Secure Interoperable Open Smart Grid Demonstration Project

Final Technical Report
Appendices

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List of Abbreviations

Abbreviation	Description
AC	Alternating Current
AES	Advanced Encryption Standard
AHJ	Authority Having Jurisdiction
AMI	Advanced Metering Infrastructure
ASME	American Society of Mechanical Engineers
BAT	Brooklyn Army Terminal
BAU	Business as Usual
BMS	Building Management System
BNL	Brookhaven National Lab
BRKE	Business Rules Knowledge Engine
CBL	Customer Baseline Load
CHAdeMO	Charge de Move
CIM	Common Information Model
CIP	Critical Infrastructure Protection
CLE	Common Logging Engine
COTS	Commercial Off-the-Shelf
CR	Counting Recloser
CSRP	Commercial System Relief Program
CSV	Comma Separated Values
CT	Current Transformer
CVR	Conservation Voltage Reduction
DC	Direct Current
DCC	Distribution Control Center
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DEW	Distribution Engineering Workstation
DG	Distributed Generation
DLRP	Distribution Load Relief Program
DMS	Distribution Management System
DNP3	Distributed Network Protocol
DOB	Department of Buildings

DOE .... Department of Energy

DOT .... Department of Transportation

DR .... Demand Response

DRCC.................................. Demand Response Command Center

DRMS.................................. Demand Response Management System

DSCADA .... Distribution Supervisory Control and Data Acquisition

EDD..................................... Electrical Distribution Design

EDN .... Energy Delivery Network

EMS..................................... Energy Management System

EO.. Energy Optimizer

EV .... Electric Vehicle

EVSE .... Electric Vehicle Service Equipment

FAT .... Factor Acceptance Testing

FB .... Feeder Breaker

FDNY .... Fire Department of New York

FTR...................................... Final Technical Report

GCN .... Green Charge Networks, LLC

GIS....................................... Geographic Information System

GPS...................................... Global Positioning System

GRC..................................... Governance, Risk, and Compliance

GSNI .... Grid Synergy Network Integrator

GSNOC............................... Grid Synergy Network Operations Center

HTTP(S) .... Hyper Text Transfer Protocol (Secure)

HVAC .... Heating, Ventilating, and Air Conditioning

IBCU .... Incremental Building Control Unit

ICCP.................................... Inter-Control Center Communications Protocol

IEC....................................... International Electrotechnical Commission

IP .... Internet Protocol

IRIG..................................... Inter-Range Instrument Group

IRR .... Internal Rate of Return

ISM .... Integrated Systems Model

IT .... Information Technology

IVR .... Interactive Voice Response

JACE .... Java Applet Control Engine

JMS...................................... Java Messaging Service kW.. Kilowatt

kWh...................................... Kilowatt-Hours

LPDS .... Load Profile Data System

LSR...................................... Line Side Reset

LTE...................................... Long Term Evolution

MDM.................................... Meter Data Management

MDMS .... Meter Data Management System

MHP.................................... Mandatory Hourly Pricing

MHz .... Megahertz

MR....................................... Midpoint Recloser

MW .... Megawatts

NAESB................................. North American Energy Standards Board

NEC..................................... National Electric Code

NERC.................................. North American Electric Reliability Corporation

NIST .... National Institute of Standards and Technology

NOC.................................... Network Operations Center

NYC .... New York City

NYCEDC .... New York City Economic Development Corporation

NYISO................................. New York Independent System Operator

NYPSC................................ New York Public Service Commission

NYSERDA .... New York State Energy Research and Development Authority

O&R .... Orange and Rockland

OASIS .... Organization for the Advancement of Structured Information Standards

OLE .... Object Linking and Embedding

OMS .... Outage Management System

OPC..................................... OLE for Process Control

OPDS .... Open Data Source

OpenADR........................... Open Automated Demand Response

PID .... Proportional-Integral-Derivative

POTS .... Plain Old Telephone Service

PPS .... Pulse per Second

PV.. Photovoltaic

PVL .... Poly-Voltage Load-flow

QA....................................... Quality Assurance

RFP...................................... Request for Proposal

ROI .... Return on Investment
RTU .... Remote Terminal Unit
SAT .... Site Acceptance Testing
SCADA .... Supervisory Control and Data Acquisition
SCR .... Special Case Resource
SG .... Smart Grid
SGAM .... Smart Grid Architecture Model
SGDM .... Smart Grid Disturbance Monitor
SGDP .... Smart Grid Demonstration Project
SHPO .... State Historic Preservation Office
SLA .... Service Level Agreement
SOA .... Service Oriented Architecture
SOAP .... Simple Object Access Protocol
SOE .... Sequence of Events
SPM .... Service Performance Manager
SQL .... Structured Query Language
SR .... Sectionalizing Recloser
SSGU .... Smart Storage and Generation Unit
TR .... Tie Recloser
TRUC .... Transient Recorders Users Council
TSP .... Thermal Storage Plant
UL .... Underwriters Laboratory
UML .... Unified Modeling Language
UN .... United Nations
UPS .... United Parcel Service
VIS .... Visualization
VPN .... Virtual Private Network
VRLA .... Valve Regulated Lead Acid
VVC .... Volt-var control
WSDL .... Web Services Description Language
WS-SEC .... Web Services Security
XML .... Extensible Markup Language

Appendix A Reports Submitted by Project Partners

These subproject reports were written by the project partners and Con Edison to provide more detail and background on the individual subprojects. They have been provided here for completeness.

A.1 Siemens / TIBCO: Distributed Energy Resource Management System (DERMS)

The Siemens/TIBCO team developed a summary of Smart Grid Demonstration Project (SGDP) activities as part of the input to the Final Technical Report (FTR). Results and information below has been used to develop the overall takeaways and lessons learned in the FTR.

A.1.1 Executive Summary

The Con Edison DERMS project, sponsored by the United States Department of Energy (DOE), integrates multiple sources of operations and logistical information to visualize delivery grid condition and manage available Distributed Energy Resources (DERs), both demand and generation, to enable energy delivery reliability and security.

The project leverages Siemens' expertise in Utility Real-Time Operations domains and information technology (IT) in tandem with TIBCO's service-oriented middleware architecture to bridge functional silos, collecting data from heterogeneous applications and establishing secure, reliable communication connections between them. Siemens' platform additionally enables Con Edison users to visualize and monitor integrated data from a range of sources and take informed actions. Internal users of SGDP do not require installation of client as the system is enabled with Microsoft virtual application (Microsoft App-V) and can be used and run by any workstation that was authorized to run the DERMS virtual application.

A.1.2 Project Goals and Accomplishments

Understanding the stated project goals is essential to accurately evaluating the DERMS's tactical accomplishments. The following section depicts Siemens' major objectives and the technological achievements that resulted.

A.1.2.1 Project Objectives

- **Objective:** Improve control capabilities of existing grid assets
  Description: Siemens developed and integrated a wide-area visualization platform to manage, monitor and control a distribution system utilizing secured web services. Siemens provided near-real-time status of distributed energy resources onto existing network real-time displays, integrated-load flow analysis and decision aid capability during peak load conditions, enabled impact analysis of distributed energy and load resources and implemented targeted Demand Response (DR) on electric distribution systems. The integrated package establishes wide-area situational awareness for electrical distribution operators.
- **Objective:** Minimize peak load growth and maximize energy efficiency savings throughout the electrical grid
  Description: Siemens platform in coordination with DR providers allows, identification of DER that correlate with Con Edison distribution network components with the potential for relieving

overloads on specific feeders or transformers by placing targeted DR requests. This opens the possibility for capacity deferrals in system infrastructure plans.

- **Objective:** Provide world-class cyber security for smart grid (SG) systems
  Description: Siemens employed secure web services to request the reduction of load or additional generation, and securely queried status of availability and curtailment capacity using industry standards. The communication platform supports multiple secure technology standards such as, message level security and transport level security. In addition Siemens implemented security controls in the area of user authentication and role based access control.
- **Objective:** Demonstration of open standards and interoperability with vendors with commercially available products
  Description: Siemens leveraged open standards and integrated newly developed technologies while simultaneously interfacing to legacy applications. Messages used for communication with third party vendors comply with existing standards and any extensions will be proposed for inclusion in future standard revisions.
- **Objective:** Maintenance of electrical delivery system reliability and increased utilization of existing equipment
  Description: Siemens platform enables distribution system operators to visualize and remotely manage various distributed resources in the Con Edison distribution network including available Distributed Generation (DG) and controllable demand. The ability to manipulate these resources extends the equipment life and utilization, avoids potential equipment damage, and should improve the general feeder equipment condition reducing overall maintenance requirements and improving reliability.

A.1.2.2 Other Project Accomplishments

During the course of the project Siemens also provided:

- Modeling of DG and DR sites and resources utilizing and/or extending existing Common Information Model (CIM) standard.
- Support for grouping multiple sites (each with multiple resources) which, for example, could be used for support of microgrid interoperability
- Support for mobile generation resources – for dynamic connection, analysis, and monitoring
- Modeling and monitoring support for generation (solar sites, diesel, and gas generation).
- Interoperability with existing legacy models and tools
- Support for interoperability of site/resource model and dynamic data with existing and future Electric Distribution Systems – Load Flow, Pocket Analysis, Microgrid tools, etc.
- Support for impact measurement of DERs and load variations on the Distribution system components
- Support for simulation of DER sites and resources to identify critical sites with greatest potential benefit on the grid for DR
- Integration of the existing Con Edison Load Flow analysis program which can prioritize DR sites and provide decision aid to operators for targeted DR

- Support for identification and monitoring of critical infrastructure sites for grid component operator alerts

A.1.2.3 Challenges and Lessons Learned

Table A-1. Challenges and Lessons Learned

Deliverable	Challenges	Lessons Learned
Meeting scheduled demonstration dates	• Communication w/ project partners	• Documentation, communication and scope agreement are critical to timely success
Data Integration of legacy and SG systems	• Timely access to subject matter experts • Presenting data in unified manner • Data resides within silos, facilitate bringing these silos together	• Must understand technical capabilities of diverse group of partners during system integration activities
Cyber Security	• Coordination with multiple DR providers	• Utility and Third Party legacy systems have cyber- security challenges that require advance planning & careful implementation.

A.1.2.4 Commercialization – Configurability and Scalability

The DERMS project started as a demonstration project for the DOE with two boroughs, two distribution primary networks, and one substation in Con Edison's service territory. The project has been evaluated by Con Edison teams during the period of multiple demonstrations to the DOE and has been extended for the Con Edison production system. The platform is extremely flexible and scalable and currently represents Con Edison's six boroughs and 64 networks. It has been extended to encompass the entire Con Edison service area.

With the visualization layering capability, it is possible to include as many sites as required for monitoring the availability and accessing the condition of the distribution network. It is also possible to transfer an existing SG site to a DR site and vice versa based on Con Edison tariff for load relief programs or future potential tariffs for targeted DR.

A.1.3 Project Activities

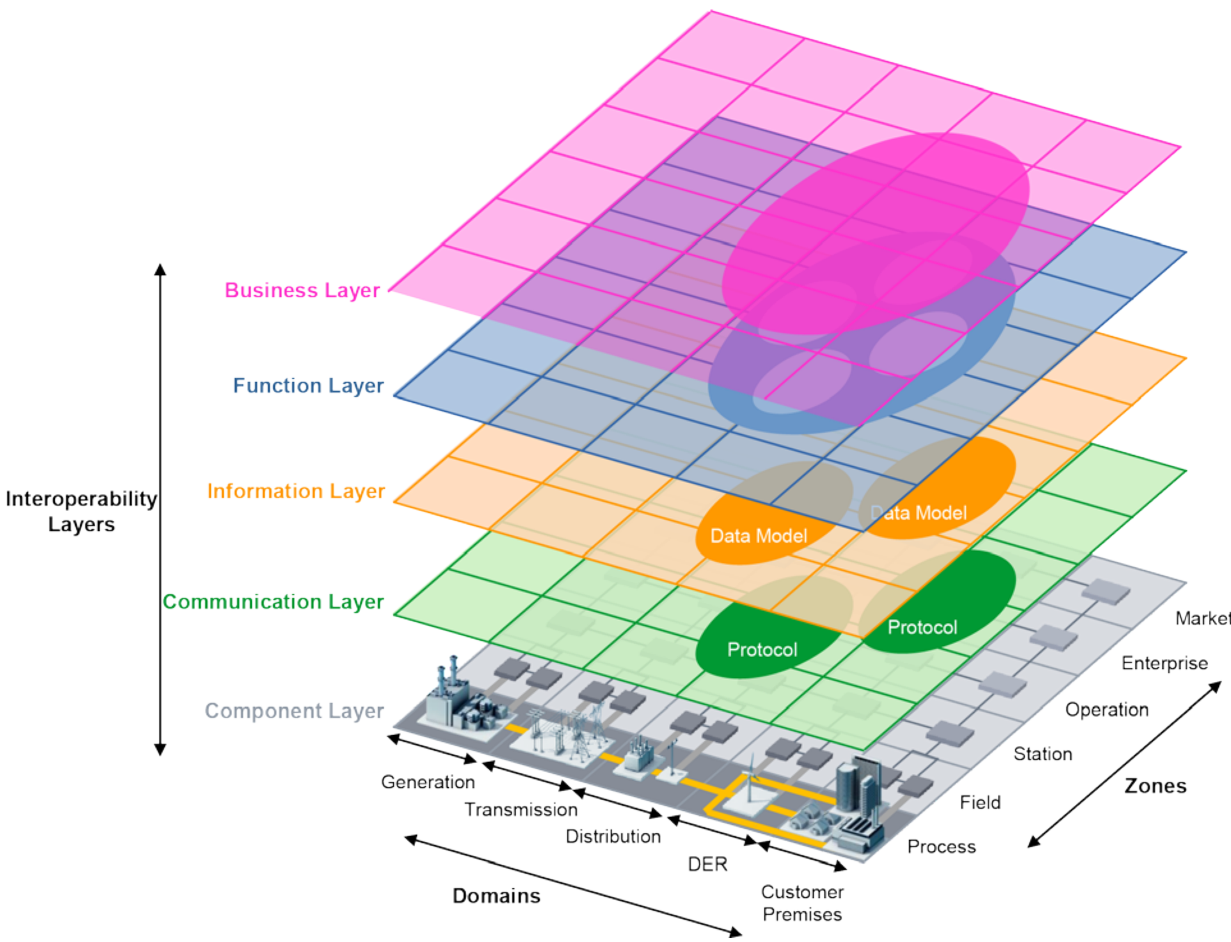
A.1.3.1 Approach

The SGDP teamed Con Edison with Siemens and TIBCO in an effort to implement an interoperable information exchange platform to integrate information from multiple utility domains, capitalizing on Siemens' SG expertise and TIBCO's middleware products.

Applying the SG Reference Architecture
The Smart Grid Architecture Model (SGAM) is a comprehensive "all-in-one" SG toolbox. The SGAM divides the energy industry into five domains, six zones of information management and five layers of interoperability. Siemens leveraged the below reference architecture model to design and implement the DERMS visualization and interoperable platform specified by Con Edison. While the DERMS does not span all the zones and domains shown in the figure below, the Siemens platform does allow flexibility and scalability in support of Con Edison's roadmap.

Siemens' Model Driven Integration approach leverages the International Electrotechnical Commission (IEC) CIM model as the Data/Domain Model within the Information layer to map and model data interface requirements. These requirements are driven by Functional Use Cases within the Function Layer, which in turn is influenced by Con Edison's Business Objectives and Processes within the Business Layer. Ultimately the interfaces are implemented within the Communication Layer or the middleware, enabling interoperability between the various zones.

Figure A-1. Siemens Smart Grid Architecture Model

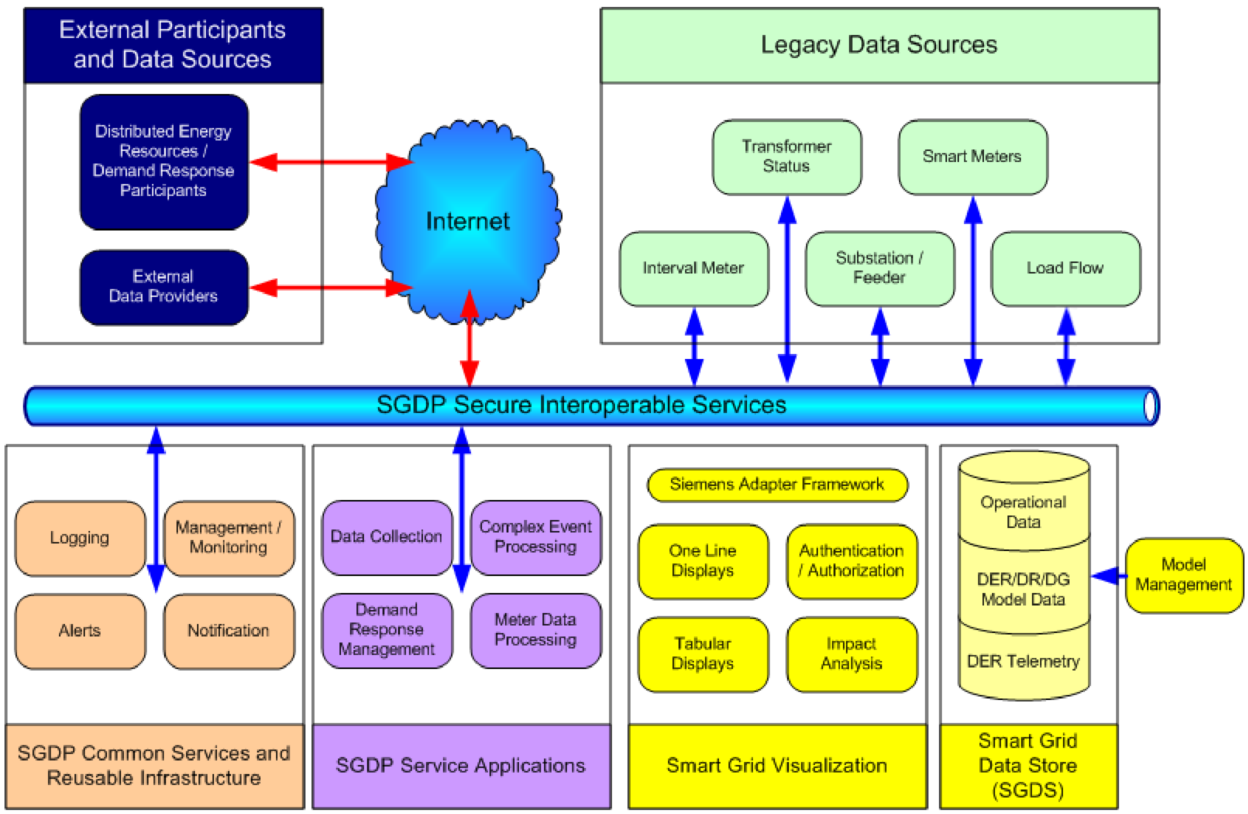


Source: European Smart Grid Coordination Group; based on National Institute of Standards and Technology (NIST) Smart Grid 1108 and 7628

SGDP Secure Interoperable Architecture

The SGDP Secure Interoperable Architecture, depicted below, implements standardized data models and protocols to integrate multiple functions across various applications, within and external to Con Edison. The TIBCO middleware enables dynamic data exchanges between various functions within SGDP while the Operational Data Store (OPDS) maintains data for archiving, reporting, and analysis purposes. Each of the rounded rectangles represents actors (i.e., the services, programs, or entities) that exchange information or requests.

Figure A-2. SGDP Secure Interoperable Architecture



SGDP leverages Web Services to enable dynamic data exchanges between various functions. These Web Services leverage industry standards such as Simple Object Access Protocol (SOAP), Extensible Markup Language (XML), Web Services Description Language (WSDL), etc. These web services carry XML payloads which Siemens has designed from the IEC CIM Unified Modeling Language (UML) model. Siemens has created CIM extensions for DR attributes which did not exist within the CIM UML model and mapped to existing CIM attributes where available. These Web Services have been implemented and deployed within the TIBCO middleware and leverage the Hyper Text Transfer Protocol (HTTP[S]) and Java Messaging Service (JMS) protocols for transport.

A.1.3.2 Common and Reusable Infrastructure

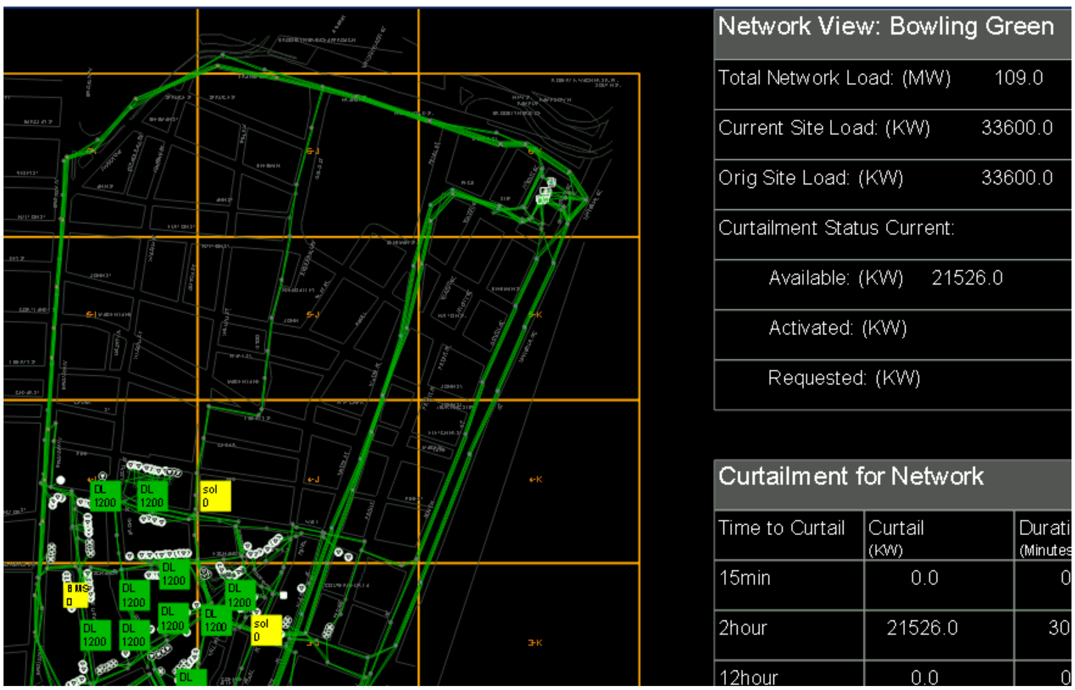
SGDP leverages an Service Oriented Architecture (SOA) based enterprise architecture which brings integration best practices such as component reuse, monitoring, security, and standards.

A Convergent Visualization Platform

The Siemens Visualization (VIS) solution overlays data from newly implemented applications on top of Con Edison's existing geographic maps related information from legacy systems. VIS provides a consistent display of information without regard to the data source and plays a major role in situational awareness.

VIS pushes dynamic updates to clients as the OPDS changes. Users on the VIS client directly trigger CIM-compliant messages to the DERMS Common Integration.

Figure A-3. SGDP Visualization Display



The DERMS visualization display example above depicts VIS one-lines automatically converted from Con Edison's existing one-line displays. Configuration-driven display building allows Con Edison to quickly create and deploy tabular and other displays.

Reusable Service Infrastructure

DERMS applies a common framework and employs a standardized design for all new TIBCO Business Works applications, an architecture that supports fast demonstrations of meta-applications like Complex Event Processing. DERMS applications also implement a set of reusable services supporting the use of applications developed outside of the DERMS solution: Any authorized system can use the CIM-compliant messages to partially or fully integrate into SGDP.

Siemens and TIBCO Commercial Off-the-Shelf (COTS) products have been utilized in the development of the following services:

- **Notification Service** is a simple re-use component that allows SGDP Applications to send e-mail notifications to other systems.
- **Alerts Service** is a listening service that collects CIM-compliant alert messages and aggregates them in the Operational Data Store and Visualization.
- **Common Logging Engine** (CLE) receives debug, informational and critical logs from all SGDP Applications. Administrators analyze these logs to determine root causes for service issues in SGDP.
- **TIBCO HAWK** and **Hardware Management/Monitoring** provide low-level hardware monitoring for SGDP Administrators. The Alert and Notification systems support initial visibility to administrators and supervisors, and TIBCO Service Performance Manager (SPM) provides Service Level Agreement (SLA) monitoring.

A.1.3.3 Data Integration

The quality and consistency of DERMS data underlines the venture's success. The DERMS brings together numerous functional areas to forge a single OPDS. The functional areas fall into two categories: legacy system integration and new system integration.

Legacy System Integration via Internal Services
The DERMS retrieves information from a host of existing Con Edison data sources, a strategy enabling the utility to onboard new data sources with greater accuracy and speed. Siemens deployed well-defined web services against existing Con Edison applications to abstract internal functional details and standardize interfaces, simplifying maintenance and enabling monitoring.

The following Con Edison existing legacy applications have been integrated as part of the DERMS.

- **Load Profile Data System (LPDS)** provides Interval Meter data and High Voltage Vault Meter data from the ITRON MV-90xi.
- **Advanced Metering Infrastructure (AMI)** provides Smart Meter data from UtilityIQ.
- **Data Acquisition** provides Feeder Status, Substation Status and Network data.
- **Model Data** provides SG Distributed DR Energy Resources connectivity points.
- **Load Flow** provides Decision Aid data.

New Integration via External Services
The SGDP also enables new Con Edison information access and functionality. Secure Web Services ensure protected interactions with DR-participant companies, supported by a CIM-compliant message structure. New CIM extensions for these use cases were created as necessary. New external data providers were connected to the SGDP as well.

The following external Con Edison partners and data services have been integrated as part of the DERMS.

- **External DR Participants** provide DERMS with options for load relief at their systems. DERMS DR IEC CIM compliant messaging allows Con Edison to securely request Status and Demand Curtailment over the Internet to these participants. When Con Edison is ready to return to normal operations, the utility can request DR Participant to Stop Curtailment. All requests are sent with Transport Level and Message Level security compliant to Organization for the Advancement of Structured Information Standards (OASIS) Web Services Security (WS-SEC) standards.

- **Solar** (external data provider) delivers near real-time photovoltaic (PV) resources information across the area covered by DERMS.
- **Deep Thunder** (external data provider) delivers customized weather forecast data.

A.2 Alstom Grid: Demand Response Management System (DRMS)

The Alstom team developed the following summary of SGDP activities as part of the input to the FTR. Results and information below has been used to develop the overall takeaways and lessons learned in the FTR.

A.2.1 Executive Summary

Con Edison utilizes DR programs to incent customers to reduce their energy use during times of distribution system constraint and peak demand. The primary drivers for utilizing DR resources are to manage Emergency Capacity Reserves and Peak Load Reduction. The primary business functions and processes associated with Con Edison's DR program, such as enrollment, notification and settlement, are largely manual today.

Operating two types of commercial DR programs – Contingency and Peak Shaving – Con Edison seeks to maximize electric distribution system opportunities through effective DR program execution from May 1 through October 31 each year. Con Edison's contingency programs are initiated at short notice in response to engineering conditions on the electric distribution system (feeder outages, voltage reduction) and are available across the whole service territory. The Peak Shaving programs are initiated when the Day Ahead System Forecast is at 96% or higher of the forecasted system's summer peak level. The Peak Shaving program is only applicable to New York Independent System Operator (NYISO) Zone J (the five boroughs of New York City [NYC]).

In 2013 there were about 750 unique customers enrolled in Con Edison's Commercial DR programs, the majority of whom were represented by one of 12 DR aggregators/curtailment services providers. These customers/aggregators accounted for approximately 1,100 meters. The potential exists that the programs could increase fivefold in customer and meter size over the next few years and any management system needs to be scalable.

As part of the SGDP, Consolidated Edison has an objective of implementing technology to help alleviate the constraints caused by the manual processes currently utilized to manage their DR programs.
The technical solution to address this requirement is the implementation of a DRMS. Alstom Grid was selected by Con Edison to deploy their DRBizNet software solution and to assist in managing the deployment of the DRMS system.

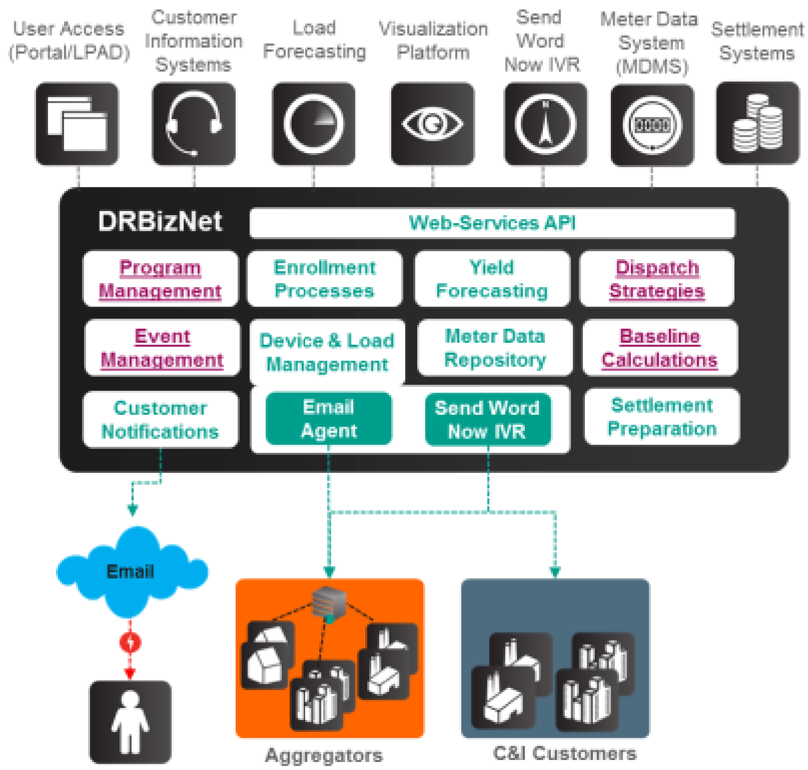
A.2.2 Project Scope

SGDP demonstrated monitoring and control capabilities, leveraging controllable field assets (curtailable customers, switches, DG, battery storage, electric vehicle (EV) charging stations, building management systems (BMSs), home area networks, high tension monitoring, and AMI) to shift, balance, or reduce load in response to system contingencies or emergencies in a way that reduced load where and when needed.

A.2.3 Deliverables

Con Edison selected the e-terra*DRBizNet* solution from Alstom Grid as the preferred DRMS. DRBizNet is designed to enable advanced load management for Retail electric distribution operators. The system has a robust suite of functionality built upon a modular architecture that can be adapted to address the unique needs of each customer.

Figure A-4. Diagram of DRMS Components offered by Alstom

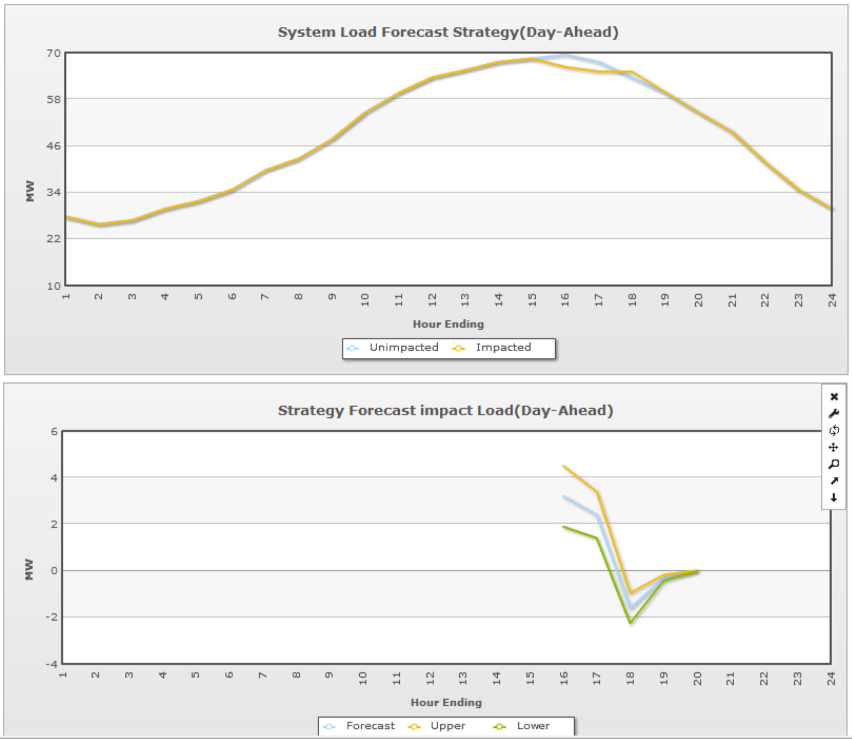


DRBizNet at Consolidated Edison

For Con Edison, Alstom Grid is delivering the entire suite of DRMS functionality including:

- **Program Management**: allows for simple and rapid creation of Retail customer programs that Con Edison will offer to its customer base. This functionality can apply to Commercial, Industrial and Residential-type DR programs.
- **Customer Registration**: tracks customer locations and manages the processes for enrollment in programs and limits enrollment when prohibited by program rules.
- **Forecasting**: provides available DR forecasting that accommodates program constraints such as device availability, weather, and profile including decay and snapback, as well as real-time feedback of opt outs, and confidence levels of forecast capabilities. e-terra*DRBizNet* can forecast available DR according to location/zone and/or network model including the substation, feeder bank, and feeder/circuit (see Figure A-5).

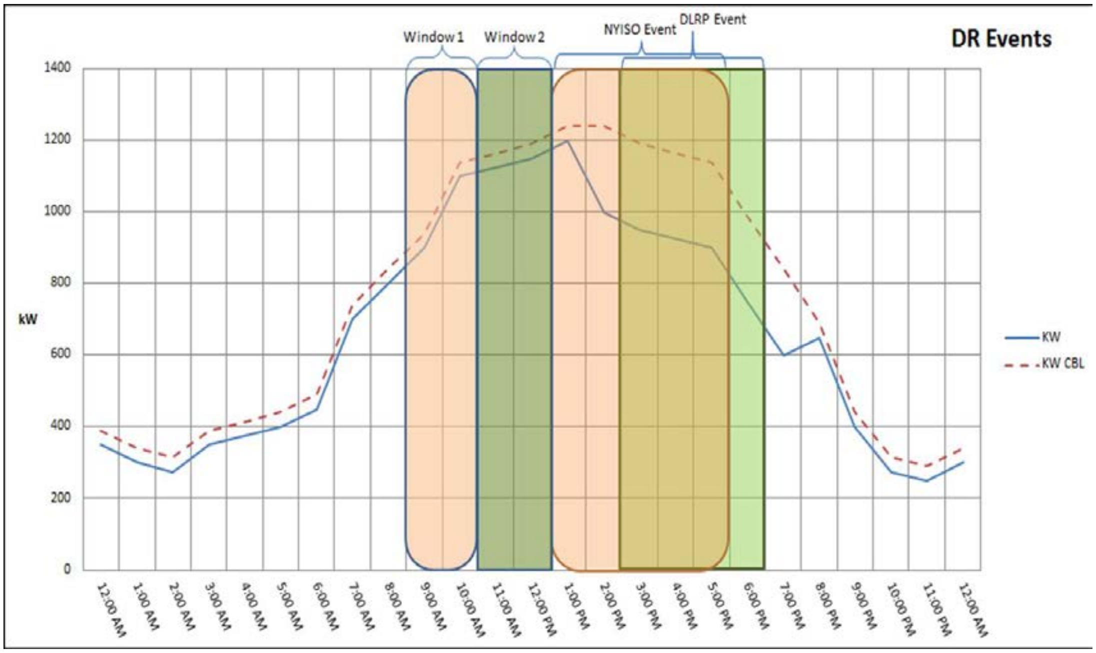
Figure A-5. Example of Load Forecasting Capability



Strategy Impact Confidence(Day-Ahead				
Hour Ending	Impact	75% impacted	95% confidence	Cos
1	-	-	-	0
2	-	-	-	0
3	-	-	-	0
4	-	-	-	0
5	-	-	-	0
6	-	-	-	0
7	-	-	-	0
8	-	-	-	0
9	-	-	-	0
10	-	-	-	0
11	-	-	-	0
12	-	-	-	0
13	-	-	-	0
14	-	-	-	0
15	-	-	-	0
16	3.2	2.4	0.664	0
17	2.4	1.8	0.51	0
18	-1.6	-1.2	0.332	0
19	-0.3	-0.225	0.066	0
20	0	0	0.01	0
21	-	-	-	0
22	-	-	-	0
23	-	-	-	0
24	-	-	-	0

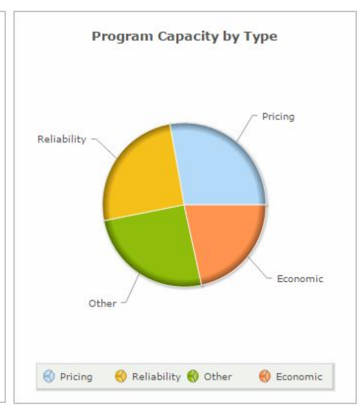
- **Optimization:** includes DR resource optimization with multiple objective functions such as reducing peak load during high cost energy periods, or maximizing profit based upon market forecasted prices.
- **Event Management**: provides dispatch operators with a way to construct event dispatch schedules, which could range from simple single resource group quick dispatches, to multi-leg events for longer events. These dispatch methods can be saved as templates and easily recalled and launched by adding start time and end time or event duration.
- **Notification Management**: notifies devices using supported protocols such as Open Automated Demand Response (OpenADR) and/or people of event dispatch schedules through email. For this project, Send Word Now Interactive Voice Response (IVR) is being deployed.
- **Local Control and Event Overrides**: supports customer overrides when participating in an event while capturing and tracking the number of overrides per customer.
- **Meter Data Integration**: provides two methods to upload meter data for performance calculations – standard Application Programming Interface (API) and comma separated values (CSV) files (i.e., spreadsheets).
- **Performance and Settlements**: follows North American Energy Standards Board (NAESB) standard baseline methodologies to calculate performance per customer event.

Figure A-6. DR Event Performance Review Display



- **Dashboard/Reporting**: provides a dashboard for charts and reports of program operating data such as Marketing Campaign performance, device installation work order summary, installation status, device population status, service request summary, customer defection, forecast of available DR per program, amount of DR called to date by program and others.

Figure A-7. Example of DR Reporting Dashboard



Program Capacity

Program	Total Devices	Total MW	Avg MW per Zone	Avg MW per Substation	Avg MW per Feeder
Residential AC	4472	7.2241	0.4515	0.1762	0.0737
Residential Hot Water	41	6.2313	0.3895	0.152	0.0636
Commercial Industrial Program	91	8.4263	0.5266	0.2055	0.086
Capacity Bidding	28	1.3321	0.0833	0.0325	0.0136
Total	4632.0				
Average		5.8	0.36	0.14	0.06

Total Count:4 1

Remaining Program Capacity

Program	ID	Season Events	Avg Ev Remaining	Prc Ev Remaining	Season Hours	Avg Hr Remaining	Prc Hr Remaining	Monthly Events	Avg Mo Remaining	Prc Mo Remaining
Residential Hot Water	RHW	42	34.2	80	120	105.5	90	6	1	20
Commercial Industrial Program	CIP	30	22.5	80	120	105.9	90	30	22.5	80
Residential AC	RAC	25	18.6	70	100	88.1	90	15	8.6	60
Capacity Bidding	CBP	35	18.1	50	264	231.4	90	30	13.2	40
Total					604.0	530.9				
Average		33.0	23.35	70.0	151.0	132.73	90.0	20.25	11.33	50.0

Total Count:4 1

- **Portal Access**: provides customer portal APIs and provides existing customer-facing solution giving access to DR data while allowing customers to update authorized information.
- **Integration**: Alstom is providing the DRMS APIs and integration design and support to move DR related data to and from Con Edison's back office systems including: Customer Information System, Meter Data Management System (MDMS), load forecasting, legacy load management systems, customer portal, new load management systems, settlements and billing systems.

A.2.4 Project Methodology

Alstom Grid is providing the domain expertise to manage the DRMS requirements gathering, software configuration, implementation, support of integration to back office systems, and DRMS testing.

Alstom Grid also provided the Business Analysts to review the Con Edison programs, processes, data flows, integrations, user roles, and key functionality requirements.

Alstom Grid will configure the DRMS and provide custom software development and support as needed.

A.2.5 Project Schedule

- The contract was signed and a purchase order received on February 25th, 2014.
- Factory Acceptance Testing (FAT) was completed at the end of July 2014.
- The system is currently undergoing Site Acceptance Testing (SAT).
- The system is scheduled to be deployed and operational in a production environment by December 2014.

A.3 O&R / EDD: Integrated Systems Model (ISM) and Control Algorithms

The Orange and Rockland (O&R) and Electrical Distribution Design (EDD) team developed the following summary of SGDP activities as part of the input to the FTR. Results and information below has been used to develop the overall takeaways and lessons learned in the FTR.

A.3.1 Executive Summary

A.3.1.1 Goals, Objectives, and Accomplishments

The objective of the real-time control systems work was to demonstrate that a single, detailed, reusable model of the electric distribution system can be used in a secure, interoperable environment for multiple objectives. A model-centric approach was used wherein the complete distribution system is modeled and updated in real-time. Model-centric systems, due to their comprehensive understanding of the system, can be used for control applications such as fault isolation and restoration to improve system reliability. In addition, a prime objective of the system was to coordinate volt-var control (VVC) to reduce system losses and energy consumption.

The second major objective was to develop and integrate a system into the interoperable environment that monitors weather conditions and the receipt of outage calls in real time to detect the beginning of storm events causing electric system outages and predicts the total number of outages that will be received looking one hour and three hours ahead using a real-time feed forward loop. Knowing the number of outage incidents that a storm will generate early in the storm allows the utility to right-size the restoration resource sooner, which reduces time to full restoration.

Listed below in Table A-2 are the high-level goals/objectives and the associated accomplishments of the work performed under this project.

Table A-2. High-Level Project Goals/Objectives and Related Accomplishments

Goals/Objectives	Accomplishments
Develop Model-Centric Auto Restoration System	Developed and demonstrated a model-centric auto restoration capability based on peer-reviewed journal papers on Graph Trace Analysis reconfiguration for restoration algorithm
Develop Model-Centric Coordinated VVC System	Developed and demonstrated a model-centric coordinated VVC system based on peer-reviewed journal and conference papers on Graph Trace Analysis coordinated control algorithms
Develop Model-Centric Storm Detection and Outage Prediction System	Developed and demonstrated a model-centric outage prediction system that accurately predicted the number of outages for control samples of historical storms based on peer-reviewed journal paper
Develop a cyber-secure environment for the model-centric approach	A cyber-secure, high-value network architecture was designed and mapped to NIST's standards and documented in this report.
Develop an interoperable environment for the model-centric approach	Interoperability was demonstrated using TIBCO middleware.

A.3.1.2 Control System Development

This integration permits higher penetration of automation within the electric power grid so that enhanced system reliability, deferred capital investment, energy conservation, and improved overall efficiency benefits can be realized.

This open architecture system can simplify the adoption and control of renewable resources and energy storage devices, and can facilitate the integration of new and emerging technologies such as microgrids.

Development, use, and maintenance of an ISM, and application of fast analytical processing of real-time data streams by electronic software applications, provide the analytical backbone that enables this model-centric approach to command and control the system. This approach also enables efficient and effective expansion of proof-of-concept and pilot projects to full-scale utility deployment.

Present distribution automation systems rely on equipment that uses voltage and/or current sensing at the device as inputs to their local electronic controls. The equipment knows nothing about what is taking place on the rest of the system and cannot react to optimize system conditions. These controls use set-points to determine when and how the equipment should operate. When sensing indicates that specific electrical parameters venture out of user-specified bandwidths around the setpoint, the equipment reacts to it automatically. This limits localized automatic control logic to a single reaction for a locally sensed condition. This type of automation operates without remote monitoring and without remote control, and is the most prevalent type of distribution automation currently in service. The operating scenario must be predetermined by an engineer and setpoint values calculated for the device. Careful coordination of setpoints between devices and the addition of timers to the device's electronics has allowed the devices to be used to provide single-function, non-optimal automatic control.

Some vendors have developed proprietary systems that use peer-to-peer communications between automation devices in the field to determine what is happening elsewhere on the system. These devices work together and can adjust for changing conditions. For the system to be effective, each and every possible normal and contingency operating scenario must be identified and programmed into to all of the devices. Should a scenario occur that has not been identified and programmed, the system will either react in an unintentional manner or may totally shut down and not operate. Should this occur during storm conditions or other emergency conditions, the results would be problematic. While these systems can and do work well in very small deployments, O&R feels they are too restrictive and complex for full-scale utility deployment.

The next step up from automatic local control is a combination of automatic local control and Distribution Supervisory Control and Data Acquisition (DSCADA) systems. DSCADA systems have been installed to monitor and remotely control automation and remote operable equipment. After the device has operated via its automatic localized control logic, a Distribution System Operator can change the condition of the device to help accommodate conditions elsewhere on the system. The limitation of operator control is the speed at which an operator can understand and react to changing conditions and the onslaught of data that he is subjected to. If conditions change too rapidly, as during emergency events and storm conditions, it can take a substantial amount of time for an operator to analyze the incoming data to determine what has transpired, identify a course of action, and to adjust the system to accommodate the situation.

