged to coincide with the meter installation schedule.

Table 3-5: Mailing Timeline

Audience	Description	Date
All Demonstration Project Customers	Welcome to SmartGrid letter	September 2010
All Demonstration Project Customers	Meter notification	Ongoing
Green Impact Zone Customers	Product Postcard	October 2010
Broader Project Area Customers (outside Green Impact Zone)	SmartGrid Status Update	October 2010
Broader Project Area Customers (outside Green Impact Zone)	Product Postcard	January 2011

3.8.2.3 SmartGrid Welcome Kit

For most customers, meter installation represents the first interaction with Smart Grid. At the time of SmartMeter installation, customers are provided with a KCP&L SmartGrid Demonstration Project welcome kit. Included in the welcome kit is a welcome book, MySmart product information, a SmartGrid DVD, information on community weatherization and energy assistance resources, a schedule of upcoming energy fairs and a compact fluorescent light bulb. The welcome kits are either given directly to the customer or left at the front door if no one is available.

3.8.2.4 SmartGrid DVD

Working with a local Women's Business Enterprise (WBE) video production company, KCP&L developed an overview video that creates general awareness and understanding of KCP&L's SmartGrid Demonstration Project and the customer benefits. Featured on the video are Mike Chesser, CEO of KCP&L; U.S. Rep. Emanuel Cleaver, II, Congressman for Missouri's 5th District; and Margaret May, Executive Director of the Ivanhoe Neighborhood Council. In addition, KCP&L worked with Tendril to develop two short instructional videos for MySmart Display and MySmart Portal, which are included as chapters on the DVD.

3.8.2.5 E-mail Outreach

KCP&L already has a well established online service for its customers called AccountLink. Through AccountLink, customers can access their account information and billing history, and make payments online. There are already more than 2,800 AccountLink customers within the Demonstration Project area. With access to these customers' e-mail addresses, KCP&L will be able to distribute targeted e-mails to customers who already use and are familiar with the company's online platform. The remainder of KCP&L customers are required to register for AccountLink the first time they sign on to MySmart Portal to view their usage information. As more customers are acquired and product adoption increases, more of the public education and outreach can be conducted online via e-mail.

3.8.2.6 Advertising

Paid advertising represents an important part of KCP&L's public education and outreach efforts, but the geographic boundaries of the Demonstration Project area present some unique challenges. Paid advertising effectiveness and impact is a derivative of layering multiple avenues, building a reach of at least 70 percent, while still maintaining a healthy frequency of at least 4x. In order to achieve the necessary reach and frequency, KCP&L will utilize a combination of radio, print and outdoor advertising.

- Radio – Because the Demonstration Project customers include a wide age range, it is vital to use a medium that is high reaching. Radio is the second highest reaching medium available (after TV) and is also one of the most cost effective mediums.
- Print – Despite the overall decrease in physical newspaper consumption, smaller, more niche community papers (like those read in and around the Demonstration Project area) continue to hold their base as their traditionally older readership is less likely to consume their news online. Additionally, print offers a higher retention rate than radio, allowing KCP&L's message to resonate with consumers and customers without the requirement of higher frequencies.
- Outdoor – Urban environments like the Demonstration Project area are ideal settings for outdoor advertising. Even though population density is higher, residents are still very mobile — walking, driving and taking public transportation on a daily basis. This is also a medium that will have a much wider mass-market focus. By placing billboards strategically in and around the Demonstration Project area, KCP&L is able to cover the entire customer base.

3.8.2.7 Automated Customer Notification

KCP&L has had great success reaching customers for its Connections Program (energy efficiency and bill payment assistance) through the use of automated customer notification calls. These calls allow KCP&L to reach a large number of customers in a relatively short amount of time and at a low cost. In particular, KCP&L is using automated calls to drive attendance to upcoming energy fairs, where members of the SmartGrid team provide an overview of the project as well as training on the MySmart suite of products.

3.8.2.8 Energy Fairs

In addition to utilizing existing neighborhood and community meetings, KCP&L plans to host a series of energy fairs in the Demonstration Project area. These educational events will serve as training workshops for those customers interested in learning more about SmartGrid, specifically the MySmart suite of products. They are also an ideal opportunity for KCP&L to get anecdotal feedback via one-on-one interaction with customers. The schedule of upcoming energy fairs is included in the welcome kits delivered to customers at meter installation and is also listed on the website. In addition, KCP&L has been making inbound automated calls to customers who have received their new SmartMeter, notifying them of upcoming energy fairs.

Table 3-6: Schedule of Energy Fairs

Location	Date	Attendance
Missouri Department of Conservation Discovery Center	Nov. 2, 2010	25
Paseo High School	Nov. 6, 2010	8
St. James United Methodist Church	Nov. 18, 2010	50
Paseo High School	Dec. 4, 2010	200
Missouri Department of Conservation Discovery Center	Jan. 15, 2011	Unknown

3.8.2.9 Social Media

Evidence points to significant use of mobile phones in the Demonstration Project area, making a social media strategy important to the overall public education and outreach effort as the Demonstration Project progresses. Texting, Twitter, etc., will inform residents about upcoming events, ways to increase energy efficiency and other important SmartGrid information. A mobile platform will allow real-time notification of installation appointments, completions and other notifications, improving the overall customer experience. In addition, KCP&L will be able to engage in a two-way dialogue with customers and receive instant feedback on customer reaction/sentiment. The Demonstration Project social media strategy will be balanced against KCP&L's larger communications efforts and will be conducted in coordination with the company's broader social media strategy and rollout.

3.8.3 Civic Outreach

A number of formal and informal community groups exist within the SmartGrid Demonstration Project area. KCP&L plans to engage in frequent communication with these groups to gather project feedback and communicate messages back to the end users.

3.8.3.1 Key Leaders

Critical to the success of the Demonstration Project public education and outreach effort is the endorsement and support of key community and neighborhood leaders. KCP&L has already begun to partner with community leaders within the Demonstration Project area to raise awareness of SmartGrid and other KCP&L initiatives, particularly the company's energy efficiency products and services. On September 14, 2010, KCP&L hosted about 40 key leaders at a SmartGrid briefing at the Green Impact Zone offices. This meeting was an opportunity to exchange information, answer questions and proactively address any concerns. This event was preceded by a letter that was mailed to approximately 150 community leaders providing them an update on the project. Continued, frequent, thorough two-way communication with key leaders over the course of the Demonstration Project will allow them to become effective ambassadors for KCP&L, build support for SmartGrid initiatives and ease any community concerns that may arise. KCP&L's Government Affairs department will manage direct communications with key leaders and elected officials.

3.8.3.2 Community Organizations

A number of credible, well-established community organizations operate in and around the Demonstration Project area. Key organizations include Brush Creek Community Partners, Blue Hills Community Services, the Southtown Council and Swope Community Builders. These organizations have long-standing relationships with residents in the Green Impact Zone and beyond and will be effective partners in educating residents and engaging them in SmartGrid initiatives. KCP&L Community Relations will work closely with these organizations and engage community leaders via one-on-one communication. These organizations can also be utilized to help spread information about the Demonstration Project at their regular meetings and through their organizational newsletters.

3.8.3.3 Neighborhood Associations

Neighborhood associations are critical to Green Impact Zone initiatives. Their engagement in the SmartGrid Demonstration Project will lend credibility and grant access to an established communication infrastructure. KCP&L will work closely with neighborhood organizations within the Demonstration Project area to build advocates and cultivate positive relationships in support of the Demonstration Project. Members of KCP&L's Community Relations team have already met with seven neighborhood associations and approximately 250 residents. A number of additional neighborhood meetings are planned for early 2011. In addition to providing an overview of the Demonstration Project, these meetings allow KCP&L to demonstrate the MySmart suite of products and speak directly to the customer benefits. KCP&L will maintain ongoing communication with neighborhood associations throughout the course of the SmartGrid Demonstration Project.

Table 3-7: Schedule of Neighborhood Meetings

Neighborhood	Location	Date	Attendance
Town Fork Creek	Mazuma Credit Union	Sept. 25, 2010	30
Troostwood	Coffee Break	Oct. 2, 2010	8
Manheim Park	Immanuel Lutheran Church	Oct. 9, 2010	9
Squier Park	DeLaSalle High School	Oct. 19, 2010	10
Ivanhoe	Ivanhoe Neighborhood Council	Oct. 23, 2010	85
Blue Hills	Blue Hills Neighborhood Assn.	Oct. 23, 2010	80
Brush Creek Community Partners	Midwest Research Institute	Nov. 5, 2010	20
Oak Park	Brush Creek Community Center	TBD	N/A
Crestwood	TBD	TBD	N/A
Rockhill Homes	TBD	TBD	N/A
Country Side	Minsky's	TBD	N/A
Hyde Park	Central Presbyterian Church	TBD	N/A
49/63 Coalition	Rockhurst Community Center	TBD	N/A
Rockhill Crest	TBD	TBD	N/A

3.8.3.4 Faith Communities

The primary churches in the Demonstration Project area represent important community hubs. KCP&L will work with these churches to educate their membership about SmartGrid initiatives to build awareness and encourage participation in the project. A designated KCP&L liaison will work with the large churches within the Demonstration Project area to communicate recent news and to educate leaders and residents about the project's components and benefits. In addition, KCP&L will develop content appropriate for church displays and for publication in church bulletins.

3.8.3.5 Schools

The Green Impact Zone is home to three schools, and there are several more in the broader Demonstration Project area. Schools are excellent communication/education vehicles for both children and parents. KCP&L will work with the Kansas City, Missouri School District to create a curriculum module to teach students about the Smart Grid, and its role in energy and energy efficiency. In addition to engaging students, school-based outreach can reach parents, grandparents, neighbors, etc. and build a stronger sense of community around the Demonstration Project area. Students at Commercial & Industrial rebate-eligible schools may be able to assist in making energy improvements while learning about the benefits of energy efficiency.

3.8.4 Consumer Advocate Interaction

Throughout the KCP&L SmartGrid Demonstration Project implementation, a number of paid and unpaid advocates will be utilized to help spread information to the consumer.

3.8.4.1 KCP&L Employees

With the Demonstration Project, KCP&L has the unique opportunity to utilize the company's 3,600 employees as SmartGrid ambassadors. As media coverage and interest of the project in the broader service territory increases, employees will be asked by friends, family and neighbors about SmartGrid. Starting in 2010 and continuing throughout the project, KCP&L will make Demonstration Project updates a priority for internal employee communications. Already, the project has been prominently featured in the employee newsletter, The Source, as well as in the daily e-Source updates, Leadership Link videos and at the managers Leadership Forum. In addition, KCP&L has a number of employees who live within the Demonstration Project area. These employees have already been contacted about being vocal advocates for the Demonstration Project within their neighborhoods. KCP&L will create an employee volunteer program specifically for the Demonstration Project to enhance education, promote programs, install products, weatherize homes, etc. These efforts will demonstrate KCP&L's commitment to the Green Impact Zone and its residents in a highly visible manner.

3.8.4.2 Green Impact Zone Staff

Much of the person-to-person interaction with residents occurs through the staff of the Green Impact Zone. KPC&L's project outreach coordinator manages these relationships to ensure that the Green Impact Zone team has the latest information about SmartGrid initiatives and is prepared to answer questions or to direct customers to additional KCP&L resources. In addition, KCP&L plans to provide ongoing training to Green Impact Zone ambassadors about SmartGrid and will maintain regular communication to ensure that education and outreach goals are achieved.

3.8.4.3 Ambassadors

In addition to the Green Impact Zone staff, much of the direct customer interaction within the Green Impact Zone portion of the Demonstration Project area will occur through community organizers known as ambassadors. Residents of the Green Impact Zone will be recruited to be ambassadors and will serve as project spokespeople responsible for increasing awareness of SmartGrid and its benefits by serving as a resource for residents by providing them with information and updates on the Demonstration Project. KCP&L will work with the Green Impact Zone to recruit and train ambassadors and will have on-going interaction to ensure education and outreach goals are achieved.

3.8.4.4 SmartGrid Customer Service Representatives

KCP&L has hired and trained three dedicated customer service representatives to serve as the SmartGrid support team. These individuals are the first point of contact for customers who have questions, need additional information or want to sign up for SmartGrid products/services. In addition, having a dedicated team improves continuity and message consistency. The SmartGrid support team can be reached via dedicated phone numbers (1-800-535-7687 or 816-737-7129) and a dedicated e-mail address (smartgridinfo@kcpl.com).

3.8.4.5 SmartGrid Office

In addition to all of the integrated ongoing channels outlined as part of the public education and outreach efforts, KCP&L wants to be able to interact face-to-face with customers on a daily basis within the Demonstration Project area. KCP&L has established a SmartGrid office within the Green Impact Zone offices at 4600 Paseo. In addition to greater customer interaction, having a KCP&L office staffed by SmartGrid team members within the Green Impact Zone also will strengthen communication with the Green Impact Zone team.

3.8.5 Technology Education and Knowledge Transfer

One of KCP&L's main responsibilities with the SmartGrid Demonstration Project is to transfer its knowledge and experience to regulating bodies, standards bodies and other utilities around the country. This will be communicated through a variety of channels.

3.8.5.1 Kansas City Media Briefings

Although Smart Grid initiatives have been rolled out in other parts of the country, KCP&L's Demonstration Project is the first to introduce these technologies to the urban core. As such, it has already attracted significant local media attention. Local media targets in the Kansas City area include *The Kansas City Star, Kansas City Business Journal, The Call, The Globe*, KMBZ 980 AM, KCUR 89.3 FM, WDAF-4, KSHB-41, KCTV-5 and KMBC-9. KCP&L has a set of reactive statements prepared to respond to general media inquiries regarding SmartGrid. In addition, KCP&L has identified a number of short- and long-term project milestones that will serve as opportunities for proactive media outreach. For example, on November 11, KCP&L conducted a SmartGrid media day featuring demonstrations of the MySmart suite of products.

Figure 3-16: Screenshot of SmartGrid News Story

3.8.5.2 State Regulatory Commission Proceedings

KCP&L's retail operations are regulated by both the Missouri Public Service Commission (MPSC) and the Kansas Corporation Commission (KCC). As such, KCP&L participates in any formal proceedings initiated by or with either regulatory body. The future Smart Grid is being discussed in a variety of proceedings. KCP&L will continue to participate and provide appropriate input to all future proceedings regarding the Smart Grid. The following are some recent Commission proceedings that have directly involved Smart Grid topics.

3.8.5.3 MPSC PURPA Considerations Required by EISA

On December 19, 2007, the Energy Independence and Security Act of 2007 ("EISA") was signed into law, requiring state utility commissions to consider the standards set out in the EISA, including Smart Grid. On December 17, 2008 the MPSC established the workshops to do so. The docket opened for Smart Grid consideration was EW-2009-0292. Since establishment of this docket, KCP&L responded to requests for information and participated in a workshop on May 18, 2010 presenting information regarding its SmartGrid Demonstration Project. KCP&L also participated in a second MPSC-sponsored workshop that included Smart Grid vendors on June 28 and June 29, 2010. KCP&L will continue to participate in this docket until its completion.

3.8.5.4 KCC PURPA Considerations Required by EISA

On December 19, 2008, the KCC opened Docket No. 09-GIME-360-GIE for the purpose of investigating the standards as directed by EISA. KCP&L supplied comments regarding the standards on January 30, 2009. On September 18, 2009, KCP&L participated in the KCC Smart Grid roundtable. On December 14, 2009, the KCC closed this docket, electing not to adopt the EISA Smart Grid standards.

3.8.5.5 MPSC Integrated Resource Planning (IRP) Rulemaking

On May 15, 2009, the MPSC opened Docket No. EW-2009-0415 for the purpose of conducting workshops and providing a repository for work done in conjunction with rewriting the commission rules and procedures related to the IRP that each utility must conduct. Workshops were held and KCP&L participated in those workshops. On March 10, 2010, the MPSC opened a rulemaking case, EX-2010-0254 and subsequently published its IRP Proposed Amendment in the Missouri Register on December 1, 2010. Comments are to be provided to the MPSC by January 3, 2011, and a Public Hearing is scheduled for January 6, 2011. The rule as proposed includes a provision requiring utilities to address "contemporary issues" which are intended to include Smart Grid functions in future integrated resource plans developed by all Missouri utilities.

3.8.5.6 MO SmartGrid Stakeholder Group

Because several aspects of the SmartGrid Demonstration Project require MPSC approvals, KCP&L has initiated communication with various Missouri Smart Grid stakeholders to create an informal group. The purpose of this group is to inform relevant parties about our SmartGrid Demonstration Project and to solicit input from them.

The members of the stakeholder group include representatives of the MPSC Staff, Office of Public Counsel, and Missouri Department of Natural Resources. On July 23, 2010 we had our initial meeting with the Missouri SmartGrid stakeholder group, introduced our team members and gave an overview of the SmartGrid Demonstration Project. We discussed the following:

- Smart Grid Vision and SmartGrid Demonstration Project Overview
- SmartGrid Demonstration Project Technology and Interoperability
- The Community and Our Customers
- The Customer Value Proposition
- SmartGrid Demonstration Project Timelines
- How We Continue to Collaborate

On September 20, 2010 we again met with the MO SmartGrid Stakeholder group to discuss our customer communication plan. Future periodic meetings are planned to discuss our technology choices, evaluation plans, customer programs, customer service issues and status updates.

3.8.5.7 MO and KS Commission Smart Grid Staff

The MPSC and KCC each received separate DOE funding to support additional Smart Grid staff and staff education. In addition to the more organized interactions with the commission described in the previous section, KCP&L has invited, and will continue to invite, both Missouri and Kansas Smart Grid staff to participate in several Demonstration Project design and knowledge transfer workshops and meetings. To date, the MPSC and KCC staffs have participated in the following project opportunities.

- KCP&L hosted a "Day of Sharing" on January 28, 2010 with the Green Impact Zone and invited both the MPSC and KCC Smart Grid staff to attend, which they did. They were able to learn about the challenges and opportunities specific to the Green Impact Zone.
- On February 10 and 11, 2010, KCP&L hosted a Smart Grid technical conference with our vendor partners. Both the MPSC and KCC staffs were represented and were able to ask questions and broaden their understanding of the interdependencies our vendors are working through.
- In October 2010, EPRI conducted a series of Smart Grid use case workshops with KCP&L subject matter experts. The Commission Smart Grid staff was represented at several of the sessions and was able to ask questions and broaden their understanding of the use case process and how it will document the project interoperability requirements.

3.8.5.8 EPRI's Smart Grid Demonstration Project Participation

As a member of EPRI's five-year Smart Grid demonstration project, KCP&L's technology transfer activities will be coordinated through EPRI's formalized Smart Grid demonstration project. Specifically, EPRI will coordinate the sharing of field results, lessons learned, architectural challenges, issues impacting standards, key technology gaps and useful tools to help interoperability of Smart Grid technologies and systems related to the project. In addition, detailed project information will be communicated via EPRI's Smart Grid resource center (www.smartgrid.epri.com) and additional technology transfer activities including workshops, webcasts and periodic publications. The workshops will include presentations on status of field demonstrations, lessons learned to date, architectural challenges, issues impacting standards and common interest areas to explore. Technical summaries in the form of presentations and white papers/articles will be prepared for public dissemination. These publications will include a synthesis of contributions to standards bodies and common messages to deliver to industry and public entities such as state and federal agencies.

3.8.5.9 Technical Project Website

In addition to the customer focused SmartGrid website, KCP&L also will create an industry focused website. This website will be created in collaboration with the project partners, and it will allow agencies, legislators, regulators, other utilities and the Smart Grid industry as a whole to remain abreast of the Demonstration Project. It will address issues and discuss results so that the entire industry can accelerate the "utility of the future."

3.8.5.10 Technical Publications

One of the most effective ways to transfer knowledge to a diverse audience is through technical publications. These publications will be prepared for public dissemination throughout the life of the SmartGrid Demonstration Project, and they will include a combination of contributions to standards bodies, and common messages to deliver to industry and public entities such as state and federal agencies. Possible publications include the following:

- White papers
- Technical reports
- Trade journal articles
- Periodical papers
- Conference papers/presentations

3.8.5.11 Technical Education

In addition to published documents, KCP&L will seek to transfer knowledge and experience through technical training sessions, such as workshops and webinars. These sessions could include content on project status, challenges faced, specific technical topics, interoperability issues or lessons learned.

3.8.6 Project Tours & Field Demonstrations

Hands-on training is often the most effective way to communicate with the target audience. During the Demonstration Project, project tours and field demonstrations will provide an opportunity for the industry experts as well as the general public to get a first-hand look at SmartGrid possibilities.

3.8.6.1 SmartGrid Demonstration House Tour

As part of KCP&L's SmartGrid Demonstration Project, KCP&L is the lead sponsor of the Metropolitan Energy Center's Project Living Proof (PLP), an initiative that will allow KCP&L customers to experience the future of energy. PLP consists of a demonstration house, located at 917 Emanuel Cleaver II Blvd., where visitors can see first-hand the new MySmart tools and products available to customers in the Demonstration Project area. The house will facilitate communication by allowing customers to touch, feel, interact with and learn about Smart Meters, in-home displays, home area networking, hyper-efficient appliances and a PHEV charging station.

3.8.6.2 Field Tour

This tour will include a trip through the retrofitted substation, where participants will be able to see the DCADA system. The tour will also allow participants to see the grid-connected battery and solar projects associated with the Demonstration Project.