Model-Centric Control Systems

The model-centric control system is the next evolution in distribution system control. In this type of control system, the distribution system is fully modeled in detail in an ISM where circuit topology changes are updated in real time for automatic devices under Supervisory Control and Data Acquisition (SCADA) control such as line reclosers and SCADA operable switches, and in near real time for manually operated switching devices, such as hook-stick-operated disconnect switches and manually operated, grouped interrupter switches. Real-time data from substation circuit breakers and distribution automation devices is attached to the model via SCADA. Fast analytical software then runs power flows on the model each time a real-time value within the model changes. As a result, real-time or calculated values of system electrical parameters are known for each section of wire and piece of equipment within the model. This information is then used by the control system algorithms to determine the optimal solution to changing system conditions. The control system is interfaced to the DSCADA system so that once the best course of action is determined by the control system; it is automatically executed through the interconnection to the DSCADA system.

Model-centric control has knowledge of electrical parameters and circuit topology across the entire system through the ISM and can rapidly make and execute decisions on how best to react to changing system conditions in real time. Having system electrical parameters in real time, either actual or calculated, for each section of wire and piece of equipment, allows the control system to vary solutions based on time varying loading. Thus, the ISM control solutions are not singular. They continuously optimize the response and vary depending on system parameters at the time of the response.

The model-centric control system rapidly responds to changing conditions and can handle multiple system contingencies, which singular function, automatic operation cannot do, and which automatic operation under operator control takes a significant amount of time to do. Additionally, because model-centric control is open architecture, as long as a device can be communicated with via DSCADA, it can be added to the control system by adding it to the ISM. Line reclosers, SCADA operable switches, switched shunt capacitor banks, voltage regulators, power quality nodes, faulted circuit indicators, and voltage and current sensors are examples of some of the present-day equipment that can be included in the system.

A direct connection to DSCADA allows solutions to be executed once they have been determined by the model-centric control system. This relieves the Distribution Operator from having to cope with the onslaught of data during system emergencies and storm conditions and from having to analyze the data to determine solutions, thus speeding restoration. Instead of having to focus on solving individual restoration problems, the operator can monitor and focus on the big picture and communications with field crews.

The ISM is interfaced to the distribution DSCADA system so automatic operation of distribution automation devices updates circuit topology in real time. In the future, the ISM will be interfaced to O&R's Geographic Information System (GISs) switch order system, which will provide near real-time topology updates from manual switching, and changes to topology and assets resulting from completed construction projects. This will fully automate the upkeep of the ISM, insuring that the circuit topology remains as accurate as possible by updating it in as close to real time as possible.

Auto Restoration Model-Centric Control System Demonstration

A demonstration of the Auto Restoration model-centric control system in a laboratory environment using ISM, Distribution Engineering Workstation (DEW) power flow analysis, DSCADA, and the auto restoration model-centric control system was performed. In the lab, faults were simulated using geo-synched relay power supplies controlled via scenario programing of the power supplies. A simulated fault was entered between devices in the system. The fault clearing device reacted automatically with its local control logic to clear the fault. When the model-centric control system received a change in state from the fault clearing device via the DSCADA system, it read the information sent from all of the other devices on the circuit. Information such as status, fault indication, voltage, and fault current were returned. Using the information returned from SCADA, the model-centric control determined the location of the fault and calculated an optimal solution that maximizes the number of customers restored without violating any constraints such as minimum voltage or maximum conductor and equipment loadings. Determination of the solution required less than 300 milliseconds and was fed directly into the DSCADA system. The DSCADA system then executed the commands, operating SCADA operable devices to further isolate the fault and restore out-of-service customers. The entire operation takes under one minute.

VVC Model-Centric System Demonstration

A demonstration of the model-centric VVC system in a laboratory environment using ISM, DEW power flow analysis, DSCADA, and the Volt VAR model-centric control system was performed. Actual regulator and capacitor bank control hardware was set up in the lab in a configuration matching an actual distribution circuit. The demonstration used all of the production systems, such as the production DSCADA system, actual 220 MHz radio communications between the controls set up in the lab, and a production master radio site for the DSCADA system, as well as the production backhaul communications to the DSCADA servers. Varying substation loadings were injected manually into the model and the VVC system reacted by turning on or off switched capacitor banks to meet var requirements and adjusted voltages to be adequate, but at the minimally adequate level so energy reduction from conservation voltage reduction (CVR) could be realized.

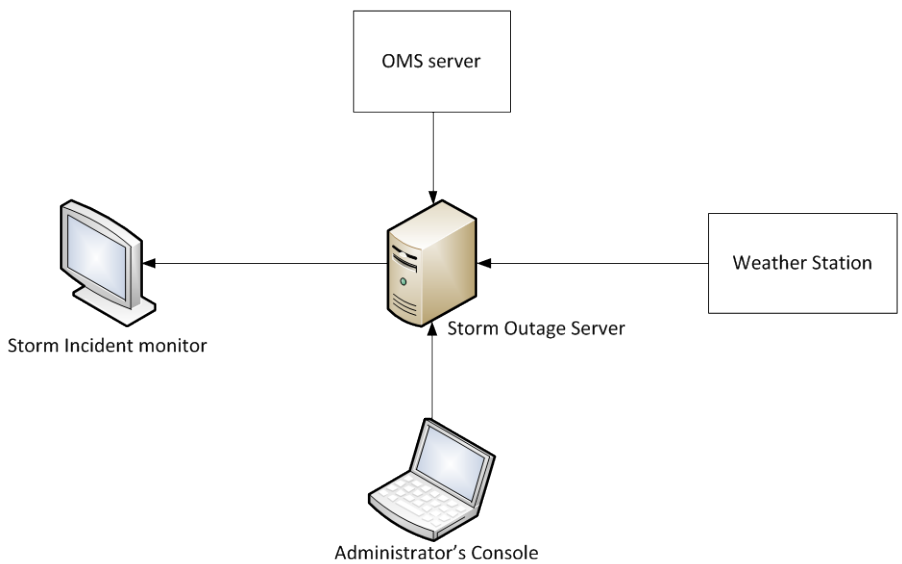
A.3.1.3 Storm Outage Detection and Prediction System

The Storm Outage Detection and Prediction system was also described in section 4-A.3 of the main report.

System Architecture

Storm Outage Detection and Prediction interfaces with the existing Outage Management System (OMS) and real-time weather information to detect or predict outages caused by storms. The program runs continuously on the Storm Outage Server, shown in Figure A-8, automatically selecting the appropriate mode (i.e., Detection or Prediction) based on the relevant data and control settings. Applicable run parameters and control settings are input from the Administrator's console.

Figure A-8. Storm Outage Relationship Diagram

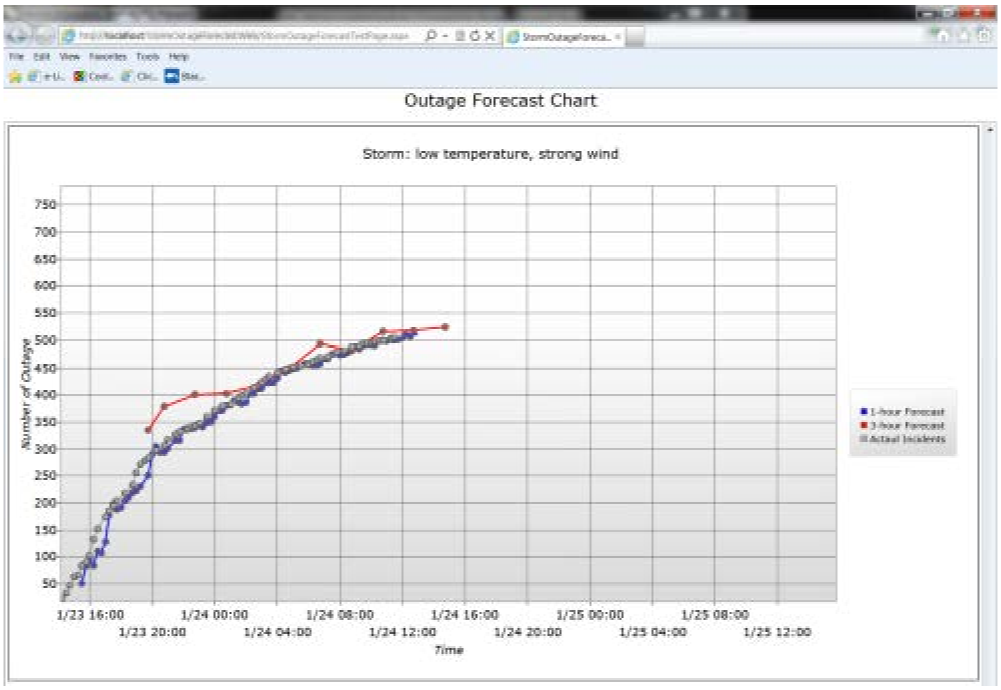


Detection Mode

In Detection mode, the program monitors the number of incidents received from the OMS server. If the number of incidents or changes in the number of incidents meets specified detection criteria, the program generates a storm warning based on the current weather condition from the weather station and switches into the Prediction mode. In the Prediction mode the program uses the reported outages to project the accumulated total of expected incidents for the next hour, with updates every 15 minutes. It also gives an hourly update of the total projected incidents that will be accumulated over the next three hours. When the defined prediction period is over, the program returns to the Detection mode and continues to monitor the number of incidents.

Results Visualization
The predictions and the actual number of incidents are presented in a line chart on a webpage, an example of which is given below. This output can be viewed with a web browser from any computer with access to the Storm Outage Server.

Figure A-9. Webpage Example



Storm Detection Process
In the Detection mode the program polls the number of incidents every 10 minutes from OMS. If the number of incidents is greater than the detection threshold, then a storm warning is generated. Otherwise, the number of incidents is put into a queue. Once the number of data points reaches the observation window length and the first number in the queue is larger than the trend line threshold, the program calculates a trend line from the queue. If the trend line gradient exceeds the defined slope value, then a storm warning is generated. The initial/default values of the detection criteria are:

Trend line threshold	7
Observation window length	4
Slope value	0.5
Detection threshold	40

Storm Outage Prediction Process
In the Prediction mode, the program polls the number of incidents every 15 minutes and feeds the number into a computational observer. The observer utilizes this data and the empirical model applicable for current storm with error compensation, to predict the number of incidents for the next 15 minutes, which is later used in a regression algorithm to generate the predicted number of incidents for the next hour and the next three hours. The empirical model is a statistical model derived from historical data that

describes the outage pattern for each storm type. More information about the empirical model and the observer is available in the footnoted article.[1]

Demonstration

To demonstrate this application, storm outages from O&R's storm outage database were used along with historical weather data. This historical data was fed into the system to simulate real-time receipt of the data and the output was visualized on the web page. Storm prediction was only 80% accurate, so clearly additional work is needed to determine when a storm has arrived and when the system should switch from determination to prediction mode. Brookhaven National Laboratory (BNL) has recently been awarded a New York State Energy Research and Development Authority (NYSERDA) grant to study the use of Doppler Weather Radar for storm outage prediction O&R will be working collaboratively with BNL on this project along with EDD, the developers of this software for O&R. This study has the potential for providing the means to significantly improve the accuracy of the storm detection portion of the software.

Once the software detects a storm it switches to prediction mode. In the demonstration, the real-time observer adjusted the prediction curve, making it more accurate as time advanced. This allowed the total number of outages to be known long before all of the customer outages were received.

Conclusions and Lessons Learned from the Demonstration

Table A-3 lists conclusions and lessons learned associated with each conclusion.

Table A-3. Conclusions and Lessons Learned

Conclusions	Lessons Learned
While not demonstrated completely in the project, the model-centric approach provides a seamless approach from design to evaluation of alternatives to economic justification to real-time analysis to real-time control	The model-centric approach provides flexibility that is not available in systems that are designed from a functional perspective.
SG devices and algorithms need to be tested in a laboratory environment prior to field-testing to minimize field troubleshooting and repair.	Manufacturer's documentation is not always clear on how devices respond in a real-world environment. Lab testing is required to assure that device controls respond as needed.
Testing should involve production communication protocols and systems.	To reduce communication traffic, during events devices should only communicate data needed by control and decision systems. SCADA systems need the ability to suppress unneeded data.
Hardware-in-a-simulation loop environment provides an effective testing environment	Many issues that would have resulted in problems in the field were able to be identified and corrected in the lab.

[1] Zhu, D., Cheng, D., Broadwater, R., & Scirbona, C. (2007). Storm modeling for prediction of power distribution system outages. *Electric Power Systems Research, volume 77, issue 8*, 973 - 979.

Conclusions	Lessons Learned
A very detailed system model can be used in real-time calculations for control.	This provides an alternative to programming for each scenario that a control system needs to respond to.
Once a type of storm is successfully classified, the number of outages can be accurately predicted as a storm progresses using feed forward statistical models and feedback from actual measured outages	Empirical storm-outage models need to be developed and continually maintained. It is preferable that the model maintenance be automated as new storm and outage data is obtained

A.3.2 Software Development and Testing

A.3.2.1 O&R

O&R worked with Siemens, TIBCO and EDD to integrate a number of corporate applications with control center applications. Working with EDD O&R developed two real time control and one real time storm outage prediction applications. A key component of O&R's Demonstration Project is demonstration of system interoperability and cyber security.

A.3.2.2 Scope of Work and Schedule

O&R's work was incorporated into a sub-award agreement that was executed in April 2011 and amended in May 2012.

O&R's scope of work focused on demonstrating that the reliability of the grid can be improved through a combination of enhanced monitoring and control capabilities along with intelligent analysis tools in the following areas:

- Intelligent Storm Impact Analysis
- System Interoperability
- Cyber Security
- Integration of field device information into Distribution SCADA to perform automated control via intelligent, model-centric control systems.

A.3.2.3 Software Requirements Development Process

The software development for this project built upon existing engineering applications by modifying and re-tasking existing algorithms and software applications to provide intelligent real time command and control.

The process included building upon previously funded DOE work and incorporates recent technical findings from third party, peer reviewed technical publications into the system. A list of applicable technical publications is provided in Appendix E.

The requirements for the software included the capability for taking real time system data from substations and field installed devices into a very detailed ISM, consisting of approximately 365,000 multi-phase components. This translates into approximately 1,000,000 node voltage values. A real-time power flow application is run on the ISM each time a change in a real-time value exceeds a threshold. The real-time power flow application, developed prior to this project, processes the ISM sufficiently fast for real-time analysis (i.e., on the order of a few seconds). The results of the power flow are used by other processes and systems to make control decisions. The other processes and systems execute the decisions through a real-time interconnection to an Energy Management System (EMS) and a DSCADA system. The interface to the EMS system is for control of substation load tap changers and feeder breakers. The interface to the DSCADA system is for control of all distribution automation devices.

The requirements development process was based on providing the vendor with the details of the system architecture, details of the cyber-security requirements, as well as the communications protocols, and a description of what the system was to accomplish.

Cyber security requirements were mapped to NIST requirements and appropriate measures were put in place to secure vulnerabilities and permit sharing of data between the systems on the corporate network and those on the high-value, cyber-secure network where the real time systems reside. See Appendix D for cyber-security details.

A.3.2.4 Software Specification Development Process

The specifications were iteratively developed around the concept of a model-centric implementation. The specifications were developed with low-cost flexibility and extendibility in mind. O&R specifications for the software were:

1. The model-centric control system must work with off-the-shelf, distribution automation equipment communicating with the SCADA systems.
2. All real-time analysis and control functions must use the same real time ISM model.
3. The power flow application must solve the ISM model from the O&R transmission system through to each individual customer load. (Developed under earlier project)
4. The same analysis functions that are used in planning analysis must be reused in real time analysis for the control systems.
5. The power flow application must be distributable and able to solve the ISM in a few seconds. (Developed under earlier project)
6. Real-time power flow results must be able to drive hundreds of real-time interfaces. (Developed under earlier project)
7. ISM model updates must occur in near real time. (Developed under earlier project)
8. The ISM model updates must have a model Quality Assurance (QA) process. (Currently under development outside of the DOE project)
9. Storm identification must use a set of time series values of outages coupled with weather measurements to identify the presence and type of storm.
10. Storm prediction must use a sampled interval of outages coupled with weather measurements to predict outage volumes.
11. Load estimation must take into account weather measurements provided from substations.

12. Auto reconfiguration must execute within 300 milliseconds.
13. Coordinated control must be able to work with ganged control devices, individual phase control devices, and multi-step devices, including multi-step capacitor banks.
14. Coordinated control, in CVR mode, must maintain customer level voltages at the primaries of distribution transformers above a user specified value.
15. Coordinated control, in either CVR or feeder efficiency modes, must switch to Maximum Capacity mode if low voltages or equipment overloads are detected.
16. The real-time applications must be easily extendable to work with solar generation, wind generation, storage devices, and EVs.
17. The auto-restoration application must operate correctly in the presence of islands.
18. All real-time functions must work seamlessly with selected middleware and within specified architectural design.

A.3.2.5 Software Development Process

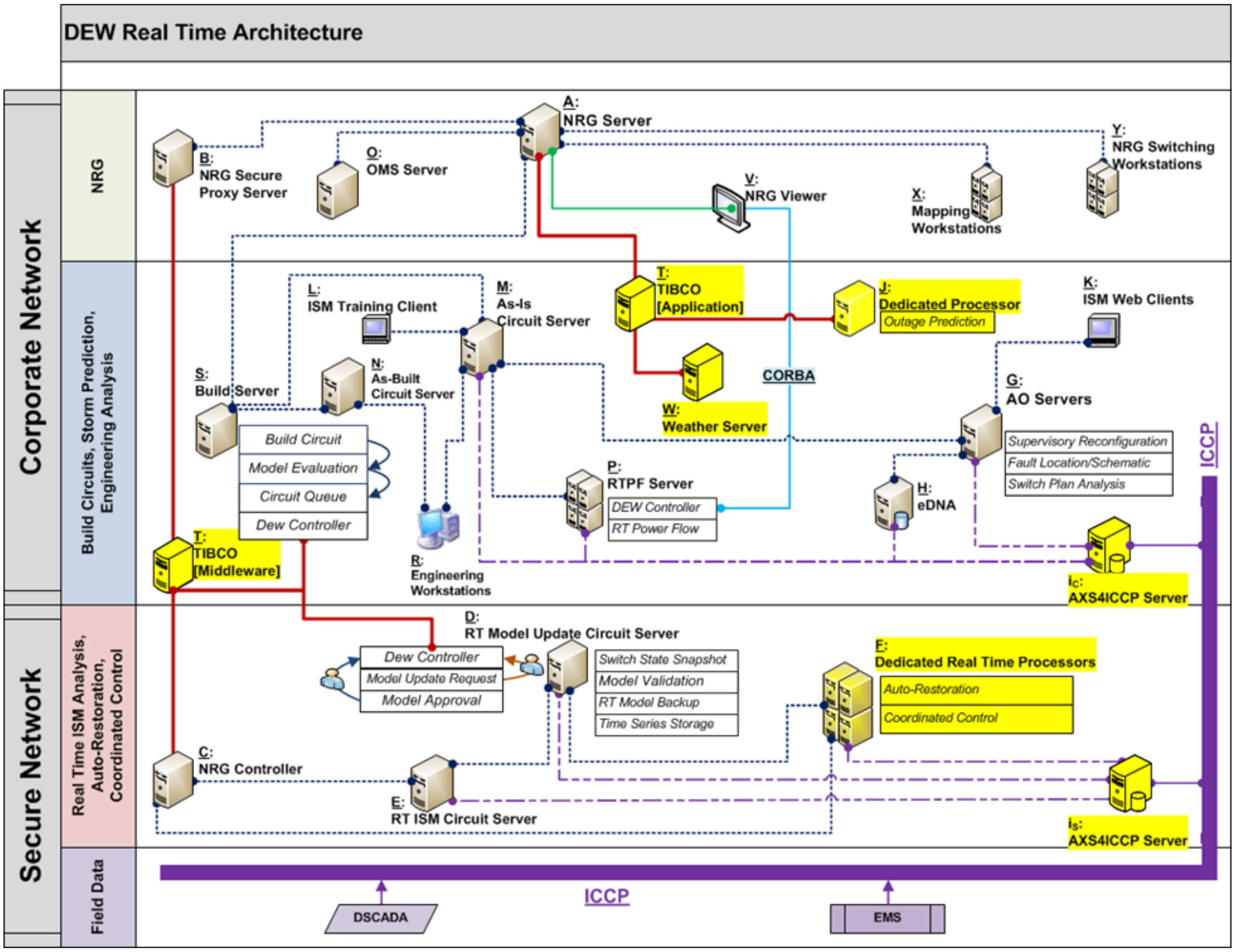
History

The software developed in this DOE project leverages previous efforts and is part of the development of O&R's Distribution Management System (DMS).

Development Process

The architecture for the real-time analysis and control hardware and software was established. This architecture defined the framework for the real time applications. The architecture defined the interfaces for each real time application. For communications between the secure network and the corporate network Inter-Control Center Communications Protocol (ICCP) communications was selected. For real time analysis and control application interfaces to EMS and DSCADA, Object Linking and Embedding (OLE) for Process Control (OPC) was selected. For interfaces to operator displays, Mico Corba was selected. TIBCO middleware was selected to simplify interoperability and enhance cyber security among systems. Figure A-10 illustrates the overall hardware/software architecture. The servers highlighted in yellow and communication paths shown in red are all part of this DOE project.

Figure A-10. O&R DMS Hardware/Software Architecture



Each software application was developed using an incremental, test driven process. O&R provided initial requirement specifications listed in Section 4 of this report. A prototype of the software was developed, tested by the software developers, and then tested by personnel independent of the developers. O&R personnel then reviewed the software, provided feedback on the software features, and a second phase of the software development was performed. This incremental, agile development process was continued until O&R was satisfied with the software features and operability.

To meet the O&R specifications, the following real time software capabilities were identified and developed:

1. EMS and DSCADA interfaces to ISM circuit server.
2. Instantiation of measurement driven, auto-restoration event process, where the planning reconfiguration for restoration application was encapsulated as a real-time application.
3. Coordinated control as measurement driven, continuous process, where the planning coordinated control application was encapsulated as a real-time application.
4. Storm identification as a measurement-driven application.

5. Outage volume prediction as a measurement-driven application with memory.
6. Real-time testing simulator that will be transitioned to a training simulator after the DOE project.

A.3.3 Testing Process

A.3.3.1 Control Systems Testing

A real-time simulator was developed for use in testing the auto-restoration and the coordinated control real time applications. The simulator uses the same communication interfaces as used in the production system. Thus, software that is successfully tested in this simulator environment can be directly moved into the production environment with no changes.

The following process was used for testing of the real-time analysis and control software developed for O&R.

1. Control Algorithm Implementation and Testing.
    a. Implement algorithm in a real-time simulator framework.
    b. Test real-time implementation using O&R pilot circuit models running in simulator.
2. Utility Real-Time Simulator and Lab Testing.
    a. Test control applications using pilot circuits running in real time simulator framework.
    b. Test production software in O&R SG Lab with end-to-end, hardware-in-the-loop simulation using production DSCADA system and production communication systems.
3. Utility Field Test (to be implemented): Test real-time control running on O&R's electric distribution system.

A.3.3.2 Storm Identification/Prediction Testing

A testing driver was set up to test the storm identification/prediction application. Figure A-11 and Figure A-12 show the software messages/interactions that were tested for the storm identification and storm outage prediction, respectively. Actual data for two storms was selected from the O&R historical storm database. One storm was a high-temperature storm whose outage data matched the expected high temperature storm model fairly well. The other storm, a high temperature-strong wind storm, was abnormal in that its outage data did not match well with the expected high-temperature-strong wind-storm model.

Figure A-11. Message Interaction for Storm Identification

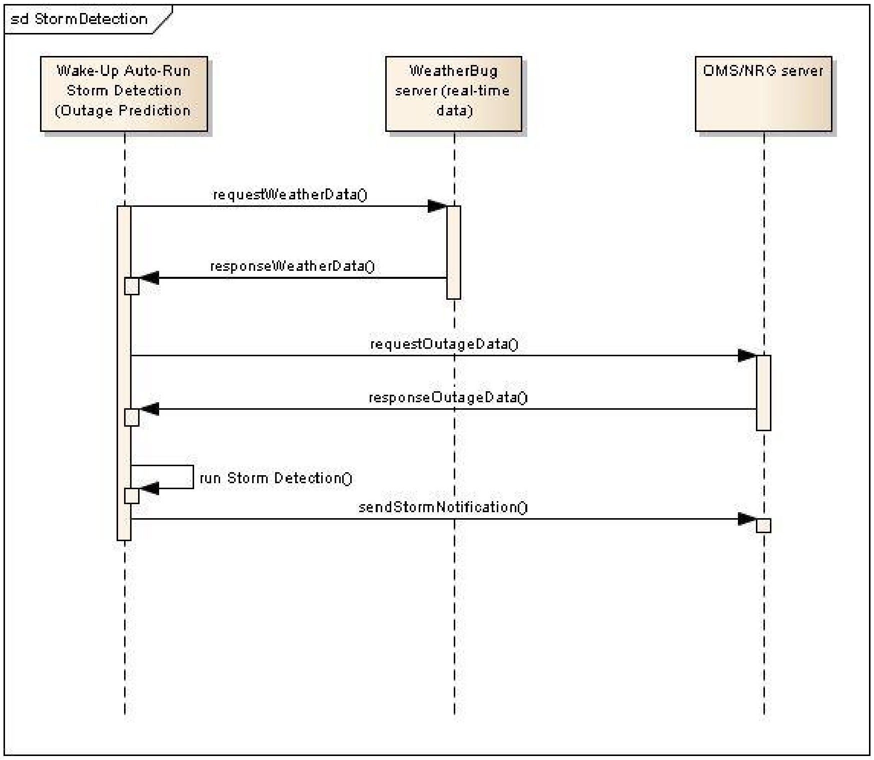
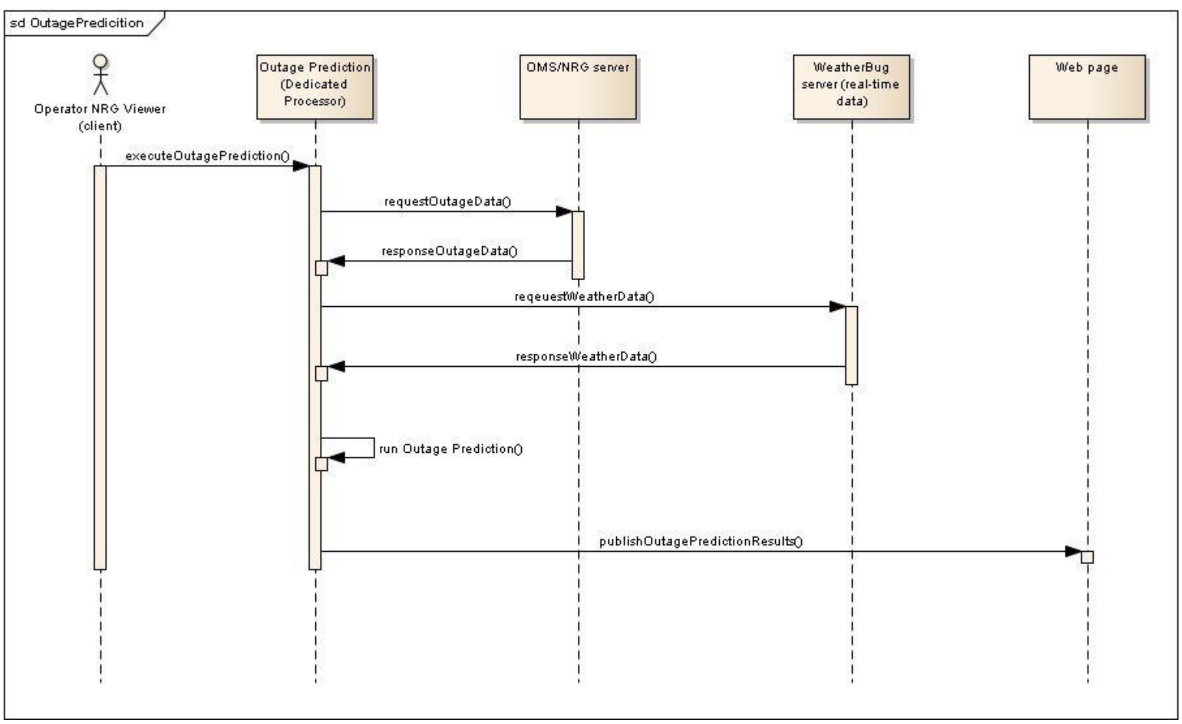


Figure A-12. Message Interactions for Storm Outage Prediction



A.3.3.3 *Testing Status*

The testing status is as follows:

1. The GIS integration to power flow modeling has been completed and tested (see TIBCO report for software development and testing).
2. The OMS interface to the storm prediction module is in the final iteration of testing. The storm prediction module is complete but is being modified to run as a Web service integrated with the TIBCO Middleware.
3. The DSCADA and EMS systems have been tied through ICCP interfaces to DEW control systems. These interfaces have been tested and have been reviewed by cyber security consultants for compliance with North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) requirements.
4. Cyber-security requirements have been fulfilled with a review of architecture and procedures performed by cyber security consultants.
5. The model-centric auto-restoration control system has been developed and tested on field hardware in a laboratory environment.
6. The model-centric coordinated VCC system has been developed and tested on the real-time simulator.
7. The coordinated VCC system will be tested in the O&R SG Lab with production software, production communication systems, and production DSCADA system in June 2013.

A.3.4 Demonstrations

A.3.4.1 *Auto-Restoration Control System*

The real time simulator will be used to demonstrate one or more complex restoration scenarios. Following the real-time simulator demonstration, the O&R SG Lab will be used to demonstrate one or more scenarios using actual automation hardware, communications, and production software. The lab demonstration setup and procedure are provided below.

Lab Demonstration Setup

1. Six control cabinets from distribution automation equipment are installed in O&R SG Lab.
2. Six geo-synched power supplies are setup and programmed to inject faults into the controls.
3. The controls are equipped with radios and RTUs and communicate with O&R's Spring Valley master radio site.
4. At the master radio site a gate-way communicates with O&R's SCADANET, a cyber-secure, private Internet Protocol (IP) system.
5. The data is back-hauled to concentrators in O&R's NERC CIP compliant, secure server room.
6. Within the O&R secure server room, Distributed Network Protocol (DNP3) over IP communications brings the data from the concentrators into O&R's EMS and DSCADA systems as appropriate.

7. ICCP connects the EMS/DSCADA data with the auto-restoration control system.

Lab Procedure

1. A fault is injected into the system by the geo-synched power supplies.
2. The automation equipment will clear the fault and communicate status and analog information to DSCADA.
3. The auto-restoration control system reads the change in status of the devices, checking downstream devices to determine the faulted line section.
4. The control system will isolate the fault by sending control signals to DSCADA operable devices to open.
5. The control system will restore customers on unfaulted line sections by sending control signals to the appropriate DSCADA operable devices to close.

A.3.4.2 Coordinated VVC System

The real time simulator will be used to demonstrate one or more complex coordinated VVC scenarios. Following the real time simulator demonstration, the O&R SG Lab will be used to demonstrate one or more scenarios using actual automation hardware, communications, and production software. Three modes of control will be demonstrated which are: 1-Conservation Voltage Reduction; 2-Optimum Feeder Efficiency; 3-Maximum Capacity.

The lab demonstration setup and procedure are provided below.

Lab Demonstration Setup

1. Controls for voltage regulating equipment and capacitor banks will be setup in the O&R SG Lab.
2. The controls are equipped with radios and Remote Terminal Units (RTUs) and communicate with O&R's Spring Valley master radio site.
3. At the master radio site a gate-way communicates with O&R's SCADANET, a cyber-secure, private IP system.
4. The data is back-hauled to concentrators in O&R's NERC CIP compliant, secure server room.
5. Within the O&R secure server room, DNP3 over IP communications brings the data from the concentrators into O&R's EMS and DSCADA systems as appropriate.
6. ICCP connects the EMS/DSCADA data with the coordinated control system.

Lab Procedure

1. The CVR control mode is selected.
2. Voltages and currents are injected as appropriate at the substation controller, the voltage regulator controller, and the capacitor bank controller.
3. The coordinated VVC system minimizes feeder voltage levels without creating any low customer voltages.

4. The Optimum Feeder Efficiency control mode is selected.
5. Voltages and currents are injected as appropriate at the substation controller, the voltage regulator controller, and the capacitor bank controller.
6. The coordinated VVC system adjusts feeder voltage levels to minimize feeder losses without violating any operating constraints.
7. The Maximum Capacity control mode is selected.
8. Voltages and currents are injected as appropriate at the substation controller, the voltage regulator controller, and the capacitor bank controller, where one of the voltages leads to a low customer voltage.
9. The coordinated VVC system adjusts feeder voltage levels to eliminate the low customer voltage.

A.3.4.3 Storm Identification/Outage Prediction System

The storm identification/outage prediction system was demonstrated using the software developed for testing the system. Storm data from an actual, high temperature-strong wind storm was used in the demonstration.

Using outage volume measurements and weather measurements, the storm identification algorithm may identify the onset of the storm and the type of storm.

As noted in section A3.1.3, to demonstrate this application, storm outages from O&R's storm outage database were used along with historical weather data. This historical data was fed into the system to simulate real-time receipt of the data and the output was visualized on the web page. Storm prediction was only 80% accurate, so clearly additional work is needed to determine when a storm has arrived and when the system should switch from determination to prediction mode. BNL was awarded a NYSERDA grant to study the use of Doppler Weather Radar for storm outage prediction. O&R will be working collaboratively with BNL on this project along with EDD, the developers of this software for O&R. This study has the potential for providing the means to significantly improve the accuracy of the storm detection portion of the software.

A.3.5 Supporting Documentation

O&R ISM design documentation, which includes:

- Use Cases
- Architecture
- Process Definitions

Storm identification/outage prediction documentation, which includes:

- Overview
- Process Descriptions
- Program Interfaces
- Data Storage

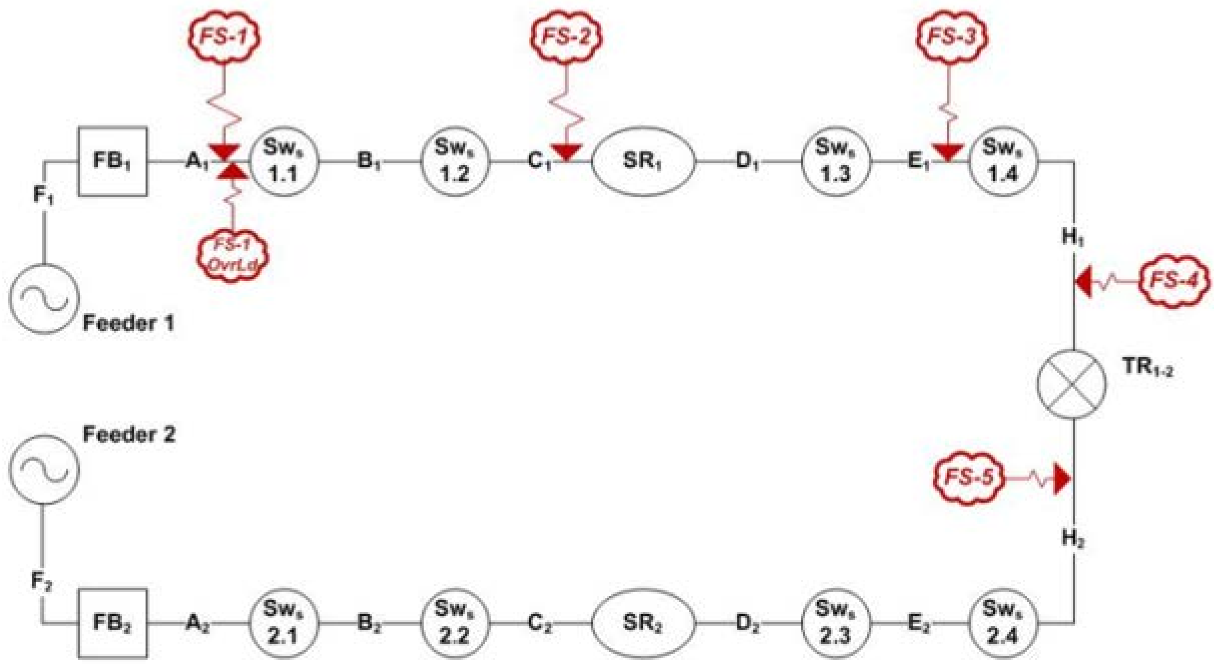
- Deployment Instructions

A.3.6 Auto-Restoration Scenarios

A.3.6.1 Real-Time Simulator Testing

Figure A-13 shows a schematic that is referred to by the scenarios presented in this appendix.

Figure A-13. Schematic Used in Auto-Restoration Scenarios



FS-1: Fault in Segment A_1, No Overload
Initial State: Circuit in normal operation, TR1-2 open, No faults, Reconfiguration control model fault, and switch operation flags cleared.

Table A-4. FS-1 Sequence of Events

Distribution System	ICCP Status & Control Signals	Reconfiguration Controller
Fault occurs in line segment A_1.		Watch for Feeder Breaker (FB) open signals Watch for fault indicator signals **Note**: FB do not send fault indicator signals.

Distribution System	ICCP Status & Control Signals	Reconfiguration Controller
FB_1 opens for fault SR_1 senses loss of voltage, starts LS timer TR_{1-2} senses loss of voltage, starts LS timer	Status FB_1 – Open (1)	Open FB_1 in model Start FB_1 lockout timer (70 sec)
FB_1 recloses in ½ second SR_1 loss of voltage timer resets TR_{1-2} loss of voltage timer resets	Status FB_1 – Closed (1)	Close FB_1 in model
FB_1 opens SR_1 senses loss of voltage, starts LS timer TR_{1-2} senses loss of voltage, starts LS timer	Status FB_1 – Open (1)	Open FB_1 in model
FB_1 recloses (15 sec typical) SR_1 loss of voltage timer resets TR_{1-2} loss of voltage timer resets	Status FB_1 – Closed (1)	Close FB_1 in model
FB_1 opens SR_1 senses loss of voltage, starts LS timer TR_{1-2} senses loss of voltage, starts LS timer	Status FB_1 – Open (1)	Open FB_1 in model
FB_1 recloses (30 sec typical) SR_1 loss of voltage timer resets TR_{1-2} loss of voltage timer resets	Status FB_1 – Closed (1)	Close FB_1 in model

Distribution System	ICCP Status & Control Signals	Reconfiguration Controller
FB_1 opens and locks out SR_1 senses loss of voltage, starts LS timer $TR_{1\text{-}2}$ senses loss of voltage, starts LS timer	Status FB_1 – Open (1)	Open FB_1 in model FB_1 watch timer times out Deem FB_1 to be open & Trip to Lockout Set fault flags: FB_1 Run Radial Reconfiguration: Generates switch operation list: Open: (1) $SWs_{1.1}$, (2) FB_1 Close: (3) $TR_{1\text{-}2}$ Block open: Radial reconfiguration: Sets switch operation flags Clears fault flags
		Generate control signals: Open $SWs_{1.1}$, FB_1 Close $TR_{1\text{-}2}$
	Control signal $SWs_{1.1}$ – Trip to Lockout Control signal FB_1 – Trip to Lockout	Set App Inhibit on isolation switches App Inhibit FB_1, $SWs_{1.1}$ Send isolation signals: Trip to Lockout FB_1 (Note FB1 already open) Trip to Lockout $SWs_{1.1}$ Verify FB_1 open. If not received in 5 sec generate Dew alarm. Watch for SWs1.1 to open. If not received in 5 sec generate Dew alarm.
FB_1 remains open $SWs_{1.1}$ opens	Status FB_1 – Open (1) Status $SWs_{1.1}$ – Recloser Open (1) Status $SWs_{1.1}$ – Control Lockout (1)	Open FB_1 in model Open $SWs_{1.1}$ in model
	Control signal $TR_{1\text{-}2}$ – Close	Send restoration signals: Close $TR_{1\text{-}2}$ Watch for $TR_{1\text{-}2}$ close. If not received in 5 sec generate Dew alarm.
$TR_{1\text{-}2}$ closes	Status $TR_{1\text{-}2}$ – Recloser Closed (1)	Close $TR_{1\text{-}2}$ in model
		Automated reconfiguration complete

FS-1 Overload: Fault in Segment A_1, With Overload on Segment A_2
Initial State: Circuit in normal operation, TR_{1-2} open, No faults, Reconfiguration control model fault, and switch operation flags cleared.

Table A-5. FS-1 Overload Sequence of Events

Distribution System	ICCP Status & Control Signals	Reconfiguration Controller
Fault occurs in line segment A_1.		Watch for FB open signals Watch for fault indicator signals **Note**: Feeder breakers do not send fault indicator signals.
FB_1 opens for fault SR_1 senses loss of voltage, starts LS timer TR_{1-2} senses loss of voltage, starts LS timer	Status FB_1 – Open (1)	Open FB_1 in model Start FB_1 lockout timer (70 sec)
FB_1 recloses in ½ second SR_1 loss of voltage timer resets TR_{1-2} loss of voltage timer resets	Status FB_1 – Closed (1)	Close FB_1 in model
FB_1 opens SR_1 senses loss of voltage, starts LS timer TR_{1-2} senses loss of voltage, starts LS timer	Status FB_1 – Open (1)	Open FB_1 in model
FB_1 recloses (15 sec typical) SR_1 loss of voltage timer resets TR_{1-2} loss of voltage timer resets	Status FB_1 – Closed (1)	Close FB_1 in model
FB_1 opens SR_1 senses loss of voltage, starts LS timer TR_{1-2} senses loss of voltage, starts LS timer	Status FB_1 – Open (1)	Open FB_1 in model
FB_1 recloses (30 sec typical) SR_1 loss of voltage timer resets TR_{1-2} loss of voltage timer resets	Status FB_1 – Closed (1)	Close FB_1 in model

Distribution System	ICCP Status & Control Signals	Reconfiguration Controller
FB$_1$ opens and locks out SR$_1$ senses loss of voltage, starts LS timer TR$_{1-2}$ senses loss of voltage, starts LS timer	Status FB$_1$ – Open (1)	Open FB$_1$ in model FB$_1$ watch timer times out Deem FB$_1$ to be open & Trip to Lockout Set fault flags: FB$_1$ Run Radial Reconfiguration: Generates switch operation list: Open: (1) SWs$_{1.1}$, (2) FB$_1$ Close: Block open: (3) TR$_{1-2}$ Radial reconfiguration: Sets switch operation flags Clears fault flags
		Generate control signals: Open SWs$_{1.1,}$ FB$_1$ Block open TR$_{1-2}$
	Control signal SWs$_{1.1}$ – Trip to Lockout Control signal FB$_1$ – Trip to Lockout Control signal TR$_{1-2}$ – Source I Disable Control signal TR$_{1-2}$ – Source II Disable	Set App Inhibit on isolation switches App Inhibit FB$_{1,}$ SWs$_{1.1}$ Send isolation signals: Open SWs$_{1.1,}$ FB$_1$ Block open TR$_{1-2}$ Verify FB$_1$ open. If not received in 5 sec generate Dew alarm Watch for SWs1.1 to open. If not received in 5 sec generate Dew alarm. Watch for TR1-2 to block open. If not received in 5 sec generate Dew alarm.
FB$_1$ remains open SWs$_{1.1}$ opens TR$_{1-2}$ blocked open	Status FB$_1$ – Open (1) Status SWs$_{1.1}$ - Recloser Open (1) Status SWs$_{1.1}$ – Control Lockout (1) Status TR$_{1-2}$ – Source I Status (0) Status TR$_{1-2}$ – Source II Status (0)	Open FB$_1$ in model Open SWs$_{1.1}$ in model Open TR$_{1-2}$ in model
		Send restoration signals: None

Distribution System	ICCP Status & Control Signals	Reconfiguration Controller
		Automated reconfiguration complete

FS-2: Fault in Segment C_1, No Overload
Initial State: Circuit in normal operation, TR_{1-2} open, No faults, Reconfiguration control model fault, and switch operation flags cleared.

Table A-6. FS-2 Sequence of Events

Distribution System	ICCP Status & Control Signals	Reconfiguration Controller
Fault occurs in line segment C_1.		Watch for FB open signals Watch for fault indicator signals **Note**: Feeder breakers do not send fault indicator signals.
FB_1 opens for fault SR_1 senses loss of voltage, starts LS timer TR_{1-2} senses loss of voltage, starts LS timer	Status FB_1 – Open (1) Status SWs $_{1.1}$ Phase A Fault Indicator (1) Status SWs $_{1.1}$ Phase B Fault Indicator (1) Status SWs $_{1.1}$ Phase C Fault Indicator (1) Status SWs $_{1.2}$ Phase A Fault Indicator (1) Status SWs $_{1.2}$ Phase B Fault Indicator (1) Status SWs $_{1.2}$ Phase C Fault Indicator (1)	Open FB_1 in model Start FB_1 lockout timer (70 sec)
FB_1 recloses in ½ second SR_1 loss of voltage timer resets TR_{1-2} loss of voltage timer resets	Status FB_1 – Closed (1)	Close FB_1 in model
FB_1 opens SR_1 senses loss of voltage, starts LS timer TR_{1-2} senses loss of voltage, starts LS timer	Status FB_1 – Open (1)	Open FB_1 in model
FB_1 recloses (15 sec typical) SR_1 loss of voltage timer resets TR_{1-2} loss of voltage timer resets	Status FB_1 – Closed (1)	Close FB_1 in model

Distribution System	ICCP Status & Control Signals	Reconfiguration Controller
FB_1 opens SR_1 senses loss of voltage, starts LS timer TR_{1-2} senses loss of voltage, starts LS timer	Status FB_1 – Open (1)	Open FB_1 in model
FB_1 recloses (30 sec typical) SR_1 loss of voltage timer resets TR_{1-2} loss of voltage timer resets	Status FB_1 – Closed (1)	Close FB_1 in model
FB_1 opens and locks out SR_1 senses loss of voltage, starts LS timer TR_{1-2} senses loss of voltage, starts LS timer	Status FB_1 – Open (1)	Open FB_1 in model FB_1 watch timer times out Deem FB_1 to be open & locked Set fault flags: FB_1, $SWs_{1.1}$, $SWs_{1.2}$ Run Radial Reconfiguration Generates switch operation list: Open: (1) $SWs_{1.2}$, (2) SR_1 Close: (3) TR_{1-2} (4) FB_1 Block open: Radial reconfiguration: Sets switch operation flags Clears fault flags
		Generate control signals: Open $SWs_{1.2}$, SR_1 Close TR_{1-2}, FB_1 Clear switch operation flags
	Control signal $SWs_{1.1}$ – Trip to Lockout Control signal SR_1 – Trip to Lockout	Set App Inhibit on isolation switches App Inhibit $SWs_{1.2}$, SR_1 Send isolation signals: Open $SWs_{1.2}$, SR_1 Watch for $SWs_{1.2}$ to open. If not received in 5 sec generate Dew alarm. Watch for SR1 to open. If not received in 5 sec generate Dew alarm.

Distribution System	ICCP Status & Control Signals	Reconfiguration Controller
$SWs_{1.1}$ Opens SR_1 Opens	Status $SWs_{1.1}$ – Recloser Open (1) Status $SWs_{1.1}$ – Control Lockout (1) Status SR_1 – Recloser Open (1) Status SR_1 – Control Lockout (1)	Open $SWs_{1.1}$ in model Open SR_1 in model
		Send restoration signals: Close TR_{1-2}, FB_1
	Control signal TR_{1-2} – Close Control signal FB_1 – Close	Watch for TR_{1-2} close. If not received in 5 sec generate Dew alarm Watch for FB1 close. If not received in 5 sec generate Dew alarm
TR_{1-2} closes FB_1 closes	Status TR_{1-2} – Recloser Closed (1) Status FB_1 – Circuit Breaker Closed (1)	Close TR_{1-2} in model Close FB_1 in model
		Automated reconfiguration complete

FS-3: Fault in Segment E_1, No Overload
Initial State: Circuit in normal operation, TR_{1-2} open, No faults, Reconfiguration control model fault, and switch operation flags cleared.

Table A-7. FS-3 Sequence of Events

Distribution System	ICCP Status & Control Signals	Dew Reconfiguration Controller/Model
Fault occurs in line segment E_1.		Watch for FB open signals Watch for fault indicator signals **Note**: Feeder breakers do not send fault indicator signals.

Distribution System	ICCP Status & Control Signals	Dew Reconfiguration Controller/Model
SR_1 opens (overcurrent trip) $TR_{1\text{-}2}$ senses loss of voltage, starts LS timer	Status SR_1 – Recloser Open (1) Status SR_1 Phase A Fault Trip (1) Status SR_1 Phase B Fault Trip (1) Status SR_1 Phase C Fault Trip (1) Status SWs $_{1.3}$ Phase A Fault Indicator (1) Status SWs $_{1.3}$ Phase B Fault Indicator (1) Status SWs $_{1.3}$ Phase C Fault Indicator (1) Status SWs $_{1.2}$ Phase A Fault Indicator (1) Status SWs $_{1.2}$ Phase B Fault Indicator (1) Status SWs $_{1.2}$ Phase C Fault Indicator (1) Status SWs $_{1.1}$ Phase A Fault Indicator (1) Status SWs $_{1.1}$ Phase B Fault Indicator (1) Status SWs $_{1.1}$ Phase B Fault Indicator (1)	Open SR_1 in model
SR_1 recloses in ½ second $TR_{1\text{-}2}$ loss of voltage timer resets	Status SR_1 – Recloser Closed (1)	Close SR_1 in model
SR_1 opens $TR_{1\text{-}2}$ senses loss of voltage, starts LS timer	Status SR_1 – Recloser Open (1)	Open SR_1 in model
SR_1 recloses (17 sec typical) $TR_{1\text{-}2}$ loss of voltage timer resets	Status SR_1 – Recloser Closed (1)	Close SR_1 in model
SR_1 opens $TR_{1\text{-}2}$ senses loss of voltage, starts LS timer	Status SR_1 – Recloser Open (1)	Open SR_1 in model
SR_1 recloses (32 sec typical) $TR_{1\text{-}2}$ loss of voltage timer resets	Status SR_1 – Recloser Closed (1)	Close SR_1 in model

Distribution System	ICCP Status & Control Signals	Dew Reconfiguration Controller/Model
SR_1 opens and locks out $TR_{1\text{-}2}$ senses loss of voltage, starts LS timer	Status SR_1 – Recloser Open (1) Status SR_1 – Control Lockout (1)	Open SR_1 in model Set fault flags: $SWs_{1.3}$, SR_1, $SWs_{1.2}$, $SWs_{1.1}$ Run Radial Reconfiguration: Generates switch operation list: Open: (1) $SWs_{1.3}$, (2) $SWs_{1.4}$ Close: (3) $TR_{1\text{-}2}$, (4) SR_1 Block open: Radial reconfiguration: Sets switch operation flags Clears fault flags
		Generate control signals: Open $SWs_{1.3}$, $SWs_{1.4}$ Close $TR_{1\text{-}2}$, SR_1 Clear switch operation flags
	Control signal $SWs_{1.3}$ – Trip to Lockout Control signal $SWs_{1.4}$ – Trip to Lockout	Set App Inhibit on isolation switches Inhibit $SWs_{1.3}$, $SWs_{1.4}$ Send isolation signals: Open $SWs_{1.3}$, $SWs_{1.4}$ Watch for $SWs_{1.3}$ to open. If not received in 5 sec generate Dew alarm. Watch for $SWs_{1.4}$ to open. If not received in 5 sec generate Dew alarm.
$SWs_{1.3}$ opens $SWs_{1.4}$ opens	Status $SWs_{1.3}$ – Recloser Open (1) Status $SWs_{1.3}$ – Control Lockout (1) Status $SWs_{1.4}$ – Recloser Open (1) Status $SWs_{1.4}$ – Control Lockout (1)	Open $SWs_{1.3}$ in model Open $SWs_{1.4}$ in model
		Send restoration signals: Close $TR_{1\text{-}2}$, SR_1

Distribution System	ICCP Status & Control Signals	Dew Reconfiguration Controller/Model
	Control signal TR_{1-2} – Close	Watch for TR_{1-2} to close. If not received in 5 sec generate Dew alarm. Watch for SR_1 to close. If not received in 5 sec generate Dew alarm.
TR_{1-2} closes	Status TR_{1-2} – Recloser Closed (1)	Close TR_{1-2} in model
SR_1 closes	Status SR_1 – Recloser Closed (1)	Close SR_1 in model
		Automated reconfiguration complete

FS-4: Fault in Segment H_1, No Overload

Initial State: Circuit in normal operation. TR_{1-2} open. No faults. Reconfiguration control set to let reclosers operate and lock.

Table A-8. FS-4 Sequence of Events

Distribution System	ICCP Status & Control Signals	Dew Reconfiguration Controller/Model
Fault occurs in line segment H_1		Watch for FB open signals Watch for fault indicator signals **Note**: Feeder breakers do not send fault indicator signals.
SR_1 opens (overcurrent trip) TR_{1-2} senses loss of voltage, starts LS timer	Status SR_1 – Recloser Open (1) Status SR_1 Phase A Fault Trip (1) Status SR_1 Phase B Fault Trip (1) Status SR_1 Phase C Fault Trip (1) Status SWs $_{1.4}$ Phase A Fault Indicator (1) Status SWs $_{1.4}$ Phase B Fault Indicator (1) Status SWs $_{1.4}$ Phase C Fault Indicator (1) Status SWs $_{1.3}$ Phase A Fault Indicator (1) Status SWs $_{1.3}$ Phase B Fault Indicator (1) Status SWs $_{1.3}$ Phase C Fault Indicator (1) Status SWs $_{1.2}$ Phase A Fault Indicator (1) Status SWs $_{1.2}$ Phase B Fault Indicator (1) Status SWs $_{1.2}$ Phase C Fault Indicator (1) Status SWs $_{1.1}$ Phase A Fault Indicator (1) Status SWs $_{1.1}$ Phase B Fault Indicator (1) Status SWs $_{1.1}$ Phase B Fault Indicator (1)	Open SR_1 in model
SR_1 recloses in ½ second TR_{1-2} loss of voltage timer resets	Status SR_1 – Recloser Closed (1)	Close SR_1 in model
SR_1 opens TR_{1-2} senses loss of voltage, starts LS timer	Status SR_1 – Recloser Open (1)	Open SR_1 in model
SR_1 recloses (17 sec typical) TR_{1-2} loss of voltage timer resets	Status SR_1 – Recloser Closed (1)	Close SR_1 in model
SR_1 opens TR_{1-2} senses loss of voltage, starts LS timer	Status SR_1 – Recloser Open (1)	Open SR_1 in model
SR_1 recloses (32 sec typical) TR_{1-2} loss of voltage timer resets	Status SR_1 – Recloser Closed (1)	Close SR_1 in model

Distribution System	ICCP Status & Control Signals	Dew Reconfiguration Controller/Model
SR_1 opens and locks out TR_{1-2} senses loss of voltage, starts LS timer	Status SR_1 – Recloser Open (1) Status SR_1 – Control Lockout (1)	Open SR_1 in model Set fault flags: $SWs_{1.4}$, $SWs_{1.3}$, SR_1, $SWs_{1.2}$, $SWs_{1.1}$ Run Radial Reconfiguration: Radial reconfiguration generates switch operation list: Open: (1) $SWs_{1.4}$, (2) TR_{1-2} Close: (3) SR_1 Block open: Radial reconfiguration: Sets switch operation flags Clears fault flags
		Generate control signals: Open $SWs_{1.4}$ Block open TR_{1-2} Clear switch operation flags
	Control signal $SWs_{1.4}$ – Trip to Lockout Control signal TR_{1-2} – Source I Disable Control signal TR_{1-2} – Source II Disable	Set App Inhibit on isolation switches Inhibit $SWs_{1.4}$, TR_{1-2} Send isolation signals: Open $SWs_{1.4}$, Block open TR_{1-2} Watch for $SWs_{1.4}$ to open. If not received in 5 sec generate Dew alarm. Watch for TR_{1-2} to block open. If not received in 5 sec generate Dew alarm.
$SWs_{1.4}$ opens TR_{1-2} blocked open	Status $SWs_{1.4}$ - Recloser Open (1) Status $SWs_{1.4}$ – Control Lockout (1) Status TR_{1-2} – Source I Status (0) Status TR_{1-2} – Source II Status (0)	Open $SWs_{1.4}$ in model Open TR_{1-2} in model
		Send restoration signals: Close SR_1

Distribution System	ICCP Status & Control Signals	Dew Reconfiguration Controller/Model
	Control signal SR_1 – Close	Watch for SR_1 to close. If not received in 5 sec generate Dew alarm.
SR_1 closes	Status SR_1 – Recloser Closed (1)	Close SR_1 in model
		Automated reconfiguration complete

FS-5: Fault in Segment H_2, No Overload
Initial State: Circuit in normal operation, TR_{1-2} open, No faults, Reconfiguration control model fault, and switch operation flags cleared.

Table A-9. FS-5 Sequence of Events

Distribution System	ICCP Status & Control Signals	Dew Reconfiguration Controller/Model
Fault occurs in line segment H_2		Watch for FB open signals Watch for fault indicator signals **Note**: Feeder breakers do not send fault indicator signals.
SR_2 opens (overcurrent trip) TR_{1-2} senses loss of voltage, starts LS timer	Status SR_2 – Recloser Open (1) Status SR_2 Phase A Fault Trip (1) Status SR_2 Phase B Fault Trip (1) Status SR_2 Phase C Fault Trip (1) Status SWs $_{2.4}$ Phase A Fault Indicator (1) Status SWs $_{2.4}$ Phase B Fault Indicator (1) Status SWs $_{2.4}$ Phase C Fault Indicator (1) Status SWs $_{2.3}$ Phase A Fault Indicator (1) Status SWs $_{2.3}$ Phase B Fault Indicator (1) Status SWs $_{2.3}$ Phase C Fault Indicator (1) Status SWs $_{2.2}$ Phase A Fault Indicator (1) Status SWs $_{2.2}$ Phase B Fault Indicator (1) Status SWs $_{2.2}$ Phase C Fault Indicator (1) Status SWs $_{2.1}$ Phase A Fault Indicator (1) Status SWs $_{2.1}$ Phase B Fault Indicator (1) Status SWs $_{2.1}$ Phase B Fault Indicator (1)	Open SR_2 in model
SR_2 recloses in ½ second TR_{1-2} loss of voltage timer resets	Status SR_2 – Recloser Closed (1)	Close SR_2 in model
SR_2 opens TR_{1-2} senses loss of voltage, starts LS timer	Status SR_2 – Recloser Open (1)	Open SR_2 in model
SR_2 recloses (17 sec typical) TR_{1-2} loss of voltage timer resets	Status SR_2 – Recloser Closed (1)	Close SR_2 in model

Distribution System	ICCP Status & Control Signals	Dew Reconfiguration Controller/Model
SR_2 opens TR_{1-2} senses loss of voltage, starts LS timer	Status SR_2 – Recloser Open (1)	Open SR_2 in model
SR_2 recloses (32 sec typical) TR_{1-2} loss of voltage timer resets	Status SR_2 – Recloser Closed (1)	Close SR_2 in model
SR_2 opens and locks out TR_{1-2} senses loss of voltage, starts LS timer	Status SR_1 – Recloser Open (1) Status SR_1 – Control Lockout (1)	Set SR_2 open Set fault flags: $SWs_{2.4}$, $SWs_{2.3}$, SR_2, $SWs_{2.2}$, $SWs_{2.1}$ Run Radial Reconfiguration: Generates switch operation list: Open: (1) $SWs_{2.4,}$ (2) TR_{1-2} Close: (2) SR_2 Block open: Radial reconfiguration: Sets switch operation flags Clears fault flags
		Generate control signals: Open $SWs_{2.4}$ Block open TR_{1-2} Clear switch operation flags
	Control signal $SWs_{2.4}$ – Trip to Lockout Control signal TR_{1-2} – Source I Disable Control signal TR_{1-2} – Source II Disable	Set App Inhibit on isolation switches Inhibit $SWs_{2.4,}$ TR_{1-2} Send isolation signals: Open $SWs_{2.4}$ Block open TR_{1-2} Watch for $SWs_{2.4}$ to open. If not received in 5 sec generate Dew alarm. Watch for TR_{1-2} block to open. If not received in 5 sec generate Dew alarm.
$SWs_{2.4}$ opens TR_{1-2} blocked open	Status $SWs_{2.1}$ - Recloser Open (1) Status $SWs_{1.1}$ – Control Lockout (1) Status TR_{1-2} – Source I Status (0) Status TR_{1-2} – Source II Status (0)	Open $SWs_{2.4}$ in model Open TR_{1-2} in model
		Send restoration signals: Close SR_2
	Control signal SR_2 – Close	Watch for SR_2 to close. If not received in 5 sec generate Dew alarm.
SR_2 closes	Status SR_2 – Recloser Closed (1)	Close SR_2 in model

Distribution System	ICCP Status & Control Signals	Dew Reconfiguration Controller/Model
		Automated reconfiguration complete

A.3.6.2 Auto-Restoration O&R SG Lab Test Results

The Auto-Restoration test consists of six Reclosers in the lab environment which correlate with a Breaker and five Reclosers in a DEW model. This model represents a circuit in the O&R distribution system. These units communicate through DigitaLogic IGIN units and master radio to the DSCADA server. Specific status points are forwarded to the DEW simulation server by ICCP and OPC servers. Omicron test units are coordinated by Global Positioning System (GPS) synchronization and supply fault currents and appropriate states to each of the Recloser controllers.

The devices are connected in series from the breaker, Sectionalizing Recloser (SR1), Counting Recloser (CR1), Midpoint Recloser (MR1),), Sectionalizing Recloser (SR2), and Tie Recloser (TR1). All are initially closed, except for TR1, which is open and configured with Line Side Reset (LSR).

The tests consist of programmed plans in the Omicron test units to inject faults between each of the Reclosers. Switch status changes and Device Lock-Out flags are evaluated by DEW, an Auto-Restoration solution is calculated, and commands are systematically sent to the sectionalizing Devices, while switch status changes are monitored, and opened switches are flagged in the model for non-operation. The non-operational flags in the model ensure that DEW will not consider closing the switches for a next event until they are cleared by an operational close command. Table A-5 shows the results of the five lab tests.

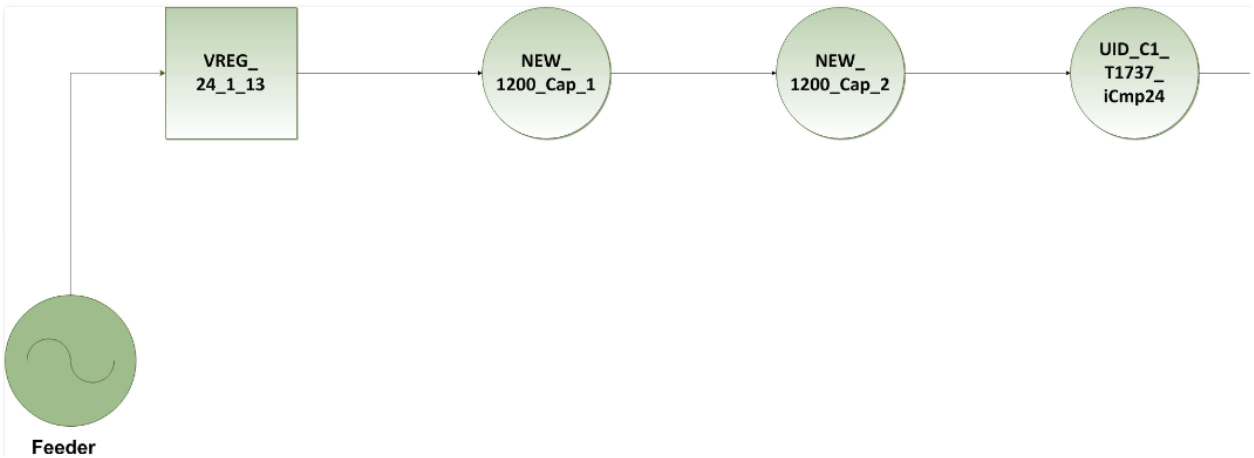
Table A-10. Results of Auto-Restoration Tests in SG Lab

Fault Action	Expected Result	Result Pass / Fail
Fault between breaker and SR1	Breaker Open, Locked-Out ; Commands: Open SR1; Close TR1	Pass
Fault between SR1 and CR1	Breaker Trip/Reclose; SR1 Open Locked-Out; Commands: Open CR1; Close TR1	Pass
Fault between CR1 and MR1	Breaker Trip/Reclose; SR1 Open Locked-Out; Commands: Open MR1 Open; CR1; Close SR1; Close TR1	Pass
Fault between MR1 and CR2	Breaker Trip/Reclose; SR1 Open Locked-Out; Commands: Open MR1; Open CR2; Close SR1; Close TR1	Pass
Fault between CR2 and TR1	Breaker Trip/Reclose; SR1 Open Locked-Out; Commands: Open CR2; Close SR1	Pass

A.3.7 Coordinated VVC Test Scenarios

Figure A-14 shows a schematic that is referred to from the scenarios presented in this appendix.

Figure A-14. Schematic Used in Coordinated Control Scenarios



A.3.7.1 Scenario 1: Low Load Point

Date/Time: January 5, 2013, 2 a.m.
Feeder Amps: 24-1-13 Feeder settings at 170 Amps
Sub-Transformer Voltage: 24-1-13 at 120 Volts
Config File: Lower Limit 100%, Upper Limit 110%, Efficiency Mode
Iteration Steps:

1. New_1200_CAP_2 Set to 1
2. Set Feeder to 175, NEW_1200_CAP_1 Set to 1
3. Set Feeder to 170, UID_C1_T1737_ICmp24 Set to 1
4. Set Feeder to 160, VREG_24_1_13 Set to 1
5. Set Feeder to 170, VREG_24_1_13 Set to 2
6. Set Feeder to 160, VREG_24_1_13 Set to 3
7. Set Feeder to 170, VREG_24_1_13 Set to 4
8. Set Feeder to 160, VREG_24_1_13 Set to 5
9. Set Feeder to 170, VREG_24_1_13 Set to 6
10. Set Feeder to 160, no violations to improve
11. Set Feeder to 170, no violations to improve

A.3.7.2 Scenario 2: Artificially Extreme Low Load Point

Date/Time: January 5, 2013, 2 a.m.
Feeder Amps: 24-1-13 Feeder settings at 15 Amps
Sub-Transformer Voltage: 24-1-13 at 120 Volts

Config File: Lower Limit 100%, Upper Limit 110%, Efficiency Mode
Iteration Steps:

1. New_1200_CAP_2 Set to 1
2. Set Feeder to 10 Amps, UID_C1_T1737_ICmp24 Set to 1
3. Set Feeder to 5 Amps, VREG_24_1_13 Set to 1
4. Set Feeder to 10 Amps, VREG_24_1_13 Set to 2
5. Set Feeder to 5 Amps, VREG_24_1_13 Set to 3
6. Set Feeder to 10 Amps, VREG_24_1_13 Set to 4
7. Set Feeder to 5 Amps, VREG_24_1_13 Set to 5
8. Set Feeder to 10 Amps, VREG_24_1-13 Set to 6

A.3.7.3 Scenario 3: High Load Point

Date/Time: July 4, 2013, 5 p.m.
Feeder Amps: 24-1-13 Feeder settings at 170 Amps
Sub-Transformer Voltage: 24-1-13 at 120 Volts
Config File: Lower Limit 100%, Upper Limit 110%, Efficiency Mode
Iteration Steps:

1. New_1200_CAP_2 Set to 1
2. Set Feeder to 180, NEW_1200_CAP_1 Set to 1
3. Set Feeder to 190, UID_C1_T1737_ICmp24 Set to 1
4. Set Feeder to 200, VREG_24_1_13 Set to 1
5. Set Feeder to 210, VREG_24_1_13 Set to 2
6. Set Feeder to 220, VREG_24_1_13 Set to 3
7. Set Feeder to 230, VREG_24_1_13 Set to 4
8. Set Feeder to 220, VREG_24_1_13 Set to 5
9. Set Feeder to 230, VREG_24_1_13 Set to 6
10. Set Feeder to 220, VREG_24_1_13 Set to 7
11. Set Feeder to 230, VREG_24_1_13 Set to 8
12. Set Feeder to 220, VREG_24_1_13 Set to 9
13. Set Feeder to 230, VREG_24_1_13 Set to 10
14. Set Feeder to 220, VREG_24_1_13 Set to 11
15. Set Feeder to 230, VREG_24_1_13 Set to 10
16. Set Feeder to 220, VREG_24_1_13 Set to 11
17. Set Feeder to 230, VREG_24_1_13 Set to 10

A.3.7.4 Scenario 4: High Load Point change to Low Load Point

Date/Time: January 5, 2013, 2 a.m.
Feeder Amps: 24-1-13 Feeder settings at 150 Amps
Sub-Transformer Voltage: 24-1-13 at 120 Volts
Config File: Lower Limit 100%, Upper Limit 110%, Efficiency Mode
Caps: Cap_1, CAP_2 and ICMP24 all set to 1 initially.
Iteration Steps:

1. Set Feeder to 150, VREG_24_1_13 Set to 1
2. Set Feeder to 170, VREG_24_1_13 Set to 2
3. Set Feeder to 180, VREG_24_1_13 Set to 3
4. Set Feeder to 170, VREG_24_1_13 Set to 4
5. Set Feeder to 160, no update
6. Set Feeder to 150, no update
7. Set Feeder to 100, UID_C1_T1737_ICMP24 Cap set to 0

A.3.7.5 Scenario 5: Customer Voltage Regulation Prioritized

Date/Time: January 5, 2013, 2 a.m.
Feeder Amps: 24-1-13 Feeder settings at 150 Amps
Sub-Transformer Voltage: 24-1-13 at 120 Volts
Config File: Lower Limit 93%, Upper Limit 96%, Voltage Mode
Iteration Steps:

1. Set Feeder to 150, VREG_24_1_13 Set to -1
2. Set Feeder to 160, VREG_24_1_13 Set to -2
3. Set Feeder to 170, VREG_24_1_13 Set to -3
4. Set Feeder to 180, VREG_24_1_13 Set to -4
5. Set Feeder to 200, VREG_24_1_13 Set to -5
6. Set Feeder to 220, UID_C1_T1737_ICmp24 Cap set to 1
7. Set Feeder to 250, no update

A.3.8 NIST Cyber-Security Requirements

NIST has outlined guidelines for SG Cyber Security. Each security requirement is allocated to one of three categories: governance, risk, and compliance (GRC), common technical or unique technical. The intent of the GRC requirements is to have them addressed at the organization level. It may be necessary to augment these organization-level requirements for specific logical interface categories and/or SG information systems. The common technical requirements are applicable to all of the logical interface categories. The unique technical requirements are allocated to one or more of the logical interface categories. The common and unique technical requirements should be allocated to each SG system and not necessarily to every component within a system, as the focus is on security at the system level.

Each organization must develop security architecture for each SG information system and allocate security requirements to components/devices. SG security policy can be included as part of the general information security policy for the organization. However, procedures can be developed for the security program in general and for a particular SG information system when required.
For the Logical Reference Model, NIST categorizes the SG into seven domains: Transmission, Distribution, Operations, Bulk Generation, Markets, Customers and Service Provider. A domain is a high-level grouping of actors with similar objectives relying on or participating in similar types of applications. Actors are devices, systems or programs that make decisions and exchange information necessary for executing applications within the SG. The interactions between different NIST actors are further defined by logical interfaces, which are grouped by category, based on common attributes for security requirements.

The following two tables extract the actors and logical interfaces defined by the NIST guidelines that are applicable for the O&R SG implementation with DEW. For example, the interaction between NRG and DEW corresponds with the NIST defined interaction between the GIS (actor-17) and the DMS (actor-27) utilizing the logical interface "U102", found in logical interface category #2.

Table A-11. Actor Descriptions for Logical Reference Model

Actor Number	Domain	Actor	Abbreviation	Description
15	Distribution	Distribution Remote Terminal Unit/Intelligent Electronic Device	RTUs or IEDs	Receive data from sensors and power equipment, and can issue control commands, such as tripping circuit breakers, if they sense voltage, current, or frequency anomalies, or raise/lower voltage levels in order to maintain the desired level.
17	Distribution	GIS	NRG	A spatial asset management system that provides utilities with asset information and network connectivity for advanced applications.
26	Operations	Distribution Engineering	DEW (planning)	A technical function of planning or managing the design or upgrade of the distribution system. For example: • The addition of new customers • The build-out for new load • The configuration and/or capital investments for improving system reliability.
27	Operations	DMS	DEW (operations)	A suite of application software that supports electric system operations. Example applications include topology processor, online three-phase unbalanced distribution power flow, contingency analysis, study mode analysis, switch order management, short-circuit analysis, volt-var management, and loss analysis. These applications provide operations staff and engineering personnel additional information and tools to help accomplish their objectives.
28	Operations	Distribution Operator	DO	Person operating the distribution system.
29	Operations	Distribution Supervisory Control and Data Acquisition	DSCADA	A type of control system that transmits individual device status, manages energy consumption by controlling compliant devices, and allows operators to directly control power system equipment.

Actor Number	Domain	Actor	Abbreviation	Description
30	Operations	EMS	EMS	A system of computer-aided tools used by operators of electric utility grids to monitor, controls, and optimize the performance of the generation and/or transmission system. The monitor and control functions are known as SCADA; the optimization packages are often referred to as "advanced applications." (Note: Gas and water could be separate from or integrated within the EMS.)
36	Operations	Outage Management System	OMS	An OMS is a computer system used by operators of electric distribution systems to assist in outage identification and restoration of power. Major functions usually found in an OMS include: • Listing all customers who have outages. • Prediction of location of fuse or breaker that opened upon failure. • Prioritizing restoration efforts and managing resources based upon criteria such as location of emergency facilities, size of outages, and duration of outages. • Providing information on extent of outages and number of customers impacted to management, media, and regulators. • Estimation of restoration time. • Management of crews assisting in restoration. • Calculation of crews required for restoration.

Table A-12. Logical Interfaces by Category

LI Cat#	Logical Interface Category	Logical Interfaces
2	Interface between control systems and equipment without high availability, but with compute and/or bandwidth constraints, for example: • Between NRG (NIST actor 17) and DEW (NIST actor 27)	U102
4	Interface between control systems and equipment without high availability, without compute nor bandwidth constraints, for example: • Between distribution SCADA (NIST actor 29) and RTUs or IEDs (NIST actor 15)	U117
10	Interface between control systems and non-control/corporate systems, for example: • Between NRG proxy and NRG Controller	User defined

The following matrix outlines the Cyber Security processes utilized by O&R to protect logical interfaces U102, U117 and the user defined interface between NRG Proxy and the NRG Controller.

Table A-13. O&R SG Cyber Security Compliance Matrix

SG Security Requirement	SG Requirement Name	O&R SG Cyber Security processes to protect logical interfaces U102, U117 and the user defined interface between NRG Proxy and the NRG Controller.
SG.AC	Access Control	Active Directory to be utilized for domain authentication. Access determined by application protocols.
SG.AT	Awareness and Training	Yearly Cyber Security training required by corporate policy.
SG.AU	Audit and Accountability	Review of cyber security policies and procedure by corporate auditing.
SG.CA	Security Assessment and Authorization	Compliance audits and incident reviews to gauge effectiveness of the security program.
SG.CM	Configuration Management	Configuration Management software will document system configuration. Tests, validates, and documents configuration changes (e.g., patches and updates) before installing them on the operational SG information system.
SG.CP	Continuity of Operations	Redundancy built in to the system to allow for continual operation. Alternate control center to be utilized when primary control center is unavailable.
SG.IA	Identification and Authentication	Active Directory to be utilized for domain authentication. Access determined by application protocols.
SG.ID	Information and Document Management	Corporate record and documentation management requirements. Non- disclosure agreements utilized for transfer of sensitive information (CEII).
SG.IR	Incident Response	Incident response plan in place to track and report incidents on the system. Corporate disaster recovery procedure used as well.
SG.MA	Information System Development and Maintenance	Change management procedure used to implement and document changes and upgrades to the network. Change control procedure utilized for assets.
SG.MP	Media Protection	Corporate policy for media protection and disposal.

SG Security Requirement	SG Requirement Name	O&R SG Cyber Security processes to protect logical interfaces U102, U117 and the user defined interface between NRG Proxy and the NRG Controller.
SG.PE	Physical and Environmental Security	ECC access is restricted via corporate card access control in a CIP compliant environment. Utilize ECC access control procedures. Field devices are in locked cabinets with door alarms tied back to ECC.
SG.PL	Strategic Planning	Disaster recovery procedures in place to insure continuity of operation.
SG.PM	Security Program Management	Corporate information system security policy and DOE Cyber Security plan outline overall CS framework.
SG.PS	Personnel Security	Corporate security screening and background checks for critical staff positions and access control.
SG.RA	Risk Management and Assessment	Risk identification and classification process is continually performed to monitor the SG information system's compliance status.
SG.SA	Information System and Service Acquisitions	Cyber Security compliance is part of the purchasing process. Vendors must certify compliance to be considered. Use of nondisclosure agreements with vendors to ensure confidentiality.
SG.SC	Information System and Communication Protection	Firewalls and 256 bit data encryption utilized to protect the system.
SG.SI	Information System and Information Integrity	Stealthwatch IDS continually monitors the network. Application protocols (IGIN, DEW) provide data validation and integrity checks.

The NIST defined guidelines that are outlined in the 'O&R SG Cyber Security Compliance Matrix' are described below.

A.3.8.1 Access Control (SG.AC)

The focus of access control is ensuring that resources are accessed only by the appropriate personnel, and that personnel are correctly identified. Mechanisms need to be in place to monitor access, and report inappropriate activity.

A.3.8.2 Awareness and Training (SG.AT)

SG information system security awareness is a critical part of SG information system incident prevention. Implementing a SG information system security program may change the way personnel access computer programs and applications, so organizations need to design effective training programs based on individuals' roles and responsibilities.

A.3.8.3 Audit and Accountability (SG.AU)

Periodic audits and logging of the SG information system need to be implemented to validate that the security mechanisms present during SG information system validation testing are still installed and operating correctly. These security audits review and examine a SG information system's records and activities to determine the adequacy of SG information system security requirements and to ensure compliance with established security policy and procedures. Audits also are used to detect breaches in security services through examination of SG information system logs.

A.3.8.4 Security Assessment and Authorization (SG.CA)

Security assessments include monitoring and reviewing the performance of the SG information system. Internal checking methods, such as compliance audits and incident investigations, allow the organization to determine the effectiveness of the security program. Finally, through continuous monitoring, the organization regularly reviews compliance of the SG information systems. If deviations or nonconformance exist, it may be necessary to revisit the original assumptions and implement appropriate corrective actions.

A.3.8.5 Configuration Management (SG.CM)

The organization's security program needs to implement policies and procedures that create a process by which the organization manages and documents all configuration changes to the SG information system. A comprehensive change management process needs to be implemented and used to ensure that only approved and tested changes are made to the SG information system configuration. SG information systems need to be configured properly to maintain optimal operation. Therefore, only tested and approved changes should be allowed on a SG information system. Vendor updates and patches need to be thoroughly tested on a non-production SG information system setup before being introduced into the production environment to ensure that no adverse effects occur.

A.3.8.6 Continuity of Operations (SG.CP)

Continuity of operations addresses the capability to continue or resume operations of a SG information system in the event of disruption of normal system operation. The ability for the SG information system to function after an event is dependent on implementing continuity of operations policies, procedures, training, and resources. The security requirements recommended under the continuity of operations family provide policies and procedures for roles and responsibilities, training, testing, plan updates, alternate storage sites, alternate command and control methods, alternate control centers, recovery and reconstitution and fail-safe response.

A.3.8.7 Identification and Authentication (SG.IA)

Identification and authentication is the process of verifying the identity of a user, process, or device, as a prerequisite for granting access to resources in a SG information system. The SG information system uniquely identifies and authenticates users. The authentication mechanisms must obscure feedback of authentication information during the authentication process to protect the information from possible exploitation/use by unauthorized individuals.

A.3.8.8 Information and Document Management (SG.ID)

Information and document management is generally a part of the organization records retention and document management system. Digital and hardcopy information associated with the development and execution of a SG information system is important and sensitive, and need to be managed. SG information system design, operations data and procedures, risk analyses, business impact studies, risk tolerance profiles, etc., contain sensitive organization information and need to be protected. This information must be protected and verified that the appropriate versions are retained.

A.3.8.9 Incident Response (SG.IR)

Incident response addresses the capability to continue or resume operations of a SG information system in the event of disruption of normal SG information system operation. Incident response entails the preparation, testing, and maintenance of specific policies and procedures to enable the organization to recover the SG information system's operational status after the occurrence of a disruption. Disruptions can come from natural disasters, such as earthquakes, tornados, floods, or from manmade events like riots, terrorism, or vandalism. The ability for the SG information system to function after such an event is directly dependent on implementing policies, procedures, training, and resources in place ahead of time using the organization's planning process. The security requirements recommended under the incident response family provide policies and procedures for incident response monitoring, handling, reporting, testing, training, recovery, and reconstitution of the SG information systems for an organization.

A.3.8.10 SG Information System Development and Maintenance (SG.MA)

Security is most effective when it is designed into the SG information system and sustained, through effective maintenance, throughout the life cycle of the SG information system. Maintenance activities encompass appropriate policies and procedures for performing routine and preventive maintenance on the components of a SG information system. This includes the use of both local and remote maintenance tools and management of maintenance personnel. Maintenance records must be maintained showing date and time of maintenance, name of individual performing the maintenance, description of maintenance performed and list of equipment removed or replaced including identification numbers.

A.3.8.11 Media Protection (SG.MP)

The security requirements under the media protection family provide policy and procedures for limiting access to media to authorized users. Security measures also exist for distribution and handling requirements as well as storage, transport, sanitization (removal of information from digital media), destruction, and disposal of the media. Media assets include compact discs; digital video discs; erasable, programmable read-only memory; tapes; printed reports; and documents.

A.3.8.12 Physical and Environmental Security (SG.PE)

Physical and environmental security encompasses protection of physical assets from damage, misuse, or theft. Physical access control, physical boundaries, and surveillance are examples of security practices used to ensure that only authorized personnel are allowed to access SG information systems and components. Environmental security addresses the safety of assets from damage from environmental concerns. Physical and environmental security addresses protection from environmental threats.

A.3.8.13 Planning (SG.PL)

The purpose of strategic planning is to maintain optimal operations and to prevent or recover from undesirable interruptions to SG information system operation. Interruptions may take the form of a natural disaster (hurricane, tornado, earthquake, flood, etc.), an unintentional manmade event (accidental equipment damage, fire or explosion, operator error, etc.), an intentional manmade event (attack by bomb, firearm or vandalism, hacker or malware, etc.), or an equipment failure. The types of planning considered are security planning to prevent undesirable interruptions, continuity of operations planning to maintain SG information system operation during and after an interruption, and planning to identify mitigation strategies.

A.3.8.14 Security Program Management (SG.PM)

The security program lays the groundwork for securing the organization's enterprise and SG information system assets. Security procedures define how an organization implements the security program.

A.3.8.15 Personnel Security (SG.PS)

Personnel security addresses security program roles and responsibilities implemented during all phases of staff employment, including staff recruitment and termination. The organization screens applicants for critical positions in the operation and maintenance of the SG information system. The organization may consider implementing a confidentiality or nondisclosure agreement that employees and third-party users of facilities must sign before being granted access to the SG information system. The organization also documents and implements a process to secure resources and revoke access privileges when personnel terminate.

A.3.8.16 Risk Management and Assessment (SG.RA)

Risk management planning is a key aspect of ensuring that the processes and technical means of securing SG information systems have fully addressed the risks and vulnerabilities in the SG information system.

An organization identifies and classifies risks to develop appropriate security measures. Risk identification and classification involves security assessments of SG information systems and interconnections to identify critical components and any areas weak in security. The risk identification and classification process is continually performed to monitor the SG information system's compliance status.

A.3.8.17 SG Information System and Services Acquisition (SG.SA)

SG information systems and services acquisition covers the contracting and acquiring of system components, software, firmware, and services from employees, contactors, and third parties. A policy with detailed procedures for reviewing acquisitions should reduce the introduction of additional or unknown vulnerabilities into the SG information system. The organization must consider the increased security risk associated with outsourcing as part of the decision-making process to determine what to outsource and what outsourcing party to select. The organization must consider confidentiality or nondisclosure agreements and intellectual property rights.

A.3.8.18 SG Information System and Communication Protection (SG.SC)

SG information system and communication protection consists of steps taken to protect the SG information system and the communication links between SG information system components from cyber intrusions. Although SG information system and communication protection might include both physical and cyber protection, SG.SC addresses only cyber protection. Physical protection is addressed in SG.PE, Physical and Environmental Security.

A.3.8.19 SG Information System and Information Integrity (SG.SI)

Maintaining a SG information system, including information integrity, increases assurance that sensitive data have neither been modified nor deleted in an unauthorized or undetected manner. The security requirements described under the SG information system and information integrity family provide policy and procedure for identifying, reporting, and correcting SG information system flaws. Requirements exist for malicious code detection. Also provided are requirements for receiving security alerts and advisories and the verification of security functions on the SG information system. In addition, requirements within this family detect and protect against unauthorized changes to software and data; restrict data input and output; check the accuracy, completeness, and validity of data; and handle error conditions.