3.8.6.3 Grid Management Systems Tour

This tour will show participants the back office side of the Demonstration Project. They will be able to walk through the command center, and they will learn about 'first responder' functions, the DMS and the DERM.

3.8.7 Targeted Education & Outreach Initiatives

3.8.7.1 AMI Education and Outreach

KCP&L teams from Public Affairs and Corporate Communications developed multiple channels to communicate with customers during the entire implementation process. Information was mailed to the customers approximately 60 days prior to the first meter install explaining the project and letting them know what to expect. One month prior to scheduled meter change out the customer received a post card reminding them about the coming change. Another card with additional metering information was mailed one week prior to installation. Lastly, individuals and businesses received a phone call two days prior to installation.

- **Smart Grid Residential Customer Letter Final – August 31, 2010.** Mailed to all customers (residential and commercial) in early September 2010. The SmartGrid Fact Sheet was included.
- **KCP&L Smart Grid Mailer Postcard (residential and commercial).** Mailed to customers approximately four weeks prior to smart meter installation.
- **Smart Grid Meter Installation Postcard.** Mailed to customers approximately one week prior to smart meter installation.
- **Smart Grid Welcome Kit** letter, Fact Sheet, Sorry We Missed You panel (if applicable), and Welcome Kit Booklet. Distributed to customer in person on day of meter exchange.
- **KCP&L Smart Grid Demonstration House fact sheet.** Copies available to visitors at the Demonstration House.
- **FAQ.** Available on the web and distributed at events, along with the fact sheet.

All communication directed customers to a project specific web site, e-mail address, and phone number to contact in the event they had questions or needed more information.

KCP&L created a dedicated Smart Grid Support Team to inform customers of the process and answer questions specific to the project. These employees were able to set appointments for installation and give customers timely answers to technology and implementation questions.

For a portion of the project area, on the day a customer's meter was changed, Ambassadors went door to door offering residents an informational Welcome kit and addressed customer concerns face-to-face. Meter installers also made contact with residents immediately prior to exchange.

3.8.7.2 Residential SmartEnd-Use Products

To be completed in future releases of this report…

3.8.7.3 Residential TOU Rates

To be completed in future releases of this report…

3.8.7.4 SmartGrid Demonstration House

In 2006, the Metropolitan Energy Center (www.kcenergy.org), with assistance from KCP&L, advanced the idea for Project Living Proof (PLP), a demonstration house, located at 917 Emanuel Cleaver II Blvd., to promote the development of sustainable communities by showcasing weatherization, landscaping, efficient appliances and other energy-efficient features.

KCP&L has again invested in this project and the demonstration house by deploying existing and emerging renewable energy and energy management technologies. The demonstration house will allow KCP&L customers to experience the future of the energy and see first hand the new MySmart tools and products available to customers in the SmartGrid project area.

- **Smart Meter**. The smart meter unlocks the benefits of the SmartGrid by enabling two-way communication between the utility and the customer. This provides real-time energy usage information for consumer products such as the MySmart Portal, MySmart Display and MySmart Network. In the future, it also will allow customers to receive price signals and participate in "time of use" and other rate plans options.
- **MySmart Portal**. Each customer with a smart meter will have access to a customized website to view usage information and receive additional updates on energy saving options.
- **MySmart Display**. This portable energy management tool provides consumers with access to current electricity usage and bill information.
- **MySmart Thermostat** The programmable thermostat can help customers save energy and helps KCP&L control peak demands.
- **Rooftop Solar**. The Solar Photovoltaic (PV) system is able to produce 3.15 kWh of solar power on a sunny day. In the future, this system will connect to KCP&L's SmartGrid enabling KCP&L to view and manage output from the panel. See Figure 3-17.
- **Battery Storage**. The battery backup can store up to 8 kWh of energy from the Solar PV system, which can be discharged to offset energy use during peak demand. Stored energy and energy from the Solar PV system can also be sold back to the grid.
- **Electric Vehicle Charging Station.** The 110v Coulomb Technologies charging station complements the overall theme of the SmartGrid experience. KCP&L will install up to 10 charging stations in the project area and another 10 throughout the metropolitan area.
- **Energy Efficiency Programs**. KCP&L will showcase its full suite of energy efficiency programs to benefit customers.
- **Weatherization**. The demo house, built in 1911, contains exposed demonstrations of proper air sealing, insulation, window tightening and replacement.

Tours of the Demonstration House are offered during weekdays.

Figure 3-17: Rooftop PV Installation on Project Living Proof Demonstration House

3.8.7.5 Innovation Park

The KCP&L SmartGrid Innovation Park, located north of KCP&L's Midtown Substation, represents an innovative and operational aggregation of smart grid technologies and provides a unique educational opportunity for the public. "KCP&L is committed to this SmartGrid Demonstration Project as a way to learn new ways to reduce electricity delivery costs, enhance reliability and make Kansas City smarter about energy," said President and CEO Terry Bassham. "But we also want to share what we are learning, and this park is a great way for all of our customers to come and learn more about the smart grid."

Park visitors will see how KCP&L is enhancing the electric grid in Kansas City's urban core by viewing:

- An informational kiosk that explains KCP&L's entire Demonstration Project, including how power distribution is enhanced with smart grid technologies, the customer in-home experience, and the history of electric meters.
- A sophisticated, 1.0 MW-hour grid-connected lithium ion battery storage system, one of the largest of its kind in the country.
- A public EV charging station with dual level II ports.
- A ground-mounted 5.0 kW PV array, one of 13 project-funded PV arrays.
- A demonstration of KCP&L's new smart distribution management systems.

Figure 3-18: KCP&L's Smart Grid Innovation Park Site Layout

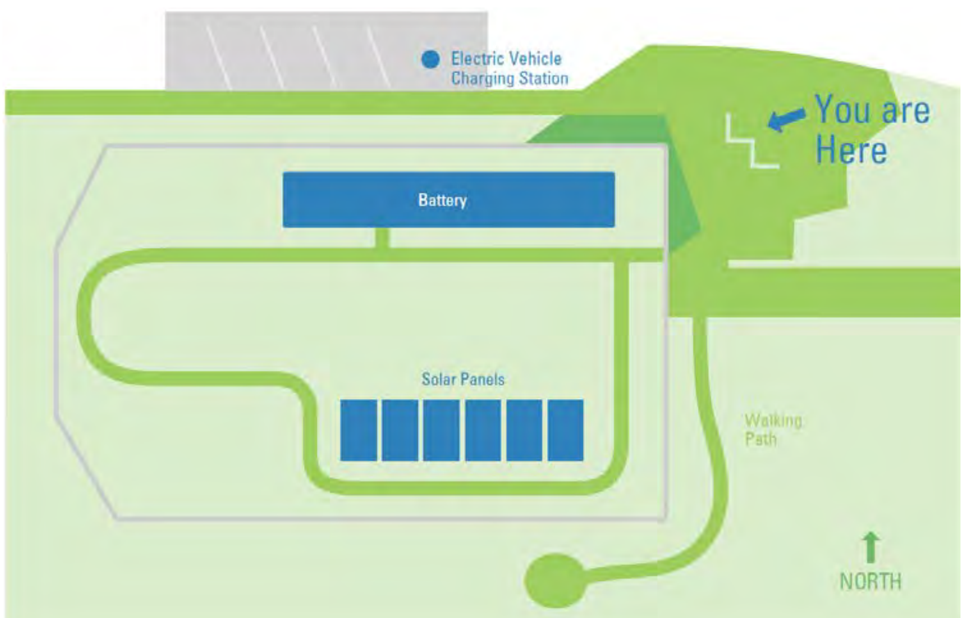


Figure 3-18 shows a layout of KCP&L's new Smart Grid Innovation Park. A ribbon cutting ceremony was held on October 12, 2012 to open the Innovation Park to the public. The event was attended by Congressman Emanuel Cleaver II, KCP&L CEO Terry Bassham, and about 100 other community leaders and representatives, as well as reporters.

4 Performance Results

To be completed in future releases of this report…

4.1 Interoperability

To be completed in future releases of this report…

4.2 Cyber Security

To be completed in future releases of this report…

4.3 SmartSubstation

To be completed in future releases of this report…

4.4 SmartDistribution

To be completed in future releases of this report…

4.5 SmartMetering

To be completed in future releases of this report…

4.6 SmartGeneration

To be completed in future releases of this report…

4.7 SmartDR/DER Management (DERM)

To be completed in future releases of this report…

4.8 SmartEnd-Use

To be completed in future releases of this report…

4.9 Education & Outreach

To be completed in future releases of this report…

5 Findings and Conclusions

To be completed in future releases of this report…

5.1 Lessons Learned

To be completed in future releases of this report…

5.2 Best Practices

To be completed in future releases of this report…

6 Future Plans

To be completed in future releases of this report…

6.1 Next Steps

To be completed in future releases of this report…

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Appendix A Glossary

ADA / DA – Advanced Distribution Automation
AMI – Advanced Metering Infrastructure
AMR – Automated Meter Reading
AHE – AMI Head-End
BESS – Battery Energy Storage System
BMS – Building (Energy) Management System
CIM – Common Information Model
CIP – Critical Infrastructure Protection (CIP)
CIS – Customer Information System
DAC – Distribution Automation Controller
DCADA – Distributed Control and Data Acquisition
DDC – Distribution Data Concentrator
DER / DERM – Distributed Energy Resource Management
DG – Distributed Generation
DLC – Direct Load Control
DM / DMS – Distribution Management System
DNA – Distribution Network Analysis
DR – Demand Response
D-SCADA – Distributed System Control and Data Acquisition
DSPF – Distribution System Power Flow
DSSE – Distribution System State Estimator
DVC – Dynamic Voltage Control
EMS – Energy Management System
EPRI – Electric Power Research Institute
ESB – Enterprise Service Bus
EV – Electric Vehicle
FAN – Field Area Network
FCI – Fault Circuit Indicator
FDIR – Fault Detection, Isolation and Restoration
FERC – Federal Energy Regulatory Commission
FISR – Fault Isolation and Service Restoration
FLOC – Fault Location
FLT – Feeder Load Transfer
GIS – Geographic Information System
GOOSE – Generic Object-Oriented Substation Event
GWAC – GridWise Architecture Council
HAN – Home Area Network
HEMP – Home Energy Management Portal
HMI – Human Machine Interface
IEC – International Electrotechnical Commission
IED – Intelligent Electronic Device
IHD – In-Home Display
IP – Internet Protocol
KCP&L – Kansas City Power & Light

MDM – Meter Data Management
MMS – Manufacturing Messaging Specification
MPLS – Multi-Protocol Label Switching
NERC – North American Electric Reliability Corporation
NIST – National Institute of Standards and Technology
ODR – On-Demand Read
OMS – Outage Management System
PAS – Power Automation System
PCS – Power Conditioning System
PCT – Programmable Communicating Thermostat
PHEV – Plug-in Hybrid Electric Vehicle
PLC – Programmable Logic Controller
PV – Photo Voltaic (Solar)
RTU – Remote Terminal Unit
SGAC – Smart Grid Architecture Committee
SGDP – SmartGrid Demonstration Project
SGIP – Smart Grid Interoperability Panel
SICAM – Siemens Integrated Control and Monitoring
SOA – Service-Oriented Architecture
SPN – Substation Protection Network
TOU – Time of Use
UCAIug – UCA International Users Group
VCMS – Electric Vehicle Charging Management System
VEE – Validation, Estimation and Editing
VVC – Volt/Var Control
WAN – Wide Area Network
XML – Extensible Markup Language

Appendix B KCP&L SmartGrid Use Cases

Appendix B.1 Automated Metering Infrastructure (AMI)

Appendix B.1.1 Customer Requested Remote Service Order Completion

This Use Case describes the steps in a customer requested remote service order completion. Traditionally, utilities send a field technician to the Customer premise to (dis)connect service to the meter. With an Automated Metering Infrastructure, the (dis)connect can be performed remotely by initiating a remote service order request. The remote service order request could be made due to customer move-in/out or for billing related reasons. The customer move-in/out and reinstatement for payment received allow for the use of remote service order completion directly. A disconnect for non-payment, however, requires a technician to be deployed to the premise for proper notification prior to the actual disconnect. See Section 3.3.2 for Regulations.

This Use Cases addresses three service types that can be completed using an automated procedure.

- Customer move out with landlord revert
- Customer move out without landlord revert
- Customer move in

The standard turn-on and turn-off operations are batched for daily processing by CIS. The disconnect for non-payment is processed in quasi real-time to reduce the chances that a Customer will receive their final disconnect notice and contact a Customer Service Representative prior to the batch processing.

Appendix B.1.2 On-Demand Meter Read

An on-demand meter read may be requested by multiple systems for a number of reasons. The process is carried out by transferring a meter read request message from the requesting system to the desired SmartMeter. In order to obtain a real-time meter read, the meter read request will travel to the SmartMeter via the Field Automation Network. The SmartMeter then sends the requested meter read data back to the requesting system via the Field Automation Network. The meter read data can be analyzed and processed as needed upon receipt by the requesting system.

This Use Case describes the process of the Customer Information System (or other system) requesting and receiving an on-demand meter read from a SmartMeter.

Appendix B.1.3 On-Demand Meter Status Check

Once the Distribution Management System software is integrated with the Meter Data Management System and AMI Head End, the network operations personnel can automatically check the status of the SmartMeter. This functionality has the potential to limit field visits to verify service status by service technicians. It can also be used to verify that service has been restored in the event of an outage.

An on-demand meter status check may be requested by multiple persons, systems, or organizations for a number of reasons including service status verification, SmartMeter health/functionality, power restoration, and service (dis)connect status. The process is carried out by transferring a meter read request message from the requesting system to the desired SmartMeter via the Field Automation Network. The SmartMeter then sends the requested meter read data back to the requesting system via the Field Automation Network.

Appendix B.1.4 Automated Daily Meter Read

This Use Case describes the automated meter reading process. The SmartMeter records interval usage readings every fifteen minutes and pushes the data to the AMI Head-End every four hours throughout the day. Each SmartMeter uses a random offset to level traffic across the AMI network. Daily register readings (total daily usage) are taken at midnight and pushed to the AMI Head-End at a random offset after midnight. The random offsets are used to level traffic across the AMI network with the goal of having all daily register readings to the AMI Head-End by 4:00 AM.

While each SmartMeter is pushing data to the AMI Head-End every four hours, the AMI Head-End is sending data to the Meter Data Management System on a different schedule. The AMI Head-End aggregates data from multiple SmartMeters and pushes a batch file to the Meter Data Management System on an hourly basis. This batch file can contain both interval and register data.

In addition to pushing data to the Meter Data Management System, the AMI Head-End contains the intelligence to recognize when meter reading data is missing and make specific requests to SmartMeters for the missing data to be resent. Once the data is retrieved, it is sent to the Meter Data Management System with the next hourly data push.

Appendix B.1.5 SmartMeter Alarm Events

The Advanced Metering Infrastructure system provides each SmartMeter with event capabilities to inform the Utility that the status of the SmartMeter has changed. Events are enabled within the SmartMeter to proactively identify possible tampering and/or diversion conditions, power quality conditions, and device status conditions. Each SmartMeter Event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from SmartMeter to SmartMeter depending on the application. Events enabled on the SmartMeter may represent, but are not limited to, the following categories:

- Power Quality
- Meter Health
- Revenue Protection

This Use Case details the process of a SmartMeter sending an Event with an Alarm status after a status change within the SmartMeter. The SmartMeter sends any Alarm Events to the AMI Head-End in real-time. From there, the Alarm Event may be sent on to the Meter Data Management System.

Appendix B.1.6 SmartMeter Advisory Events

The Advanced Metering Infrastructure system provides each SmartMeter with event capabilities to inform the Utility that the status of the SmartMeter has changed. Events are enabled within the SmartMeter to proactively identify possible tampering and/or diversion conditions, power quality conditions, and device status conditions. Each SmartMeter Event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from SmartMeter to SmartMeter depending on the application. Events enabled on the SmartMeter may represent, but are not limited to, the following categories:

- Power Quality
- Meter Health
- Revenue Protection

This Use Case details the process of a SmartMeter sending an Event with an Advisory status after a status change within the SmartMeter. The SmartMeter sends any Advisory Events to the AMI Head-End every four hours, with the next SmartMeter data push. From there, the Advisory Event may be sent on to the Meter Data Management System.

Appendix B.1.7 SmartMeter Log Only Events

The Advanced Metering Infrastructure system provides each SmartMeter with event capabilities to inform the Utility that the status of the SmartMeter has changed. Events are enabled within the SmartMeter to proactively identify possible tampering and/or diversion conditions, power quality conditions, and device status conditions. Each SmartMeter Event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from SmartMeter to SmartMeter depending on the application. Events enabled on the SmartMeter may represent, but are not limited to, the following categories:

- Power Quality
- Meter Health
- Revenue Protection

This Use Case details the process of a SmartMeter sub-device sending an Event with a Log Only status after a status change within the SmartMeter. The SmartMeter sub-device sends any Log Only Events to the Meter FAN Radio, where they are logged and maintained for diagnostics and troubleshooting purposes. Log Only Events can be retrieved by sending a command to the SmartMeter via the AMI Head End or other system.

Appendix B.1.8 SmartMeter Source Power Events

The Advanced Metering Infrastructure (AMI) system provides each SmartMeter with event capabilities to inform the Utility that the status of the SmartMeter has changed. Events are enabled within the SmartMeter to proactively identify possible tampering and/or diversion conditions, power quality conditions, and device status conditions. Each SmartMeter Event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from SmartMeter to SmartMeter depending on the application.

Events enabled on the SmartMeter may represent, but are not limited to, the following categories:

- Power Quality
- Meter Health
- Revenue Protection

This Use Case details a specific type of Alarm Event – those dealing with SmartMeter source power. The outage event serves as a surrogate for the Customer's call, often allowing the problem to be fixed before the Customer even becomes aware of the outage. AMI systems also help the Outage Management System (OMS) and dispatcher understand and efficiently respond to widespread outage conditions. The restoration event will follow a similar path and will notify the Utility when power has been restored to a SmartMeter.

This Use Case is detailed in two sequences that describe outage events and restoration events. When a power outage is detected at a SmartMeter, an outage event message is sent from that SmartMeter to the Meter Data Management System. The Meter Data Management System determines whether or not the outage information needs to be sent to the Distribution Management System for processing. Once power is restored to a SmartMeter, a restoration event message is sent from that SmartMeter to the Meter Data Management System. The Meter Data Management System then sends the restoration information to the Distribution Management System for processing.

Appendix B.1.9 FAN Device Alarm Events

The Field Automation Network (FAN) within the Advanced Metering Infrastructure system provides each device with event capabilities to inform the Utility that the status of the FAN device has changed. Events are enabled within the devices to proactively identify possible tampering and/or diversion conditions, source power quality conditions, and FAN device status conditions. Each FAN device event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from FAN device to FAN device depending on the application. Events enabled on a FAN device may represent, but are not limited to, the following categories:

- Source Power Quality
- Device Health
- Revenue Protection

This Use Case details the process of a FAN device sending an Event with an Alarm status after a status change within the FAN device. The FAN device sends any Alarm Events to the AMI Head-End in real-time.

Appendix B.1.10 FAN Device Advisory Events

The Field Automation Network (FAN) within the Advanced Metering Infrastructure system provides each device with event capabilities to inform the Utility that the status of the FAN device has changed. Events are enabled within the devices to proactively identify possible tampering and/or diversion conditions, source power quality conditions, and FAN device status conditions. Each FAN device event can be configured to one of the four following statuses: Log

Only, Advisory, Alarm, or Disabled. These configurations can vary from FAN device to FAN device depending on the application. Events enabled on a FAN device may represent, but are not limited to, the following categories:

- Source Power Quality
- Device Health
- Revenue Protection

This Use Case details the process of a FAN device sending an Event with an Advisory status after a status change within the FAN device. The FAN device sends any Advisory Events to the AMI Head-End every four hours, with the next FAN device data push. From there, the Advisory Event may be sent on to the Meter Data Management System.

Appendix B.1.11 FAN Device Log Only Events

The Field Automation Network (FAN) within the Advanced Metering Infrastructure system provides each device with event capabilities to inform the Utility that the status of the FAN device has changed. Events are enabled within the devices to proactively identify possible tampering and/or diversion conditions, source power quality conditions, and FAN device status conditions. Each FAN device event can be configured to one of the four following statuses: Log Only, Advisory, Alarm, or Disabled. These configurations can vary from FAN device to FAN device depending on the application. Events enabled on a FAN device may represent, but are not limited to, the following categories:

- Source Power Quality
- Device Health
- Revenue Protection

This Use Case details the process of a FAN device logging an Event with a Log Only status after a status change within the FAN device. The FAN device logs any Log Only Events to internal memory, where they are logged and maintained for diagnostics and troubleshooting purposes. Log Only Events can be retrieved by sending a command to the FAN device via the AMI Head End or other system.

Appendix B.1.12 Events Remote SmartMeter Update

The SmartMeter is adaptive to the Utility's changing environment, and it has the capacity to be remotely modified via the Field Automation Network. The SmartMeter program, which defines the functionality of the SmartMeter, can be modified from one rate structure to another. For example, the SmartMeters can be modified from flat rate meters to time-of-use meters. The SmartMeter configuration, which determines the program settings, can be modified to incorporate specific settings of the current meter program. For example, if the SmartMeter program is defined as a time-of-use meter, then the Utility could update the configuration to modify the time-of-use bucket definitions. Both the program and the configuration can be updated remotely.