****** This document references the document NISTIR 7628 - Guidelines for SG Cyber Security: Vol. 1, SG Cyber Security Strategy, Architecture, and High-Level Requirements, August 2010.**

To facilitate review of the O&R implementation with the appropriate guidelines, the DEW Real Time Architecture drawings have been annotated with the corresponding actors and logical interface categories defined by the NIST Cyber Security guidelines. In the following illustrations, the overall and the process-specific architectures are presented with their NIST Logical Reference Model correlations:

Figure A-15. NIST Legend

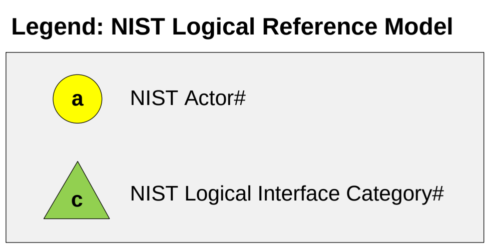


Figure A-16. DEW Real-Time Architecture

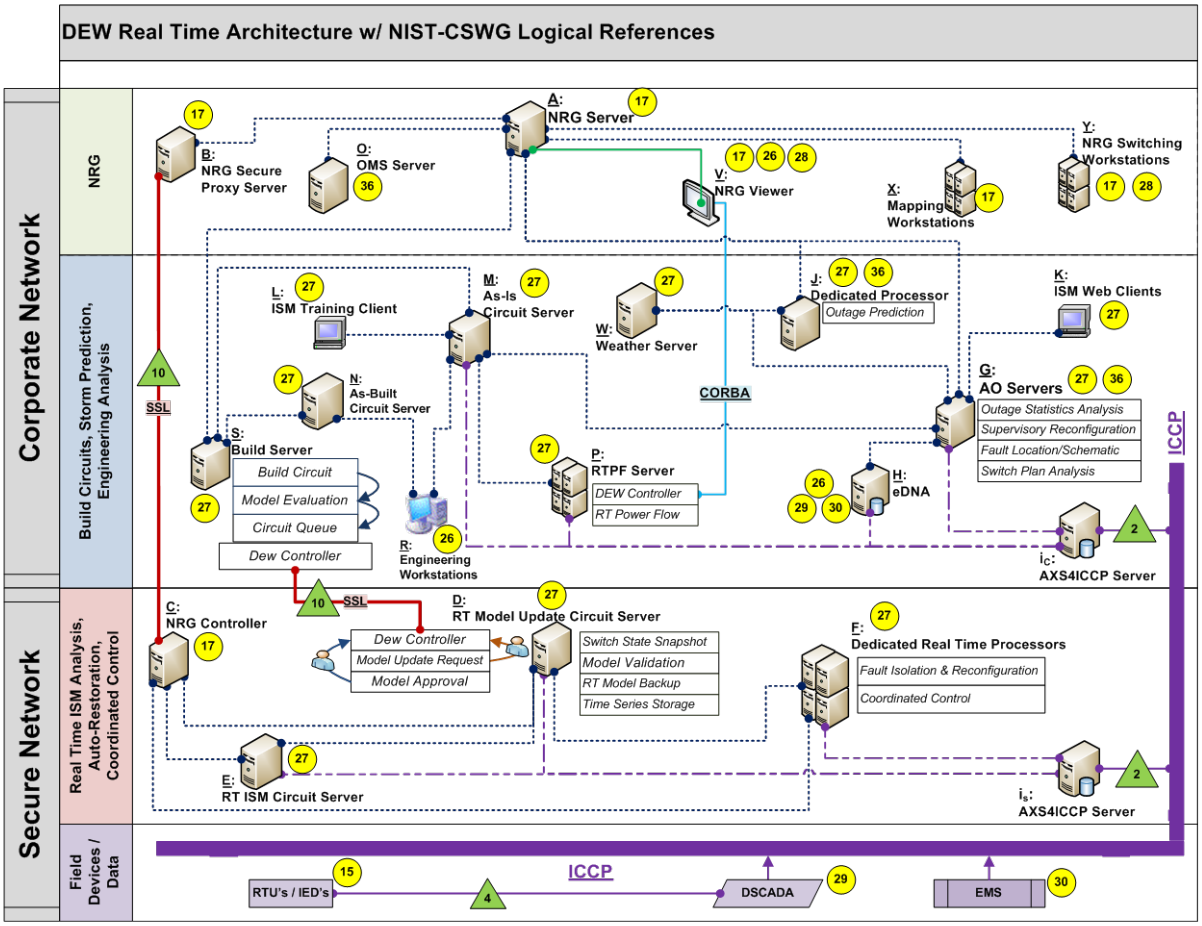


Figure A-17. Model Validation Architecture

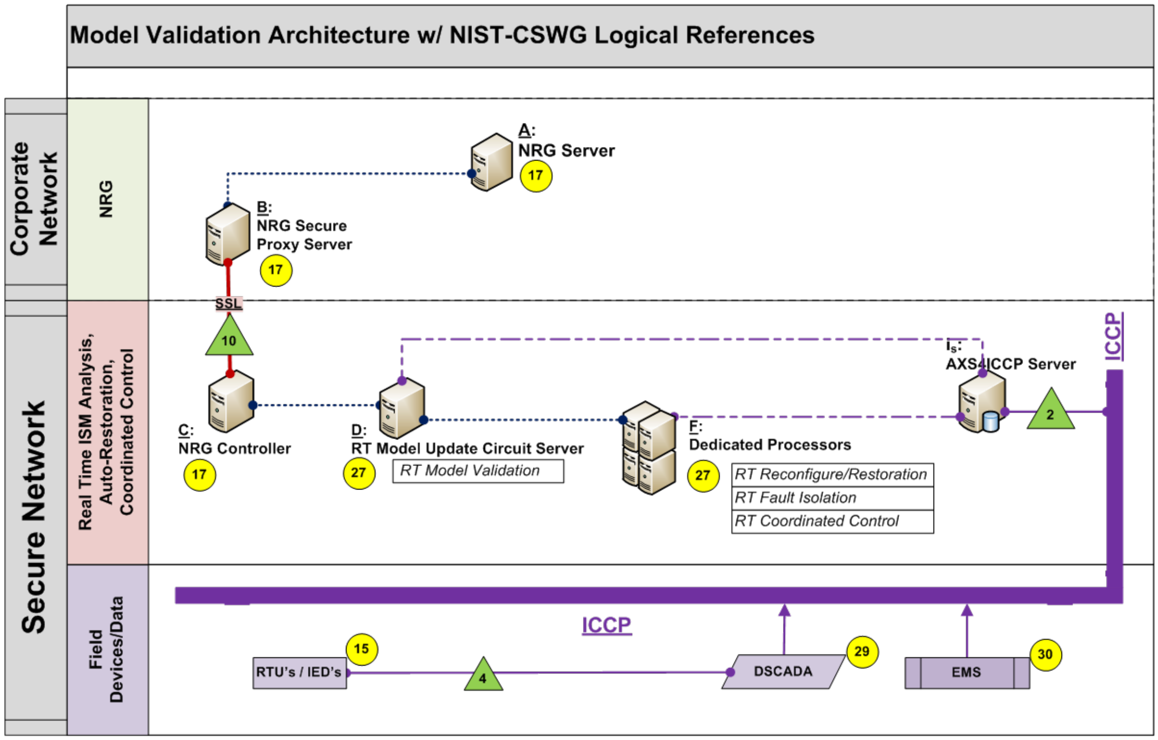


Figure A-18. Automatic Switching Operations Architecture

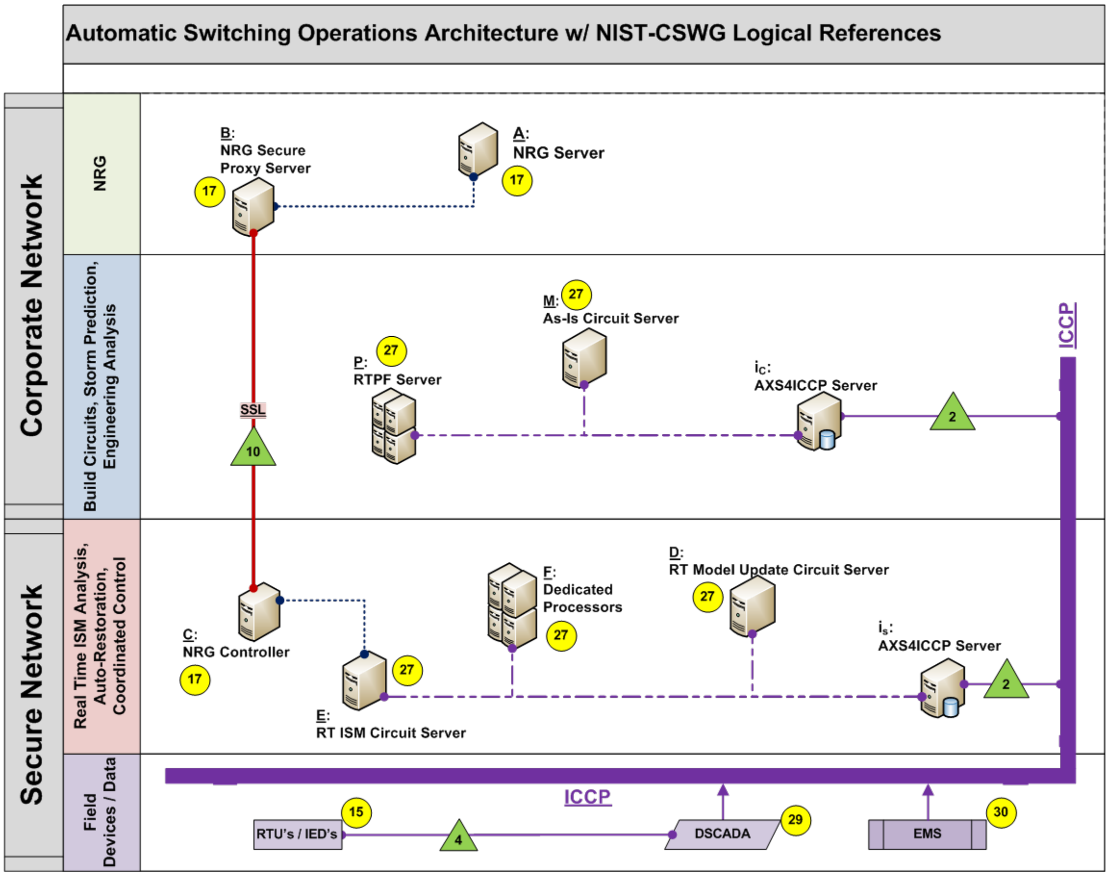


Figure A-19. Manual Switching Operations Architecture

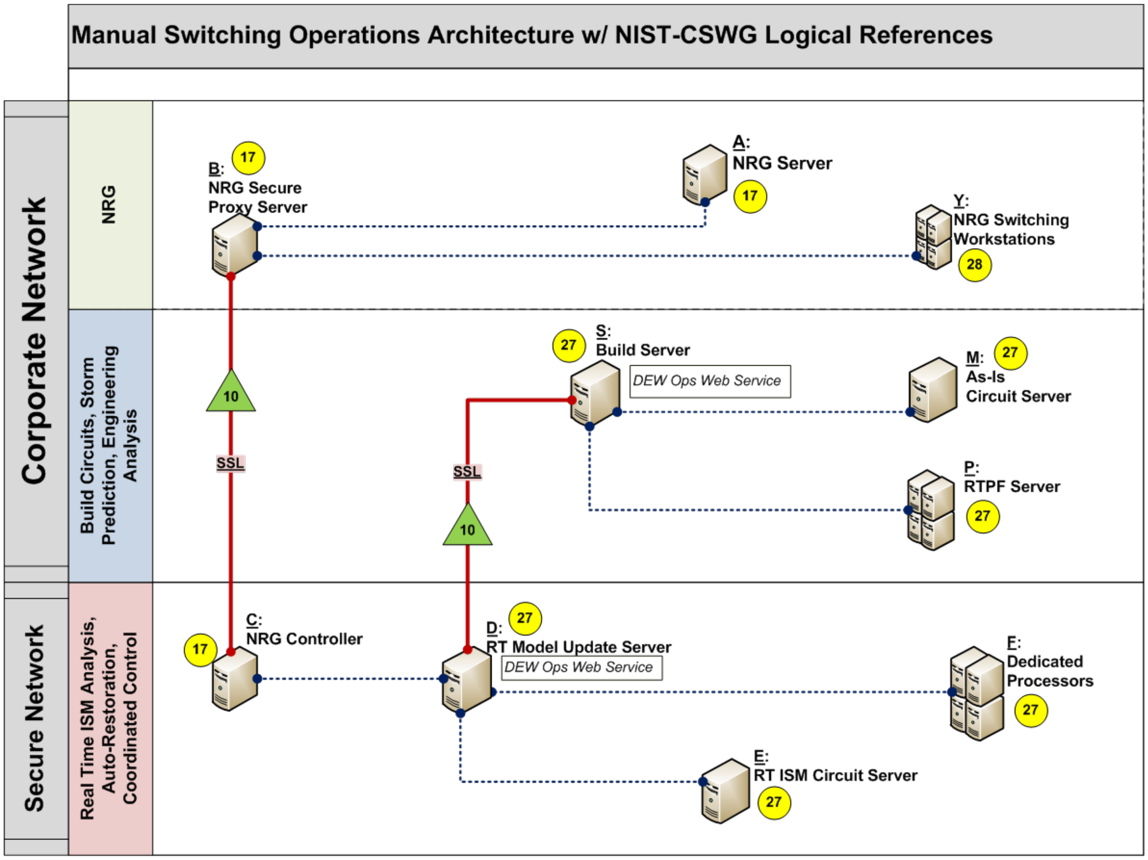


Figure A-20. RT Coordinated Control Network

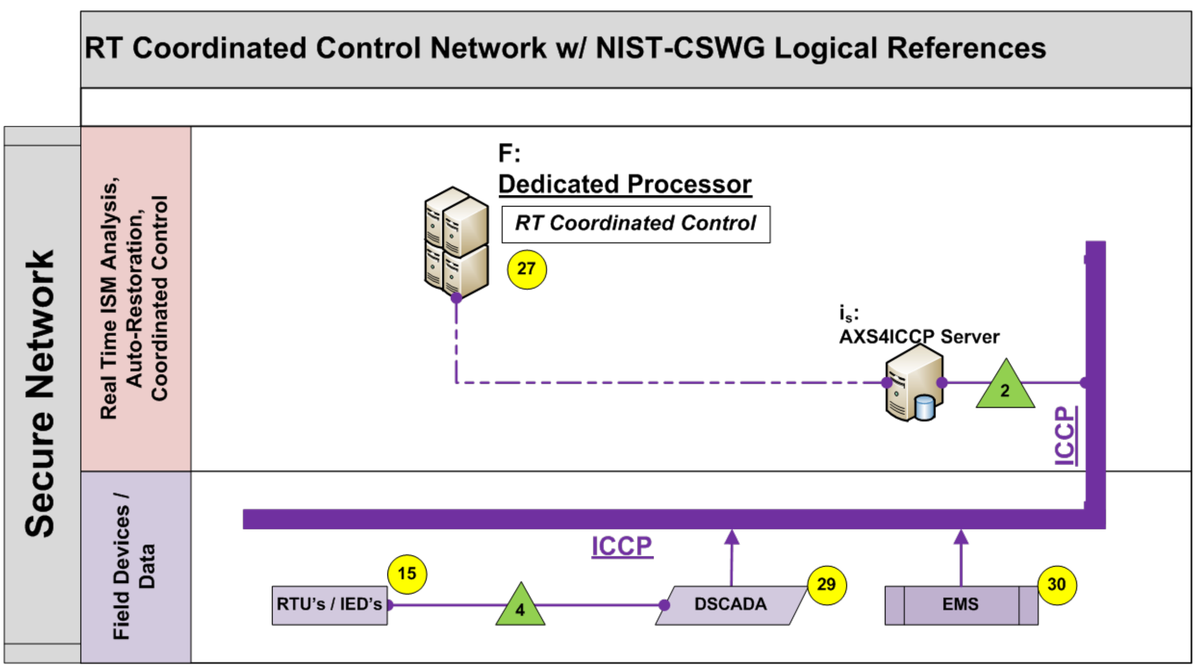


Figure A-21. Real-Time Fault Isolation Architecture

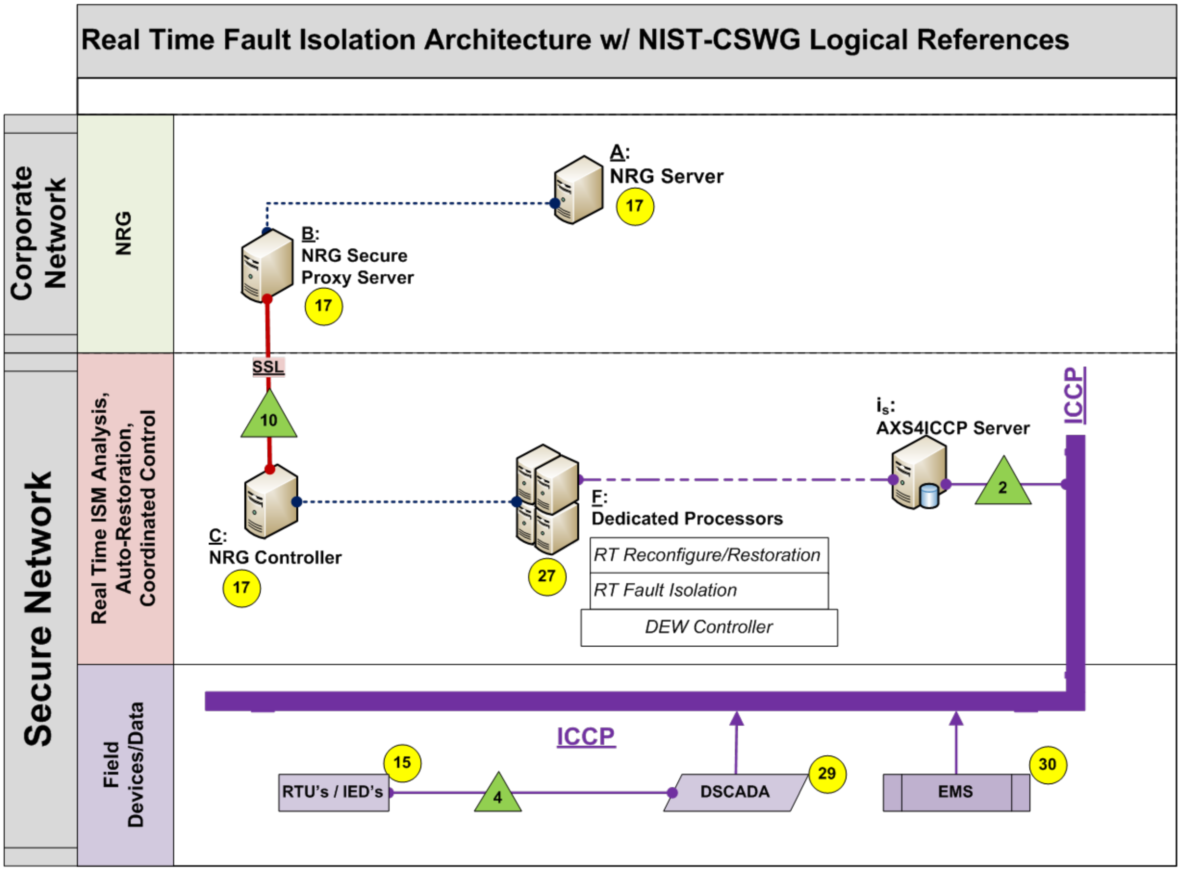


Figure A-22. Fault Location Architecture

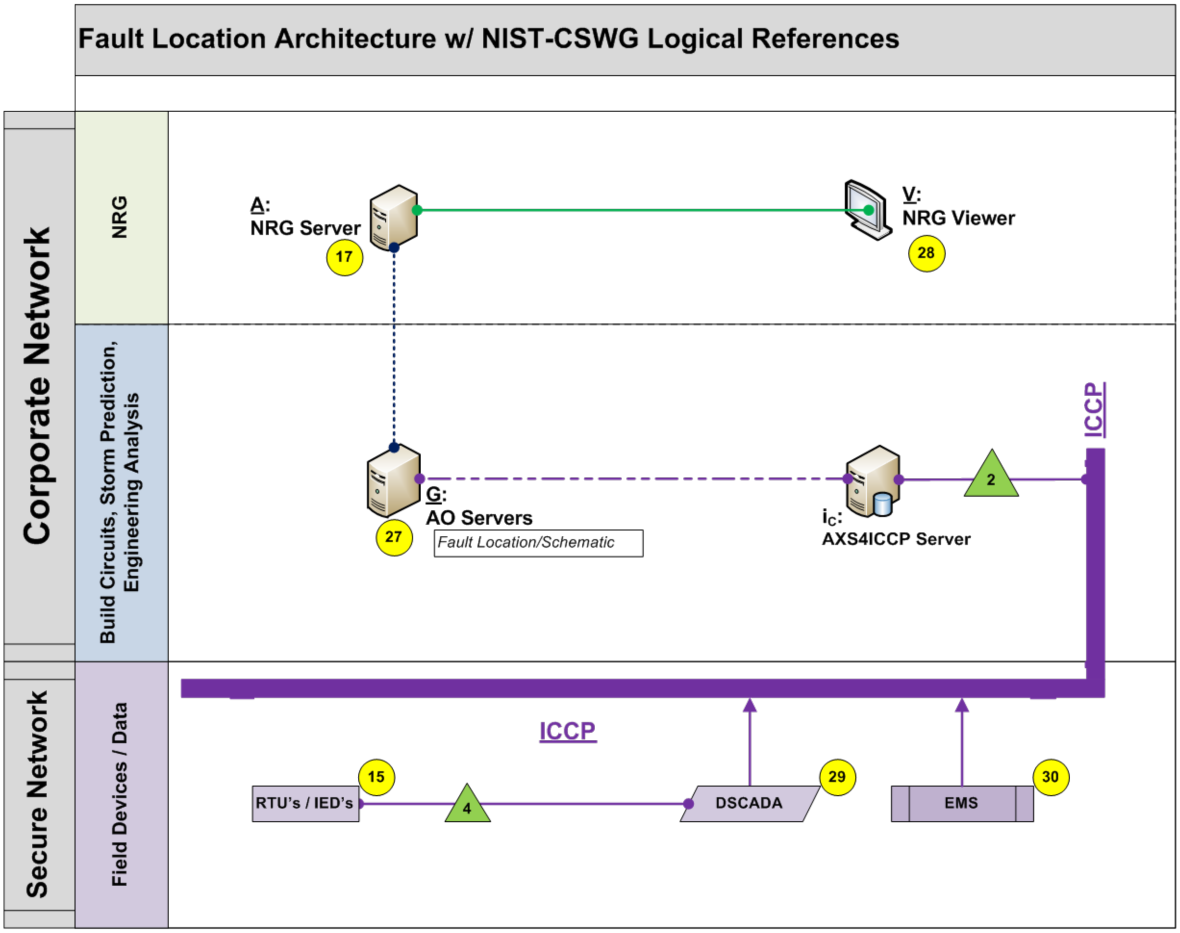


Figure A-23. Model Maintenance Architecture

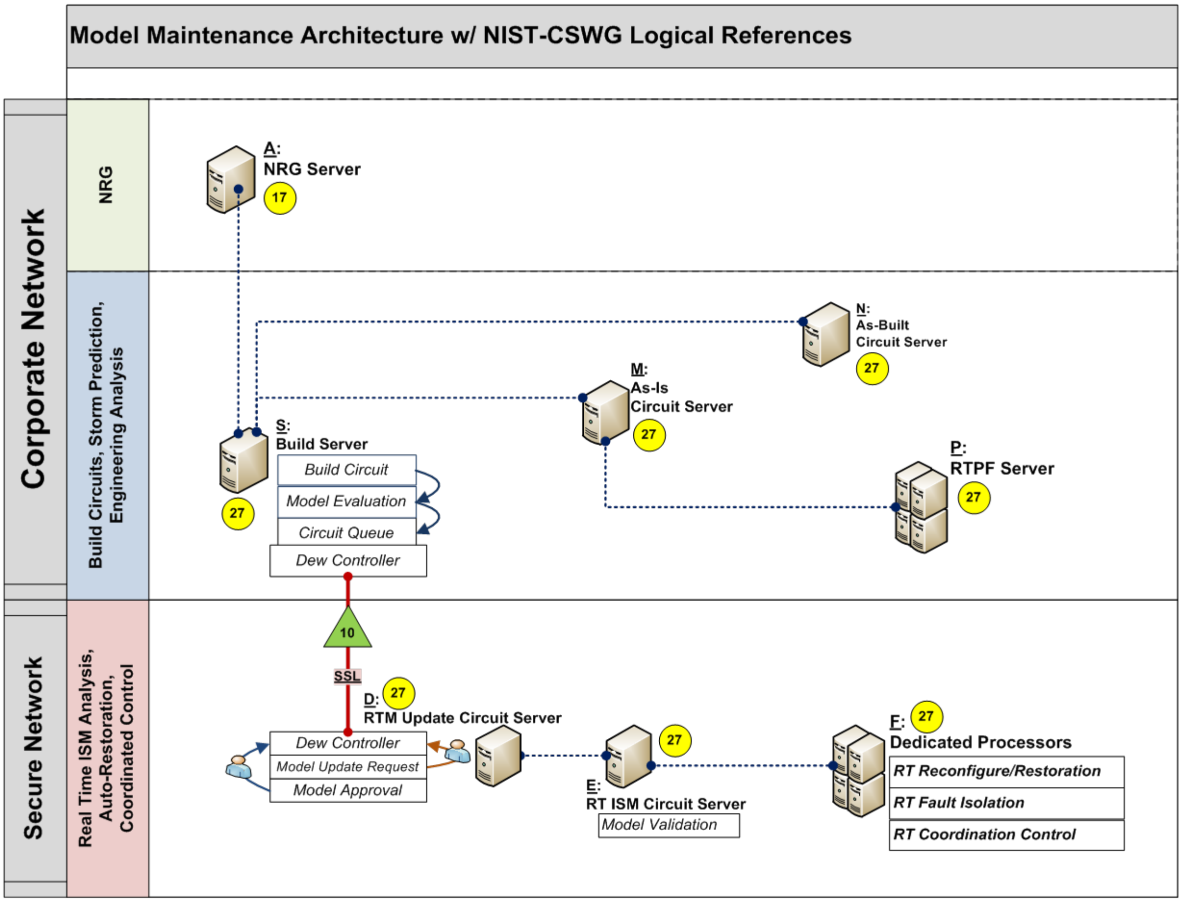


Figure A-24. Model Amendment Architecture

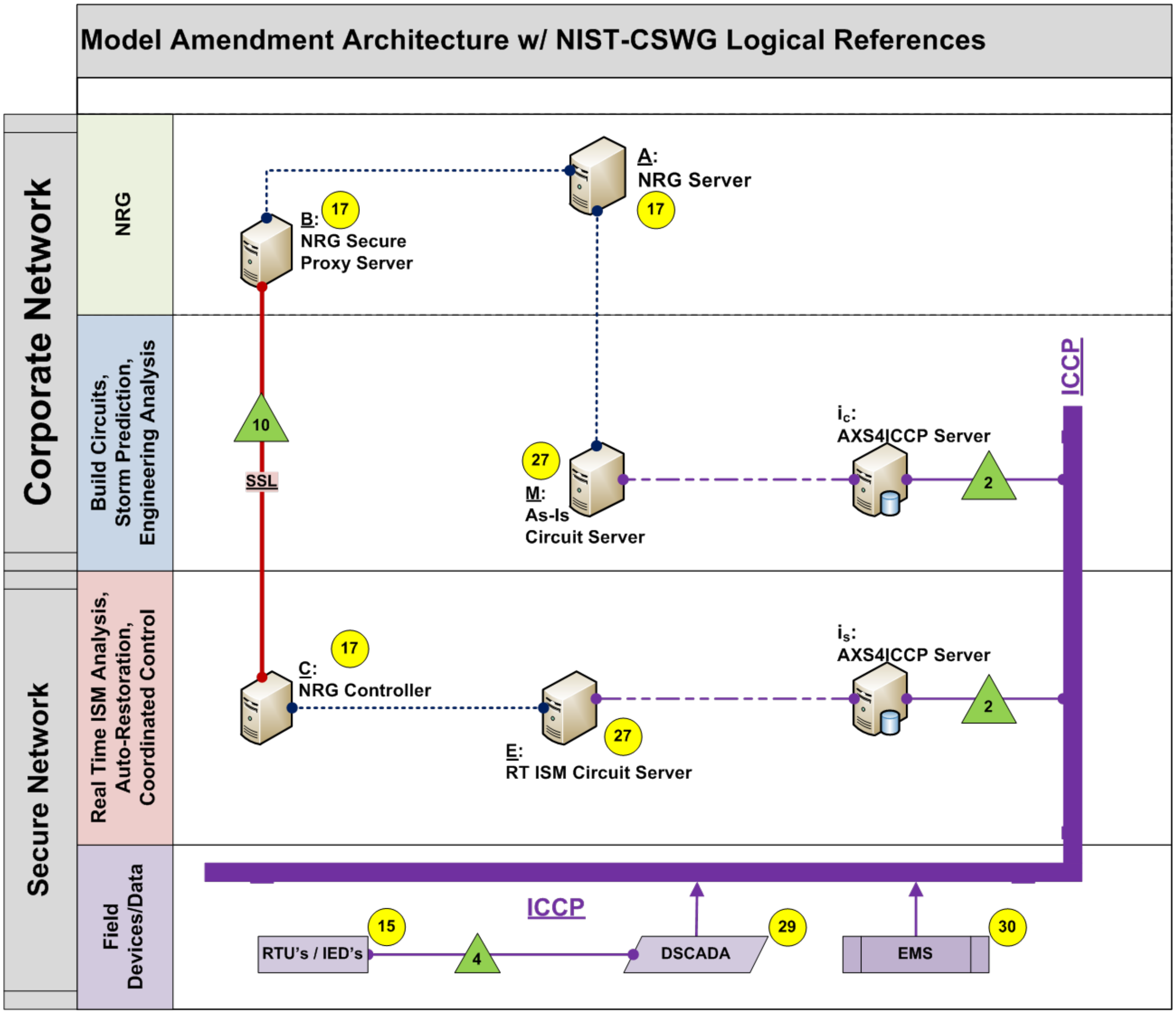


Figure A-25. Real-Time Power Flow Architecture

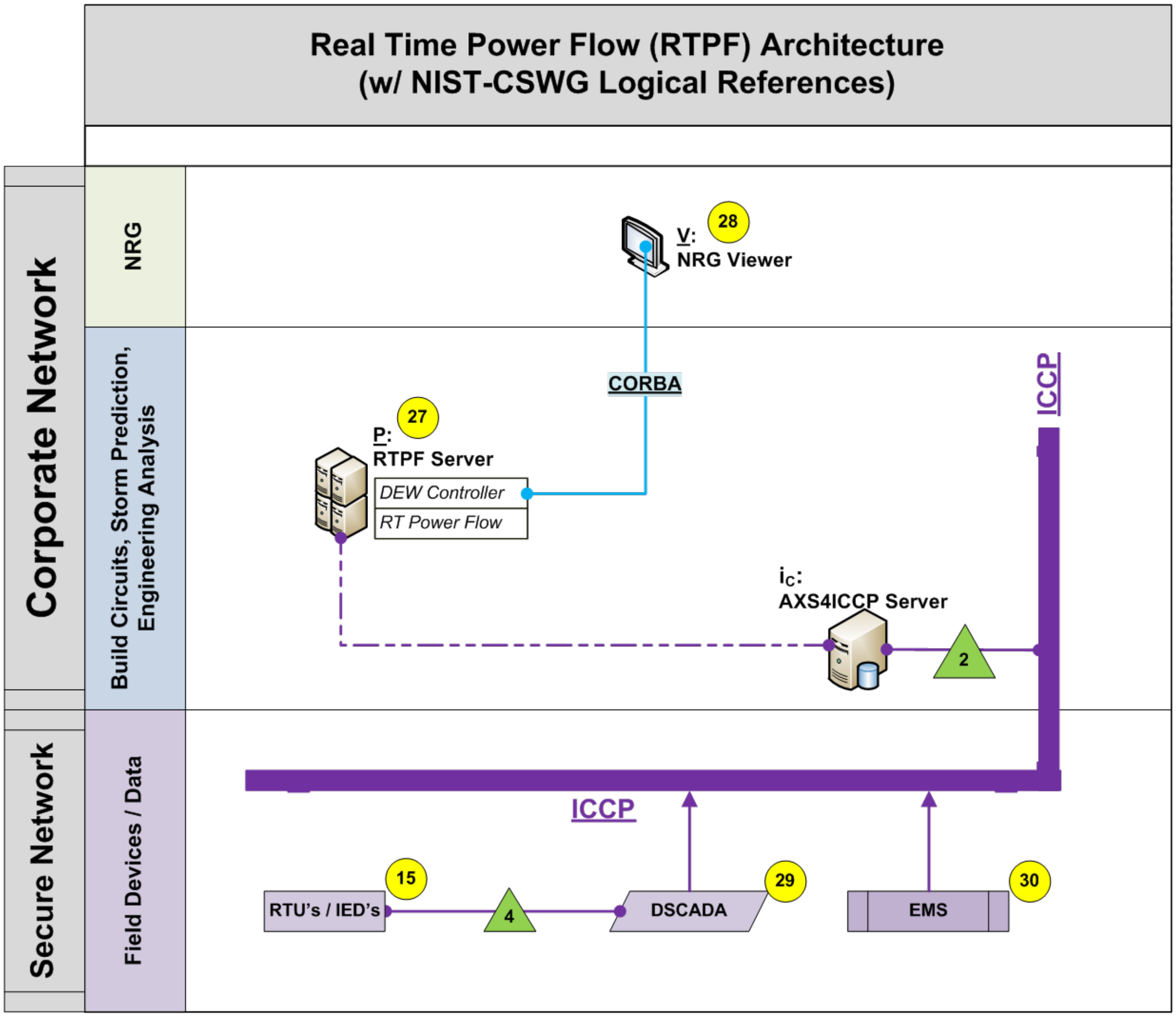


Figure A-26. Supervisory Reconfiguration Architecture

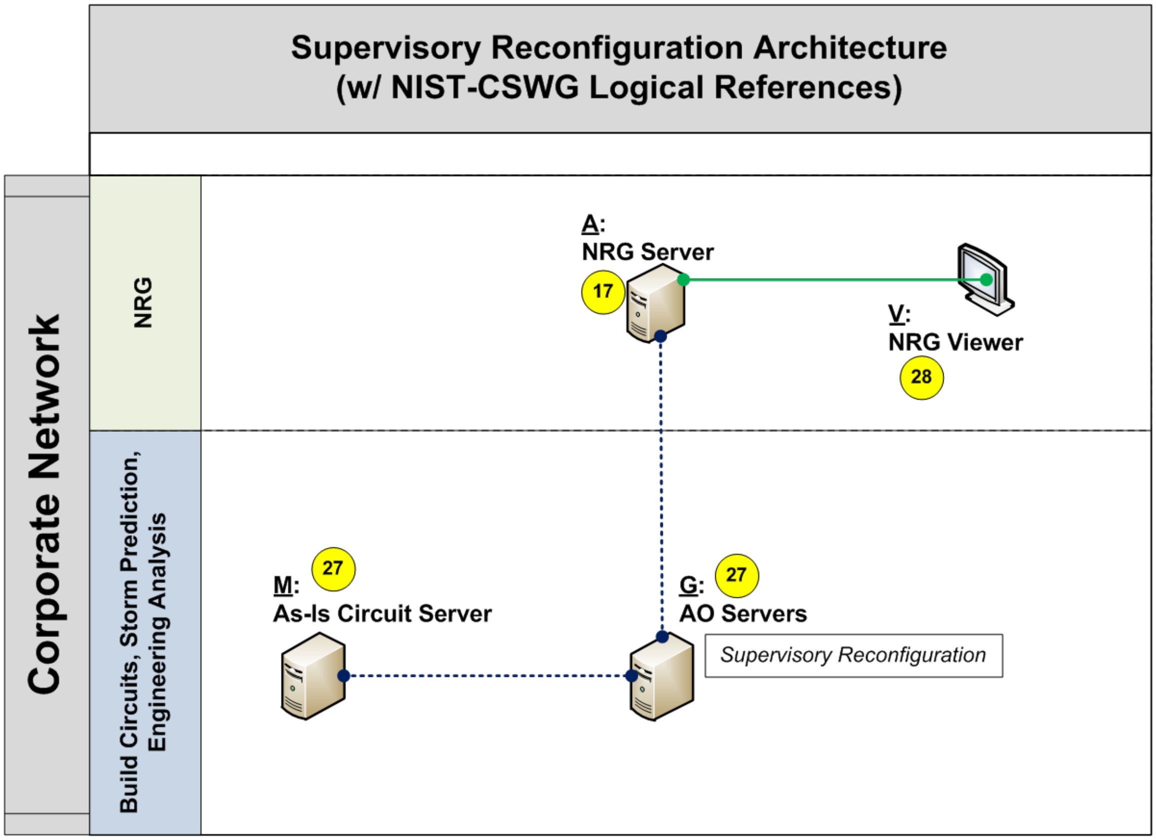


Figure A-27. Switch Plan Analysis Architecture

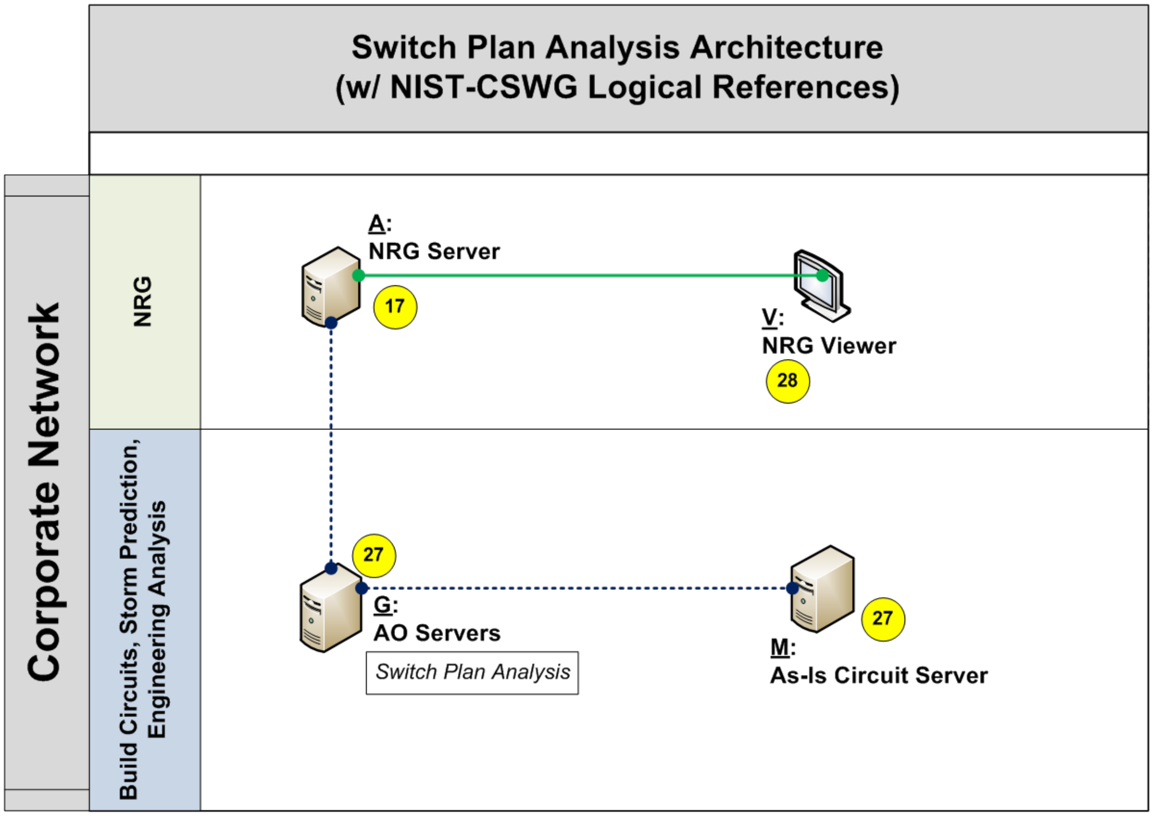
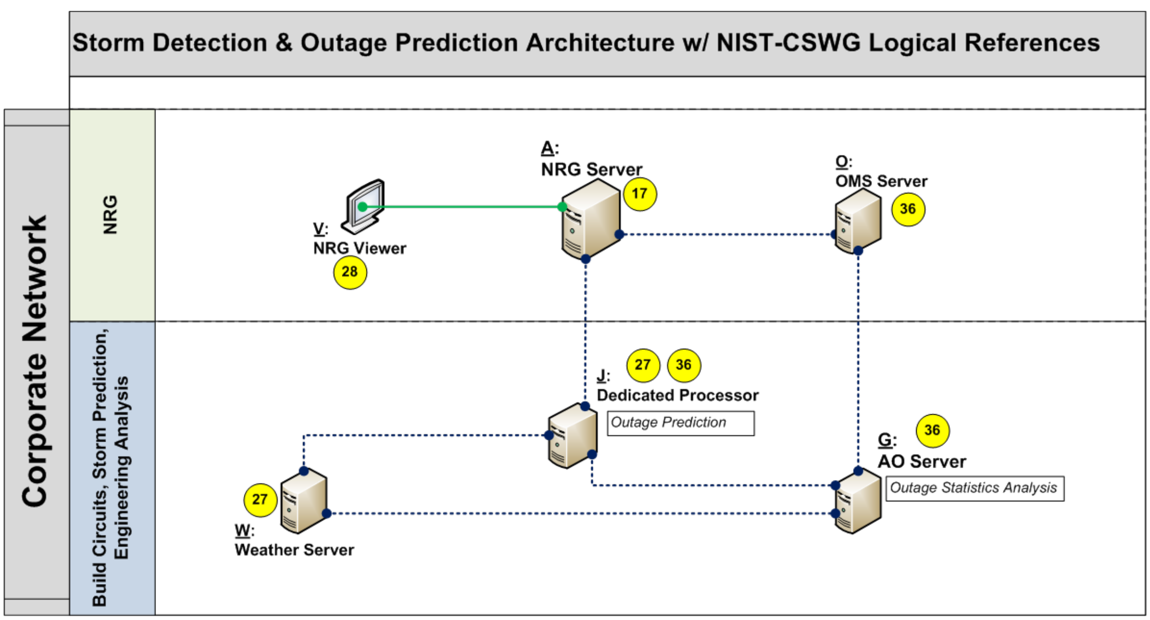


Figure A-28. Storm Detection and Outage Prediction Architecture



A.3.9 Relevant Technical Publications

1. Ahmet Onen, Jeremy Woyak, Reza Arghandeh, Jaesung Jung, Charlie Scirbona, Robert P. Broadwater, "Time-varying Cost of Loss Evaluation in Distribution Networks Using Market Marginal Price,"
   accepted for publication in International Journal of Electrical Power and Energy Systems.
2. Ahmet Onen, Jeremy Woyak, Reza Arghandeh, Jaesung Jung, Charlie Scirbona, Robert P. Broadwater Danling Cheng, Ahmet Onen, Reza Arghandeh, Jaesung Jung, Robert Broadwater, Charlie Scirbona, "Model Centric Approach for Monte Carlo Assessment of Storm Restoration and Smart Grid Automation," Proceedings of the ASME 2014 Power Conference, July 28-31, 2014, Baltimore, MD.
3. Jaesung Jung, Ahmet Onen, Reza Arghandeh, Robert Broadwater, "Coordinated Control of Automated Devices and Photovoltaic Generators for Voltage Rise Mitigation in Power Distribution Circuits," Renewable Energy 66C (2014), pp. 532-540.
4. Ahmet Onen, Danling Cheng, Reza Arghandeh, Jaesung Jung, Jeremy Woyak, Murat Dilek, Robert P. Broadwater, "Model Based Coordinated Control Based on Feeder Losses, Energy Consumption, and Voltage Violations," Electric Power Component and Systems, Vol. 41, Issue 16, Oct. 23, 2013.
5. D. Kleppinger, R. Broadwater, and C. Scribona, "Generic reconfiguration for Restoration," *Electric Power Systems Research*, Vol. 80, pp. 287-295, March 2010.
6. D. Zhu, D. Cheng, R. Broadwater, C. Scribona, "Storm modeling for prediction of power distribution system outages", Electric Power Systems Research, June 2007.
7. "Configurable, Hierarchical, Model-based Control of Electrical Distribution Circuits," Josh Hambrick, Robert Broadwater, IEEE Transactions on Power Systems, Pages Volume:26, Number:3, August 2011, Pages 1072-1079.
8. "Advantages of Integrated System Model-Based Control for Electrical Distribution System Automation," Josh Hambrick, Robert Broadwater, Proceedings of 18th IFAC World Congress, Aug. 28 – Sept. 2, 2011, Milano, Italy.
9. "Real Time Control of Distributed Generation," R. P. Broadwater, M. Murat, Electric Power Generation, Transmission, and Distribution, Taylor & Francis Group, April 2007.
10. F. Li, and R. Broadwater., "Distributed Algorithms with Theoretic Scalability Analysis of Radial and Looped Load Flows for Power Distribution," *Electric Power Systems Research*, Vol. 65, 2003.
11. K. Russell, and R. Broadwater, "Graph Trace Analysis Based Interdependent System Recoverability Analysis Criteria, Constraints and Measures," *Naval Engineerins Journal*, Accepted for publication 2011.
12. D. Kleppinger, K. Russell, K. and R. Broadwater, "Graph Trace Analysis Based Shipboard HM&E System Priority Management and Recovery Analysis," *IEEE Electric Ship Technologies Symposium*, pp. 109-114, May 2007.
13. L. Feinauer, K. Russell, and R. Broadwater, "Graph Trace Analysis and Generic Algorithms for Interdependent Reconfigurable System Design and Control," Naval Engineers Journal, vol. 120, issue 1, pp. 29-40, March 2008.

14. "Object-Oriented Analysis of Distribution System Reconfiguration for Power Restoration," I. Drezga, R. Broadwater, A. Sugg, Proceedings of 2001 IEEE Power Engineering Society Summer Meeting, July 15-19, 2001, Vancouver, Canada.

15. "A Heuristic Nonlinear Constructive Method for Distribution System Reconfiguration," T. E. McDermott, R. Broadwater, IEEE Transactions on Power Systems, Vol. 14, No. 2, pp. 478-483, May 1999.

A.4 Digi / Ambient: Wireless Communication and Meter Data Management (MDM)

A.4.1 Executive Summary

In order to provide a data feed into the visualization and decision aid platform (i.e., DERMS) that was developed as part of the SGDP, as well as in support of Con Edison's Demand Response reporting requirements, a near real-time feed of customer interval meter data was necessary. In late 2012 the focus was to investigate the necessary system/hardware changes required to support 15-minute interval meter data collection by MV-90 xi, and to modify the data connections to MDM, the visualization system, and Customer Care portal to make use of the more timely data.

The initial investigation found that the data was collected from the interval meters by the MV-90xi system and then passed into LPDS and the MDM. Also found were several system limitations that needed to be addressed:

1. The MDM system as implemented at Con Edison was on an aging hardware and software platform, and suffered from poor performance. In addition, this system is critical for calculating billing determinants and could not be taxed with any further requests for data.
2. LPDS (a Con Edison legacy system) did not suffer from performance issues; however, it is dependent on a feed from MV-90xi, which collects the data from interval meters in the field via phone, cellular, and other communication means.

A.4.2 Project Goals and Accomplishments

An initial assessment determined that LPDS was capable of handling whatever additional load that would be required. Con Edison's Customer Operations group had a plan and funding to upgrade MDMS hardware and software. They worked with Itron, KEMA, and Information Resources on a Con Edison capital project that will enhance the throughput, processing, and storage capabilities of the MDMS. This effort could support the visualization platform by integrating billing meter data from our Distribution Load Relief Program (DLRP) customer's sites into the DERMS system, thus enhancing ability to visualize the DLRP customer load. This project is categorized as cost share for the SGDP.

The MDMS project exceeded the initial goals of the project. The MDMS project did the following:

- Converted from an Oracle database to Structured Query Language (SQL) Server
- Completed a version upgrade of Itron's MDMS software from V 7.0 to v 8.1, allowing the MDMS to benefit from using a 64- rather than 32-bit operating system and database
- Upgraded the hardware configuration, increasing the database processing capability by 500% and memory by 400%. In addition, solid-state, rather than spinning drives, were used for temp file processing, which dramatically improved performance.

Figure A-29 and Figure A-30 shown below, the first from the 06/06/13 test and the second graph from the 2/26/14 test, depict the increase in throughput rate for interval meter data collected by MV-90xi and exported to the MDM for the same 1,160 meters. Although the scale of this test does not fully stress the new XML export function, this data, in conjunction with data from the daily billing runs, can be used to project an increase in the ability to support retrieval and display of 15-minute data from approximately 640 meters for a DR event to the ability to support approximately 910 meters for a DR event, nearly a 30% increase in throughput. There are ongoing issues still being investigated that will improve system performance.

The throughput improvement that has been made to date is depicted in the following graphs:

Figure A-29. Example Peak Throughput prior to Improvements

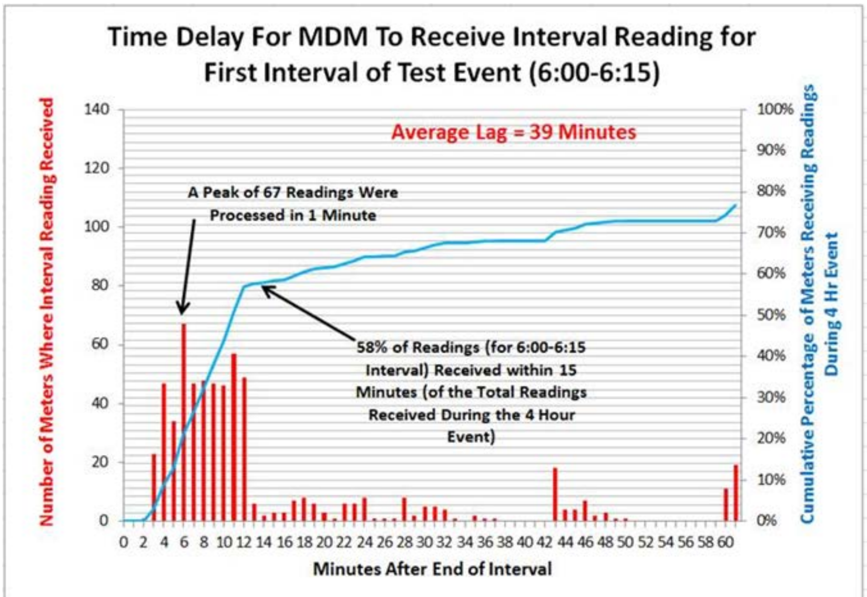
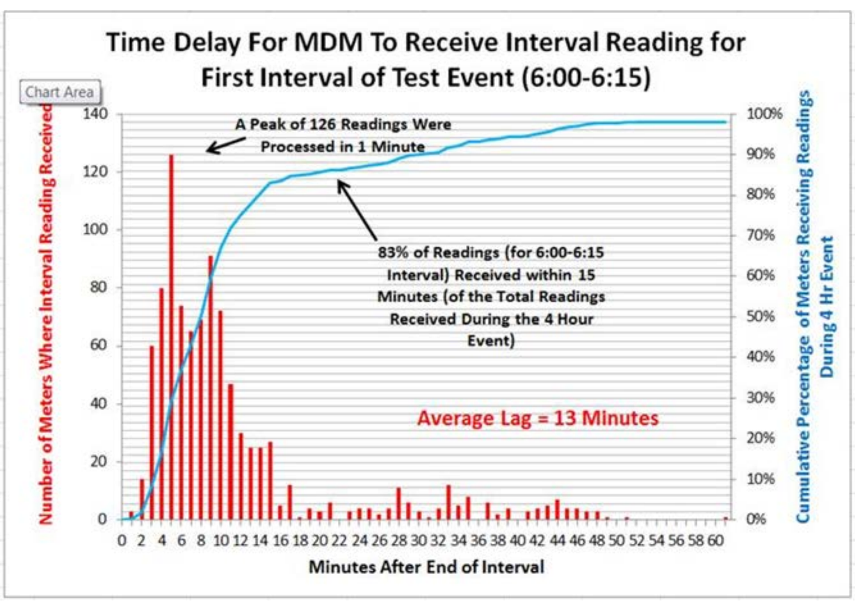


Figure A-30. Example of Peak Throughput after Improvements



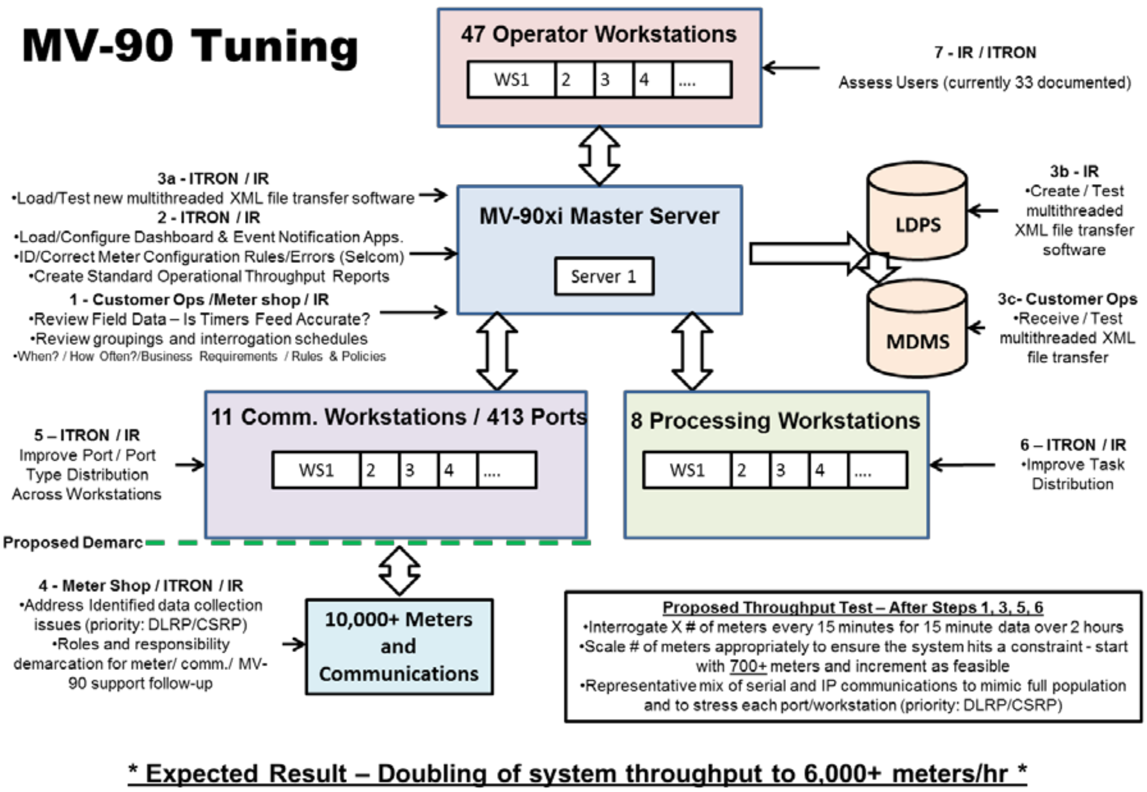
A.4.3 Project Activities

As the processing demands on MDMS continued to grow from increased numbers of billing and demand response accounts, it became more difficult to process all the required data requests in a timely manner. The MDMS hardware platform was outdated and the software needed to be upgraded. The server hardware was no longer supported by Hewlett Packard and the current version of the MDMS software was not supported under newer versions of Oracle. As a result of this data processing and obsolescence dilemma, in 2013 the MDM underwent a major overhaul. An effort was launched to convert the data in the existing Oracle database to SQL server. The migration required converting nearly five billion rows of data and 600 data tables from Oracle to SQL Server.

To get additional benefits and performance, Con Edison also performed a version upgrade of the MDMS software from v7.0 to v8.1. This upgrade allowed the MDMS to benefit from using a 64- rather than 32-bit operating system and database. This version upgrade was coupled with a new hardware configuration that increased the database processing capability by 500% and memory by 400%. In addition, solid-state, rather than spinning, drives were used for temp file processing, which also added to dramatically improved performance.

Finally, additional MDM modifications were needed to implement and test Green Button functionality for the MHP customer class and to better support fast polling that informs DR customers of their usage in near real time during an event. In the past, these DR customers would only be able to determine how they performed in an event the day after the event was called; fast polling allows them to see their usage each 15 minutes. This was achieved through MV-90 tuning, changing file exports to MDMS from single threading to multi-threading and through hardware and software upgrades to the MDMS that enabled high-speed data aggregation, which was essential when coupled with fast polling.

Figure A-31. MV-90 Tuning



In addition to the system improvements described in section 4-A.4 of the main report, there were also many small operational improvements. One operational improvement was an increase to MV-90xi throughput via reorganization of the call groups and call group schedule. Two of the primary benefits of this reorganization include:

- Concentrated call schedules at two points of the day – 1a.m. and 1 p.m. This opens up time during the day for other maintenance tasks on the MV-90xi system such as backups and patches, so that these tasks do not affect throughput during meter interrogations.
- Moved meters with "problem communications" (meters that have not been successfully interrogated in over six months) to a separate call group called once per week. This reduced the number of failed MV-90xi meter interrogations by over 4,000/day, providing relief to system resources. These meters will be automatically returned to their appropriate call group once they begin to communicate.

A.4.4 Wireless Communication Project Update

Con Edison's largest customers have their meter interval data collected via the Itron MV-90xi system. Data are collected through a variety of communication channels, including cellular, broadband IP and Plain, Old Telephone Service (POTS). Some of the meters are installed in underground vaults or building basements where a "typical" wireless or phone line solutions are not readily available which makes it challenging to communicate with them and hence, very difficult to collect timely billing data.

Funded partially by the DOE, the Wireless Communications project was established to repair approximately 1200 non-communicating interval meters. The primary accounts targeted in this project are approved DR program customers and high and low service-voltage customers who have interval meters that are not communicating. Below is a breakdown on the interval meters currently in the scope:

- 297 - DR meters
- 722 – Low and high service voltage meters
- 263 – High voltage railroad meters

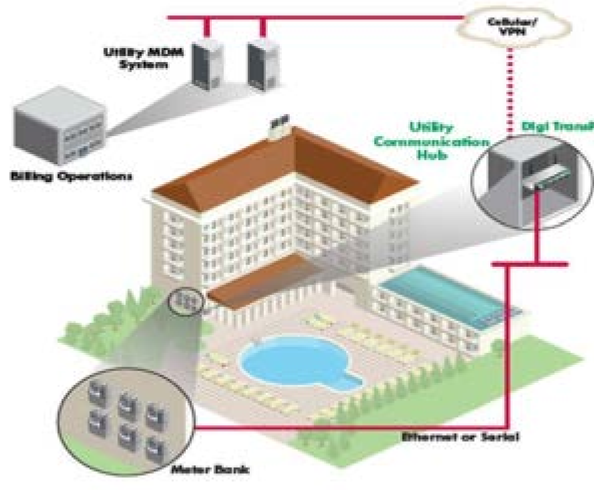
Wireless communication nodes from two manufacturers, Digi International and Ambient Corporation, were utilized in this project. Both Ambient Corporation and Digi International agreed to offer cost share.

Figure A-32. Digi International TransPort WR21

Figure A-33. Ambient MiniNode

The communication equipment that was deployed utilized the latest and most advanced Verizon 4G Long Term Evolution (LTE) cellular network, with private IP addresses, Secure Shell (SSH) point-to-point password validation, and Advanced Encryption Standard (AES) data encryption for extra security. Con Edison also plans to further enhance cyber security by deploying Virtual Private Network (VPN) tunnels between Con Edison firewall and wireless nodes, as depicted in Figure A-34.

Figure A-34. Meter Remote Communication Diagram

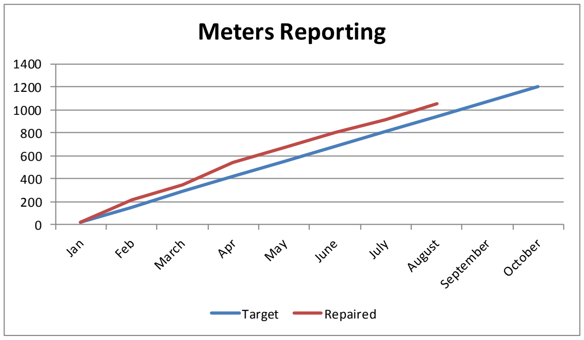


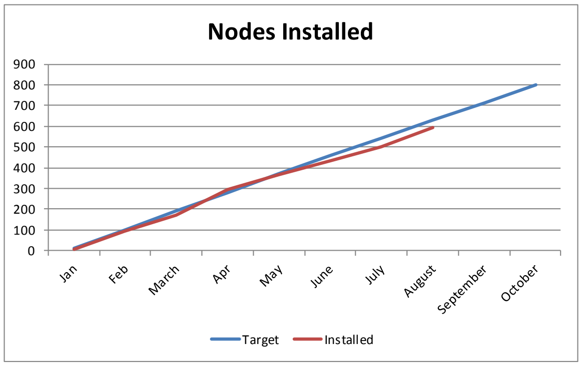
As the project progressed, Digi equipment displayed robust performance while the Ambient equipment had some technical issues that delayed deployment of their nodes. Ambient has been working proactively with Con Edison to address these issues.

As of August 27th 2014, the project team has made significant progress in repairing communication links, with a total of 1055 interval meters repaired and 595 wireless nodes installed, as depicted in Figure A-35. Of 595 installed nodes, 569 were provided by Digi International and 26 by Ambient Corporation. Currently the project is under budget and on schedule to complete implementation phase by October 31st 2014, repairing communication links with at least 1200 interval meters.

Figure A-35. Wireless Metering Communications Project Progress

Total				
	Meters Reporting		Nodes Installed	
	Target	Repaired	Target	Installed
Totals	**1200**	**1055**	**800**	**595**
Monthly				
Month	**Target**	**Repaired**	**Target**	**Installed**
Jan	21	26	10	6
Feb	135	194	90	89
March	134	129	90	75
Apr	130	189	90	124
May	130	138	90	74
June	130	122	90	67
July	130	120	85	66
August	130	137	85	94
September	130	0	85	0
October	130	0	85	0
Cumulative				
Month	**Target**	**Repaired**	**Target**	**Installed**
Jan	21	26	10	6
Feb	156	220	100	95
March	290	349	190	170
Apr	420	538	280	294
May	550	676	370	368
June	680	798	460	435
July	810	918	545	501
August	940	1055	630	595
September	1070	1055	715	595
October	1200	1055	800	601





A.5 *Viridity: DR and BMS Integration*

The Viridity team developed the following summary of SGDP activities as part of the input to the FTR. Results and information below has been used to develop the overall takeaways and lessons learned in the FTR.

A.5.1 Executive Summary

Viridity Energy, among other partners, was selected by Con Edison to deploy SG technology within NYC and demonstrate the ability to integrate and optimize distributed energy resources to enhance efficiency, reliability, and economic savings for the utility and end users alike.

Viridity's contribution to the Con Edison SG Initiative, sponsored by the DOE, illustrates the value of the load management function to individual participating customers, the local utility, and to a smart city as a whole. The project couples real-time information and insight into the electricity market with advanced communication protocols to enable pro-active customer involvement in the markets.

In the aggregate, the project realized 5.4 MW in reliability benefits from Con Edison DLRP and NYISO DR program. The projected annual economic benefits associated with this integrated, controllable load follow.

NYISO Capacity Market Revenue	$ 481,194
Con Edison Capacity Program Revenue	$ 259,200
Distribution Demand Charge Savings	$ 365,402
Combined Value (Revenue + Savings)	**$1,105,796**

Through this project, VPower™ was integrated with energy consuming and controlling resources at 23 buildings throughout NYC with an estimated 5.4 MW of curtailable load. Via additional integration with Con Edison, Viridity can support distribution system load relief through virtual power, which is realized through the VPower™ integration to end use customers.

Leveraging the project investment in ongoing commercialization, Viridity is now entering 2014 summer program operations representing 32.85 megawatts at $8.7M estimated economic value (revenue from NYISO / Con Edison). These impressive results and the implied benefit to economic and environmental sustainability are directly attributable to Viridity's partnership with Con Edison made possible with the DOE project funding.

The approach and results are consistent with the tenets of the New York Public Service Commission's (NYPSC) recent strategic report[2] highlighting the need for increased reliability at improved costs

[2] Reforming the Energy Vision, NYS DEPARTMENT OF PUBLIC SERVICE STAFF REPORT AND PROPOSAL, April 24, 2014.

leveraging distributed energy resources to complement and even offset large centralized generation plants.

A.5.2 Project Goals and Accomplishments

Evaluating the tactical accomplishments within the sub-award component of the project can only be done with an understanding of the following stated project goals.

Viridity Scope of Work

- Establish interfaces to buildings and BMSs in NYC
- Provide data and control capabilities through Con Edison middleware platform
- Interface with NYISO
- Optimize building system operations for customers
- Validate building resource models

Viridity Project Objectives

- Improve Control Capabilities of Existing Grid Assets
- Minimize Peak Load Growth & Improve Grid Reliability
- Provide Customers with Greater Visibility, Flexibility and Value
- Promote Cyber Security

The following table demonstrates how Viridity's major deliverables (scope) map into the project objectives. In short, the original intent of the project investment has been met.

Table A-14. Deliverables and Objectives

Deliverable	Description	Objective Mapping
VPower™ Building and Resource Models	Viridity Energy's scope includes establishing interfaces to 23 BMSs located throughout our service territory and using VPower™ platform to create a "virtual generation" capability via demand reductions. Each building has a unique curtailment strategy that has been modeled in VPower™. Viridity Energy's platform is capable of creating optimal schedule for market participation and optimizes loads behind the meter and interfaces through its Network Operations Center (NOC) to the visualization platform in the Distribution Control Center (DCC).	✔ Improve Control Capabilities of Existing Grid Assets ✔ Minimize Peak Load Growth & Improve Grid Reliability ✔ Provide Customers with Greater Visibility, Flexibility and Value ✔ Promote Cyber Security
Con Edison Interface	Viridity developed and implemented an interface to the Siemens middleware platform that was validated during several tests and demonstrations. Through this secure communication, Con Edison can dispatch DR via VPower™ to assist in responding to distribution-level system contingencies, for instance, relieving overloads on specific feeders. In turn, VPower™ exercises load control strategies at specific buildings.	✔ Improve Control Capabilities of Existing Grid Assets ✔ Minimize Peak Load Growth & Improve Grid Reliability ✔ Provide Customers with Greater Visibility, Flexibility and Value ✔ Promote Cyber Security
NYISO Interface	Viridity developed and tested a NYISO interface targeting price forecasting in VPower™. As a result Viridity has integrated NYISO Real Time price forecasts as part of the market participation process in VPower™.	✔ Improve Control Capabilities of Existing Grid Assets ✔ Minimize Peak Load Growth & Improve Grid Reliability ✔ Provide Customers with Greater Visibility, Flexibility and Value

A.5.2.1 Other Project Accomplishments

In the course of achieving the scope of work, Viridity completed other notable interim deliverables, including:

- Vetted VPower™ cyber security via NIST compliance assessments by two independent auditors
- Applied advanced modeling, forecasting, and adaptive control techniques such as Block Box modeling, Kalman Filtering, and proportional-integral-derivative (PID) loop control

- Provided monthly economic benefit reports reflecting potential demand savings and market participation revenue for each fully implemented building in the program
- Conducted integrated system demonstration and testing
- Continues to operate related project participants in Con Edison and NYISO curtailment programs
- Focused on commercialization of the approach to fully leverage the DOE project (below)

Commercialization: Commercialization is the process of contracting with a site to participate in a DR program. By the summer of 2013, Viridity Energy commercialized five (of 23) sites by operating them in both NYISO and Con Edison DR (capacity) programs in parallel to project participation. As of April 2014, Viridity increased the volume of commercialized sites to 16 (of 23). Through demonstrating the economic value of curtailment within the project and by emphasizing our business development work in NYC, Viridity enrolled an additional 15 sites with these same building owners/operators participating in the SGDG, bringing the total to 31 SGDG-related sites.

Figure A-36. Commercialization

	Grant Related Commercialization Progression						Capture Improvement	
	MW Value	Grant Sites	Last Reported	Current	Extension	Combined	Value	%
Site Count		**23**	**5**	**16**	**15**	**31**	**26**	**520%**
Curtailable Load (SCR) *MW*	---	---	5.154	7.45	3.90	11.35	6.20	120%
Curtailable Load (DLRP) *MW*	---	---	3.402	7.05	3.90	10.95	7.55	222%
Curtailable Load (CSRP) *MW*	---	---	3.894	7.05	3.50	10.55	6.66	171%
Total Curtailable Load	---	---	**12.45**	**21.55**	**11.30**	**32.85**	**20.40**	**164%**
Est. Economic Annual Value	**$265,100**	---	**$3,300,495**	**$5,712,905**	**$2,995,630**	**$8,708,535**	**$5,408,040**	**164%**
viridityenergy power economics redefined	Conservative average annual value of 1 MW of curtailable load across these non-exclusive DR programs	Total number of sites that participated in the program / grant with Viridity	Initially commercialized with 5 of 23 sites as reported in the 2013 technical review in WV	Improved commercialization to 16 of 23 sites participating in program	Extended commercial terms to 15 additional sites of real estate portfolio managers benefitting from program / grant	Total sites commercialized as direct result of program / grant	Realized improvement in commercialization in the past 12 months stemming from program / grant, related NYSERDA programs, ConEdison DR incentives, and Viridity Market Strategy	

A.5.2.2 *Challenges and Learning*

As expected, the full project lifecycle was complex and completed with many challenges, shifts in approach, and opportunities to learn which went beyond the original intent of the project. The table below summarizes notable challenges by major deliverable and the related learning points.

Deliverable	Challenges	Lessons Learned
VPower™ Building and Resource Models	• Buildings not yielding meaningful DR • NYC commercial building culture & configuration presented a learning curve • Scope dependent on actual site acquisition (sales of a sort) leading to some missed expectations	• Developed screening methods to target high potential sites • Refined approach helped in targeting and acquiring sites • Target but not commit to specific sites unless contracts are in place – risk based planning
Con Edison Interface	• Middleware provider established 20 months into project	• Develop requirements and design to greatest extent possible, as done with the Con Edison - VPower™ messaging interface
NYISO Interface	• First operational exposure to NYISO market rules • NYISO price forecasting tools somewhat unreliable	• Trained the NOC resources appropriately & adjusted strategy • Augmented with an external pricing feed
Other	• Hurricane Sandy flooded several sites which remain inactive	• Consider risk in site-assessment and equipment location

A.5.3 Project Approach and Activities

During the Con Edison SGDP, Viridity Energy integrated with 23 separate buildings in NYC and with Con Edison to demonstrate the value of distributed and secure control of DR resources.

The DOE funding supported the purchase and integration of control related equipment at each commercial building site. Viridity designed a unique DR strategy for each site and programmed the related sequence of operations into each site's Building Automation System. As a result, Viridity is able to monitor the related building loads, trigger curtailment events in response to NYISO and Con Edison needs, and monitor real-time building curtailment responses in our NOC in Philadelphia, PA.

The project scope and related benefits were achieved by leveraging the following approach which, in practice was iterative and incrementally accomplished, moving from one site to the next. This outline ignores commercial aspects including customer contracting and Market settlement operations. Each is subsequently presented in more detail.

- Con Edison – VPower™ System Integration

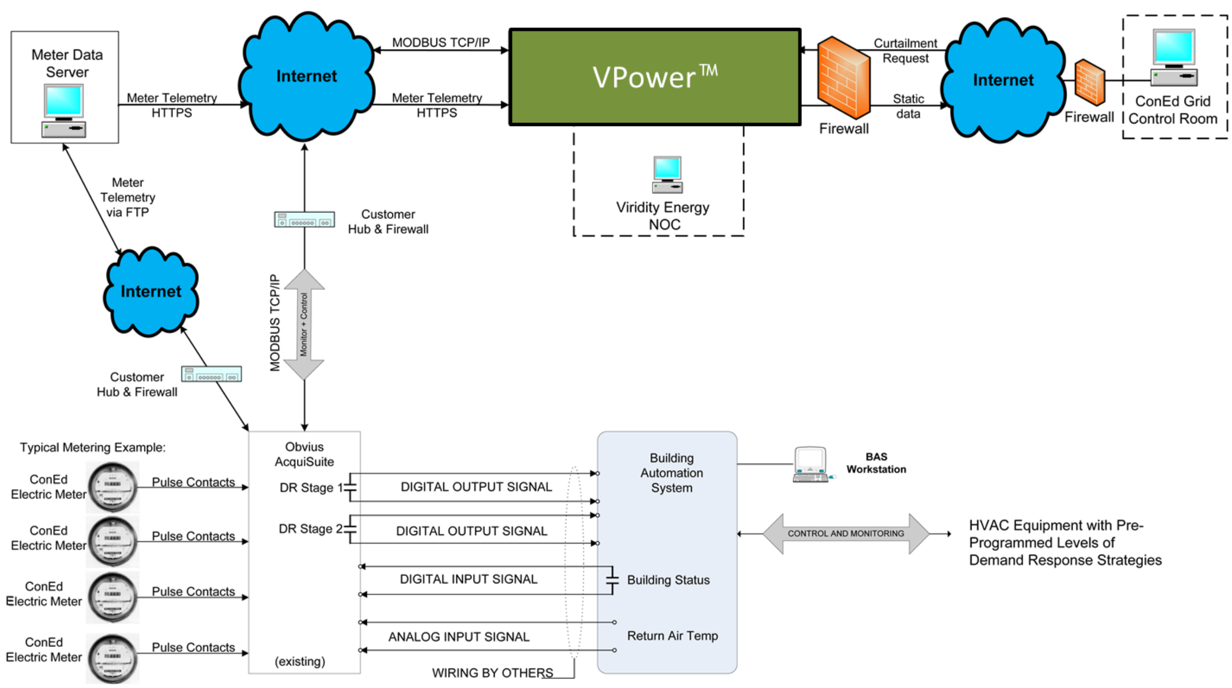
- Resource-Specific Integration & Control
- VPower™ Resource Modeling & Optimization
- VPower™ Resource Model Validation & Tuning
- Monthly Benefit Analysis & Reporting

A.5.3.1 Con Edison – VPower™ System Integration

In Figure A-37 below depicting the Con Edison – VPower™ system integration, a general sequence of operations is implied. The end-to-end system supports full data acquisition and control signaling with VPower™ brokering the exchange of information to and from the end use resources in this distributed model.

VPower™ communicates via XML messaging using a Java Applet Control Engine (JACE®) as a communication translator. Other approved gateway related infrastructure includes VPower SCADA, Obvius, and AquiSuite. The data acquisition and control is conducted over IP in a secure framework.

Figure A-37. VPower™ System Integration



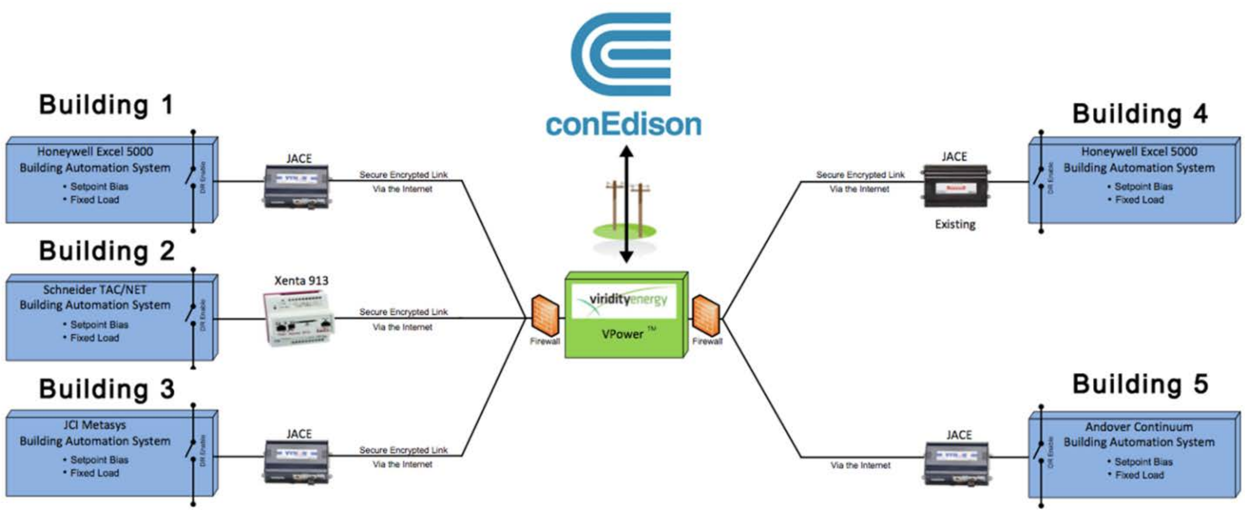
A.5.3.2 Resource-Specific Integration and Control

The actual resource telemetry yielding performance to Con Edison and/or NYISO program participation is a result of a broader integration approach. Those steps are outlined below.

1. Site and Resource Assessment
2. Market/Curtailment Strategy
3. Communications and Control Strategy
4. VPower™ Resource Modeling
5. JACE® Programming
6. BMS Programming
7. System Communication and Resource Integration Testing
8. Training and Operational Knowledge Transfer
9. Ongoing Market/System Operations with VPower™

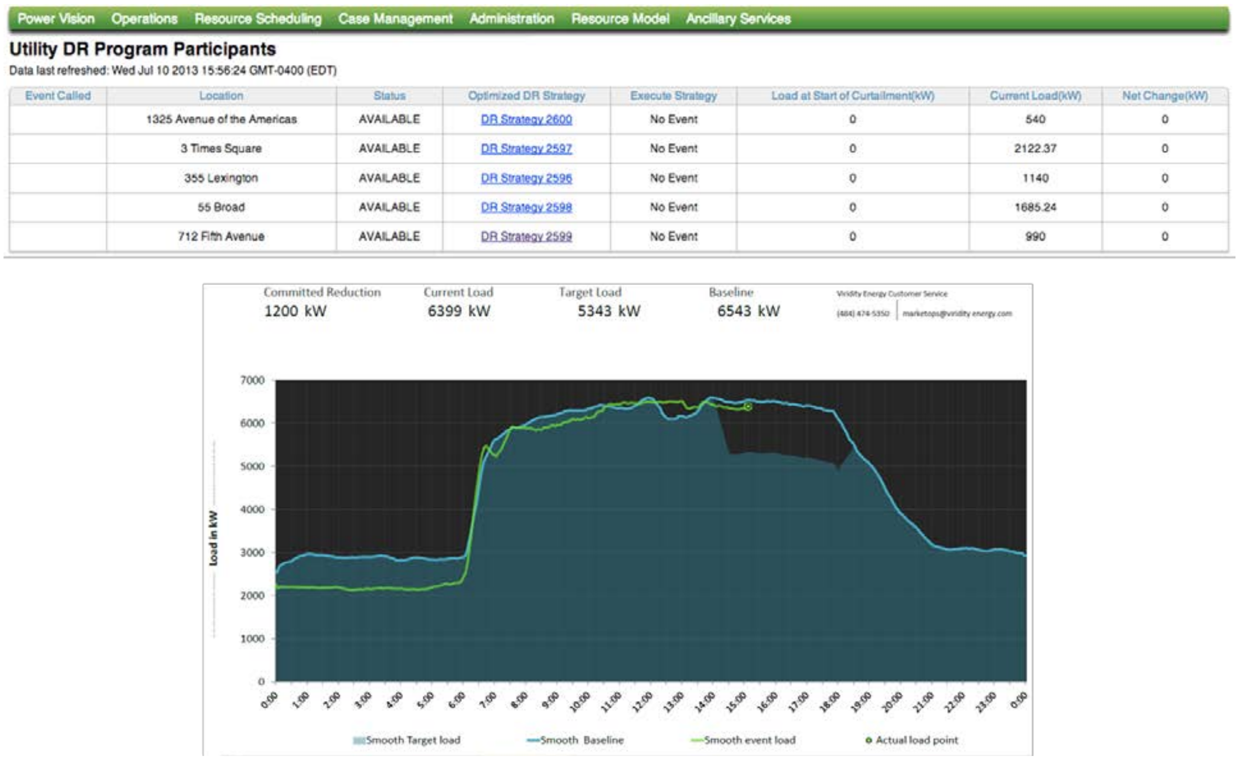
A simplified representation of the Con Edison – VPower™ – End-User integration is shown below.

Figure A-38. VPower™ End-User Integration



Through the exchange of information between VPower™ and Con Edison, there is a common understanding of resource availability and resource performance. This is supported by XML messaging with the Con Edison middleware structures. The VPower ™ screen shot graphic below displays some of this messaging, along with a view of event performance.

Figure A-39. VPower™ Screen Shot



Event Called	Location	Status	Optimized DR Strategy	Execute Strategy	Load at Start of Curtailment(kW)	Current Load(kW)	Net Change(kW)
	1325 Avenue of the Americas	AVAILABLE	DR Strategy 2600	No Event	0	540	0
	3 Times Square	AVAILABLE	DR Strategy 2597	No Event	0	2122.37	0
	355 Lexington	AVAILABLE	DR Strategy 2596	No Event	0	1140	0
	55 Broad	AVAILABLE	DR Strategy 2598	No Event	0	1685.24	0
	712 Fifth Avenue	AVAILABLE	DR Strategy 2599	No Event	0	990	0

A.5.3.3 VPower™ Resource Modeling and Optimization

A building resource is modeled in VPower™ with the following information:

- Specific DER - their key performance and operational characteristics
- Setpoint temperature at the building (occupied and unoccupied)
- Maximum occupancy
- Mass of building and overall heat transfer coefficient
- Black-box methods were deployed as well for lower cost/higher accuracy

VPower™ optimizer determines an operating schedule, which minimizes costs and maximizes revenue for optimal economic operational value. This may yield NYISO market bids or Con Edison program availability or other energy cost savings strategies for the end user such as demand charge mitigation.

- Model inputs: pricing forecast, weather forecasts, and building values
- Techniques applied: linear and non-linear programming relative to (Customer Baseline Load) CBL and other inputs

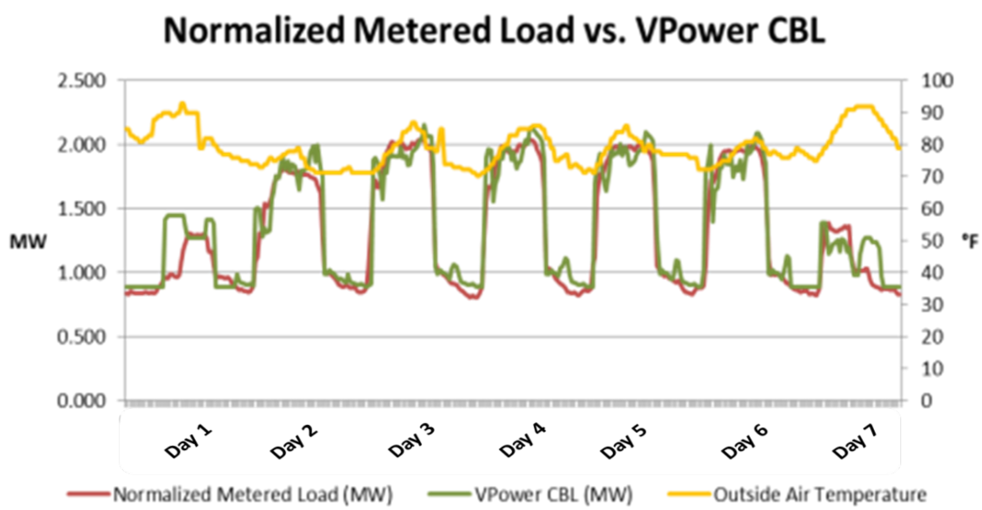
- Outputs: time series plans for market bidding and building/DER setpoints
- Operationally, a PID control loop was applied for dynamic variance correction.

A.5.3.4 VPower™ Resource Model Validation and Tuning

To assure that the resource models leveraged in VPower™ were effective, and that they offered an accurate view of resource load consumption variation, Viridity performed some statistical tests and tuned the models accordingly.

The CBL is a simulation of would-be customer load without planned curtailment action. This generally supports curtailment performance relative to "baseline" loads. The VPower™ model is validated by comparing the CBL produced by the model to the metered load from the building(s) for a historical period, typically 30 days.

Figure A-40. Time Series Plot of Normalized Metered Load and VPower™ CBL



The resource model parameters were tuned to produce a best match between the business as usual (BAU) CBL and the building(s) metered load. The best match is obtained when the average value of the absolute value of the BAU CBL relative error for the entire validation period is minimized.

A.5.3.5 Monthly Benefit Analysis and Reporting

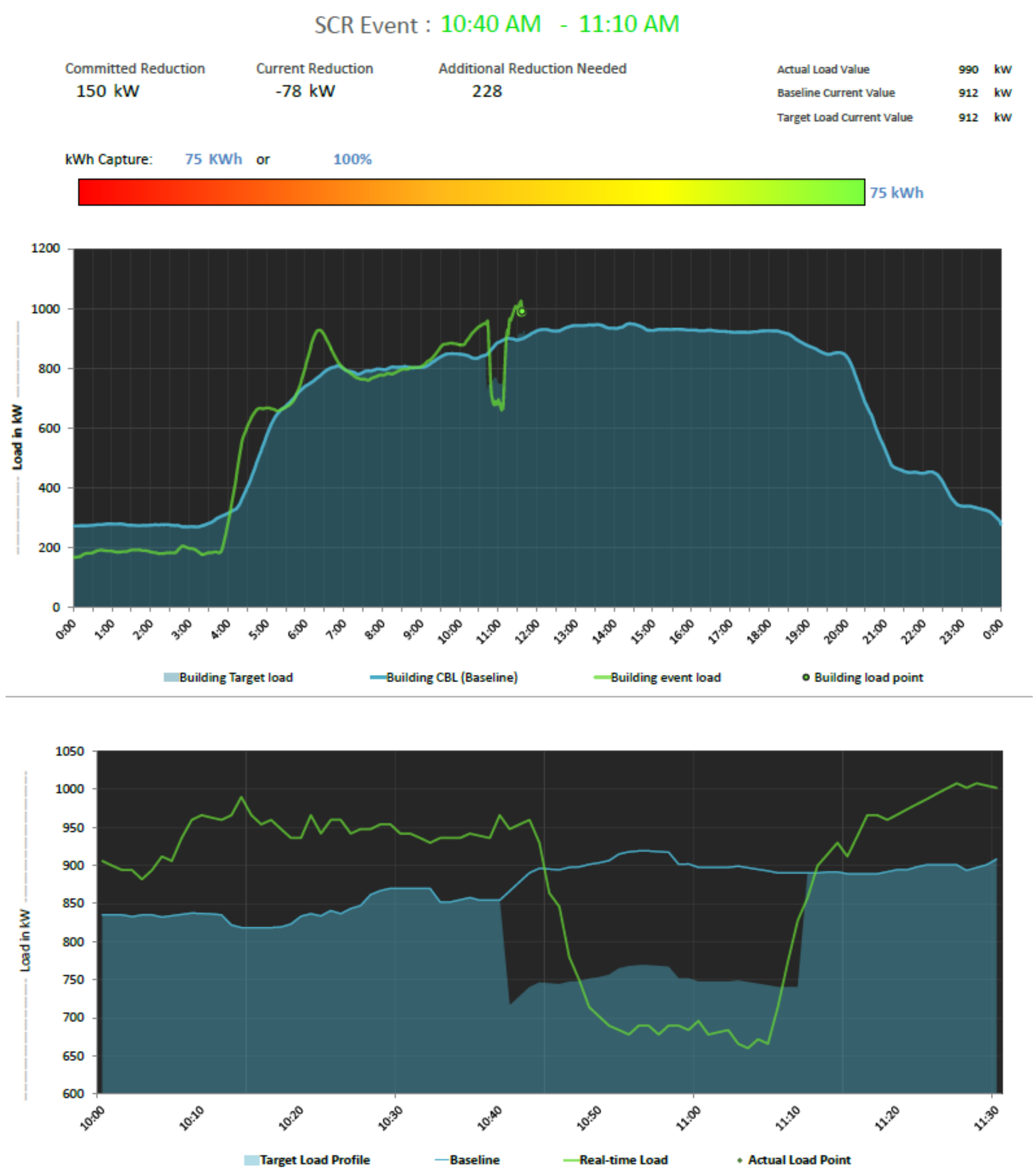
In collaboration with Con Edison program staff, Viridity developed a method for determining/ simulating the economic value of participation in NYISO and Con Edison curtailment programs. Once developed, Viridity executed these reports on a monthly basis and distributed them to Con Edison. These reports also helped us monitor actual event performance before developing similar capability in VPower™. The reports offered the additional value of supporting a commercialization discussion whereby project participants would enter commercial operations with Viridity and Con Edison and/or NYISO.

A.5.1 Product Development and Technology Transfer

The following documentation provides insight to the work completed, the demonstration results, and simulated economic benefits related to the SGDP.

1. Submitted to Con Edison separately is a performance view of the two buildings leveraged in the Capstone Demonstration on July 15, 2013. These reports, produced from a performance-monitoring feature in VPower™ 2.0, a new software platform developed independent of the project and related funding, are quite meaningful and serve as evidence of a successful demonstration. An example of the reports is shown in Figure A-41. The results show load curtailed in response to a simulated grid-based event solely for the purposes of the Capstone Demonstration. However, the system conditions were such that all curtailment was beneficial with extremely hot and humid conditions and peak loads across the system. Just as in real grid operations, the DR results varied by asset/site. In this case, the DR resources under Viridity control performed well.

Figure A-41. Example of Demonstration Report



2. The economic benefit reporting and analysis described earlier in this document helped to refine the approach, define good prospects, and ultimately to commercialize. This file was submitted to Con Edison separately.

3. Viridity generated the following "awareness" related to the SGDP:

   a. 2009 press release on Business Wire resulting in the following placements:

      i. Smart Grid Observer

      ii. Bloomberg

iii. [Pipeline & Gas Journal]

iv. [Consulting Engineer]

v. [Keystone Edge]

vi. [Philly Tech News]

b. Viridity has also featured the Con Ed demonstration in a number of public presentations, including:

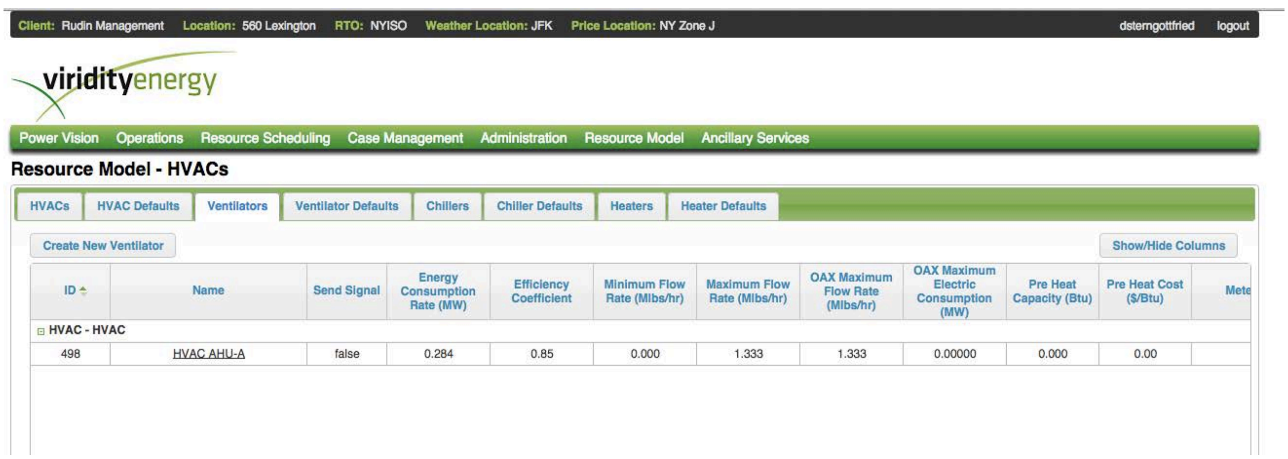
i. [Emerging Issues Policy Forum]

ii. [Americans for Clean Energy Grid]

c. Viridity created a "case study" (submitted separately) related to the project work with Con Edison, which leverages the document based on client/partner situational interest.

4. Viridity developed the VPower™ and VPower™ 2.0 software platforms independently of project funding. Energy resource models (not "computer models") were configured within the VPower™ operating environment as a way to test certain curtailment strategies. An example of this resource modeling is show in Figure A-42.

Figure A-42. Resource Modeling Example



A.6 GCN: Smart Storage and Generation Units (SSGUs)

The Green Charge Networks (GCN) team developed the following summary of SGDP activities as part of the input to the FTR. Results and information below has been used to develop the overall takeaways and lessons learned in the FTR.

A.6.1 Executive Summary

Green Charge Networks LLC (Small Business Entity, 10 C.F.R. 600.325, App. A, FAR 52.227-23, 10 U.S.C. 784) is a SG technology company based on California with offices in New York. The main accomplishment for Green Charge Networks on this SGDP is the demonstration of a behind-the-meter energy storage system for the private sector. The paradigm shift is to gear away from energy (kWh) arbitrage, and focus on power (kW). These appliances called the SSGU, or GreenStation, are intended to reduce the monthly demand charges assessed on commercial ratepayers. When taking into account the value streams from demand charge reduction, infrastructure upgrade avoidance, and EV charging enablement, energy storage could become economical and can gain adoption by the private sector without significant public subsidies. The hardware demonstrated has proven to be robust, having survived hurricane Sandy, and the current software is stable, having been in 24/7 operations for more than two years. This platform may gain market adoption and open up a new market for Power Efficiency solutions (as opposed to Energy Efficiency solutions) in the private sector. It may directly enable the propagation of energy storage for commercial, behind-the-meter customers.

The GreenStation has taken root in California through a combination of state government support (California Energy Commission) and private-sector sales. A number of large-scale private sector customers have signed up for the offering, including Walgreens, UPS, Avis, Kaiser Permanente, and 7-Eleven.