In addition to updating the SmartMeter program and configuration remotely, the SmartMeter firmware can be updated remotely via the Field Automation Network. The SmartMeter consists of three independent sub-devices which all have their own firmware. These sub-devices are the

Meter FAN Radio, Meter Metrology Board and Energy Services Interface Radio. The SmartMeter vendor can issue a firmware update for any or all of these sub-devices for various reasons (bug fixes, feature enhancements, manufacturing changes, etc.). These updates can be completed remotely.

This Use Case describes how SmartMeter program updates, configuration updates, and firmware updates are implemented remotely via the Field Automation Network.

Appendix B.1.13 Field SmartMeter Update

The SmartMeter is adaptive to the Utility's changing environment, and it has the capacity to be modified by a field technician. Each SmartMeter has an Opticom port allowing the meter program, configuration, and firmware to be updated by field technicians. Using a laptop equipped with an Opticom probe and the SmartMeter vendor programming software, the technician can update the SmartMeter program file, configuration file, or the firmware to any of the sub-devices within the SmartMeter.

The SmartMeter program, which defines the functionality of the SmartMeter, can be modified from one rate structure to another. For example, the SmartMeters can be modified from flat rate meters to time-of-use meters. The SmartMeter configuration, which determines the program settings, can be modified to incorporate specific settings of the current meter program. For example, if the SmartMeter program is defined as a time-of-use meter, then the Utility could update the configuration to modify the time-of-use bucket definitions. Both the program and the configuration can be updated in the field.

In addition to updating the SmartMeter program and configuration, the SmartMeter firmware can also be updated in the field. The SmartMeter consists of three independent sub-devices which all have their own firmware. These sub-devices are the Meter FAN Radio, Meter Metrology Board and Energy Services Interface Radio. The SmartMeter vendor can issue a firmware update for any or all of these sub-devices for various reasons (bug fixes, feature enhancements, manufacturing changes, etc.).

This Use Case describes how SmartMeter program, configuration, and firmware updates are implemented in the field by a field technician.

Appendix B.1.14 Remote FAN Device Update

The Field Automation Network (FAN) devices are adaptive to the Utility's changing environment, and they have the capacity to be remotely modified via the FAN. The FAN devices include FAN Endpoint Nodes, FAN Routers, and FAN Collectors. The FAN device configuration, which defines how frequently data is pushed from the devices, can be updated remotely. The FAN Device firmware can also be updated remotely.

This Use Case describes how FAN device configuration and firmware updates are implemented remotely via the Field Automation Network.

Appendix B.1.15 Field FAN Device Update

The Field Automation Network (FAN) devices are adaptive to the Utility's changing environment, and they have the capacity to be modified by a field technician. The FAN devices include FAN Endpoint Nodes, FAN Routers, and FAN Collectors. Each FAN device has an Opticom port allowing the FAN device configuration (defining how frequently data is pushed from the device) and firmware to be updated by field technicians. Using a laptop equipped with an Opticom probe and the vendor programming software, the technician can update the FAN device configuration file or firmware to any of the FAN devices.

This Use Case describes how FAN device configuration and firmware updates are implemented in the field by a field technician.

Appendix B.1.16 Remote Service Order Completion

This Use Case describes the steps in a remote service order completion. Traditionally, utilities send a field technician to the Customer premise to (dis)connect service to the meter. With an Automated Metering Infrastructure, the (dis)connect can be performed remotely by initiating a remote service order request. The remote service order request could be made due to customer move-in/out or for billing related reasons. The customer move-in/out and reinstatement for payment received allow for the use of remote service order completion directly. A disconnect for non-payment, however, requires a technician to be deployed to the premise for proper notification prior to the actual disconnect. See Section 3.3.2 for Regulations.

This Use Cases addresses four service types that can be completed using an automated procedure.

- Turn On at Meter
- Turn Off at Meter
- Service Investigation Order for Vacant with Usage

The standard turn-on and turn-off operations are batched for daily processing by CIS. The disconnect for non-payment is processed in quasi real-time to reduce the chances that a Customer will receive their final disconnect notice and contact a Customer Service Representative prior to the batch processing.

Appendix B.1.17 SmartMeter Replaced by Field Crew (*Future*)

Appendix B.2 SmartSubstation (SUB)

Appendix B.2.1 DCADA Monitors and Controls Substation Devices

This Use Case describes the Distributed Control and Data Acquisition System (DCADA) monitoring and control of substation devices. The DCADA system monitoring process works in two ways: DCADA polling a substation device for status and a substation device reporting status (or status change) to DCADA due to an exception. When the configuration settings of a Distribution Automation Device in the substation need to be updated, DCADA sends a control signal to the device. DCADA makes use of the Substation Distribution Protection Network to communicate with substation devices. The Distribution Data Concentrator is a sub-system of DCADA that is utilized to communicate with Distribution Automation Devices. The substation devices include various Distribution Automation Devices such as voltage monitors, transformer tap changer controls, breaker relays, capacitor bank controls, voltage regulators, and automated switches.

Appendix B.2.2 DCADA Monitors and Controls Field Devices

This Use Case describes the Distributed Control and Data Acquisition System (DCADA) monitoring and control of field devices. The DCADA system monitoring process works in two ways: DCADA polling a field device for status and a field device reporting status (or status change) to DCADA due to an exception. When the configuration settings of a Distribution Automation Device in the field need to be updated, DCADA sends a control signal to the device. DCADA makes use of the Field Automation Network to communicate with field devices. The Distribution Data Concentrator is a sub-system of DCADA that is utilized to communicate with Distribution Automation Devices. The field devices include various Distribution Automation Devices such as voltage monitors, automated reclosers, capacitor bank controls, voltage regulators, automated switches and fault indicators.

Appendix B.2.3 Substation Transformer DGA & Thermal Monitoring

Monitoring devices and probes are installed on Substation transformers that are capable of sampling and evaluating dissolved gasses and recording oil-temperature. The probes will continuously monitor oil temperature and will send Dissolved Gas Analysis (DGA) data to DCADA system as often as once per hour. DCADA will contain a rule engine with preconfigured asset-specific parameters that trigger alarms, alerting D-SCADA when transformers are in condition that requires additional analysis.

Appendix B.2.4 Substation Transformer Dynamic Ratings

This Use Case describes the process of calculating dynamic ratings for substation transformers to maximize energy throughput. Dynamic transformer ratings are calculated by a DCADA Dynamic Transformer Rating (DTR) module using a series of algorithms. These algorithms utilize asset and condition data obtained from Dissolved Gas Analysis (DGA) devices, transformer sensors, substation sensors, and the EAMS. DGA devices provide dissolved gas levels, moisture, and partial discharge information. Transformer sensors provide information about other transformer components beyond the tank and windings, such as Load Tap Changers and Cooling System Status. Weather data can be incorporated from local Substation sensors or National Weather Service. DGA device data and substation sensor data are both delivered to DTRS via a Data Concentrator. EAMS information includes the transformer's static rating and other information, which might include heat run test data and historical loading data.

The dynamic transformer ratings consist of a normal rating and a series of 3 emergency ratings (15 minute, 30 minute, and one hour). After calculating this series of dynamic ratings, the DTR module updates the dynamic transformer rating values in the local DCADA data base.

Appendix B.2.5 Feeder Cable Dynamic Ratings

This Use Case describes the process of calculating dynamic Feeder Cable ratings to maximize energy throughput. Dynamic transformer ratings are calculated by a DCADA Dynamic Cable Rating (DCR) module using a series of algorithms. These algorithms utilize asset condition data obtained from duct temperature sensors, substation sensors, and the EAMS. Weather data can be incorporated from local substation sensors or National Weather Service. EAMS information includes the cable's static rating and other information, which might include historical loading data.

The dynamic cable ratings consist of a normal rating and a series of 3 emergency ratings (15 minute, 30 minute, and one hour). After calculating this series of dynamic ratings, the DCR module updates the dynamic transformer rating values in the local DCADA database.

Appendix B.3 First Responder (1ST)

Appendix B.3.1 DCADA Performs Fault Detection, Location, Isolation, and Restoration

Many types of faults can occur on a line section of a distribution system. Transient faults can be cleared after power has been disconnected for a short period of time. Transient faults are cleared by distribution automation devices, such as reclosers. Persistent faults can only be cleared by removing power from the line section where the fault has occurred and dispatching a field crew. Fault management applications are used to locate distribution network faults and provide fault isolation and service restoration. The fault location capabilities determine the location of permanent faults, whereas fault isolation and service restoration capabilities isolate the faulty section or area of distribution network and provide possible switching procedure to restore service.

This use case describes how the Distributed Control and Data Acquisition System (DCADA) responds to a persistent fault on a line section by approximately locating the fault, isolating the faulted line segment, and restoring service to customers through automated switching. Ultimately, the DCADA passes control authority to the Distribution Management System to dispatch field crews, correct the fault, and complete service restoration to Customers.

Appendix B.3.2 DCADA Performs Volt-Var Management

This Use Case describes the Volt/Var Control (VVC) functionality of the Distributed Control and Data Acquisition System (DCADA). The VVC can be executed through a centralized, a decentralized or a hybrid approach. Under normal operating conditions, the VVC manages voltage along an entire distribution circuit to achieve a voltage profile based upon KCP&L design parameters.

The primary objective of VVC functionality is to satisfy voltage and loading constraints. VVC functionality can be executed to satisfy any of the following 4 objective functions.

- Minimize subsystem power losses
- Minimize power demand
- Maximize generated reactive power
- Maximize revenue

This Use Case describes VVC execution via a distributed logical architecture.

Appendix B.3.3 DCADA Performs Dynamic Voltage Reduction for Demand Response (*Future*)

Appendix B.3.4 DCADA Performs Localized Load Transfer due to Overload

This Use Case describes the process by which Distribution Control and Data Acquisition (DCADA) to identify and respond to a feeder overload condition within its area of control. This function involves the DCADA communicating in a coordinated manner with the various Distribution Automation Devices (DADs) in both the field and the substation via the Substation Distribution Protection Network (SDPN) and the Distribution Automation Network (DAN).

Appendix B.3.5 DCADA Initiates Relay Protection Re-coordination (RPR) (*Future)*

This application adjusts the relay protection settings to real-time conditions based on the preset rules. This is accomplished through analysis of relay protection settings and operational mode of switching devices (i.e., whether the switching device is in switch or recloser mode), while considering the real-time connectivity, tagging, and severe weather conditions. The application is called to perform after feeder reconfiguration and in the case when conditions are changed and fuse saving is required. The updates needed to meet the Smart Grid requirements include coordinating feeder protection and re-synchronization with Distributed Energy Resources and with Micro-grids.

Appendix B.4 Distribution Management System (DMS)

Appendix B.4.1 DMS Network Model Maintenance

Map technician updates the electrical connectivity model (topology model) and the monitoring and control equipment relationships to the electrical devices after receiving notification of a change in the characteristics of the electrical network.

Appendix B.4.2 DMS Monitors and Controls Substation Devices

This Use Case describes the Distribution Supervisory Control and Data Acquisition System (D-SCADA) monitoring and control of substation devices. The D-SCADA system monitoring process works in two ways: the D-SCADA can poll a substation device for status, or a substation device can report the status (or status change) to D-SCADA due to an exception. When the configuration settings of a Distribution Automation Device in the substation need to be updated, D-SCADA sends a control signal to the device. D-SCADA makes use of the Distribution Management System Virtual Private Network, the Distribution Data Concentrator, and the Substation Distribution Protection Network to communicate with substation devices. The Distribution Data Concentrator is a sub-system of the Distributed Control and Data Acquisition System (DCADA) that is utilized to communicate with Distribution Automation Devices. The substation devices include various Distribution Automation Devices such as relays, voltage monitors, transformer tap changer controls, breaker relays, capacitor bank controls, voltage regulators, and automated switches.

Appendix B.4.3 DMS Monitors and Controls Field Devices

This Use Case describes the Distribution Supervisory Control and Data Acquisition System (D-SCADA) monitoring and control of field devices. The D-SCADA system monitoring process works in two ways: the D-SCADA can poll a field device for status, or a field device can report the status (or status change) to D-SCADA due to an exception. When the configuration settings of a Distribution Automation Device in the field need to be updated, D-SCADA sends a control signal to the device. D-SCADA makes use of the Distribution Management System Virtual Private Network, the Distribution Data Concentrator, and the Field Automation Network to communicate with field devices. The Distribution Data Concentrator is a sub-system of the Distributed Control and Data Acquisition System (DCADA) that is utilized to communicate with Distribution Automation Devices. The field devices include various Distribution Automation Devices such as automated reclosers, capacitor bank controls, fault indicators, and battery energy storage systems.

Appendix B.4.4 DMS Processes Protective Device Alarms

Utilities are constrained in their response to outages by the sensors and the information currently available to them. SCADA systems typically extend only to the substation. By definition, AMI is the only system that extends to the edges of a utility network, sensing every line segment and transformer on the system. This AMI capability is used in conjunction with OMS functions to predict outage locations and to verify power restoration, enabling utilities to proactively identify customers whose power has yet to be restored.

When outages reported by other systems such as SCADA, DCADA (Distributed Control and Data Acquisition) System, or protective devices themselves, these outages can be immediately recorded as confirmed and bypass or discontinue the OMS prediction process. This Use Case will outline the systems interaction anticipated when the D-SCADA processes protective device alarms and send the appropriate messages to OMS and MDM systems.

- The OMS, upon notification that a protective device has operated will create a confirmed outage for that device and discontinue any downstream outage prediction processing.
- The MDM, upon notification that a protective device has operated will mark all downstream customers as out of service. It will continue to process meter grid alerts, but will discontinue sending any meter out notifications to OMS.

Appendix B.4.5 DMS Performs Emergency Load Transfer

The Distribution Management System (DMS) can trigger emergency load reduction for several reasons. At the substation level, the Distributed Control and Data Acquisition System (DCADA) might detect an immediate overload (or approaching overload trend; within the next hour) within its area of control that it cannot resolve even after utilizing the “first responder” Feeder Load Transfer (FLT) application. As a result, the DCADA notifies and passes control to the DMS Operator for load reduction. The DMS Operator calls upon Demand Response (DR) programs and/or grid-connected Distributed Energy Resources (DER) via the Distributed Energy Resource Management System (DERM). The DERM determines this solution to the overload based on priorities and economics and commits the appropriate assets for load reduction.

Emergency load reduction can also be initiated as a result of monitoring conducted at the DMS level, either through the Distribution System State Estimator (DSSE) application or the Distribution Supervisory Control and Data Acquisition (D-SCADA) sub-system. During DMS-initiated emergency load reduction, the DMS Operator calls upon one or multiple strategies in order to solve the problem. The DMS Operator could utilize FLT, DR programs, or grid-connected DER. If the overload condition still exists, then the DMS requests emergency DR from the DERM. The DERM determines this solution to the overload based on priorities and economics and commits the appropriate assets for load reduction.

Appendix B.4.6 DMS Schedules Required Load Transfer

The Distribution Management System Operator (DMSOP) can initiate a Studycase in the Distribution Management System (DMS) at any time. The operator might choose to run a Studycase each morning, or he could run a Studycase when he thinks the system load might be problematic due to weather, system maintenance, or some other issue. The Studycase will show the DMSOP the predicted condition of the distribution system during a certain time period in the future. The DMSOP will have 168 hourly values for all loads at his disposal. These values can be modified by using the correction coefficient to represent the expected future network conditions.

Upon creation of a Studycase, the DMS runs Distribution System Power Flow (DSPF) to determine whether any overloads are predicted during the Studycase time period. If so, the DMSOP uses a combination of iterative switching of Demand Response (DR) and Distributed Energy Resources (DER) in the DERM application to determine an optimal solution to the predicted overloads. Once the DMSOP is satisfied with the outcome, he can save the proposed schedule to be applied at the appropriate time. This solution will be verified before executing it in order to see if any changes have occurred between the study and execution time affecting the validity of the original solution.

Appendix B.4.7 DMS Manages Scheduled Events for Grid-Connected DER

The Utility will make use of various Distributed Energy Resources as needed to temporarily reduce or shift load on the distribution system. Distributed Energy Resources may include distributed generation sources and distributed storage devices. The Utility will implement a Distributed Energy Resource Management System to schedule, track, and dispatch the various Distributed Energy Resources that are available for Utility use. This Use Case describes the process by which the Distribution Management System manages scheduled event to dispatch grid-connected DER for grid reliability and/or economic reasons.

Appendix B.4.8 DMS Operator Returns Grid to NORMAL Configuration

This Use Case describes what activities are performed by the DMS Operator in the control center when the grid must be returned to its normal operating conditions after completion of service restoration, maintenance, or repair to a portion of the grid. The DMS Operator sends the appropriate switching commands to the field devices needed to restore each feeder to NORMAL Configuration.

Appendix B.4.9 DMS Performs Fault Detection, Location, Isolation, and Restoration

Many types of faults can occur on a line section of a distribution system. Transient faults can be cleared after power has been disconnected for a short period of time. Transient faults are cleared by distribution automation devices, such as reclosers. Persistent faults can only be cleared by removing power from the line section where the fault has occurred and dispatching a field crew. Fault management is a Distribution Network Analysis (DNA) application to locate distribution network faults and providing fault isolation and service restoration. Fault location function defines the location of permanent faults whereas fault isolation and service restoration function isolates the faulty section or area of distribution network and provides possible switching procedure to restore service.

This use case describes how the Distribution Supervisory Control and Data Acquisition System respond to a persistent fault on a line section.

Appendix B.4.10 DMS Performs Volt-Var Management

This Use Case describes the Volt/Var Control (VVC) functionality of the Distribution Management System (DMS). The VVC is executed through distributed logical architecture as opposed to a fully integrated, centralized environment. Under normal operating conditions, the VVC manages voltage along an entire distribution circuit to achieve a voltage profile based upon KCP&L design parameters or to satisfy any of the objective functions.

The primary objective of VVC functionality is to satisfy voltage and loading constraints. VVC functionality can be executed to satisfy any of the following 4 objective functions.

- Minimize subsystem power losses
- Minimize power demand
- Maximize generated reactive power
- Maximize revenue

Appendix B.4.11 DMS Performs Dynamic Voltage Reduction for Demand Response

This Use Case describes the Volt/var Control (VVC) functionality of the Distribution Network Analysis within the Distribution Management System (DMS). The VVC is executed through distributed logical architecture as opposed to a fully integrated, centralized environment. For load reduction scenarios, the VVC can lower the line voltage through a technique known as Dynamic Voltage Control (DVC).

Appendix B.4.12 DMS Initiates Relay Protection Re-coordination (*Future*)

Appendix B.5 Distributed Energy Resources Management (DRM)

Distributed Energy Resources Management (DERM), includes multiple forms of Distributed Generation (DG), storage and Demand Response (DR) resources.

Appendix B.5.1 DR/DER Resource/Asset is Registered in DERM

Appendix B.5.2 DERM Manages DR/DER Resource Availability

Appendix B.5.3 DERM Distributes DR/DER Event Schedule to Resource/Asset to Control Authority

The Utility will make use of various Distributed Energy Resources (DER) and Demand Response (DR) as needed to temporarily reduce or shift load on the distribution system. DER may include in-home devices, building management systems, and distributed generation and storage devices. The Utility may dispatch the DER for grid-reliability and/or economic reasons. DR and DER will be utilized in the following three categories:

- Grid-Connected
- Residential
- Commercial and Industrial

The Utility will implement a Distributed Energy Resource Management System (DERM) to determine the availability of the various DER for Utility use and schedule them when needed for a DR/DER event. The DERM will communicate with the above three categories of DER through the following systems:

- Distribution Management System, which acts as the control authority for Grid-Connected DER
- Home Energy Management Portal, which acts as the control authority for Residential DR (located at the Residential Customer premise)
- Commercial Building Management System, which acts as the control authority for Commercial and Industrial DR (located at the Commercial and Industrial Customer premise)
- Vehicle Charge Management System, which acts as the control authority for Electric Vehicle Charging Stations (EVCS) (located at Residential and Commercial and Industrial Customer premise)

This Use Case describes the process by which the DERM sends DR/DER event schedules to one or multiple residential, commercial and industrial, and grid-connected DER control authorities after DER have been committed and a DR/DER Event has been scheduled.

Appendix B.5.4 DMS Manages Grid-Connected DER Event Messages

The Distribution Management System (DMS) is the control authority for Grid-Connected Distributed Energy Resources (DER). Distributed Energy Resources include small-scale generation or energy storage of any kind. DER can exist in a number of forms, including photovoltaic panels, batteries, or wind generators. The location of proposed and future DER could be either inside or outside of a substation, but all DER will be associated with a particular substation and will be treated as field devices. Although the communication to the DER will occur via a substation Distribution Data Concentrator (DDC), the control authority for the DER is the DMS. This Use Case describes how the DMS manages the schedules of Grid-Connected DER.

Appendix B.5.5 Home Energy Management Platform Manages DR Event Messages

When the Distributed Energy Resource Management System schedules a Demand Response (DR) event, the event details are pushed to the Home Energy Management Platform (HEMP). The HEMP is then responsible for delivering the DR event message to Home Area Network (HAN) devices via the Advanced Metering Infrastructure (AMI) and the HAN Gateway (HANG). This use case describes how create, modify, and cancel DR event messages are pushed from the HEMP to HAN devices via the AMI or the HANG.