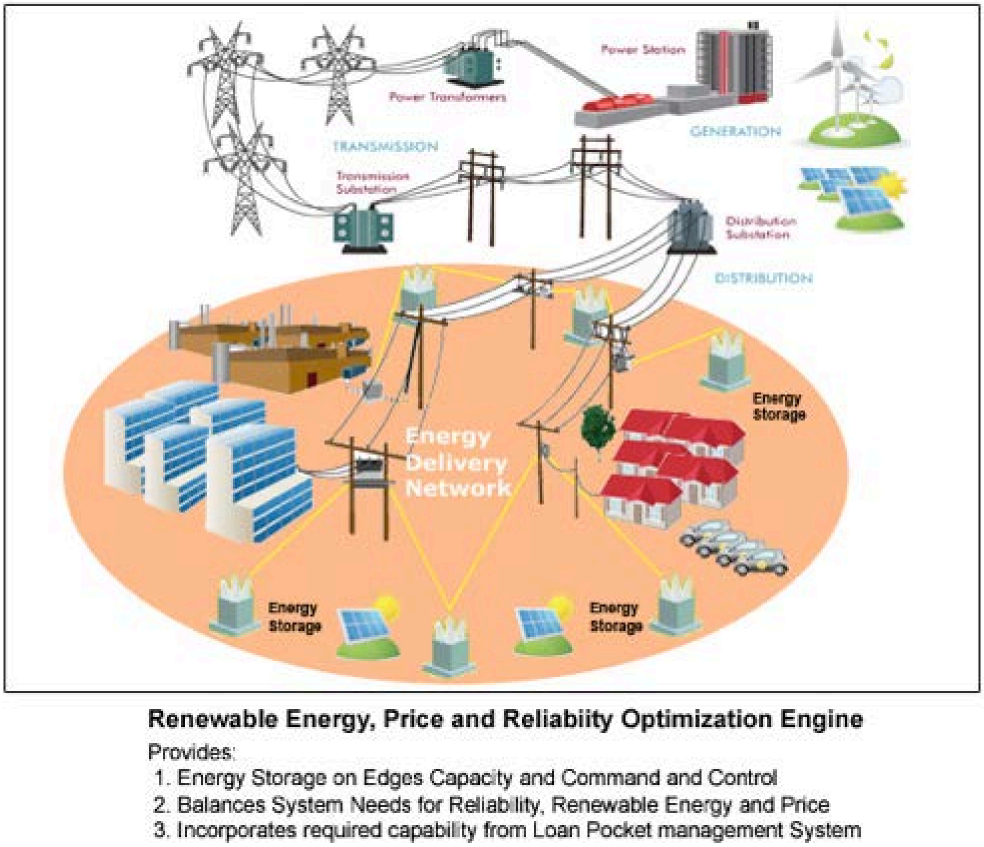
The second accomplishment of this project is to prove out the integration of energy storage with EV adoption and PV. Setting up EV chargers in electrically congested area can be difficult and costly, and energy storage is a viable path forward for deploying these high-powered devices. In fact, the technology from this program has already cross-pollinated to California, where the California Energy Commission awarded a project for GCN to install energy storage + EV charger in combination. The integration with PV proved that where PV is about kWh, energy storage complements existing PV projects by providing kW support. The two are entirely complementary, and provide two separate and distinct value streams to the host customer. Furthermore, in the case of the 7-Eleven installation, the savings have reached parity.

Finally, the integration with a premier utility like Con Edison is the third accomplishment that GCN is very proud of. It enhances the value for the entire electrical distribution chain, and becomes a win-win for all parties involved. The equipment deployed as part of this project enables targeted DR capability.

A.6.2 Background

Current distribution systems typically have limited resilience to absorb renewable energy. The advent of EVs of 200-mile range (40 kWh) will further stress distribution grids as significant market penetration occurs.

Figure A-43. Energy Delivery Network (EDN) Operating in the Distribution Grid



With respect to relieving peak local energy congestion and demands, localized energy generation, storage, and curtailment offer a potentially economically attractive and environmentally responsible alternative to transmitting power from afar. The scope of the EDN project was to validate and demonstrate the feasibility of this assertion.

Multiple SSGUs were installed on Con Edison's distribution grid. SSGUs include renewable generation in the form of PV panels, energy storage in the form of battery banks, and both level II alternating current (AC) and Quick Charging EV Chargers. Distributed energy storage and generation units on the order of 27 kW to 300 kW are small enough that they can be sited in areas with existing electrical load congestion or future EV charging station locations.

EVs represent an opportunity to reduce dependence on foreign oil, CO_2 emissions, and fuel costs. Without the Smart Grid, electrification of automotive transportation at scale could require expensive infrastructure upgrades to reinforce existing distribution feeders.

Despite the fact that the local generation and storage is significantly smaller in magnitude than adjacent loads on the distribution grid, it has the potential ability to relieve local overloaded secondary distribution lines. For example, a typical 250,000 ft^2 office building with a peak demand of 1,500 kW vs. 1,100 kW average summer demand, a nearby 200 kW storage unit could supply half of the surge in peaking demand, thereby significantly reducing the strain on the grid and improving reliability.

Utilities are driven to reduce electric rates and looking for cost effective methods to avoid infrastructure investments. Rapid adoption of EVs will drive utilities to broaden adoption of systems that enable widespread charging of EVs that don't create large capital outlays for the utility and which tend to stabilize the demand on the local grid.

A.6.2.1 Energy Distribution Network Description

A comprehensive, distributed system of "on the edge" generation and energy storage will help to ensure robust reliability as the grid grows larger, greener, and more complex. This "on the edge" system consists of multiple smart energy storage devices that are coupled with DG to augment normal grid power.

The EDN can help manage local loads. It is designed to optimize renewable energy usage and enable recharging of EVs even in areas of electrical congestion. It enables peak shaving. It can also accommodate combinations of the above. By sensing renewable energy availability, it can charge energy storage devices or flow renewable energy directly to discretionary and price sensitive loads during periods of high renewable energy availability.

Storing and generating energy in an EDN "on the edge" alleviates electrical congestion by surgically inserting power during periods of peak demand. The actual sized SSGUs that comprise the EDN are small enough (each providing anywhere between 27 kW to 300 kW) that the tiny footprint in theory should allow for rapid site approvals and installations, following the trajectory in the solar industry once interconnection procedures are standardized. The relatively low cost for each SSGU allows for a low-risk - gradual scale up vs. the step function normally associated with upgrading transmission capacity. The transformational concept behind GCN's new technology is not in the storage and generation products themselves, but in the interconnecting of these different nodes together to formulate a reliable EDN network. Key features of EDNs are:

1. Secure, reliable, and real-time communication between control center and distributed SSGU nodes
2. Remote monitoring of system state-of-health, charge/discharge state
3. Distributed intelligent agents enabling arbitrage opportunities between peak / off-peak etc.
4. Central command and control capability that can override local SSGU behavior in order to alleviate system-wide peak load or congestion
5. Advanced modeling and real-time decision aids to control SSGU clusters based on evolving needs
6. Distributed SSGUs

Data contained on the SSGUs are inherently distributed. Each local model represents knowledge learned from the local data source, but could lack *global* knowledge. SSGUs communicate by message passing over a wireless network, in order to keep track of the global information. Since the data stored in SSGUs is distributed – this model results in a large, *dynamic and distributed* environment storing data in different modalities. Such distributed environments with many data and computing resources require novel methodology for supporting efficient data retrieval and analysis.

A.6.2.2 SSGU Components

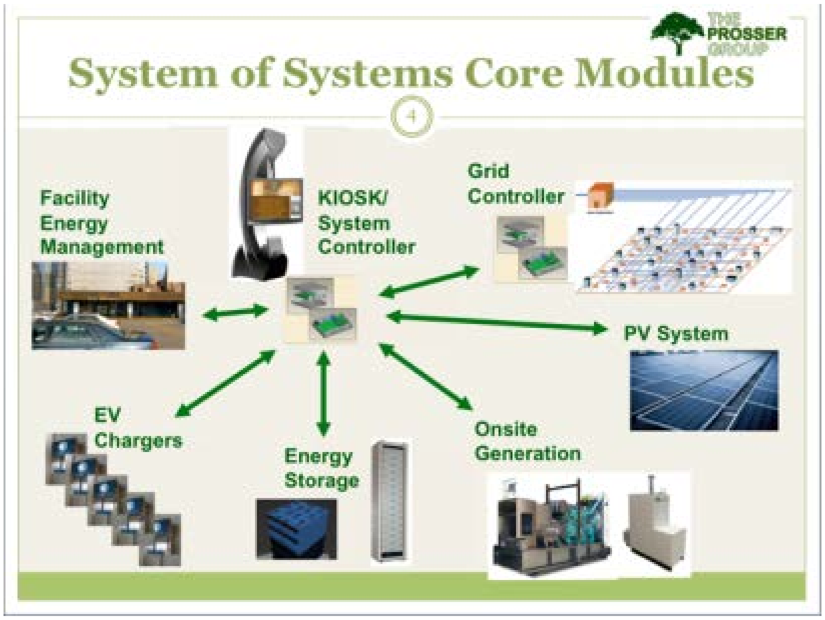
EV Charging System
SSGUs are, in part, designed to help alleviate the increased capacity requirements associated with increased EV charging, and as a result, need to have a smart EV charging system such as an level II Electric Vehicle Service Equipment (EVSE) capable of IP network communications via a CAT5 cable, Zigbee, WiFi, or cellular 3G. Due to safety concerns and insurance requirements, only Underwriters Laboratory (UL) certified equipment were installed in deployed SSGUs. There are multiple EVSE suppliers and selection was based on aesthetic appeal, cost, functional ability, and ease of use. Additionally, at SSGU7, GCN deployed a CHAdeMO ("Charge de Move") based direct current (DC) Fast Charger that could charge a Nissan Leaf up to 80% state of charge under 30 minutes.

Figure A-44. EV Charging System

Energy Storage System
In order to smooth the peaks associated with EV charging and to participate in DR markets, SSGUs require a reliable energy storage system. Lithium-ion battery banks were selected for use in the EDN demonstration project. The batteries were sized based on number of site-specific conditions. Chemistries such as zinc-bromine flow batteries and sealed lead acid batteries were also considered, but failed to provide the same benefits as the lithium-ion battery. Safety, reliability, cost, energy density, and charge & discharge rate were the significant battery chemistry selection metrics. Lithium-ion batteries used in automotive applications lose the ability to hold a full charge over time, resulting in replacement. EDN provides a significant market for these used batteries, most of which are replaced when unable to hold less than 70% of original charge.

A battery management system ensures safe charging of the individual lithium ion cells, ensuring even distribution of heat and current. The battery management system interfaces with a bi-directional inverter system. This system consists of a series of inline inverters and transformers allowing for the charging and discharging of the battery system. All inverters used to discharge energy from the energy storage to the distribution grid must be UL1741 compliant, specifically regarding the IEEE1547 Anti-Islanding provisions.

Figure A-45. SSGU System Controller



PV System

The PV system compliments the other components of the SSGU by providing a means for charging the EVs locally, when power is available, or soring excess solar energy until it is needed by the grid. Crystalline silicon modules were used in the EDN Demonstration due to their low cost, availability, and large number of suppliers. They are installed in rooftop applications. Panel supplier and models are selected based on price, availability, lead time, efficiency, and energy density. An in-line grid-tied inverter was used to convert the DC power generated by the panels into AC power to be consumed by the system. The PV inverter was equipped with a maximum power point-tracking system to optimize power output. Like the energy storage discharging inverters, PV inverters must also be UL1741/IEEE1547 compliant.

Electrical Connection

Con Edison and NYC Department of Buildings (DOB) were operating under National Electric Code (NEC) 2005 version at the time of implementation. According to these codes, in commercial applications, the sum of the maximum current rating, in amps, of all circuit breakers supplying power to an electrical panel cannot exceed the maximum rated amperage of that panel. In residential applications, the sum of maximum ratings can be less than or equal to 120% of the panel rating. This allows for the installation of small power sources (i.e., energy storage or PV solar) in a residential panel without altering the main panel.

In typical commercial applications, a business owner has few practical options if she or he wants to install a power source such as an SSGU. Their first option is to de-rate the main disconnect breaker through which power from the utility is traditionally provided. This reduces the overall capacity of the location to consume power, which is typically undesirable to most commercial customers. A second option is to upgrade their main panel. This option is a costly and time-consuming. The main panel must be isolated, de-terminated, and upgraded. A new, higher rated panel must be purchased, installed, terminated, inspected, and activated. This process involves not only Con Edison, but also coordination with NYC

DOB and an electrical contractor. Depending on the customer, this option can be more or less attractive than the first. However, it is still a significant undertaking.

Fortunately, a third option exists that is commonly referred to as a 'line side tap' or a 'line side splice'. In this case, the new power source (i.e. battery or PV system) is connected upstream of a building's main panel. In order to take advantage of the power generated by PV systems, the connection is made downstream of the utility revenue meter. By connecting power sources between the meter and the panel, the building can consume the same amount of power while taking advantage of the revenue generated by PV systems. In addition, the distribution grid can take advantage of having energy storage which can be used to reduce the consumption of or supply all of an SSGU's building power. Most SSGU customers will probably prefer a line side tap installation.

System Controller
In order for all of the above components to work collaboratively and integrate with the broader EDN, they need an intelligent controller. Each SSGU was subject to a constantly fluctuating energy environment. PV output fluctuated based on cloud cover. Building loading will change based on heating, ventilating, and air conditioning (HVAC), elevator, and other load usage. The system controller is the rules based local engine that monitors local energy conditions and dispatches the EVSE & battery accordingly.

The system controller has several sub-functions including electrical monitoring and interfacing with Con Edison's distribution grid operations control center through business rules knowledge engine (BRKE). In the event that Con Edison calls upon an SSGU to support the grid, the utility communicates can control energy storage and EVSE through the system controller.

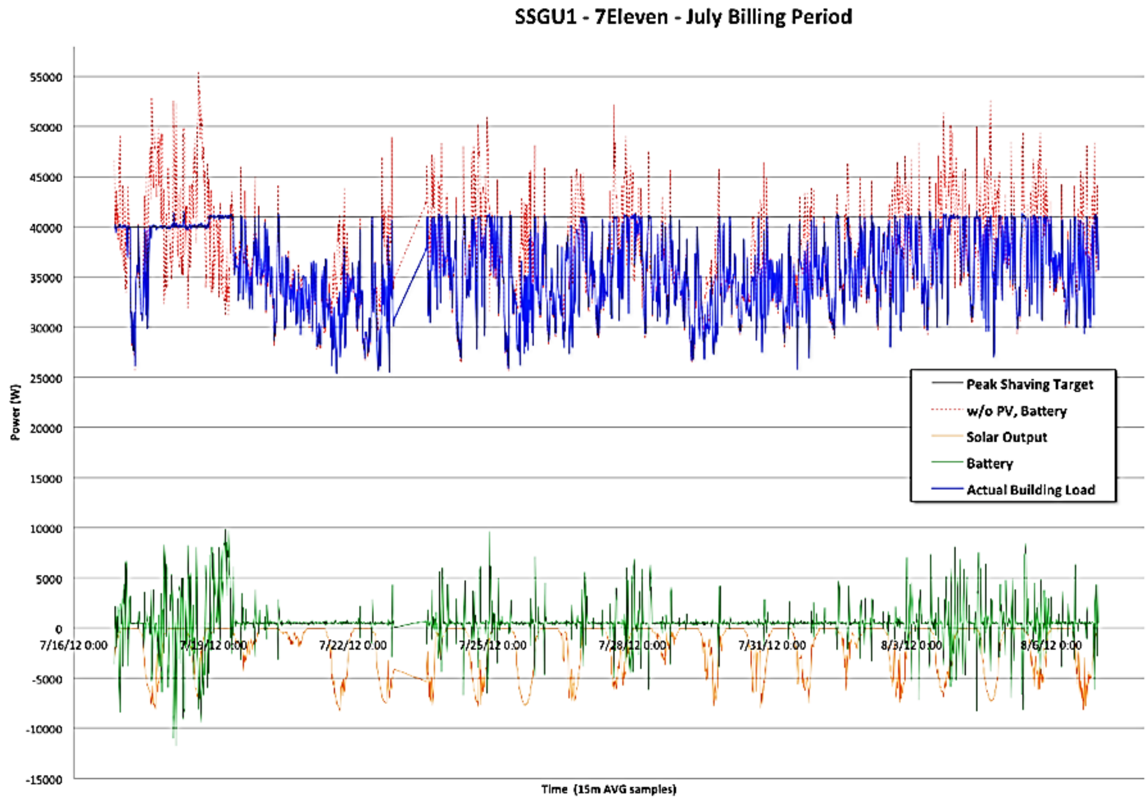
A.6.3 Project Goals and Accomplishments

Below are the highlights of our actual accomplishments.

A.6.3.1 Field Deployment of an EDN with Multiple SSGUs

One of the project accomplishments was that the integration of PV, EV charging, and energy storage occurred very early in the program, with a significant amount of data captured. Below is a screenshot of a month's performance.

Figure A-46. SSGU1 Billing Period, July 2012



GCN accumulated more than two years of data on numerous installations on a second-by-second basis, inclusive of energy storage charge/discharge rate, temperature, state of charge, voltage, PV solar output, and EV usage. These systems have overcome summer heat waves, polar vortexes, and even hurricane Sandy. The deployments covered four separate use cases of distributed energy storage:

1. **Reduce demand charge for the host customer**. GCN gathered two years of performance data, tracking predicted demand charge reduction vs. actual at the end of the billing period.
2. **Avoidance of utility service upgrades**. At Avis LaGuardia Airport, a utility service upgrade (transformer and underground cable) would have been necessary to support the installation of 21 level II EV chargers. The addition of SSGU to serve the local peak loading avoided the need for the service upgrade, saving Avis $400,000 in construction cost.
3. **Forming an EDN (Multiple SSGUs working together)**. In July 2013, GCN demonstrated three SSGU systems working in unison to dispatch energy upon command from Con Edison operator with seconds delay.
4. **Mobile SSGU**. GCN developed a mobile SSGU with the intention of being easily transportable, connected to PV, and also provide portable EV charging. However, Department of Transportation (DOT) regulations pertaining to lithium ion batteries proved to be a major hurdle that prevented the deployment of the mobile unit.

Photos of the various installations follow.

Figure A-47. SSGU1 – 7-Eleven Northern Blvd.

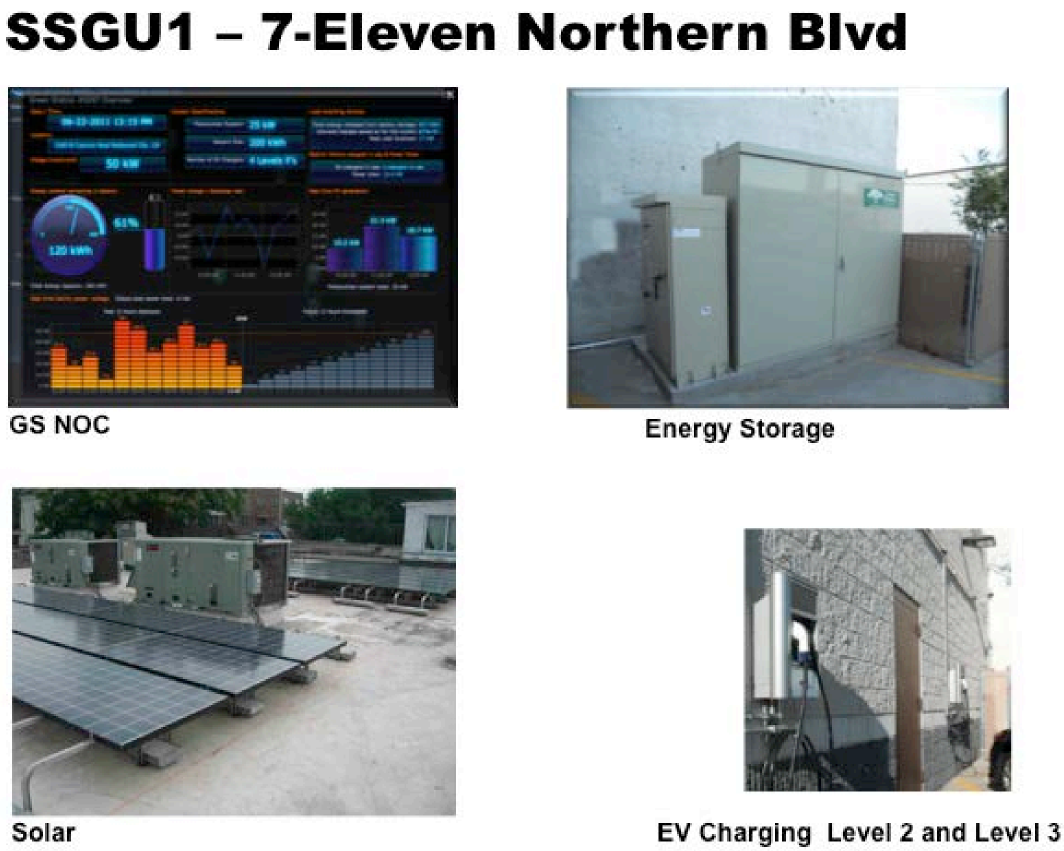


Figure A-48. SSGU2 – Avis LaGuardia

SSGU2 – Avis LaGuardia

conEdison

Figure A-49. SSGU3 – Mobile

Figure A-50. SSGU4 – 7-Eleven Francis Lewis

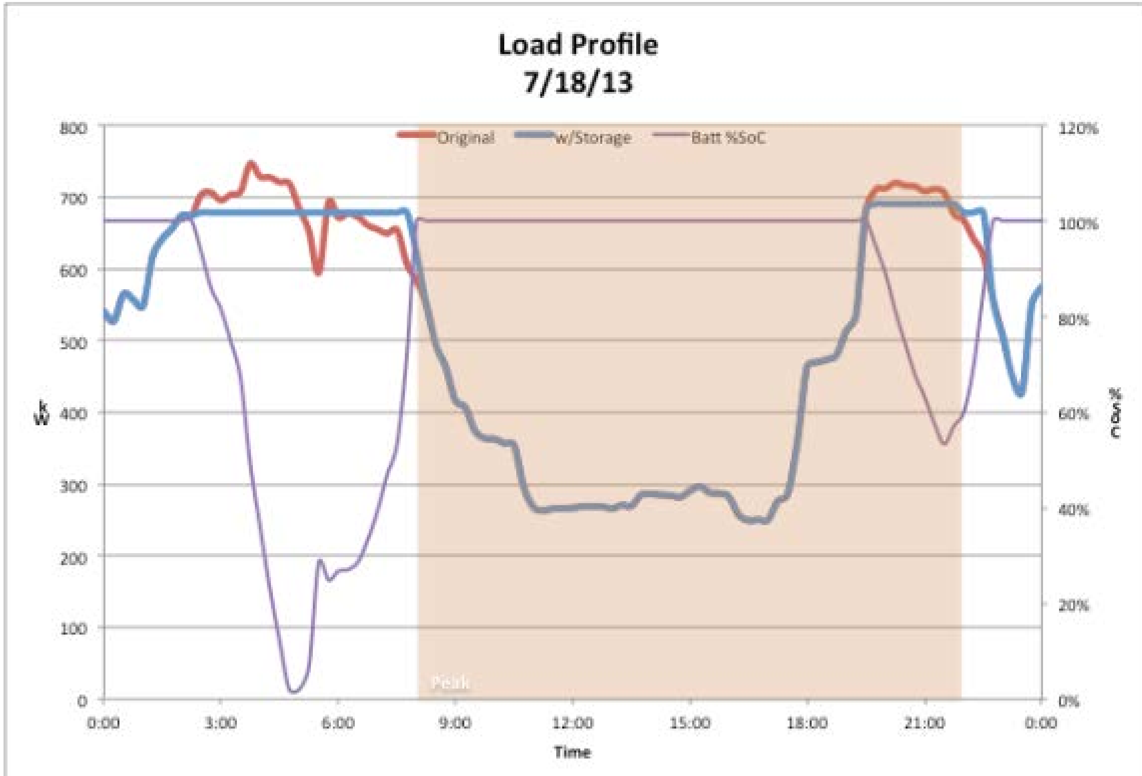
SSGU4 – 7-Eleven Francis Lewis

Figure A-51. SSGU5 - Walgreens

A.6.3.2 *Developed Business Case for Distributed Energy Storage System*

GCN developed a business model for distributed, behind-the-meter energy storage system by tackling rising demand charges. GCN field-tested charge/discharge algorithms and models for quantifying the savings. Below is an example analysis from our UPS installation (scheduled for Sept 2014).

Figure A-52. UPS Installation Example



Bill End	Abs Original Max kW	Abs Reduced Max kW	Abs Demand Shaved	G&T Peak Max kW	SetPoint G&T Peak kW	Demand Shaved G&T Peak kW	$/kW Tariff at G&T Peak	Primary Peak Max kW	SetPoint Primary Peak kW	Primary Demand Shaved kW	$/kW Tariff at Primary Peak	Second. Peak Max kW	SetPoint Sec Peak kW	Demand Shaved Sec kW	$/kW Tariff at Sec Peak	Monthly Savings	Notes
8/16/2013 0:00	746.9	690.2	56.6	406.1	306.1	100.0	$8.28	745.0	690.2	54.7	$15.49	746.9	678.1	68.8	$16.62	$2,818.59	
9/17/2013 0:00	737.3	668.3	69.0	467.5	367.5	100.0	$8.28	714.2	647.7	66.6	$15.49	737.3	668.3	69.0	$16.62	$3,006.19	
10/17/2013 0:00	687.4	625.3	62.1	426.2	326.2	100.0	$8.28	670.1	620.0	50.1	$15.49	687.4	625.3	62.1	$16.62	$2,635.52	
11/5/2013 0:00	680.6	614.6	66.1	383.0	348.4	34.7	$0.00	650.9	591.5	59.3	$11.42	680.6	614.6	66.1	$5.33	$1,029.88	
		0.0	0.0			0.0				0.0				0.0		$1,000.00	estimate
		0.0	0.0			0.0				0.0				0.0		$1,000.00	estimate
		0.0	0.0			0.0				0.0				0.0		$1,000.00	estimate
		0.0	0.0			0.0				0.0				0.0		$1,000.00	estimate
		0.0	0.0			0.0				0.0				0.0		$1,000.00	estimate
		0.0	0.0			0.0				0.0				0.0		$1,000.00	estimate
		0.0	0.0			0.0				0.0				0.0		$1,000.00	estimate
		0.0	0.0			0.0				0.0				0.0		$2,800.00	estimate
														Past 12 Months Savings		$19,290.18	

A financial analysis for this UPS site is summarized below. After planning was already underway for this project, a new incentive in NYC, at $2,100 per kW[3], became available for energy storage. Accordingly, the two financial analyses below for each 96 kWh/100 kW SSGU system include an assessment without and with the incentive. At UPS, a total of three SSGUs were installed.

[3] Note that this is based on a four-hour rating.

	Equipment Cost	Installation Cost	Energy Storage Incentive	Final Cost	Annual Savings	Payback	Internal Rate of Return (IRR) (%)
	a	b	c	d = a + b - c	-	-	-
w/o Incentive	$130,000	$133,000	$0	$263,000	$19,291	9.6 years	1.50%
w/ Incentive	$130,000	$133,000	$50,400	$212,600	$19,291	9.0 years	4.50%

NOTE: Savings are escalated five percent per year based on historical increase in demand charges in Con Edison territory.

There are two important notes about this analysis. First is that the energy storage incentive can have a significant impact in determining whether a project is financially viable or otherwise. In this analysis, the energy storage incentive improves the project payback by 0.6 years and the IRR by 3%. Second, the installation costs of this project unexpectedly became a significant driver of costs, accounting for over half of the total project cost. Construction in Manhattan can be particularly expensive, nearly doubling the cost in the outer Boroughs. Lessons-learned from this project will help stakeholders better identify cost drivers for citing an energy storage system, better allowing systems to be installed while avoiding these significant installation costs.

A.6.3.3 Distributed Energy Storage Can be Used In Place of Utility Service Upgrade

At Avis LaGuardia Airport, GCN was initially informed that 21 level II EVSEs would require a utility service upgrade. The customer transformer cannot handle the added load. Additionally, the customer-side power cables that run underneath the parking lot would need to be upsized. This upgrade would have cost $400,000, including digging up the parking lot and interrupting business for several weeks. Instead, GCN worked with the electrical professional engineer and sized the SSGU to serve the peak load. As a result, the utility service upgrade was not required.

A.6.3.4 Intelligent Software is the Key to Making Energy Storage Economical

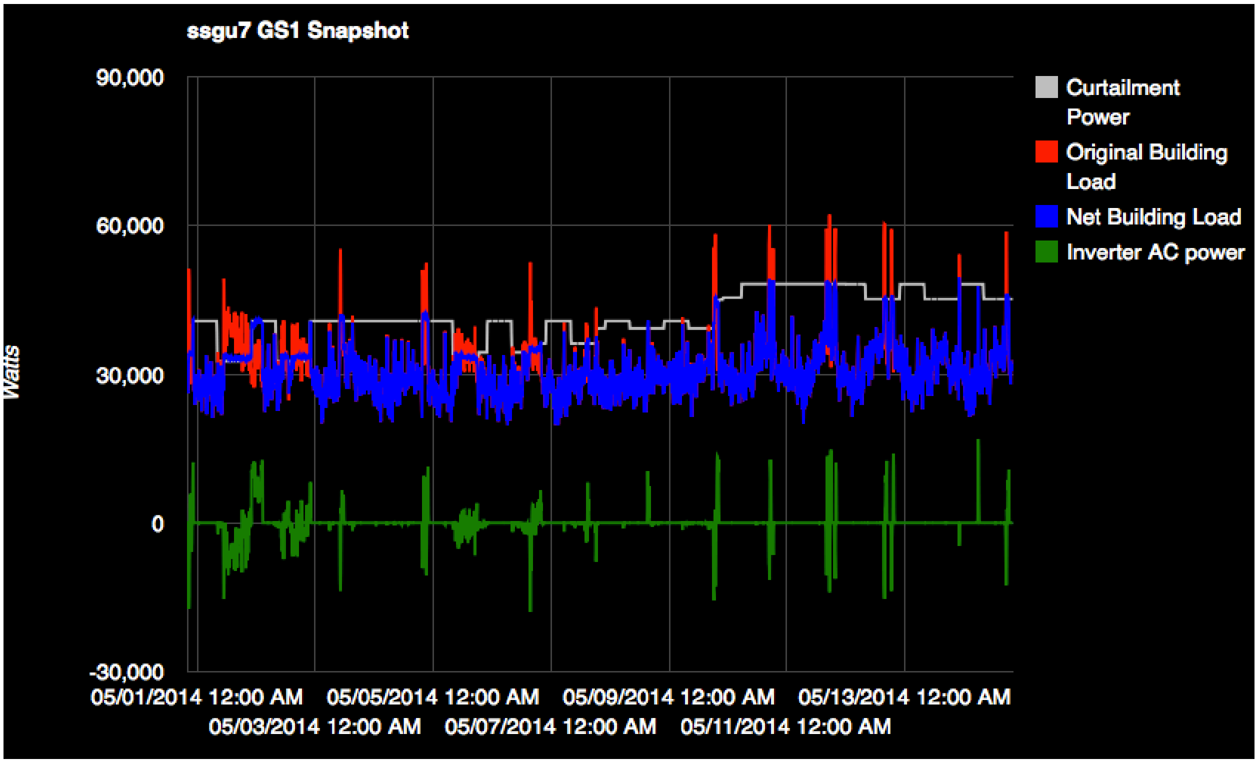
GCN demonstrated that intelligent software that is able to predict and reduce power demand is the key to shrinking the size of battery hardware needed, thereby improving the economics for mass adoption of distributed energy storage technology.

A.6.3.5 DC Fast Chargers for EVs Require Energy Storage for Mass Adoption

A DC fast charger that can charge an EV in 30 minutes is a necessary component of the EV refueling infrastructure. Demand charges are prohibitively expensive, causing host customers to either not want it or require a separate meter paid by the EV charger operator. This adds a significant obstacle and cost to deployment.

Through this project, GCN has proven that DC fast chargers for EVs (>30kW) can be installed behind the meter under existing service/meter using intelligent software and energy storage. This paves the way for mass adoption and deployment. See below screenshot of a month's performance at the 7-Eleven test site.

Figure A-53. Month's Performance Example



A.6.3.6 EDN Benefits

GCN demonstrated that a network of SSGUs can in fact operate in unison and respond to the utility in times of need. GCN demonstrated that distributed energy storage can be centrally controlled by the utility, enabling "surgical curtailment". This has multiple advantages when compared to the current crop of DR load relief technology:

- Generation assets without a single point of failure
- Surgical curtailment targeting feeders, individual utility transformers if needed
- Real-time, instantaneous response
- No humans in the loop; complete automation with performance guarantee
- No hassles or inconvenience for the end user

A.6.3.7 Mobile SSGU

Through this effort, GCN learned many important lessons relating to a portable micro-grid system, including the following:

1. Transportability of lithium ion batteries
2. Use cases for portable energy storage
3. Feasibility of providing portable EV charging

The Mobile Unit can accommodate up to 10 kW of PV as well as commercial, off-the-shelf level 2 EVSE chargers. The built-in grid-tied inverter will invert DC from PV or energy storage into AC if connected to a facility or building. The DC Fast Charger port is a special case. The commercial, off-the-shelf systems use 50kW of 480V AC power and rectify it into DC to power a vehicle. GCN applied its own independent research and development to power a DC fast charger using DC instead of AC to save the roundtrip conversion losses. The end result is a DC fast-charge controller that can power a Nissan Leaf or Mitsubishi iMiEV directly from a DC source.

GCN completed the development of one mobile SSGU unit that was demonstrated in July 2011 at a SG conference sponsored by Siemens in Raleigh Durham, NC. Subsequently, GCN discovered that there was significant costs associated with deploying a mobile lithium-ion based mobile storage unit, due to highway transportation regulations. The basis for the restrictions imposed by the federal DOT regulations is the classification of lithium ion as a DOT class 9 hazardous material. The United Nations (UN) has made specific recommendations to the DOT, titled UN Model Regulation 3480 and 3481. Getting through these regulations and tests required destructive testing on real-life equipment samples and was cost prohibitive. As a result, further mobile SSGU deployment was aborted.

Figure A-54. Mobile SSGU Specifications

Figure A-55. Mobile SSGU in Use

SSGU3 is a proof-of-concept mobile energy storage and EV charging platform. Using it and its derivatives, including the truck-based mini-system, GCN explored the various use cases for mobile energy storage and EV charging, including the needs of utilities and commercial customers. GCN also explored commercial partnerships to bring such a system into the market. GCN learned that there are many situations that warrant such a system, including providing voltage support, DG, and EV charging for public gathering events.

A.6.3.8 Comparison of Actual Results versus Original Goals

The high-level objective of GCN's project was to use sophisticated software to meet rising power demands at a fraction of the cost of utility infrastructure upgrades. This is a paradigm shift from traditional energy efficiency initiatives, which have been about energy or kWh. GCN's project tackled power (kW) efficiency. The mechanism to quantify the savings on the customer's side of the meter is through demand charge reduction. Through this project, GCN aimed to provide a solution with an economic return on investment (ROI) of less than eight years that can be readily commercialized.

Below is the summary table of the goals/objectives and actual accomplishments.

Table A-15. Summary of Goals and Results

Original	Actual	Lesson Learned
BRKE – Distilling institutional knowledge from Con Edison expert operators, improved processing of repetitive and data-intensive activities, greater clarity and speed. Integration with Columbia stochastic controller.	BRKE – Early on in the implementation, Boeing and then Siemens Energy took over the utility operator expert knowledge engine and working with Con Edison operators and IR. The scope of work evolved to a rules engine for the local environment at the facility where the SSGU is installed. GCN implemented localized rules and predictive algorithms to anticipate changing power loading based on weather and historical usage.	GCN designed a flexible platform that can accommodate the needs of utilities as well as down to the individual customer facility.
DSM – Visibility into secondary grid and connected assets, including distributed generators and curtailment. Bring DR programs into the control room; surgical curtailment of load at the feeder level.	DSM – At the final demonstration in July 2013, GCN connected three SSGUs / GreenStations to the demonstration platform under Con Edison operator's control. The operator had real-time visibility into PV generation and EV charger consumption. Furthermore, a portion of the energy content of the SSGU was dedicated to the operator's control. At the press of a button, the operator triggered DG at all three sites, thereby reducing loads within seconds. The operator was able to pick and choose specific generators, thus providing "surgical" load relief.	Aggregation of DG assets is challenging due to cybersecurity and reliability concerns; however, if done correctly and repeatedly, such a network adds tremendous value to the grid.
EDN – Validate that distributed energy storage on the edge outperforms centralized energy storage, in terms of reliability, renewable integration, weather susceptibility, demand relief in light of EV chargers, and demand charge reduction.	GCN ran into numerous issues, including permits, interconnection, contracts, and costs, which limited the number of installations GCN could do. GNC installed a total of eight systems and successfully proved the value of distributed energy storage.	Interconnection approval with the utility takes a tremendous amount of time and effort. Get this process started upfront at the beginning of a project.

A.6.4 Project Activities

A.6.4.1 Original Hypotheses

The functional software requirements of the BRKE, Demand Side Manager (DSM), and EDN were developed with the following considerations:

BRKE

1. Store a collection of business rules to be evaluated when system overload indicators arise
2. Allow network operators to maintain the business rules through a user interface
3. Continuously process near real-time data of grid assets to identify potential trouble spots and overloaded assets

4. Utilize a decision aid algorithm to propose an optimized curtailment schedule to maximize relief on stressed equipment and incorporate business logic maintained by operators
5. Securely communicate to the utility to obtain updated grid conditions and send suggested curtailment schedules

DSM

1. Securely receive DR requests from the utility
2. Send automated notifications and requests to DR aggregators and smart storage devices connected to the secondary grid
3. Provide visibility to connected assets, including distributed generators, PV, and EVSE
4. Evaluate, measure, and verify curtailment requests sent

EDN

1. Provide real-time visibility into GCN's deployed assets to the utility
2. Interface with and control smart assets within the SSGU
3. Act upon a DR request and report curtailment statuses

A.6.4.2 Original Approaches

GCN developed proof-of-concept BRKE and DSM web applications, incorporating the Bosch Visual Rules engine. Over time through the project development process, some of the requirements that were originally contemplated to be performed by GCN's BRKE and DSM were instead accomplished via the integration of Con Edison's existing poly-voltage load-flow (PVL) applications. The focus of GCN's software requirements evolved to be installation-site specific, balancing the power and energy flows of assets and devices at the customer site in a manner which would enable a reduction in peak demand.

The BRKE and DSM features are fully integrated within the Grid Synergy Network Operations Center (GSNOC). Secure messaging through a middleware and integration system will allow for the GSNOC to receive requests and data from systems within Con Edison. The EDN is made up of three of GCNs' SSGUs tied together via a Grid Synergy Network Integrator (GSNI) communicating securely to the GSNOC. By the end of September 2014, GCN will have three additional systems online at UPS for the EDN network. Day-ahead weather prediction has been integrated into the load forecast in order to determine optimal state-of-charge of the energy storage systems going into the next day. Figure A-56 and Figure A-57 below show the high-level system diagrams of the BRKE system and the DSM/EDN diagrams, respectively.

Figure A-56. High-Level BRKE System Diagram

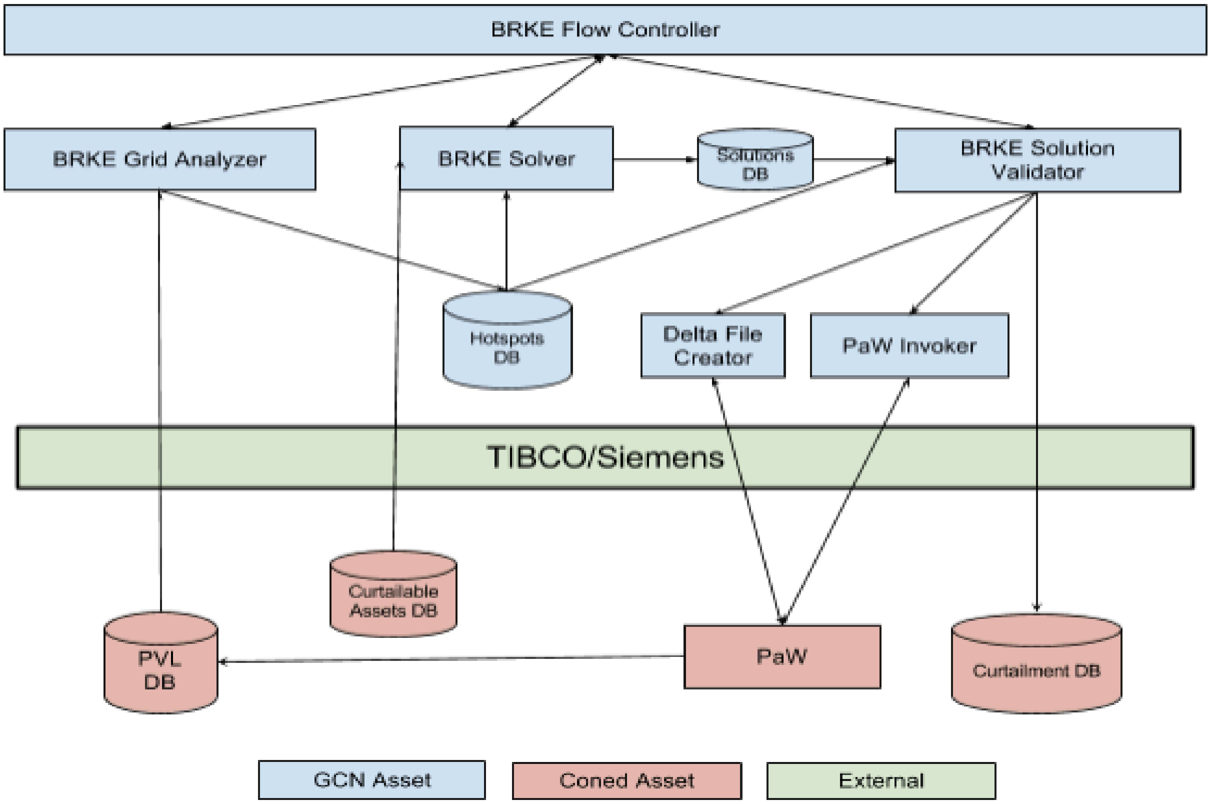
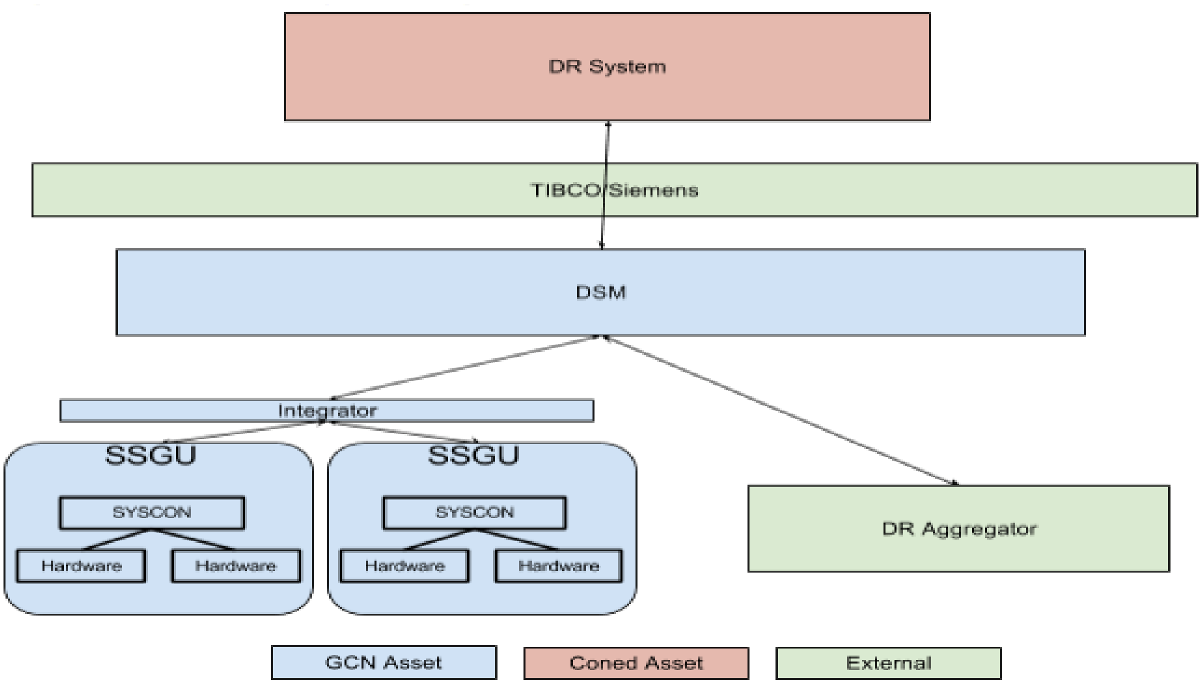


Figure A-57. High-Level DSM/EDN System Diagram



The GSNOC has been built using a SOA methodology. Using the Spring Web Service Framework, a discrete service and interface was created to handle DR requests from the utility, status requests from the utility, curtailment requests to the SSGUs, status requests to the SSGUs, and communication to a Java-based web application.

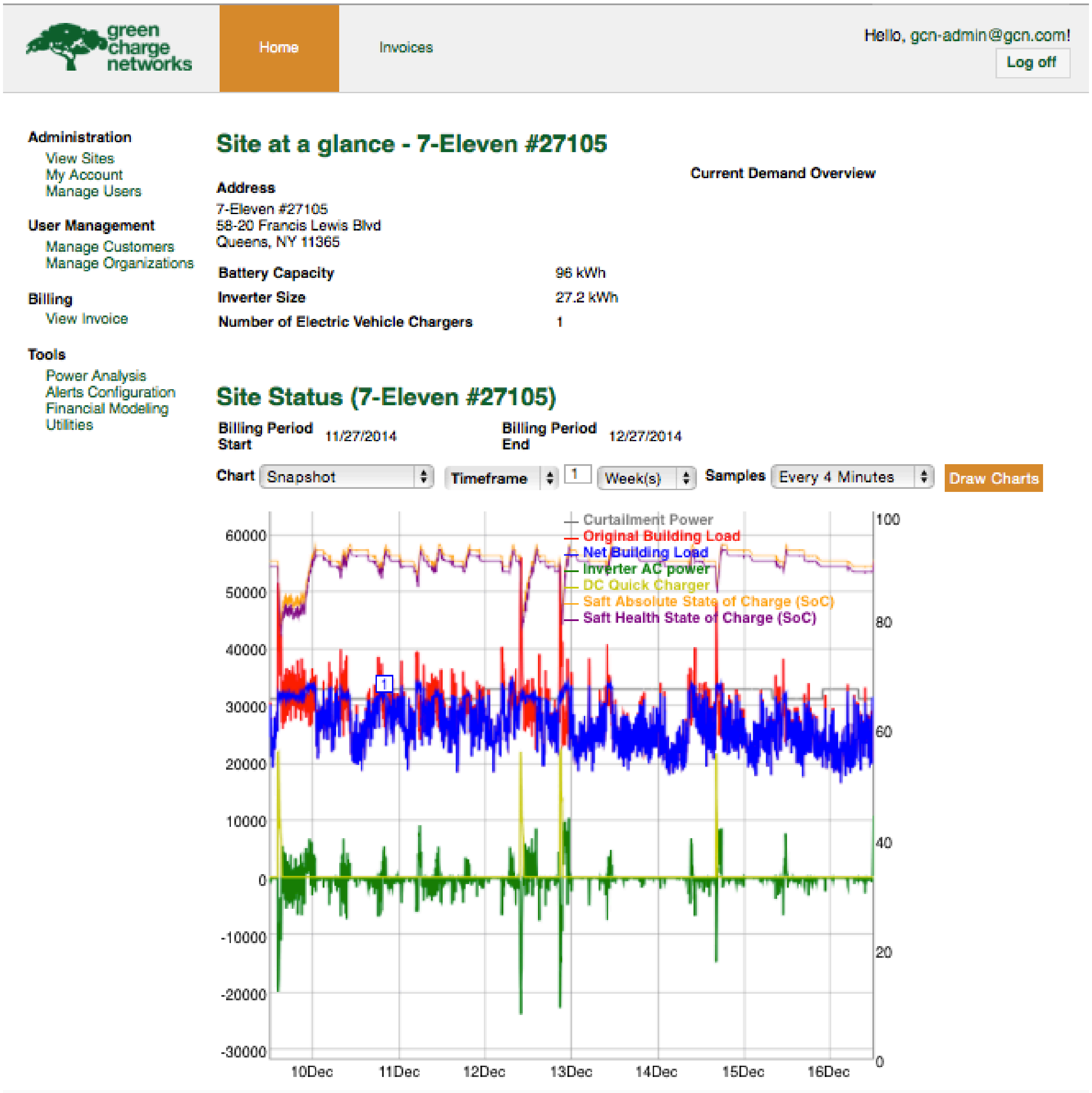
GSNOC

The GSNOC is a customer portal and an administrative interface for GSNOC operators. The GSNOC has three core administrative responsibilities: communicate with the field assets, issue peak demand set-points, and monitor the health of the assets. GSNOC operators are able to remotely monitor and control GCN's field assets, and customers can view the status of their systems.

Features:

1. Cybersecurity to NIST 7628 standards for communicating with assets in the field and to the electric utility
2. Auditable records of commands and actions taken
3. Performance and acknowledgement of command/control back to the utility
4. Monitors field assets
5. Reports of system performance, savings through demand charge reduction
6. Customer interface portal
7. GCN super-user technical and financial savings analysis tools

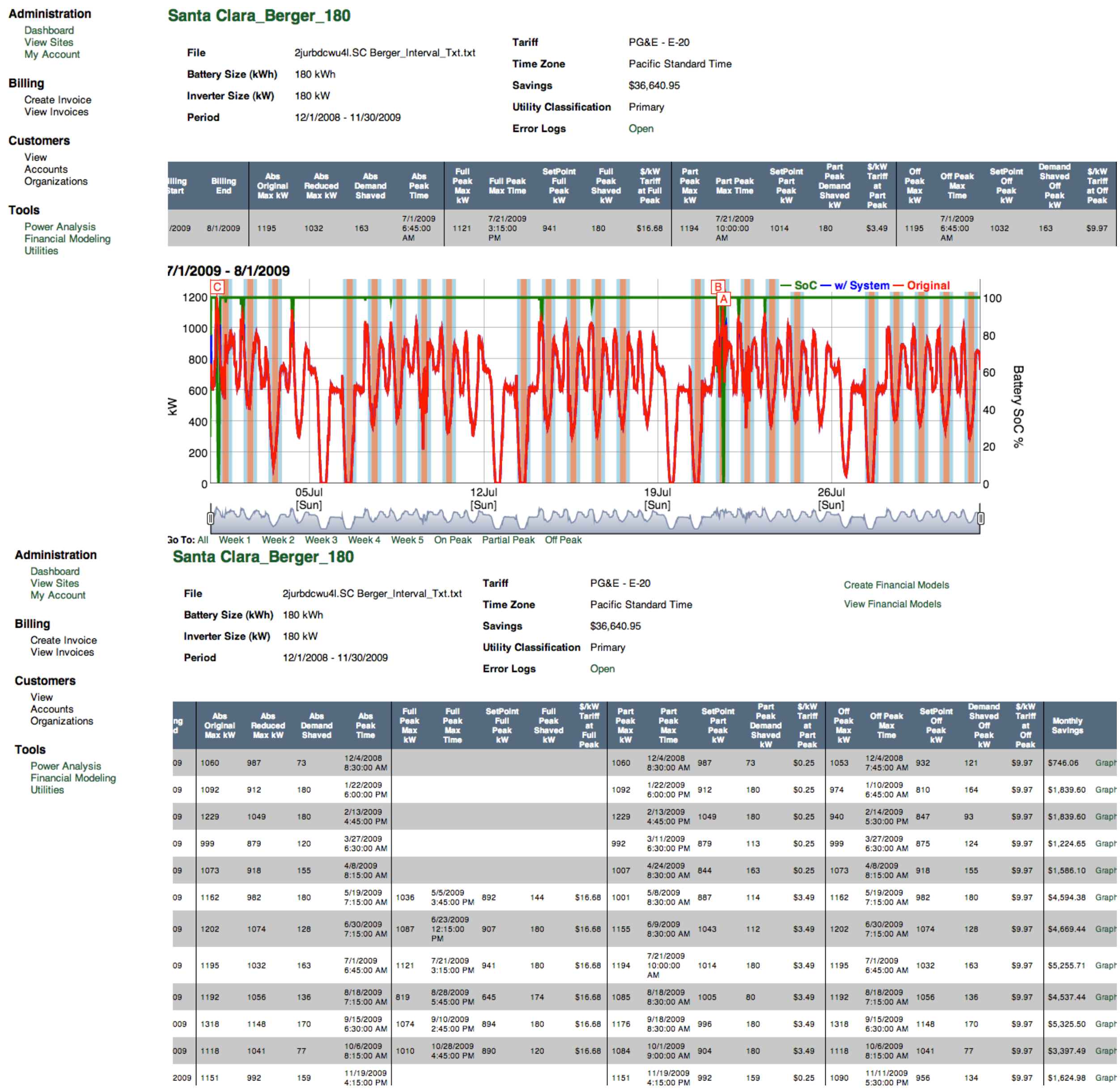
Figure A-58. GSNOC Example



All communications to and from GSNOC are encrypted via AES-128 bit security. GSNOC implements a User Access Control system. Only users with proper permissions can access certain portions of GSNOC.

GSNOC also contains "super-user" features that allow a user to perform savings analysis. Screenshots of these features are shown below.

Figure A-59. GSNOC Super-User Features Example



GSNI

Primary purpose:

- Data acquisition and storage

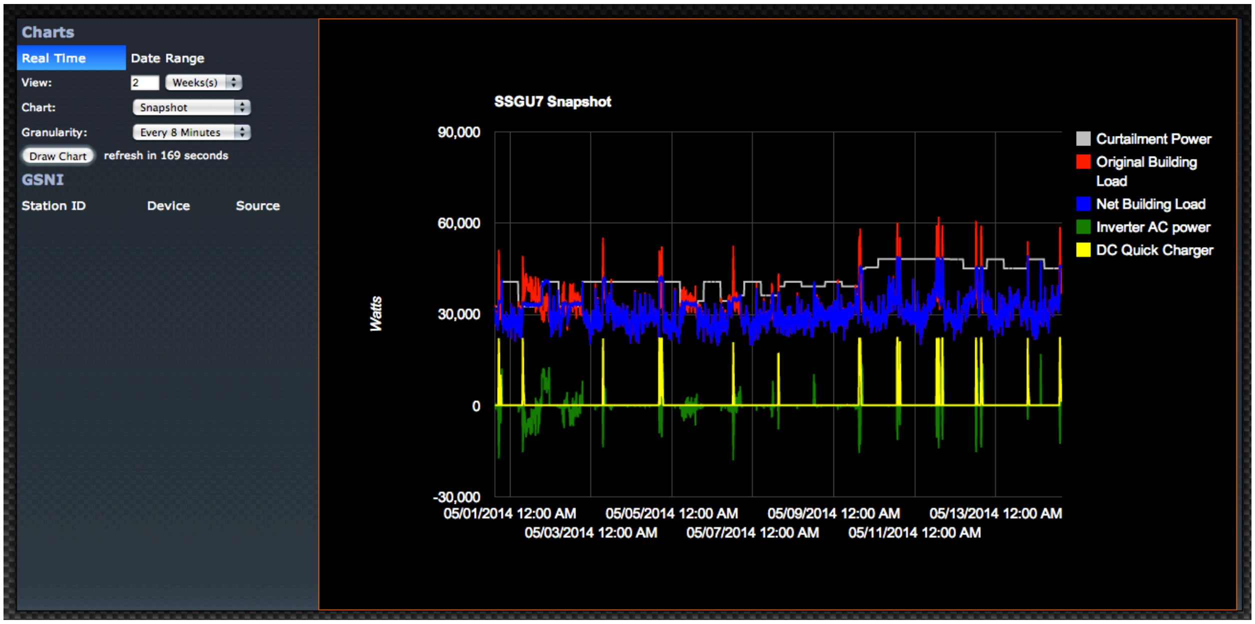
Goals:

- No data loss
- Fast performance (very fast inserts, fast queries)

- Non-blocking, high throughput (SSGUs will be posted frequently, data will be queried frequently)
- Security (authentication, privacy)
- Simplicity: insert and read only (no interpretation or editing)
- Eventual scalability

GSNI also provides an admin interface for GCN operations and monitoring. Screenshot below:

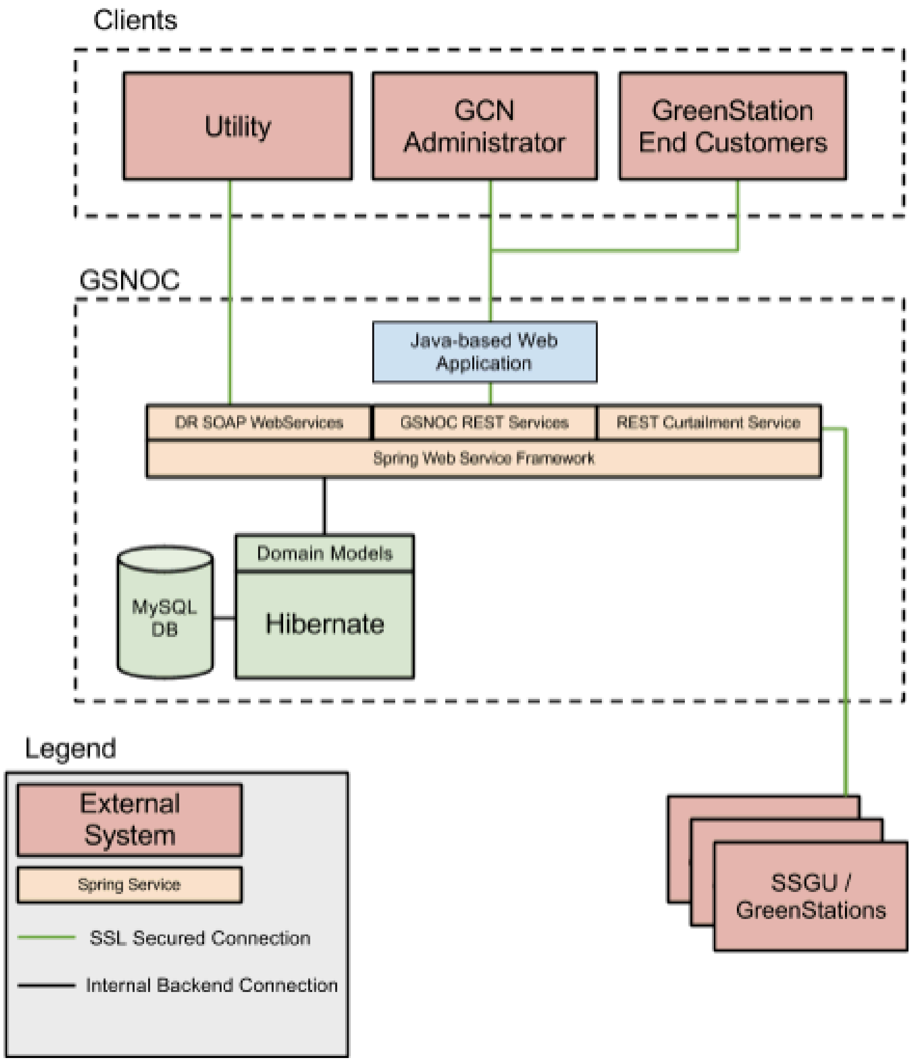
Figure A-60. GSNI Example



Scope:

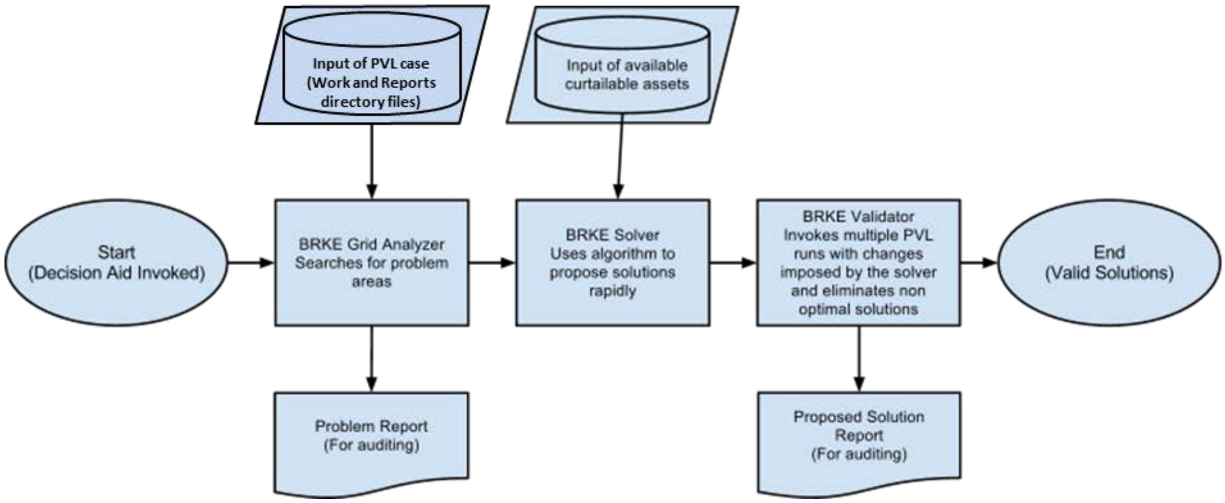
- Data collection
- Data storage
- Data query support
- Admin interface for operations and monitoring
- Configuration (does not need to be through the API)

Figure A-61. System Diagram



Within the GSNOC back end, a service was scheduled to periodically run and perform the BRKE functions. The primary functions of this service are to find overloaded or possibly overloaded grid assets, determine viable solutions to mitigate the overloads using curtailable assets, and to eliminate any solutions deemed unfeasible due to business logic. Figure A-62 below shows the Decision Aid Algorithm Flowchart.

Figure A-62. Decision Aid Algorithm Flowchart



For the EVSE demonstration, a remote operator was logged into GSNOC and issued a curtailment of the charging Nissan Leaf to curtail first to 50%, and then to 0%. The curtailment request was sent securely to the SysCon on-site, which then limited the output of the charger. A separate demonstration showcased the ability to remotely control energy storage assets and manually dispatch energy. Similar to the other demonstration with EVSE curtailments, specific discharge set-points were sent and the site's response to the commands was reported back in graphical form within seconds.

At the conclusion of this project, GCN will have demonstrated the GSNOC's ability to communicate securely between seven GCN sites (Avis, 7-Elevens at two locations, Walgreens, and three separate UPS systems) and Con Edison, including energy storage, EV charging, and PV generation. The output and curtailment capability across all seven systems can be aggregated. When a curtailment request is received from Con Edison, the BRKE will automatically determine the best optimized curtailment schedule in the background. Once the curtailment is enabled by Con Edison, the DSM will automate the DR requests sent to the SG assets. All of GCN's SSGUs will receive the requests and report back to GSNOC and through GSNOC the utility gets updated statuses and fulfillments of the request as part of the EDN.

A.6.4.3 Problems Encountered and Departure from Plan

The main problems encountered were on the EDN/SSGU side. GCN learned that there is a high cost and rather significant time required to enable these systems to be sited, permitted, and installed. As time went on, the process got easier as all parties became more familiar with the requirements.

GCN encountered a significant amount of administrative burden due to their unfamiliarity with the DOE agreement requirements and the associated grant compliance reviews. GCN was required to allocate a significant amount of time to address compliance requests that were necessary to ensure conformity with applicable federal regulations. As a result, GCN needed to scale back on the number of SSGUs that were originally planned but still will end up with eight deployments as part of this project.

GCN adjusted plans in the initial phase of the project regarding BRKE development prior to the first demonstration. Instead of focusing on control center rules and knowledge, GCN focused on managing the local site load instead. Through this effort, GCN was able to detect HVAC, refrigeration, PV, and EV charger load shifts and react appropriately with energy storage and power demand reductions. GCN demonstrated that DC fast charging for EVs (>30kW), when coupled with energy storage and software intelligence, can be deployed in scale behind the meter under existing service/meter. GCN proved that weather strongly correlates with customer load and weather forecasting tremendously improves utilization of distributed energy storage.

A.6.5 Product Development and Technology Transfer

A.6.5.1 Publications

The only publication of results has been in the form of a case study on 7-Eleven from summer 2013. It can be found here:

http://greenchargenet.com/power-efficiency-products/power-efficiency-case-study

A.6.5.2 Networks/Collaborations

The success of the project has led directly to:

1. Adoption by more private-sector customers. In addition to 7-Eleven and Avis, GCN has taken the same offering (demand reduction) to UPS and Walgreens, among others. GCN hopes to broaden the footprint beyond the initial set of pilot sites in the months and years ahead.
2. California Energy Commission PON-11-602 award, combining DC fast chargers for EVs with distributed energy storage to avoid demand charges. GCN is partnered with NRG/eVgo and Chargepoint on this deployment.

A.6.5.3 Technologies/Techniques

GCN developed the following:

1. The first distributed, behind-the-meter demand charge reduction system in the U.S., using Saft batteries and Princeton Power inverter
2. Algorithm and rules for managing set-points in the local operating environment
3. Weather input and correlation with demand
4. Management of EV charging in combination with energy storage
5. Cyber-secured connectivity of generation assets to Con Edison’s control center

A.6.5.4 Patent Applications

Table A-16. Listing of Patent Applications

83357.0005 (P004.01-UTL)	13/552,623	7/18/2012	"Multi-Mode Electric Vehicle Charging Station"	Claims priority to: 61/509,010	Pending – Ready for Examination, 1st OA prediction: 6/2015. Published 01/24/2013 (Pub. No. US-2013-0020993-A1).
83357.0008 (P007.UTL)	13/531,442	6/22/2012	"Electric Vehicle Charger Testing Systems"	None	Pending – Ready for Examination, 1st OA prediction: 6/2015. Published 12/26/2013 (Pub. No. US-2013-0346010-A1).
83357.0030 (P029-UTL)	13/531,450	06/22/2012	"Electric Vehicle Charging Protocol Selection and Testing"	None	Pending – Published 12/26/2013 (Pub. No. US-2013-0346025-A1). Ready for Examination, 1st OA prediction: 6/2015.
83357.0034 (P030.01-UTL)	13/066,609	04/19/2011	"Single Electric Vehicle Charger for Electrically Connecting to Multiple Electric Vehicles Simultaneously While Automatically Charging the Multiple Electric Vehicles Sequentially"	Claims priority to: 61/399,490	Pending – Published 01/19/2012 (Pub. No. US-2012-0013298-A1). Response to Restriction Requirement filed 12-31-13.

A.7 Innoventive: Demand Response Command Center (DRCC)

The Innoventive and Con Edison teams developed the following summary of SGDP activities as part of the input to the FTR. Results and information below has been used to develop the overall takeaways and lessons learned in the FTR.

A.7.1 Executive Summary

The Interoperability of Demand Response Resources Demonstration in NY (Interoperability Project) was awarded to Con Edison in 2009. The objective of the project was to develop and demonstrate methodologies to enhance the ability of customer-sited DR resources to integrate more effectively with electric delivery companies and regional transmission organizations.

The Interoperability Project demonstrated a number of innovative methods of integrating DR resources to help make the grid more efficient, improve grid reliability, and create economic value for facility owners. The project participants successfully demonstrated a number of concepts identified in the table below.

Table A-17. Interoperability Project Research Areas

Research Topic	Contribution of Interoperability Project
Ability of DR to Improve Reliability in the Distribution System	DR Resources with rapid response and ability to maintain load reductions for multiple hours when needed can help maintain reliability during times of grid contingencies.
Ability of DR Resources to Provide Ancillary Services to the Electric Grid	This was the first application in the NYISO control area where DR resources are dispatched in the same way as a conventional generator.
Requirements for cyber-secure interoperability between DR resources and an Electric Distribution Utility	Demonstration of remote activation of DR resources by the utility using a secure link compliant with NIST 7268
How precise controls of facility loads can be harnessed for application beyond simple peak shaving or energy efficiency	Through precise control of building loads, demonstrated ability to control resources to set points established by the Regional Transmission Operator (RTO)
The potential for an aggregation of multiple DR resources to alleviate a forecasted capacity shortage in a Control Area	Via the Virtual Generator concept, the project was able to show how a large aggregation of resources can be an economical solution to a forecasted shortage of regional capacity.

In most cases, the technical effectiveness was extensively exercised and successfully tested. Economic feasibility was tested whenever possible and when actual test data was not available, results were obtained by system modelling.

This project was comprised of a number of discrete components that were developed and demonstrated, namely:

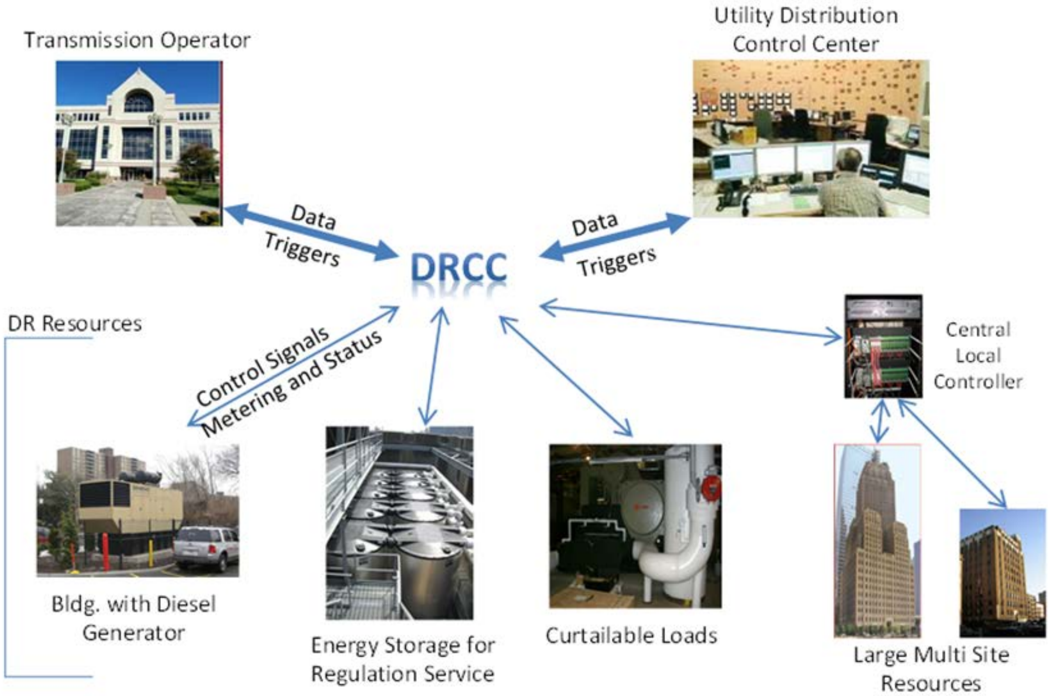
- **DRCC**
  The DRCC represents a secure software system designed to aggregate DR resources for activation in response to various conditions of the electric grid. The DRCC was tested may times throughout the project, demonstrating technical effectiveness. In fact, the DRCC developed during this project is being utilized in a production environment to enable automatic DR for project resources. A total of 23 facilities and 20 MW of generation have been integrated into the DRCC.

- **Incremental Building Control Unit (IBCU)**
  The IBCU is a set of hardware and programmed strategies that can control facility loads in response to market signals or as a tool to optimize energy efficiency. The IBCU was installed and demonstrated as part of an installation of a Thermal Storage System. Technical effectiveness of the IBCU system was tested and demonstrated. While sufficient operating experience was not acquired during the test period to enable economic feasibility to be demonstrated, results are modelled and reported later in the report.

- **Thermal Storage Unit**
  A 10,000 ton-hour Thermal Storage Plant (TSP) was installed at a Verizon facility, which houses office space and a telecom central office. The plant was installed to demonstrate how this technology could be used to supply valuable services to the electric grid while also optimizing energy efficiency at the facility. Testing to date has demonstrated the ability of the Thermal Storage Plant to supply ancillary services as well as its ability to reduce air conditioning demand during peak electric demand periods. Changes to local incentives for participation in DR programs led the team to reevaluate technical feasibility late in the project, resulting in greater economic benefits than originally envisioned.

- **Virtual Generator (VirG)**
  A VirG is created by the activation of an aggregation of DR resources by the DRCC. This aggregated set of resources is able to supply virtual generation (VirG). A VirG is able to solve a capacity shortage on the transmission system, as well as address system contingencies in electric distribution networks. Figure A-63 illustrates the type of DR resources which may be dispatched by the DRCC. Backup power provided by standby generators is an excellent candidate to provide targeted, persistent load reduction to address network events by responding to dispatch signals from a grid operator within five minutes. Economic feasibility was examined in detail and is presented in Attachment 4. The benefits provided to the grid by the Virtual Generator are shown to be greater than the costs to supply this service. In fact, the NYISO has included the concept of the VirG in its "Reliability Needs Assessment" as a potential solution to forecasted regional shortages of capacity.

Figure A-63. DRCC Architecture



The project benefits electric customers, as it demonstrated new ways to integrate DR resources into the NY electric distribution grid. Integration of existing DG resources into the VirG can be established and commissioned in a short time and can be utilized to respond to forecasted capacity shortages.

The VirG can be established in a relatively short time because it requires no siting approvals or large capital expenditures, as is the case with conventional generation or transmission lines.

A.7.2 Project Goals and Accomplishments

The Scope of Work included the following elements:

- Design and implement a DRCC capable of monitoring and dispatching aggregations of DR resources
- Demonstrate Interoperability of DR Resources with Con Edison DERMS
- Demonstrate remote activation of DR using an aggregation of telecom facilities while maintaining a high level of cybersecurity for these resources
- Design and install a 10,000 Ton-hour Thermal Storage System capable of supplying ancillary services such as Regulation and Reserves to the electric grid
- Design and implement an IBCU capable of directing an existing BMS to optimize efficiency and enable operating the facility to provide ancillary services such as Regulation and Reserves to the electric grid

- Develop and implement a plan to provide ancillary services such as Regulation and Reserves to the electric grid
- Design and implement a unique Closed Transition Switching Technique that could enable more end-user facilities to participate in DR Programs

In addition, subsequent to the award of the Interoperability Project, Con Edison was awarded the Secure Interoperable Open Smart Grid Demonstration Project [DE-OE0000197], and Con Edison invited Innoventive Power to participate in several milestone demonstrations. Participation in these demonstrations required the build-out of the web services portion of the DRCC for integration with Con Edison's Visualization Platform. Coordination with the SGDP afforded us further opportunities for testing the remote dispatch system of the DRCC, culminating in the Capstone Demonstration in July 2013.

Another accomplishment that was not anticipated in the original goals of the program was the design and implementation of a central load curtailment controller with cybersecurity provisions enabling it to be used within the framework of a major national telecom network. One of the Phase I goals of the project was to develop protocols between the end-use resources and the Curtailment Service Provider or Utility. Verizon was very concerned about outside demands to effect changes in its operation. To alleviate these concerns, a secure interface was developed that bridged the gap between the broader Internet and Verizon's internal control system in such a way that Verizon's staff is comfortable with its operation and security. This design will likely be replicated with other customers who desire such a level of security. The system also allows Verizon to leverage its manpower as efficiently as possible by providing sophisticated alarming and control capability via a secure remote link with every facility in its footprint.

Technical readiness of participation in ancillary service markets in the NYISO control area was demonstrated. Attachment 2 shows the project schedule and lists the buildings that have been and will be retrofitted to supply ancillary services as part of an aggregation of over 20 MW of curtailable load.

Additionally, the value of a large aggregation of DR resources was shown to be a possible solution to a forecasted potential shortage of capacity in the NYISO control area. The Virtual Generator concept is capable of being tested and implemented in less time and for less cost than conventional new generation or transmission capacity. This prompted the NYISO to identify the Virtual Generator as a possible solution to its forecasted capacity shortages. The potential closing of the Indian Point Nuclear Generating Station in 2016 would make the development of the Virtual Generator even more valuable.

Please refer to the previously submitted Final Interoperability Technical Report for further information regarding the DRCC sub-project.

A.8 NYCEDC: PV, Battery Storage and BMS Integration

The New York City Economic Development Corporation (NYCEDC) team developed the following summary of SGDP activities as part of the input to the FTR. Results and information below has been used to develop the overall takeaways and lessons learned in the FTR.

A.8.1 Executive Summary

The NYCEDC serves as NYC's primary engine for economic development and job creation, and works to enhance the city's business sectors by identifying, analyzing, and addressing challenges faced by industries. With over one million buildings, aging infrastructure, the second highest energy prices in the country, and increasing demand for energy, NYCEDC recognizes that NYC is well positioned to benefit from the proliferation of energy management technologies. In order to demonstrate the viability of innovative energy management solutions to the private sector, NYCEDC developed the SGDP at the Brooklyn Army Terminal (BAT) in Sunset Park.

By implementing the project, analyzing the outcomes, and sharing lessons learned, the BAT SGDP has the potential to support the growth of this new industry in NYC, create local jobs, and attract private investment in the development and widespread adoption of innovative energy technologies. These technologies offer the potential to help the City of New York reach its PlaNYC sustainability and resiliency goals, including a 30% reduction in citywide greenhouse gas emissions by 2030, as well as supporting Con Edison's Utility of the Future initiative.

A.8.2 Project Goals and Accomplishments

The completed BAT SG system integrates three main components: 1) a 100 kW solar PV array, 2) a BMS and 3) a 720 kWh battery for on-site energy storage capable of delivering 100 kW for four hours. The project set out to demonstrate the benefits of on-site renewable energy generation coupled with energy storage and management systems to reduce demand on the grid, offset energy costs, and advance NYC's PlaNYC sustainability objectives by reducing greenhouse gas emissions associated with energy generation and use. Additionally, the project findings will benefit the industry as a whole by sharing lessons learned and best practices to support acceleration across NYC.

Considering the battery's size and capabilities with an analysis of the electric load profile at BAT, the project team determined that participation in DR/capacity markets would be the most financially optimal use of the battery. The BMS at BAT was integrated with Viridity Energy's V-Power software as planned, and controls the battery operation (i.e., discharging and charging as needed for DR events).

Figure A-64. 720 kWh Battery Installation at BAT

The project accomplished its overall goals and objectives to demonstrate the capabilities of SG technologies in NYC. Although the project's battery and PV system sizes were limited due to financial constraints, the system at BAT demonstrates that integrated solar PV and energy storage systems are feasible for NYC buildings and present opportunities for financial benefits. The project's economic value includes cost savings from on-site energy generation and improved operational efficiency at the building level. While the system is currently being used for DR, its design could also enable power price arbitrage and peak shaving to reduce demand charges, depending on the future needs of the building. Through the BAT SG project, the project team was also able to identify key challenges at industry-wide and local levels, namely issues surrounding financing, permitting, and building and fire code regulations. The demonstration project at BAT will serve as a case study to guide industry stakeholders through the development and implementation of similar projects, thereby supporting the growth of the industry in NYC. An expansion of SG and energy storage technologies in NYC will support more sustainable energy use and enhance the resiliency and intelligence of the grid, mutually supporting the goals of the City's PlaNYC and Con Edison's Utility of the Future.

A.8.3 Project Activities

In December 2010, NYCEDC executed a Sub-award Agreement with Con Edison to participate in the U.S. DOE SGDP through Con Edison. In spring 2011, NYCEDC procured Plaza Construction through a competitive request for proposal (RFP) for system design and construction management. Through the specifications outlined in the RFP, the system would include a 500 kW rooftop solar PV array and a 2MWh battery to be installed in the basement. A valve regulated lead acid (VRLA) battery was selected for its safety record, maintenance-free design, versatility in orientation options, ventilation-free design, and its ability to be installed indoors. VRLA batteries are also typically lower cost and maintenance than other battery chemistries, and met NYC fire and building code regulations.[4] Both the PV and battery systems would be integrated through a BMS and have the ability to be remotely controlled using Viridity Energy's V-Power software. After analyzing expected PV production and developing strategies for

[4] A lithium-ion iron phosphate (Li-ion FeP) battery was also considered, as it shares many of the same characteristics as VRLA batteries. However, Li-ion FeP batteries were at the time relatively new; no New York City Fire Code specifications existed, and obtaining approval for Li-ion FeP batteries in the timeframe needed was not feasible.

optimizing the battery use, it was estimated that the PV system would produce 750,000 kWh and save an estimated $120,000 in displaced energy costs per year, while the battery system would be used for peak shaving to reduce demand charges and operational costs at BAT.

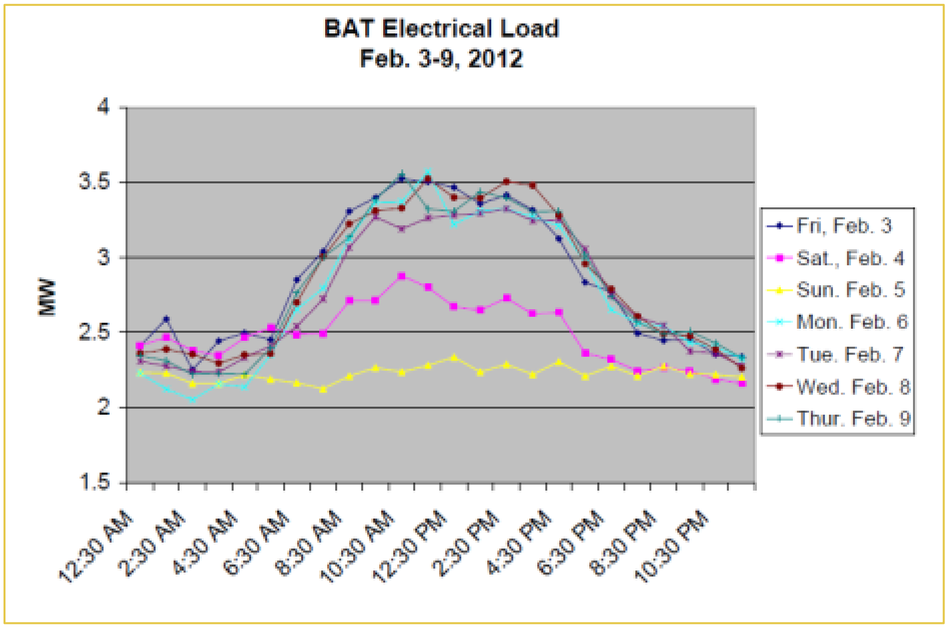
Figure A-65. 100 kW Solar PV Array at BAT

The project's total budget was originally estimated to be $9.5 million, to be funded from a combination of $3.5 million from NYCEDC and $4.5 million from the DOE SGDP through Con Edison. It was anticipated that the remaining costs would be financed through federal New Market and Investment Tax Credits, including the 1603 Treasury Grant Program, which was phased out on December 31, 2011. When obtaining such tax credits became infeasible, the project scope and budget were reduced to include only the funds available from NYCEDC and the DOE. A cost share of 47% of total project costs (up to $4.5 million) would be provided by the DOE SGDP, with NYCEDC contributing the remaining 53%. Despite the reduced budget, it was decided to maintain the same technology demonstration objectives, but simply scale back the capacities of the relevant components (to a 100 kW PV array and 720 kWh battery). In spring 2012, the construction manager, Plaza Construction, procured subcontractors Future Energy Development and Kanta Electric to design and install the PV and battery systems. Kanta Electric purchased the VRLA battery from Hitachi, who contributed a 50% cost share towards the total cost of the battery. ABM Systems provided the BMS, and Viridity Energy provided the capabilities for remote control and monitoring of the battery through their V-Power software.

The project team determined that potential revenue would be highest from participation in DR programs. This option was selected after exploring a variety of alternative uses, including the following:

1. Peak shaving: Operating the battery to avoid demand charges could result in cost savings; however, following an analysis of the load profile at BAT (see below figure), the project team concluded that there is no true peak that could be shaved by the battery alone. The profile shows that the load curve remains relatively flat for ~8 hours on weekdays, when the building is in use by the tenants. As the bulk of the total load at BAT is controlled by tenants, opportunities were limited for supplementing the battery's output through reducing consumption. Without a more pronounced spike, using the battery for peak shaving was determined not to offer a high likelihood for demand charge reduction, and thus not economically beneficial.

Figure A-66 BAT's Energy Load Profile with Flat Peak



2. Energy arbitrage: The team explored the possibility of buying and storing lower cost off-peak power and discharging the lower cost power during periods of higher cost peak demand electricity. However, this approach is only viable with a time-of-use energy price contract, where BAT has a fixed price energy contract. The system's design includes the use-case, however. If BAT's future energy prices justify this mode of operation, the system is able to operate in a timed charge/discharge program to take advantage of lower cost off-peak power.

Construction at the BAT began in January 2013. In addition to the installation of the PV and battery systems, a battery room was constructed to house the battery cells. The battery room was designed to meet fire code and building code requirements, provide structurally sufficient flooring, and to accommodate the VRLA battery technology. The room features an HVAC system, hydrogen gas detection and alarm system linked to an outside exhaust system, fire-rated walls, structural improvements to the battery room floor, acid-resistant flooring, a pre-activated dry sprinkler system, and a tempered safety shower and eye bath. An on-site controller allows for direct control and programing of the battery inverter, which is also controlled through the BMS, located on the first floor in the building's operational offices. The solar PV system was commissioned in August 2013, and has produced over 61 megawatt-hours of electricity through April 2014, averaging approximately 6.8 megawatt-hours per month. The integrated battery and BMS system was commissioned in October 2013.

In March 2014, tests of system operation showed that actual performance met or exceeded design specifications, and NYCEDC entered into an agreement with Viridity Energy to optimize and control the battery operation remotely. An operational plan was developed by Viridity Energy and approved by NYCEDC in April 2014. On May 1, 2014, the BAT began participating in three DR programs:

- NYISO Special Case Resources (SCR) Program
- Con Edison DLRP

- Con Edison Commercial System Relief Program (CSRP)

For each program, advance notice (~24 hours, varying between programs) for a DR event is given. When an event is called, the battery will discharge 100kW for a four-hour period (for a total of 400kWh). Participants in the programs receive a monthly reservation payment per kW of energy available during their enrollment in the program, as well as additional payments for each kWh reduced during an event. NYSIO's program runs during the summer and winter, whereas the Con Edison programs run May 1st – Oct 31st.

The annual revenue generated from enrollment in the DR programs is approximately $25,000, varying based on the amount of DR events called. Meanwhile, the PV array is expected to generate an estimated 100.8 megawatt hours annually, yielding $15,130 in reduced annual energy costs. In total, the system is expected to generate $40,380 of revenue per year, yielding an approximate payback period of 11 years.

Figure A-67. Viridity V-Power Energy Management Dashboard

The BAT SG project meets the technical objectives of the demonstration. Although the reduction in system size will impact the financial benefits that the project was originally envisioned to deliver, the project demonstrates the concept and capabilities of SG technologies and will allow NYCEDC and project partners to share lessons learned in order to overcome financial, technical and regulatory barriers identified, such as:

A.8.3.1 Financial

While the factors that lead to the scope and budget reduction are important to understand, key measures of the project's impact are the energy savings and revenue stream generated through the PV production and participating in DR programs (~$25,000 per year). These savings and revenues are largely fixed based on a system's total delivered power, which is independent of future reductions in capital costs or improvements in technology. Therefore, future systems modeled after BAT, but with newer technologies and built at lower costs, will yield stronger financial performances.

A.8.3.2 Technical

While battery chemistry options were limited to lead acid types at the onset of the project, energy storage technology is rapidly evolving, as are the regulations governing it. As of March 2014 revisions to the fire code now allow for a wider variety of battery chemistries:

- Lithium-ion (Li-ion)
- Lithium metal polymer
- Nickel cadmium (Ni-Cd)
- Non-recombinant
- Recombinant
- Stationary storage
- VRLA
- Vented (flooded) lead-acid

While the revisions to the fire code show progress has been made, these new chemistries have not yet been approved for applications outside emergency power systems; the Fire Department of New York (FDNY) has yet to evaluate the implications of daily usage of these new chemistries; thus, new projects would be required to apply for a variance if pursuing these battery chemistries. It is likely, however, that new regulations for advanced battery technologies will be adopted in time, allowing future projects greater flexibility to select the battery that best matches the project site and requirements. With these advancements in technology, the cost of future battery systems could be substantially lower per unit of delivered energy.

A.8.3.3 Regulatory

The need to construct the battery room to meet fire and building codes added significant cost and construction time. Net of the DOE contribution and the battery cost-share, NYCEDC's total project costs were approximately $2.2 million; however, only 20% of these costs were directly associated with the SG system components (battery, PV, and BMS). Future projects could avoid some of these costs by siting in locations already equipped with ventilation systems meeting relevant codes, and that do not require the types of structural modifications that were necessary at BAT.

In addition to FDNY and DOB regulations, as a historic building, BAT is subject to State Historic Preservation Office (SHPO) regulations; as a result, additional measures needed to be taken to ensure compliance. These additional requirements should be considered when planning future projects as they resulted in additional construction time and cost. Finally, undertaking this project as a public entity required additional time for project initiation. As a City agency, NYCEDC is bound to City procurement requirements, and was required to procure a construction and design team via a competitive public RFPs; projects not limited by the same time constraints as public entities should have more flexibility for the planning and designing of systems to meet their specific needs.

The BAT SG project successfully demonstrates the viability of integrated DG and energy storage systems and the benefits of energy management technologies, and will serve as an example for industry stakeholders, supporting the growth of the sector in NYC.