Appendix B.5.6 VCMS Manages DR Event Messages (*Future*)

The Vehicle Charge Management System (VCMS) is the control authority for the Electric Vehicle Charging Stations (EVCS). EVCSs are the physical electrical cord and connectors that are specified by applicable Society of Automotive Engineers (SAE) standards to provide transfer of electric energy from the charging point to the Plug-In Electric Vehicle (PEV), which is a motorized car or truck that runs either exclusively or partially on stored battery power. An Electric Vehicle, which relies only on electric propulsion, and a Plug-In-Hybrid Vehicle, which includes an alternative source of propulsion power, are two examples of PEVs. PEVs may be located at private or public locations. This Use Case describes how the VCMS manages the schedules of the EVCS.

Appendix B.5.7 Customer Opts Out of DR Events

When the Distributed Energy Resource Management System (DERM) schedules a Demand Response (DR) event, the event details are pushed to Home Area Network (HAN) devices, as described in Use Case DRM-05. In some cases, the Customer may choose to not participate in the DR Event. This may occur either before or after the DR Event has started. The Customer may use either the HAN device or the Home Energy Management Platform as a portal to opt out of a scheduled event. This use case describes how the CUST opts out of scheduled DR Events.

Appendix B.5.8 Verification of DR/DER Event Participation

Upon completion of a Demand Response (DR) /Distributed Energy Resources (DER) event, the Utility needs to know which customers participated in the event and which customers did not. In some cases, the Utility uses this information to determine customer compensation. In all cases, the Distributed Energy Resource Management System (DERM) uses this information to modify its forecasting algorithms to better predict load reduction for the next DR/DER event.

This Use Case describes the process by which the DERM receives participation verification from the following systems:

- Distribution Management System (for Grid-Connected DER)
- Home Energy Management Portal
- Commercial Building Management System
- Vehicle Energy Management System

Appendix B.5.9 DERM Creates DR/DER Event for Bulk Power Systems

Appendix B.5.10 DERM Generates Retail Pricing Signals (*Future*)

Appendix B.5.11 DERM Distributes Demand Response Information Messages (*Future*)

Appendix B.6 SmartEnd-Use (SEU)

Appendix B.6.1 Customer Views Historical Energy Information via Home Energy Management Platform

This Use Case describes the steps by which a Customer can access, view and analyze their historical energy usage via the Internet using the Home Energy Management Platform. The Meter Data Management System pushes updated meter usage data to the Home Energy Management Platform on a daily basis, and this information is stored internally. Upon Customer request, the Home Energy Management Platform displays the Customer's historical usage data.

Appendix B.6.2 Customer In-Home Display – Basic Functions

This Use Case describes the basic functions of the In-Home Display. As defined here, the basic functions include the display of real-time energy usage, current energy prices, and Utility-generated text messages.

Appendix B.6.3 Customer In-Home Display – Daily Bill True-Up

This Use Case describes the process of sending a Daily Bill TrueUp to the In-Home Display within a Customer premise. The In-Home Display calculates the daily and monthly usage based on regular readings received from the SmartMeter. These values are only estimates and the Daily Bill TrueUp process allows the Utility to send validated billing data to the In-Home Display for display to the Customer. The Daily Bill TrueUp message is sent as a special text message through the Field Automation Network to the SmartMeter and to the In-Home Display using the Home Area Network.

Appendix B.6.4 Customer Registers HAN Gateway to Home Energy Management Platform

This Use Case describes the process by which a Customer can register a Home Area Network (HAN) Gateway to the Home Energy Management Platform. The Utility limits the scope and number of devices that can be connected directly to the Energy Services Interface within the SmartMeter and also closely manages the communications across the Field Automation Network. Once provisioned to the SmartMeter and registered to the Home Energy Management Platform, the HAN Gateway creates the Customer HAN allowing the Customer to introduce more functionality into their HAN. The HAN Gateway includes an IP Interface for connection to the Internet allowing for third-party developed products to interact with the HAN Devices in the Customer premise.

Appendix B.6.5 Customer Uses HEMP to Provision HAN Device to HAN Gateway

This Use Case describes the steps by which a Customer can provision Home Area Network (HAN) devices to an existing HAN Gateway. The HAN Gateway communicates with the SmartMeter and allows the Customer to expand the size and scope of their HAN. Devices are authenticated on the Customer HAN through the Home Energy Management Platform, ensuring that only desired devices are allowed to communicate with the HAN infrastructure.

Appendix B.6.6 Customer Programmable Communicating Thermostat Management

This Use Case examines the management, by the Customer, of the Programmable Communicating Thermostat (PCT). Using the Programmable Communicating Thermostat and the Home Energy Management Platform (HEMP), the Customer has the option of controlling their thermostat directly or remotely. The Home Energy Management Platform is synchronized with the Programmable Communicating Thermostat such that both serve as a source of accurate, real-time information regarding the thermostat settings. The Home Energy Management Platform can communicate with the Thermostat via the Internet/Home Area Network Gateway (HANG) or through the Utility's Field Automation Network (FAN).

This Use Case covers the Customer management of the Programmable Communicating Thermostat in four sequences.

- Customer Changes Settings of PCT on UHAN and Information is Pushed to HEMP via FAN
- Customer Changes Settings of PCT on CHAN and Information is Pushed to HEMP via Internet
- Customer Changes HEMP Settings and Information is Pushed to PCT on UHAN via FAN
- Customer Changes HEMP Settings and Information is Pushed to PCT on CHAN via Internet

Appendix B.6.7 Customer Load Control Switch Management

This Use Case examines the management, by the Customer, of the Load Control Switch (LCS). Using the Load Control Switch and the Home Energy Management Platform (HEMP), the Customer has the option of controlling large energy consuming devices remotely. The Home Energy Management Platform can communicate with the Load Control Switch via the Utility's Field Automation Network (FAN) or via the Internet.

Appendix B.6.8 Customer Initiates De-Provisioning of Customer HAN Device

This Use Case describes the process by which a Customer can initiate the de-provisioning of a Home Area Network device. This Use Case applies to Home Area Network devices that are Customer owned and have been provisioned to the Home Area Network Gateway. This request could be made for a variety of reasons, such as replacing a device, moving, etc.

Appendix B.6.9 Customer In-Home Display – Prepayment (*Future*)

Appendix B.6.10 Customer Registers for DSM Rates and Programs (*Future*)

Appendix B.6.11 Customer Configures HAN Device Settings via HEMP (*Future*)

Appendix B.6.12 Customer Configures HEMP with Energy Usage Preferences (*Future*)

Appendix B.6.13 HEMP Responds to Energy Signals (*Future*)

Appendix B.6.14 HEMP Manages Customer PEV Charging (*Future*)

Appendix B.7 Home Area Network (HAN)

Appendix B.7.1 Utility Commissions Home Area Network

This Use Case describes the commissioning of the Home Area Network by the Utility. Specifically, the Utility commissions the Utility Home Area Network using the Energy Services Interface radio in the SmartMeter. In addition to the Energy Services Interface radio, the Utility Home Area Network contains other ZigBee enabled devices approved by the Utility for presence on the Utility Home Area Network. The most common devices that will be added to the Utility Home Area Network will be Programmable Communicating Thermostats, Load Control Switches, In-Home Displays and Home Area Network Gateway devices.

Appendix B.7.2 Utility Provisions HAN Device to SmartMeter

This Use Case describes the steps, initiated by the Customer, to provision a Home Area Network (HAN) Device to the SmartMeter. The Customer provides the unique identifying information for the HAN Device to the Utility, and then the Utility enters a provisioning request into its back-office systems. The Utility limits and controls the devices that can be provisioned to the SmartMeter, and the Customer has little involvement in the process beyond providing the identifying information for the HAN Device. The HAN Devices that can be provisioned to the SmartMeter include Programmable Communicating Thermostats, Load Controls Switches, In-Home Displays and HAN Gateway Devices.

Appendix B.7.3 Utility Sends Text Message to HAN Device

This Use Case describes how the Utility sends text messages to devices on the Home Area Network (HAN). This use case occurs when the Utility needs to communicate information with the customer. The messages could include marketing related correspondence or advisory messages regarding upcoming pricing changes. The text messages can reach the HAN devices via two distinct paths.

- Utility Sends Text Message to Utility HAN Devices via Field Automation Network
- Utility Sends Text Message to Customer HAN Devices via HAN Gateway

As a general rule, text messages intended for HAN devices on the Utility HAN (provisioned to the SmartMeter) will travel through the Field Automation Network. Text messages intended for HAN devices on the Customer HAN (provisioned to the HAN Gateway) will travel through the Internet. All text message confirmations will follow the same delivery path as the original text message.

Appendix B.7.4 Utility Cancels Text Message

This Use Case describes how the Utility cancels previously sent text messages to devices on the Home Area Network (HAN). When text messages are sent to Home Area Network (HAN) devices, both a start time and duration are included in the message. The HAN devices store the incoming text messages, and, at the indicated start time, they display the text messages to the Customer for the specified duration. The Utility can cancel a text message that is scheduled for display at a future start time. Upon cancellation it will be removed from the HAN device message queue. The Utility can also cancel the currently displayed message to have it removed from the HAN device display prior to its scheduled expiration time. The Utility has the option to request a confirmation that the text message was successfully cancelled.

- Utility Cancels Text Message to Utility HAN Devices via Field Automation Network
- Utility Cancels Text Message to Customer HAN Devices via HAN Gateway

As a general rule, text message cancellation messages for HAN devices on the Utility HAN (provisioned to the SmartMeter) will travel through the Field Automation Network. Text message cancellation messages intended for HAN devices on the Customer HAN (provisioned to the HAN Gateway) will travel through the Internet. All text message confirmations will follow the same delivery path as the original text message.

Appendix B.7.5 Utility Sends Pricing Signals to SmartMeter and HAN Devices

This Use Case describes how the Utility sends pricing signals to the SmartMeter and devices on the Utility Home Area Network (UHAN). This Use Case occurs when the Utility needs to communicate pricing information with the customer. This pricing information could be in the form of flat rate, time-of-use (TOU) or critical peak (CP) pricing. Pricing information is communicated to the SmartMeter using the Field Automation Network (FAN). When requested by the Pricing Signals, responses to Pricing Signals are passed from the Home Area Network devices to the Utility back-office systems via the FAN.

Appendix B.7.6 Utility Home Area Network Device Information

This Use Case describes the process by which a Utility back-office system queries the Advanced Metering Infrastructure (AMI) Head-End for information on a specific Home Area Network (HAN) device. This information returned includes device MAC Address, Installation Code, Device Type, Installation Date and Pair ID. Under specific situations, the AMI Head-End may also query the HAN device for a subset of this information.

Appendix B.7.7 Utility De-Provisions HAN Device on Utility Home Area Network

This Use Case describes the steps taken by the Utility to de-provision a Home Area Network (HAN) device from the SmartMeter. This might be done if there are issues with the HAN device or if the HAN device is to be replaced. Upon completion of this Use Case the HAN device could be re-provisioned to the Utility HAN if desired.

Appendix B.7.8 Utility De-Commissions Utility Home Area Network

This Use Case describes the process to decommission a Utility Home Area Network (HAN). This might be done if a customer moves or if problems with a HAN device necessitate resetting the Utility HAN. This process would also be completed prior to a planned SmartMeter exchange. To properly decommission the Utility HAN, the HAN devices must first be de-provisioned from the HAN. Upon completion of this Use Case, the Customer Home Area Network (if it exists) can still function, but it can’t communicate with the Utility. Pricing information and Utility status messages can no longer be sent to the Home Area Network Devices via the Field Automation Network.

Appendix B.7.9 HAN Device Vendor Change Control (*Future*)

This Use Case describes the process followed by the Utility to approve Home Area Network (HAN) devices for inclusion in the HAN by communicating directly with the SmartMeter. This process is not intended to apply to HAN devices purchased by the Customer for inclusion in the HAN by communicating directly with a gateway device. This process should be followed when evaluating product enhancements from existing HAN device vendors, evaluating new HAN device vendors or evaluating HAN devices not currently allowed to communicate with the SmartMeter.

Appendix B.7.10 HAN Device Status Check (*Future*)

This Use Case describes the steps taken to remotely check the status of a Home Area Network (HAN) device operating at the Customer premise and communicating to the SmartMeter. This function could be used by Customer Service Representatives to assist in troubleshooting Customer complaints about their HAN devices. It could also be used by the Utility to gather information about which HAN devices are being used and how. We need to determine, technically, what information needs to be returned from the HAND. This will determine which ZigBee command is used.

Appendix B.8 Plug-In Electric Vehicle (PEV)

Appendix B.8.1 PEV Charging at a Public Charge Station

Appendix B.8.2 Customer Enrolls in Utility PEV Program

Appendix B.8.3 Customer Registers PEV to Home Premise

Appendix B.8.4 Customer PEV Charging at Home Premise EVSI

Appendix B.8.5 Unregistered PEV Charging at Premise EVSI

Appendix B.8.6 Charge Validation and Settlement via Clearinghouse

Appendix B.8.7 Utility Controls PEV Charging at Public Charge Station

Appendix B.8.8 Utility Controls Customer On-Premise PEV Charging

Appendix B.9 Meter Data Management

Appendix B.9.1 MDM Distributes Daily Customer Updates

Appendix B.9.2 MDM Distributes Daily Meter Data

Appendix B.9.3 MDM Creates Billing Determinants

Appendix B.9.4 SmartMeter Inventory Management

This Use Case describes the management of Utility owned SmartMeters. Throughout the lifecycle of the SmartMeter it will be received at the Utility from the vendor, installed at a Customer premise, tested for return to inventory and periodically retrieved for statistical sampling purposes.

At each step along the way the Meter Data Management System (MDM) must be able to account for the whereabouts of the SmartMeter and communicate this status to other systems within the Advanced Metering Infrastructure (AMI). This collaboration minimizes required human intervention in the meter reading process and maximizes the Utility's return on the metering assets.

Appendix B.10 Network

Appendix B.10.1 Field Automation Network for Advanced Metering Infrastructure

The Advanced Metering Infrastructure (AMI) provides flexible, two-way communications between the SmartMeter and the AMI Head-End. This is accomplished through the implementation of a hierarchical, RF mesh network of devices known as the Field Automation Network (FAN). The FAN can be used for many applications including meter reading, smart end-use, and demand response.

FAN systems promise to provide advanced energy monitoring and recording, sophisticated tariff/rate program data collection, and load management command and control capabilities. Additionally, these powerful mechanisms will enable consumers to better manage their energy usage and allow the grid to run more efficiently from both a cost and energy delivery perspective. These advanced capabilities will also allow utilities to provision and configure the advanced SmartMeters in the field, thus offering new rate programs and energy monitoring and control.

This Use Case describes the processes of data traveling via the FAN from the AMI Head-End to the SmartMeter and from the SmartMeter to the AMI Head-End.

Appendix B.10.2 Field Automation Network for Distribution Automation

The Advanced Metering Infrastructure (AMI) provides flexible, two-way communications for Distribution Automation (DA) and Distributed Energy Resource (DER) functionality between a Distribution Automation Device Controller (DADC) or a Distributed Energy Resource Controller (DERC) and the Distribution Data Concentrator (DDC). This is accomplished through the implementation of an RF mesh network of devices known as the Distribution Automation Network (DAN). The DAN can be used for many applications including DA, DER, Volt/var Management, and Fault Detection, Location, Isolation, and Restoration (FDLIR).

This Use Case describes the following processes:

- DA messages sent from the DDC to a DADC via the DAN
- DA Messages sent from a DADC to the DDC via the DAN
- DER messages sent from the DDC to a DERC via the DAN
- DER Messages sent from a DERC to the DDC via the DAN

Appendix B.10.3 Utility Home Area Network

This Use Case describes the functionality of, and devices that comprise, the Utility Home Area Network. The Utility Home Area Network is formed by the ZigBee radio in the SmartMeter and exists as a conduit to get Utility information (energy prices, Utility text messages, etc.) into the Customer premise, as well as to provide control of energy consuming devices for demand response purposes. The Utility owns and manages all Home Area Network devices that are included in the Utility Home Area Network. Together, the Utility Home Area Network and Customer Home Area Network comprise the Home Area Network.

Appendix B.10.4 Customer Home Area Network

This Use Case describes the functionality of, and devices that comprise, the Customer Home Area Network. The Customer Home Area Network is formed by one of the ZigBee radios in the Home Area Network Gateway and exists to allow the Customer to expand the number of devices on their Home Area Network. The Home Area Network Gateway also contains an IP Interface, allowing for Internet access to Home Area Network devices. The Customer owns and manages all Home Area Network devices that are included in the Customer Home Area Network. Together, the Utility Home Area Network and Customer Home Area Network comprise the Home Area Network.

Appendix B.10.5 PEV Charge Network

Appendix B.10.6 Substation Distribution Automation Network

Appendix B.10.7 Substation Distribution Protection Network

The deployment of Smart Grid technologies presents various new challenges to the Utility industry. For instance, the implementation of IEC 61850 and the reliance on communication networks instead of direct wiring represents a fundamental change in protection and control system design and operation.

Substation control networks are deployed in harsh environments and transport critical data, which results in demanding requirements of the network and its components. The network must have high availability and low latency, providing fast, reliable communication between networked devices. Networking equipment deployed in these networks must be environmentally hardened, as it may be deployed in enclosures with limited climate control, requiring the equipment to operate across extreme humidity and temperature ranges. Therefore, a reliable physical architecture for the network is needed along with ruggedized, highly reliable network components.

Topology selection is based on a balance of several factors. The chosen topology of a highly reliable control network should achieve the following:

- Provide high-bandwidth, low-latency communications
- Minimize or eliminate single points of failure for cabling and equipment
- Minimize infrastructure costs

This Use Case describes the data flow of high-priority protection and control functions, including IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messages between protective relays and Manufacturing Message Specification (MMS) between substation devices and the Distributed Control and Data Acquisition (DCADA) within the substation via a high-speed, Ethernet communication network.

Appendix C KCP&L SmartGrid Master Interface List

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
1.a.1	Daily Bill TrueUp Msg Transfer	CIS sends Daily Bill TrueUp Msg to AHE	CIS	AHE			Daily Bill TrueUp Msg	Tunnel Text Msg from CIS to AHE that contains Daily Bill TrueUp data.	IEC 61968-9	CREATE(HANDeviceControls)	12.19.6.290	SEU-03
1.b.1	Remote Service Order Completion Msg Transfer	AHE sends Remote Service Order Completion Msg to CIS	AHE	CIS			Remote Service Order Completion Msg	Response from MFR indicating that the Remote Service Order Request was received and implemented.	IEC 61968-9	CREATED(EndDeviceControls)	3.31.6.68	AMI-08
2.a.1	Outage Event Msg Transfer		AHE	OMS								
2.b.1			OMS	AHE								
3.a.1	Control Signals		DAD	EMS								
4.a.1	Customer usage data (post VEE)		MDM	DERM								
4.b.1			DERM	MDM								
5.a.1	On-Demand Meter Read Request Transfer	AHE sends On-Demand Meter Read Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	On-Demand Meter Read Request	Request from AHE to MMB's internal reading table for current meter usage data.	L+G Proprietary	Command(OnDemandRead)		AMI-02
5.a.2	On-Demand Meter Status Request Transfer	AHE sends On-Demand Meter Status Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	On-Demand Meter Status Request	Request from AHE to MMB's internal reading table for current meter reading data. This data is used to determine meter status.	L+G Proprietary	Command(OnDemandRead)		AMI-03
5.a.3	Remote Service Order Request Transfer	AHE sends Remote Service Order Request to MFR	AHE	MFR	FAN	L+G Proprietary	Remote Service Order Request	Remote request entered into AHE by AMIOP or external system.	IEC 61968-9	CREATE(EndDeviceControls) CREATE(MeterReadings)	3.31.6.68	AMI-08
5.a.4	Commission HAN Command Transfer	AHE sends Commission HAN Command to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Commission HAN Command	Command from the AHE to the MTR to turn on the ESI and enable the UHAN.	L+G Proprietary	Command(CommissionHAN)		HAN-01
5.a.5	Provision HAND Command Transfer	AHE sends Provision HAND Command to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Provision HAND Command	Request from AHE to MTR for HAND provisioning. Contains Meter ID, HAND MAC Address and HAND Install Code, and Allow Joining duration.	L+G - Aligns with SEP 1.0	Command(ProvisionHANDevice)		HAN-02
5.a.6	Text Msg Transfer	AHE sends Text Msg to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Text Msg	Request from AHE to ESI to send a text Msg to HAND. Contains text Msg, start time, duration and confirmation flag.	L+G - Aligns with SEP 1.0	Command(HANMsg)		HAN-03
5.a.7	Cancel Text Msg Request Transfer	AHE sends Cancel Text Msg Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Cancel Text Msg Request	Request from AHE to ESI to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests an acknowledgement of receipt.	L+G - Aligns with SEP 1.0	Command(CancelTextMsg)		HAN-04
5.a.8	Pricing Signals Transfer	AHE sends Pricing Signals to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Pricing Signals	Pricing information sent from AHE to ESI. Contains flat, time-of-use, or critical peak pricing.	L+G - Aligns with SEP 1.0	Command(HANPricing)		HAN-05
5.a.9	HAND Pairing Info Request Transfer	AHE sends HAND Pairing Info Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	HAND Pairing Info Request	Request from AHE to ESI for HAND pairing information.	L+G - Aligns with SEP 1.0	Command(GetPairingDetails)		HAN-06
5.a.10	HAND De-Provision Request Transfer	AHE sends HAND De-Provision Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	HAND De-Provision Request	Request sent from AHE to ESI for the de-provisioning of a HAND.	L+G - Aligns with SEP 1.0	Command(DeprovisionHANDevice)		HAN-07
5.a.11	UHAN De-Commission Request Transfer	AHE sends UHAN De-Commission Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	UHAN De-Commission Request	Request from AHE to ESI for de-commissioning of the UHAN.	L+G Proprietary	Command(DecommissionHAN)		HAN-08
5.a.12	DR Event Msg Transfer	AHE sends DR Event Msg to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	DR Event Msg	Msg from AHE to ESI, through MFR, that contains the load curtailment details for a specific MTR. Details are based upon the type of DR event and user defined preferences in the HEMP.	L+G - Aligns with SEP 1.0	Command(LoadControl)	TBD	UDR-02
5.a.13	Gap-Filling Meter Read Request Transfer	AHE sends Gap-Filling Meter Read Request to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Gap-Filling Meter Read Request	Request from AHE to MMB for a specific set of interval and/or register MTR data.	L+G Proprietary	GET(MeterReadings)	TBD	AMI-04
5.a.14	MTR Program Update Transfer	AHE sends MTR Program Update to MFR of target MTR via FAN	AHE	MFR	FAN	L+G Proprietary	MTR Program Update	TBD	TBD	TBD	TBD	AMI-12
5.a.15	MTR Configuration Update Transfer	AHE sends MTR Configuration Update to MFR of target MTR via FAN	AHE	MFR	FAN	L+G Proprietary	MTR Configuration Update	TBD	TBD	TBD	TBD	AMI-12
5.a.16	MFR Firmware Update Transfer	AHE sends MFR Firmware Update to MFR of target MTR via FAN	AHE	MFR	FAN	L+G Proprietary	MFR Firmware Update	TBD	TBD	TBD	TBD	AMI-12