A.8.4 Product Development and Technology Transfer

A.8.4.1 Web site or other Internet sites that reflect the results of this project

- http://www.nycedc.com/industry/clean-technology-energy
- Agrion Energy Storage Initiative (forthcoming; expected in early June 2014)

A.8.4.2 Networks or collaborations fostered

NYCEDC fostered various networks and collaborations though the development and implementation of the SG installation at BAT, including the following:

- Con Edison – DOE SGDP lead
- General Contractors
    - Plaza Construction – Construction Manager
    - Cosentini Associates – BMS design
    - Mitchell–Giurgola Architects – design
    - altPower Inc. – PV system Design
    - Future Energy Development – battery design
    - Kanta Electric Corp. – electrical systems
- Equipment Providers
    - Hitachi – battery provider
    - Princeton Power – battery inverter provider
    - Solar Energy Systems, LLC – PV system equipment
    - Suntech – PV provider
    - Advanced Energy – PV inverter provider
    - ABM Systems – BMS provider
- Viridity Energy – software and DR program partner
- Agrion – clean-tech industry network (organizing New York Energy Storage Initiative)

A.8.4.3 Technologies/Techniques

The SG project at BAT demonstrates the ability to use software to remotely control energy assets (in this case, a battery), allowing for performance optimization and yielding the greatest financial returns. Viridity Energy's V-Power software allows for remote control of the discharging and charging of the battery system at BAT, and provides real-time monitoring of the system's overall performance, including the financial impacts gained through operating the system. The V-Power software is integrated with a BMS which controls the battery inverter and issues commands for the battery to charge or discharge (either manually or following an automatic schedule). The BMS also monitors PV production, providing a comprehensive picture of the SG System's performance. Taken together, these technologies can provide data that can assist in bringing transparency to and accelerating investment in SG, solar, and energy storage by building owners, financial institutions, and other key stakeholders.

A.9 Gehrlicher: Streamlined PV Design and Installation

A.9.1 Executive Summary

In 2013, Con Edison contracted Gehrlicher Solar America Corp. to install a 40 kWac solar installation at Con Edison's 4 Irving Place headquarters. By integrating this installation into the project, Con Edison gained hands-on experience with the process of installing equipment on NYC commercial building rooftops. This project was unique in that this behind-the-meter solar installation was completed atop a 19th-story roof of a NYC landmark building housing multiple tenants.

More than 200 panels were installed. The panels were manufactured in the United States by Suniva Inc. The company has also connected the solar array to a remote monitoring system that is updated every 15 minutes and enables Con Edison operators to monitor the production of the panels in real time. Con Edison completed the installation in only five weeks.

An added benefit to the public is that the system supplies enough electricity to light two floors at the Con Edison headquarters and will save Con Edison ratepayers about $7,000 a year in electricity costs.

A.9.2 Project Goals and Accomplishments

The accomplishments met the goals and objectives of the project.

Goals and objectives:

- Design a PV electric generation system with the highest possible capacity per:
  - Existing structural/spatial conditions at Con Edison's Auditorium/Cafeteria rooftop; and
  - Existing electrical service conditions at the determined-location of PV system interconnection.
- Acquire all permits and approvals from Authorities Having Jurisdiction (AHJs) and the utility.
- Install and commission the PV system.

Accomplishments:

- All permits and approvals were received from local AHJs, including NYC DOB, Environmental Control Board (for electrical review and inspection), Landmarks Preservation Commission, and Con Edison's DG Dept. for utility interconnection.
- PV system was successfully installed, inspected, and commissioned. It is currently operating at its full capacity.

A.9.3 Project Activities

A.9.3.1 Logistics

Lack of high-capacity freight elevators, inability to use a crane in busy traffic and on high-rise roof, and limited loading dock space in concert with existing high volume of delivery traffic, proved troublesome in our efforts to mobilize our project material and construction equipment to the project site. On-site conditions only allowed slower and more deliberate methods to move all the material to the rooftop.

A.9.3.2 Weather Issues and Delays

Unfortunately, NY experienced abnormally inclement weather conditions during this past winter. Snowy and icy conditions were often confronted and detrimentally affected the construction efficiency and schedule. In the case of moderate snow events, pilings of snow required re-allocation of labor hours to clean the snow off of the roof (construction area) and PV modules. And in severe snowstorms or in compilations of multiple snow events in series, schedule delays were necessary to prevent installation errors and, more importantly, construction safety hazards.

A.9.3.3 Installation Hours

Racking structural requirements of Con Edison's PV system included mechanical attachments that chemically bond to the concrete substrate of the existing Auditorium/Cafeteria roof structure. This type of work entails cutting and removal of roof membrane and insulation as well as drilling into and applying epoxy adhesive to the existing concrete decking. Due to potential hazard of moisture introduction, the entire mechanical attachment installation procedures had to be performed during dry weather conditions, which often conflicted with only short notices. In addition, the periods of drilling into the concrete decking had to be very carefully coordinated with Con Edison's use of their Auditorium in order to minimize disruption due to noise and vibration.

A.9.3.4 Removal of the Existing Stanchions

During initial site survey, there existed a large antenna structure on the southeast section of the Auditorium/Cafeteria roof. Had it remained, it would have not only reduced the total PV system array area, but also would have reduced the efficiency of the PV system due to its shading effects on its surroundings. In order to maximize the PV system's size and its power/energy output, a resolution to remove the structure was concluded. A roofing manufacturer-approved contractor was hired to remove the entire structure, as well as to seal the roof membrane after its removal.

A.9.3.5 Electrical Interconnection

In order to be able to carry the full back-feed current of the PV system's output, one of the 100-amp branch circuit breakers was upgraded from 100-amp rating to 150-amp rating, and the conductors between the two panel boards were upgraded as well. "EDC" was replaced with a brand-new 400-amp Square D panel board that has two 150-amp main circuit breakers on opposite ends of its bus, one for its utility main source, and the other for the PV system source.

In lieu of the previously existing feeder splice connections a 100-amp branch circuit breaker was added to the new panel board as its source and feeder protection.

The demonstration was intended to provide Con Edison with firsthand knowledge of the challenges of a behind-the-meter solar installation, the complexities and logistical challenges of installing solar on a high-rise building in NYC, the process for meeting landmarks certification, and to provide a test bed for connecting behind-the-meter solar to operator visualization systems. Given the challenges mentioned above, Con Edison believed that this is representative of a worst-case installation.

A.10 *Softstuf: Smart Grid Disturbance Monitor (SGDM)*

The Softstuf team developed the following summary of SGDP activities as part of the input to the FTR. Results and information below has been used to develop the overall takeaways and lessons learned in the FTR.

A.10.1 Executive Summary

Executive summary provided in the main report.

A.10.2 Project Goals and Accomplishments

The main goals and objectives of the project included technical effectiveness and feasibility, field performance and scalability, universality and signature analysis capabilities, and commercialization. These are described in more detail below.

Figure A-68. Softstuf Test Facility with Simulator and Test Set

A.10.2.1 Technical Effectiveness

- ***Objective:*** Prove the technical effectiveness of the SGDM prior to delivery to Con Edison by running an extensive set of tests repeatedly in the lab environment.
- ***Accomplishment:*** A substation simulator was designed and a state of the art power system test set was procured (see Figure A-68). The simulator and test set were used extensively to test the SGDM prior to delivery. Both transient and dynamic test plans were conducted and the successful performance of the SGDM in detecting and reporting on fault and disturbance conditions proved its technical effectiveness. At the end of the project, the simulator and test set were delivered to the Con Edison Learning Center.

A.10.2.2 Economic Feasibility

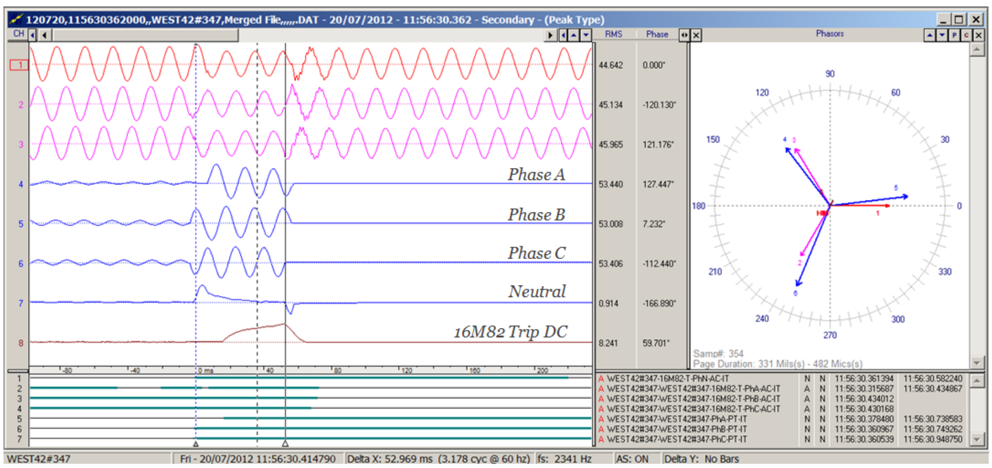
- ***Objective:*** Prove the economic feasibility by deploying the SGDM on live circuits without having to plan for outages or disturb existing equipment.
- ***Accomplishment:*** The Con Edison success in service deployment at the Farragut substation proved the economic advantage in installation over traditional monitoring systems. Figure A-69 shows a picture of the in service deployment of the sensors at one of the relay houses at Farragut. (Two panels with sensor infrastructure are shown for monitoring primary and backup protection.)

Figure A-69. In-Service Deployment at the Farragut Substation

A.10.2.3 Field Performance

- ***Objective:*** Verify the technical effectiveness of the SGDM by monitoring performance of the deployed sensors at the Farragut substation.
- ***Accomplishment:*** Fault and disturbance conditions are rare, random events. It was unclear if any such conditions would occur during the life of the project. However, a number of disturbances did occur in 2011 and 2012 including but not limited to a major 345kV transformer event, a phase angle regulator fire, and Hurricane Sandy. The performance of the sensors during these real-life disturbances successfully verified their effectiveness in discovery and cataloging of fault signatures based on targets, fault magnitude and duration. An example of an unbalanced three phase fault that was captured by the sensors on 7/20/2012 is shown in Figure A-70.

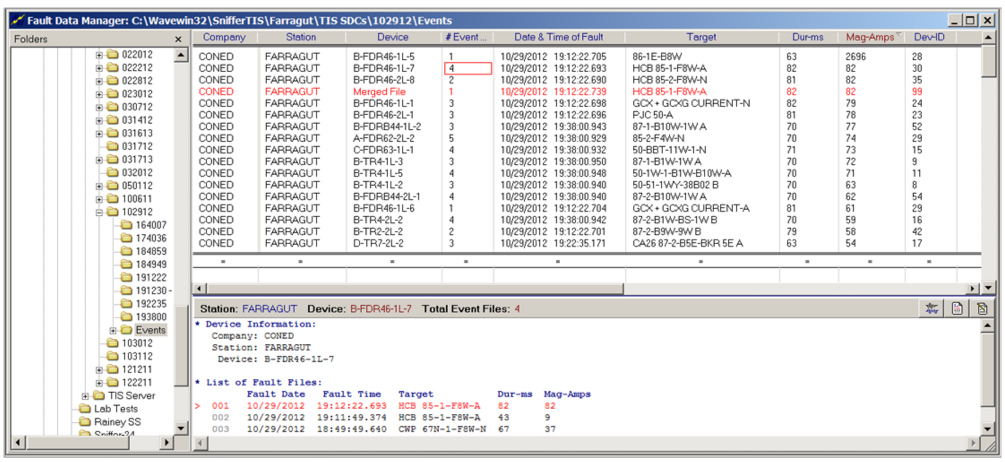
Figure A-70. Multiphase Fault-Captured by the Sensors (30,000 Amps Magnitude)



A.10.2.4 *Data Management and Scalability*

- ***Objective:*** Prove the data management capabilities and scalability by deploying the SGDM expert software on a central server located at Irving Place (main Con Edison building).
- ***Accomplishment:*** The software was successfully deployed on the server and the performance was monitored for an extended duration. The results demonstrated the data management capabilities of the software in ranking disturbances and organizing/cataloging data records based on date and time of occurrence. The deployment further demonstrated scalability with the software receiving and processing high speed data from thousands of sensors reporting through a large array of recorders, switches, concentrators, and fire walls. A copy of the expert software is shown in Figure A-71.

Figure A-71. SGDM Software Installation at the 4IP Server



A.10.2.5 *Universality/Reusability*

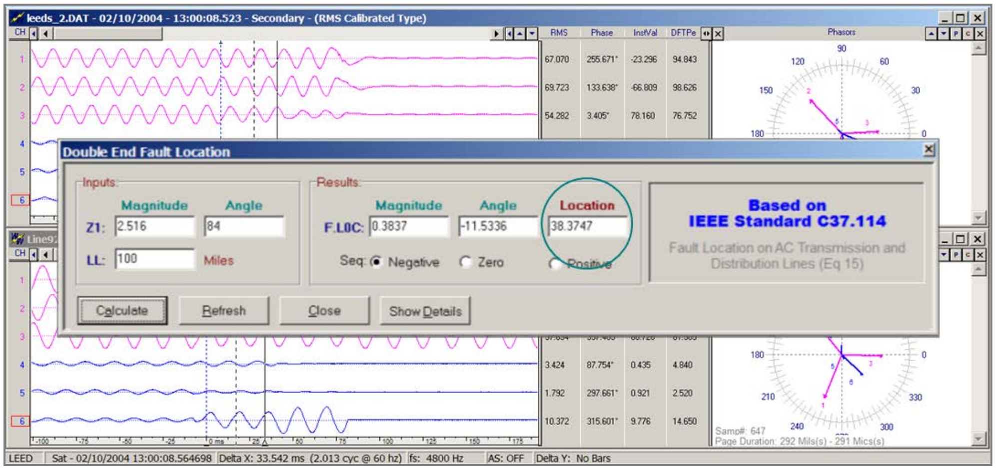
- ***Objective:*** Ensure universality by supporting IEEE Standards COMTRADE and COMNAME which enable the SGDM to work with disturbance data from other types of monitoring devices.
- ***Accomplishment:*** The software was successfully developed in compliance with these standards and the data from the new sensors is also saved in compliance with the standards. Users can analyze data from the new sensors with their own compliant software, or they can use the new software to analyze data from their own monitoring devices such as digital relays, fault recorders, phasor measurement units, power quality monitors, and so forth.

A.10.2.6 *Advanced Analysis*

- ***Objective:*** Develop a number of specialized algorithms for measuring fault location, detecting current transformer (CT) saturation, timing breaker operations, and modeling fault currents.
- ***Accomplishment:*** The specialized algorithms were successfully developed, coded and repeatedly tested in the lab environment. The algorithms were also tested in the field. For example, the fault location algorithm was successfully benchmarked by Con Edison using data from available digital relays and fault records and is currently being used as one of their primary sources for locating faults. (An example location is shown in Figure A-72.) The CT saturation algorithm,

based on harmonics, was also verified by a number of disturbances captured by the sensors and other types of devices.

Figure A-72. Double-Ended Fault Location Display with Synchronized Ends



A.10.2.7 Commercialization

- ***Objective:*** Make the SGDM commercially available in whole and in part by packaging, advertising, and soliciting investment capital.
- ***Accomplishment:*** The process of commercialization was initiated during the project and has taken center stage at Softstuf since the end of the project. The SGDM was properly package in small, modular units that can be deployed on a small or large scale basis. The results were utilized at a number of additional installations at Con Edison and at a number of other utilities including two nuclear power plants. In all installations, the sensors and software were essential in identifying root causes of fault and disturbance conditions. As for the tasks of advertising and soliciting investment capital, they have proved to be the most difficult ones. Softstuf has so far showcased the SGDM at a number of professional conferences, solicited a number of major manufactures for investment capital, and is in the process of developing a web site for marketing the SGDM. The future of this technology is very promising and the commercializing efforts will continue. The pace of growth will depend on whether or not Softstuf can procure the needed investment capital.

A.10.3 Project Activities

The DOE SG funding through Con Edison started for Softstuf in October 2010 and ended in June 2012. Softstuf continued, at its sole expense, to provide support and maintenance services for the installed equipment until December 2013. The project activities were multifold and proceeded in parallel. The main focus was on building the simulator, delivering the sensors and supporting hardware, and installing the SGDM software on the central server.

A.10.3.1 Simulator

The simulator, representing a substation with three feeders, was designed and assembled at the Softstuf Lab at 333 Bainbridge Street in Philadelphia. The feeders are a ring bus mimic with two analog schemes (electromechanical protection) and one digital scheme (numeric relay). The simulator is equipped with a state of the art three phase current/voltage injection test set and includes sensors, concentrators, a server with the SGDM software, and a breaker simulator mounted in a panel to mimic a substation control board. A barebones diagram of the mimic control board is shown in Figure A-73, and a simplified schematic of the simulator is shown in Figure A-74.

The simulator and test set were used for application of various types of fault and disturbance conditions including balanced and unbalanced faults (phase to phase and phase to ground faults) designed to challenge both the sensors and the developed software. The simulator and test set were invaluable in demonstrating the features of the SGDM which are not easily done on in service equipment because fault occurrences are unpredictable by nature.

Figure A-73. Simulator Mimic Board

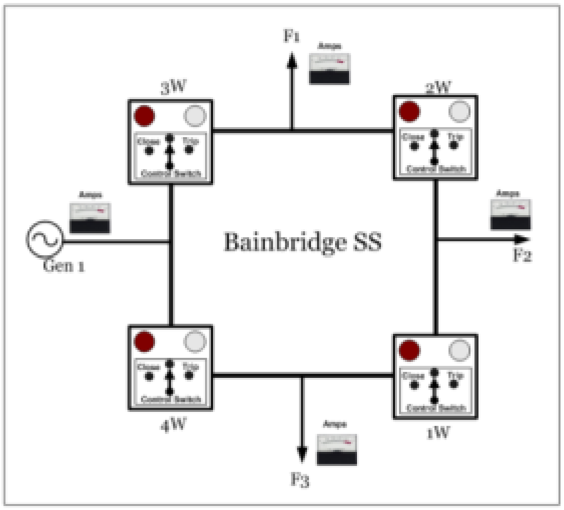
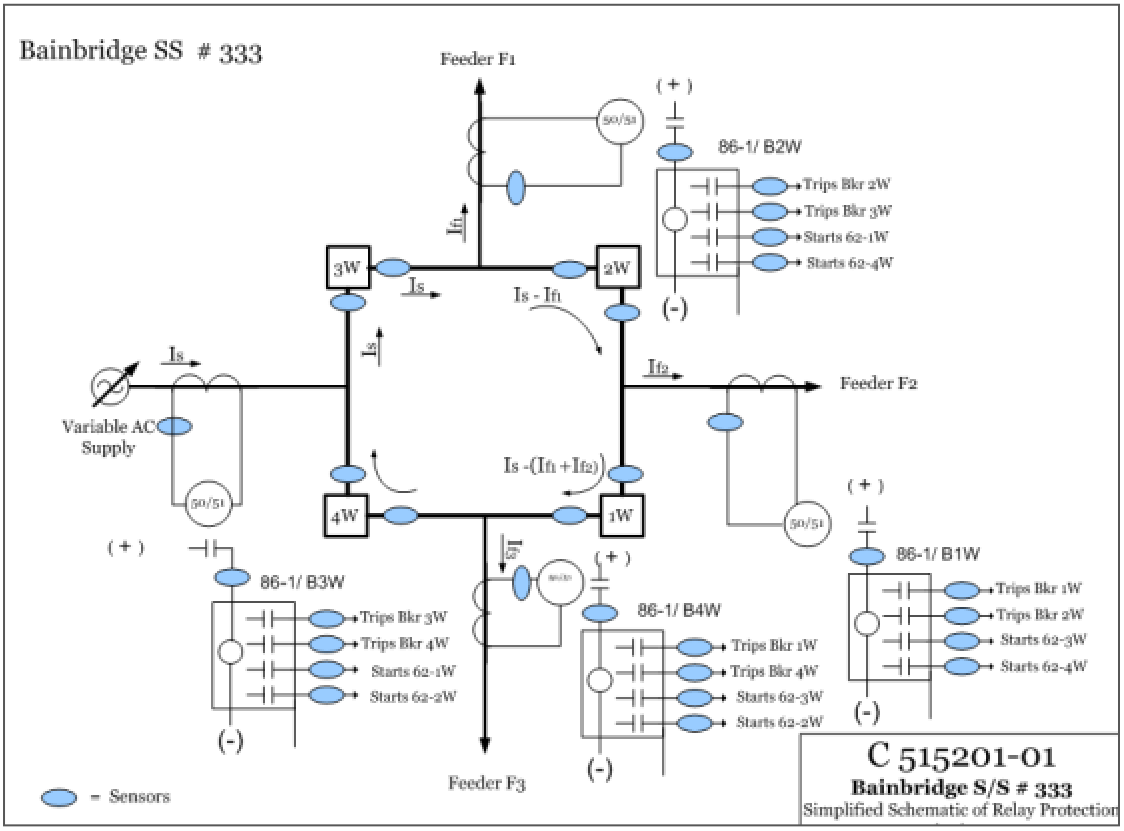


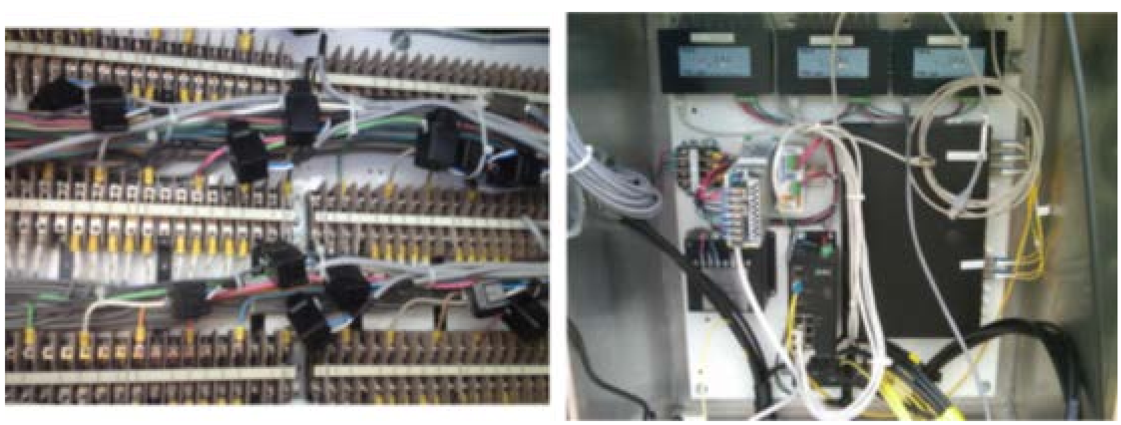
Figure A-74. Simplified Schematic of the Substation Simulator



A.10.3.2 Sensors and Infrastructure

Over 1,000 sensors were produced and delivered to Con Edison within the first three months of the project start. The required infrastructure was also procured and delivered along with the sensors. The required infrastructure included 100 sampling units, 40 network switches, four data concentrators, and other supporting components such as cables, connectors, and power supplies. A picture of one of the Con Edison sensor deployments at a 345kV breaker is shown in Figure A-75.

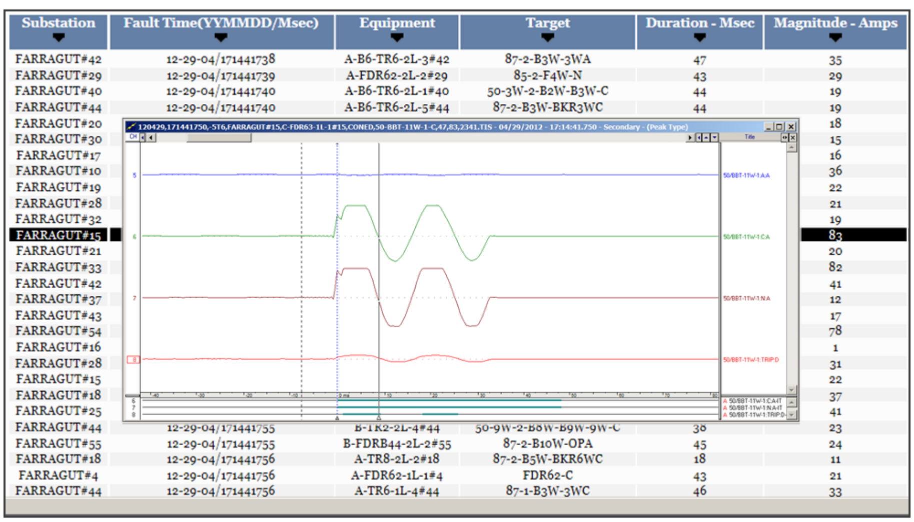
Figure A-75. Breaker Monitor: Sensors (left), Samplers, and Switches (right)



The sensors connect to the sampling units, which broadcast their measurements thru the switches to the data concentrators. The data concentrators process the incoming measurements at the microsecond level and generate waveform captures of any detected fault or disturbance signatures. The captures include both pre- and post-fault measurements and are transmitted to the central server upon occurrence (report by exception). A picture of the deployed data concentrators is shown in Figure A-76.

Figure A-76. Data Concentrators Deployment at the Farragut Control House

Figure A-77. SGDM Software Deployment at the 4IP Central Server



A.10.3.3 Central Server

The server was provided by Con Edison and Softstuf was given secure access to remotely deploy, monitor and refine the performance of the software. The software was successfully deployed, the performance was monitored for an extended period, and the software was then refined accordingly. A picture of the software is shown in Figure A-77. The software receives sensor data captures from the concentrators in the field and includes an expert module designed to organize the sensor data based on monitored circuits and time of fault occurrence. The software also includes an adaptive engine that processes and ranks the data captures based on fault magnitude, duration and targets. A number of additional interfaces are also provided for manual diagnostics and visual purposes including sequence of events reports (SOE) and three phase metering displays as shown in Figure A-78 and Figure A-79. Access to the server ended at the end of the project (December 2013).

Figure A-78. Sequence of Events for Diagnostics and Analysis

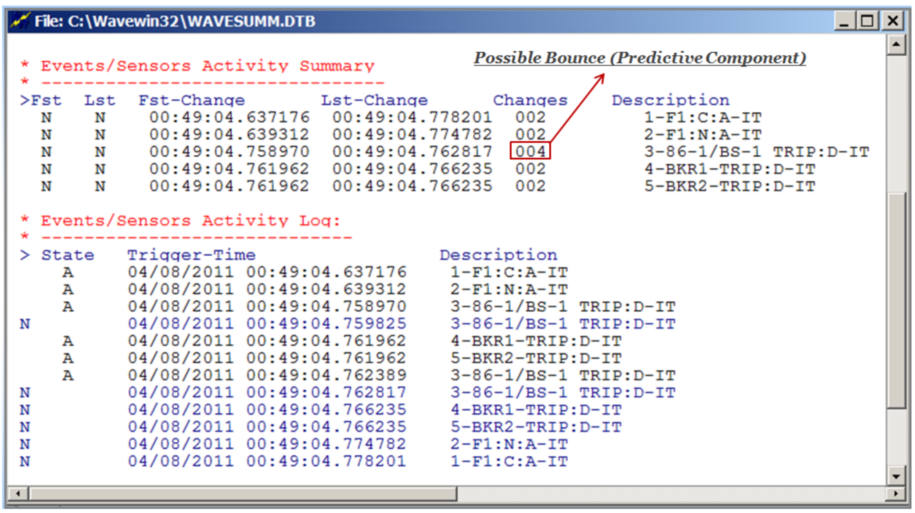
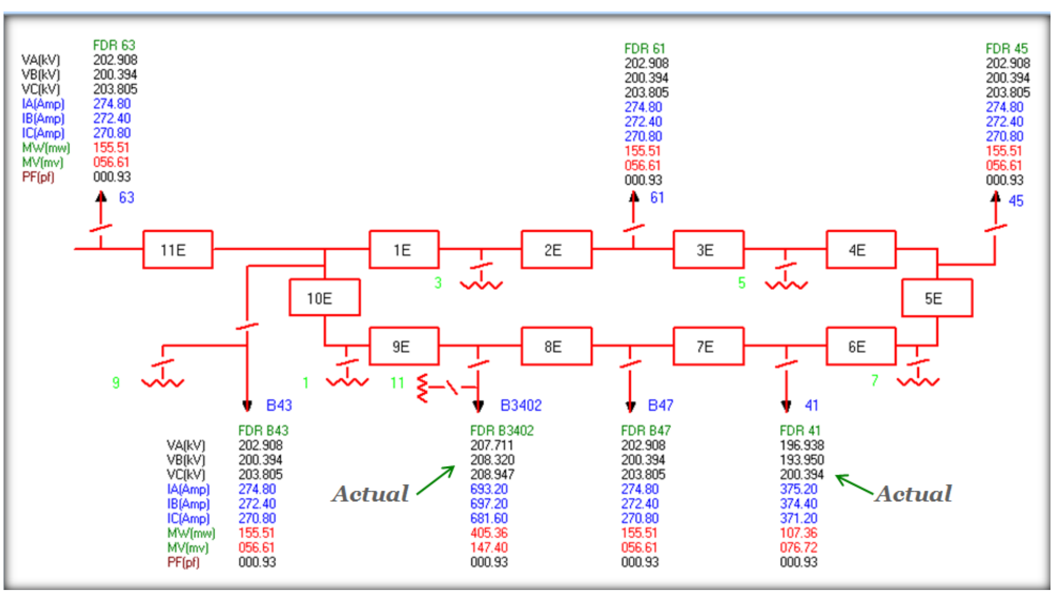


Figure A-79. Three-Phase Metering Application with Real-Time Values



A.10.3.4 Synchronization

One of the most challenging parts of the project was synchronizing the data from all of the sensors. For the software to work properly the data had to be synchronized to a resolution of less than one millisecond. Initially, a state of the art GPS clock was used to synchronize the data concentrators in the control house but due to latency issues with the network switches the time tags for the sensors would drift at times up to a resolution of 10 milliseconds. To solve the latency issues, Softstuf procured an array of GPS clocks with inter-range instrument group (IRIG-B) and pulse per second (PPS) time signals and Con Edison installed the clocks at the sensor level by connecting their signals to the sampling units. The burden of installation required additional budgets and lengthened the project duration but the solution was highly effective.

A.10.4 Product Development and Technology Transfer

The SGDM is a modular design. Each component is available as an independent product. Users may use the full depth and breadth of the SGDM solution as described in this report, or may just choose to use a particular type of sensor with their own solutions. The sensor products developed during the project are listed at www.wavegrid.net under the Products tab. Detailed manuals with schematics and user guides are available under the Downloads tab. The site was developed by Softstuf to help market the sensors technology to the industry. The site also includes new types of specialized sensors called "Intelligent Electronic Sensors" that were developed independent of the project but that are in line with the natural evolution of the technology. The new sensors pack enough intelligence onboard in order for analysis and discovery to occur inside the sensor without having to stream data for analysis at a central location.

Two technical papers that describe a number of the aspects of the technology were developed by Softstuf and published at the Fault and Disturbance Analysis Conference which is the most prestigious conference on the subject in North America. The first paper was presented in 2010 and the second one in 2013. Both papers were very well received and both won the "Best Paper Award" for the year. The conference is organized by the Transient Recorders Users Council (TRUC) and sponsored by Georgia Tech. Copies of the papers are also available at the website under the Downloads tab. The future for this technology is very promising.

A.11 *CALM: ISM and Decision Aid*

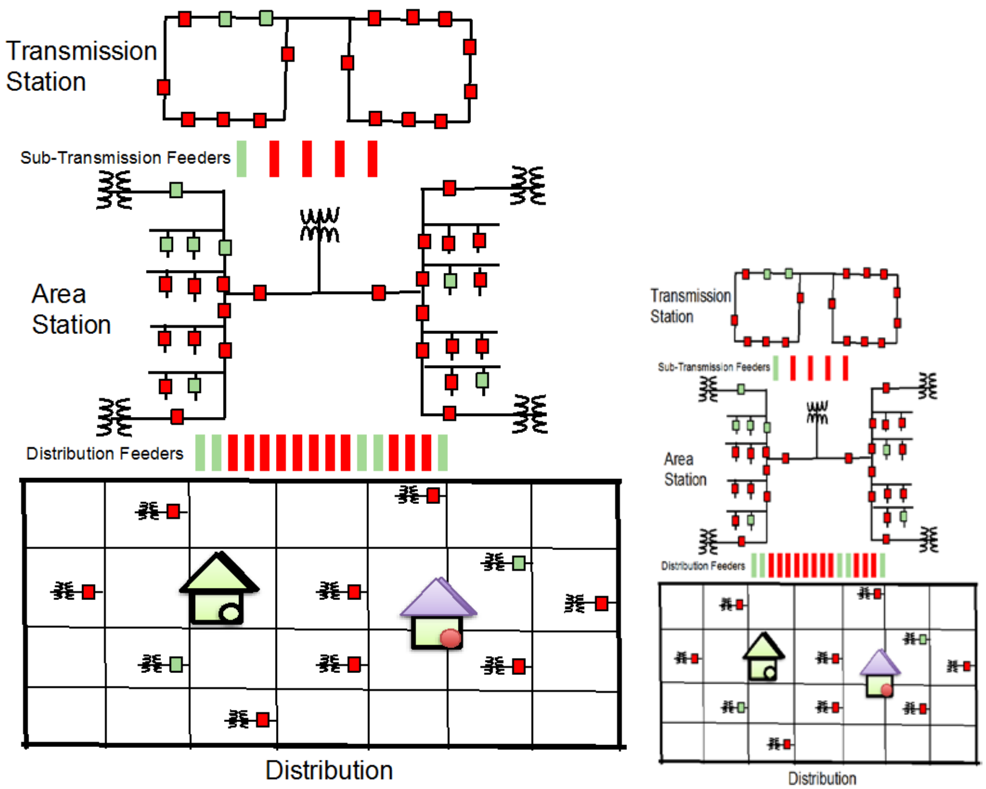
The CALM team developed the following summary of SGDP activities as part of the input to the FTR. Results and information below has been used to develop the overall takeaways and lessons learned in the FTR.

A.11.1 Executive Summary

CALM Energy's demonstrated technology included:

- Its ISM Decision Aid platform for use by transmission and distribution operators
- Its building smart node energy optimization controller

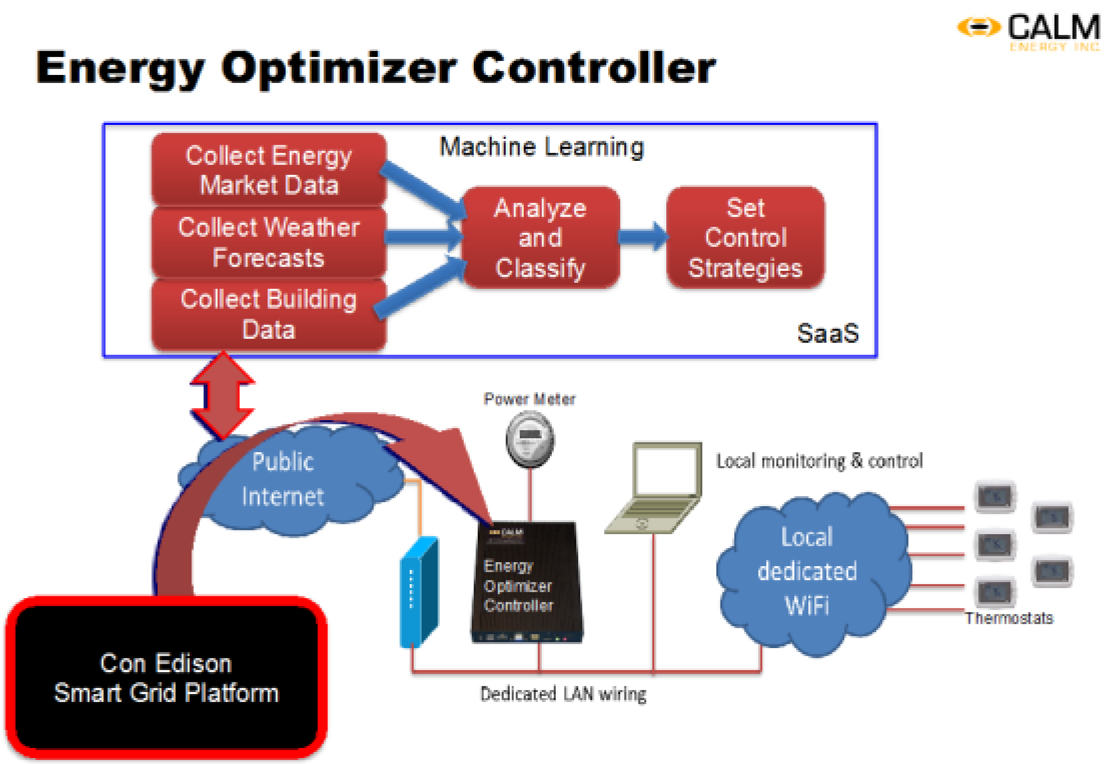
Figure A-80. Reliability



Having continuous automated detection of predicted vulnerabilities in the transmission and distribution system versus reacting to emergencies after they happen will improve grid reliability and reduce costs, especially given increasing uncertainty in intermittent customer loads and supplies (e.g., energy storage, EVs, and PVs). Most catastrophic incident investigative reports developed by utility management investigative teams after an incident occurs, using existing legacy historic data, determine with pinpoint accuracy multiple precursors to an incident that had they been detected in advance by operations and properly acted upon, could have been prevented or at least could have significantly mitigated the incident. The ISM decision aid platform demonstrates the viability of such technology in detecting and acting in advance on predicted incidents to prevent major outages through software intelligence implemented for an Area Substation and its distribution network where the ISM has fully integrated knowledge of both the transmission system and the distribution system, and served customers surrounding the Area Station. The ISM decision aid platform was demonstrated as part of the capstone demonstration using off-line transmission system, area station, distribution system, and customer data from the Long Island City network and North Queens Area Station. It is believed that the ISM Decision Aid holds promise of supporting the prevention and mitigation of these types of major outages. Besides improved reliability, the ISM decision aid holds promise of improving energy efficiency within the grid through scheduled modulation of customer's loads and greater certainty in managing electrical component peak loads to their capabilities, improving the planned and real-time dispatch of generation sources and DR.

In addition to the ISM Decision Aid, CALM Energy demonstrated its building smart node energy optimizer (EO) controller, through funding from CALM Energy and NYSERDA, to interoperate with the utility's SG DERMS platform developed by Siemens.

Figure A-81. EO Controller



The Smart Node EO Controller communicated with the Con Edison DERMS SG Platform using NIST SG standards of cyber-security for monitoring the state of the building and initiating DR to curtail load on the electric grid. The demonstration of CALM Energy's Smart Node Controller for buildings using the latest NIST SG standards and having the smart node controller communicating directly with the Siemen's platform provides proof that such technology can be deployed by the regulated utility to improve grid reliability and energy efficiency without a third-party NOC. This portion of the demonstration was initially a NYSERDA/CALM project that was added to the demonstration, as it was a fit with the original intent of the SGDP to demonstrate cyber-secure interoperability for automated DR.

A.11.2 Project Goals and Accomplishments

The primary goals and objectives of the overall project as proposed to the DOE were to research, develop, and demonstrate SG advancements for utility operations for improving grid energy efficiency and reliability. An additional goal of the project, being a 2009 ARRA-funded project, was to provide jobs to stimulate the economy.

Major accomplishments of the project included:

- Development and demonstration via simulation of a Transmission to Distribution to Customer integrated GIS/Virtual-SCADA based decision aid and controller.
- Progress toward developing and demonstrating CALM's patented technology
- ISM Decision Aid project with NYSERDA development and demonstration
- Development and demonstration of a low cost building EO controller for small and mid-sized commercial buildings that communicates directly with Con Edison's DERMS Platform
- Development and demonstration of low cost thermostatic control of multiple HVAC units in tow building through the EO controller using building's existing internet
- Development of EO capabilities to reduce peak loads and reduce energy usage at the building

Partway through the project, an additional task was added, at no additional cost to the DOE, to demonstrate the successful interoperation of the NYSERDA/CALM-funded smart node building controller with the DOE project-funded DERMS system.

This successfully demonstrated end-to-end communication between utility-based control systems and a building controller, without the need for an intermediate data center, in full compliance with all relevant cyber-security specifications and standards. This additional demonstration highlights a new proven capability for direct interaction between utilities and customers that exceeded the DOE original scope of work.

A.11.3 Project Activities

The initial project proposal to the DOE and the hypothesis of the SGDP activities were to collaborate with the recipient and sub-recipients to develop and demonstrate a novel approach to utility operations that included, detection of predicted anomalies, analysis leading to optimized recommendations for surgically scheduled initiation of DR. The planned methodology of lean sprints of software development commonly referred to as agile software development was performed by CALM Energy, making the execution of the ISM Decision Aid scope of work simpler to perform, with results outperforming expectations.

CALM's original plan was adjusted due to the replacement of Boeing with Siemens/TIBCO. As such, CALM's development actions were conducted independent of the DERMS platform.

A.11.4 Product Development and Technology Transfer

CALM Energy's participation in the SGDP advanced the development of two pieces of technology: The ISM Decision Aid platform, funded directly by this project, and the CALM EO building controller, funded by NYSERDA and CALM Energy, which were both demonstrated as a part of this project. The ISM Decision Aid Platform is a prototype. Certain features are readily available to be piloted in production, while other portions still need substantial development. The building energy controller is in prototype production at two buildings and is being sold to channel partners.

The CALM/NYSERDA-funded building controller development and demonstration is still on going with NYSERDA and is presently a product being sold to channel partners for monitoring and energy cost reductions within buildings. CALM anticipates DR to be an additional valuable functionality for buildings as the utility industry moves towards NIST standards of cyber-secure automated DR.

A.11.4.1 Modeling

(This section refers to the ISM Decision Aid and associated modeling.)

Model Description

The purpose of the ISM Decision Aid is to improve reliability by intelligently targeting DR both prior to an incident and as an incident unfolds. The model answers five questions:

1. *"What parts of Area Station, distribution feeders, and transmission system are predicted at risk of failure?"* where risk is calculated based on a learned forecasted load and a subsequent power flow analysis is performed leveraging an existing distribution feeder matrix-based power flow analysis, coupled with power flow analysis for every component within the Area Station, including sub-transmission.
2. *"What is the impact of a failure?"* where impact is the failure triggering overloads and failures in other parts of the network and area station. Additional simulations are performed for 1st contingency analysis for every component within the Area Station and every distribution feeder fed from this area station.
3. *"What demand reduction is needed?"* at a level of detail down to the individual substation and distribution feeder and customer: exactly where, when, and by how much should demand be reduced, in order to mitigate the predicted risks associated with overloading?
4. *"How should I reduce demand?"* or, more specifically, which customers should I contact to automatically request DR? The model answers this question based on data about individual customer history and DR behavior when-called, aggregated to create a DR schedule that is likely to yield the required reduction in demand.
5. *"Am I getting the relief I asked for?"* or more specifically, what is the measured performance of the automated scheduled and initiated request to reduce demand on specific distribution feeders that are relieving the distribution feeder, Area Station or sub-transmission feeder or transmission system?

The model depends upon accurate data about the network itself (obtained from the utility's T&D model and integrated data communication architecture), upon individual and aggregate customer response data (obtained via learning from records of past curtailment requests and customer response).

Performance Criteria

The model is performant to the extent that:

- Model predictions of network load track actual data obtained from metering and monitoring gear,
- Model predictions of failure impacts track actual failures, when run using historical data,
- Model predictions of customer response to DR requests track actual response, when run using historical data.
- Model-recommended reductions in load translate, in practice, into reduced number of overloads and reduced tendency of failures to propagate into catastrophic network outages.

Testing Results

Validation occurred through repeated simulations of identical model states and data indicating consistent output results. Validation also occurred through verification of similar results through hand calculations and use of Excel spreadsheet models. It was initially intended to demonstrate model performance criteria over three years of operational testing upon integration.

Model Theory

1. For forecasting Area Station load, the model uses historical data from weather, station loads, and sparse AMI loads. The algorithm uses a proprietary learning technique to predict station load based on updated weather forecasts and learned experience.
2. For power flow analysis, the model uses a combination of existing PVL matrix-based power flow analysis with CALM's proprietary power flow analysis to determine, based on predicted station load and feeder loading, what will be the loading at any point in the area substation.
3. For simulations of contingencies, the model uses the same power flow analysis above with modified station configurations.
4. For analysis of specific component failures within a station, the model simulates the relay protection scheme of breaker isolation through a rules-based engine, which then triggers a power flow analysis using shifted load analysis obtained from Con Edison's PVL matrix- based power flow for distribution feeders. The model uses this shifted power flow analysis to determine predicted overloads in distribution feeders.
5. The system uses a tracing algorithm to identify, for every predicted overloaded distribution feeder, all potential DR scenarios. The model uses a superposition analysis of the five closest loads to any distribution feeder transformer, which is then amalgamated for potential scheduling of load curtailment. The model then analyzes and compares potential response scenarios using a rules-based approach, with data derived from observed customer and network response to past calls for DR. From this analysis, the operator is provided with a suggested schedule of load curtailment based on a genetic optimization algorithm, where the operator can accept these suggestions or dial in other values of scheduled curtailment.

For the Smart Node Building Controller, our methods of energy optimization through models are proprietary information outside the scope of this project.

A Functionality and Operations User Guide has been provided for the ISM Decision Aid. No such manual exists at this time for the Smart Node building controller as the project is still ongoing.