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
5.a.17	MMB Firmware Update Transfer	AHE sends MMB Firmware Update to MFR of target MTR via FAN	AHE	MFR	FAN	L+G Proprietary	MMB Firmware Update	TBD	TBD	TBD	TBD	AMI-12
5.a.18	ESI Firmware Update Transfer	AHE sends ESI Firmware Update to MFR of target MTR via FAN	AHE	MFR	FAN	L+G Proprietary	ESI Firmware Update	TBD	TBD	TBD	TBD	AMI-12
5.a.19	Daily Bill TrueUp Msg Transfer	AHE sends Daily Bill TrueUp Msg to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	Daily Bill TrueUp Msg	Tunnel Text Msg from AHE to ESI that contains Daily Bill TrueUp data.	L+G - Aligns with SEP 1.0	Command(HANMsg)		SEU-03
5.a.20	HEMP Settings Update Transfer	AHE sends HEMP Settings Update to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	HEMP Settings Update	Msg from AHE to ESI containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	Aligns with SEP 1.0	Demand Resonse and Load Control Cluster	ZigBee SEP 1.0 § D.2	SEU-06
5.a.21	HEMP Settings Update Transfer	AHE sends HEMP Settings Update to MFR via FAN	AHE	MFR	FAN	L+G Proprietary	HEMP Settings Update	Msg from AHE to ESI containing changes to the HEMP settings. Includes schedule and on/off state.	Aligns with SEP 1.0	Demand Resonse and Load Control Cluster	ZigBee SEP 1.0 § D.2	SEU-07
5.b.1	On-Demand Meter Read Data Transfer	MFR sends On-Demand Meter Read Data to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	On-Demand Meter Read Data	Current meter usage data retrieved from MMB's internal reading table and sent to AHE.	L+G Proprietary	Response(Readings)		AMI-02
5.b.2	On-Demand Meter Status Response Transfer	MFR sends On-Demand Meter Status Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	On-Demand Meter Status Response	Current meter reading data retrieved from MMB's internal reading table and sent to AHE. This data is used to determine meter status.	L+G Proprietary	Response(Readings)		AMI-03
5.b.3	Aggregated Meter Read Data Transfer	MFR pulls Interval and Register Meter Read Data stored since its last data push and sends it to the AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Aggregated Meter Read Data	Aggregated data (could include Interval Meter Read Data and Register Meter Read Data) from a single MTR compiled at the MFR and sent to the AHE.	L+G Proprietary	TBD		AMI-04
5.b.4	Outage Event Msg Transfer	MFR sends Outage Event Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Outage Event Msg	Msg generated by a MTR and sent from the MFR to the AHE when the MFR detects a sustained voltage loss lasting at least 30 seconds.	L+G Proprietary	Event (Endpoint Power Outage)		AMI-08
5.b.5	Restoration Event Msg Transfer	MFR sends Restoration Event Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Restoration Event Msg	Msg generated by a MTR and sent from the MFR to the AHE when the MFR detects a voltage following an outage.	L+G Proprietary	Event (Endpoint Power Restore)		AMI-08
5.b.6	Advisory Event Msg Transfer	MFR sends Advisory Event Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Advisory Event Msg	Msg generated in MTR and sent from the MFR to the AHE. Contains any MTR events defined as "advisory" that were created since the last data push.	L+G Proprietary	Various. See AMI-06 for details.	Various. See AMI-06 for details.	AMI-06
5.b.7	Alarm Event Msg Transfer	MFR sends Alarm Event Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Alarm Event Msg	Msg generated in MTR and sent from the MFR to the AHE. Contains any MTR events defined as "alarm".	L+G Proprietary	Various. See AMI-05 for details.	Various. See AMI-05 for details.	AMI-05
5.b.8	Remote Service Order Completion Msg Transfer	MFR issues Remote Service Order Completion Msg to the AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Remote Service Order Completion Msg	Response from MFR indicating that the Remote Service Order Request was received and implemented.	IEC 61968-9	CREATED(EndDeviceControls) CREATED(MeterReading)		AMI-08
5.b.9	HAN Commissioned Response Transfer	MFR sends HAN Commissioned Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	HAN Commissioned Response Transfer	Response from the ESI to the AHE indicating that the ESI has been enabled and the UHAN has been established. Contains Meter ID and HAN Network ID.	L+G Proprietary	Response(HANCommissioned)		HAN-01
5.b.10	Ready-to-Pair Response Transfer	MFR sends Ready-to-Pair Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Ready-to-Pair Response	Response from MTR to AHE indicating UHAN is commissioned and ESI is ready to begin the pairing process.	L+G - Aligns with SEP 1.0	Response(Ready-to-Pair)		HAN-02
5.b.11	Provision Complete Response Transfer	MFR sends Provision Complete Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Provision Complete Response	Response from MTR to AHE indicating that HAND has been provisioned to ESI.	L+G - Aligns with SEP 1.0	Response(PairingComplete)		HAN-02
5.b.12	Text Msg Response Transfer	MFR sends Text Msg Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Text Msg Response	Confirmation from ESI to AHE that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	L+G - Aligns with SEP 1.0	Response(TextMsgCreated)		HAN-03
5.b.13	Cancel Text Msg Confirmation Transfer	MFR sends Cancel Text Msg Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Cancel Text Msg Confirmation	Optional Msg from ESI to AHE indicating successful cancellation of a previously sent text Msg. Requirement for this Msg is controlled by the Cancel Text Msg Request.	L+G - Aligns with SEP 1.0	Response(TextMsgCancelled)		HAN-04
5.b.14	Pricing Signals Acknowledgement Transfer	MFR sends Pricing Signals Acknowledgement to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Pricing Signals Acknowledgement	Acknowledgement from ESI to AHE that Pricing Signals were received. Requirement for this Msg is controlled by the Pricing Signals.	L+G - Aligns with SEP 1.0	Response(HANPricing)		HAN-05
5.b.15	HAND Pairing Info Response Transfer	MFR sends HAND Pairing Info Response to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	HAND Pairing Info Response	Response from ESI to AHE containing HAND pairing information. Response includes MAC Address, Device Type and Pair ID.	L+G - Aligns with SEP 1.0	Response(PairingDetails)		HAN-06
5.b.16	HAND De-Provision Confirmation Transfer	MFR sends HAND De-Provision Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	HAND De-Provision Confirmation	Confirmation from ESI to AHE that the HAND has been de-provisioned.	L+G - Aligns with SEP 1.0	Response(HANDeviceDeprovisioned)		HAN-07

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
5.b.17	UHAN De-Commission Confirmation Transfer	MFR sends UHAN De-Commission Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	UHAN De-Commission Confirmation	Response from ESI to AHE confirming that the UHAN has been de-commissioned.	L+G Proprietary	Response(HANDecommissioned)		HAN-08
5.b.18	DR Event Received Acknowledgement Transfer	MFR sends DR Event Received Acknowledgement to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	DR Event Received Acknowledgement	Response Msg from ESI to AHE, through MFR, indicating that the demand response event has been scheduled at the PCT.	L+G - Aligns with SEP 1.0	Response(LoadControl)	TBD	UDR-02
5.b.19	Gap-Filling Meter Read Data Transfer	MFR sends Gap-Filling Meter Read Data to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	Gap-Filling Meter Read Data	Interval and/or register MTR data for a specific period of time that is retrieved from MMB and sent to AHE.	L+G Proprietary	REPLY(MeterReadings)	TBD	AMI-04
5.b.20	MTR Program Update Confirmation Transfer	MFR sends MTR Program Update Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	MTR Program Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
5.b.21	MTR Configuration Update Confirmation Transfer	MFR sends MTR Configuration Update Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	MTR Configuration Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
5.b.22	MFR Firmware Update Confirmation Transfer	MFR sends MFR Firmware Update Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	MFR Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
5.b.23	MMB Firmware Update Confirmation Transfer	MFR sends MMB Firmware Update Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	MMB Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
5.b.24	ESI Firmware Update Confirmation Transfer	MFR sends ESI Firmware Update Confirmation to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	ESI Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
5.b.25	PCT Settings Update Transfer	MFR sends PCT Settings Update to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	PCT Settings Update	Msg from ESI to AHE containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Set	ZCL 1.0 § 6.3.2.2.2	SEU-06
5.b.26	DR Event Started Msg Transfer	MFR sends DR Event Started Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	DR Event Started Msg	Msg from ESI to AHE, through MFR, indicating that the demand response event has started.	L+G - Aligns with SEP 1.0	Response(LoadControl)		UDR-02
5.b.27	DR Event Completed Msg Transfer	MFR sends DR Event Completed Msg to AHE via FAN	MFR	AHE	FAN	L+G Proprietary	DR Event Completed Msg	Msg from ESI to AHE, through MFR, indicating that the demand response event has ended.	L+G - Aligns with SEP 1.0	Response(LoadControl)		UDR-02
6.a.1	On-Demand Meter Read Request Transfer	MDM sends On-Demand Meter Read Request to appropriate AHE via ESB	MDM	AHE	ESB		On-Demand Meter Read Request	Request from MDM to AHE for current meter usage data.	IEC 61968-9	REPLY(MeterReading)		AMI-02
6.a.2	On-Demand Meter Status Request Transfer	MDM sends On-Demand Meter Status Request to appropriate AHE via ESB	MDM	AHE	ESB		On-Demand Meter Status Request	Request from DMS (or other system) to AHE for current meter status, which is accomplished through a meter reading.	IEC 61968-9	GET(MeterReading)	TBD	AMI-03
6.a.3	Remote Service Order Completion Msg Transfer											
6.b.1	On-Demand Meter Read DataTransfer	AHE sends On-Demand Meter Read Data to MDM via ESB	AHE	MDM	ESB		On-Demand Meter Read Data	Current meter usage data retrieved from MMB's internal reading table and sent from AHE to CIS (or other system).	IEC 61968-9	REPLY(MeterReading)		AMI-02
6.b.2	On-Demand Meter Status Response Transfer	AHE sends On-Demand Meter Status Response to MDM via ESB	AHE	MDM	ESB		On-Demand Meter Status Response	Current meter reading data retrieved from MMB's internal reading table and sent from AHE to DMS (or other system). This data is used to determine meter status.	IEC 61968-9	REPLY(MeterReading)	TBD	AMI-03
6.b.3	Aggregated Multi-Meter Data Transfer	AHE pulls Aggregated Meter Read Data from multiple MTRs stored since its last data push and sends it to the MDM via ESB	AHE	MDM	ESB		Aggregated Multi-Meter Data	Aggregated data from multiple MTRs compiled at the AHE and sent as a batch file to the MDM.	IEC 61968-9	TBD		AMI-04
6.b.4	Outage Event Msg Transfer	AHE sends Outage Event Msg to MDM via ESB	AHE	MDM	ESB		Outage Event Msg	Msg generated by a MTR and sent from the AHE to the MDM when the MFR detects a sustained voltage loss lasting at least 30 seconds.	IEC 61968-9	CREATED(EndDeviceEvents)	3.26.9.185	AMI-08
6.b.5	Restoration Event Msg Transfer	AHE sends Restoration Event Msg to MDM via ESB	AHE	MDM	ESB		Restoration Event Msg	Msg generated by a MTR and sent from the AHE to the MDM when the MFR detects a voltage following an outage.	IEC 61968-9	CREATED(EndDeviceEvents)	3.26.9.216	AMI-08
6.b.6	Advisory Alert Msg Transfer	AHE sends Advisory Event Msg to MDM via ESB	AHE	MDM	ESB		Advisory Event Msg	Msg sent from the AHE to the MDM. Contains any MTR events defined as "advisory" that were created since the last data push.	IEC 61968-9	CREATED(EndDeviceEvents) Various. See AMI-06 for details.	Various. See AMI-06 for details.	AMI-06
6.b.7	Alarm Event Msg Transfer	AHE sends Alarm Event Msg to MDM via ESB	AHE	MDM	ESB		Alarm Event Msg	Msg sent from the AHE to the MDM. Contains any MTR events defined as "alarm".	IEC 61968-9	CREATED(EndDeviceEvents) Various. See AMI-05 for details.	Various. See AMI-05 for details.	AMI-05
6.b.8	Remote Service Order Completion Msg Transfer	AHE forwards Remote Service Order Completion Msg to MDM	AHE	MDM	ESB		Remote Service Order Completion Msg	Response from MFR indicating that the Remote Service Order Request was received and implemented.	IEC 61968-9	CREATED(EndDeviceControls)	3.31.6.68	

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
6.b.9	HAN Commissioned Response Transfer	AHE sends HAN Commissioned Response to MDM via ESB	AHE	MDM	ESB		HAN Commissioned Response	Response from AHE to MDM and external system that initiated HAN Commissioning, if applicable, that ESI has been enabled and the UHAN has been established. Contains Meter ID and HAN Network ID.	IEC 61968-9	CREATED(HANDeviceEvents)	12.23.17.42	HAN-01
6.b.10	Provision Complete Response Transfer	AHE sends Provision Complete Response to MDM via ESB	AHE	MDM	ESB		Provision Complete Response	Response from AHE to MDM and HEMP indicating that HAND has been provisioned to ESI.	IEC 61968-9	CREATED(EndDeviceEvents)	12.7.16.242	HAN-02
6.b.11	Text Msg Response Transfer	AHE sends Text Msg Response to MDM via ESB	AHE	MDM	ESB		Text Msg Response	Confirmation from AHE to HEMP (or other originating system) that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg. For FAN-delivered Text Msgs, AHE also sends this response to MDM.	IEC 61968-9	CREATED(HANDeviceEvents)	12.19.17.290	HAN-03
6.b.12	Cancel Text Msg Confirmation Transfer	AHE sends Cancel Text Msg Confirmation to MDM via ESB	AHE	MDM	ESB		Cancel Text Msg Confirmation	Optional Msg from AHE to HEMP (or other originating system) and MDM indicating successful cancellation of a previously sent text Msg. Requirement for this Msg is controlled by the Cancel Text Msg Request.	IEC 61968-9	CREATED(HANDeviceEvents)	12.19.17.24	HAN-04
6.b.13	Pricing Signals Acknowledgement Transfer	AHE sends Pricing Signals Acknowledgement to MDM via ESB	AHE	MDM	ESB		Pricing Signals Acknowledgement	Acknowledgement from AHE to DERM and MDM that Pricing Signals were received. Requirement for this Msg is controlled by the Pricing Signals.	IEC 61968-9	CREATED(HANDeviceEvents)	12.23.17.291	HAN-05
6.b.14	HAND De-Provision Confirmation Transfer	AHE sends HAND De-Provision Confirmation to MDM via ESB	AHE	MDM	ESB		HAND De-Provision Confirmation	Confirmation from AHE to HEMP and MDM that the HAND has been de-provisioned.	IEC 61968-9	CREATED(EndDeviceEvents)	12.39.17.212 12.40.17.212 12.41.17.212 12.42.17.212 12.43.17.212 12.44.17.212 12.45.17.212 12.46.17.212 12.47.17.212	HAN-07
6.b.15	UHAN De-Commission Confirmation Transfer	AHE sends UHAN De-Commission Confirmation to MDM via ESB	AHE	MDM	ESB		UHAN De-Commission Confirmation	Response from AHE to HEMP and MDM confirming that the UHAN has been de-commissioned.	IEC 61968-9	CREATED(HANDeviceEvents)	12.23.17.68	HAN-08
6.b.16			AHE	MDM	ESB							
6.b.17			AHE	MDM	ESB							
6.b.18			AHE	MDM	ESB							
6.b.19	MTR Program Update Confirmation Transfer	AHE sends MTR Program Update Confirmation to MDM via ESB	AHE	MDM	ESB		MTR Program Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
6.b.20	MTR Configuration Update Confirmation Transfer	AHE sends MTR Configuration Update Confirmation to MDM via ESB	AHE	MDM	ESB		MTR Configuration Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
6.b.21	MFR Firmware Update Confirmation Transfer	AHE sends MFR Firmware Update Confirmation to MDM via ESB	AHE	MDM	ESB		MFR Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
6.b.22	MMB Firmware Update Confirmation Transfer	AHE sends MMB Firmware Update Confirmation to MDM via ESB	AHE	MDM	ESB		MMB Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
6.b.23	ESI Firmware Update Confirmation Transfer	AHE sends ESI Firmware Update Confirmation to MDM via ESB	AHE	MDM	ESB		ESI Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
7.a.1	Analog and Status Data, alerts											
7.b.1	Fault Detected Msg Transfer	DMS sends Fault Detected Msg to internal sub-systems (D-SCADA and OMS)	DMS	D-SCADA			Fault Detected Msg	A signal sent from the DAC to the DMS & other internal systems indicating the DAD has detected a fault.	IEC 61850	TBD		1st-01
7.b.2	Recloser Open and Fault Detected Msg Transfer	DMS sends Recloser Open and Fault Detected Msg to internal sub-systems (D-SCADA and OMS)	DMS	D-SCADA			Recloser Open & Fault Detected Msg	A signal sent from the DAC to the DMS & other internal systems indicating the Recloser is open due to a fault.	IEC 61850 or DNP3	TBD		1st-01
7.b.3	DAD Status Update Transfer	DMS sends DAD Status Update to internal sub-systems	DMS	D-SCADA			DAD Status Update	A Msg sent from the DAC to the DMS & other internal systems containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
7.b.4	Lock-Out Signal Transfer	DMS sends Lock-Out Signal to internal sub-systems (D-SCADA and OMS)	DMS	D-SCADA			Lock-Out Signal	A signal sent from the DAC to the DMS & other internal systems indicating the CBR is locked due to the fault.	IEC 61850 or DNP3	TBD		1st-01
7.c.1												
7.d.1												

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
7.e.1	Restoration requests											
7.f.1	Work order completion notifications											
7.g.1												
8.a.1	On-Demand Meter Read Request	CIS issues On-Demand Meter Read Request to MDM via ESB	CIS	MDM	ESB		On-Demand Meter Read Request	Request from CIS (or other system) to MDM for current meter usage data.	IEC 61968-9	GET(MeterReading)		AMI-02
8.b.1	On-Demand Meter Read Data Transfer	MDM sends On-Demand meter Read Data to CIS via the ESB	MDM	CIS	ESB		On-Demand Meter Read Data	Current meter usage data retrieved from MMB's internal reading table and sent from AHE to CIS (or other system).	IEC 61968-9	REPLY(MeterReading)		AMI-02
9.a.1	Historical Usage Transfer	MDM sends Historical Usage to HEMP via ESB	MDM	HEMP	ESB		Historical Usage	Response from MDM to HEMP containing historical energy usage for a specific CUST over a specified time range.	IEC 61968-9	REPLY(MeterReadings)	TBD	SEU-01
9.b.1	Historical Usage Request Transfer	HEMP sends Historical Usage Request to MDM via ESB	HEMP	MDM	ESB		Historical Usage Request	Request from HEMP to MDM for historical energy usage for a specific CUST for a specified time range.	IEC 61968-9	GET(MeterReadings)	TBD	SEU-01
10.a.1	On-Demand Meter Status Request	DMS issues On-Demand Meter Status Request to MDM via ESB	DMS	MDM	ESB		On-Demand Meter Status Request	Request from DMS (or other system) to AHE for current meter status, which is accomplished through a meter reading.	IEC 61968-9	GET(MeterReading)	TBD	AMI-03
10.a.2	Lock-Out Signal Transfer	DMS sends Lock-Out Signal to MDM via ESB	DMS	MDM	ESB		Lock-Out Signal	A signal sent from the DMS to the MDM indicating the CBR is locked due to the fault via the ESB.	IEC 61850	TBD		1st-01
10.b.1	On-Demand Meter Status Response Transfer	MDM sends On-Demand Meter Status Response to DMS via ESB	MDM	DMS	ESB		On-Demand Meter Status Response	Current meter reading data retrieved from MMB's internal reading table and sent from AHE to DMS (or other system). This data is used to determine meter status.	IEC 61968-9	REPLY(MeterReading)	TBD	AMI-03
10.b.2	Outage Event Msg Transfer	MDM sends Outage Event Msg to DMS via ESB, if necessary	MDM	DMS	ESB		Outage Event Msg	Msg generated by a MTR and sent from the MDM to the DMS when the MFR detects a sustained voltage loss lasting at least 30 seconds.	IEC 61968-9	CREATED(EndDeviceEvents)	3.26.9.185	AMI-08
10.b.3	Restoration Event Msg Transfer	MDM sends Restoration Event Msg to DMS via ESB	MDM	DMS	ESB		Restoration Event Msg	Msg generated by a MTR and sent from the MDM to the DMS when the MFR detects a voltage following an outage.	IEC 61968-9	CREATED(EndDeviceEvents)	3.26.9.216	AMI-08
11.a.1	DAD Status Request Transfer	DDC sends DAD Status Request to DAD via SDPN/DAN	DDC	DAD	DAN		DAD Status Request	A Msg sent from the DAC to the DDC &DAD containing a request for the configuration settings of the DAD.	DNP3	TBD		1st-01
11.a.2	Circuit Reconfiguration Transfer	DDC sends Circuit Reconfiguration to DAD via SDPN/DAN	DDC	DAD	DAN		Circuit Reconfiguration	A command sent from a DAC to the DAD containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
11.a.3	DAD Status Request Transfer	DDC sends DAD Status Request to all DADs within the area of control via the SDPN/DAN	DDC	DAD	DAN		DAD Status Request	Monitor request sent by DCADA to DAD to determine optimal system parameters.	IEC 61850 or DNP3	TBD		1st-02
11.a.4	DAD Control Signal Transfer	DDC sends DAD Control Signal to all relevant DADs via SDPN/DAN	DDC	DAD	DAN		DAD Control Signal	Updated configuration settings for a Substation or Field DAD as determined by VVC.	IEC 61850 or DNP3	TBD		1st-02
11.a.5	DAD Control Signal Transfer	DDC sends DAD Control Signal to DAD via DAN to initiate load reduction	DDC	DAD	DAN		Field DAD Control Signal	Configuration settings for a Field DAD sent from the DCADA to a Field DAD.	DNP3	TBD		1st-04
11.b.1	DAD Status Response Transfer	DAD sends DAD Status Response to DDC via SDPN/DAN	DAD	DDC	DAN		DAD Status Response	A Msg sent from a DAD to the DDC containing the configuration settings of the DAD.	DNP3	TBD		1st-01
11.b.2	DAD Status Update Transfer	DAD sends DAD Status Update to DDC via SDPN/DAN	DAD	DDC	DAN		DAD Status Update	A Msg sent from a DAD to the DAC containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
11.b.3	DAD Status Response Transfer	DAD sends DAD Status Response to DDC via SDPN/DAN	DAD	DDC	DAN		DAD Status Response	Response from DAD to DCADA that DAD Status has been sent.	IEC 61850 or DNP3	TBD		1st-02
11.b.4	DAD Alarm Report	Field DAD sends DAD Alarm to DDC via DAN	DAD	DDC	DAN		Field DAD Alarm	An alarm Msg sent from a Field DAD to the DCADA to report an alert condition that has occurred at the DAD.	DNP3	TBD		1st-04
11.b.5	DAD Status Report	DAD sends DAD Status Update to DDC via DAN	DAD	DDC	DAN		Field DAD Status	A Msg containing DAD status sent from a Field DAD to the DCADA.	DNP3	TBD		1st-04
12.a.1			DMS	DAC	Backhaul WAN							
12.b.1	Fault Detected Msg Transfer	DAC sends Fault Detected Msg to DMS	DAC	DMS			Fault Detected Msg	A signal sent from the DAC to the DMS & other internal systems indicating the DAD has detected a fault.	IEC 61850	TBD		1st-01

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
12.b.2	Estimated Fault Isolation Msg Transfer	DAC sends Estimated Fault Isolation Msg to DMS	DAC	DMS			Estimated Fault Isolation Msg	A command sent by the DAC to a DAD to isolate a fault that has occurred.	IEC 61850	TBD		1st-01
12.b.3	Recloser Open and Fault Detected Msg Transfer	DCADA sends Recloser Open and Fault Detected Msg to DMS	DAC	DMS			Recloser Open & Fault Detected Msg	A signal sent from the DAC to the DMS & other internal systems indicating the Recloser is open due to a fault.	IEC 61850 or DNP3	TBD		1st-01
12.b.4	DAD Status Update Transfer	DAC sends DAD Status Update to DMS	DAC	DMS			DAD Status Update	A Msg sent from the DAC to the DMS & other internal systems containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
12.b.5	Lock-Out Signal Transfer	DCADA sends Lock-Out Signal to DMS	DAC	DMS			Lock-Out Signal	A signal sent to the DAC from a DAD indicating the CBR is locked due to the fault.	IEC 61850 or DNP3	TBD		1st-01
12.b.6	Network Configuration Update Transfer	DCADA sends a distribution system Network Configuration Update to the DMS	DAC	DMS			Network Configuration Update	Updated configuration settings for relevant DADs is sent to DMS.	IEC 61850 or DNP3	TBD		1st-02
12.c.1					Backhaul WAN							
12.d.1					Backhaul WAN							
13.a.1			GIS	DMS								
14.a.1	Switch status updates, everything included in DMS-05 and DMS-06		D-SCADA	DERM								
14.b.1			DERM	D-SCADA								
14.c.1												
14.d.1												
15.a.1	Schedule DR Event Msg Transfer	DERM sends Schedule DR Event Msg to HEMP	DERM	HEMP			Schedule DR Event Msg	Msg from DERM to HEMP that initiates a utility scheduled demand response event.	IEC 61968-9	TBD		UDR-02
15.b.1	Confirmation/acknowledgement of DR event create, modify, delete, opt out information, availability info		HEMP	DERM								
16.a.1	Text Msg Transfer	HEMP sends Text Msg to IPI	HEMP	IPI	Internet	IP	Text Msg	Request from HEMP to CHR to send a text Msg to HAND. Contains text Msg, start time, duration and confirmation flag.	Tendril - Aligns with SEP 1.0			HAN-03
16.a.2	Provision HAND Command Transfer	HEMP sends Provision HAND Command to IPI	HEMP	IPI	Internet	IP	Provision HAND Command	Command from HEMP to CHR to open the provision window and allow HANDs to join the HAN.	Tendril - Aligns with SEP 1.0	Proprietary		SEU-05
16.a.3	HEMP Settings Update Transfer	HEMP sends HEMP Settings Update to IPI	HEMP	IPI	Internet	IP	HEMP Settings Update	Msg from HEMP to CHR containing changes to the HEMP settings including set piont, fan operation and daily/weekly schedule.	Tendril - Aligns with SEP 1.0			SEU-06
16.a.4	HEMP Settings Update Transfer	HEMP sends HEMP Settings Update to IPI	HEMP	IPI	Internet	IP	HEMP Settings Update	Msg from HEMP to CHR containing changes to the HEMP settings. Includes schedule and on/off state.	Tendril - Aligns with SEP 1.0			SEU-07
16.a.5	HAND De-Provision Request Transfer	HEMP sends HAND De-Provision Request to IPI	HEMP	IPI	Internet	IP	HAND De-Provision Request	Request from HEMP to CHR to de-provision a HAND from the HANG.	Aligns with ZigBee SEP 1.0			SEU-08
16.a.6	Cancel Text Msg Request Transfer	HEMP sends Cancel Text Msg Request to IPI	HEMP	IPI	Internet	IP	Cancel Text Msg Request	Request from HEMP to CHR to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests and acknowledgement of receipt.	Tendril - Aligns with SEP 1.0			HAN-04
16.b.1	Text Msg Response Transfer	IPI sends Text Msg Response to HEMP	IPI	HEMP	Internet	IP	Text Msg Response	Confirmation from CHR to HEMP that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	Tendril - Aligns with SEP 1.0			HAN-03
16.b.2	HANG Information Transfer	HANG sends HANG Information to HEMP	HANG	HEMP	Internet	IP	HANG Information	MAC Address and Install Code for the HANG. Provided by the HANG manufacturer and typically printed on a sticker applied to the device.	Tendril - Aligns with SEP 1.0	MAC Address Install Code		SEU-04
16.b.3	Read-to-Pair Response Transfer	IPI sends Ready-to-Pair Response to HEMP	IPI	HEMP	Internet	IP	Ready-to-Pair Resposne	Response from CHR to HEMP acknowledging that the provision window is open and the CHR is ready to join new HANDs to the HAN.	Tendril - Aligns with SEP 1.0	Proprietary		SEU-05
16.b.4	Provision Complete Response Transfer	IPI sends Provision Complete Response to HEMP	IPI	HEMP	Internet	IP	Provision Complete Response	Response from CHR to HEMP indicating that the HAND has been provisioned to the CHR and joined the CHAN.	Tendril - Aligns with SEP 1.0	Proprietary		SEU-05

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
16.b.5	PCT Settings Update Transfer	IPI sends PCT Settings Update to HEMP	IPI	HEMP	Internet	IP	PCT Settings Update	Msg from CHR to HEMP containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	Tendril - Aligns with SEP 1.0			SEU-06
16.b.6	HAND De-Provision Confirmation Transfer	IPI sends HAND De-Provision Confirmation to HEMP	IPI	HEMP	Internet	IP	HAND De-Provision Confirmation	Confirmation from CHR to HEMP that HAND has been de-provisioned from HANG.	Aligns with ZigBee SEP 1.0			SEU-08
16.b.7	Cancel Text Msg Response Transfer	IPI sends Cancel Text Msg Response to HEMP	IPI	HEMP	Internet	IP	Cancel Text Msg Confirmation	Confirmation from CHR to HEMP indicating successful cancellation of a previously sent text Msg.	Tendril - Aligns with SEP 1.0			HAN-04
17.a.1	Modify DR event, delete DR event, availability request, pricing information		DERM	BMS								
17.b.1	Confirmation/acknowledgement of DR event create, modify, delete, opt out information, availability info		BMS	DERM								
18.a.1			DERM	VCMS								
18.b.1			VCMS	DERM								
19.a.1			VCMS	EVSE								
19.b.1			EVSE	VCMS								
20.a.1	Current (projected schedules) DR available		DERM	RTO								
20.b.1	Potentially query for available DR		RTO	DERM								
21.a.1	DAD Status Request Transfer	DDC sends DAD Status Request to DAD via DAN/SDPN	DDC	DAD	SDPN		DAD Status Request	A Msg sent from the DAC to the DDC &DAD containing a request for the configuration settings of the DAD.	IEC 61850	TBD		1st-01
21.a.2	Circuit Reconfiguration Transfer	DDC sends Circuit Reconfiguration to DAD via DAN/SDPN	DDC	DAD	SDPN		Circuit Reconfiguration	A command sent from a DAC to the DAD containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
21.a.3	DAD Status Request Transfer	DDC sends DAD Status Request to all DADs within the area of control via DAN/SDPN	DDC	DAD	SDPN		DAD Status Request	Monitor request sent by DCADA to DAD to determine optimal system parameters.	IEC 61850 or DNP3	TBD		1st-02
21.a.4	DAD Control Signal Transfer	DDC sends DAD Control Signal to all relevant DADs via DAN/SDPN	DDC	DAD	SDPN		DAD Control Signal	Updated configuration settings for a Substation or Field DAD as determined by VVC.	IEC 61850 or DNP3	TBD		1st-02
21.a.5	DAD Control Signal Transfer	DDC sends DAD Control Signal to DAD via SDPN to initiate load reduction	DDC	DAD	SDPN		Substation DAD Control Signal	Configuration settings for a Substation DAD sent from the DCADA to a Substation DAD.	IEC 61850	TBD		1st-04
21.b.1	Fault Detected Msg Transfer	RELAY sends Fault Detected Msg to DDC via SDPN	DAD	DDC	SDPN		Fault Detected Msg	A signal sent to the DAC from a DAD indicating the DAD has detected a fault.	IEC 61850	TBD		1st-01
21.b.2	DAD Status Response Transfer	DAD sends DAD Status Response to DDC via DAN/SDPN	DAD	DDC	SDPN		DAD Status Response	A Msg sent from a DAD to the DDC containing the configuration settings of the DAD.	IEC 61850	TBD		1st-01
21.b.3	Recloser Open and Fault Detected Msg Transfer	RECL sends Recloser Open and Fault Detected Msg to DDC via SDPN	DAD	DDC	SDPN		Recloser Open & Fault Detected Msg	A signal sent to the DAC from a DAD indicating the Recloser is open due to a fault that has occurred.	IEC 61850	TBD		1st-01
21.b.4	DAD Status Update Transfer	DAD sends DAD Status Update to DDC via DAN/SDPN	DAD	DDC	SDPN		DAD Status Update	A Msg sent from a DAD to the DAC containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
21.b.5	Lock-Out Signal Transfer	RELAY sends Lock-Out Signal to DDC via SDPN	DAD	DDC	SDPN		Lock-Out Signal	A signal sent to the DAC from a DAD indicating the CBR is locked due to the fault.	IEC 61850 or DNP3	TBD		1st-01
21.b.6	DAD Status Response Transfer	DAD sends DAD Status Response to DDC via DAN/SDPN	DAD	DDC	SDPN		DAD Status Response	Response from DAD to DCADA that DAD Status has been sent.	IEC 61850 or DNP3	TBD		1st-02
21.b.7	DAD Alarm Report	Substation DAD sends DAD Alarm to DDC via SDPN	DAD	DDC	SDPN		Substation DAD Alarm	An alarm Msg sent from a Substation DAD to the DCADA to report an alert condition that has occurred at the DAD.	IEC 61850	TBD		1st-04
21.b.8	DAD Status Report	DAD sends DAD Status Update to DDC via SDPN	DAD	DDC	SDPN		Substation DAD Status	A Msg containing DAD status sent from a Substation DAD to the DCADA.	IEC 61850	TBD		1st-04
22.a.1	Control signals, requests (event and oscillography logs), settings		D-SCADA	DDC								
22.b.1	Analog and Status Data, alerts		DDC	D-SCADA								

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
23.a.1	Pricing Signals Transfer	DERM sends Pricing Signals to AHE via ESB	DERM	AHE	ESB		Pricing Signals	Pricing information sent from DERM to AHE. Contains flat, time-of-use, or critical peak pricing.	IEC 61968-9	CREATE(HANDeviceControls)	12.23.6.291	HAN-05
23.b.1	Pricing Signals Acknowledgement Transfer	AHE sends Pricing Signals Acknowledgement to DERM via ESB	AHE	DERM	ESB		Pricing Signal Acknowledgement	Acknowledgement from AHE to MDM and DERM that Pricing Signals were received. Requirement for this Msg is controlled by the Pricing Signals.	IEC 61968-9	CREATED(HANDeviceEvents)	12.23.17.291	HAN-05
24.a.1	DAD Status Request Transfer	DAC begins Fault Isolation Calculation by sending DAD Status Request to DDC	DAC	DDC			DAD Status Request	A Msg sent from the DAC to the DDC &DAD containing a request for the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
24.a.2	Circuit Reconfiguration Transfer	DAC sends Circuit Reconfiguration Command to DDC	DAC	DDC			Circuit Reconfiguration	A command sent from a DAC to the DAD containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
24.a.3	DAD Status Request Transfer	DCADA sends a DAD Status Request to DDC	DAC	DDC			DAD Status Request	Monitor request sent by DCADA to DAD to determine optimal system parameters.	IEC 61850 or DNP3	TBD		1st-02
24.a.4	DAD Control Signal Transfer	DAC creates and sends a DAD Control Signal to DDC	DAC	DDC			DAD Control Signal	Updated configuration settings for a Substation or Field DAD as determined by VVC.	IEC 61850 or DNP3	TBD		1st-02
24.a.5	DAD Control Signal Transfer	DAC sends DAD Control Signal to DDC	DAC	DDC			DAD Control Signal	Configuration settings for a Substation/Field DAD sent from the DCADA to a Substation DAD.	IEC 61850	TBD		1st-04
24.a.6	DAD Control Signal Transfer	DAC sends DAD Control Signal to DDC	DAC	DDC			Field DAD Control Signal	Configuration settings for a Field DAD sent from the DCADA to a Field DAD.	DNP3	TBD		1st-04
24.b.1	Fault Detected Msg Transfer	DDC sends Fault Detected Msg to DAC	DDC	DAC			Fault Detected Msg	A signal sent to the DAC from a DAD indicating the DAD has detected a fault.	IEC 61850	TBD		1st-01
24.b.2	DAD Status Response Transfer	DDC sends DAD Status Response to DAC	DDC	DAC			DAD Status Response	A Msg sent from a DAD to the DDC containing the configuration settings of the DAD.	IEC 61850	TBD		1st-01
24.b.3	Recloser Open and Fault Detected Msg Transfer	DDC sends Recloser Open and Fault Detected Msg to DAC	DDC	DAC			Recloser Open & Fault Detected Msg	A signal sent to the DAC from a DAD indicating the Recloser is open due to a fault that has occurred.	IEC 61850	TBD		1st-01
24.b.4	DAD Status Update Transfer	DDC sends DAD Status Update to DAC	DDC	DAC			DAD Status Update	A Msg sent from a DAD to the DAC containing the configuration settings of the DAD.	IEC 61850 or DNP3	TBD		1st-01
24.b.5	Lock-Out Signal Transfer	DDC sends Lock-Out Signal to DAC	DDC	DAC			Lock-Out Signal	A signal sent to the DAC from a DAD indicating the CBR is locked due to the fault.	IEC 61850 or DNP3	TBD		1st-01
24.b.6	DAD Status Response Transfer	DDC sends DAD Status Response to DCADA	DDC	DAC			DAD Status Response	Response from DAD to DCADA that DAD Status has been sent.	IEC 61850 or DNP3	TBD		1st-02
24.b.7	DAD Alarm Transfer	DDC sends DAD Alarm to DAC	DDC	DAC			Substation DAD Alarm	An alarm Msg sent from a Substation DAD to the DCADA to report an alert condition that has occurred at the DAD.	IEC 61850	TBD		1st-04
24.b.8	DAD Alarm Transfer	DDC sends DAD Alarm to DAC	DDC	DAC			Field DAD Alarm	An alarm Msg sent from a Field DAD to the DCADA to report an alert condition that has occurred at the DAD.	DNP3	TBD		1st-04
24.b.9	DAD Status Transfer	DDC sends DAD Status Update to DAC	DDC	DAC			Substation DAD Status	A Msg containing DAD status sent from a Substation DAD to the DCADA.	IEC 61850	TBD		1st-04
24.b.10	DAD Status Transfer	DDC sends DAD Status Update to DAC	DDC	DAC			Field DAD Status	A Msg containing DAD status sent from a Field DAD to the DCADA.	DNP3	TBD		1st-04
25.a.1	Provision HAND Command Transfer	HEMP sends Provision HAND Command to AHE via ESB	HEMP	AHE	ESB		Provision HAND Command	Request from administrative portion of HEMP to AHE for HAND provisioning. Contains Meter ID, HAND MAC Address and HAND Install Code, and Allow Joining duration.	IEC 61968-9	CREATE(HANDeviceAssets)		HAN-02
25.a.2	Text Msg Transfer	HEMP sends Text Msg to AHE via ESB	HEMP	AHE	ESB		Text Msg	Request from HEMP (or other external system) to AHE to send a text Msg to HAND. Contains text Msg, start time, duration and confirmation flag.	IEC 61968-9	CREATE(HANDeviceControls)	12.19.6.290	HAN-03
25.a.3	Cancel Text Msg Request Transfer	HEMP sends Cancel Text Msg Request to AHE via ESB	HEMP	AHE	ESB		Cancel Text Msg Request	Request from HEMP (or other Utility back-office system) to AHE to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests an acknowledgement of receipt.	IEC 61968-9	CREATE(HANDeviceControls)	12.19.6.24	HAN-04
25.a.4	HAND Info Request Transfer	HEMP sends HAND Info Request to AHE via ESB	HEMP	AHE	ESB		HAND Info Request	Request from HEMP (or other Utility back-office system) to AHE for HAND information.	IEC 61968-9	GET(HANDeviceAssets)		HAN-06
25.a.5	HAND Pairing Info Request Transfer	HEMP sends HAND Pairing Info Request to AHE via ESB	HEMP	AHE	ESB		HAND Pairing Info Request	Request from HEMP (or other Utility back-office system) to AHE for HAND pairing information.	IEC 61968-9	GET(HANDeviceAssets)		HAN-06

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
25.a.6	HAND De-Provision Request Transfer	HEMP sends HAND De-Provision Request to AHE via ESB	HEMP	AHE	ESB		HAND De-Provision Request	Request sent from HEMP to AHE for the de-provisioning of a HAND.	IEC 61968-9	DELETE(HANDeviceAssets)		HAN-07
25.a.7	UHAN De-Commission Request Transfer	HEMP sends UHAN De-Commission Request to AHE via ESB	HEMP	AHE	ESB		UHAN De-Commission Request	Request from HEMP to AHE for de-commissioning of the UHAN.	IEC 61968-9	CREATE(HANDeviceControls)	12.23.6.68	HAN-08
25.a.8	DR Event Msg Transfer	HEMP sends DR Event Msg Transfer to AHE	HEMP	AHE	ESB		DR Event Msg	Msg from HEMP to AHE that contains the load curtailment details for a specific MTR. Details are based upon the type of DR event and user defined preferences in the HEMP.	IEC 61968-9	CREATE(HANDeviceControls)	12.15.6.236	UDR-02
25.a.9	HEMP Settings Update Transfer	HEMP sends HEMP Settings Update to AHE via ESB	HEMP	AHE	ESB		HEMP Settings Update	Msg from HEMP to AHE containing changes to the HEMP setings including set point, fan operation and daily/weekly schedule.	IEC 61968-9	CREATE(PANDeviceAssets)		SEU-06
25.a.10	HEMP Settings Update Transfer	HEMP sends HEMP Settings Update to AHE via ESB	HEMP	AHE	ESB		HEMP Settings Update	Msg from HEMP to AHE containing changes to the HEMP settings. Includes schedule and on/off state.	IEC 61968-9	CREATE(PANDeviceAssets)		SEU-07
25.a.11	Commission HAN Command Transfer	HEMP (or other Utility back-office system) sends Commission HAN Command to AHE via ESB	HEMP	AHE	ESB		Commission HAN Command	Command from HEMP to AHE for commissioning the UHAN.	IEC 61968-9	CREATE(HANDeviceControls)	12.23.6.42	HAN-01
25.b.1	Ready-to-Pair Response Transfer	AHE sends Ready-to-Pair Response to HEMP via ESB	AHE	HEMP	ESB		Ready-to-Pair Response	Response from AHE to HEMP indicating UHAN is commissioned and ESI is ready to begin the pairing process.	IEC 61968-9	CREATED(EndDeviceEvents)	12.7.7.76	HAN-02
25.b.2	Provision Complete Response Transfer	AHE sends Provision Complete Response to HEMP via ESB	AHE	HEMP	ESB		Provision Complete Response	Response from AHE to MDM and HEMP indicating that HAND has been provisioned to ESI.	IEC 61968-9	CREATED(EndDeviceEvents)	12.7.16.242	HAN-02
25.b.3	Text Msg Response Transfer	AHE sends Text Msg Response to HEMP via ESB	AHE	HEMP	ESB		Text Msg Response	Confirmation from AHE to HEMP (or other originating system) that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg. For FAN-delivered Text Msgs, AHE also sends this response to MDM.	IEC 61968-9	CREATED(HANDeviceEvents)	12.19.17.290	HAN-03
25.b.4	Cancel Text Msg Confirmation Transfer	AHE sends Cancel Text Msg Confirmation to HEMP via ESB	AHE	HEMP	ESB		Cancel Text Msg Confirmation	Optional Msg from AHE to HEMP (or other originating system) and MDM indicating successful cancellation of a previously sent tet Msg. Requirement for this Msg is controlled by the Cancel Text Msg Request.	IEC 61968-9	CREATED(HANDeviceEvents)	12.19.17.24	HAN-04
25.b.5	HAND Info Response Transfer	AHE sends HAND Info Response to HEMP via ESB	AHE	HEMP	ESB		HAND Info Response	Response from AHE to HEMP (or originating Utility back-office system) containing HAND information. Response includes MAC Address, Device Type, Installation Code, Installation Date and Pair ID.	IEC 61968-9	REPLY(HANDeviceAssets)		HAN-06
25.b.6	HAND Pairing Info Response Transfer	AHE sends HAND Pairing Info Response to HEMP via ESB	AHE	HEMP	ESB		HAND Pairing Info Response	Response from AHE to HEMP (or originating Utility back-office system) containing HAND pairing information. Response includes MAC Address, Device Type and Pair ID.	IEC 61968-9	REPLY(HANDeviceAssets)		HAN-06
25.b.7	HAND De-Provision Confirmation Transfer	AHE sends HAND De-Provision Confirmation to HEMP via ESB	AHE	HEMP	ESB		HAND De-Provision Confirmation	Confirmation from AHE to HEMP and MDM that the HAND has been de-provisioned.	IEC 61968-9	CREATED(EndDeviceEvents)	12.39.17.212 12.40.17.212 12.41.17.212 12.42.17.212 12.43.17.212 12.44.17.212 12.45.17.212 12.46.17.212 12.47.17.212	HAN-07
25.b.8	UHAN De-Commission Confirmation Transfer	AHE sends UHAN De-Commission Confirmation to HEMP via ESB	AHE	HEMP	ESB		UHAN De-Commission Confirmation	Response from AHE to HEMP and MDM confirming that the UHAN has been de-commissioned.	IEC 61968-9	CREATED(HANDeviceEvents)	12.23.17.68	HAN-08
25.b.9	DR Event Received Acknowledgement Transfer	AHE sends DR Event Received Acknowledgement to HEMP via ESB	AHE	HEMP	ESB		DR Event Received Acknowledgement	Response Msg from AHE to HEMP indicating that the demand response event has been scheduled at the PCT.	IEC 61968-9	CREATED(HANDeviceEvents)	12.15.17.236	UDR-02
25.b.10	PCT Settings Update Transfer	AHE sends PCT Settings Update to HEMP via ESB	AHE	HEMP	ESB		PCT Settings Update	Msg from AHE to HEMP containing changes to the PT settings including set point, fan operation and daily/weekly schedule.	IEC 61968-9	CREATED(PANDeviceAssets)		SEU-06
25.b.11	DR Event Started Msg Transfer	AHE sends DR Event Started Msg to HEMP via ESB	AHE	HEMP	ESB		DR Event Started Msg	Msg from AHE to HEMP indicating that the demand response event has started.	IEC 61968-9	CREATED(HANDeviceEvents)	TBD	UDR-02

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
25.b.12	DR Event Completed Msg Transfer	AHE sends DR Event Completed Msg to HEMP via ESB	AHE	HEMP	ESB		DR Event Completed Msg	Msg from AHE to HEMP indicating that the demand response event has ended.	IEC 61968-9	CREATED(HANDeviceEvents)	TBD	UDR-02
25.b.13	HAN Commissioned Response Transfer	AHE sends HAN Commissioned Response to HEMP (or originating Utility back-office system) via ESB	AHE	HEMP	ESB		HAN Commissioned Response	Response from AHE to MDM and HEMP indicating that ESI has been enabled and the UHAN has been established. Contains Meter ID and HAN Network ID.	IEC 61968-9	CREATED(HANDeviceEvents)	12.23.17.42	HAN-01
26.a.1	Create, modify, delete DR event, control signals		DDC	DER								
26.b.1	Analog and Status Data, alerts, acknowledgements		DER	DDC								
27.a.1			CIS	MWFM								
27.b.1	Customer-ready-to-disconnect Msg (triggers remote disconnect)		MWFM	CIS								
28.a.1			HANG	DER								
28.b.1			DER	HANG								
29.a.1			ALINK	HEMP								
29.b.1	Single sign on info		HEMP	ALINK								
30.a.1	Customer connectivity information		CIS	GIS								
30.b.1	Customer connectivity information		GIS	CIS								
31.a.1	Customer account information and programs		CIS	HEMP								
32.a.1	Customer account information and programs, devices to be controlled (with utility managed DR)		CIS	DERM								
33.a.1	Interval data and register reads		DMAT	MDM								
33.b.1	Request interval data		MDM	DMAT								
34.a.1			EVSE	PEV								
34.b.1			PEV	EVSE								
35.a.1			BMS	DER								
35.b.1			DER	BMS								
36.a.1			DAC	DAC								
36.b.1			DAC	DAC								
37.a.1			CIS	DMS								
38.a.1			CRM	DERM								
39.a.1			CRM	HEMP								
40.a.1			AHE	DMAT								
41.a.1												
41.b.1												
42.a.1												
42.b.1												
43.a.1												
43.b.1												
44.a.1												
44.b.1												
45.a.1												
45.b.1												

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
46.a.1												
46.b.1												
47.a.1												
47.b.1												
48.a.1												
48.b.1												
49.a.1												
49.b.1												
50.a.1	On-Demand Meter Read Request Transfer	MFR sends On-Demand Meter Read Request to MMB	MFR	MMB	Meter Internal	L+G Proprietary	On-Demand Meter Read Request	Request from AHE to MMB's internal reading table for current meter usage data.	L+G Proprietary	Command(OnDemandRead)		AMI-02
50.a.2	Gap-Filling Meter Read Request Transfer	MFR sends Gap-Filling Meter Read Request to MMB	MFR	MMB	Meter Internal	L+G Proprietary	Gap-Filling Meter Read Request	Request from AHE to MMB for a specific set of interval and/or register MTR data.	L+G Proprietary	GET(MeterReading)	TBD	AMI-04
50.a.3	On-Demand Meter Status Request Transfer	MFR sends On-Demand Meter Status Request to MMB	MFR	MMB	Meter Internal	L+G Proprietary	On-Demand Meter Status Request	Request from AHE to MMB's internal reading table for current meter reading data. This data is used to determine meter status.	L+G Proprietary	Command(OnDemandRead)		AMI-03
50.a.4	MTR Program Update Transfer	MFR sends MTR Program Update to MMB	MFR	MMB	Meter Internal	L+G Proprietary	MTR Program Update	TBD	TBD	TBD	TBD	AMI-12
50.a.5	MTR Configuration Update Transfer	MFR sends MTR Configuration Update to MMB	MFR	MMB	Meter Internal	L+G Proprietary	MTR Configuration Update	TBD	TBD	TBD	TBD	AMI-12
50.a.6	MMB Firmware Update Transfer	MFR sends MMB Firmware Update to MMB	MFR	MMB	Meter Internal	L+G Proprietary	MMB Firmware Update	TBD	TBD	TBD	TBD	AMI-12
50.b.1	On-Demand Meter Read Data Transfer	MMB sends On-Demand Meter Read Data to MFR	MMB	MFR	Meter Internal	L+G Proprietary	On-Demand Meter Read Data	Current meter usage data retrieved from MMB's internal reading table and sent to AHE.	L+G Proprietary	Response(Readings)		AMI-02
50.b.2	Interval Meter Read Data Transfer	MMB sends Interval Meter Read Data to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Interval Meter Read Data	ANSI C12.19 formatted interval usage data generated and stored in the MMB's reading table and sent to MFR.	L+G Proprietary	IntervalReadings		AMI-04
50.b.3	Register Meter Read Data Transfer	MMB sends Register Meter Read Data to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Register Meter Read Data	ANSI C12.19 formatted total daily usage reading generated and stored in the MMB's register and sent to MFR.	L+G Proprietary	RegisterReadings		AMI-04
50.b.4	Advisory Event Msg Transfer	ESI, MMB, or MFR sends Advisory Event Msg to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Advisory Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "advisory".	L+G Proprietary	Various. See AMI-06 for details.	Various. See AMI-06 for details.	AMI-06
50.b.5	Log Only Event Msg Transfer	ESI, MMB, or MFR sends Log Only Event Msg to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Log Only Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "log only".	L+G Proprietary	Various. See AMI-07 for details.	Various. See AMI-07 for details.	AMI-07
50.b.6	Alarm Event Msg Transfer	ESI, MMB, or MFR sends Alarm Event Msg to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Alarm Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "alarm".	L+G Proprietary	Various. See AMI-05 for details.	Various. See AMI-05 for details.	AMI-05
50.b.7	On-Demand Meter Status Response Transfer	MMB sends On-Demand Meter Status Response to MFR	MMB	MFR	Meter Internal	L+G Proprietary	On-Demand Meter Status Response	Current meter reading data retrieved from MMB's internal reading table and sent to AHE. This data is used to determine meter status.	L+G Proprietary	Response(Readings)		AMI-03
50.b.8	MTR Program Update Confirmation Transfer	MMB sends MTR Program Update Confirmation to MFR	MMB	MFR	Meter Internal	L+G Proprietary	MTR Program Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
50.b.9	MTR Configuration Update Confirmation Transfer	MMB sends MTR Configuration Update Confirmation to MFR	MMB	MFR	Meter Internal	L+G Proprietary	MTR Configuration Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
50.b.10	MMB Firmware Update Confirmation Transfer	MMB sends MMB Firmware Update Confirmation to MFR	MMB	MFR	Meter Internal	L+G Proprietary	MMB Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
50.b.11	Gap-Filling Meter Read Data Transfer	MMB sends Gap-Filling Meter Read Data to MFR	MMB	MFR	Meter Internal	L+G Proprietary	Gap-Filling Meter Read Data	Interval and/or register MTR data for a specific period of time that is retrieved from MMB and sent to AHE.	L+G Proprietary	REPLY(MeterReadings)	TBD	AMI-04
50.c.1					Meter Internal	L+G Proprietary			L+G Proprietary			
50.d.1					Meter Internal	L+G Proprietary			L+G Proprietary			
50.e.1					Meter Internal	L+G Proprietary			L+G Proprietary			
50.f.1	Commission HAN Command Transfer	MFR sends Commission HAN Command to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Commission HAN Command	Command from the AHE to the MTR to turn on the ESI and enable the UHAN.	L+G Proprietary	Command(CommissionHAN)		HAN-01

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
50.f.2	Provision HAND Command Transfer	MFR sends Provision HAND Command to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Provision HAND Command	Request from AHE to MTR for HAND provisioning. Contains Meter ID, HAND MAC Address and HAND Install Code, and Allow Joining duration.	L+G - Aligns with SEP 1.0	Command(ProvisionHANDevice)		HAN-02
50.f.3	Text Msg Transfer	MFR sends Text Msg to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Text Msg	Request from AHE to ESI to send a text Msg to HAND. Contains text Msg, start time, duration and confirmation flag.	L+G - Aligns with SEP 1.0	Command(HANMsg)		HAN-03
50.f.4	Cancel Text Msg Request Transfer	MFR sends Cancel Text Msg Request to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Cancel Text Msg Request	Request from AHE to ESI to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests an acknowledgement of receipt.	L+G - Aligns with SEP 1.0	Command(CancelTextMsg)		HAN-04
50.f.5	Pricing Signals Transfer	MFR sends Pricing Signals to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Pricing Signals	Pricing information sent from AHE to ESI. Contains flat, time-of-use, or critical peak pricing.	L+G - Aligns with SEP 1.0	Command(HANPricing)		HAN-05
50.f.6	HAND Pairing Info Request Transfer	MFR sends HAND Pairing Info Request to ESI	MFR	ESI	Meter Internal	L+G Proprietary	HAND Pairing Info Request	Request from AHE to ESI for HAND pairing information.	L+G - Aligns with SEP 1.0	Command(GetPairingDetails)		HAN-06
50.f.7	HAND De-Provision Request Transfer	MFR sends HAND De-Provision Request to ESI	MFR	ESI	Meter Internal	L+G Proprietary	HAND De-Provision Request	Request sent from AHE to ESI for the de-provisioning of a HAND.	L+G - Aligns with SEP 1.0	Command(DeprovisionHANDevice)		HAN-07
50.f.8	UHAN De-Commission Request Transfer	MFR sends UHAN De-Commission Request to ESI	MFR	ESI	Meter Internal	L+G Proprietary	UHAN De-Commission Request	Request from AHE to ESI for de-commissioning of the UHAN.	L+G Proprietary	Command(DecommissionHAN)		HAN-08
50.f.9	DR Event Msg Transfer	MFR sends DR Event Msg to ESI	MFR	ESI	Meter Internal	L+G Proprietary	DR Event Msg	Msg from AHE to ESI, through MFR, that contains the load curtailment details for a specific MTR. Details are based upon the type of DR event and user defined preferences in the HEMP.	L+G - Aligns with SEP 1.0	Command(LoadControl)	TBD	UDR-02
50.f.10	ESI Firmware Update Transfer	MFR sends ESI Firmware Update to ESI	MFR	ESI	Meter Internal	L+G Proprietary	ESI Firmware Update	TBD	TBD	TBD	TBD	AMI-12
50.f.11	Daily Bill TrueUp Msg Transfer	MFR sends Daily Bill TrueUp Msg to ESI	MFR	ESI	Meter Internal	L+G Proprietary	Daily Bill TrueUp Msg	Tunnel Text Msg from AHE to ESI that contains Daily Bill TrueUp data.	L+G - Aligns with SEP 1.0	Command(HANMsg)		SEU-03
50.f.12	HEMP Settings Update Transfer	MFR sends HEMP Settings Update to ESI	MFR	ESI	Meter Internal	L+G Proprietary	HEMP Settings Update	Msg from AHE to ESI containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Set	ZCL 1.0 § 6.3.2.2.2	SEU-06
50.f.13	HEMP Settings Update Transfer	MFR sends HEMP Settings Update to ESI	MFR	ESI	Meter Internal	L+G Proprietary	HEMP Settings Update	Msg from AHE to ESI ciontaining changes to the HEMP settings. Includes schedule and on/off state.	Aligns with SEP 1.0	Demand Resonse and Load Control Cluster	ZigBee SEP 1.0 § D.2	SEU-07
50.g.1	HAN Commissioned Response Transfer	ESI sends HAN Commissioned Response to MFR	ESI	MFR	Meter Internal	L+G Proprietary	HAN Commissioned Response	Response from the ESI to the AHE indicating that the ESI has been enabled and the UHAN has been established. Contains Meter ID and HAN Network ID.	L+G Proprietary	Response(HANCommissioned)		HAN-01
50.g.2	Ready-toPair Response Transfer	ESI sends Ready-to-Pair Response to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Ready-to-Pair Response	Response from MTR to AHE indicating UHAN is commissioned and ESI is ready to begin the pairing process.	L+G - Aligns with SEP 1.0	Response(Ready-to-Pair)		HAN-02
50.g.3	Provision Complete Response Transfer	ESI sends Provision Complete Response to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Provision Complete Response	Response from MTR to AHE indicating that HAND has been provisioned to ESI.	L+G - Aligns with SEP 1.0	Response(PairingComplete)		HAN-02
50.g.4	Advisory Event Msg Transfer	ESI, MMB, or MFR sends Alarm Event Msg to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Advisory Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "advisory".	L+G Proprietary	Various. See AMI-06 for details.	Various. See AMI-06 for details.	AMI-06
50.g.5	Log Only Event Msg Transfer	ESI, MMB, or MFR sends Log Only Event Msg to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Log Only Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "log only".	L+G Proprietary	Various. See AMI-07 for details.	Various. See AMI-07 for details.	AMI-07
50.g.6	Alarm Event Msg Transfer	ESI, MMB, or MFR sends Alarm Event Msg to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Alarm Event Msg	Msg generated in a MTR sub-device and sent to the MFR. Contains any MTR events defined as "alarm".	L+G Proprietary	Various. See AMI-05 for details.	Various. See AMI-05 for details.	AMI-05
50.g.7	Text Msg Response Transfer	ESI sends Text Msg Respone to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Text Msg Response	Confirmation from ESI to AHE that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	L+G - Aligns with SEP 1.0	Response (TextMsgCreated)		HAN-03
50.g.8	Cancel Text Msg Confirmation Transfer	ESI sends Cancel Text Msg Confirmation to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Cancel Text Msg Confirmation	Optional Msg from ESI to AHE indicating successful cancellation of a previously sent text Msg. Requirement for this Msg is controlled by the Cancel Text Msg Request.	L+G - Aligns with SEP 1.0	Response(TextMsgCancelled)		HAN-04
50.g.9	Pricing Signals Acknowledgement Transfer	ESI sends Pricing Signals Acknowledgement to MFR	ESI	MFR	Meter Internal	L+G Proprietary	Pricing Signals Acknowledgement	Acknowledgement from ESI to AHE that Pricing Signals were received. Requirement for this Msg is controlled by the Pricing Signals.	L+G - Aligns with SEP 1.0	Response(HANPricing)		HAN-05
50.g.10	HAND Pairing Info Response Transfer	ESI sends HAND Pairing Info Response to MFR	ESI	MFR	Meter Internal	L+G Proprietary	HAND Pairing Info Response	Response from ESI to AHE containing HAND pairing information. Response includes MAC Address, Device Type and Pair ID.	L+G - Aligns with SEP 1.0	Response(PairingDetails)		HAN-06

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
50.g.11	HAND De-Provision Confirmation Transfer	ESI sends HAND De-Provision Confirmation to MFR	ESI	MFR	Meter Internal	L+G Proprietary	HAND De-Provision Confirmation	Confirmation from ESI to AHE that the HAND has been de-provisioned.	L+G - Aligns with SEP 1.0	Response(HANDeviceDeprovisioned)		HAN-07
50.g.12	UHAN De-Commission Confirmation Transfer	ESI sends UHAN De-Commission Confirmation to MFR	ESI	MFR	Meter Internal	L+G Proprietary	UHAN De-Commission Confirmation	Response from ESI to AHE confirming that the UHAN has been de-commissioned.	L+G Proprietary	Response(HANDecommissioned)		HAN-08
50.g.13	DR Event Received Acknowledgement Transfer	ESI sends DR Event Received Acknowledgement to MFR	ESI	MFR	Meter Internal	L+G Proprietary	DR Event Received Acknowledgement	Response Msg from ESI to AHE, through MFR, indicating that the demand response event has been scheduled at the PCT.	L+G - Aligns with SEP 1.0	Response(LoadControl)		UDR-02
50.g.14	ESI Firmware Update Confirmation Transfer	ESI sends ESI Firmware Update Confirmation to MFR	ESI	MFR	Meter Internal	L+G Proprietary	ESI Firmware Update Confirmation	TBD	TBD	TBD	TBD	AMI-12
50.g.15	PCT Settings Update Transfer	ESI sends PCT Settings Update to MFR	ESI	MFR	Meter Internal	L+G Proprietary	PCT Settings Update	Msg from ESI to AHE containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Set	ZCL 1.0 § 6.3.2.2.2	SEU-06
50.g.16	DR Event Started Msg Transfer	ESI sends DR Evnet Started Msg to MFR	ESI	MFR	Meter Internal	L+G Proprietary	DR Event Started Msg	Msg from ESI to AHE, through MFR, indicating that the demand response event has started.	L+G - Aligns with SEP 1.0	Response(LoadControl)	n/a	UDR-02
50.g.17	DR Event Completed Msg Transfer	ESI sends DR Evnet Completed Msg to MFR	ESI	MFR	Meter Internal	L+G Proprietary	DR Event Completed Msg	Msg from ESI to AHE, through MFR, indicating that the demand response event has ended.	L+G - Aligns with SEP 1.0	Response(LoadControl)	n/a	UDR-02
50.h.1					Meter Internal	L+G Proprietary			L+G Proprietary			
51.a.1	Text Msg Transfer	IPI sends Text Msg to CHR	IPI	CHR	HANG Internal	Tendril Proprietary	Text Message	Request from HEMP to CHR to send a text Msg to HAND. Contains text Msg, start time, duration and confirmation flag.	Tendril - Aligns with SEP 1.0			HAN-03
51.a.2	Provision HAND Command Transfer	IPI sends Provision HAND Command Transfer to CHR	IPI	CHR	HANG Internal	Tendril Proprietary	Provision HAND Command	Command from HEMP to CHR to open the provision window and allow HANDs to join the HAN.	Tendril - Aligns with SEP 1.0	Proprietary		SEU-05
51.a.3	HEMP Settings Update Transfer	IPI sends HEMP Settings Update to CHR	IPI	CHR	HANG Internal	Tendril Proprietary	HEMP Settings Update	Msg from HEMP to CHR containing changes to the HEMP setings including set point, fan operation and daily/weekly schedule.	Tendril - Aligns with SEP 1.0			SEU-06
51.a.4	HEMP Settings Update Transfer	IPI sends HEMP Settings Update to CHR	IPI	CHR	HANG Internal	Tendril Proprietary	HEMP Settings Update	Msg from HEMP to CHR containing changes to the HEMP settings. Includes schedule and on/off state.	Tendril - Aligns with SEP 1.0			SEU-07
51.a.5	HAND De-Provision Request Transfer	IPI sends HAND De-Provision Request to CHR	IPI	CHR	HANG Internal	Tendril Proprietary	HAND De-Provision Request	Request from HEMP to CHR to de-provision a HAND from the HANG.	Aligns with ZigBee SEP 1.0			SEU-08
51.a.6	Cancel Text Msg Transfer	IPI sends Cancel Text Msg to CHR	IPI	CHR	HANG Internal	Tendril Proprietary	Cancel Text Msg Request	Request from HEMP to CHR to cancel a previously sent text Msg. Includes ID of previously sent text Msg and, optionally, requests an acknowledgement of receipt.	Tendril - Aligns with SEP 1.0			HAN-04
51.b.1	Text Msg Response Transfer	CHR sends Text Msg Response to IPI	CHR	IPI	HANG Internal	Tendril Proprietary	Text Msg Response	Confirmation from CHR to HEMP that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	Tendril - Aligns with SEP 1.0			HAN-03
51.b.2	Ready-to-Pair Response Transfer	CHR sends Ready-to-Pair Response to IPI	CHR	IPI	HANG Internal	Tendril Proprietary	Ready-to-Pair Response	Response from CHR to HEMP acknowledging that the prvision window is open and the CHR is ready to join new HANDs to the HAN.	Tendril - Aligns with SEP 1.0	Proprietary		SEU-05
51.b.3	Provision Complete Response Transfer	CHR sends Provision Complete Response to IPI	CHR	IPI	HANG Internal	Tendril Proprietary	Provision Complete Response	Response from CHR to HEMP indicating that the HAND has been provisioned to the CHR and joined the CHAN.	Tendril - Aligns with SEP 1.0	Proprietary		SEU-05
51.b.4	PCT Settings Update Transfer	CHR sends PCT Settings Update to IPI	CHR	IPI	HANG Internal	Tendril Proprietary	PCT Settings Update	Msg from CHR to HEMP containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	Tendril - Aligns with SEP 1.0			SEU-06
51.b.5	HAND De-Provision Confirmation Transfer	CHR sends HAND De-Provision Confirmation to IPI	CHR	IPI	HANG Internal	Tendril Proprietary	HAND De-Provision Confirmation	Confirmation from CHR to HEMP that HAND has been de-provisioned from HANG.	Aligns with ZigBee SEP 1.0			SEU-08
51.b.6	Cancel Text Msg Response Transfer	CHR sends Cancel Text Msg Response to IPI	CHR	IPI	HANG Internal	Tendril Proprietary	Cancel Text Msg Confirmation	Confirmation from CHR to HEMP indicating successful cancellation of a previously sent text Msg.	Tendril - Aligns with SEP 1.0			HAN-04
51.c.1												
51.d.1												
51.e.1												
51.f.1												

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
52.a.1	Text Msg Transfer	ESI sends Text Msg to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	Text Msg	Request from ESI to HAND to display a text Msg. Contains text Msg, start time, duration and confirmation flag.	ZigBee SEP 1.0	Display Msg	SEP 1.0 § D.5.2.3.1	HAN-03
52.a.2	Cancel Text Msg Request Transfer	ESI sends Cancel Text Msg Request to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	Cancel Text Msg Request	Request from ESI to HAND to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests an acknowledgement of receipt.	ZigBee SEP 1.0	Cancel Msg	SEP 1.0 § D.5.2.3.2	HAN-04
52.a.3	Pricing Signals Transfer	ESI sends Pricing Signals to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	Pricing Signals	Pricing information sent from ESI to HAND. Contains flat, time-of-use, or critical peak pricing.	ZigBee SEP 1.0	Publish Price	SEP 1.0 § D.4.2.4.1	HAN-05
52.a.4	HAND Pairing Info Request Transfer	ESI sends HAND Pairing Info Request to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	HAND Pairing Info Request	Request from ESI to HAND for HAND pairing information.	ZigBee SEP 1.0	Device Discovery	ZigBee-2007 § 2.4.2.1	HAN-06
52.a.5	HAND De-Provision Request Transfer	ESI sends HAND De-Provision Request to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	HAND De-Provision Request	Request from ESI to HAND for the HAND to leave the UHAN.	ZigBee SEP 1.0	Leave Command	ZigBee-2007 § 3.4.4	HAN-07 HAN-08
52.a.6	DR Event Msg Transfer	ESI sends DR Event Msg to PCT via UHAN	ESI	PCT	UHAN	IEEE 802.15.4	DR Event Msg	Msg from ESI to PCT that contains the load curtailment details for a specific MTR. Details are based upon the type of DR event and user defined preferences in the HEMP.	ZigBee SEP 1.0	Load Control Event	n/a	UDR-02
52.a.7	Daily Bill TrueUp Msg Transfer	ESI sends Daily Bill TrueUp Msg to IHD via UHAN	ESI	IHD	UHAN	IEEE 802.15.4	Daily Bill TrueUp Msg	Tunnel Text Msg from ESI to IHD that contains Daily Bill TrueUp data.	ZigBee SEP 1.0	Display Msg	SEP 1.0 § D.5.2.3.1	SEU-03
52.a.8	Real-Time Energy Usage Response Transfer	ESI sends Real-Time Energy Usage Response to IHD via UHAN	ESI	IHD	UHAN	IEEE 802.15.4	Real-Time Energy Usage Response	Response from ESI to IHD containing real-time energy usage.	ZigBee SEP 1.0	Instantaneous Demand	SEP 1.0 § D.3.2.2.5.1	SEU-02
52.a.9	Current Price Response Transfer	ESI sends Current Price Response to IHD via UHAN	ESI	IHD	UHAN	IEEE 802.15.4	Current Price Response	Response from ESI to IHD containing current energy prices.	ZigBee SEP 1.0	Publish Price	SEP 1.0 § D.4.2.4.1	SEU-02
52.a.10	Text Msg Response Transfer	ESI sends Text Msg Response to IHD via UHAN	ESI	IHD	UHAN	IEEE 802.15.4	Text Msg Response	Response from ESI to IHD containing the latest utility-generated text Msg.	ZigBee SEP 1.0	Display Msg	SEP 1.0 § D.5.2.3.1	SEU-02
52.a.11	HEMP Settings Update Transfer	ESI sends HEMP Settings Update to PCT via UHAN	ESI	PCT	UHAN	IEEE 802.15.4	HEMP Settings Update	Msg from ESI to PCT containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Cluster	ZCL 1.0 § 6.3.2.2.2	SEU-06
52.a.12	HEMP Settings Update Transfer	ESI sends HEMP Settings Update to LCS via UHAN	ESI	LCS	UHAN	IEEE 802.15.4	HEMP Settings Update	Messge from ESI to LCS containing changes to the HEMP settings. Includes schedule and on/off state.	ZigBee SEP 1.0	Demand Resonse and Load Control Cluster	ZigBee SEP 1.0 § D.2	SEU-07
52.a.13	ZigBee Command Transfer	ESI sends ZigBee Command to HAND via UHAN	ESI	HAND	UHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the ESI or a HAND. The destination could be a HAND or the ESI.	ZigBee SEP 1.0	Various	n/a	NWK-03
52.b.1	Text Msg Resonse Transfer	HAND sends Text Msg Response to ESI via UHAN	HAND	ESI	UHAN	IEEE 802.15.4	Text Msg Response	Confirmation from HAND to ESI that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	ZigBee SEP 1.0	Msg Confirmation	SEP 1.0 § D.5.3.3.2	HAN-03
52.b.2	Cancel Text Msg Confirmation Transfer	HAND sends Cancel Text Msg Confirmation to ESI via UHAN	HAND	ESI	UHAN	IEEE 802.15.4	Cancel Text Msg Confirmation	Optional Msg from HAND to ESI indicating successful cancellation of a previously sent text Msg. Requirement for this Msg is controlled by the Cancel Text Msg Request.	ZigBee SEP 1.0	Msg Confirmation	SEP 1.0 § D.5.3.3.2	HAN-04
52.b.3	Pricing Signals Acknowledgement Transfer	HAND sends Pricing Signals Acknowledgement to ESI via UHAN	HAND	ESI	UHAN	IEEE 802.15.4	Pricing Signals Acknowledgement	Acknowledgement from HAND to ESI that Pricing Signals were received. Requirement for this Msg is controlled by the Pricing Signals.	ZigBee SEP 1.0	Publish Price Response	SEP 1.0 § D.4.2.4.1	HAN-05
52.b.4	HAND Pairing Info Response Transfer	HAND sends HAND Pairing Info Response to ESI via UHAN	HAND	ESI	UHAN	IEEE 802.15.4	HAND Pairing Info Response	Response from HAND to ESI containing HAND pairing information. Response includes MAC Address, Device Type and Pair ID.	ZigBee SEP 1.0	Simple Descriptor Startup Parameters Attribute Set	ZigBee 2007 § 2.3.2.5 ZCL 2008 § 3.15.2.21	HAN-06
52.b.5	DR Event Received Acknowledgement Transfer	PCT sends DR Event Received Acknowledgement to ESI via UHAN	PCT	ESI	UHAN	IEEE 802.15.4	DR Event Received Acknowledgement	Response from PCT to ESI indicating that the demand response event has been scheduled at the PCT.	ZigBee SEP 1.0	Report Event Status Command	n/a	UDR-02
52.b.6	Real-Time Energy Usage Request Transfer	IHD sends Real-Time Energy Usage Request to ESI via UHAN	IHD	ESI	UHAN	IEEE 802.15.4	Real-Time Energy Request	Request from IHD to ESI for real-time energy usage.	ZigBee SEP 1.0	Instantaneous Demand	SEP 1.0 § D.3.2.2.5.1	SEU-02
52.b.7	Current Price Request Transfer	IHD sends Current Price Request to ESI via UHAN	IHD	ESI	UHAN	IEEE 802.15.4	Current Price Request	Request from IHD to ESI for current energy prices.	ZigBee SEP 1.0	Get Current Price	SEP 1.0 § D.4.2.3.1	SEU-02
52.b.8	Text Msg Request Transfer	IHD sends Text Msg Request to ESI via UHAN	IHD	ESI	UHAN	IEEE 802.15.4	Text Msg Request	Request from IHD to ESI for latest utility-generated text Msg.	ZigBee SEP 1.0	Get Last Msg	SEP 1.0 § D.5.3.3.1	SEU-02

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
52.b.9	PCT Settings Update Transfer	PCT sends PCT Settings Update to ESI via UHAN	PCT	ESI	UHAN	IEEE 802.15.4	PCT Settings Update	Msg from PCT to ESI containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Cluster	ZCL 1.0 § 6.3.2.2.2	SEU-06
52.b.10	ZigBee Command Transfer	HAND sends ZigBee Command to ESI via UHAN	HAND	ESI	UHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the ESI or a HAND. The destination could be a HAND or the ESI.	ZigBee SEP 1.0	Various	n/a	NWK-03
52.b.11	DR Event Started Msg Transfer	PCT sends DR Event Started Msg to ESI via UHAN	PCT	ESI	UHAN	IEEE 802.15.4	DR Event Started Msg	Msg from PCT to ESI indicating that the demand response event has started.	ZigBee SEP 1.0	Report Event Status Command	n/a	UDR-02
52.b.12	DR Event Completed Msg Transfer	PCT sends DR Evnet Completed Msg to ESI via UHAN	PCT	ESI	UHAN	IEEE 802.15.4	DR Event Completed Msg	Msg from PCT to ESI indicating that the demand response event has ended.	ZigBee SEP 1.0	Report Event Status Command	n/a	UDR-02
52.c.1	ZigBee Command Transfer	HAND sends ZigBee Command to another HAND via UHAN	HAND	HAND	UHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the ESI or a HAND. The destination could be a HAND or the ESI.	ZigBee SEP 1.0	Various	n/a	NWK-03
53.a.1	Text Msg Transfer	CHR sends Text Msg to HAND via CHAN	CHR	HAND	CHAN	IEEE 802.15.4	Text Msg	Request from CHR to HAND to display a text Msg. Contains text Msg, start time, duration and confirmation flag.	ZigBee SEP 1.0	Display Msg	SEP 1.0 § D.5.2.3.1	HAN-03
53.a.2	HEMP Settings Update Transfer	CHR sends HEMP Settings Update to LCS via CHAN	CHR	LCS	CHAN	IEEE 802.15.4	HEMP Settings Update	Msg from CHR to LCS containing changes to the HEMP settings. Includes schedule and on/off state.	ZigBee SEP 1.0	Demand Response and Load Control Cluster	ZigBee SEP 1.0 § D.2	SEU-07
53.a.3	HAND De-Provision Request	CHR sends HAND De-Provision Request to HAND via CHAN	CHR	HAND	CHAN	IEEE 802.15.4	HAND De-Provision Request	Request from CHR to HAND to de-provision a HAND from the HANG.	ZigBee SEP 1.0	Leave Command	ZigBee 2007 § 3.4.4	SEU-08
53.a.4	ZigBee Command Transfer	CHR sends ZigBee Command to HAND via CHAN	CHR	HAND	CHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the CHR or a HAND. The destination could be a HAND or the CHR.	ZigBee SEP 1.0	Various	n/a	NWK-04
53.a.5	Cancel Text Msg Transfer	CHR sends Cancel Text Msg request to HAND via CHAN	CHR	HAND	CHAN	IEEE 802.15.4	Cancel Text Msg Request	Request from CHR to HAND to cancel a previously sent text Msg. Includes ID of previously sent Msg and, optionally, requests an acknowldgement of receipt.	ZigBee SEP 1.0	Cancel Msg	SEP 1.0 § D.5.2.3.2	HAN-04
53.a.6	HEMP Settings Update Transfer	CHR sends HEMP Settings Update to PCT via UHAN	CHR	PCT	CHAN	IEEE 802.15.4	HEMP Settings Update	Msg from CHR to PCT containing changes to the HEMP settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Cluster	ZCL 1.0 § 6.3.2.2.2	SEU-06
53.b.1	Text Msg Response Transfer	HAND sends Text Msg Response to CHR via CHAN	HAND	CHR	CHAN	IEEE 802.15.4	Text Msg Response	Confirmation from HAND to CHR that CUST acknowledged receipt of text Msg. Requirement for this Msg is controlled by the Text Msg.	ZigBee SEP 1.0	Msg Confirmation	SEP 1.0 § D.5.3.3.2	HAN-03
53.b.2	ZigBee Command Transfer	HAND sends ZigBee Command to CHR via CHAN	HAND	CHR	CHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the CHR or a HAND. The destination could be a HAND or the CHR.	ZigBee SEP 1.0	Various	n/a	NWK-04
53.b.3	Cancel Text Msg Response Transfer	HAND sends Cancel Text Msg Response to CHR via CHAN	HAND	CHR	CHAN	IEEE 802.15.4	Cancel Text Msg Confirmation	Confirmation from HAND to CHR indicating successful cancellation of a previously sent text Msg.	ZigBee SEP 1.0	Msg Confirmation	SEP 1.0 § D.5.3.3.2	HAN-04
53.b.4	PCT Settings Update Transfer	PCT sends PCT Settings Update to CHR via CHAN	PCT	CHR	CHAN	IEEE 802.15.5	PCT Settings Update	Msg from PCT to CHR containing changes to the PCT settings including set point, fan operation and daily/weekly schedule.	ZigBee SEP 1.0	Thermostat Settings Attribute Cluster	ZCL 1.0 § 6.3.2.2.2	SEU-06
53.c.1	ZigBee Command Transfer	HAND sends ZigBee Command to another HAND via CHAN	HAND	HAND	CHAN	IEEE 802.15.4	ZigBee Command	Generic ZigBee compliant command originating from either the CHR or a HAND. The destination could be a HAND or the CHR.	ZigBee SEP 1.0	Various	n/a	NWK-04
54.a.1			DAD	DAD	SDPN							
54.b.1			DAD	DAD	SDPN							
55.a.1			DAD	DAD	FAN							
55.b.1			DAD	DAD	FAN							
56.a.1			DER	DER								
56.b.1			DER	DER								
57.a.1												
57.b.1												

Msg ID	Name of Process/Transaction	Description of Process/Transaction	Producer (Actor 1)	Receiver (Actor 2)	Transport Network	Network Protocols	Information Object Name	Information Object Description	Interface Standard	Standard Msg Name	Standard Msg Code	Use Case
100.a.1	Data Packet Transfer	MFR sends RF Data Packet to another MFR via RF mesh	MFR	MFR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
101.a.1	Data Packet Transfer	FANE sends RF Data Packet to MFR via RF mesh	FANE	MFR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
101.b.1	Data Packet Transfer	MFR sends RF Data Packet to FANE via RF mesh	MFR	FANE		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
102.a.1	Data Packet Transfer	FANR sends RF Data Packet to MFR via RF mesh	FANR	MFR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
102.b.1	Data Packet Transfer	MFR sends RF Data Packet to FANR via RF mesh	MFR	FANR		L+G Proprietary	RF Data Packet	Any packet of daya sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
103.a.1	Data Packet Transfer	FANC sends RF Data Packet to MFR via RF mesh	FANC	MFR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
103.b.1	Data Packet Transfer	MFR sends RF Data Packet to FANC via RF mesh	MFR	FANC		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
104.a.1	Data Packet Transfer	FANE sends RF Data Packet to another FANE via RF mesh	FANE	FANE		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
105.a.1	Data Packet Transfer	FANR sends RF Data Packet to FANE via RF mesh	FANR	FANE		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
105.b.1	Data Packet Transfer	FANE sends RF Data Packet to FANR via RF mesh	FANE	FANR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
106.a.1	Data Packet Transfer	FANC sends RF Data Packet to FANE via RF mesh	FANC	FANE		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
106.b.1	Data Packet Transfer	FANE sends RF Data Packet to FANC via RF mesh	FANE	FANC		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
107.a.1	Data Packet Transfer	FANR sends RF Data Packet to another FANR via RF mesh	FANR	FANR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
108.a.1	Data Packet Transfer	FANC sends RF Data Packet to FANR via RF mesh	FANC	FANR		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
108.b.1	Data Packet Transfer	FANR sends RF Data Packet to FANC via RF mesh	FANR	FANC		L+G Proprietary	RF Data Packet	Any packet of data sent via RF mesh from the FANC to the MFR or from the MFR to the FANC.	L+G Proprietary	Any data transmitted via the FAN		NWK-01
109.a.1	Data Packet Transfer	AHE sends TCP/IP Data Packet to FANC via the Backhaul WAN	AHE	FANC		TCP/IP	TCP/IP Data Packet	Any TCP/IP formatted packet of data sent from the AHE to the FANC or from the FANC to the AHE.	TCP/IP	Any data transmitted via the FAN		NWK-01
109.b.1	Data Packet Transfer	FANC sends TCP/IP Data Packet to AHE via the Backhaul WAN	FANC	AHE		TCP/IP	TCP/IP Data Packet	Any TCP/IP formatted packet of data sent from the AHE to the FANC or from the FANC to the AHE.	TCP/IP	Any data transmitted via the FAN		NWK-01
110.a.1			DDC	FANC								
110.b.1			FANC	DDC								
111.a.1			FANE	DADC								
111.b.1			DADC	FANE								
112.a.1			FANE	DERC								
112.b.1			DERC	FANE								

End of Document

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